Doctoral Dissertation
Doctoral Program in Energy Enginering (32.th cycle)

Physical and Economic Impacts of Increasing the Integration of EU Electricity Systems from the Network Operation and Market Perspective

Shaghayegh Zalzar
* * * * * *

Supervisor
Prof. Ettore Francesco Bompard

Doctoral Examination Committee:
Prof. Z. Lukszo, Referee, Delft University of Technology
Prof. M. Marzband, Referee, Northumbria University

Politecnico di Torino
January, 2020

I hereby declare that, the contents and organisation of this dissertation constitute my own original work and does not compromise in any way the rights of third parties, including those relating to the security of personal data.

. . . .

Shaghayegh Zalzar
Turin, January, 2020

Summary

Electricity system of the European countries are strongly interconnected via high-voltage AC and DC interconnections. This feature provides an opportunity for the national/regional market operators, as well as the system operators, to strengthen their coordination and collaboration on managing the electricity system in Europe-wide scale, with the aim of enhancing energy security, sustainability, and affordability. European countries have already established some degree of regional cooperation in market, reserve provision, resource adequacy, risk preparedness and security analysis levels. Enhancing cooperation among the countries necessitates the increase of physical integration among regions and harmonization of the national and regional regulations.

The present thesis aims at investigating the potential impacts of enhancing the integration among the European electricity systems from market operation and network management perspectives. In particular, this thesis focuses on three main integration scenarios in Europe, already planned by the European Commission, as:

1. Enhancing the integration of the Baltic States to the EU electricity systems, following their joining to the Union.

2. Integrating electricity markets in Europe, towards establishing a single Europe-wide day-ahead and intraday electricity market.

3. Enhancing cooperation among the neighbouring countries in preparing risk preparedness plans, to manage abnormal situations more efficiently.

The above scenarios are investigated individually in this thesis, in three chapters (Chapter 3-5). Accordingly, the main contributions of this thesis can be listed as follows:

1. Developing a Europe-wide integrated market analysis tool, covering 34 European countries and in line with the EU target model, with the following specifications:

    - Zonal pricing approach with one or several market zones per country;

- Network-constrained market model with implicit allocation of inter-zonal network capacities;
- Auction-based intraday market modelling;
- Monte-Carlo stochastic optimization approach, taking into account the uncertainty of wind/solar production and load, due to the day-ahead forecast errors;
- Co-optimization of energy and operating reserves' provision, including FCR and FRR reserves, according to the current European regulations regarding reserve provision in different synchronous areas;
- Modelling market participation of hydro pumped-storage technologies, with the ability to generalize the model to other storage technologies, as well as demand response programs.

2. Developing a decision-making algorithm for risk preparedness planning in multi-regional level, with network and security constraints.

3. Proposing a multi-regional assisted rotational load shedding approach for managing crisis in interconnected regions.

In what follows, the research questions which are dealt with in this thesis are briefly elaborated.

- Which Baltic-EU synchronization scheme is the best option from market perspective?

Baltic de-synchronization from Russia and synchronization to EU electricity system has been assessed by comparing three prospective scenarios, proposed by ENTSO-S: i) Baltic synchronization to Nordic countries via Estonia-Finland interconnection; ii) Baltic synchronization to continental Europe via Lithuania-Poland interconnection; and iii) autonomous synchronous operation of the Baltic States. The scenarios are modelled through market participation of the Baltic countries in a Europe-wide integrated day-ahead market model, followed by a national redispatch market within each Baltic State to manage the potential transmission network constraints. To do so, the model applies the detailed transmission network model of the Baltic power system and the zonal model of the EU power system, connected through inter-zonal transmission capacities, in 2030. Comparing the results of the three scenarios led us to the key conclusion that Baltic synchronization with the Continental European Network is the most preferred option form market performance perspective, resulting in the highest generation surplus, lowest redispatch cost, and adequate reserve capacity within the Baltics. This outcome, even if driven from different results, is in line with previous technical analyses.

- What is the impact of integrating European adjustment markets under high share of renewables?

While the European integrated day-ahead market model has been widely studied, there are still many open questions about the potential impacts of integrating intraday markets. In this thesis, the current option of regional intraday market has been compared with the option of an integrated Europe-wide one, with reference to three European test cases, including the Iberian market, the Italian market, and the German market. The integrated intra-day market is modelled through stochastic Monte-Carlo optimization approach, considering the uncertainty of wind/solar production and electricity demand. The simulation results for a market scenario of 2030 led us to the following key findings:

- Intraday market integration reduces the surplus of conventional generator companies, while providing economic benefits for the customers.
- Integrating electricity markets in Europe, together with market participation of hydro pumped-storage generators, succeeds in converging day-ahead and intraday market prices, as well as diminishing RES curtailment in the market.
- Network expansion increases the total generators' surplus within Europe, while it reduces the total operation cost of the system.
- Flexibility provided by hydro pumped storage units reduces the potential benefits of market integration on market performance. Due to the fact that there are other novel flexibility options to support system operation under high penetration of renewables, e.g. demand response programs, a more rigorous cost-benefit analysis is strongly recommended to assess the economic justification of intraday market integration.

- What are the potential benefits of increasing cooperation among countries to manage abnormal situation?

Currently, European countries implement national rules for preventing, preparing for, and managing crisis situations and behave very differently under crisis circumstance. However, the recent European Commission's proposal on risk preparedness in the electricity sector sets out how member states should cooperate to prevent and manage crisis situations, while ensuring that even under crisis, the electricity is delivered where it is most needed. This thesis provides a mathematical model for analysing the impact of crisis in one region, within an interconnected multi-regional system, under different levels of cooperation among the regions. The model is formulated as a decision making algorithm to manage crisis, aiming at continuous supply of protected demands and essential reliability services, i.e. reserves in this study, at minimum cost and with the least social impact on non-protected consumers. The simulation results on a 3-zone test case (IEEE RTS-96 system) led to the following key findings:

- Multi-regional cooperation among the interconnected regions to manage potential electricity crises operates effectively in continuous supply of sensitive loads and provision of reserves within the region under crisis.

- Rotational curtailment of the interruptible loads on different buses of the affected and supporting regions leads to reduction of interruption duration on each customer and minimizes the socio-economic impacts of crisis.

- The capability of the neighbouring regions to provide support to the affected region depends on both the available interconnection capacity and the initial state of the affected region in terms of being electricity exporter or importer. Furthermore, making wrong decisions in ceasing the support provision to the affected region, through preventing energy exports to this region, may lead to adverse results on the operation of the interconnected regions.

Acknowledgements

I would like to pay special thankfulness, warmth and appreciation to my supervisor, Prof. Ettore Bompard, who made my research successful and assisted me at every point to cherish my goal. I would also like to extend my deepest gratitude to Prof. Gianfranco Chicco for his constructive comments and warm encouragements during my PhD. My sincere gratitude also goes to the Department of Energy "Galileo Ferraris" in Politecnico di Torino for giving me this opportunity to carry out my PhD here and also for providing an excellent academic environment. I am deeply grateful to all the professors, researchers, staff, and PhD students of the Energy Department for their generous support during my PhD, with special thanks to Dr. Tao huang, and Dr. Andrea Mazza, for their delightful collaboration on parts of my thesis.

I am deeply grateful to the members of the Joint Research Center of the European Commission for their valuable advices and insightful comments on my thesis. Special thanks to Dr. Marcelo Masera and Dr. Arturs Purvins for their wonderful collaboration and for the opportunity I was given to conduct part of my research at the Joint Research Center in Petten, the Netherlands.

I owe my deepest gratitude to my beloved family, my mother and my brother Zavosh, for all their love and encouragement during these memorable and pleasant, though challenging period of doctoral studies. Last, but not the least, I am deeply indebted to my beloved husband, Arzhang, who always keeps me going. Without his guidance and support, this thesis would not have been possible. I want you to know that I am truly thankful for having you in my life and you are the reason of my smiles.

I would like to dedicate this thesis to the memory of my late father, Dr. Mehrnoush Zalzar whose endless love and memory always inspired me in my life.

Note

During my PhD, I collaborated with Joint Research Center (JRC) of the European Commission on the following projects:

1. *Integration of the Baltic States into the EU electricity system: A cost-benefit and geo-political energy security analysis. Project No: 2017.3516*

2. *Regional Smart Load Shedding Strategies (ReSLoS)*

Accordingly, a part of my PhD activities have been devoted to perform analysis for these projects which are not fully covered in the present thesis, due to confidentiality of the data and results, as well as copyright issues. However, both of these topics are discussed in chapters 3 and 5 of the thesis, respectively.

The study performed on the *integration of the Baltic States into the EU electricity system* have been also published as a monograph by the Publications Office of the European Union in 2017. This study was referred by the European Union in its Ten-Year Development Plan (TYNDP-2018) as one of the main feasibility analyses which supported the Union to identify the best option for Baltic-EU synchronization and to progress to synchronise the Baltic States' electricity networks with the continental European networks via Lithuania-Poland interconnection. As the detailed network model of the Baltic States and its neighbouring European countries have been used in this project, and due to the confidentiality of the data, the security analysis performed in this study is not presented in the thesis.

Contents

List of Tables

List of Figures

Chapter 1

Introduction

1.1 Aim of the research

The European Commission lunched the "Energy Union" strategy on 25 February 2015, with the aim of enhancing energy security, sustainability, affordability, and competitiveness, for the EU consumers [1]. To fulfil these objectives, Europe's energy system needs to go through fundamental transformation. However, currently there are some barriers in EU electricity system against the energy union's goals which are considered by the European commission as its energy policy priorities and are also the focus of this study.

One barrier against EU energy security is strong interconnection of part of EU electricity system to non-EU power systems which is considered by the commission as a threat against EU's energy security and independency. Baltic States, i.e. Estonia, Latvia, and Lithuania, joined the European Union in 2004, while their electricity network is still strongly interconnected and synchronized with the Integrated Unified Power system of IPS/UPS. Currently, Russian power system provides primary frequency response and ensures energy security within the Baltic region. However, after joining the European Commission in 2004, Baltic States are required to obey EU energy policies in terms of energy security, independency, and market regulations. Hence, Baltic desynchronization from IPS/UPS and integration into the European electricity market turn into an energy policy priority by the commission. The European Network of Electricity Transmission System Operators (ENTSO-E) have proposed three potential re-synchronization schemes for the Baltic power systems after desynchronizing from IPS/UPS system to be analysed [2]. As the starting point of assessing the impact of enhancing integration among European electricity systems, I analysed and compared the prospective Baltic-EU synchronization schemes by 2030 in terms of energy security and market performance within EU. The results of this analysis have been used as the basis for the rest of my studies.

European Union has adopted one of the most ambitious renewable energy policies with target of at least 32% share of renewables in the Union's gross final energy consumption by 2030 [3]. Electricity sector with high potential in adopting renewables plays a key role in achieving this energy target. The share of electricity produced by renewable energy sources in Europe is expected to exceed 50% by 2030. Relying on more renewable energy sources in electricity sector can also support EU to achieve its energy sustainability and security targets. Integration of renewable energy sources, more specifically wind and solar generators, into the electricity systems bring new operational challenges to the transmission and distribution system operators. Their variable and uncertain power production leads to the requirement of additional flexibility and fast-response reserve capacity within power systems. Large-scale renewable power plants connected to the transmission system, are usually installed in far distances from load centers which in turn could increase the transmission network congestion. Furthermore, their output power is uncontrollable and does not follow demand variations, which in turn increases the need for flexibility from demand side or the integration of storage technologies into the system. As stated by the commission in its new revised "Renewables energy directive (2018/2001)" it is needed to support the integration of renewable energy sources into the transmission and distribution grid and the use of energy storage technologies to integrate variable production of energy from these sources [3].

Maintaining continuous balance of electricity supply and demand, as well as preserving network constraints, is under the responsibility of the transmission system operator. However, in strongly interconnected power systems like the European one, transmission system operators can share their resources to increase total system flexibility and reduce net imbalances. This is efficiently applicable through coupling their electricity markets, which is the main platform for energy transactions in restructured power systems.

EU rules have to be updated in order to facilitate integration of more renewable generators into the grid. Electricity market designs need to be modified accordingly to attract more investments on renewable and storage technologies. To address this issue, on 30 November 2016, the European commission presented a legislative proposal for regulating the European internal electricity market, as part of a comprehensive legislative package on the energy union. The main purpose of the proposed regulation is to make the electricity market fit for more flexibility, de-carbonization, and innovation [4]. The proposal sets out rules for integrating day-ahead and intraday electricity markets in Europe to be managed jointly by transmission system operators and nominated electricity market operators. The idea is to allow free transaction and flow of electricity across the borders which leads to maximum efficiency and competitiveness. I modelled the Europe-wide integrated day-ahead and intraday market, in 2030, with predicted installed capacity of different renewable/non-renewable technologies to meet EU 2030 renewable target. The model follows general EU market clearing rules and is based on the

EU target model for market integration. The developed market modelling tool is used to analyze the quantitative impact of Europe-wide market integration, in both day-ahead and intraday markets, on market performance within each country.

Another concern of the new EU legislation is the security of electricity supply and enhancing the cooperation among member states in performing risk preparedness tasks. The new "Risk Preparedness Regulation" enforces all member states to prepare plans to deal with all potential prospective electricity crises and undertake appropriate tools to prevent, prepare for, and manage these situations [1]. Previous experiences show that the response of member states to potential crises tend to focus on national level, neglecting the cross-border impact of crises and even exacerbating the problems in some cases by undermining the functioning of the market. Therefore, in the new regulation the member states are asked to use common methods to identify national and regional electricity crisis scenarios and prepare risk preparedness plans accordingly. The proposed risk preparation plan also establishes new framework monitoring the security of electricity supply more systematically, via the Electricity Coordination Group. In summary, the new rules aim at maximizing the preparedness of electricity systems in Europe against electricity crises and enhance efficiency of crisis management, while ensuring that markets continuo to function as long as possible. Accordingly, in this study a regional cooperation plan is proposed to be used for mutual support among neighboring countries to manage crisis, based on implementing circular load shedding within the region. The problem is formulated as a decision-making algorithm to be implemented by a Regional Coordination Entity. The main objective is to perform efficient regional actions to ensure continuous supply of reliability services within the region, taking into account inter/intra zonal network constraints and the security of supply within the region.

1.2 Novelty and technical contribution

In this thesis, a network-constrained market modelling tool has been developed which models the Europe-wide integrated day-ahead and intraday markets with hourly time intervals, for the year 2030. To the best of our knowledge, there is no similar model in the literature to provide a comprehensive and numerical analysis on the impact of EU decisions on market performance within each country. Hence, to fill this research gap, the present study intends to shed light on the impact of Europe-wide market integration, in both day-ahead and intraday levels, on market performance in terms of total generation cost, market clearing prices, generators' surplus, total cost to load, and renewable energy curtailment/ renewable hosting.

The model assumes day-ahead hourly consumption and renewable production based on the time series historical data related to the individual market zones, and takes into account the day-ahead prediction error of wind/solar production and demand to be re-balanced in the intraday market. The Europe-wide market model, covering 34 European countries, follows EU market rules and the Commission's target model. Accordingly, the integrated intraday market model follows an auction-based market design with implicit allocation of inter-zonal network capacities. It is assumed that the continuous energy trading is only allowed after the closure of individual intraday auctions and on the remained inter-zonal network capacities. The system's security constraint is modelled by provision of Frequency Containment Reserve (FCR) and Frequency Restoration Reserve (FRR) within each country, according to the European operation rules corresponding to sharing of reserves within each synchronous area.

The developed network and market modelling tool can be used to assess the market impacts of different EU energy policies, both in EU level and on the individual countries' level. For instance, this tool has been used to analyse the impact of Baltic States' desynchronization from Russia, followed by different re-synchronization schemes to Europe, from market operation perspective. Furthermore, the tool has been used in this thesis to analyse the role of market participation of large-scale storage technologies (hydro pumped-storage generators) on day-ahead and intraday market performance. Finally, the impact of releasing inter-zonal network congestion through enhancing transmission network infrastructures has been assessed, using the developed EU market modelling tool.

Another contribution of this thesis is to propose and formulate a rotational load shedding algorithm for mutual support of integrated power systems to manage abnormal situation. The proposed algorithm aims at enhancing regional cooperation of interconnected European power systems to achieve an efficient risk preparedness plan with lowest socio-economic impact on the customers. Furthermore, the model is expanded to perform regional (N-1) security analysis to ensure the provision of operating reserves following the occurrence of abnormal situation within one/more countries. The simulation results on a 3-region standard test case (IEEE RTS-96) implies on the effectiveness of regional coordination in interconnected countries to manage the crisis situation and prevent loss of reliability services or in worst case, a complete blackout within the affected region.

1.3 Focus and methodology

In summary, this thesis intends to address the impact of evolving scenarios and policies in the European electricity system, regarding enhancing the integration among interconnected European countries in network management and market operation perspectives. In particular, three recent scenarios, targeted by the European commission, have been addressed in this thesis:

1. Strengthening the interconnection of Baltic Region into the European power system

2. Harmonizing market rules within Europe and integrating day-ahead and intraday electricity markets

3. Enhancing the coordination among system operators of the interconnected countries to perform competent risk preparedness plans

To address each of the above issues, the following methodologies have been implemented:

1.3.1 Enhancing Baltic-Europe interconnections

This issue is addressed by decoupling Baltic countries from IPS/UPS system, constructing new transmission capacity between Baltics and Europe, and finally synchronizing Baltic power systems to a European synchronous area. Enhancing the interconnection capacity between Baltic countries and Europe will improve the energy security and market competitiveness within the region. The research question is that which prospective Baltic-Europe synchronization scheme should be taken as the most efficient option. There are three possible Baltic-Europe synchronization schemes, proposed by ENTSO-E, as follows [2]:

i. Synchronous operation of Baltic states with Continental Europian network, through Lithuania-Poland HVAC interconnection, along with the soft coupling supported by the existing HVDC links;

ii. Synchronous operation of Baltic states with Nordic countries, through Estonia-Finland HVAC interconnection, along with the soft coupling supported by the existing HVDC links;

iii. Autonomous Synchronous operation of Baltic States, along with the soft coupling supported by the existing HVDC links;

To answer the above research question regarding optimum Baltic-Europe synchronization scheme, integration of the Baltic countries to the Europe-wide integrated day-ahead electricity market under each of these three schemes have been modelled and analyzed. The difference of market results among the schemes is resulted by: 1) different available generation capacity to participate in the market, because of different reserve capacity requirements under each synchronization scheme; and 2) different Available Transfer Capacity (ATC) of Baltics' interconnections, due to the Transmission Reliability Margin (TRM) capacity allocated for reserve sharing under each scheme.

The day-ahead market model follows zonal pricing, with implicit allocation of inter-zonal network capacities, while neglecting intra-zonal congestion. The transmission network model in the market follows ATC-based model which is widely used in Europe at present. Following the closure of the integrated day-ahead market, intra-zonal congestions are managed by the Transmission System Operators within each control area. In this study, a market-based re-dispatch mechanism is implemented for managing intra-zonal congestion within Estonia, Latvia, and Lithuania, under the three synchronization schemes. The results are compared in terms of wholesale electricity prices, generation surpluses, primary reserve adequacy, and re-dispatch costs.

1.3.2 Electricity market coupling across Europe

Day-ahead electricity markets are already integrated in many European countries, while intraday markets are usually performed in national or regional level. Currently there are different forms of intraday markets held within Europe, including auction-based or continuous markets and different number of auctions per day. However, with respect to the European Commission's target toward forming a single European electricity market, the market rules need to be harmonized within Europe.

In this regard, the present thesis provides an overview on the results of discussions among the Commission and European TSOs on the prospective intraday market design and cross-border transmission allocation [5]. The final is decided to be an auction-based intraday market model with implicit allocation of cross-zonal transmission capacities, followed by continuous markets on theavailable and remained cross-zonal capacities. The Europe-wide day-ahead and intraday markets are formulated as Mixed Integer Linear Program (MILP). The integrated market model covers 34 European countries, considering a single market zone per country with the exception of Denmark (2 zones), Italy (6 zones), Norway (3 zones), and Sweden (4 zones). The day-ahead market is modelled as a deterministic optimization with predicted data of wind/solar generation and demand by 2030 (based on the time series of the historical data within each country) with hourly market time units. The day-ahead market results of each day are used as the input data of the auction-based intraday market model. The intraday market is modelled as a scenario-based stochastic optimization with Monte-Carlo simulation approach, consideration the uncertainty of wind/solar production and demand. The uncertainty of the stochastic variables corresponds to their day-ahead prediction errors which should be balance in the intraday market.

Intra-zonal transmission allocation is performed implicitly within the electricity market. In this study we implement ATC-based network model, with bi-directional interconnection capacity data, corresponding to different export and import ATCs. Five synchronous areas are considered among the 34 European countries in the model: (i) Continental Europe, (ii) Nordic countries, (iii) Great Britain, (iv) Ireland, and (v) Cyprus. With respect to the results of the first analysis on Baltic-Europe synchronization Schemes (section 1.3.1), Baltic States are assumed to join the Continental European synchronous area by 2030. The FCR and FRR reserve capacities within each market zone are calculated according to the corresponding European operational regulations regarding the provision and sharing of reserves within each synchronous area. The market model allows for simultaneous optimization of energy and reserves in all market zones, considering regional reserve requirements as the optimization constraints. Although currently energy and operating reserves are procured separately in European power systems, provision of reserve affects bidding strategy of generators and generation schedules within the energy market. The co-optimization model can tackle the bidding strategy of conventional and hydro power plants in energy market taking into account their opportunity cost by participating in reserve market, also in a simplified manner. Furthermore, the behavior of traders that can freely participate in both energy and reserve markets and arbitrage price difference between these markets will be implicitly considered into the model.

As day-ahead markets are already integrated, this study focuses on the impact of Europe-wide intraday market integration on market performance within different market zones. Accordingly, the intraday market performance, before and after integration, are compared in terms of the expected value of the intraday market prices, generators' surplus, cost to load, and wind/solar energy curtailment, over 8760 hourly time intervals of 2030.

1.3.3 Developing coordinated risk-preparedness plans in Europe

This issue is addressed by proposing a decision-making algorithm to be used by a Regional Coordination Entity for managing abnormal situation within an interconnection electricity system, with the aim of preserving system reliability and preventing the evolution of the arisen crisis to a complete blackout. The proposed decision-making algorithm is formulated as an optimization problem based on Mixed Integer Linear Programming (MILP). The formulated optimization problem has been solved by CPLEX solver in GAMS.

The focus of this study is mainly on the abnormal situations with relatively extensive and long-lasting impact on power systems which can be usually predicted in short term before their occurrence, e.g. dry season, fuel shortage, and extreme weather condition. The basic idea is to share all the available resources within the interconnected area to supply the protected loads and reliability services within the affected and supporting countries and manage the abnormal situation before evolving into a real crisis or in the worst case into a blackout situation. To do so, load shedding on the less sensitive demands is utilized as the last resort to be activated when no other solutions to maintain the system operation within its stability and security margins are available. The abnormal situation is modelled by its gradual impact on the available generation capacities, hourly demand, and the availability of water for hydro-electric generators and pumped-storage units.

In this study, a multi-area circular/rotational load shedding agreement is proposed to provide mutual support among the interconnected countries within their risk-preparedness plans. Accordingly, three load categories are defined inside each country/area as: ① protected /sensitive loads with highest priority to be supplied, ② interruptible loads with lowest priority to be supplied, and ③ non-interruptible loads with supply priority between interruptible and protected loads. Following the occurrence of a severe abnormal situation which leads to shortage of available generation capacities, the decision-making algorithm starts with curtailing interruptible loads within all regions in a circular manner, taking into account the maximum duration of interruption on each customer per day. The reliability services in our model are defined as FCR and FRR reserves which should be provided quickly by synchronous generators or fast-response storage technologies. If interruptible loads are not adequate to preserve system reliability, the second resort is interruption of non-interruptible loads within the affected area (area under crisis) and then inside the interconnected supporting areas. Finally, as the last solution in the more severe cases, the algorithm starts with reducing the available FRR reserve capacity within the affected area to ensure FCR reserve and continuous supply of protected loads in all regions. To do so, the objective function of the optimization problem is defined as the minimization of the total operation cost of the system under crisis, where priority of different actions are defined by setting appropriate weighting/penalty factors added to the objective function.

In this thesis, we present two approaches for addressing the decision-making process under the abnormal situation. In the first approach, reserve capacity requirements within each area are assumed to be set according to the pre-defined regulations in European power systems. These reserve requirements are defined as hard constraints in the optimization algorithm. It is assumed that the (N-1) security analysis will be performed afterwards, within each area, by its corresponding TSO. This assumption is similar to the current case in most European countries in which TSOs are in charge of ensuring security within their own area individually. However, the second approach considers a more coordinated operation within the interconnected region, with free sharing of reserves and performing regional security analysis which leads to more efficient and feasible solutions.

Both approaches require detailed transmission network model within the interconnected areas, with all the technical limits of generators. Hence, due to the lack of real such data, the simulation is performed on a standard test case of modified IEEE RTS-98 system with three interconnected regions. The simulation results with/without performing the multi-area circular load shedding are compared.

1.4 Structure of the thesis

The remainder of this thesis is structured in the following way. Chapter 2 provides an introduction on the current state of the European interconnected power system in Europe, in terms of market operation, transmission network management, and security of supply. Then some of the evolving scenarios in the European power system and corresponding operational challenges are introduced. Finally, the potential impacts of enhancing integration among the European power systems, from market operation to network management, in order to solve the introduced operational challenges are presented.

Chapter 3 deals with the market impacts of Baltic States' desynchronization from Russia and different synchronization schemes to the EU electricity system, which is one of the prospective scenarios to increase integration among the European power systems. The simulation results propose the optimum Baltic-EU synchronization scheme form the perspective of the market performance within the Baltic States.

In Chapter 4, the impacts of integrating electricity markets across Europe, in day-ahead and intraday market levels, is examined. A Europe-wide integrated market model, containing 34 European countries, is presented based on the ENTSO-E predictions on generation mix within each market zone and the interconnection capacities, by 2030.

Chapter 5 proposes a multi-regional coordinated risk-preparedness plan to assess the impacts of increasing the cooperation among EU countries to manage crisis situation. The proposed model implements a rotational load shedding plan within the interconnected regions to reduce the socio-economic impacts of crisis on the affected region. Two crisis management algorithms are formulated based on the network-constrained and security-constrained approaches.

Finally, a summarized conclusion based on the studies performed in Chapters 3-5 of the thesis, followed by the suggestions for future works, are provided in Chapter 6.

Chapter 2

EU Transition in Power Sector

2.1 European interconnected power system: present state

Innovations in high voltage transmission technologies enabled electricity systems in Europe to take advantage of cross-border energy exchanges for supplying their local demand, instead of solely relying on their local generation sources [6]. Evolving over the 20th century, the European power system was tightly interconnected and hierarchically controlled and directed by monopolists. Cross-border electricity exchange was primarily based on bilateral contracts and not market-based trades. At that time and before the liberalization in electricity sector, the interconnectors among Member States were mainly used for serving security of supply requirements and were developed to allow intra-area electricity trade through long-term contracts [7]. During the late 20th century, in the 1990s, energy sector's liberalization process started in Europe and electricity markets formed under various design principles [8]. Promoting cross-country electricity trade has become a major European energy policy issue [9].

Liberalization in European electricity markets has been coupled with privatization to enhance competition and reduce market prices for the electricity consumers [10]. After the first EU's liberalization directive was approved in 1996 and before the adoption of third EU Energy Package in 2009, the energy policies of EU were focused on creating the European Internal Energy Market (IEM). The establishment of IEM relies on the efficient coordination among national electricity markets, such that electricity can flow freely among Member States. Free cross-country electricity exchange in Europe requires adequate interconnection capacities, as well as efficient cross-border congestion management mechanisms [11]. Starting from 21st century, energy sustainability, security of supply, affordability to customers, and price competitiveness have become the new concerns and priorities of the European energy policy agenda [12]. The energy sustainability and environmental concerns have inspired Member states to promote the integration of renewable energy sources in their electricity system. However, the electricity networks in Europe are mostly designed in consideration of the location and capacity of the installed conventional power plants. Hence, currently a large share of energy produced by renewable generators, particularly from wind and solar generators, does not match with the network architecture [7]. To cope with the growing penetration of renewables, in addition to the internal network infrastructure, the interconnectors are key components to create new electricity corridors connecting the areas with excess production to the areas of energy scarcity. Accordingly, the European Council in 2014 subscribed the Commission's proposal to extend the present 10% interconnection enhancement objective to 15% [7].

2.1.1 Electricity markets

Generally, electricity can be traded in organized electricity markets, called power exchanges, or through bilateral over the counter contracts. There are different markets for trading electricity in Europe in different time steps, from one/more year(s) before the delivery to (near) real-time markets [13]. The successive markets in Europe and the related network codes/guidelines are represented in Figure 2.1. According to the European Commission's implementing Regulations in [14], [13]:

- FCA (Forward Capacity Allocation Guideline) focuses on long-term transmission capacity markets with the aim of fostering the trades on transmission capacity rights;
- EBGL (Electricity Balancing Guideline) focuses on harmonizing balancing market arrangement including balancing market designs and imbalance settlement mechanisms;
- SOGL (System Operation Guideline) addresses the harmonization of reserves' regulations in terms of reserve categories, sizing, and activation strategies;
- CACM (Capacity Allocation and Congestion Management Guideline) is the key regulation outlining the design and integration of the day-ahead and intraday market.

Electricity can be traded several years before delivery, in forward markets. The trades in forward markets can be purely financial or with the physical delivery agreement. Forward markets can prolong up to one day before the delivery time. The main objective of these markets which are categorized as long-term markets is to reduce the risk of volatile prices in spot markets and allow hedging for market participants [13, 15–18].

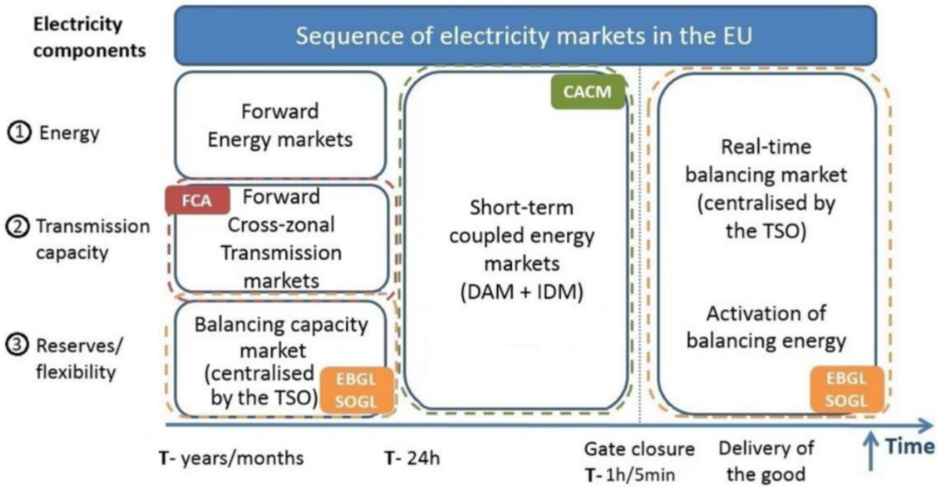

Figure 2.1: Sequence of EU electricity markets and corresponding network codes/guidelines [13] .

In competitive market environments, a significant share of the electricity production/ consumption is traded in short-term markets which are closed closer to delivery and are more transparent. Short term electricity markets include day-ahead, intraday, and real-time balancing markets [13]. Day-ahead market is a daily auction-based market, with hourly market time units. It is held one day before delivery for all the 24 hours of the following day. Every day, market participants provide their generation offers and/or consumption bids into the day-ahead Market Operator (MO), before market gate closure (usually at 12:00 CET). Following gate closure, the production/consumption orders are matched to maximize the social welfare, taking into account the simplified transmission network constraints [19], [20]. Currently day-ahead markets in Europe are mostly harmonized and integrated. The matching of orders in the integrated European day-ahead market is performed through a common algorithm called EUPHEMIA (EU + Pan-European Hybrid Electricity Market Integration Algorithm) [21].

Day-ahead market is cleared based on the prediction of producers/consumers on their hourly generation/demand during the next day (delivery day). However, after the gate closure of day-ahead market, producers and consumers are able to update their predictions and adjust their positions accordingly through the subsequent market, called intraday market. Growing penetration of variable renewable energy sources in Europe leads to increasing volumes of intraday trading, due to the high day-ahead forecast error of the power production by these generators [22], [23]. Intraday markets in Europe are held through two mechanisms: ① multi-session auctions (e.g. in Spain and Portugal), and ② continuous trading (e.g. in Belgium, France, and the Netherlands) [13]. Although the European Commission has set the target of integrating intraday markets in addition to the already integrated day-ahead markets, there are still open questions regarding the harmonization of market rules and the final design of the Europe-wide integrated intraday market [24].

Currently intraday markets are the last option for generators and consumers in Europe to trade electricity directly, through active market participation. After gate closure of the intraday market, the real-time deviations of market participants from their market schedules will be adjusted only by the TSO in so-called balancing market/mechanism. TSOs are responsible for ensuring continuous generation-demand balance in power systems is necessary to preserve system stability. Balancing can be provided through two markets corresponding to two products: ① market for balancing capacity, and ② market for balancing energy. Balancing capacity can be provided in markets held from one year up to one day before the delivery time. Currently, the exact timing of these markets is not harmonized in Europe. In balancing capacity market, producers/consumers are contracted for being available to deliver a certain amount of balancing energy in real-time. On the contrary, balancing energy market is held very close to real time, where producers/consumers participate by submitting the price they are willing to receive to adjust their energy production/consumption in real time. Producers/ consumers already contracted in balancing energy market are obliged to participate in this market. After the gate closure, the TSO activates the least-cost orders submitted to the market to rebalance system in real-time [13]. Harmonizing and integrating balancing markets in Europe is also the future plan of the European Commission [8].

2.1.2 Interrelation of market and network

Due to the limited capacity of transmission network, one important aspect of designing electricity markets is how to deal with the complexity of grid infrastructures and physical power flow model, when trading electricity. Generally, pricing mechanism in electricity markets can be divided into two categories, with respect to the network representation approach into the market model: ① nodal pricing, and ② zonal pricing. Nodal pricing is employed in the US and New Zealand, whereas European (short-term) electricity markets follow zonal pricing approach [25]. Under the nodal pricing approach, all the transmission network constraints are considered in the market clearing mechanism. All the market participants are cleared according to the locational prices of the node where they are located. Considering the detailed network model in the market clearing approach potentially leads to the most efficient generators' dispatch and the highest social welfare. Furthermore, the highly granular electricity prices under the nodal pricing approach provides more accurate locational signals for generation and network investment plans [26].

On the contrary, zonal pricing considers a simplified transmission network model into its market clearing process. Therefore, the results may be accompanied by some social welfare loss, compared to the nodal pricing approach [27]. In zonal pricing approach, transmission network nodes are aggregated into price zones (bidding zones) with uniform prices [25]. Bidding zone is defined by ENTSO-E as "*The largest geographical area within which market participants are able to exchange energy without capacity allocation*" [28]. The transmission network within each bidding zone is assumed to be a copper plate, i.e. physical network capacity is assumed as infinite. Bidding zones are connected through cross-zonal interconnectors which are equivalent transmission lines in a zonal network model. All the producers/consumers within a bidding zone are subject to the same unique market clearing price. However, the market price in adjacent bidding zones may diverge if the cross-zonal interconnector among them is fully utilized (congested). In summary, zonal pricing approach takes into account the inter-zonal network congestion, while neglecting the intra-zonal congestion. Hence, a proper congestion management approach would be needed to solve the potential intra-zonal congestions, following a zonal market clearing [8], [29]. From the other side, the unique market prices within each bidding zone is beneficial in terms of higher market liquidity, effectiveness, and transparency [30].

Proper design of bidding zones is crucial in zonal electricity markets, such as the case of the European short-term markets. TSOs are responsible to define zonal boundaries. Different zone boundaries impact the total social welfare in the market and the surplus of individual agents [31]. Traditionally, bidding zones are defined in consonance with the national borders [8], [30]. While most of the European countries still consist of a single bidding zone, several bidding zones in a country can also be found in some countries, including Norway, Sweden, Denmark, and Italy [32]. Current division of electricity markets' bidding zones in Europe is illustrated in Figure 2.2. The division of national borders into several bidding zones is applied based on the commonly observed congestions within the area which represent network bottlenecks [12], [33].

2.1.3 Transmission allocation and congestion management

The role of transmission networks in liberalized electricity systems has expanded to facilitate competition in electricity networks, in addition to providing a reliable path for transferring electricity from producers to consumers [35]. Traditionally, cross-border interconnections between European countries had been considered as back-up infrastructures to be used in critical situations. However, regarding the European Commission's goal to integrate the national European electricity markets and create a unique internal market in Europe, there has been a noticeable evolution in usage of cross-border interconnections [8].

In the Resolution of July 6th, 2000 of the European Parliament on the Commission's report about state of liberalization on energy markets, the commission is asked to provide conditions for using European electricity networks which do not

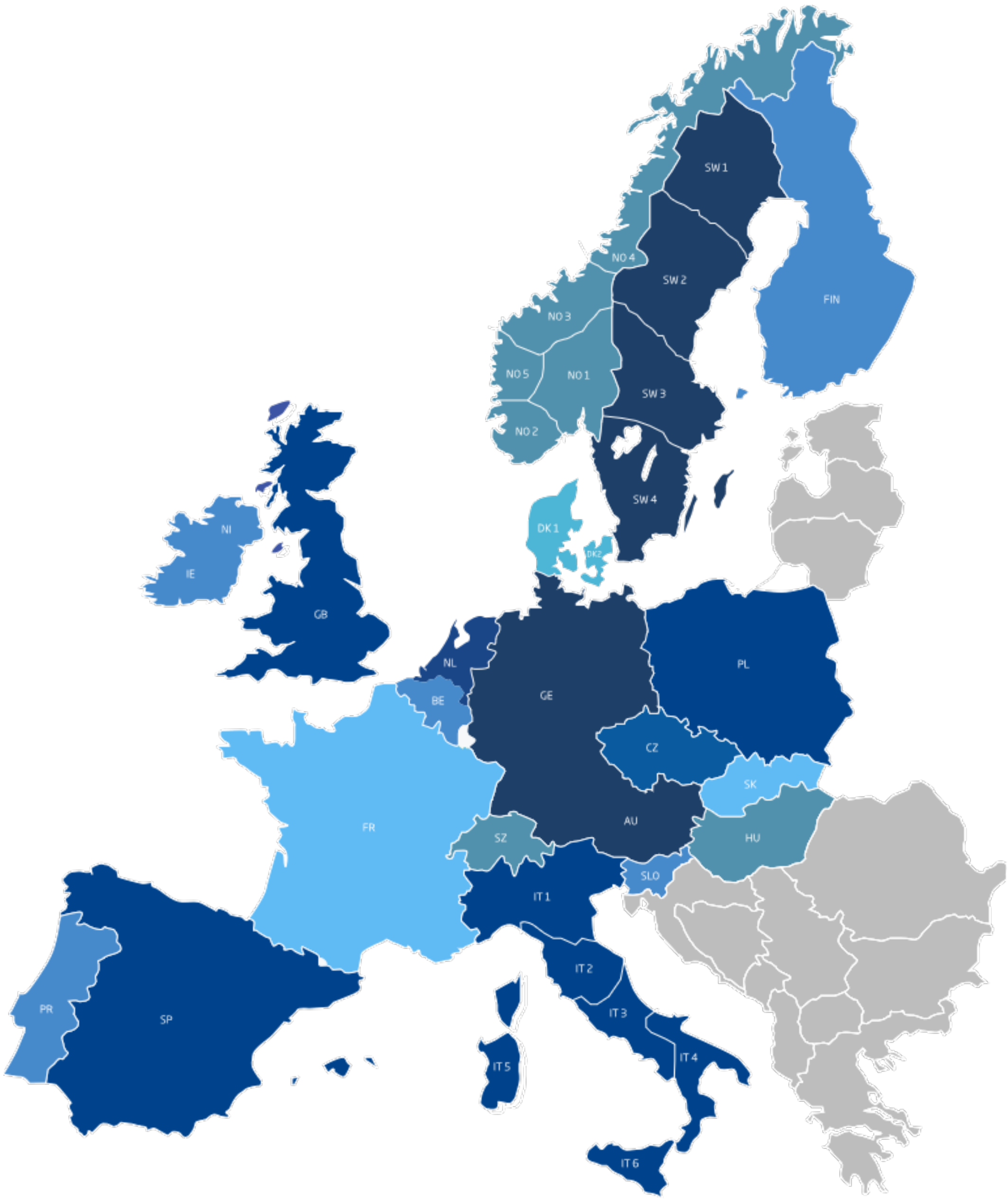

Figure 2.2: Bidding zones in Europe- 2018 [34].

hinder cross-border trade [36]. In a competitive electricity market, the available transfer capacities and the operational standards of the cross-border interconnections should be transparent for market participants. The transmission system operator should be compensated for the costs incurred by hosting cross-border power flows on their network and this cost should be paid by the national transmission system operators of the systems where those flows originated and where the flows end [36].

Approaching a fully integrated electricity market needs for further harmonizing the current capacity allocation rules and congestion management approaches in Europe. In integrated European electricity markets, cross-zonal congestion is managed differently form intra-zonal congestions. Inter-zonal or cross-zonal congestions are managed by a preventive approach through determining the available transfer capacities on each interconnection and allocating it to the market participants [8]. If the allocated inter-zonal transmission capacity between two market zones is fully utilized, the market clearing prices in the two interconnected zoned would be different. As the market clearing mechanism in European electricity markets does not take into account the full transmission network constraints and instead uses a simplified network model, there would be difference between market congestion conditions and physical network congestions. According to the definitions contained in Article 2 of Commission Regulation (EU) 2015/1222 of 24 July 2015, concerning establishing a guideline on capacity allocation and congestion management, 'market congestion' and 'physical congestion' are defined as follows [37]:

- **Market Congestion:** *"a situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints"*.
- **Physical Congestion:** *"any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system"*.

Market congestion and the associated economic loss is better described by the following illustrative example, representing a zonal market with two interconnected bidding zones (Zone A and Zone B). If there is no available transfer capacity on the interconnection between Zone A and Zone B, the electricity markets in each zone will be cleared independently and isolated from the other zone. The corresponding market clearing price (P^*) and quantity (Q^*) are determined by the intersection point of the aggregated demand and supply curves. Without loss of generality, in this example, demand is assumed to be inelastic with a vertical demand curve, implying on its price independency. Furthermore, a price cap equal to WtP^{max} is defined for both markets, to avoid large price spikes under generation scarcity. $W_{A/B}^{CON}$ and $W_{A/B}^{PROD}$ in Figure 2.3 represent the consumers' surplus and the producers' surplus in Zone A/B, respectively. The aggregated supply curves in Zone A and B ($S_{A/B}$) indicates that there are more cheap generation resources in Zone A compared to Zone B, such that although demand in higher in Zone A, still the market clearing price in this zone is lower than Zone B. form the price difference between the two market zones, one can conclude that if there was any available transfer capacity on the interconnection between the two zones, power would be exported from Zone A to Zone B, up to the point that either the price in both zoned would be equal or the interconnection would be fully used.

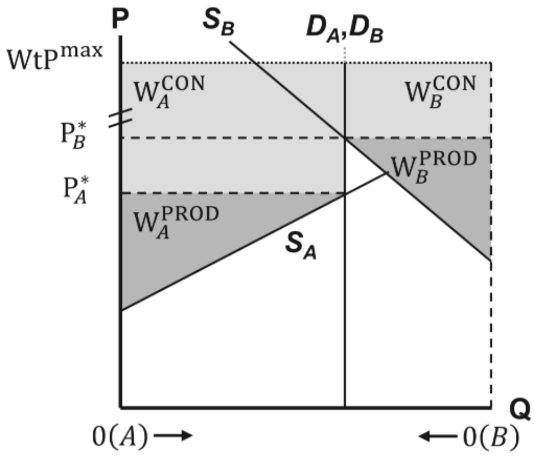

Figure 2.3: Welfares' distribution with no interconnection capacity [8].

Assuming a theoretically unlimited transfer capacity on the interconnection between Zone A and Zone B leads to the full integration of the electricity markets in two zones. Under this condition, the market clearing prices in two zones would be equal and the social welfare, e.g. the sum of producers' surplus and consumers' surplus, would be maximized. The distribution of the generators/consumers' surpluses in Zone A and Zone B are represented in Figure 2.4. The dark triangle in the right side of Figure 2.4, indicated by $W^{WG,MC}$, represents the additional social welfare which is resulted by the full integration of the two markets.

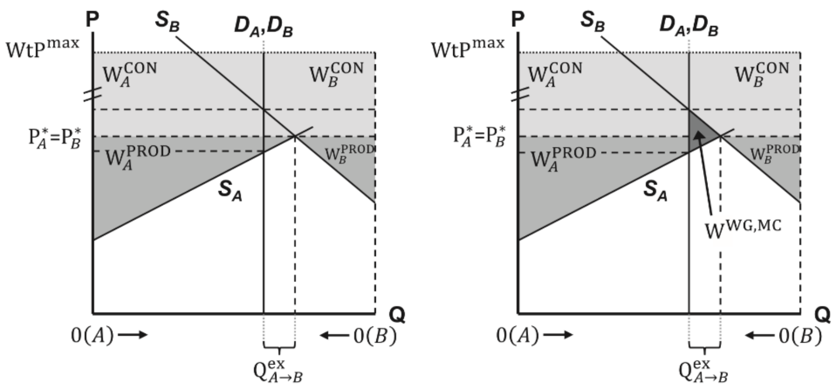

Figure 2.4: Welfares' distribution under unlimited interconnection capacity [8]

Finally, under a normal condition, where the interconnection between the two market zones has limited available capacity, it can get congested before full integration of the two markets. In this situation, transmission capacity would be insufficient to make price convergence in two zones and it has an economic value which is determined by the price difference between the two interconnected zones. The market clearing price and quantity, as well as the distribution of consumers'/producers' surplus under this situation is shown in Figure 2.5. The value of interconnection which is equal to the congestion rent is represented by the dark rectangle in left side of Figure 2.5 (indicated by W^{CR}). The holder of capacity right in this situation can use his/her right to arbitrage power between the two zones and make profit by buying power with lower price from Zone A and selling it with higher price in Zone B. Although under the scares interconnection capacity, the market cannot reach full integration with the highest social welfare, but still there is an additional welfare gain compared to the case of no cross-zonal power exchange. The welfare increment in this case is represented by the dark trapezoid on the right diagram in Figure 2.5.

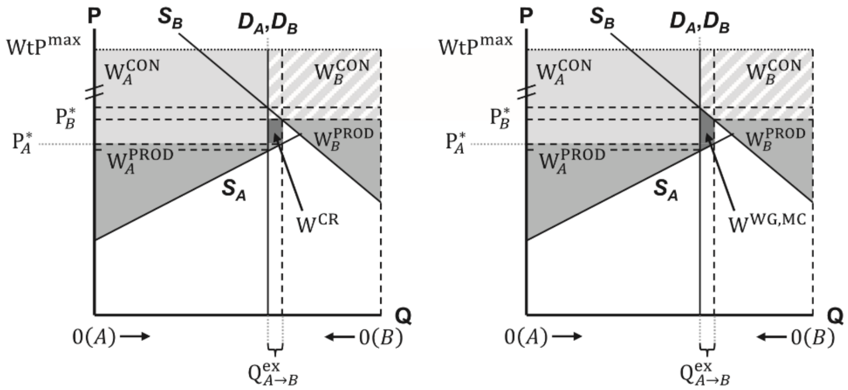

Figure 2.5: Welfares' distribution under scares interconnection capacity [8]

After the market is closed and generation/consumption schedules are sent back to the market participants, the TSOs are in charge of checking the physical power flows within their network and managing any potential physical congestion. The physical network congestions within each market zone would be managed in a corrective manner, through re-scheduling the available resources within that zone by the corresponding TSO.

2.1.3.1 Inter-zonal congestion management

The allocation of cross-zonal interconnections' capacities and congestion management for market-based inter-zonal trades in Europe is performed in two ways: 1) explicit auction, and 2) implicit auction. Explicit auction refers to trading the Available Transfer Capacities (ATCs) of each interconnection, in an auction separated from the energy trades. The ATC values are calculated and posted by interconnected TSOs for energy importing and exporting capability between two interconnected areas. Currently explicit auction is mainly performed for allocation of scarce interconnection resources in Europe. However, this approach is found to cause inefficient utilization of the transmission network due to the difficulties in anticipating the value of each interconnection for the market participants in advance, and also over/under allocation of interconnections' capacities when several interconnections are involved in a transactions [38]. The alternative solution is to perform implicit auctions for allocating transmission capacities, where the allocation of interconnection capacities are implicitly cleared in the energy market. Implicit auctions are the main approach for inter-zonal transmission allocation and congestion management in integrated European electricity markets [38].

From the other perspective, under the implicit allocation of cross-zonal interconnection capacities, the network model and the inter-zonal transmission constraints in the market mechanism can follow two approaches: ATC-based approach and flow-based approach. The ATC-based approach have been widely used Europe from the first stages of the market integration and is still under usage in some regions, including the Nordic electricity market. However, there is an ongoing trend towards employing the flow-based model in Europe, which is more complicated but also more efficient. Central Western European (CWE) market is currently using flow-based model [25].

The ATC-based approach considered transmission network as a transportation road in which market zones are connected through equivalent interconnectors with limited capacity. The equivalent transmission interconnectors are simply considered as transportation road, representing a given topology. Electricity is assumed to flow only through the predefined paths, i.e. the equivalent interconnections, while the only defined limit is the ATC of the interconnectors. The intra-zonal network constraint is ignored in market clearing process and is supposed to be managed afterwards, through a re-dispatch mechanism [21], [25]. The steps and timing of information exchange between market operator and market participants under the ATC-based approach is illustrated in Figure 2.6.

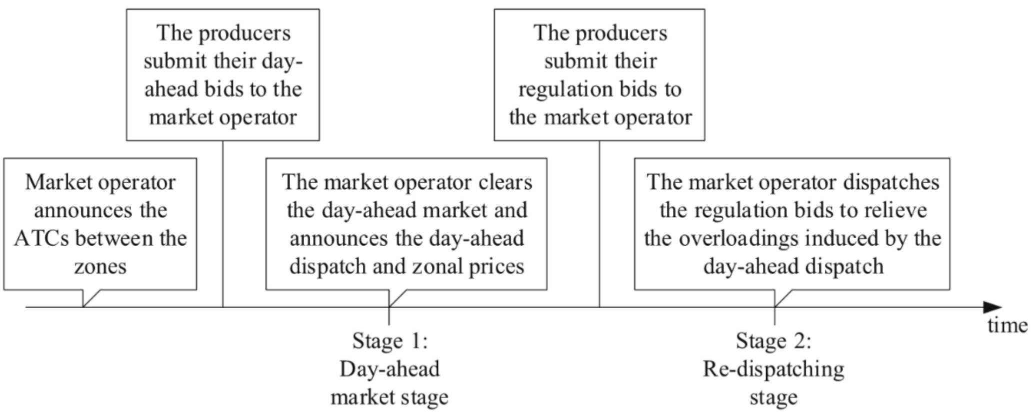

Figure 2.6: Steps of information exchange under ATC-based approach [25]

The flow-based approach is an alternative to the ATC-based approach for modelling inter-zonal transmission network in the European zonal markets, which leads to a more precise modelling of the physical flows [21]. The flow-based approach takes into account a set of network constraints, corresponding to a predefined set of critical transmission lines. These critical lines/branches represent the set of inter-zonal or intra-zonal lines which strongly impact the cross-border trades [25]. The market operator announces the set of critical branches (CBs) and their corresponding Remaining available Capacity (RAMs) with respect to its forecast on the cross-border trades, before market clearing. The market clearing mechanism models the simplified transmission network with the RAMs of the critical branches and a zonal Power Transfer Distribution Factor (PTDF) matrix which is a reduced version of the nodal PTDF matrix of the transmission network [21], [25]. Although this approach provides a better representation of the transmission network constraints, but it still requires a corrective intra-zonal congestion management as the critical lines/branches are selected before market clearing. The information exchange between market operator and market participants in zonal markets, under the flow-based approach, is illustrated in Figure 2.7

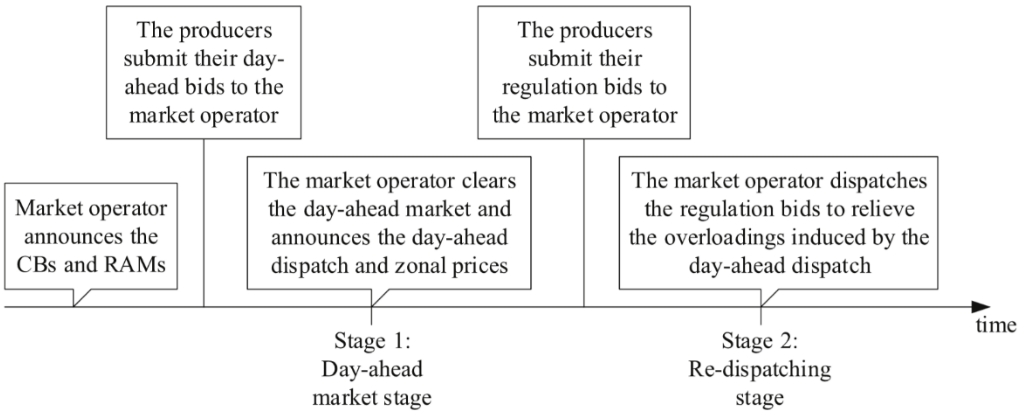

Figure 2.7: Steps of information exchange under flow-based approach [25]

2.1.3.2 Intra-zonal congestion management

The European zonal electricity markets implicitly perform inter-zonal congestion management, however neglect intra-zonal congestions. Although, in determining the ATC values of the cross-zonal interconnections, TSOs somehow take into account the intra-zonal congestions, uncertainty, and other externalities, such that the ATC values are beneath the aggregated physical line capacities [29]. Generally, in zonal electricity markets, due to the simplification of network model in the market clearing algorithm, market dispatch can be infeasible in terms of physical transmission network constraints. In this situation, a corrective congestion management approach in each market zone is taken by the corresponding TSO to find a feasible solution in a cost-efficient manner, typically through re-dispatching generators and loads [12], [39]. Other short-term solutions to perform corrective congestion management in transmission networks include changing the set-point of flexible transmission system devices, supplying reactive power support, and curtailing transactions [40, 41]. However, in the European electricity sector, re-dispatching is the most commonly used approach by the TSOs, to relieve transmission grid congestions [42]. In long-run, the system operators may also decide to invest on network infrastructure to enhance transfer capability and solve the structural network congestions.

Re-dispatching is defined by the European Commission, in its Regulation 543/ 2013, as "*A measure activated by one or several system operators by altering the generation and/or load pattern in order to change physical flows in the transmission system and relieve a physical congestion*" [43]. The number and proper configuration of bidding zones in the European zonal electricity markets has a remarkable impact on the occurrence of congestions and the need for re-dispatch [32], [44]. For instance, due to the frequent congestions in German power system and high cost of curative congestion management in this country, the splitting of the German market zone into several bidding zones and its impact on the reduction of re-dispatch costs have gained a recent research interest [29], [45].

After the integrated zonal electricity markets in Europe get cleared, the TSOs perform an ex-post analysis to check the feasibility of market dispatched within the bidding zones which are under their control. This analysis is typically performed by a power flow program on the detailed transmission network model of the system. If the analysis leads to any network congestion within a bidding zone, the corresponding TSO is in charge of solving it before occurrence, through re-dispatching. Re-dispatching is performed centrally, by the TSOs, usually through a market-oriented mechanism [42]. The TSOs can activate different types of re-dispatch orders, taking into account the related cost of each order and full network constraints. Re-dispatch orders may consist of an increase/decrease in the output power of conventional generators compared to the market dispatched, a decrease in the production of renewable generators (renewable energy curtailment), an increase/decrease in the consumption level of flexible demands, and a generation/consumption offer from storage technologies. The optimum re-dispatch solution is to find the least-cost set of orders which lead to a safe and secure grid operation which can be solved through Optimal Power Flow (OPF) or Security Constrained Optimal Power Flow (SCOPF) algorithms. SCOPF is the more general solution of the OPF in which additional constraints representing a set of post-contingency states is also taken into consideration. SCOPF is basically a non-linear, non-convex, optimization problem which is computationally complicated and difficult to solve for a large-scale electricity system [42].

2.1.4 Security of supply

Power system security is defined as the ability of the electric system to confront abrupt disturbances, such as unforeseen outage of system elements [46]. The traditional regulated and vertically integrated power systems tended to be more secure, mainly due to the integrated operation and planning of the generation and transmission assets, by monopolists. Hence, the generation and transmission expansion planning used to be in line with the load growth which in turn limited the overloading and equipment failures. Furthermore, maintenance programs were rigorous in vertically integrated power systems. Finally, generation and transmission systems were operating in a planned and cooperative manner. However, the restructuring of electric power industry and its evolution toward open markets has increased the potential sources of disturbances and insecurity in power systems [47].

The concept of security in electricity systems is strictly correlated with the definition and classification of system's operational states. An operational state refers to a specific situation of the transmission system which is characterized by its operational limits [48]. In general, system operation is defined by five states: Normal, Alert, Emergency, Blackout, and Restoration state. ENTSO-E defines operational security as the ability of a transmission system to remain in the normal state or to come back to a normal state quickly. Operational security in transmission system is characterized by thermal limits, voltage constraints, frequency limits, stability limits, and short circuit current [49]. In order to preserve operational security in transmission systems, TSOs apply remedial actions. A widely used criterion in assessing operational security in electricity systems is (N-1) criterion which is defined as the rule according which following the occurrence of a contingency within a control area, the remained operating elements within that are able to accommodate the new operational situation, without violating security limits [50]. Remedial actions contribute in fulfilling (N-1) criterion and preserving operational security limits. Furthermore, the TSOs determine the operational state of the systems according to (N-1) security assessment within their control area, taking into account the impact of neighbouring systems and the efficiency of remedial actions.

Accordingly, the operational states are defined in the ENTSO-E Network code on Operational Security [49] as follows:

- Normal State: "*the system state where the system is within operational security limits in the N-Situation*[1] *and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions*".

[1]N-Situation refers to a situation where none of the elements of the transmission system are unavailable as a result of a fault.

- Alert Stats: "*the system state where the system is within operational security limits, but a contingency from the contingency list has been detected, for which in case of occurrence, the available remedial actions are not sufficient to keep the Normal state*".

- Emergency State: "*the system state where operational security Limits are violated and at least one of the operational parameters is outside of the respective limits*".

- Blackout State: "*the system state where the operation of part or all of the transmission system is terminated*".

- Restoration State: "*the system state in which the objective of all activities in transmission system is to re-establish the system operation and maintain operational security after a Blackout*".

Operational state of a power system and the corresponding operation actions under each state are represented in Figure 2.8. Transmission systems are most of the time kept in normal or alert states by the TSOs.

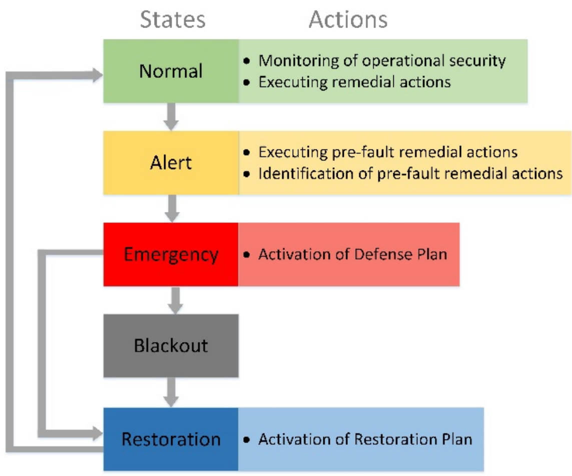

Figure 2.8: Operational states and corresponding actions in system operation

Security of supply in European transmission systems is inherently coupled with the efficient functioning of internal electricity market and network assets, together with the integration of the solitary electricity markets of the Member States [37]. In principal, security constraints are not directly considered in European electricity markets. Cross-zonal transfer capacity limits are the only means in the European electricity markets to ensure that trading decisions are technically feasible, implicitly considering and respecting the system security requirements. The selection of boundaries on the transfer capacity limits of a single cross-zonal interconnection can impact the security of supply in other bidding zones, not limited to the neighbouring zones [51]. Accordingly, besides market efficiency considerations, the system security aspects must be reflected in the assessment of the configuration of bidding zones in the market. On the contrary to the European markets, the U.S. day-ahead electricity markets, including PJM, NYISO, and ISO New England, initially perform a Security Constrained Unit Commitment (SCUC) with DC representation of the transmission network, along with the security constraints [52].

Ensuring security of supply in European electricity systems is intrinsically a local issue which is addressed by the TSOs independently or under some regional cross-border cooperation agreements [26]. However, defining a set of minimum requirements for EU-wide system operation and cross-border cooperation between TSOs is essential to assure the operational security of the interconnected European transmission system. While currently there are some voluntary regional cooperation initiatives among TSOs, the European Union in its Regulation (EC) NO 1485/2017 has admitted that establishing a formalised coordination among TSOs for operating the transmission system of the Union is necessary to address the revolution of the electricity market towards an integrated EU-wide one [50]. According to this regulation, participation of TSOs in regional security coordinators (RSCs) is supposed to become mandatory. The authorization of RSCs and their tasks intend to enhance the security of supply standards in Europe. In any case, the TSO remain responsible for preserving operational security within its control area. Ensuring operational security is considered as a major concern in operational and planning activities of the TSOs in different time frames. Figure 2.9 provides an overview on the activities of TSOs based on their timing, from real-time to long term time frames. However, this thesis focuses on the medium/short term TSOs' activities to preserve operational security. Within this time frame, the most import objective of the system operator is to guarantee a well-functioning electricity market, but not at the expense of losing security.

2.2 Evolving scenarios and emerging operational challenges

2.2.1 De-synchronization from non-European systems

Due to some historical reasons, currently the Baltic States are operated synchronously with the electricity system of Russia and Belorussia, called IPS/UPS[2] system. Russian power system provides the frequency regulation and primary reserve requirement of the power systems. Baltic power systems are members of

[2]Integrated Power System/Unified Power System

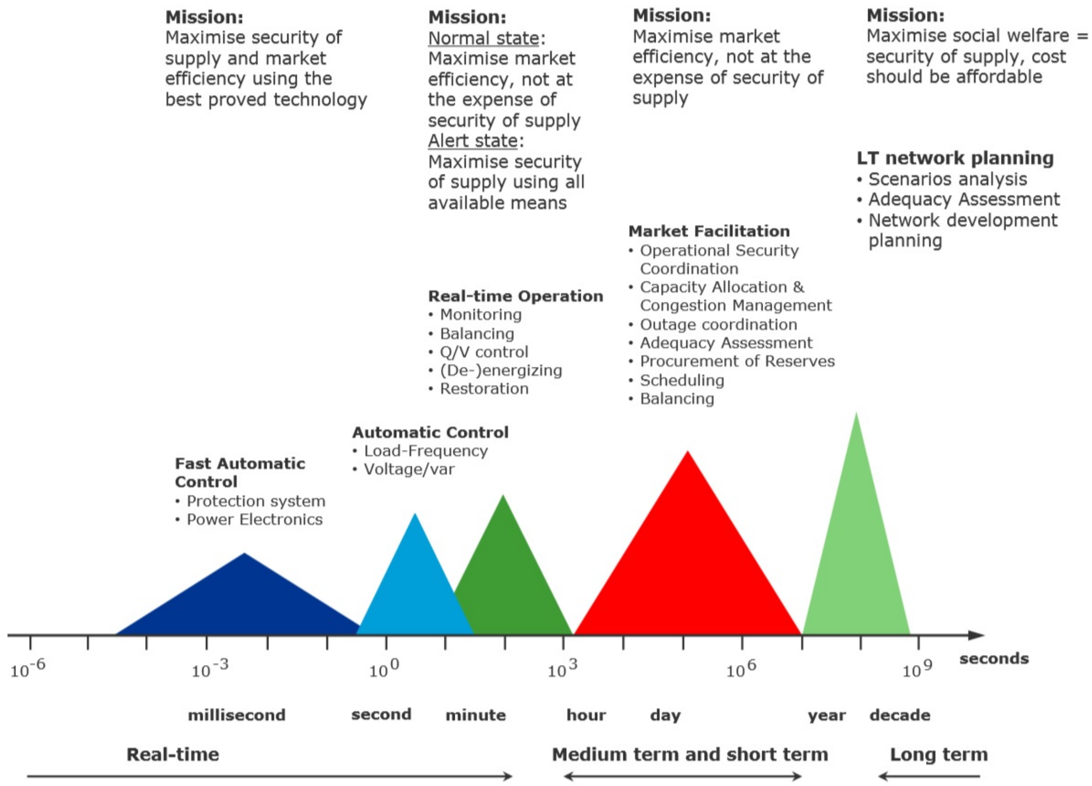

Figure 2.9: Timing of the TSO's operational and planning activities [48]

the BRELL electrical ring, involving Russia, Belarus, Estonia, Latvia, and Lithuania. The tightly interconnected electrical system of Baltic States with Russia and Belarus, through 330 kV AC transmission lines, have long been operated reliably and securely. In addition to the interconnections with Russian and Belarussian networks, the Baltic power systems are also asynchronously interconnected to the power system of Nordic countries and Continental Europe Figure 2.10. The interconnection to Nordic system is via the two HVDC links between Estonia and Finland (Estlink 1 and Estlink 2) and one link between Lithuania and Sweden (NordBalt). Also there is a double-circuit AC line with Back-to-Back DC power converter between Lithuania and Sweden (Litpol Link).

After Baltic States became members of the European Union in 2004, integration of Latvia, Lithuania, and Estonia into the common European energy market became the leading energy policy of the Union and the Baltic States. Finally in June 2007, prime minister of the Baltic States undersigned a communique which required the TSOs of the three countries to perform studies on strategic objective of integrating Estonia, Latvia, and Lithuania, into the common EU electricity market and on possible scenarios regarding synchronization of the Baltic States to the EU electricity system. The project of Baltic-EU synchronization is supported by the

European Commission and aligns with the Baltic States' objective towards enhancing electricity indecency. In January 2015, the energy ministers of the Baltic States signed the "Declaration on energy Security of Supply" which askes for: developing a fully functioning and competitive regional electricity market, planning and constructing required infrastructures, integration of electricity market, implementing the European Energy Security Strategy, and synchronization of the Baltic power system to the Continental European network [53]. Following the establishment of various cooperation contracts on desynchronization of Baltics form IPS/UPS system, the Baltic's TSOs conducted a number of feasibility analyses on Baltic –EU synchronization schemes, from the technical and economic perspectives. The finalized studies on this topic are summarized in Table 2.1.

Table 2.1: Finalized feasibility studies on Baltic synchronization schemes

Study/Research project	**Conducted by**	**Year**
Interconnection variants for the integration of the Baltic States to the EU internal electricity market1	Energy sector consultant Gothia Power and Baltic TSOs	2012-2013
Synchronisation roadmap	Baltic TSOs	2015
Large scale unit implementation in Baltic	Gothia Power and Litgrid	2015
Integration of the Baltic States into the EU electricity system: A technical and economic analysis	DG ENERGY/JRC	2015-2017
Study of isolated operation of the Baltic power system	Energy sector consultant Tractebel Engineering and Baltic TSOs	2017

The study conducted by the Joint research Center (JRC) of the European Commission, with collaboration of the Politecnico di Torino University, investigated different prospective interconnection scenarios for Baltic de-synchronization from IPS/UPS and re-synchronization to EU. The potential synchronization schemes of Baltic States in this study include: Baltic synchronization to the Continental European network through Lithuania-Poland interconnection, Baltic synchronization to Nordic electricity network through Estonia-Finland interconnection, and Baltic States asynchronous operation mode with soft coupling to EU through existing HVDC links [54]. According to this study, synchronous operation of the Baltic States with the Continental European Network has been identified as the best feasible scenario, from technical and economic perspectives.

Finally in June 2018, Jean-Claude Juncker as the President of the European Commission, and the heads of Governments of the three Baltic countries and

Figure 2.10: Power system of the Baltic States [53]

Poland, reached an agreement on the political roadmap of synchronizing the power grid of the Baltic States to the Continental European synchronous area, by 2025 [53].

2.2.2 Accelerated penetration of renewables

Historically, electricity generation in European countries without abundant hydro generation sources, have been dominated by fossil fuels. In recent years, the increasing integration of renewable energy sources into the electricity networks, along with the shutdown of several thermal power plants in response to the European environmental standards, the share of fossil fuels in the total electricity generation of European countries has reduced. In 2017, 34.1% of the total electricity consumption in Europe (ENTSO-E members) was supplied by renewable generation [55]. The share of renewables in total electricity consumption in each country is shown in Figure 2.11.

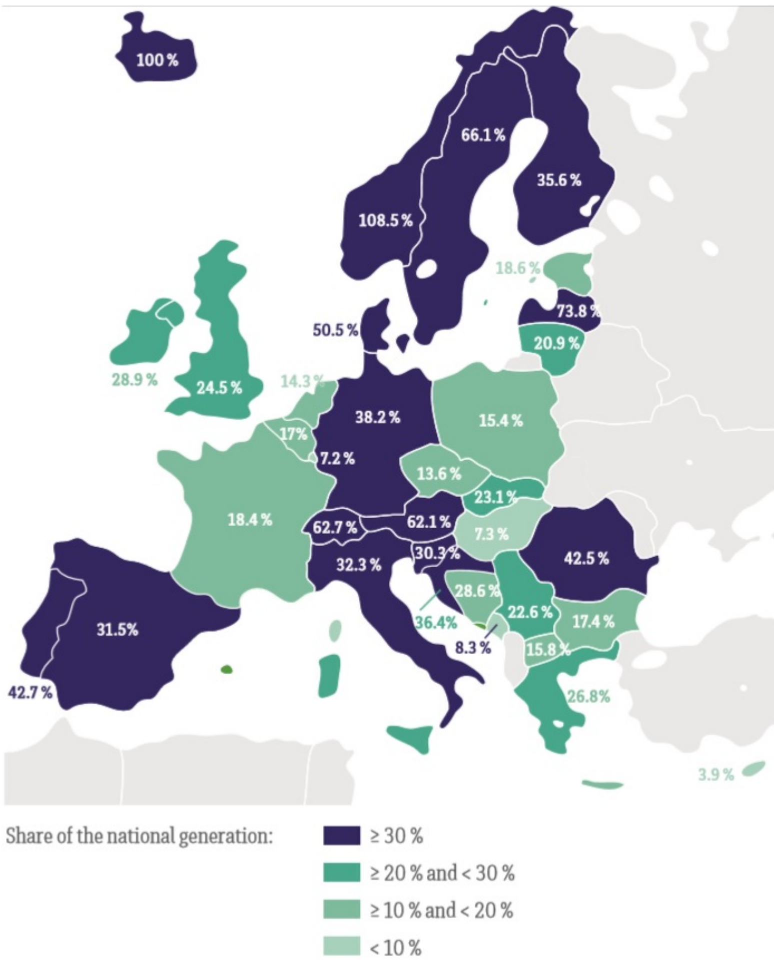

Figure 2.11: Share of renewable energy in total electricity consumption in Europe in 2017 [55]

The global renewable electricity capacity has almost doubled between 2005 and 2017. By 2017, renewables accounted for more than 70% of the added net global electricity generation capacity. The global growth rate of renewables is dominated by high investments on wind and solar electricity generators, accounting for more than 80% of the total investments on renewables [56]. EU plays the leading role in renewable electricity capacity per capita with 0.87 kW installed renewable capacity per person in 2017 [56]. According to the power statistics delivered by ENTSO-E's members, representing 43 electricity TSOs from 36 European countries, Net Generating Capacity (NGC)[3] of hydro power plants in Europe was almost stable from 2013 to 2017. However, NGC of non-hydro renewable energy sources, mainly wind and solar generators, increased by 44.4% in this period. The evolution of NGCs during the period 2013-2017, in ENTSO-E countries, is illustrated in Figure 2.12. In contrast to the rapid growth of renewable energy sources in Europe, generating capacity of fossil fuels and nuclear generators gradually decreased during the last years.

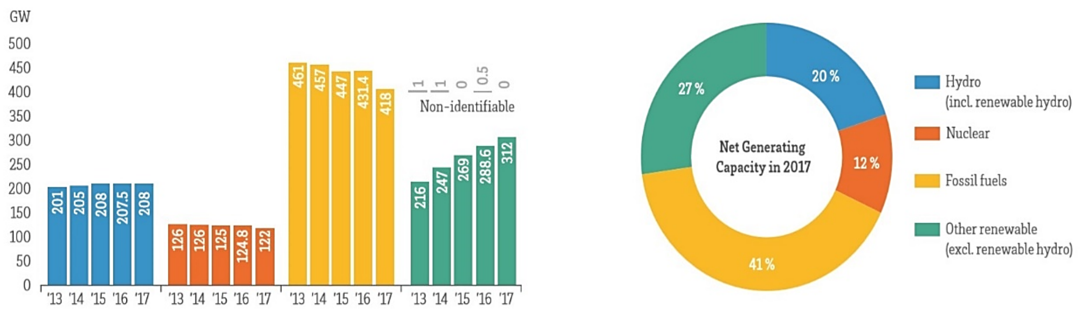

Figure 2.12: Evolution of net electricity generation capacity in Europe from 2013 to 2017 [55]

Share of electrical energy generated by wind and solar generators in the total national electricity generation inside European countries in 2017, are represented by Figure 2.13 and Figure 2.14.

Wind and solar generators belong to the category of Variable Renewable Energy (VRE) sources as they cannot produce energy around the clock which is their major disadvantage. The output power of wind and solar generators is weather-dependent, uncontrollable, and hardly predictable. The integration of VREs into the power systems increases the need for operational flexibility to cope with their variability and uncertainty at various time frames. In order to accommodate system integration of VREs while maintaining high security of supply standards, additional costs incur in the system, mainly for providing reserves and back-up generation capacities, the required investment costs for network expansion, network congestion costs, subsidy, and storage costs. These costs are known as VRE's system integration costs [57], [58]. Generally, integration costs can be divided into three cost components, each driven by a specific feature of VRE sources: "balancing costs" (driven by VRE's uncertainty), "grid-related costs" (driven by VRE's location), and "profile costs" (driven by VRE's variability) [59], [60]. Balancing costs occur due

[3] Net Generating Capacity of a power station is the maximum electrical net active power it can produce continuously throughout a long period of operation in normal conditions.

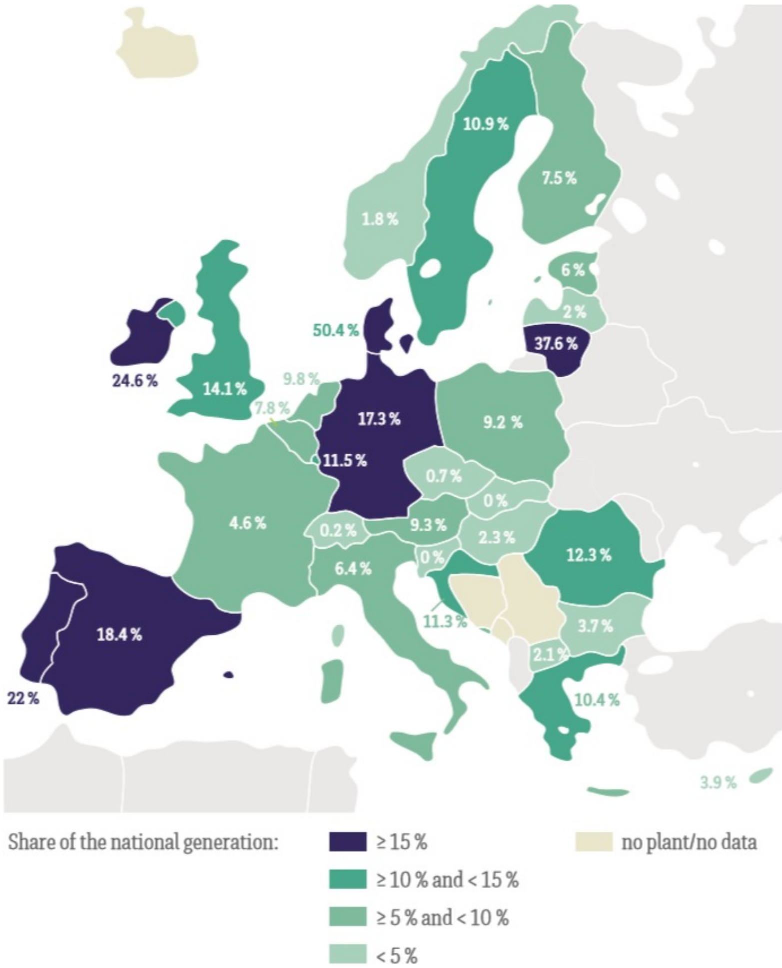

Figure 2.13: Share of wind energy in national electricity generation in Europe in 2017 [55]

to the uncertainty and forecast error of VRE production which leads to deviation from generation schedules and hence unscheduled adjustments and reserves from dispatchable generators. The grid-related costs emerge as VREs are mostly located in far distances from load centres and it leads to grid constraint and congestion management costs in short-term, but also requires large investment costs for network expansion in long/mid-term. Finally, profile cost occur due to the variability of VREs' production and the fact that output power of these generators does not follow the variations of load profiles. Therefore, in high VRE penetration levels, back-up capacities are required to cope with variability of these sources. From the other side, the full-load hours of dispatchable generators reduces, while these capital-intensive sources need to provide flexibility to the system through ramping up and down more often, leading to increased ramping and cycling costs. Numerous

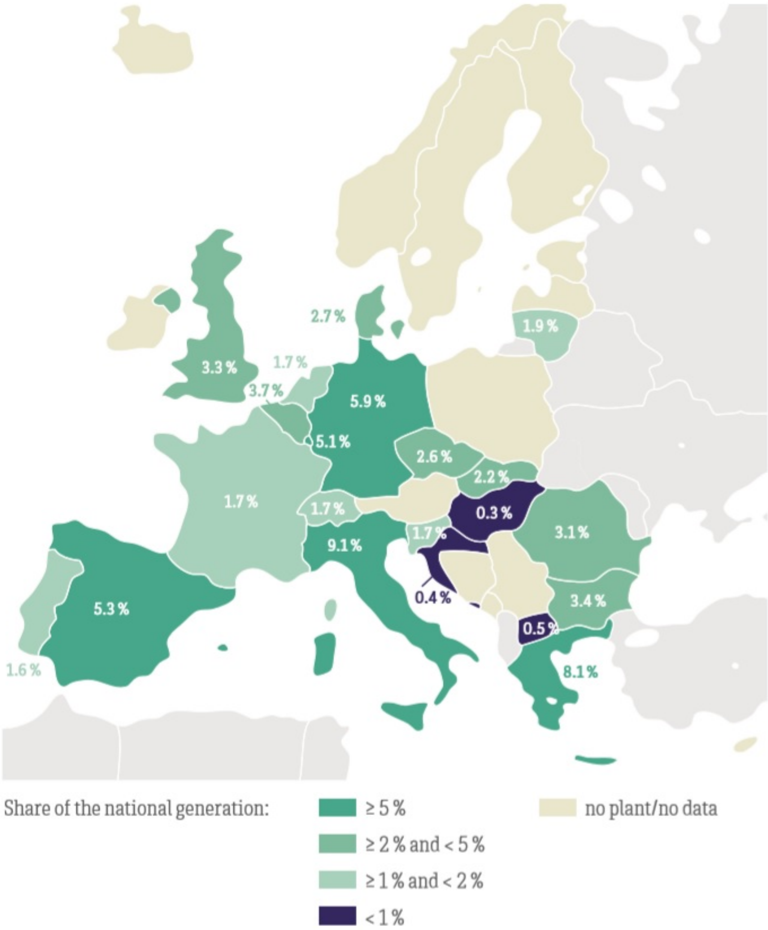

Figure 2.14: Share of solar energy in national electricity generation in Europe in 2017 [55]

studies have dealt with the integration costs of VREs [58–64].

Besides incurring system integration costs, VREs' characteristics lead to numerous operational challenges for system/market operators. The main difficulty of integrating VREs into the electricity systems arises from the fact that power systems were designed based on the concept of large and fully dispatchable electric generators, while the intermittent production of VREs disrupts the conventional techniques for planning the daily operation of the system. The output power fluctuations of VREs over various time horizons enforces the TSOs to adjust their day-ahead, intraday, and real-time operating procedures. Although the variability and uncertainty of VREs' production bring several challenges to the system operation, it is not impossible to cope with their characteristics and there are a number of strategies to overcome these challenges. As electrical energy is mainly traded in competitive electricity markets, an efficient strategy to facilitate VREs' network integration would be to modify market rules to cope with specific characteristics of these resources. Some of these market-related strategies are represented in Figure 2.16.

Many researchers have studied the impact of large-scale implementation of VRE technologies on power systems' operation and market performance, in recent years. Hasan et al. [65] analysed the stability of power system under significant penetration of renewables, taking into account the impact of their generation intermittency and variability on the grid. They provided a review on the existing approaches for power system stability analysis, including small/large disturbance angular stability, voltage stability, and frequency stability) and assessed the most widely used probabilistic computational techniques with the aim of finding the most appropriate method to be used for stability analysis in systems with significant VRE penetration. The concept of Real-Time Dispatchability (RTDA) of power systems with VRE generations have been introduced in [66] to investigate the feasibility of real-time dispatches from the perspective of uncertainties. RTDA indicates, from a current operating point in a certain dispatch interval, how much uncertainty of nodal injection a power system can accommodate. Ciupăgeanu et al. [67] addressed the impact of large penetration of wind generators in Romanian power system on the national power system vulnerability. The vulnerability assessment is based on the impact of different shares on wind energy on voltage magnitude and transient time in fault conditions. The reason to focus on wind energy in this study is its widest confidence interval and largest power output fluctuations among VRE technologies. The increasing share of VREs' production coinciding with the reduction of conventional generators' capacity, makes the provision of adequate reserve capacity and flexibility in power systems a major challenge. Operational flexibility in power grids can be provided through a variety of resources including physical assets, e.g. storage technologies and fast-ramping generators, as well as improved operation approaches, e.g. shorter dispatch intervals and incorporating new ancillary services. Typically, the category of improved operation approaches are cheaper than physical investment options. A cost comparison of different approaches to enhance power systems' operational flexibility is shown in Figure 2.15.

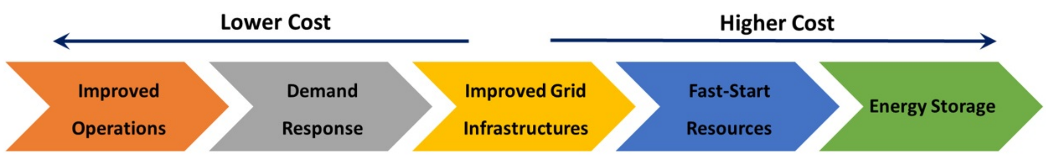

Figure 2.15: Cost comparison of different options for enhancing power systems' operational flexibility [68]

A stochastic programming approach have been presented by Bukhsh et al. [69] to solve a multi-period Optimal Power Flow (OPF) problem under high uncertainty in power systems, caused by VREs' production. The proposed OPF model in [69] is formulated as a two stage problem where the first stage determines the operating point of conventional generators and the second stage incorporated demand-side flexibility to optimally accommodate the realized generation of VREs. Ref. [70], analysed the impact of flexibility provided by demand-side participation in spot and reserve markets within Germany power system. Different scenarios have been implemented to model power system of Germany in 2030 and the value of demand flexibility on reserve and spot energy market under each scenario have been assessed. The simulation results led to the conclusion that provision of reserve from demand flexibility reduces the cost of providing reserve and diminishes the energy curtailment of VREs which in turn greatly supports the integration of higher VREs into the system. Domínguez et al. [71] analysed the procurement of reserve in power systems dominated by renewable energy sources under different market design and concluded that simultaneous optimization of energy and reserve would be the most efficient approach. Furthermore, scheduling reserve before energy market clearing, which is the current approach in some European countries, has been found to be as the least efficient approach. The growing integration of VREs in power systems reduces the systems' synchronous inertia and leads to frequency instability. Therefore, alternative options for fast-frequency responsive resources are required to ensure operation security and stability in power systems under high renewable penetration. Karbouj et al. [72] provided a comprehensive review on the potential non-synchronous sources fast-response frequency control reserves to solve diminishing synchronous reserve in VRE-integrated systems. The potential sources of reserve in [72] include wind turbines, solar PV panels, storage technologies, demand-response programs, and High Voltage Direct Current (HVDC) systems. An important culprit of frequency deviations and power balance violations in highly renewable-penetrated power systems is the scarcity of ramp capability from flexible resources. To address this issue and improve the availability of ramping capability, provision of flexible ramping products through market-based approaches have been proposed by two major Independent System Operators (ISO) or Regional Transmission Operators (RTO) in the United States- CAISO and Midcontinent ISO (MISO) [68]. Accordingly, the market clearing process would address the required ramp capability in the system to cover various sources of variability and uncertainty, reduce the probability of ramp shortages, and ensure the robustness and reliability of system operation [73]. Flexible ramping products introduce two new variables to the existing unit commitment and economic dispatch formulations, corresponding to flexible ramp-up and flexible ramp-down capabilities. Ref. [68] provided an overview on the industrial practices of performing flexible ramping products in different market structures and introduced the practices of incorporating these products in the existing co-optimization frameworks used in the industry, commonly for providing energy and ancillary services. Some advantages of providing flexible ramping products in the electricity markets include: reducing the frequency of power balance violations, reducing the deployment if regulation services, enhancing the operational reliability and flexibility, leading to tangible cost savings, and increasing market efficiency.

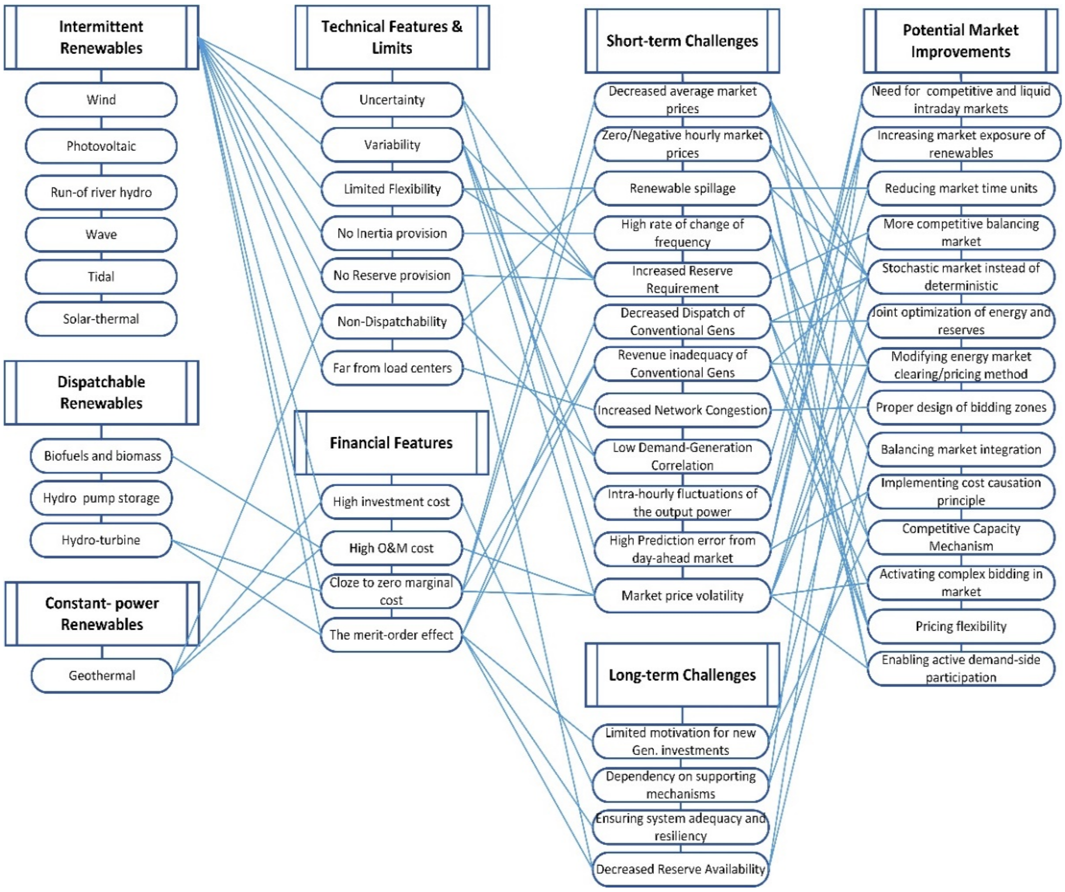

Figure 2.16: Operational and financial challenges of renewables and efficient market adjustments

One of the most critical challenges for energy management in power systems with large-scale integration of uncontrollable renewables is to construct reliable operation strategies for continuous balance of generation and loads. Traditionally, energy management in power systems were performed through deterministic approaches, e.g. Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). However, when penetration of renewables in power system increases, not only more spinning reserve will be required to ensure system reliability, but also possible transmission congestions after reserve deployment should be taken into consideration. Therefore, implementing a decision-making approach which takes both economy and reliability of system operation into consideration, would be of great importance [74–77]. Among recent trends on such methodologies, stochastic optimization and robust optimization approaches have gained much attention. Wei et al. [78] proposed a robust energy and reserve dispatch model to cope with uncertainty and variability of VREs in renewable-dominated power systems, taking for both pre-dispatch and re-dispatch operating decisions. The model imposes a robust feasibility constraint set on pre-dispatch operating variables with respect to the predicted VRE production, such that operating constraints can be recovered through re-dispatch decisions after VRE generation realization.

Following the massive integration of VREs in power systems, expansion planning of energy storage systems have gained remarkable research interest. Energy storage systems can be divided into short-term and long-term storage technologies. Short-term storage technologies, e.g. flywheels, capacitors, and battery storage systems, have a storage capacity of seconds to days. On the contrary, long-term storage technologies, e.g. water reservoirs, hydrogen storage, and gas storage, have energy storage capacity from weeks to seasons. Hydro pump storage and heat storage systems can serve both short-term and long-term storage objectives, depending on their size [79]. Different types of storage technologies have different costs and operation characteristics which makes them suitable for various applications, including and not limited to ancillary services, transmission services, and customer energy management services. Ref. [80] reviewed the state-of-the-art storage technologies and their operational characteristics and identified their potential applications accordingly. Haas et al. [79] provided an extensive review on the existing energy storage technologies and their expansion planning approaches, to provide flexibility in power systems with high renewable penetration. In [81], the problem of finding the optimum size and location of large-scale batteries in transmission grids to provide required flexibility in power systems with high VRE penetration is studied. Besides storage expansion planning, renewable integration also impacts the optimal network reinforcement planning in power systems. The integration of new generation sources is one of the key drivers of transmission expansion in electricity systems. From the other side, uncertainty factors, e.g. the VREs' production, can significantly impact the Transmission Expansion Planning (TEP) process. Therefore, optimal TEP decisions in power systems with increasing penetration of VREs has received growing attention in recent years. Janda et al. [30] studied the impact of increased production of solar and wind power sources on the transmission network of the Central Europe and concluded that higher wind and solar production increases the total electricity transmission among TSO areas, the average loading of lines, and the volatility of power flows. Furthermore, they identified solar power as the key contributor to increased power flow volatility and wind power as the key contributor for loop flows. Ref. [82] developed a model for solving optimum TEP problem with respect to investment and operation costs, taking into account also the penalties for unserved energy in case of contingencies. The model implements a stochastic optimization approach to minimize the expected value of aggregated costs and penalties, taking into account VRE uncertainties. Finally, the feasibility of achieving 100% renewables in European power systems by 2050, as the most ambitious target, have been assessed by Zappa et al. in [83]. Their analysis included seven scenarios for a fully renewable European power system in 2050 and the results confirmed that the 100% renewable system in Europe is feasible and can operate with the same level of adequacy as today. However, realizing such system requires significant investment on expanding generation capacities, cross-border transmission capacities, large-scale mobilization of Europe's biomass resources, and enhancing solid biomass and biogas capacities. Furthermore, it is necessary to implement energy efficiency measures to avoid massive increment of electricity demand and to manage integration of heat-pumps and electric vehicles through demand-side technologies with the aim of reducing peak demand.

2.2.3 Lack of coordination among national risk-preparedness plans

The recent dramatic changes in the European power systems have caused them to be operated closer to the technical limits [84]. The significant integration of renewable energy sources into the electricity networks led to power injections at different locations from conventional generators. Whereas, electricity network infrastructures had been designed with respect to the capacity and location of the conventional generators. Furthermore, integration of electricity markets in Europe caused a noticeable increase in power flow on cross-border interconnections. Whereas, the interconnections were traditionally used mainly for security support among member states. The ongoing world-wide trend of operating power systems closer to their operational limits increases the risk of wide-area blackouts [84].

Principally, power systems are designed and operated based on a security criterion, e.g. N-x, such that they can cope with a predefined set of plausible contingencies, where each contingency corresponds to the outage of x system components. However, it is also possible that a power system faces a more severe condition. In other words, even when markets and systems operate well, there might be a variety of circumstances, e.g. extreme weather conditions, fuel shortage, and malicious attack, which can lead to the risk of an electricity crisis. Electricity crisis is defined by the European Commission as "a situation of significant electricity shortage or impossibility to deliver electricity to end-consumers, either existent or imminent" [85]. In the strongly interconnected power systems, like the European one, crisis situations often have a cross-border effect and might affect several member states simultaneously.

The European Union (EU) is updating its energy policy framework in order to facilitate the energy transition through the "Clean Energy for All Europeans" package [86]. The Risk-Preparedness Regulation Proposal [85] is one of the eight legislative acts and focuses on "how to secure the electricity system as a whole and how to manage electricity crises when they occur, by ensuring that all Member States put in place the appropriate tools to prevent, prepare for and manage these situations". Until now, electricity crises in Europe were managed at national level [87]. Member States behave differently in preventing, preparing for, and managing crisis situations. National practices for risk-preparedness and crisis management are focused solely on national context and disregard the cross-border impact of crisis. Furthermore, the information sharing and transparency among Member States, regarding their approach for handling electricity crisis situations, is quite restricted. For example, if it is predicted that in the next months there will be a serious stress on their electricity system, Member States often take action along with their TSOs and do not inform other States. This situation is resulted by a regulatory gap in the current EU legislation on the security of supply [88], [89] which does not define a common way for the Member States to manage crisis situations and leaves them free to achieve security of supply objectives in such situation.

The cold spell in Southeast Europe during January and February 2017 can be considered as a recent example which shows the impact of coordination among European countries in managing crisis. The extreme cold weather condition affected several countries in Southeast Europe including Bulgaria, Serbia, the Former Yugoslav Republic of Macedonia, Romania, and Greece [90]. Although day-ahead electricity market prices reflected the scarcity across the region, several measures were undertaken by the TSOs to safeguard the systems with respect to the expected widening imbalance between demand and available generation capacity. In Bulgaria, the Minister of Energy obliged the system operator to terminate the access of electricity transmission network for exporting electricity from the country, until all the reserve capacity needed for the operation of Bulgarian system have been restored. The export capacity of Greek power system was also curtailed for 2 days. The NTC of cross-border interconnection from France to Spain was reduced in peak hours of several days to ensure the security of supply within France. Furthermore, the export capacity from Italy to France have been curtailed for a few hours during 18^{th} and 19^{th} January. The impact of market integration on managing the extreme situation cannot be ignored, such that without cross-border power exchanges, some countries, e.g. Italy, Belgium, and Switzerland, might have experienced supply shortage [91]. However, analysis of price movements in the region suggested that some of these market interventions were unnecessary and led to significant loss of welfare in the region, due to non-efficient utilization of cross-border capacities. The experience of cold spell in Jan. 2017 indicated how the decisions on curtailing the export capacities can lead to larger regional implications. Furthermore, it highlighted the need for a more strict cooperation among TSOs and the authorities, especially during the periods of system stress [90].

The Risk-Preparedness Regulation Proposal [85] attempts to fill this regulatory gap and set out how Member States should cooperate with each other to manage crisis situation through providing common ways for risk assessment, enhancing transparency and comparability among Member States in preparation phase and during crisis, and ensuring even during a crisis, the electricity is delivered where it is needed most. Applying a regional approach to prevent, prepare for, and manage crisis situation results in economic benefits due to better utilization of power system resources (power plants, interconnection capacity, storage facilities, and demand response) and mitigating the probability of loss of protected loads. Achieving an adequate level of risk preparedness across Europe would increase the trust and cooperation among Member states and reduce the impact of crisis on electricity customers. However, the regional cooperation among Member States should be based on pre-agreed measures which had been already set out in the risk-preparedness plans [85]. The common approach for electricity crisis management in Europe should rely on market mechanisms as long as possible. Whereas, non-market measures, such as forced disconnection of demand, should be used only as the last resort when all the possible resourced offered by the market were already tried out. Accordingly, forced demand disconnection can only be activated after all the possible voluntary demand disconnections have been used.

2.2.4 Impact of enhancing integration of the European power systems

Given the newly arisen challenges for the electricity industry in Europe, a critical question is whether the rate of developments in market design and system operation regulations can compete with the rate of transforms in the electricity industry? How European electricity markets and system operation can be adjusted to cope with the new state of power systems, dominated by uncertain, uncontrollable, and variable renewable energy sources? To address these issues, strengthening the integration and coordination among European TSOs, regarding their operational/planning process, is a key solution to enhance system performance economically, through efficient utilization of available resources. The establishment of a fully functioning and integrated internal electricity market in Europe is vital to achieve the EU objectives of maintaining security of supply, enhancing competitiveness, and energy accessibility and affordability to all consumers in electricity system [37].

Resource adequacy is a critical issue in modern power systems that postulates advanced methods for analyzing scarce events which lead to detrimental consequences on electricity supply. The term adequacy means the ability of a power system to meet its demand [92]. Adequacy implies on the continuous balance between net available generation capacity (i.e. available generation - export capacity + import capacity) and net demand (i.e. load – voluntary demand side response) [93]. The increasing penetration of VREs in European power systems, along with the coupling of European energy markets, have intensified the importance of adequacy issue and the need for harmonization and cooperation across Europe to perform resource adequacy studies. In this regards, ENTSO-E publishes seasonal system adequacy forecasts (Seasonal Outlook) with respect to the TSOs' view on the risk of security of supply, as well as their planned countermeasures [92]. The analyses are performed twice a year, for winter and summer seasons in which weather condition and its impact on power system can be more extreme. The ENTSO-E seasonal outlooks are performed in both country level and pan-European level, investigating the contribution of neighboring countries in performing power balance in the power system under stress. Publishing these adequacy forecast reports by ENTSO-E enables the TSOs of the neighboring countries to consider providing support to the system which may be under the risk and contributes in enhancing the security of supply in the region through promoting cross-border cooperation. The results of ENTSO-E resource adequacy forecast in the national level, on winter outlook 2018/2019 (published in 2018 [92]), under normal and severe conditions are represented in Figure 2.17. Severe conditions are modelled by cold wave in winter and heat wave in summer.

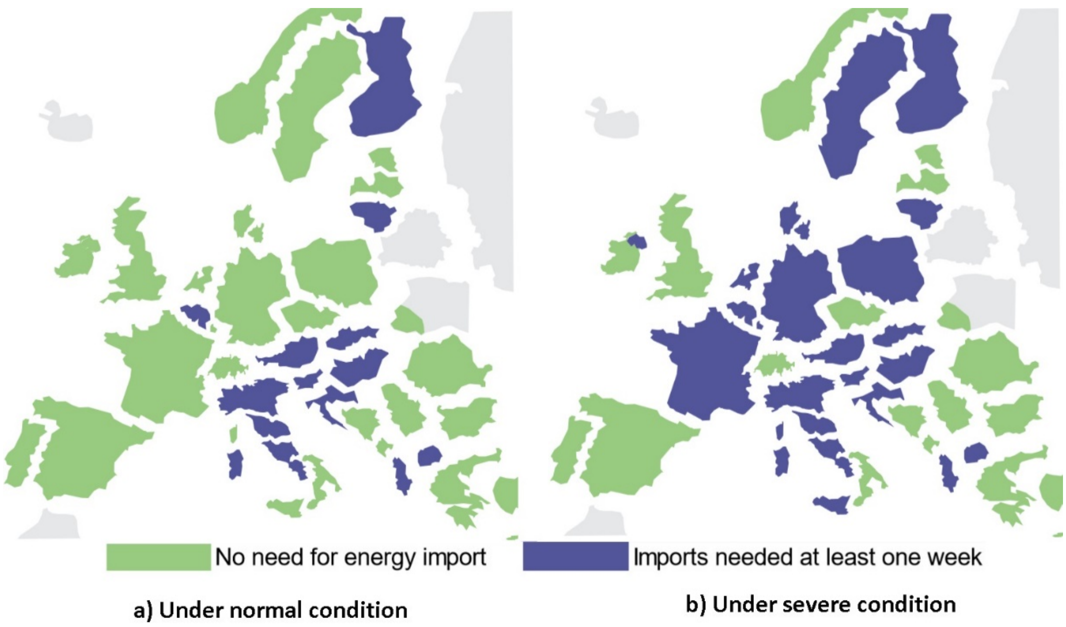

Figure 2.17: Resource adequacy forecast map in winter 2018/2019 under a) normal and b) severe conditions [92]

The countries are coloured in green if their reliably available capacity (generation capacity and available market based demand side response) is sufficient to supply expected demand during the season. Otherwise, if the country relies on imports to supply its demand at least in one week in the season, it is coloured in purple. As shown in Figure 2.17, more countries would require imports to ensure resource adequacy under severe conditions. This is mainly due to the higher demand, lower VRE production, and increased outages resulted by the severe condition, i.e.

cold spell. To complement the national adequacy results, the pan-European adequacy forecast analysis takes into account the import/export capacity limits of cross-border interconnections on a weekly basis. The counties that cannot even fully supply their load with imports, due to inadequate cross-border transmission capacity or shortage of excess generation capacity in the region, are in the risk of facing adequacy issues. For instance, the results of winter outlook 2018/2019 [92] imply on some adequacy issues under severe conditions in Belgium, Finland, Central-Northern Italy, Lithuania, Poland, and Slovenia, at the beginning of 2019. However, the adequacy of France, Sweden, Germany, Denmark, Netherlands, Austria, Slovakia, Northern Ireland, Hungary, and the rest of Italy, can be ensured through importing the energy provided by the excess supply resources of the neighbouring countries. These results highlight the importance of regional cooperation among TSOs to ensure resource adequacy across Europe, under both normal and severe conditions. The optimum solution is to let the integrated market operate as long as possible, even under severe conditions. Whereas, uncoordinated non-market measures such as limiting the NTC of the interconnections by some TSOs, leads to inefficient use of cross-border transmission capacities and can cause security problems for the regions with power deficit, while still there might have existed excess generation capacity in other countries to support it.

Resource adequacy is not just the matter of available generation and transmission capacity to supply the demand. Historically, adequacy was considered as a long-term issue in power systems' planning, and its assessment was carried out based on the ability of a system (supply sources and transmission infrastructure) to supply its peak demand. However, the recent evolution of the electricity systems poses new challenges to traditional adequacy assessments. The rapid growth of variable renewable energy sources in European electricity systems along with the reduction of conventional fossil-fuel generation capacity, increased the need for more operational flexibility in power systems to cope with fluctuations of the residual demand. Critical situations in performing supply-demand balance are no longer defined by peak demand and may occur at different times. Flexibility has become a critical issue in new power systems, both in operation and planning phases. In this view, flexibility should also be included in the new approaches for supply adequacy assessments, to capture more security of supply risks in highly renewable-penetrated systems [94]. Accordingly, ENTSO-E is also working on improving its adequacy methodologies with a special focus on system flexibility requirement and interconnectors. Based on the ENTSO-E's new proposal regarding Short-term and Seasonal Adequacy Assessments Methodology in accordance with Article 8 of Regulation of the European Parliament and Council on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC [95], European TSOs and Regional Coordination Centres (RCC) should continuously monitor adequacy within their system/region through performing ENTSO-E's methodology for week-ahead to at least day-ahead adequacy assessments. The new seasonal and short-term adequacy assessment methodology is a probabilistic approach (Monte-Carlo approach) which should cover the variability of demand and production of renewables, probability of outages of power plants and transmission elements, as well as the probability of occurrence of electricity crisis. Enhancing the integration among the European power systems increases the operational flexibility, security of supply, and resource adequacy within the region, in all time scales. Integrating electricity markets and network management allows for efficient utilization of interconnection capacities for sharing the available supply and demand-side resources for providing the required energy, reserves, and operational flexibility within the region. Furthermore, interconnecting a larger geographical area with different renewable energy sources and weather conditions, can facilitate the real-time generation-demand balance in the system and reduce the balancing costs through imbalance netting process. Imbalance netting is a process by which two or more TSOs agree to offset opposing imbalances between neighbouring areas, taking into account the available cross-border capacity among them. Imbalance netting process aims at preventing counteracting activation of balancing energy within the interconnected areas, leading to efficient energy exchange from the area with surplus energy to the one with deficit [96]. Currently, imbalance netting covers an important share of the balancing energy requirement in several European electricity markets.

From the electricity market perspective, integrating electricity markets across the borders enhances market liquidity and competition, reduces market prices, flattens price fluctuations, and increases the hosting capacity for renewable energy sources. The growing share of variable renewable generation in electricity markets increases price fluctuations and may lead to hours with (close to) zero/negative market clearing price. Zero market prices are resulted by high renewable production with close to zero marginal cost, coinciding with low demand. If this condition in the market happens simultaneously with low flexibility of conventional generators, it may lead to negative market prices. Such situation may be due to the impossibility to shut-down some of the conventional generators in a quick and cost efficient manner; such that producing power with negative price would be a more economic decision for them. Market clearing diagram under the situation leading to negative price is illustrated in Figure 2.18. Negative prices have been occasionally witnessed in European and U.S. electricity markets. For instance, in Germany, negative prices had been observed during 146 hours on 24 days, on the day-Ahead market in 2017 [97].

Integrating national/regional electricity markets to a wider extent geographically and enhancing the cross-border interconnection capacities can reduce the frequency of occurrence of negative prices in the market through efficient sharing of the excess production among the regions. Furthermore, market integration has the potential to lessen the probability of price spikes in the market, as well as reducing the energy curtailment from renewables. Energy curtailment and very low (or negative) market prices can negatively impact the integration of renewables into the

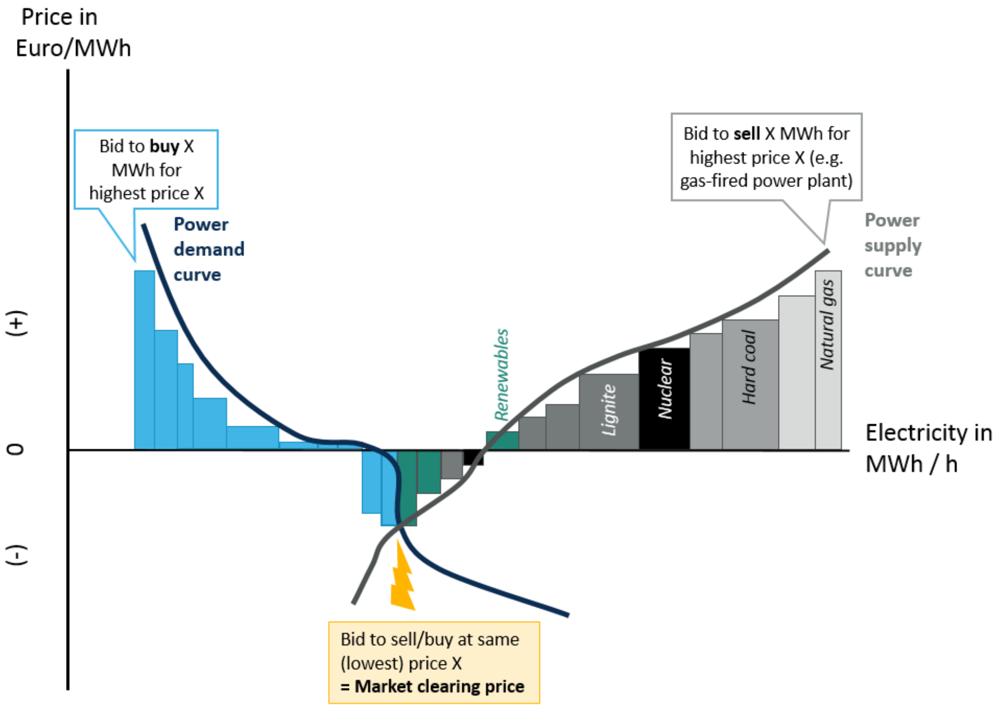

Figure 2.18: Diagram of situations leading to negative price in electricity market clearing [98]

market by dis-incentivising new investors on these technologies. Therefore, market integration can promote renewables' penetration.

Chapter 3

Integration of the Baltic States into the EU Electricity System

"This chapter is the extension of the study which has been previously published in [99]."

For historical reasons, the power transmission grid of the Baltic States is still operated in a synchronous mode with the Integrated/Unified Power System (IPS/UPS), which is the wide area synchronous transmission grid of some CIS[1] countries. Currently, the IPS/UPS system is in charge of providing frequency regulation and security of supply within the Baltic States. However, Baltic countries joined the European Union (EU) in 2004 and since then, they have been following the energy policies and targets of the Union. Presently, the Baltic States are participating in NordPool electricity market which is an integrated European power market, offering day-ahead and intraday trades. NordPool's day-ahead trading covers the electricity markets of Nordics, Baltics, Central Western Europe, and UK, and its intraday trading covers Nordic, Baltic, German, Dutch, French, UK, Austrian, and Belgian markets. However, market integration in Europe is an ongoing procedure and NordPool market is also expected to join the pan-European electricity market—the European target model for power market integration. Another upcoming scenarios towards increasing the integration of Baltic States into the EU electricity system is the synchronization of Baltic's power grid into a European transmission network. EU energy policies contemplate to desynchronize the power grid of the Baltic States from the IPS/UPS system in near future, mainly due to some political reasons and with the aim of enhancing security of supply and energy independency of the Baltic countries as EU members. This chapter of my thesis deals with the aforementioned

[1]The Commonwealth of Independent States (CIS) is a regional intergovernmental organization of originally ten post-Soviet republics in Eurasia formed following the dissolution of the Soviet Union in 1991.

policy trends within the Baltic States and evaluated their impact on market performance within the Baltics. This study complements the existing feasibility analyses on Baltic-IPS/UPS desynchronization schemes form the technical perspective and evaluates them in terms of wholesale electricity market prices, generators' surplus, primary reserve adequacy, and the intra-zonal congestion management costs within the Baltic States.

The list of abbreviations and symbols used in this chapter is provided at the end of the chapter.

3.1 Introduction

Currently, the power system in the Baltic States is operated in the synchronous mode with the Integrated/Unified Power System (IPS/UPS), including the Russian and Belarussian power grids, through 330 kV high voltage alternating current (HVAC) transmission lines [100]. As the most geographically extended power system in the world, the IPS/UPS provides the required primary control reserves and security of supply within the Baltic States. Besides being interconnected to the IPS/UPS through HVAC interconnectors, the Baltic States are also interconnected to the European electricity system, through high voltage direct current (HVDC) interconnectors to Finland, Sweden, and Poland. Estonia and Finland are connected by two HVDC cables—Estlink 1 and Estlink 2—with 350 MW and 650 MW capacities, respectively. The Nordbalt link, with 700 MW capacity, connects Lithuania to Sweden, while there is also a 500 MW interconnector, Litpol link1, between Lithuania and Poland [101]. It is also planned to construct a Litpol link2, with 500 MW capacity, by 2025, doubling the interconnection capacity between Lithuania and Poland [101].

After integrating into the European Union in 2004 and deregulation of their electricity markets, the three Baltic States, i.e. Estonia, Latvia, and Lithuania, joined NordPool electricity market in the period 2010-2013 [102]. During the last decade, power system of the Baltic States have been experiencing a transition between East and West interconnections which led to attract remarkable research attention [103–105].

The Baltic States, as EU members, are required to follow the Union's energy policies and objectives. One principal EU energy policy regarding the electricity sector is to integrate the electricity markets across Europe, with the aim of reducing electricity prices and increasing security of supply in the power system [106]. A Europe-wide integrated electricity market leads to more efficient allocation of the electricity supply sources and transmission capacities across the EU, as well as eliminating the market power of the market participants. However, substantial modification of market designs toward harmonizing market rules is essential before market integration. Furthermore, expanding interconnections' capacities to enable free trading of power across the borders is of great importance in achieving a fully integrated electricity market [106]. Accordingly, strengthening the power grid connecting the electricity system of the Baltics and the EU countries is a necessary step toward establishing an integrated Europe-wide electricity market [107]. Furthermore, in order to achieve the full integration of Baltics' electricity system into the EU electricity market, desynchronization of Baltics' electricity network from the IPS/UPS and its re-synchronization with the power systems of the Union is demanded by EU energy policy [107]. From the energy policy perspective inside the Baltic States' also desynchronization from Russia is a fundamental issues to pursue energy independency targets.

There are three scenarios regarding Baltic States interconnections' status after Baltics-IPS/UPS desynchronization, as proposed in the literature [104], [108] (1) synchronous operation of the Baltic States and the Continental Europe Network (CEN), (2) synchronous operation of Baltic States and Nordic countries, and (3) autonomous synchronous operation of the Baltic States. As reported in [104], each of these prospective synchronization schemes ask for an additional amount of investment and operation costs needed for constructing the required network infrastructures, as well as providing the primary reserve inside the Baltics. Primary reserve requirement of the Baltics' power system is presently provided by Russia. However, after desynchronization from IPS/UPS, primary reserve provision must be implemented either directly inside the Baltic States or with mutual support of the countries within a European synchronous area. Scenario 1—Baltics/CEN synchronization—has been identified as the best synchronization option from a technical point of view, which also leads to the minimum required investment cost [104].

The study performed in this thesis complements the previous feasibility assessments on the three Baltics-IPS/UPS desynchronization scenarios by providing supplementary market performance results in terms of generation surplus, electricity wholesale prices, and congestion management costs. The three scenarios are analysed with regard to the participation of the Balti States into the pan-European electricity market, following their desynchronization from the IPS/UPS and under possible alternative Baltic-EU interconnection schemes. Primary reserve inside the Baltic States is considered as a shared service to be provided regionally through all the countries belonging to the same synchronous area. The share of each Baltic country in providing the total amount of required primary reserve, under different desynchronization schemes, is assigned with respect to the current regulations in the Nordic and Continental European synchronous areas. The day-ahead integrated electricity market in Europe, covering Baltic States and 31 other European countries, is modelled based on a zonal pricing approach. Zonal pricing is an electricity market pricing approach which is currently implemented in European countries and is also the target pricing model for the planned Europe-wide integrated electricity market. The so-called "bidding zone" in zonal pricing approach is defined as the largest geographical area within which market participants can exchange energy without capacity allocation [109]. Accordingly, zonal pricing represents inter-zonal power flow limits, while ignoring the intra-zonal transmission constraints [110]. Transmission system operators (TSOs) in Europe are in charge of ensuring a sound operation of the integrated European electricity market, with respect to the internal network constraints within the bidding zones located in their control area. Consequently, a proper congestion management approach is needed to solve any potential intra-zonal congestion.

Typically, each European country consists of one up to several bidding zones. In this study, 34 European countries including: Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, former Yugoslav Republic of Macedonia, Germany, Great Britain, Greece, Hungary, Ireland (and North Ireland as separated region), Italy, Latvia, Lithuania, Luxembourg, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, and Switzerland, are modelled as one bidding zone per country. In order to assess the impact of Baltics-EU synchronization schemes, two sequential market models are implemented, as follows:

- A Europe-wide integrated day-ahead market model with an inter-zonal congestion management approach (including 34 European countries, modelled as one node per country)
- A regional re-dispatch market model inside the Baltic States for intra-zonal congestion management (on detailed power grid model of the Baltic States).

Firstly, the primary reserve requirement within Estonia, Latvia, and Lithuania, is determined with respect to the operational rules in each synchronous area under different synchronization schemes. The amount of reserve capacity to be preserved in Baltics States has two major impacts on market performance: i) it limits the available capacity of generators to participate in the energy market, and ii) it defines the reliability margin on the cross-border interconnections and hence determines the NTC of interconnectors in the market. Following the day-ahead market-clearing, power flow is run by each Baltic TSO, based on the day-ahead generation schedules, cross-border power exchanges, and internal network constraints with respect to the detailed network model of the Baltic States, developed in previous studies [103]. Network model of the Baltic States which is used in this study is comprised of 245 generation units, 910 buses, and 1178 transmission lines. Intra-zonal congestions are managed through a market-based re-dispatch approach. Figure 3.1 summarizes the steps in solving inter-zonal and intra-zonal congestion, while preserving required primary reserve capacities.

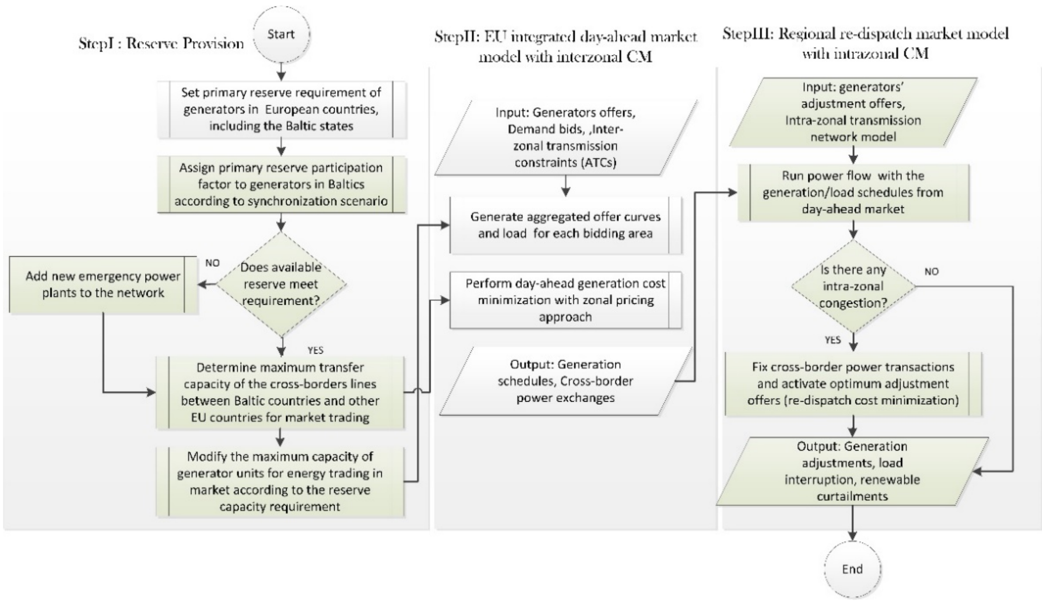

Figure 3.1: Conceptual framework for primary reserve, market clearing and CM under different synchronization schemes

3.2 Desynchronization schemes for the Baltic States and corresponding primary frequency regulations

Based on [104], [108], this study considers three cross-border interconnection schemes after desynchronization of the Baltic power system from IPS/UPS by 2030:

1. BCEN Scheme: Baltic synchronization with the CEN synchronous area via Poland.
2. BNS Scheme: Baltic synchronization with the Nordic synchronous area through newly constructed HVAC undersea cables between Estonia and Finland.
3. BAS Scheme: Baltic States' autonomous synchronous operation.

The schematic representation of HVAC and HVDC cross-border interconnections between the Baltic States and their European neighbouring countries is presented in Figure 3.2- Figure 3.4.

Baltic synchronization with the CEN, as represented by Figure 3.2, was modelled through the existing double-circuit AC line connecting Lithuania and Poland (LitPol link1) and the new planned double-circuit AC line (LitPol Link 2), with a total of 2 $\times$ 1683 MW (1870 MVA with 0.9 power factor assumption) capacity [111].

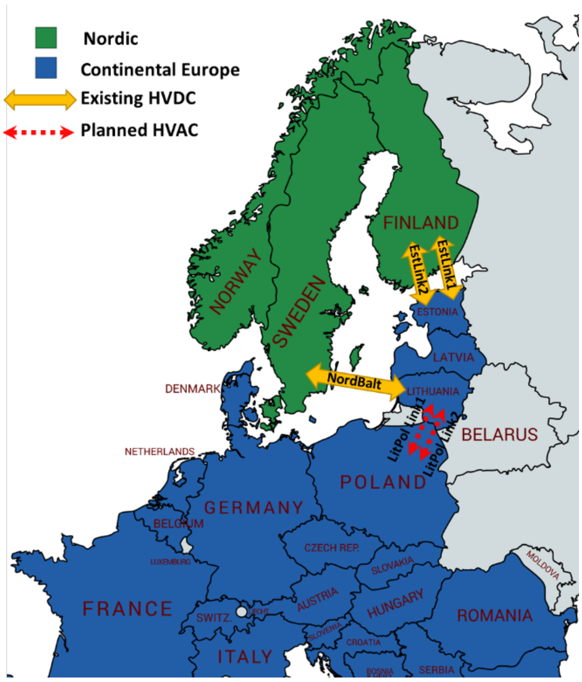

Figure 3.2: Baltic-EU interconnections under Baltic synchronization with the Continental Europe Network (CEN) scheme

Baltic synchronization with the Nordic synchronous area, represented in Figure 3.3, was modeled by adding new HVAC undersea cables connecting Estonia and Finland, in addition to the existing HVDC links: Estlink1 with 350 MW capacity and Estlink2 with 650 MW capacity. The new HVAC cables for Baltic-Nordic synchronization were modeled by 3 × 225 MW undersea cables [108].

Under the Baltic states' autonomous synchronous operation, shown by Figure 3.4, all the current HVDC connections between the Baltic states and their European neighboring countries (Estlink1&2, LitPol link1, NordBalt), as well as planned interconnections (LitPol link2), exist to the support Baltic states in energy exchanges, while no HVAC interconnection was added to the model. This scenario is important due to its ability to pinpoint major weaknesses and challenges of the existing power system in the Baltics in terms of generation adequacy and available primary reserve capacity.

Each of the above-mentioned desynchronization schemes can impact the electricity market performance and market-clearing results inside Baltic countries and other bidding zones in two ways: through different cross-border transmission capacities for energy exchange in the electricity market, and through limiting the available generation capacity of conventional power plants for energy production inside the market, due to the requirement to keep adequate primary reserve inside each control area, which varies under different schemes. The electricity market

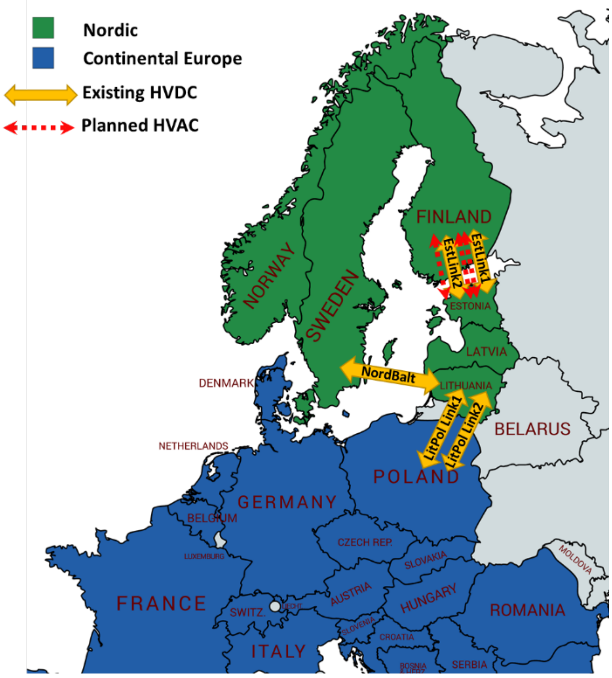

Figure 3.3: Baltic-EU interconnections under Baltic synchronization with Nordic scheme

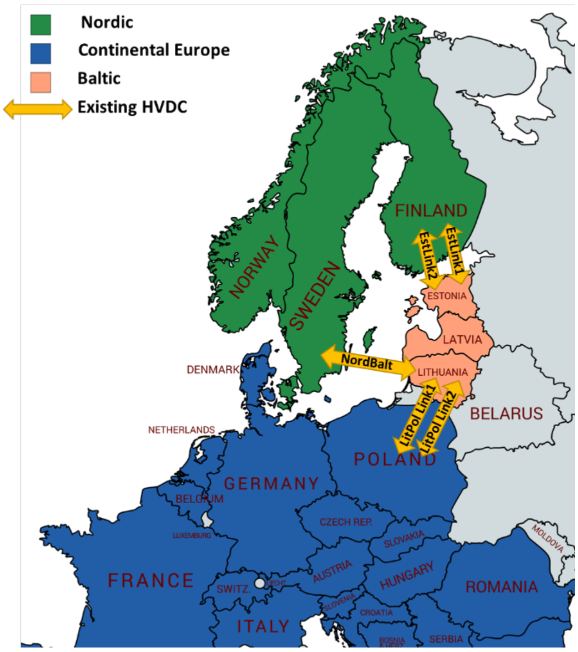

Figure 3.4: Baltic-EU interconnections under Baltic States' autonomous synchronous operation scheme

considered in this study is the European integrated day-ahead electricity market, followed by a national re-dispatch mechanism to solve the congestion management inside the Baltic countries. The focus of this thesis is to analyze the impact of desynchronization schemes inside the Baltic States.

In the following Sections 3.2.1-3.2.3, the required primary reserve capacity inside the Baltic States under different desynchronization schemes is presented. Table 3.1 provides an overview of the primary reserve requirement in each Baltic country under the three aforementioned schemes.

Table 3.1: Estimated required primary reserves for different desynchronization schemes (2030)

Schemes	Status	Required Primary Reserve Capacity (MW)				
		ES Estonia	LV Latvia	LT Lithuania	Nordic Countries (without Baltics)	CEN Countries (without Baltics)
BCES	Baltic synchronization with CEN	9	8	15	1400	2968
BNS	Baltic synchronization with Nordics	66	110	122	1102	3000
BAS	Baltic island operation	253	175	272	1400	3000

3.2.1 Primary reserve regulation in the CEN synchronous area

The primary reserve capacity requirement in the CEN synchronous area is equal to 3000 MW (based on N-2 criterion [112]), which must be provided by all the CEN members together. The share of each country in providing the required primary reserve is assigned through contribution coefficients based on their energy share of the previous year in the synchronous area. These coefficients are determined and published annually [113]. The primary reserve capacity provided by each control region in the CEN synchronous area is expressed by:

$$r_i^k = \frac{G_i^{k-1}}{\sum_{i \in I} G_i^{K-1}} R \tag{3.1}$$

where G_i^{k-1} represents the total electrical energy generation in control region i during $k-1$th year, and R represents the total capacity required as primary reserve in the synchronized area. The term $\frac{G_i^{k-1}}{\sum_{i \in I} G_i^{K-1}}$ is the contribution coefficient of each area i belonging to the set I of countries in the CEN synchronized area.

The share of each Baltic and CEN country under Baltic-CEN synchronization scheme is calculated on the basis of the forecasted generation in 2030 (ENTSOE, [114]) and is reported in Table 3.2. Under this scheme, the HVAC interconnections between Lithuania and Poland are used for both cross-border energy exchange and primary reserve exchange in emergencies.

Table 3.2: Primary reserve contribution coefficient of Baltic-CEN countries based on annual generation (2030)

Country	Generation in 2030[GWh]	Contribution Coefficient[%]	FCRs [MW]
Belgium	72313	2.4	74
Bulgaria	50487	1.7	51
Czech Republic	85766	2.9	87
Denmark (western)	10473	0.4	11
Germany	610832	20.7	621
Bosnia and Herzegovina	17056	0.6	17
Greece	54970	1.9	56
Spain	287052	9.7	292
France	608391	20.6	618
Croatia	14117	0.5	14
Italy	323149	10.9	328
FYROM	5932	0.2	6
Luxembourg	4547	0.2	5
Hungary	41925	1.4	43
Montenegro	3404	0.1	3
Netherlands	136741	4.6	139
Austria	79933	2.7	81
Poland	203166	6.9	207
Portugal	48243	1.6	49
Romania	75464	2.6	77
Slovenia	18787	0.6	19
Slovakia	38296	1.3	39
Switzerland	79477	2.7	81
Serbia	49583	1.7	50
Latvia	7539	0.3	8
Lithuania	14421	0.5	15
Estonia	9441	0.3	9
Total	2951505	100	3000

3.2.2 Primary reserve regulation in Nordic synchronous area

The so-called frequency containment reserve (FCR) product used in the Nordic power system [111] is equivalent to the primary reserve service. Generally, the FCR is the operating reserve with the purpose of balancing the system within the normal frequency band (i.e., 49.9–50.1 Hz) and in case of disturbance. To preserve the consistency of the FCR in Nordic countries with the primary reserve in CEN countries, this study focuses on the frequency containment reserve under disturbance (FCR-D).The FCR-D capacity inside the Nordic synchronous area is based on the concept of a dimensioning fault/incident in each control region that is "the fault which entails the loss of individual major components (production, lines, transformers, bus bars, consumption, etc.) and entails the greatest impact upon the power system from all fault events that have taken into account" [111], [115]. The required FCR-D capacity is equal to the dimensioning fault power minus 200 MW, i.e., the effect of frequency-dependent loads. The response from frequency-dependent loads can be ignored in this study.

Starting from the computation of the dimensioning fault within each control region, the share of FCR-D is computed with respect to the current regulations in the Nordic synchronous area [115]. The share of each control region in providing FCR-D, r_i^k, is:

$$r_i^k = \frac{D_i^k}{\sum_{i \in I} D_i^k} R \tag{3.2}$$

where D_i^k represents the dimensioning fault in the control region i during the year k, and R represents total capacity required as primary reserve (FCR-D) in the Nordic synchronized area, which is equal to $max_{i \in I}\{D_i^k\}$ minus the effect of frequency dependent loads. I is defined as the set of Nordic countries.

The share of each Baltic country in providing the required primary reserve in the Baltic-Nordic synchronization scheme, as well as the share of Nordic countries, according to the corresponding dimensioning faults, is presented in Table 3.3.

3.2.3 Primary reserve in the Baltics under autonomous synchronous operation

Under the Baltic autonomous synchronous operation scenario, Estonia, Latvia, and Lithuania are supposed to form a new synchronous area in Europe, for which there are no predefined regulations. We assumed the same regulations for the primary reserve of the Nordic synchronous area for the Baltic synchronous area (in Section 3.2.2). The dimensioning fault in this synchronization scheme, which determines the total required primary reserve in the Baltic synchronous area, is NordBalt interconnection, between Lithuania and Sweden, with 700 MW capacity.

Table 3.3: Primary reserve contribution coefficient of Baltic-Nordic countries based on dimensioning faults (2030)

Country	Dimensioning Fault[MW]	FCR Contribution Coefficient	FCR Requirement [MW]
Finland	1300	0.2273	0.2273×1400=318
Sweden	1400	0.2448	0.2448×1400 = 343
Norway	1200	0.2098	0.2098×1400 = 294
Denmark	600	0.1049	0.1049×1400 = 147
Estonia	270	0.0472	0.0472×1400 = 66
Latvia	450	0.0787	0.0787×1400 = 110
Lithuania	500	0.0874	0.0874×1400 = 122

3.3 EU market clearing and congestion management in Baltic States

The single auction platform for EU day-ahead market coupling purposes is known as Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA), which is the key achievement of the Price Coupling of Regions (PCR) project [116]. Currently, EUPHEMIA is used to calculate day-ahead electricity prices and electrical energy allocation across 23 European countries, including Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the UK, with the objective function of maximizing total social surplus. In summary, EUPHEMIA uses several bidding areas as the smallest entities in which generation offer/demand bids can be submitted, then it computes the market-clearing price for each bidding area through an optimization model. Currently, the widely used approach in Europe for energy exchange among bidding areas in day-ahead market coupling is based on Available Transfer Capacities (ATC). The ATC model represents the bidding areas linked by interconnectors in a given topology, considering the power transmission lines simply as transportation corridors. The electrical energy flow between the neighboring bidding areas is limited by the ATC of the interconnectors. The ATC values in the EU day-ahead market coupling are defined by the corresponding TSOs.

Area pricing model performed in EUPHEMIA, as well as in the NordPool electricity market, conforms to the so-called zonal pricing model [117]. In general, European electricity markets are usually modeled as simplified zonal-pricing power markets without considering inter-zonal congestions inside the market model, which results in a uniform market price in each zone, typically a country or state [117–122]. The network model of each zone in the simplified zonal pricing model is replaced by one equivalent node connected to equivalent inter-zonal transmission lines, while intra-zonal network constraints and potential congestions are neglected. It is mostly expected that the prospective integrated European power market will also work based on a zonal-pricing model. Therefore, centralized congestion management approaches will be required to ensure the technical feasibility of market outputs with respect to intra-zonal network constraints.

In a restructured power system, market participants have open access to the transmission system, and the independent TSO is responsible for taking necessary actions, referred to as congestion management approaches, to ensure a feasible system operation state without violations of grid constraints [123], [124]. Basically, in electricity markets with a zonal-pricing scheme, like the target model of the European integrated day-ahead electricity market, the highly simplified grid representation of the market clearance may result in infeasible power flows due to transmission congestions [125]. When a market dispatch, typically with the zonal pricing approach, fails to provide a feasible operating state without intra-zonal constraint violations, the TSOs re-dispatch generations and loads to reach a feasible state at least cost.

Following day-ahead market clearing, each Baltic TSO checks the feasibility of the day-ahead market results in terms of eventual intra-zonal congestions, and in case of potential network violations, runs congestion management for intra-zonal congestion relief by re-dispatching its region, while cross-border power exchanges from the day-ahead integrated market are kept fixed. We assume that if the TSOs cannot achieve a feasible solution by activating upward/downward re-dispatch offers in the market, they would proceed to load curtailment as the most expensive solution. The cost of load curtailment is quantified by the value of lost load (VOLL). Re-dispatch market clearing in this study was modeled by the pay-as-bid approach.

The re-dispatch market was modeled through a network-constrained optimization problem with a direct current (DC) network representation that minimizes the re-dispatch costs, as formulized through Equations (3.3)–(3.6).

Objective Function:

$$\begin{aligned} Min\ C^{\ CM} = &\sum_{g\in\mathcal{G}} \left(\rho_g^{CM,\ up} \Delta P_g^{CM,\ up} - \rho_g^{CM,\ dn} \Delta P_g^{CM,\ dn}\right) + \\ &\sum_{v\in\mathcal{V}} \left(K_v^{CM,\ cu} P_v^{CM,\ cu}\right) + \sum_{d\in\mathcal{D}} \left(V_d^l L_d^{CM,\ l}\right) \end{aligned} \tag{3.3}$$

The first term of objective function represents the cost of activating generation adjustments by multiplying the adjustment offer prices ($\rho_g^{CM,up/dn}$) and accepted adjustment power quantities ($\Delta P_g^{CM,up/dn}$). The second term is defined to exert a penalty for renewable curtailment due to congestion management. The third term represents the cost of load curtailment. We did not consider demand response for congestion management in this study. However, by this term, the model can easily apply load curtailment services from active demand by assigning different values for load curtailment prices for different customers (V_d^l).

The accepted adjustment power of generator g in the re-dispatch mechanism should be assigned in such a way that its final output power does not exceed the upper and lower band defined by the generator capacity and minimum technical limit, respectively (Equations (3.4) and (3.5)). The net value of total upward and downward adjustment powers in each control region should be equal to zero, as presented by Equation (3.6).

$$P_g^{DA} + \Delta P_g^{CM,\ up} - \Delta P_g^{CM,\ dn} + P_g^{Res} \leq P_g^{Max} \tag{3.4}$$

$$P_g^{Min} \leq P_g^{DA} - \Delta P_g^{CM,\ dn} \tag{3.5}$$

$$\sum_{g \in \mathcal{G}} \left(\Delta P_g^{CM,\ up} - \Delta P_g^{CM,\ dn} \right) - \sum_{v \in \mathcal{V}} P_v^{CM,\ cu} + \sum_{d \in \mathcal{D}} L_d^{CM,\ l} = 0 \tag{3.6}$$

Equations (3.7)–(3.9) indicate the final power flow between nodes i and j (F_{ij}^{CM}) after congestion management, based on DC power flow. Generation–demand balance in each node is demonstrated by Equation (3.9), in which the aggregated generation of all generators connected to node i in the re-dispatch market is equal to the final demand at node i plus aggregated outflows through the lines connected to that node (F_{ij}^{CM}).

$$F_{ij}^{CM} = B_{ij}(\theta_i^{CM} - \theta_j^{CM}) \tag{3.7}$$

$$-F_{ji}^{Max} \leq F_{ij}^{CM} \leq F_{ij}^{Max} \tag{3.8}$$

$$\begin{aligned} &\sum_{g \in \mathcal{G}_i} \left(P_g^{DA} + \Delta P_g^{CM,\ up} - \Delta P_g^{CM,\ dn} \right) + \sum_{v \in \mathcal{V}_i} \left(P_v^{DA} - P_v^{CM,\ cu} \right) \\ &- \sum_{d \in \mathcal{D}_i} \left(L_d^{DA,\ l} - L_d^{CM,\ l} \right) - \sum_{j \in B, j \neq i} F_{ij}^{CM} = 0 \end{aligned} \tag{3.9}$$

Figure 3.5 illustrates the possible actions taken by TSOs in a re-dispatch market, and the associated re-dispatch costs or revenues.

3.4 Modelling assumptions

We have set a market model for 2030 based on the data source provided in ENTSO-E Vision 3 of "National Green Transition" [111]. The day-ahead market simulation was performed by PLEXOS® Integrated Energy Model [125] version

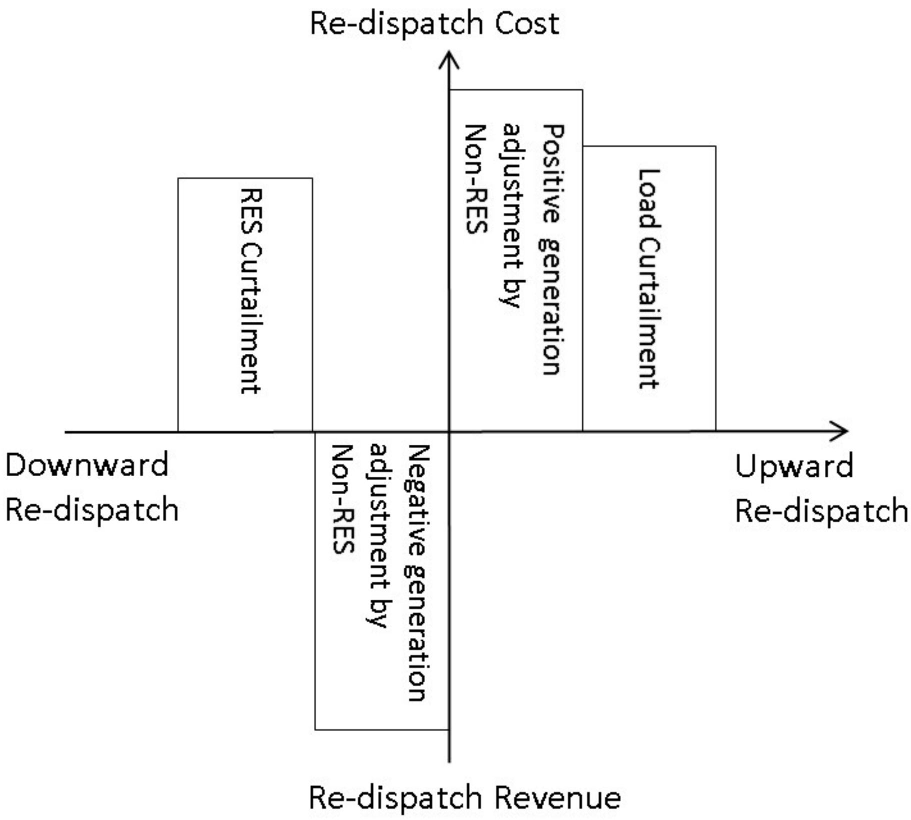

Figure 3.5: Schematic representation of re-dispatch actions by transmission system operator (TSOs)

7.4 (Energy Exemplar, North Adelaide, Australia). In particular, the following assumptions have been made:

(a) Each connection is characterized by its net transfer capacity (NTC) [126], [127], i.e., the maximum power exchange capacity between two areas compatible with security standards [119]. Assuming high liquidity of the day-ahead electricity market, the NTC is considered fully available for the day-ahead market, thus, it is assumed that ATC = NTC. This assumption is in line with the current ATC-based network modeling in EUPHEMIA. Under the ATC-based model, the impact of HVDC or HVAC interconnection types are inherently considered in calculation of NTCs.

(b) In each zone, except for the Baltics, all the generators of the same type are lumped in one equivalent generator, with rated capacity equal to the sum of the individual generators [128]. Inside the Baltics, large generators are individually represented (30 in Estonia, 20 in Latvia, and 22 in Lithuania).

(c) I considered the ENTSO-E winter-peak snapshot in January (19:00 p.m.) and summer-peak snapshot in July (11:00 a.m.) [128]. The aggregated electricity demand in the Baltic States is 5520 MW in the winter peak and 3780 MW in the summer peak. Electricity consumption in all the European countries included in the model, in winter and summer snapshots, are represented in Figure 3.6.

(d) The output power of wind and solar power plants in the summer-peak snapshot have been assumed equal to the average generation profiles during 11:00 a.m. for the July days in [129], [130], and modified based on the installed capacities under ENTSO-E Vision 3. Similarly, for the winter-peak snapshot, the average of the generation data for wind and solar power plants during the January 19:00 p.m. days was extracted from [129] and [130].

(e) Primary reserve is assumed to be provided by thermal and hydro power plants equipped with droop control on the governor system. Considering 5% droop on generators' governor system [131], and full activation of primary reserve in response to a 200 mHz frequency drop, it has been approximated that all the online thermal and hydro generators inside the Baltic states can provide up to 8% of their available capacity for primary reserve. This assumption is not in contrast to the reserve requirement in Table 3.1. However, it limits the maximum available primary reserve capacity inside each Baltic country.

(f) Primary reserve service is not co-optimized with energy in the day-ahead electricity market and is supposed to be provided through a separate approach, before energy market clearing, e.g., through long-term contracts or individual ancillary service markets. This assumption is in line with the current European market model. Therefore, first the primary reserve requirement is allocated to all the thermal and hydro power plants of each bidding zone according to the merit order list, based on their marginal generation costs. The primary reserve market modeling and pricing mechanism is out of the scope of this study.

(g) The VOLL is considered to be 1000 €/MWh. Since demand response programs are not included in this study, I considered a relatively high VOLL (compared to marginal generators' cost) to avoid load curtailment as long as possible.

3.5 Comparative analysis of synchronization schemes

Three different synchronization schemes, as listed in Section 3.2, are compared in terms of day-ahead market performance (zonal prices and generation surplus), congestion management costs, and primary reserve adequacy inside the Baltic States.

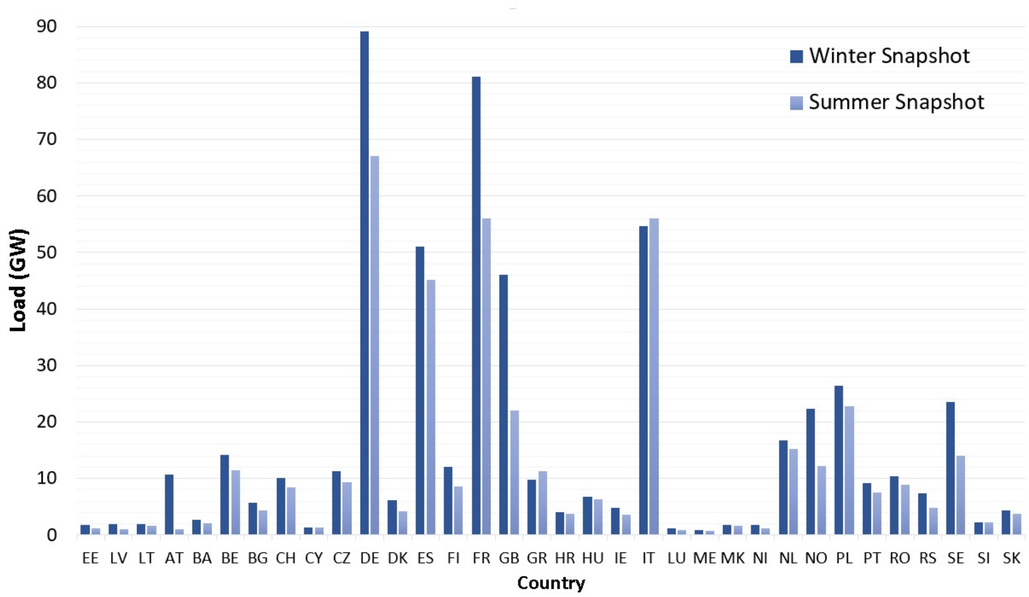

Figure 3.6: Electricity demand in European countries in ENTSO-E's winter-peak and summer-peak snapshots

3.5.1 EU integrated day-ahead market performance

Different synchronization schemes may impact the market performance, since, under different schemes, NTCs between the three Baltic zones and the rest of Europe, with respect to the EU day-ahead market clearing, may change and the required provision of the primary reserve may impact differently the power that the generation units can bid on the market. The cross-zonal NTCs are calculated by subtracting the total available transmission capacity and a security margin based on N-1 security criteria, plus the required capacity for transferring primary reserves between the corresponding zones.

Baltic synchronization with CEN countries reduces the NTC from Poland to Lithuania for energy transactions in the day-ahead market to 927 MW, while the NTC in the opposite direction, from Lithuania to Poland, is 1588 MW [104]. In the other synchronization schemes, the NTC of the Lithuania–Poland interconnection is 1000 MW. The NTCs between Estonia and Finland (1016 MW) and Lithuania and Sweden (700 MW) do not change in the three synchronization schemes.

From the other side, the required primary reserve in the Baltic States under Baltic-CEN synchronization scheme is 32 MW and can be provided solely by hydro power plants. However, under the other synchronization schemes (Baltic-Nordic and Baltic autonomous synchronous operation schemes), 8% of the available hydro and thermal capacity is held for primary reserve, which reduces the available thermal capacity of the Baltic States in the day-ahead market, from 3485 MW to 3206 MW. Moreover, the relatively high requirement of the primary reserve in these schemes requires maintaining all the thermal power plants spinning in the Baltic power systems, running close to their minimum technical limit, which in turn leads to insufficient revenue of conventional generators in the day-ahead market and requires uplift charges.

The day-ahead market results are represented in Figure 3.7 and Table 3.4. Figure 3.7 illustrates the cross-border power exchanges between the Baltic States and other European countries. The results indicate energy import to the Baltics from Poland and energy export from the Baltics to Sweden during winter-peak snapshots in all desynchronization scenarios. However, the energy exchanges between Finland and Estonia change significantly from the first synchronization Scenario (BCES), in Scenario 2 (BNS) and Scenario 3 (BAS).

Table 3.4: Day-ahead market results in different synchronization schemes (2030)

Market Performance Metrics	BCES Scheme		BNS Scheme		BAS Scheme	
	Winter Peak	Summer Peak	Winter Peak	Summer Peak	Winter Peak	Summer Peak
Baltic's Day-head Price [€/MWh]	61.5	21.3	61.5	21.3	61.5	21.3
Baltic's Net export [MW]	789	-2121	-546.5	-1445	-569.5	-967.8
Europe-wide Settlement /Merchandize[2] Surplus [€]	20,025	261,840	20,165	261,840	20,165	261,840
Baltic's Generation Surplus [€]	161,893	31,575	155,822	13,644	155,012	-4304
Europe-wide Generation Surplus [M€]	24.515	5.366	24.509	5.348	24.508	5.330

The impact of the synchronization scheme on the day-ahead market performance is higher in the summer snapshot with lower energy demand, because social welfare minimization results in 100% renewable generation in the Baltic States, while, to ensure available primary reserve for emergencies, it is required to keep the conventional generators with governor system synchronized in the power system. Since the primary reserve contracts/market is supposed to be cleared before the day-ahead market clearing, it is the producers' responsibility to keep spinning and to be available to activate their primary reserve, if required by the TSO. Therefore, we assumed that primary reserve providers offer zero price at the day-ahead market for their minimum technical limit and offer their marginal costs for the

[2]Merchandize surplus is the difference between the aggregate amount paid by consumers and the aggregate amount paid to generators

rest of their capacity. Under this assumption, the generators' surplus in the Baltic States reaches a negative value under the Baltic autonomous synchronous operation scheme (BAS).

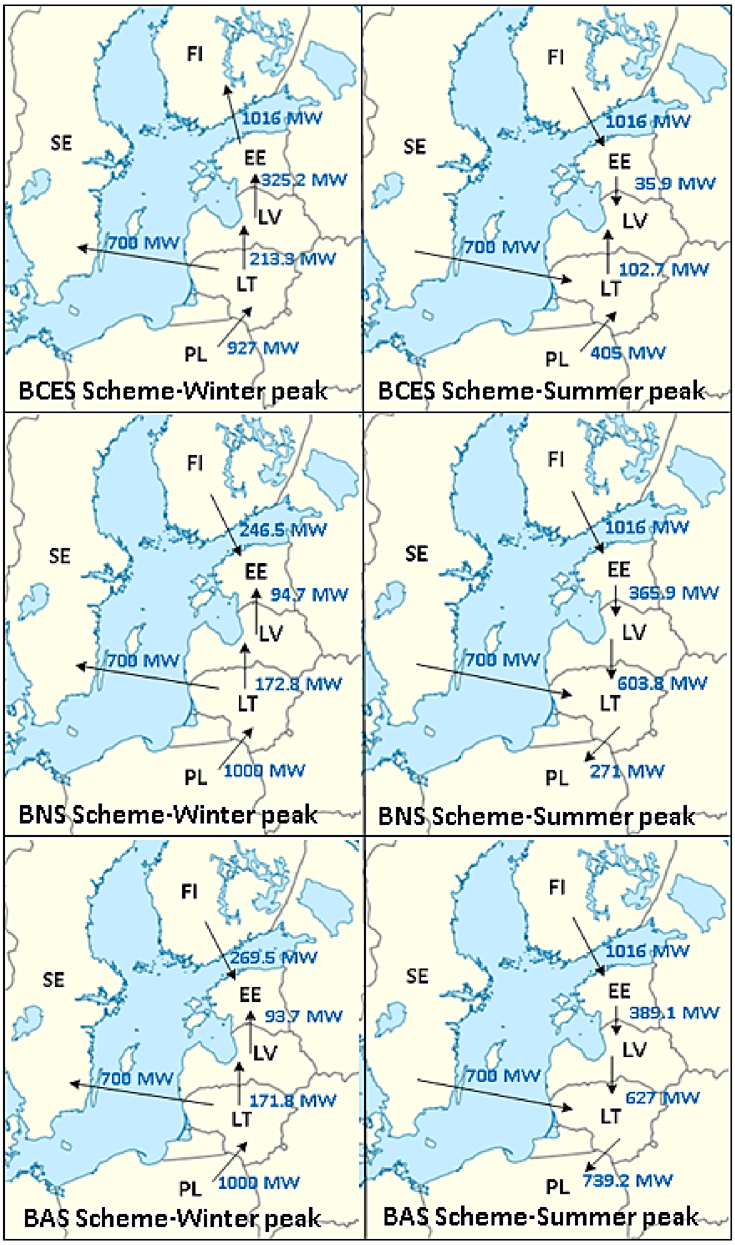

Figure 3.7: Cross-border power exchanges resulting from the European day-ahead market integration model (2030)

Table 3.4 summarizes the financial outputs of the day-ahead market model in the three predefined desynchronization scenarios in both winter-peak and summer-peak snapshots, including the day-ahead market price in the Baltic states, the Baltics' net interchange, settlement surplus (difference between cost to load and generator revenues), and generation surplus (generator's profit). The results show higher generation surplus inside the Baltic States and all of Europe in Scenario 1 (BCES), compared to the other two scenarios. The resulting financial loss of reserve-provider generators is supposed to be covered through uplift payments or reserve remuneration mechanisms.

3.5.2 Congestion management results within the Baltic States

The Baltic synchronization scheme impacts the generation schedules in the day-ahead market, as well as cross-border power exchange between the Baltic States and the rest of the Europe, as shown in Figure 3.7. Therefore, the synchronization scheme may change the intra-zonal power flows inside the Baltic States and lead to intra-zonal congestion.

We implemented congestion management inside the Baltic States through modeling a network-constrained re-dispatch market model, considering a detailed transmission network of the three Baltic States [106], as well as power exchange with the neighboring countries. The re-dispatch market results are summarized in Table 3.5 and Figure 3.8 - Figure 3.10.

Table 3.5: Re-dispatch results in Estonia, Latvia, and Lithuania—winter peak (2030)

Scheme	Re-dispatch Cost [€/h]			Renewable Curtailment [MWh]		
	Estonia	Latvia	Lithuania	Estonia	Latvia	Lithuania
BCES	0	0	7877	0	0	125
BNS	493	0	7996	0	0	127
BAS	499	0	8175	0	0	130

As it can be seen in Figure 3.8 - Figure 3.10, generation schedules in the day-ahead market result in no congestion inside Latvia in all the three synchronization scenarios. However, in Estonia and Lithuania, network constraints compel the system operator to dispatch more expensive units as waste and geothermal power plans, while decreasing the output of cheaper units from the day-ahead market results. Over the summer-peak snapshot in all three desynchronization schemes, the day-ahead market schedules satisfy internal network constraints inside Estonia, Latvia, and Lithuania, and there is no need to re-dispatch the generation units.

Baltic-CEN synchronization scheme leads to free flow of power dispatches resulted by day-ahead market schedules, within the power grid pf Estonia and Latvia,

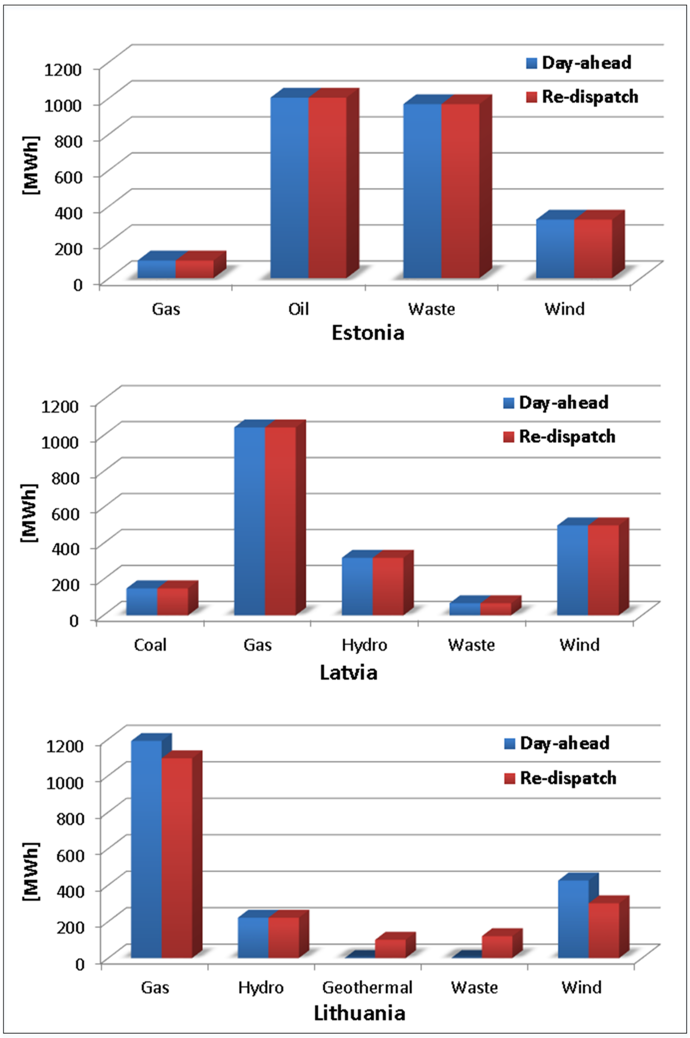

Figure 3.8: Comparison of energy generation by each fuel type in day-ahead and re-dispatch markets under BCES synchronization Scheme —winter peak (2030)

in the winter snapshot. However, the Lithuanian TSO needs to re-dispatch some generators and curtail wind energy to manage congestions on its transmission network (Figure 3.8).

Under Baltic-Nordic synchronization scheme (BNS), besides Lithuania, Estonian transmission grid also gets congested from the day-ahead market schedules. However, re-dispatch in Estonia does not lead to renewable curtailment and re-dispatch cost is also considerably lower than in Lithuania (Figure 3.9). As shown in Figure 3.10, the situation is almost similar in the case of Baltic Autonomous synchronization scheme (BAS), as in both BAS and BNS schemes, Baltic States are net electricity importer. Importing electricity from Finland in day-ahead market violates some of the internal network constraints in Estonia which in turn increases

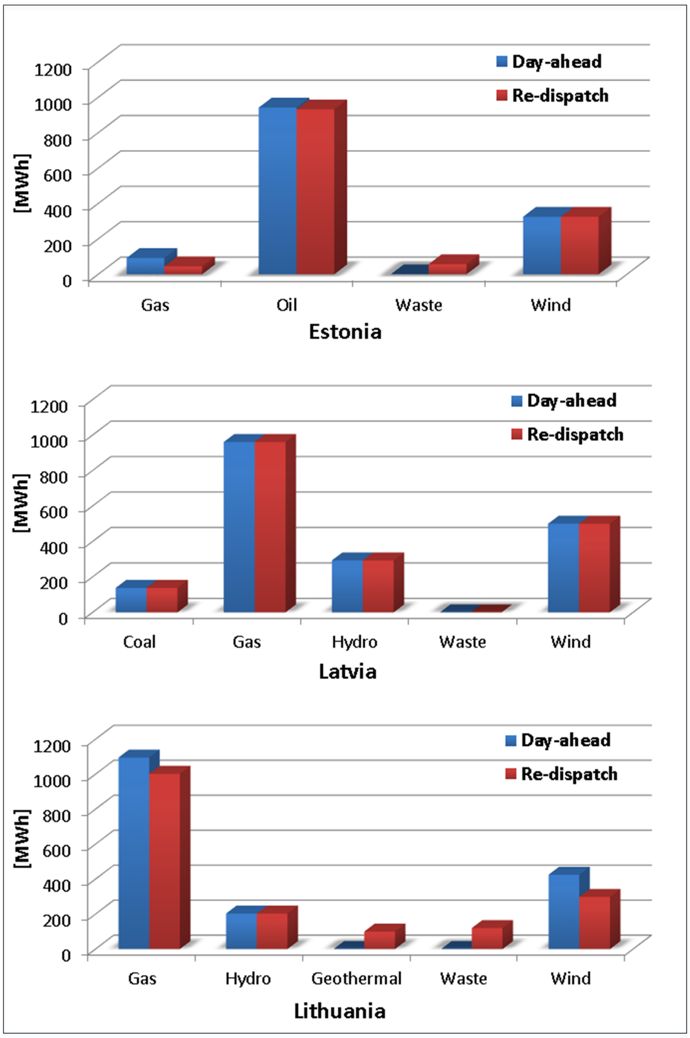

Figure 3.9: Comparison of energy generation by each fuel type in day-ahead and re-dispatch markets under BNS synchronization Scheme —winter peak (2030)

the congestion management costs in the Baltics, making the BCES synchronization scheme the prior option in terms of re-dispatch costs.

3.5.3 Primary reserve adequacy in the Baltic States

As reported in Table 3.1, the required primary reserve capacity in the three Baltic States under different synchronization schemes differs significantly. The total primary reserve requirements in the Baltic States are 32 MW in the Baltic-CEN synchronization scheme (BCES), 298 MW in Baltic-Nordic synchronization scheme (BNS), and 700 MW in the Baltic autonomous synchronous operation scheme (BAS). However, the maximum available primary reserve in each Baltic state is

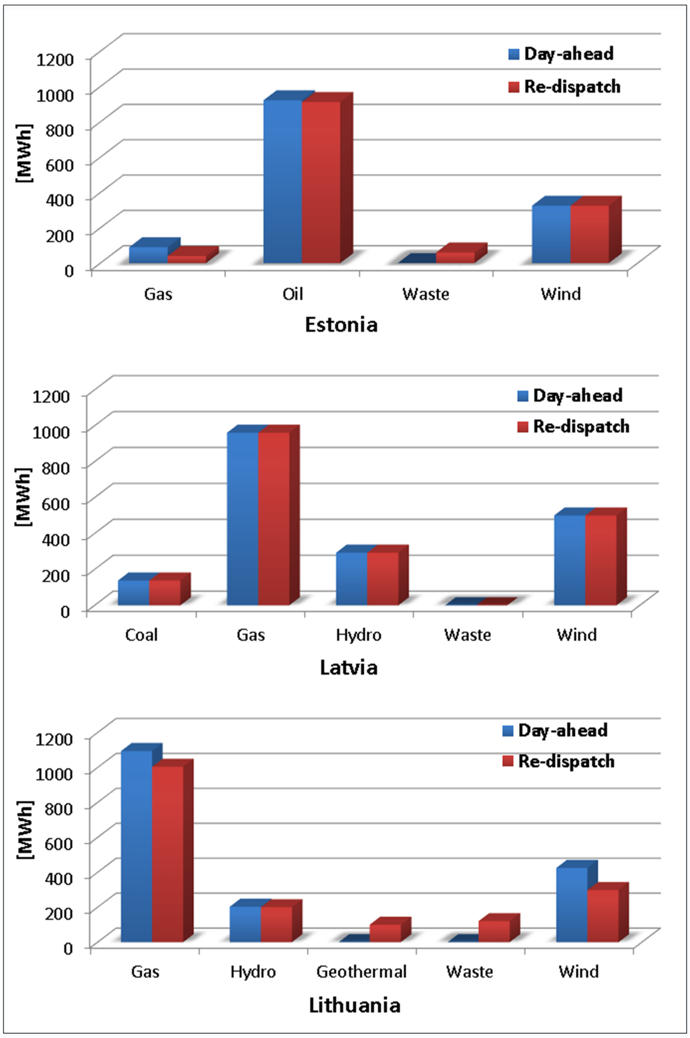

Figure 3.10: Comparison of energy generation by each fuel type in day-ahead and re-dispatch markets under BAS synchronization Scheme —winter peak (2030)

limited, which may result in reserve deficit under some synchronization schemes.

The available primary reserve capacity and reserve deficit in Baltic power systems are listed in Table 3.6. The reported reserve deficit is calculated as the difference between reserve requirement in each scenario (Table 3.1) and the available reserve in each country. The fifth unit of the pumped-storage hydroelectricity plant Kruonis in Lithuania, planned by 2020, is considered to provide an additional 170 MW primary emergency reserve capacity. As represented in Table 3.6, the Baltic autonomous synchronous operation scheme (BAS) causes a primary reserve deficit in Estonia and Latvia, leading to additional investment cost for building new emergency power plants under this scheme.

Table 3.6: Primary reserve capacity and reserve deficit in Baltic States (2030)

Country	Available Primary Reserve[MW]	Primary Reserve Requirement[MW]			Primary Reserve Deficit[MW]		
		BCES	BNS	BAS	BCES	BNS	BAS
Estonia	88	9	66	253	0	0	165
Latvia	121	8	110	175	0	0	54
Lithuania	113(+170)	15	122	272	0	0	0

3.6 Conclusions and discussion

In this study, three future synchronization schemes of the Baltic States power system—(1) Baltic-CEN synchronization, (2) Baltic-Nordic synchronization, and (3) Baltics in autonomous synchronous operation—were compared in terms of day-ahead market performance, congestion management, and reserve adequacy.

The modeling results for 2030 show that Baltic synchronization with the CEN (BCES) leads to the highest generation surplus and lowest re-dispatch cost in the Baltic States. Day-ahead market clearing in this scheme leads to intra-zonal congestion only inside Lithuania during the winter peak. Furthermore, the available primary reserve capacity inside the Baltic States is adequate for synchronization with the CEN.

Baltic synchronization with Nordic countries (BNS) leads to a decrease in generation surpluses in the Baltic States, especially in the summer peak. The difference between generation surpluses in different synchronization schemes is more remarkable during the summer peak with lower electricity demand, as generators need to be kept spinning to ensure a sufficient amount of primary reserves within the Baltic power system by offering a zero price in the day-ahead electricity market. Day-ahead market clearing results in intra-zonal congestion inside Estonia and Lithuania in the winter peak, and the re-dispatch cost increases, compared to BCES scheme. Even though the primary reserve requirement in the Baltic states in this scheme is a lot higher than in the Baltic-CEN synchronization scheme, with the planned emergency power plant in Lithuania (extra 250 MW by 2020), there will be no primary reserve deficit in the Baltic states.

The Baltics' autonomous synchronous operation (BAS) leads to the lowest generation surplus inside the Baltic States in the winter snapshot, and even negative surplus in the summer snapshot. The day-ahead market clearing leads to intra-zonal congestion in Estonia and Lithuania, with the highest re-dispatch cost among all the possible synchronization schemes, and the available primary reserve capacities inside Estonia and Latvia cannot meet the requirement in these countries.

To summarize, the Baltics' synchronization with the CEN is the most preferable scenario for generation companies and system operators in terms of generation surplus and intra-zonal congestion management. Even though previous studies have confirmed that all three schemes are technically feasible, the Baltic-CEN synchronization scheme requires the lowest amount of investment for network and generation expansion, which, in turn, is to be more straightforward to be implemented in terms of policy-making complexity. This outcome, even if driven from different results, is in line with previous studies [104].

Nomenclature

Abbreviations

EU	European Union
HVAC	High Voltage Alternating Current
IPS/UPS	Integrated/Unified Power System
BRELL	Belarus, Russia, Estonia, Latvia, Lithuania
CEN	Continental Europe Network
CM	Congestion Management
HVDC	High Voltage Direct Current
TSO	Transmission System Operators
NTC	Net Transfer Capacity
FCR	Frequency Containment Reserve
FCR-D	frequency containment reserve under disturbance
EUPHEMIA	EU+ Pan-European Hybrid Electricity Market Integration Algorithm
ATC	Available Transfer Capacity
VOLL	Value Of Lost Load

Symbols

$\mathcal{G}$	Set of conventional generators, indexed by g
$\mathcal{V}$	Set of renewable generators, indexed by v
$\mathcal{D}$	Set of electricity consumers, indexed by d

$\mathcal{B}$	Set of transmission network nodes, indexed by i,j
$\mathcal{G}_i$	Set of conventional generators connected to node i, indexed by g
$\mathcal{V}_i$	Set of renewable generators connected to node i, indexed by v
$\mathcal{D}_i$	Set of electricity consumers connected to node i, indexed by d
C^{CM}	Total re-dispatch/congestion management cost
G_i^{k-1}	Total energy generation in control region i during k-1th year
R	Total capacity required as primary reserve in the synchronous area
r_i^k	Primary reserve capacity provided by each control region
D_i^k	Dimensioning fault in the control region i during the year k
$\rho_g^{CM,\ up}$	Upward adjustment offer prices by conventional generator g in re-dispatch market
$\rho_g^{CM,\ dn}$	Downward adjustment offer prices by conventional generator g in re-dispatch market
$\Delta P_g^{CM,\ up}$	Upward adjustment power provided by conventional generator g in re-dispatch market
$\Delta P_g^{CM,\ dn}$	Downward adjustment power provided by conventional generator g in re-dispatch market
$K_v^{CM,\ cu}$	Penalty price of renewable curtailment in re-dispatch market
$P_v^{CM,\ cu}$	Curtailed power of renewable generator v in re-dispatch market
V_d^l	Curtailment cost of customer d in re-dispatch market (VOLL under inelastic demand assumption)
$L_d^{CM,\ l}$	Curtailed load of customer d in re-dispatch market for congestion management
P_g^{DA}	Scheduled output power of conventional generator g in day-ahead market
P_g^{Max}	Maximum power of conventional generator g
P_g^{Min}	Minimum power of conventional generator g due to technical limits
$P_{g,\ t}^{Res}$	Reserve capacity provided by conventional generator g

F_{ij}^{CM}	Power flow from node i to node j
$L_d^{DA,\ l}$	Power demand of customer g in day-ahead market
B_{ij}	Susceptance of transmission line between nodes i and j
θ_i^{CM}	Voltage angle of node i

Chapter 4

Integrating Electricity Markets in Europe

"This chapter is the extension of the study which has been previously published in [132]."

The European Commission has set a target of establishing an integrated Europe-wide electricity market for day-ahead and intraday transactions. Day-ahead electricity markets in Europe are already integrated remarkably. The next important step toward enhancing integration in European electricity markets is to establish a Europe-wide intraday market. However, there are still many open questions on the potential benefits of a Europe-wide intraday market integration and the harmonizing market rules. The study presented in this chapter of my thesis intends to provide a precise insight into the potential impacts of EU policies regarding integrating electricity markets on market efficiency and on different market players with the aim of supporting policy makers to increase the penetration of renewables in a cost efficient manner. In this chapter, I investigate and compare the current option of regional intraday electricity market with the option of an integrated Europe-wide one, with reference to the three European test cases with high renewable penetration: the Iberian electricity market including Spain and Portugal, the Italian electricity market including Italy and Slovenia, and the electricity market of Germany. Two 2030 scenarios are considered: (i) the regional/local intraday electricity market, and (ii) the integration of the current regional intraday market of the test cases into a single intraday market in Europe. The two scenarios are modelled through stochastic Monte Carlo simulation, considering uncertainty on electricity demand, wind and solar power. The performance of the intraday market under the two options are compared in terms of electricity prices, producer' surplus, load expenditure, and renewable curtailment inside the European test cases.

List of the abbreviations used in this chapter is provided at the end of the chapter.

4.1 Introduction

The ever-increasing penetration of power generators from fluctuating renewable energy sources (RES) with hardly predictable weather-dependent outputs brings new challenges to a reliable and secure operation of electricity power systems. RES promotion has long been a driving factor of the European Union (EU) policies. The European Council agreed on a 2030 Framework for climate and energy in October 2014 which includes EU-wide energy targets and policies for the period 2020 to 2030 [133]. For the 2030 horizon, the EU has established a target of 40% reduction of greenhouse gas emissions, and 32% of the final energy consumption produced from RESs [133], [134]. To ensure EU is able to meet its energy objectives, the European Commission set out its energy strategies in February 2015 based on five key areas: securing supplies, expanding the internal energy market, increasing energy efficiency, reducing emissions, and research and innovation [134].

Increasing RES penetration in electricity markets reduces the short-run wholesale electricity market prices as RES generation units have marginal costs close to zero and may replace part of thermal units in market schedules reducing market prices, eventually to zero [135]. On the other side, the management of power imbalances due to the intermittent nature of variable RES such as wind and solar, brings new challenges to the electricity markets, as these units are affected both by variability and uncertainty. This uncertainty to the power system operation leads to increasing need for higher flexibility in power demand and generation, as well as in electricity trading [136].

Day-ahead forecast errors are balanced by activating adjustment offers of generators and demand-side resources in intraday markets. Currently, an increasing number of electricity markets with high RES penetration hold intraday markets in which market participants can adjust their offers closer to the delivery time considering the most updated forecast [137]. The impacts of the intraday trading in Nordic electricity markets under different wind power shares is analyzed by Amelin [138]; the results show, as expected, that the intraday trading requires higher balancing resources in power systems with high RES penetration. Fattler and Pellinger [139] modelled a virtual intraday market integration in five European countries including Austria, Belgium, Germany, Denmark, and France assessing the impact of increasing the size of control area on flexibility requirement. The results prove that a Europe-wide intraday electricity market can significantly improve the power system's flexibility which is needed to compensate power forecast errors in real time. However, the transmission capacity between the countries has not been considered in [139].

Integration of day ahead and intraday electricity markets at the European level is considered by the European commission as a crucial way to increase competition, eliminate price difference across countries, increase social welfares and to achieve more efficient utilization of electricity networks and generation capacities

[106], [140]. The European commission has defined its target model for the unified day ahead and intraday electricity market model in Europe [141], [142]. It is generally accepted that electricity market coupling can succeed in enhancing economic welfare and generation adequacy in total, as well as in each market area. The integrated European day-ahead market model has been widely discussed in the literature [8], [33], [52], [143]. The crucial issue of providing operating reserve services inside each country has not been addressed in these studies. Therefore, the results may fail to capture the operating reserve requirement in each country in order to preserve system security. Provision of reserve affects bidding strategy of generators and generation schedules within the energy market, although currently energy and operating reserves are procured separately in European power systems [8], [144].

Modelling the Europe-wide intraday market and the potential benefits of intraday market integration have not been addressed in the literature. Integrating intraday markets plays an important role in accommodating the increasing amount of power generation from RES in Europe. The purpose of this study is to examine the potential benefits of intraday market coupling across Europe through the development of a theoretical model and its application to a comprehensive set of real real-world numerical studies based on a representative number of European countries. To fulfil this objective, this study provides a Europe-wide day-ahead and intraday market clearing model with implicit auctions for cross-border capacity allocation, incorporating the national and regional primary and secondary reserve requirements.

In this study, the integrated day-ahead electricity market is cleared simultaneously with primary reserve (frequency containment reserve) and secondary reserve (automatic frequency restoration reserve) in the European power systems, as defined by ENTSO-E in [145]. Consequently, the availability of the required reserve capacity in each country is ensured. The co-optimization model can tackle the bidding strategy of thermal and hydro power plants in energy market taking into account the opportunity cost related to their participation in the reserve market, although in a simplified manner. Furthermore, the behavior of traders that participate in both energy and reserve markets and arbitrage price difference between these markets are implicitly considered into the model [8], [146]. Despite of the generators' output power, the reserve schedules are also updated hourly in the intraday market to reduce total operation (electricity and ancillary services) costs. This 2-stage reserve provision design can facilitate the use of flexible demand-side resources in the ancillary service markets. We consider, as illustrative test case, five European power systems with high share of renewables which currently implement regional intraday markets, including Spain, Portugal, Italy, Slovenia, and Germany. ENTSO-E has anticipated the share of RESs' capacity (including wind, solar, hydro, and biofuels) to the total installed capacity in these countries as 70% in Spain, 83% in Portugal, 63% in Italy, 76% in Slovenia, and 76% in Germany, by 2030 [147].The market performance of an integrated European intraday market (in which all the 34 European countries can bid in the same intraday market) is assessed with respect to the current regional markets inside the European test cases, in terms of average intraday prices, producer surplus, loads expenditure and renewable curtailment.

In the above context, the specific contributions of this study in addressing the main question of the impacts of integrating European intraday markets, can be summarized as: ① Developing a European power dispatch model, covering 34 European countries, following ENTSO-E Scenario 2030-EUCO [147] which follows policy projections of the EU by 2030; ② Modelling the uncertainty of wind and solar production, as well as electricity demand; ③ Analysing the impact of intraday market integration on market performance within European test cases, through stochastic Monte-Carlo simulation; ④ Modelling the simultaneous optimization of energy and reserves (primary and secondary), taking into account the real-word national/regional reserve requirement; and ⑤ Assessing the role of flexibility provided by hydro pumped storage units, participating in the market, on day-ahead and intraday market performance.

4.2 Europe-wide integrated intraday market design

The growing penetration of variable renewable energy sources in European power systems enhances the importance of intraday electricity markets to balance generation/demand deviations after day-ahead gate closure. Currently European countries perform different types of intraday markets in national or regional levels which in general can be categorized into continuous and auction-based markets. For instance, NordPool offers a continuous intraday market covering the Nordic and Baltic countries, as well as UK, and Germany. Trading in this market takes place every day and all over the day until one hour before delivery [102]. Spanish and Portuguese power systems participate in an auction-based intraday market which is structured into six market sessions. Each session covers the intraday trades from 3 hours after gate closure up to the end of the day (hour 24) [148]. Epexspot holds individual intraday auctions within Great Britain and German power systems [149]. Intraday auctions in Great Britain perform half hourly trades with totally 48 half hourly batches per day; whereas German intraday market performs 15-minute auctions. However, the European Commission has set up common rules to harmonize European intraday power markets and to achieve efficient utilization of cross-border capacities, allowing cross-border electricity trading closer to real time [102].

European electricity market models follow a zonal design in which each zone is connected to other zones with equivalent cross-border transmission connections and intra-zonal congestion is neglected [8], [139], [150]. A Europe-wide intraday market design should consist of an efficient transmission capacity allocation approach to reflect congestion under transmission capacity scarcity, while no extra charges should be applied to intraday cross-zonal capacity [142]. In other worlds, transmission capacity in both day-ahead and intraday markets should be allocated through implicit methods, together with electrical energy. However, unlike the integrated day-ahead target model, the intraday market design should rely on continuous trading possibility (continuous implicit allocation [151]). The current continuous trading approaches, e.g. the intraday market of NordPool (Elbas), rely on the so called "first come – first served" principle where the highest buy price and the lowest sell price get served firsts [152]. This trading approach results in non-uniform prices for each market time unit. Furthermore, it requires a capacity management module to continually allocate cross-zonal capacity for inter-zonal trades [142] which in turn poses challenges in terms of finding an efficient pricing model, capable of reflecting capacity scarcity and providing investment signals. In other words, the potential scarcity value of cross-zonal capacity in continuous markets is captured by the quickest market participants and not the ones who value the capacity the most.

Basically, three intraday pricing options have been introduced by ENTSO-E in [142] as: i) implicit continuous trading model, ii) implicit continuous trading with pricing, and iii) implicit auction model. The implicit continuous trading model is similar to the current intraday continuous market models which do not implement any intraday cross-zonal capacity pricing approach and always sets intraday cross-zonal capacity price to zero. The main disadvantage of this model is its weakness to ensure efficient pricing of intraday market and its inability to take into account the willingness of market participants to pay for intraday cross-zonal capacity. The so called implicit continuous trading with pricing model is based on embedding the pricing of intraday cross-zonal capacity within the intraday continuous allocation, through a number of different models such as forecasting congestion during trading session or price scaling based on the share of allocated cross-zonal capacity compared to the maximum available intraday cross-zonal capacity. The cross-zonal capacity price in this model also depends on the allocation time, hence the price is lower for quicker marker participants. The main drawback of all these models is their complexity and inefficiency in cross-zonal capacity allocation.

On the contrary, the implicit auction model works based on holding implicit auction trading sessions at European level during certain periods throughout the day and allocating the available cross-zonal capacities through applying a market coupling mechanism between bidding zones. This approach allows to determine prices for intraday cross-zonal capacities that reflect capacity scarcity at the moment of the intraday auction. Furthermore, it applies uniform pricing to clear the market participant which incentivizes them to reveal their actual preferences in terms of offer prices and volumes into the market, whereas pay-as-bid mechanism is applied in the continuous matching models. In spite of all the advantages of the implicit auction only model, it is not in line with European target model in term of its incapability in continuous trading and cross-zonal capacity allocation.

To fulfil all the requirement of the European target model, a hybrid model is suggested by ENTSO-E to be implemented based on both auction model and continuous trading. Through the hybrid model, the intraday cross-zonal capacity is primarily priced through intraday auctions starting from day-ahead time frame to several intraday time frames, each covering a subset of the intraday market time units (i.e. the period for which the market price is established) for the delivery day. After closure of each intraday auction for a certain subset of market time units and publishing the auction results, a continuous matching session opens for the same market time units. Figure 4.1 illustrates the cross-zonal capacity allocation and timing of intraday auction and continuous trading in the initially proposed hybrid model by ENTSO-E in [142]. In the initial model, only two intraday auctions are considered. However, the number of auctions could be changed in future. The more regular intraday auctions decreases the trades in the continuous markets and the real-time imbalances. The implicit auctions are independent from continuous trading. The hybrid model is straightforward, practical, efficient and fair in terms of pricing and matching of supply and demand.

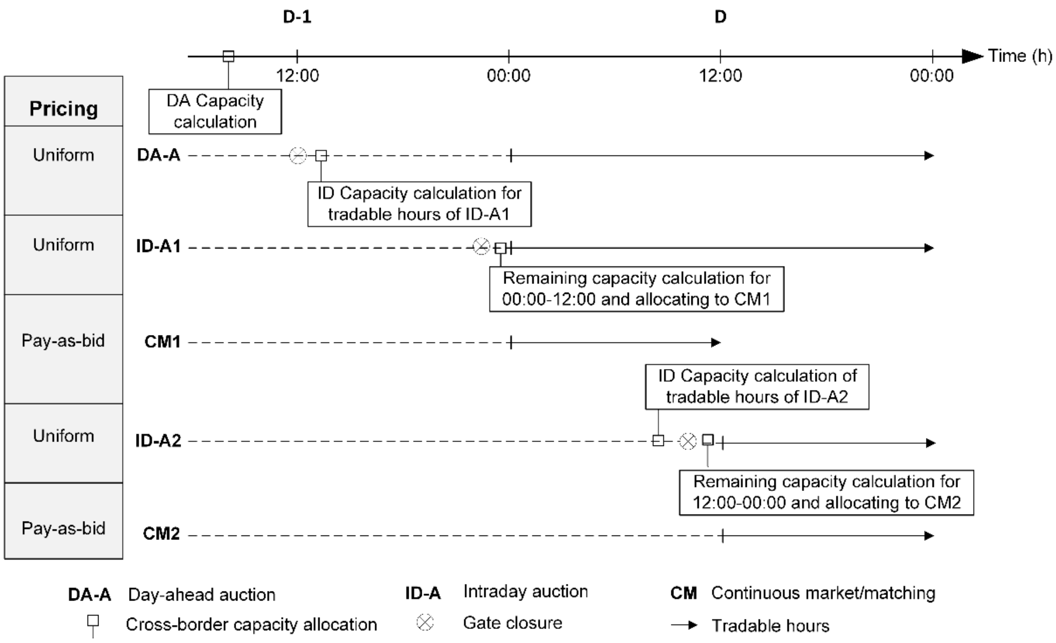

Figure 4.1: ENTSO-E intraday market and cross-border capacity allocation model

In this thesis only the intraday auction is performed, since it is executed before continuous matching and the cross-zonal capacity pricing is embedded in the auction mechanism. Therefore, it is expected that market participants with high priority to adjust their bids in intraday market will participate in the auction to ensure their access to cross-zonal transmission capacity; while the remaining capacity, if existed, will be provided for continuous matching. However, modelling continuous trades is out of the scope of this study.

4.2.1 Role of flexible resources in the market

Due to the uncertainly and variability characteristics of RESs, achieving the generation-demand balance in power systems with high RES penetration will become increasingly challenging. Gradual decommissioning of thermal peak power plants, consistent growth of electrical demand, decreasing market prices as well as the deficiency of scarcity prices within integrated markets are among the main reasons that intensify the challenges regarding integration of RESs into the power systems. Therefore, the European electricity sector requires more flexible resources to accommodate RES growth. Non-integration of flexibility into the electricity markets and power system management will lead to significant renewable curtailment and high operation costs [153]. Increasing flexibility is considered as one of the key elements in EU's energy policy [154].

Flexibility can be provided from either supply or demand side resources. Flexible supply-side resources include fast-ramping generation resources and large-scale storage technologies, e.g. hydro pumped-storage units [154], [155]. Due to the high investment costs of these resources and low capacity factors, along with the low average market prices in power systems with high RES share, persuasive incentives and considerable push by policy makers are required to motivate investors to enter this business.

Hydro Pumped Storage (HPS) power plants are considered as the most flexible and widespread technologies for large-scale electricity storage [156]. There are above 42 GW installed capacity of HPS generators in Europe, mostly concentrated in Germany, Italy, Spain, and France. HPS generators are connected to two reservoirs at different elevations. The schematic representation of HPS units in charging and discharging modes is shown by Figure 4.2. By pumping water to the up reservoir during the time intervals with low demand and high generation of non-flexible generators (i.e. variable renewable generators and base load generators), and releasing water back into the down reservoir during the scarcity intervals, HPS generators can contribute in balancing supply and demand in power systems. This supports the integration of variable renewable energy sources and non-flexible base-load power plants.

In this study, the market participation of HPS generators in day-ahead and intraday markets is modelled. Also the impact of flexibility provision from HPS units on market performance within the integrated Europe-wide day-ahead and intraday markets is assessed through comparing market results with and without

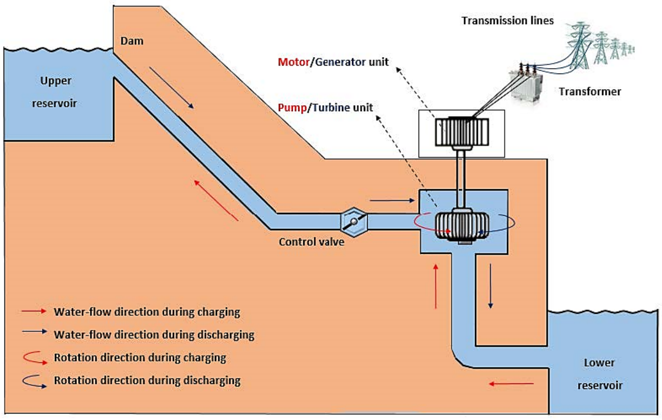

Figure 4.2: Schematic diagram of hydro pumped-storage plant [157]

their participation in the market. The market model presented in this study is able to capture the contribution of various storage technologies, not limited to HPS generators. In principal, any other storage technologies can be straightforwardly implemented by the model.

4.2.2 Day-ahead and intraday market models

The Europe-wide day-ahead and intraday electricity market models in this study are in line with the EU target model. Figure 4.3 represents the flowchart of day-ahead and intraday market models implemented in this study. As indicated in the flowchart (Figure 4.3), day-ahead market is executed based on the best forecasted values of VRE generation and demand, which are the stochastic variables in this model. The outputs of day-ahead market are then used as the input of the following intraday auctions. Intraday market model uses stochastic random variables for wind/solar production and hourly demand, generated from their day-ahead forecasted values and a predefined distribution function corresponding to their forecast error. After generating a large set of scenarios for VRE and demand realization, the optimization problem is executed for each sample, through a Monte Carlo optimization algorithm. Each day-ahead market is executed for the following 24 hours and accordingly 24 hourly intraday auctions are executed based on its outputs. Intraday forecast errors which should be balanced by TSOs in the real-time markets are neglected in this study. The mathematical formulation of the market simulation model as a MILP problem is provided in this section.

4.2.2.1 Day-ahead market model

The day-ahead market simulation model performs simultaneous optimization of energy and reserve, taking into account technical and financial constraints of

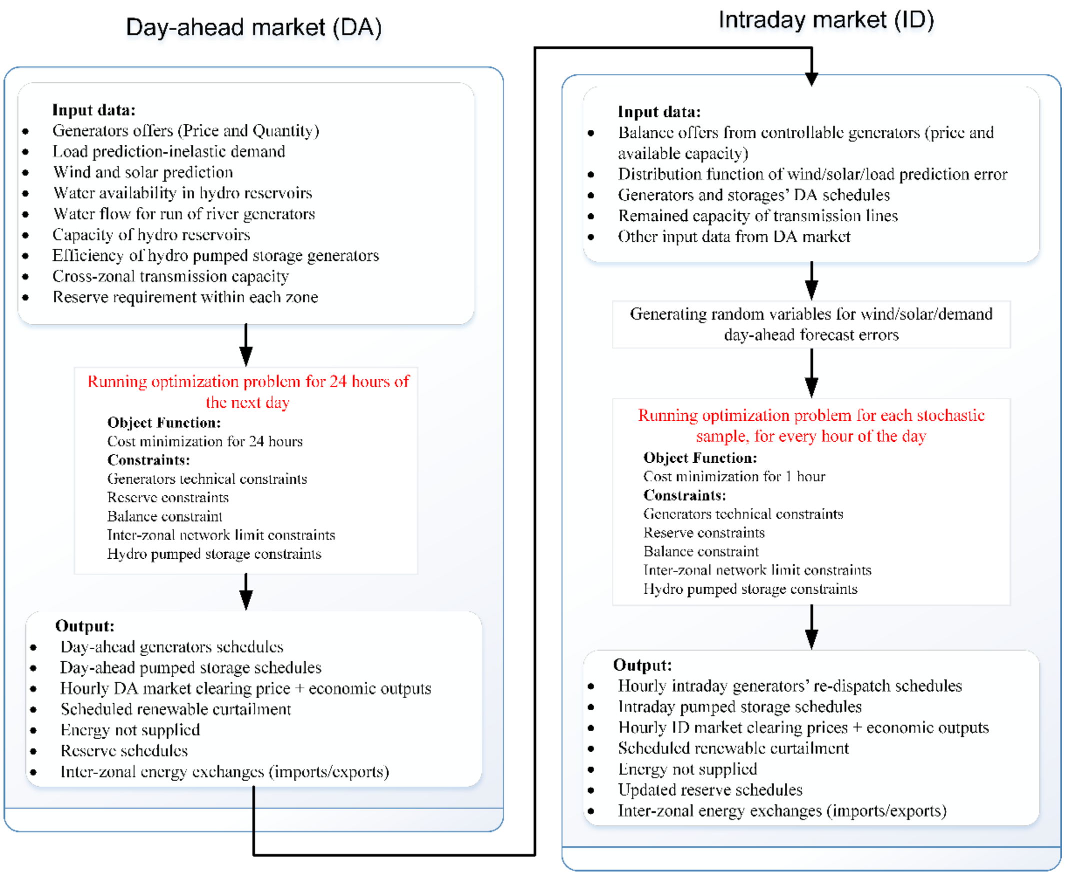

Figure 4.3: Flowchart of day-ahead and intraday market mechanism

generation units including: minimum/maximum power production limit of conventional generators, technical limits of hydro pumped-storage generators and their reservoirs' capacity limit, forecasted production profile of wind/solar generators, maximum available primary and secondary reserve capacities, as well as offer prices for energy and secondary reserve. Objective Function:

$$\underset{g^{M_1}, r^{M_1}, \mathcal{P}^{M_1}, E^{M_1}, u^{M_1}, \Phi^{II,M_1}}{Min} C^{M_1} = \sum_{t\in\mathcal{T}} \Big[\sum_{i\in\mathcal{G}} \left(g_{i,t}^{M_1} p_{i,t}^{M_1} + r_{i,t}^{II,M_1} p_{i,t}^{II,M_1}\right) + \sum_{s\in\mathcal{S}} \left(p_{s,t}^{M_1} g_{s,t}^{M_1} + \left(X_{s,t}^{M_1} - g_{s,t}^{M_1}\right) p^{S,Sp}\right) + \sum_{w\in\mathcal{W}} \left(p_{w,t}^{M_1} g_{w,t}^{M_1} + \left(X_{w,t}^{M_1} - g_{w,t}^{M_1}\right) p^{W,Sp}\right) + \sum_{n\in\mathcal{N}} \left(E_{n,t}^{M_1} V_{n,t} + \Phi_{n,t}^{II,M_1} V_{n,t}^{II}\right)\Big] \tag{4.1}$$

Generators' Constraints:

$$u_{i,t}^{M_1} \underline{g}_{i,t} \leq g_{i,t}^{M_1} \leq u_{i,t}^{M_1} \overline{g}_{i,t} \quad ;\forall i,t \tag{4.2}$$

$$\begin{cases} r_{i,t}^{I,M_1} \leq \overline{r}_i^{I} & ;\forall i \in \mathcal{G}_I, t \\ r_{i,t}^{I,M_1} = 0 & ;\forall i \notin \mathcal{G}_I, t \end{cases} \tag{4.3}$$

$$\begin{cases} r_{i,t}^{II,M_1} \leq \overline{r}_i^{II} & ;\forall i \in \mathcal{G}_{II}, t \\ r_{i,t}^{II,M_1} = 0 & ;\forall i \notin \mathcal{G}_{II}, t \end{cases} \tag{4.4}$$

$$r_{i,t}^{II,M_1} + r_{i,t}^{I,M_1} + g_{i,t}^{M_1} \leq u_{i,t}^{M_1} \overline{g}_{i,t} \quad ;\forall i, t \tag{4.5}$$

$$g_{w,t}^{M_1} \leq X_{w,t}^{M_1} \quad ;\forall w \in \mathcal{W}, t \tag{4.6}$$

$$g_{s,t}^{M_1} \leq X_{s,t}^{M_1} \quad ;\forall s \in \mathcal{S}, t \tag{4.7}$$

$$r_{i,t}^{II,M_1}, r_{i,t}^{I,M_1}, g_{i,t}^{M_1} \geq 0 \quad \forall i, t \tag{4.8}$$

$$g_{w,t}^{M_1}, g_{s,t}^{M_1} \geq 0 \quad \forall w, s, t \tag{4.9}$$

The objective function of the day-ahead market, equations (4.1), implies on the minimization of total energy and reserve provision costs. The market model is one-sided and demand is modelled as constant load with prediction errors to be balanced in intraday market. Equation (4.2) indicates that the accepted generation offer ($g_{i,t}^{M_1}$) from a conventional generator cannot exceed its dispatchable capacity[1] ($\overline{g}_{i,t}$), while it should be more than the minimum technical limit declared by the generation company ($\underline{g}_{i,t}$). Equations (4.3)-(4.6) represent the primary and secondary reserve constraints of the conventional generators. Note that not all the power plants can provide primary and secondary reserve services. Two sets $\mathcal{G}_I$ and $\mathcal{G}_{II}$ are defined for generators capable of providing primary reserve and secondary reserve, respectively. For generation units which do not belong to $\mathcal{G}_I$ and $\mathcal{G}_{II}$, primary and secondary reserve capacities are set equal to zero, by equations (4.3) and (4.4), respectively. The present market model only focuses on the provision of upward primary and secondary reserve capacities, as it is more challenging for the system operators. Furthermore, form the generation companies' viewpoint, provision of upward reserve has greater impact on their available capacity and offer strategy into the other markets. According to (4.5), the sum of accepted generation offers for provision of energy, primary reserve, and secondary reserve, in the day-ahead market, cannot exceed the generators' dispatchable capacity. Furthermore,

[1]The term "Dispatchable Capacity" in this thesis refers to the maximum production limit of a power plant which may be lower than its installed capacity due to various reasons such as planned/unplanned outages, water reservoir levels, and external temperature.

it indicates that primary and secondary reserve can only be provided by spinning generators (with $u_{i,t}^{M_1} = 1$) in day-ahead market, while non-spinning generators with no production in day-ahead market, cannot participate in reserve provision.

The model allows for planned curtailment of non-dispathcable RESs, i.e. wind and solar power plants, in the optimization problem. Therefore, the accepted output power of wind and solar power plants ($g_{w/s,t}^{M_1}$) may be less than their day-ahead predicted production ($X_{w/s,t}^{M_1}$), as indicated by equations (4.6)-(4.7). However, any curtailment in the market is penalized by a penalty factor ($p^{W/S,Sp}$) which is considered in the total operation cost in the objective function (4.1). Non-negativity constraint of scheduled energy production and reserve capacities by different generators in day-ahead market are indicated by (4.8) and (4.9).

Hydro Pumped-Storages' Constraints:

$$-\overline{\mathcal{P}}_h^p \leq \mathcal{P}_{h,t}^{M_1} + r_{h,t}^{II,M_1} + r_{h,t}^{I,M_1} \leq \overline{\mathcal{P}}_h^g \tag{4.10}$$

$$\Lambda_{h,t=0}^{head,M_1} = \Lambda_h^{0,head} \tag{4.11}$$

$$\Lambda_{h,t=0}^{tail,M_1} = \Lambda_h^{0,tail} \tag{4.12}$$

$$\Lambda_{h,t}^{head,M_1} = \begin{cases} \Lambda_{h,t-1}^{head,M_1} - \eta_h \mathcal{P}_{h,t}^{M_1} & ; if\ \mathcal{P}_{h,t}^{M_1} \leq 0 \\ \\ \Lambda_{h,t-1}^{head,M_1} - \mathcal{P}_{h,t}^{M_1} & ; if\ \mathcal{P}_{h,t}^{M_1} > 0 \end{cases} \quad ; \forall t \geq 1, h \tag{4.13}$$

$$\Lambda_{h,t}^{tail,M_1} = \begin{cases} \Lambda_{h,t-1}^{tail,M_1} + \eta_h \mathcal{P}_{h,t}^{M_1} & ; if\ \mathcal{P}_{h,t}^{M_1} \leq 0 \\ \\ \Lambda_{h,t-1}^{tail,M_1} + \mathcal{P}_{h,t}^{M_1} & ; if\ \mathcal{P}_{h,t}^{M_1} > 0 \end{cases} \quad ; \forall t \geq 1, h \tag{4.14}$$

$$\Lambda_{h,t}^{head,M_1} \leq \overline{\Lambda}_h^{head} \quad \forall t, h \tag{4.15}$$

$$\Lambda_{h,t}^{tail,M_1} \leq \overline{\Lambda}_h^{tail} \quad \forall t, h \tag{4.16}$$

$$\Lambda_{h,t=T^{start}}^{head,M_1} = \Lambda_{h,t=T^{end}}^{head,M_1} \quad \forall t, h \tag{4.17}$$

$$\Lambda_{h,t=T^{start}}^{tail,M_1} = \Lambda_{h,t=T^{end}}^{tail,M_1} \quad \forall t, h \tag{4.18}$$

HPS units can operator in both generation and pumping (i.e. load) mode which allows their output power ($\mathcal{P}_{h,t}^{M_1}$) to take positive or negative values. Also due to their quick response capability, these units can participate in providing primary and secondary reserve services. Sum of the scheduled energy production/consumption by a HPS unit in day-ahead market and its upward primary and secondary reserve capacity should not exceed the unit's maximum power production/consumption in generation/pumping mode, as indicated by (4.10). Two water reservoirs with limiter water storage capacity are considered for each HPS unit: head reservoir and tail reservoir. The initial volume of water within the head and tail reservoirs of each HPS unit is set by equations (4.11) and (4.12). Note that in order to correlate the energy production/consumption by HPS units under generating/pumping mode to the water stored into their head and tail reservoirs, the stored water is defined by its corresponding potential electrical energy. Accordingly, $\Lambda_h^{0,head}$ and $\Lambda_h^{0,tail}$ in (4.11) and (4.12) correspond to the equivalent energy stored in the head and tail reservoirs at the beginning of the simulation period ($t = 0$).

When HPS operates in generation mode (i.e. $P_{h,t}^{M_1}$>0), the water is transferred from the head reservoir to the tail reservoir which leads to the reduction of water level in the head reservoir and increment of water in the tail reservoir accordingly. However, the efficiency of HPS (η_h) is limited to 80% in this study which means consuming 100MWh energy in one time interval by an HPS unit can lead to only 80MWh electricity production in another time interval. This cycling efficiency is modelled in the pumping mode of the HPS unit, as shown in equations (4.13) and (4.14). This concept is schematically represented by Figure 4.4. As shown in Figure 4.4-(a), in pumping mode (i.e.$P \leq 0$), electricity is injected from the grid to the HPS unit to pump water from tail reservoir up to the head reservoir and the equivalent energy stored in the head reservoir of the HPS unit increases by $\eta|P|$ MWh. However, cycling efficiency does not impact the water storage in HPS reservoirs under the generation mode (Figure 4.4-(b)). The efficiency here refers to the electrical loss in the HPS unit and not the loss of water, e.g. due to evaporation. Therefore, the total equivalent energy of water in the head and tail reservoirs is assumed to remain constant under both operation modes.

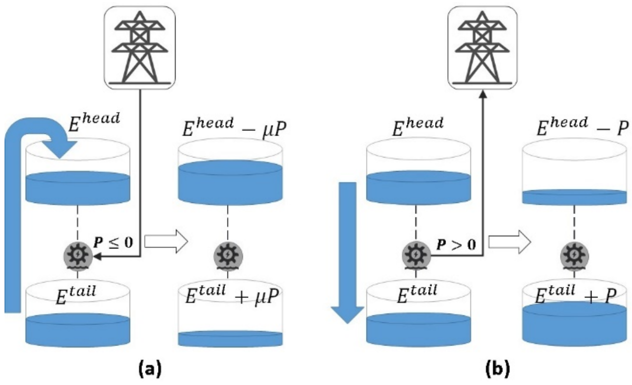

Figure 4.4: Schematic representation of the impact of HPS production/consumption on the water stored in its head and tail reservoirs: a) in pumping mode, b) in generation mode

The impact of reserve provision on the water level in the heads and tail reservoirs is neglected in this study, due to the low probability of reserve activation and short response time in case of activation. The maximum energy stored in the head and tail reservoirs at each time interval is limited by the capacity of the reservoirs, as represented by (4.15) and (4.16). It is assumed that the HPS units are constrained to operate in recycling mode in the day-ahead market which entails to keep the water level within each reservoir equal to its initial volume at the end of the optimization period (24 hours). Theses constraints are indicated by (4.17) and (4.18).

Intra-zonal constraints:

$$\sum_{i\in\mathcal{G}_n\cap\mathcal{G}_{II}} r_{i,t}^{II,M_1} + \sum_{h\in\mathcal{H}_n} r_{h,t}^{II,M_1} + \Phi_{n,t}^{II,M_1} \geq R_n^{II} \quad ;\forall t,n \tag{4.19}$$

$$\sum_{i\in\mathcal{G}_n\cap\mathcal{G}_{I}} r_{i,t}^{I,M_1} + \sum_{h\in\mathcal{H}_n} r_{h,t}^{I,M_1} \geq R_n^{I} \quad ;\forall t,n \tag{4.20}$$

$$\sum_{i\in\mathcal{G}_n} g_{i,t}^{M_1} + \sum_{s\in\mathcal{S}_n} g_{s,t}^{M_1} + \sum_{h\in\mathcal{H}_n} \mathcal{P}_{h,t}^{M_1} + \sum_{w\in\mathcal{W}_n} g_{w,t}^{M_1} - \sum_{j\in\mathcal{J}_n} D_{j,t}^{M_1} - \sum_{l\in\mathcal{L}_n} d_{n,l} f_{l,t}^{M_1} + E_{n,t}^{M_1} = 0 \;\; ;\forall t,n \tag{4.21}$$

The reserve provided by all the conventional generators and HPS unit, located inside zone n and capable of providing primary/secondary reserve, must be adequate to meet the zonal requirement of primary/secondary reserve (equations (4.19)-(4.20)). The deficit of secondary reserve, as a market-based service, is represented in the model by $\Phi_{n,t}^{II,M_1}$. Any possible deficit will be penalized by a penalty factor $V_{n,t}^{II}$ in the objective function. Equation (4.21) implements the day-ahead supply-demand balance constraint in each market zone [99]; during each market time unit, the sum of the electricity produced by conventional, renewable, and HPS generators in each zone added to the unserved energy (if any) should be equal to the demand at the same zone plus the energy exported from that zone to the neighboring zones. Day-ahead zonal market prices ($\lambda_{n,t}^{M_1}$) are also calculated as the dual value of the equation (4.21), following market execution and through fixing the binary variables to their values in market results.

Inter-zonal constraints:

$$-\overleftarrow{A}_{l,t} \leq f_{l,t}^{M_1} \leq \vec{A}_{l,t} \quad ;\forall l,t \tag{4.22}$$

Each inter-zonal interconnection (l) is defined by a default direction which shows its starting zone and ending zone. Accordingly, the power flow on the interconnection, indicated by $f_{l,t}$, can take negative or positive value. Positive values of $f_{l,t}$ correspond to the flow of power in the default direction of the line l, i.e. from the starting zone to the ending zone whereas the negative values correspond to the power flow in the opposite direction, i.e. from the ending zone to the starting zone.

The ATC of interconnections is different in the two directions. The inter-zonal power exchanges are limited by the ATC of the corresponding interconnections in both directions, as imposed by equation (4.22).

4.2.2.2 Intraday market model

Following the day-ahead market clearance with predicted demand, wind production and solar production, hourly intraday auction is performed for every hour of the operating day, with respect to the updated forecasted data, one hour before the delivery time. Similar to the day-ahead market model in Section 4.2.2.1 (equation (4.1)), the objective function of the intraday market implies on the minimization of the total intraday generation and reserve costs, as represented by equation (4.23). Intraday generation adjustments may be upward or downward to increase or decrease generation from day-ahead scheduled, respectively. Generation units submit upward and downward adjustment offer prices to the intraday market. HPS units can also provide upward/downward adjustment in the intraday market. It is assumed that the HPS units arbitrage the price between day-ahead and intraday markets. Hence they offer hourly day-ahead market clearing price for adjustment power in the intraday auctions.

Objective Function:

$$\begin{gathered}\underset{g^{M_2},r^{M_2},\Delta\mathcal{P}^{M_2},E^{M_2},u^{M_2},\Phi^{II,M_2}}{Min} C_e^{M_2} = \sum_{i\in I}(g_{i,t,e}^{U,M_2}p_{i,t}^{U,M_2} - g_{i,t,e}^{D,M_2}p_{i,t}^{D,M_2} + \\ r_{i,t,e}^{II,M_2}p_{i,t}^{II,M_2}) + \sum_{h\in\mathcal{H}}\Delta\mathcal{P}_{h,t,e}^{M_2}\lambda_{n,t}^{M_1} + \sum_{w\in\mathcal{W}} s_{w,t,e}^{M_2}p^{W,Sp} + \sum_{s\in\mathcal{S}} S_{s,t,e}^{M_2}p^{S,Sp} + \\ \sum_{N\in\mathcal{N}}\Big((E_{n,t,e}^{M_2} - E_{n,t}^{M_1})V_{n,t} + (\Phi_{n,t}^{II,M_2} - \Phi_{n,t}^{II,M_1})V_{n,t}^{II}\Big)\end{gathered} \tag{4.23}$$

Generators' constraints:

$$0 \le g_{i,t,e}^{U,M_2} \le u_{i,t,e}^{U,M_2}\left(\overline{g}_{i,t} - g_{i,t}^{M_1}\right) \quad ;\forall i,t,e \tag{4.24}$$

$$0 \le g_{i,t,e}^{D,M_2} \le u_{i,t,e}^{D,M_2}\left(g_{i,t}^{M_1} - \underline{g}_{i,t}\right) \quad ;\forall i,t,e \tag{4.25}$$

$$u_{i,t,e}^{U,M_2} + u_{i,t,e}^{D,M_2} \le 1 \quad ;\forall i,t,e \tag{4.26}$$

$$r_{i,t,e}^{II,M_2} + r_{i,t,e}^{I,M_2} + g_{i,t}^{M_1} + g_{i,t,e}^{U,M_2} - g_{i,t,e}^{D,M_2} \le \overline{g}_{i,t} \quad ;\forall i,t,e \tag{4.27}$$

$$\begin{cases} r_{i,t,e}^{I,M_2} \leq \overline{r}_i^I & \forall i \in \mathcal{G}_I, t, e \\ \\ r_{i,t,e}^{I,M_2} = 0 & \forall i \notin \mathcal{G}_I, t, e \end{cases} \tag{4.28}$$

$$\begin{cases} r_{i,t,e}^{II,M_2} \leq \overline{r}_i^{II} & \forall i \in \mathcal{G}_{II}, t, e \\ \\ r_{i,t,e}^{II,M_2} = 0 & \forall i \notin \mathcal{G}_{II}, t, e \end{cases} \tag{4.29}$$

$$r_{i,t,e}^{II,M_2}, r_{i,t,e}^{I,M_2}, g_{i,t,e}^{U,M_2}, g_{i,t,e}^{D,M_2} \geq 0 \quad \forall i, t, e \tag{4.30}$$

The upward and downward generation adjustment power is constrained according to the generator's dispatchable capacity and the minimum generation limit of adjustable generators, as well as the output power resulted from day-ahead market clearing, as indicated by equations (4.24) and (4.25). Equation (4.26) implies that upward and downward generation adjustment cannot be activated at the same time. Primary and secondary reserve constraints in intraday market are presented by (4.27)-(4.29). Equation (4.30) implies on the non-negativity constraint of generators' adjustment power and reserve variables.

Hydro Pumped-Storages' Constraints:

$$-\overline{\mathcal{P}}_h^p \leq \mathcal{P}_{h,t}^{M_1} + \Delta\mathcal{P}_{h,t,e}^{M_2} + r_{h,t,e}^{I,M_2} + r_{h,t,e}^{II,M_2} \leq \overline{\mathcal{P}}_h^g \tag{4.31}$$

$$\Lambda_{h,t,e}^{head,M_2} = \begin{cases} \Lambda_{h,t}^{head,M_1} - \eta_h \Delta\mathcal{P}_{h,t,e}^{M_2} & ; if\, \mathcal{P}_{h,t}^{M_1} + \Delta\mathcal{P}_{h,t,e}^{M_2} \leq 0 \\ \\ \Lambda_{h,t}^{head,M_1} - \Delta\mathcal{P}_{h,t,e}^{M_2} & ; if\, \mathcal{P}_{h,t}^{M_1} + \Delta\mathcal{P}_{h,t,e}^{M_2} > 0 \end{cases} \quad \forall t, h \tag{4.32}$$

$$\Lambda_{h,t,e}^{tail,M_2} = \begin{cases} \Lambda_{h,t}^{tail,M_1} + \eta_h \Delta\mathcal{P}_{h,t,e}^{M_2} & ; if\, \mathcal{P}_{h,t}^{M_1} + \Delta\mathcal{P}_{h,t,e}^{M_2} \leq 0 \\ \\ \Lambda_{h,t}^{tail,M_1} + \Delta\mathcal{P}_{h,t,e}^{M_2} & ; if\, \mathcal{P}_{h,t}^{M_1} + \Delta\mathcal{P}_{h,t,e}^{M_2} > 0 \end{cases} \quad \forall t, h \tag{4.33}$$

$$\Lambda_{h,t,e}^{head,M_2} \leq \overline{\Lambda}_h^{head} \quad \forall t, h \tag{4.34}$$

$$\Lambda_{h,t,e}^{tail,M_2} \leq \overline{\Lambda}_h^{tail} \quad \forall t, h \tag{4.35}$$

The adjustment power provided by each HPS unit in the intraday market is constrained by equation (4.31). According to (4.31), the final energy and reserve provision by a HPS unit in each intraday auction cannot exceed its maximum production/consumption limit in generating/pumping mode. The constraints of the head and tail reservoirs' capacities in intraday market are indicated by (4.32)-(4.35).

Intra-zonal constraints:

$$\sum_{i \in \mathcal{G}_n \cap \mathcal{G}_{II}} r_{i,t,e}^{II,M_2} + \sum_{h \in \mathcal{H}_n} r_{h,t,e}^{II,M_2} + \Phi_{n,t}^{II,M_2} \geq R_n^{II} \quad \forall t, e, n \tag{4.36}$$

$$\sum_{i \in \mathcal{G}_n \cap \mathcal{G}_{I}} r_{i,t,e}^{I,M_2} + \sum_{h \in \mathcal{H}_n} r_{h,t,e}^{I,M_2} \geq R_n^{I} \quad \forall t, e, n \tag{4.37}$$

$$\begin{aligned} &\sum_{i \in \mathcal{G}_n} \left(g_{i,t,e}^{U,M_2} - g_{i,t,e}^{D,M_2} \right) + \sum_{h \in \mathcal{H}_n} \Delta \mathcal{P}_{h,t,e}^{M_2} + \sum_{s \in \mathcal{S}_n} \left(X_{s,t,e}^{M_2} - g_{s,t}^{M_1} - S_{s,t,e}^{M_2} \right) + \\ &\sum_{w \in \mathcal{W}_n} \left(X_{w,t,e}^{M_2} - g_{w,t}^{M_1} - S_{w,t,e}^{M_2} \right) - \sum_{j \in \mathcal{J}_n} \left(D_{j,t,e}^{M_2} - D_{j,t}^{M_1} \right) + \left(E_{n,t,e}^{M_2} - E_{n,t}^{M_1} \right) - \\ &\sum_{l \in \mathcal{L}_n} d_{n,l} \left(f_{l,t,e}^{M_2} - f_{l,t}^{M_1} \right) = 0 \quad ; \forall t, n, e \end{aligned} \tag{4.38}$$

The intra-zonal constraints in the intraday market are presented by equations (4.36)-(4.38). Equation (4.38) indicates the intraday power balance constraint under each scenario. Starting from the supply-demand balance condition on each market zone from the day-ahead market schedules, equation (4.38) enforces that all the positive and negative deviations from the day-ahead balance point, which are resulted by the upward and downward re-dispatch of controllable generators and HPS units, updated forecast of wind and solar production, updated demand, and deviation in inter-zonal energy exchanges, should lead to a new balance point in the corresponding market zone. The intraday zonal electricity prices ($\lambda_{n,t,e}^{M_2}$) are equal to the dual value of equation (4.38) for each scenario.

Inter-zonal constraints:

$$-\overleftarrow{A}_{l,t} \leq f_{l,t,e}^{M_2} \leq \vec{A}_{l,t} \quad \forall l, t, e \tag{4.39}$$

Finally, equation (4.39) represents the inter-zonal power exchange constraint on each interconnection within the intraday market. $f_{l,t,e}^{M_2}$ is the power flow on the interconnection l after the closure of intraday auction which depends on both day-ahead schedules and accepted re-dispatch offers in the intraday auction.

4.3 European electricity market simulation: 2030 scenario generation

34 European countries are modelled by one to several market zones per country, comprising Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, former Yugoslav Republic of

Macedonia, Germany, Great Britain, Greece, Hungary, Ireland (and North Ireland as separated region), Italy, Latvia, Lithuania, Luxembourg, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Switzerland. Also Tunisia and Turkey are considered in the model to take into account the power exchange through their interconnections to the European countries. A market model for the scenario of 2030 is set based on the ENTOS-E-Scenario EUCO 2030 [147], which shows the impact of EU policies at the time of its formulation in 2014, towards meeting the 2030 decarbonisation targets.

4.3.1 Power plants' model

Following the ENTSO-E approach in [147], power plants are divided into 10 categories: Gas, Coal, Lignite, Nuclear, Oil, Hydro, Solar, Wind, Other RES and Other non-RES. Other RES category may include the rest of the power plants with renewable non-fossil fuels, e.g. running on biomass or waste. Other non-RES include mainly Combined Heat and Power (CHP) units. Three hydro-electric technologies are considered in this study, including hydro run-of-river, hydro turbine, and hydro pumped-storage units. The dispatchable capacity of generators in each country is set according to the predicted installed capacities in ENTSO-E-Scenario EUCO for 2030 [147], as represented in Tables 4.1 and 4.2. The installed capacity of thermal generators is divided into multiple generation units with around 300 MW unit size, assuming minimum stable level as 40% of the unit size. Hourly electricity demand profiles, as well as wind and solar hourly generation profiles are extracted from [147], [130]; whereas monthly water inflow profiles for the hydro power plants are extracted from the historical generation records of Eurostat [158], [159]. Table 4.3 represents the annual electricity consumption in each market zone.

A perfect competition paradigm is considered for the integrated market model which assumes that all the market participants are price takers and offer their marginal cost to the market. While generation offer price of solar, wind and hydro power plants is assumed equal to zero. Curtailment penalty of wind and solar generators are considered zero in this model. Generators' offer prices in day-ahead market are set equal to their marginal generation cost, i.e. the sum of fuel price and variable operation and maintenance cost by 2030, as predicted by ENTSO-E in [147]. The real generators' offer prices in 2030 depends on exogenous factors, including the fuel prices in each country and the trend on technology, which is complex and out of the scope of this study. However, using a unique price for each fuel type all over the Europe for 2030 in this study, the objective is to compare the relative impact of intraday market integration on market performance and marginal generation costs and the calculated prices cannot be used as an estimation for the market prices in 2030. Furthermore, it is assumed that generators offer the same prices in the intraday auctions. This assumption is based on the PJM annual performance reports implying on the convergence of day-ahead and real-time average prices [160]. Therefore, under the assumption of competitiveness in intraday electricity market, generators offer their marginal price to the market for upward balancing services. For downward balancing services also generators are likely to be willing to pay their generation cost for generating below day-ahead schedules, while keeping the profit margin from day-ahead market (the difference between market price and generation offer).

Table 4.1: Installed generation capacities in each market zone- extracted form ENTSO-E-EUCO 2030 Scenario [147]

Zone	Biofuel	Gas	Hard coal	Hydro-pump	Hydro-run	Hydro-turb.	Lignite	Nucl.	Oil	Other non-RES	Other RES	Wind	Solar
IS00	0	0	0	0	0	2615	0	0	0	0	694	0	0
AL	0	700	0	0	468	2402	0	0	0	0	0	150	80
AT	0	2566	777	6508	4672	12273	0	0	423	465	1373	5888	6501
BA	0	0	0	440	1144	1120	2536	0	0	0	0	640	100
BE	810	9688	16	1150	117	1308	0	0	218	0	0	7386	6907
BG	99	790	1011	933	600	2800	2370	1920	2	0	0	2852	3069
CH	0	1364	0	4593	4139	13580	0	1190	8	0	588	1301	0
CY	11	947	0	0	0	0	0	0	497	0	0	229	544
CZ	0	868	1596	1000	365	1050	7202	4006	64	211	617	2690	2617
DEkf	0	0	0	0	0	0	0	0	0	0	0	336	0
DE	8567	1708	22930	9792	4329	10583	13782	0	1247	1671	0	69449	81503
DKe	986	0	869	0	0	0	0	0	136	0	0	1334	283
DKk	0	0	0	0	0	0	0	0	0	0	0	600	0
DKw	1886	788	602	0	7	0	0	0	82	0	0	6171	555
EE	0	333	1	0	10	0	0	0	1412	50	204	512	0
ES	2075	27921	3968	8280	3850	19200	0	7399	2951	195	0	34597	31968
FI	0	2792	818	0	0	3200	945	3398	1109	124	3384	4140	19
FR15	0	0	0	0	197	197	0	0	404	0	47	36	165
FR	3853	7642	3780	5500	13600	13500	0	5949	1701	620	0	25150	28354
GB	17760	28713	501	0	142	1553	0	13107	2579	774	0	37662	10860
GR0	0	0	0	0	0	0	0	0	98	0	0	1000	200
GR	262	4738	0	1289	275	4009	2865	0	733	0	0	7157	7675

Table 4.2: Installed generation capacities in each market zone- extracted form ENTSO-E-EUCO 2030 Scenario [147]-continue of Table 4.1

Zone	Biofuel	Gas	Hard coal	Hydro-pump	Hydro-run	Hydro-turb.	Lignite	Nucl.	Oil	Other non-RES	Other RES	Wind	Solar
HR	0	834	655	300	500	2300	1	0	370	0	30	1211	1453
HU	358	2769	0	0	60	0	414	4482	5	89	0	1226	1766
IE	200	3138	842	442	216	442	0	0	173	0	0	5230	19
IL00	0	16199	3400	0	0	0	0	0	620	1200	320	2600	6600
ITcn	1384	1409	0	271	236	1188	0	0	0	0	0	281	4346
ITcs	642	6377	1468	1186	502	2145	0	0	0	0	0	3712	5526
ITn	3112	22838	935	3560	4605	11280	0	0	0	379	0	300	15281
ITsar	119	0	768	218	47	423	0	0	0	0	0	1256	1765
ITsic	94	3971	0	497	20	658	0	0	1445	0	0	2276	2930
ITs	841	8431	1925	0	227	762	0	0	725	0	0	7167	7263
LT	142	1348	0	950	138	1125	0	1117	0	0	0	1053	74
LUg	37	442	0	0	34	0	0	0	2	0	0	323	390
LUv	0	0	0	1026	0	1310	0	0	0	0	0	0	0
LV	138	1090	21	0	0	1619	0	0	15	0	0	549	0
ME	0	0	0	0	132	1139	450	0	0	0	39	250	30
MK	0	290	120	0	151	647	915	0	0	0	26	100	32
MT	3	615	0	0	0	0	0	0	287	0	0	4	264
NI	210	1071	0	100	0	100	0	0	512	0	0	2300	170
NL	2690	10379	4429	0	38	0	0	485	2066	433	0	10235	5933
NOm	0	0	0	84	0	5381	0	0	0	0	0	1700	0
NOn	71	835	2	1	0	5900	0	0	1	0	0	1200	0
NOs	64	1029	2	1030	0	24535	0	0	1	15	0	2640	800
PL	2358	4522	12979	1488	1033	1413	6369	0	2355	369	0	14328	1146
PT	659	3744	0	4120	735	8466	0	0	1000	0	0	6876	2127
RO	219	3846	232	0	3291	3310	1678	2828	676	6	0	6730	3214
RS	0	580	0	1260	2025	1763	5306	0	0	0	118	1068	200
SE1	227	0	0	0	0	5215	0	0	0	0	0	1790	88
SE2	474	0	0	0	0	8035	0	0	0	0	0	6069	60
SE3	1953	2789	105	0	0	2586	23	6949	560	274	0	3835	60
SE4	548	324	0	0	0	348	0	0	275	0	0	2221	23
SI	118	207	68	600	1500	600	553	696	0	0	0	337	1743
SK	455	1007	328	1486	974	2292	126	4020	84	96	0	374	680
TN00	0	16120	0	0	66	0	0	0	0	0	0	639	672
TR	0	29415	14117	0	11411	26625	15673	8400	674	500	1250	20170	8000

Table 4.3: Annual electricity demand in each market zone, extracted form ENTSO-E-EUCO 2030 Scenario [147]

Zone	Demand [GWh]	Zone	Demand [GWh]	Zone	Demand [GWh]	Zone	Demand [GWh]
AL	9,316	ITs	28,585	FI	90,478	NOn	22,681
AT	77,174	ITsar	8,621	FR	497,975	NOs	102,161
BA	15,614	ITsic	19,140	FR15	2,775	PL	185,088
BE	95,903	LT	11,496	GB	372,706	PT	49,225
BG	33,882	LUb	264	GR	50,921	RO	60,824
CH	72,153	LUf	1,248	GR03	3,735 RS	43,325	
CY	4,930	LUg	6,630	HR	18,125	SE1	11,503
CZ	71,471	LV	8,867	HU	42,301	SE2	19,722
DE	576,235	ME	5,196	IE	29,961	SE3	100,747
DKe	15,330	MK	11,134	IL00	115,366	SE4	28,128
DKw	23,968	MT	2,634	IS00	18,330	SI	15,616
DKkf	-	NI	11,770	ITcn	33,606	SK	32,806
EE	9,308	NL	118,482	ITcs	48,024	TN00	40,557
ES	272,687	NOm	27,417	ITn	180,017	TR	401,867

4.3.2 Cross-border power connections

Cross-border capacity allocation of day-ahead and intraday market models are based on the Available Transfer Capacity (ATC) which is the current approach for day-ahead market coupling in Europe. In this study, ENTSO-E reference capacities for 2027 (from TYNDP 2018 [147]) are used as inter-zonal ATCs. The ATC values of cross-zonal interconnections, in both directions, are represented in Table 4.4. Figure 4.5 illustrates the cross-border interconnections among the market zones of the European countries considered in the model. As shown in Figure 4.5, the system is modelled considering a single market zone per country with the exception of Denmark (2 zones), Italy (6 zones), Norway (3 zones), and Sweden (4 zones).

4.3.3 Operational reserve requirement

To preserve supply-demand balance in power systems continuously and keep system frequency close to its nominal value, system operators apply several frequency control actions through activating operating reserves. In the European systems, load-frequency control is performed by means of primary reserve, secondary reserve, and tertiary reserve [145]. Currently European system operators procure primary and secondary reserves through either market-based approaches or mandatory provision mechanism. The markets for reserve provision may be settled

Table 4.4: NTC of interconnection between European market zones: 2027 [147]

Capacity [MW]			Capacity [MW]			Capacity [MW]			Capacity [MW]		
Border	=>	<=	Border	=>	<=	Border	=>	<=	Border	=>	<=
AL-GR	250	250	DE-LUG	1000	1000	HU-SK	2000	2000	CZ-PLE	0	600
AL-ME	400	400	DE-LUv	1300	1300	IE-NI	1250	1200	CZ-PLI	600	0
AL-MK	500	500	DE-NL	5000	5000	ITcn-ITCO	400	400	CZ-SK	1800	1100
AL-RS	500	500	DE-NOs	1400	1400	ITcn-ITCO	400	400	DE-DEkf	400	400
AT-CH	1700	1700	DE-PLE	0	3000	ITcn-ITcs	1750	3200	DE-DKe	600	585
AT-CZ	1000	1200	DE-PLI	2000	0	ITcn-ITn	2100	4100	DE-DKw	3000	3000
AT-DE	7500	7500	DE-SE4	1315	1300	ITcs-ITs	9999	5700	DE-FR	4500	4500
AT-HU	1200	800	DKe-DKkf	600	600	ITcs-ITsar	700	900	DE-GB	1400	1400
AT-ITn	1050	850	DKe-DKw	600	600	ITcs-ME	1200	1200	DEkf-DKkf	400	400
AT-SI	1200	1200	DKe-SE4	1700	1300	ITn-SI	1640	1895	GR-ITs	500	500
BA-HR	1250	1250	DKw-GB	1400	1400	ITsar-ITCO	500	450	GR-MK	1200	1200
BA-ME	800	750	DKw-NL	700	700	ITsic-MT	200	200	GR-TR	660	580
BA-RS	1100	1200	DKw-NOs	1700	1640	ITsic-TN	600	600	HR-HU	2000	2000
BE-DE	1000	1000	DKw-SE3	740	680	ITs-ITsic	1100	1200	HR-RS	600	600
BE-FR	2800	4300	EE-FI	1016	1016	LT-LV	1200	1500	HR-SI	2000	2000
BE-GB	1000	1000	EE-LV	1379	1379	LT-PL	1000	1000	HU-RO	1300	1400
BE-LUB	380	0	ES-FR	5000	5000	LT-SE4	700	700	HU-RS	600	600
BE-LUG	300	180	ES-PT	4200	3500	ME-RS	700	700	HU-SI	1200	1200
BE-NL	3400	3400	FI-SE1	2000	2000	MK-RS	750	750	PL-PLE	3000	0
BG-GR	1350	800	FI-SE3	1200	1200	NL-NOs	700	700	PL-PLI	0	2000
BG-MK	500	500	FRc-ITCO	150	200	NOm-NOn	1300	1300	PL-SE4	600	600
BG-RO	1100	1500	FR-GB	6900	6900	NOm-NOs	1400	1400	RO-RS	1300	1300
BG-RS	350	200	FR-ITn	4350	2160	NOm-SE2	600	1000	SE1-SE2	3300	3300
BG-TR	1200	500	FR-LUF	380	0	NOn-SE1	700	600	SE2-SE3	7800	7800
CH-DE	5600	3300	GB-IE	500	500	NOn-SE2	250	300	SE3-SE4	7200	3600
CH-FR	1300	3700	GB-NI	450	280	NOs-SE3	2145	2095			
CH-ITn	6000	3700	GB-NL	1000	1000	PLE-SK	990	0			
CZ-DE	2600	2000	GB-NOs	2800	2800	PLI-SK	0	990			

after the energy market or well in advance. In any case, reserve provision by market participants affects their bidding strategy in energy market. This interdependence has both financial and technical aspects. From financial viewpoint, participating in one market (e.g. energy or reserve) contains opportunity cost for market participants resulted by not participating in the other market. From the technical viewpoint also primary and secondary reserves by conventional power plants can

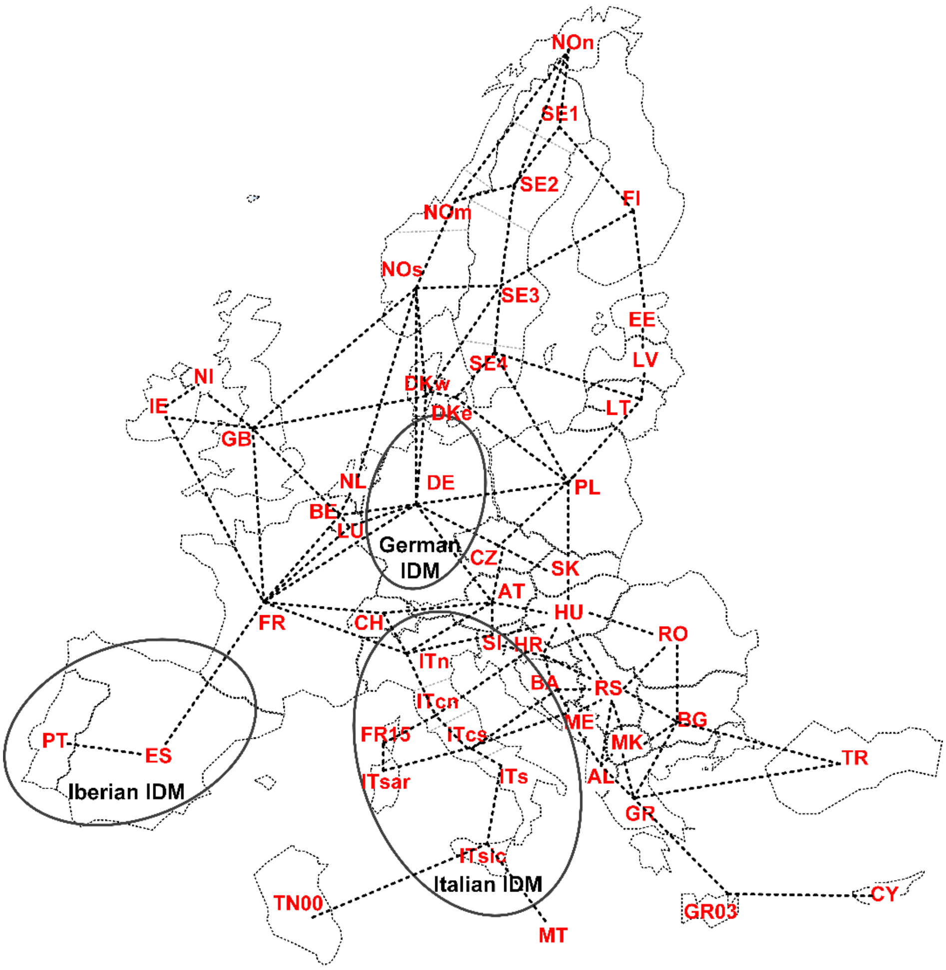

Figure 4.5: Market zones and cross-zonal electrical power interconnections in the model

only be supplied as spinning reserves provided by spinning generators. Therefore, the capability of providing primary and secondary reserve by the generators in a system depends upon the operating point of generators in normal system conditions. In other words, providing reserve limits generators' capacity for commercial trading and adds constraints on their operation. In this study, in order to tackle both technical and financial issues regarding energy and reserve provision in a simplified manner, primary and secondary reserves' procurement is co-optimized with energy in the day ahead and intraday market models.

Five synchronous areas are considered among the 34 European countries in the model: (i) Continental Europe, (ii) Nordic countries, (iii) Great Britain, (iv) Ireland, and (v) Cyprus. Primary reserve in European countries is estimated following electricity system operation requirements of ENTSO-E [152]. In the synchronous area of Continental Europe, the required primary reserve (3000 MW) is shared by all countries within the area and decided with reference to their annual generation from the previous year (as already discussed in Section 3.2). According to the previous feasibility studies [159] and the analysis performed in Chapter 3 of this thesis, it is assumed that the Baltic States will synchronize with the Continental Europe by 2030. In the synchronous area of the Nordic region the required primary reserve equals the dimensioning fault [150], [115] in the area (1400 MW) and is shared by all Nordic countries proportionally to their dimensioning faults (Section 3.2). The primary reserve requirement in the Great Britain and Ireland area is set according to [161] and [162] respectively. Finally, the primary reserve requirement in Cyprus is considered 100MW, which is close to the size of the biggest generation unit. The maximum primary reserve capacity of generators is considered as 8% of their dispatchable capacity which is equivalent to 5% droop on the governor system of all generators under contingencies leading to 200 mHz frequency deviation [99], [131].

Primary and secondary reserve in European power systems are typically provided through short-term auctions. In the market model applied in this study, secondary reserve is procured in hourly auctions through simultaneous minimization of the total costs for providing energy and reserve. It is assumed that generation units while spinning can offer their remaining capacity (i.e. the difference between dispatchable capacity and already-dispatched capacity) in the reserve market. Secondary reserve providers are usually remunerated for both reservation of their capacity and for activation of reserve and providing the required energy, in case they have been asked for [163]. However, in particular, the selection of secondary reserve bids in the markets, e.g. the secondary reserve market of Germany, is done according to the offered prices for the reservation capacity [163]. In this study, reservation offer prices are assumed according to the profit expectation of generators by providing their capacity to the day-ahead or intraday energy markets, instead of secondary reserve, i.e. the opportunity cost of providing secondary reserve. Therefore, the prices are set equal to the difference between the expected market price in each zone minus the generation cost of 1 MWh energy for each generator located in the same zone. The expected average price of energy in day-ahead and/or intraday markets is simply assumed an identical value inside all countries (30 €/MWh). Accordingly, the secondary reserve offer prices in our model are in the range 0-30 €/MW/h for generators with different fuel types which is also in line with the real prices in Germany by 2015 (18 €/MW/h [163]). It is assumed that each country with a nuclear power plant and with an aggregated capacity of steam turbine power plants above 3000 MW provides 1000 MW secondary reserve capacity for emergency situations, whereas other countries 300 MW. Another assumption is that spinning generators in the market can provide secondary reserve up to their dispatchable capacity limit. The plausible secondary reserve capacity deficits in the market are penalized by 2000 €/MW, which is twice the assumed value of lost load in this study (1000 €/MWh) in order to prioritizes the reserve provision for emergencies.

4.3.4 Uncertainty characterization

Most of the day-ahead markets are cleared 12 to 36 hours before real time. Hence, market participants with uncertain power injections/withdrawals, such as retailers and wind/solar power producers, have to predict their generation/demand 12-36 hours in advance. In the market model developed in this study, three parameters with uncertain values are considered including: demand, solar power generation and wind power generation.

There are numerous prediction tools for short term electricity demand forecasting with different level of complexity and accuracy. Demand forecast error is generally modelled by normal distribution function in literature [151]. This assumption is justified through the wide diversity of consumer classes and geographically distribution of demand. In this study, the hourly demand forecast errors are adapted as normally distributed random numbers with zero mean and 2% standard deviation [151].

Solar forecasting accuracy depends on the geographical location of the solar power plants, as well as on the time scale of the forecast [164]. In this thesis, due to the lack of data for geographical location of each solar power plant and with respect to the geographical dispersion of solar units in each market zone (a country or a part of a country), *'central limit theorem'* allows us to assume normal distribution for solar generation forecast errors. An analysis performed by National Renewable Energy Laboratory in [164], for California's system operator presents the baseline and target metrics for solar power forecast errors. Based on the standard deviation of day-ahead forecast errors [165], a zero-mean normal distribution is assumed with 4.5% of the installed capacity for solar power prediction error of each unit.

Wind speed forecast error at a specific location, as well as wind power production, do not follow normal distribution. However, the large number and geographical dispersion of wind farms in my model makes it possible to invocate central limit theorem and assume normal distribution for wind power prediction errors [151], [166]. In probability theory, the *central limit theorem* is referred to the tendency of sums of independent stochastic processes to converge in distribution to a Gaussian process [167]. Doherty and O'Malley [166] represent the standard deviation of wind power forecast errors per megawatt of installed capacity for an individual wind farm for different forecast horizons. Considering a forecast horizon of 12-36 hours before delivery in the day-ahead market, with 100MW installed capacity of each wind power plant, a zero-mean normal distribution with 20% standard deviation is assumed for wind power forecast error in this study.

4.4 European test cases

This section presents the simulation results corresponding to the Europe-wide integrated day-ahead and intraday electricity markets through a stochastic Monte Carlo simulation approach for a scenario of 2030. 1000 Monte Carlo samples are generated for electricity demand, wind power, and solar power in the 8760 hours of the year. The market simulation is performed by commercial MILP solver, CPLEX.

The day-ahead market simulation results for the annual electricity generation and demand in each country by 2030 are provided in Figure 4.6. The results of the annual generation expresses the high share of generation by variable renewable energy sources, i.e. wind and solar power plants, in Europe and particularly in the selected test cases which in turn implies on the need for a well-functioning intraday market. By comparing annual generation and demand energy, one can conclude that France will be a main energy exporter by 2030, while Italy and Germany are among the energy importers.

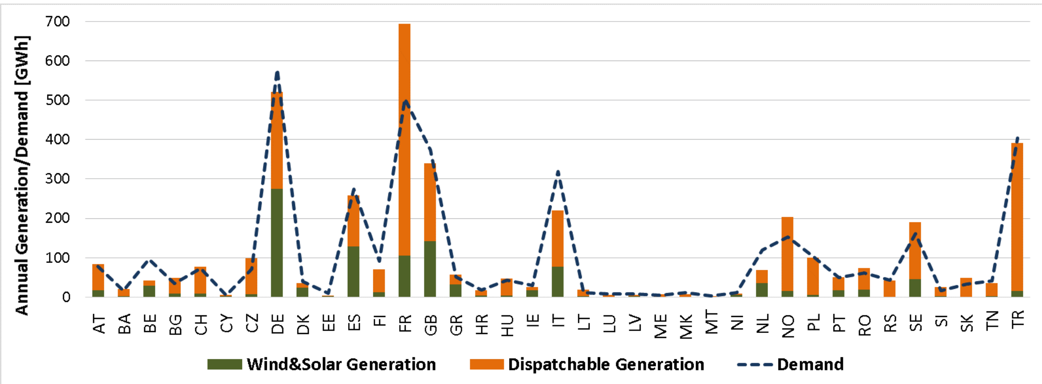

Figure 4.6: Annual generation/demand inside each country (2030)

4.4.1 Model validation

The model is validated by applying it on a current scenario for the Iberian electricity market and comparing the result with the historical market data in terms of generation mix and imports/exports. The comparative results of the simulation results and the historical data are illustrated in Figure 4.7. The values correspond to the percentage of the annual load supplied by each generator type or energy import.

The reason to select the Iberian electricity market as the test case for benchmarking the model is its limited interconnection from the rest of the Europe which makes it less affected by the market integration and inter-zonal power transactions.

As shown in Figure 4.7, the simulation results for the current scenario follow the historical data of 2018 market results in [168] with slight deviations. Some

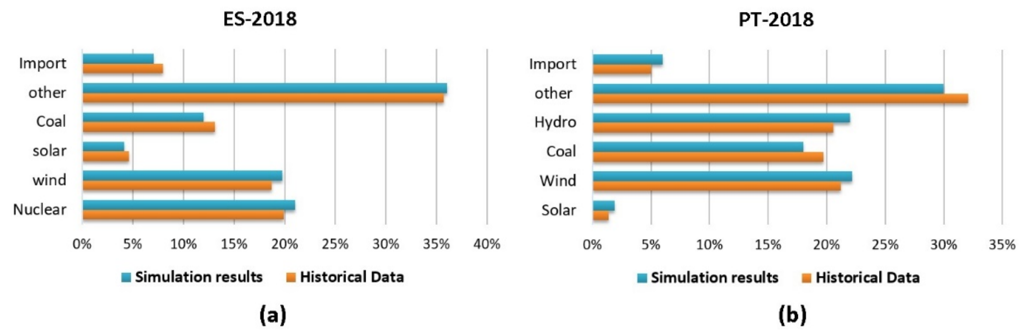

Figure 4.7: Comparative analysis of the market simulation results and the historical data of the Iberian electricity market. (a): Spain, (b): Portugal

reasons to have different results compared to the historical market data might be: a) using 2020 predicted data by ENTSO-E for generators' installed capacities and NTC of interconnections in the simulation model due to the lack of 2018 data (the installed generator capacities in Spain and Portugal are modified based on the 2018 data); b) assuming a constant NTC for each interconnection all over the year in the simulation mode; and c) considering the all generation and demand to be transacted in the day-ahead market and neglecting forward and over-the-counter contracts.

In what follows, the two proposed scenarios: 1) regional intraday electricity market, 2) a Europe-wide intraday electricity market, are modelled and the intraday market performance under these scenarios is compared inside the European test cases, including Spain, Portugal, Italy, Slovenia, and Germany, under each scenario.

4.4.2 Base-Case: Network-unconstrained integration of the European intraday electricity markets

As the basis of the analysis, we modelled full integration of the European day-ahead and Intra-day electricity markets, with no network constraints, which illustrates an ideal case. This scenario leads to a unique hourly day-ahead and intra-day electricity price inside all the simulated European regions (illustrated in Figure 4.8), without renewable curtailment throughout the year. The average intraday market price under this scenario is equal to the average day-ahead price by 2030. However, the power exchanges among the countries falls far from the planned installed capacities by 2030, implying on the non-applicability of this case. As shown in Figure 4.8, under the full integration of the European intraday electricity markets with no network constraint, the day-ahead and intraday market prices often converge. The HPS units' participation in the market and their arbitrage among the two markets play an important role in the price convergence of day-ahead and intraday markets.

The impact of inter-zonal network constraints on the annual operation cost of

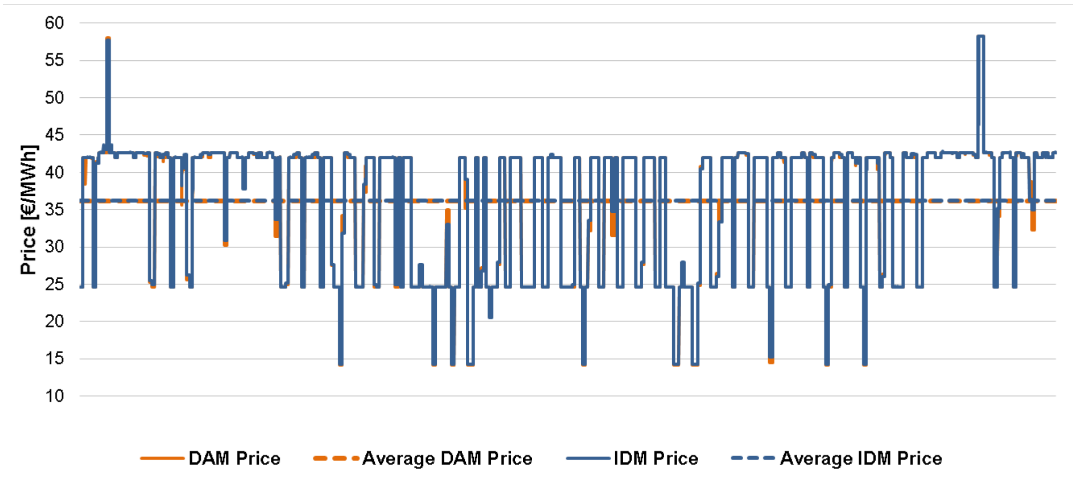

Figure 4.8: DAM and IDM prices in the base case- No network constraint

the system (total generation cost), generators' surplus, and cost to loads, under the Europe-wide day-ahead and intraday market models by 2030 is shown in Figure 4.9. It can be concluded from the simulation results that while network constraints increase the total operation cost of the system as expected, it reduces total cost to load and the total generators' surplus, as well. Therefore, network reinforcement plans to release inters-zonal congestions by 2030 are expected to be favourable for generator companies and detrimental for customers in the whole system. However, this result may be totally different within individual market zones and for different transmission expansion plans. While our model is able to capture the value of different transmission expansion plans for market participants within each market zone, the analysis is beyond the scope of this study.

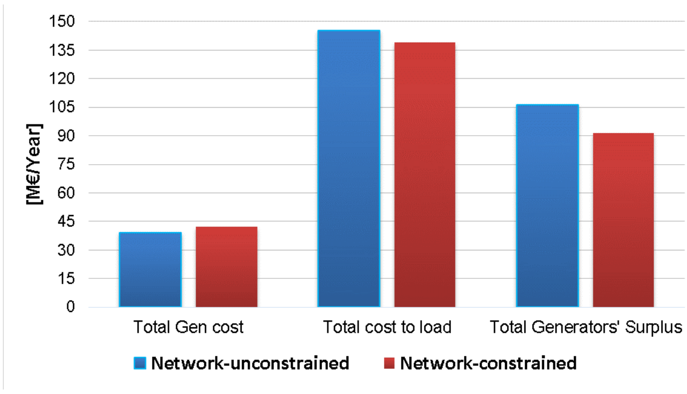

Figure 4.9: The impact of network constraints on the Europe-wide DAM and IDM performance

4.4.3 Network-constrained intraday market performance

In this section, the two aforementioned scenarios are applied on the intraday electricity market of the European test cases: 1) Iberian intraday market including Spain and Portugal, 2) Italian intraday market including Italy and Slovenia, 3) German intraday market. Under the first scenario, it is assumed that the day-ahead electricity market of the test cases are integrated to the Europe-wide day-ahead market; while their intraday market is modelled as a regional hourly auction, similar to the current intraday market performed in these countries. However, under the second scenario the integration of Spain, Portugal, Italy, Slovenia, and Germany, to the Europe-wide intraday market is modelled to identify the potential benefits of market integration inside each country.

Although the results imply that market integration reduces the average IDM prices in all the European test cases, it does not necessarily lead to lower IDM prices in all time intervals (hours). In other words, market integration may lead to higher IDM prices compared to the regional IDM prices in some intervals. Figure 4.10 illustrated the price difference between Integrated and Regional IDM inside Spain, Portugal, Italy, Slovenia, and Germany, within December 2030, as a sample month including the peak day of the year. The positive values indicate the price increment in Integrated IDM compared to the Regional IDM.

The annual performance of the IDM inside Spain, Portugal, Italy, Slovenia, and Germany, under the two scenarios are summarized in Table 4.5. The results indicate that intraday market integration (Scenario 2) decreases average intraday prices by 3% in Spain, 1.4% in Portugal, 0.5% in Slovenia, and 4.7% in Germany, and less than 1.5% in different market zones in Italy, compared to the current regional intraday market model (Scenario1). Intraday market integration also leads to slight reduction of generators' surplus and total cost to load in Italy, Spain, Portugal, and Germany. However, in Slovenia generators' surplus slightly increases under market integration. The minor differences between the two scenarios, i.e. integrated and regional IDM model, is resulted by the flexibility provided by large installed capacity of HPSs in the system by 2030. In other words, market integration and storage technologies are both means of increasing power system flexibility under high RES penetration. Integrating adequate storage capacities in the market reduces the need for market integration under normal operation of the system.

4.4.4 Role of hydro pumped-storage power plants

In this section, we compare the average DAM and IDM prices with and without HPS units in our test cases. This comparison allows us to examine the impact of market participation of HPS units installed in the European countries on the potential benefits of the Europe-wide market integration. Figure 4.11 illustrates the installed capacity of HPS units within our European test cases by 2030, according

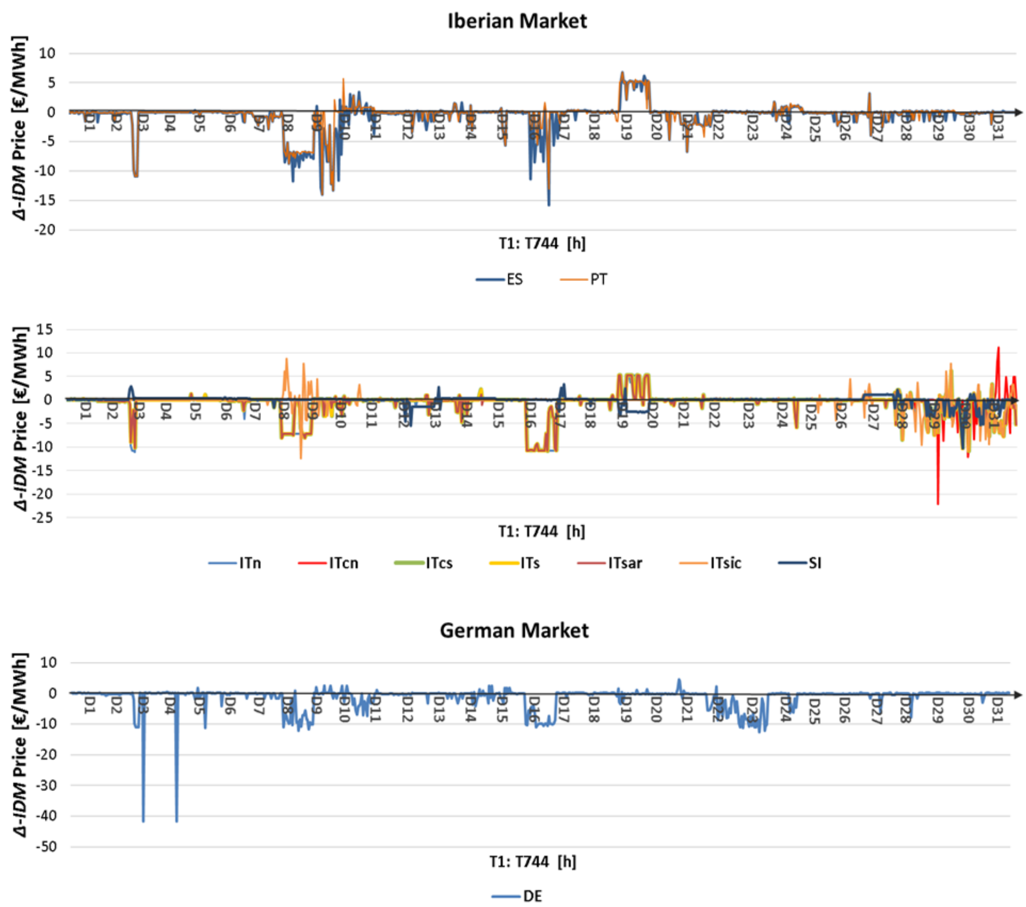

Figure 4.10: Difference between Integrated and Regional IDM Prices (December 2030)

to the EUCO-2030 scenario in TYNDP 2018 [147]. Germany and Spain have the largest installed capacity of HPS units among all the European countries which enables them to be capable of balancing their generation and demand in intraday market without any support from their neighbouring countries.

The monthly average day-ahead and intraday market prices under the two scenarios of regional and integrated intraday market, with and without HPS units, are represented in Figure 4.12-Figure 4.14.

As shown in Figure 4.12, HPS integration contributes significantly in reducing the average IDM prices and converging the DAM and IDM prices within Spain and Portugal. This is resulted by the high installed capacity of HPS within Spain and Portugal, as well as their weak interconnection to the rest of the Europe.

Comparing the monthly average prices inside Germany in Figure 4.13 indicates that the potential impact of IDM integration on the average IDM prices inside Germany is almost equal to the impact of HPS participation in the market (light

Table 4.5: Market results in the European test cases under the two scenarios (2030)

		Italian Market							Iberian Market		German Market
		ITn	ITcn	ITcs	ITs	ITsar	ITsic	SI	ES	PT	DE
Day-ahead Market	Average DAM Price [€/MWh]	37.87	38.44	38.54	38.41	37.96	55.44	28.49	29.01	26.68	36.4
	Generation Cost[M€]	0.75	0.28	0.24	0.32	0.07	0.30	0.17	1.26	0.09	5.30
Regional Intraday Market	Average IDM Price [€/MWh]	38.54	39.41	39.32	39.20	38.79	55.73	28.64	30.38	29.33	38.62
	Generation Cost[M€]	0.82	0.31	0.26	0.33	0.07	0.29	0.16	1.29	0.11	5.71
	Generators' Surplus [M€]	3.10	0.45	0.94	1.04	0.47	0.59	0.54	6.39	1.28	14.32
	Total cost to load [M€]	6.96	1.33	1.89	1.12	0.34	1.07	0.45	8.31	1.45	22.30
	Net Export [TWh]	-77.6	-14.6	-17.7	6.5	5.5	-3.3	8.7	-15.2	0.7	-60.2
Integrated Intraday Market	Average IDM Price [€/MWh]	37.94	38.88	38.78	38.65	38.22	55.69	28.50	29.47	28.91	36.82
	Generation Cost[M€]	0.83	0.31	0.26	0.31	0.08	0.28	0.17	1.25	0.10	5.58
	Generators' Surplus [M€]	3.04	0.44	0.93	1.02	0.47	0.59	0.55	6.14	1.26	13.48
	Total cost to load [M€]	6.85	1.31	1.87	1.11	0.33	1.07	0.45	8.06	1.43	21.28
	Net Export [TWh]	-76.9	-14.4	-17.2	6.1	5.7	-3.3	9.9	-15.9	0.7	-58.5

orange and dark blue lines in Figure 4.13).

The average DAM and IDM prices in Italy and Slovenia are less sensitive to the market participation of HPS units, as shown in Figure 4.14. The reason might be the generation mix within these countries. The variable renewable energy sources

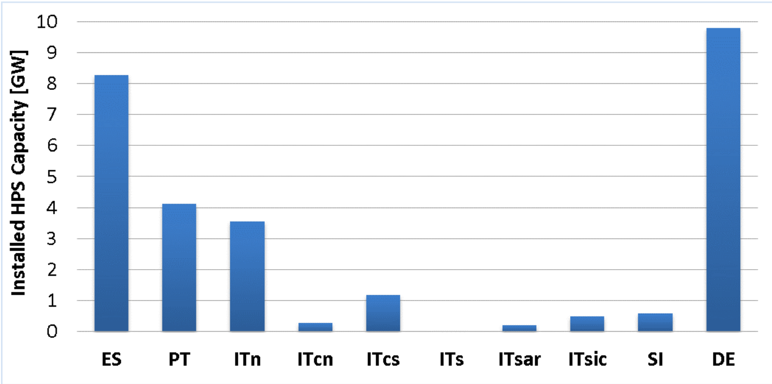

Figure 4.11: Installed capacity of HPS units in the European test cases (2030)

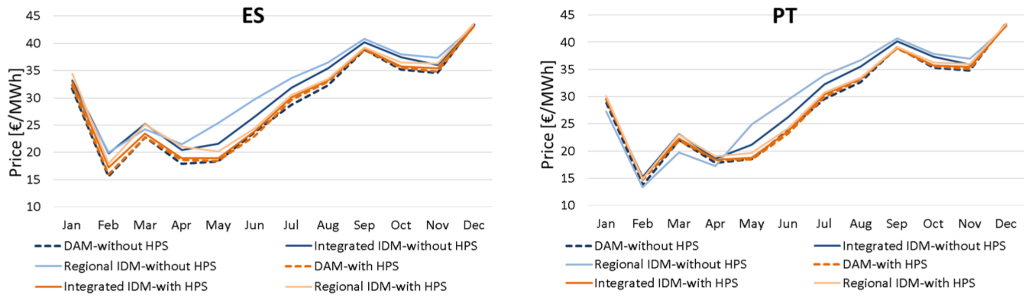

Figure 4.12: Monthly average DAM and IDM prices inside Spain and Portugal, under regional and integrated IDM, with/without HPS (2030)

in Italy and Slovenia are mostly comprised of solar power plants with 39 GW installed capacity. Solar power plants have less prediction error compared to the wind generation which leads to less intraday power adjustments. Furthermore, there will be more than 17 GW hydro turbine generators installed in Italy and Slovenia by 2030 which are highly flexible and can provide adjustment power into the IDM.

Also it can be seen from the results in all test cases (Figure 4.12–Figure 4.14) that the HPS integration makes a major contribution in providing adjustment services in the IDM compared to their DAM participation. The reason is that DAM is integrated in all scenarios which in turn reduces the need for additional flexibility providers in this market. Furthermore, the flexibility provided by conventional generators is more constrained in IDAM compared to the IDM, as only dispatched generators in DAM can provide adjustment into the IDM. Therefore, the value of additional flexibility is higher in IDM.

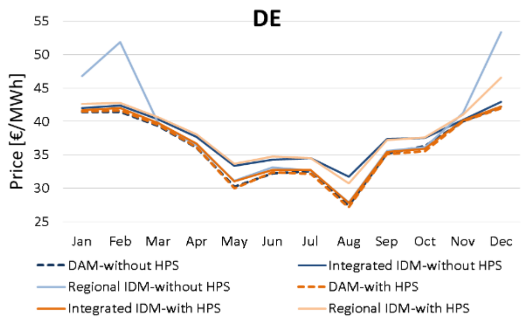

Figure 4.13: Monthly average DAM and IDM prices inside Germany, under regional and integrated IDM, with/without HPS (2030)

4.5 Conclusions and discussion

The study presented in this chapter of the thesis has assessed the market performance of a single Europe-wide intraday electricity market with a focus on three European test cases with relatively high share of renewables which currently implement regional auction-based intraday market: 1) the Iberian IDM including Spain and Portugal, 2) the Italian IDM including Italy and Slovenia, and 3) the German IDM. The results confirm that integrating the current regional intraday markets into Europe-wide intraday market leads to lower expected electricity prices on average, for all the test cases, mainly due to higher intraday market liquidity and inter-zonal sharing of flexible generation resources. However, intraday market integration reduces the surplus of conventional generator companies, due to the decreased imbalance prices, as well as the removal of those generators from the intraday market as a result of imbalance netting. On the other hand, it provides economic benefits for the customers.

Another remarkable outcome of the simulation results is that integrating day-ahead and intraday markets in Europe, together with the flexibility provided from market participation of the hydro pumped-storage generators installed within the European countries by 2030, succeed in converging day-ahead and intraday market prices, as well as diminishing RES curtailment in the market. There are already several gigawatt of hydro pumped-storage capacity installed in European countries, e.g. above 7.5 GW in Italy, 6.9 GW in France, 6.8 GW in Germany, and 6.1. GW in Spain, by 2018 [169], which also take part in day-ahead and intraday markets. However, modification of market rules by policy makers towards providing proper financial benefits for the flexibility providers can support enhancing the integration of additional storage technologies into the electricity markets to provide flexibility and ancillary services. This in turn can support the integration of additional RES capacities into the system.

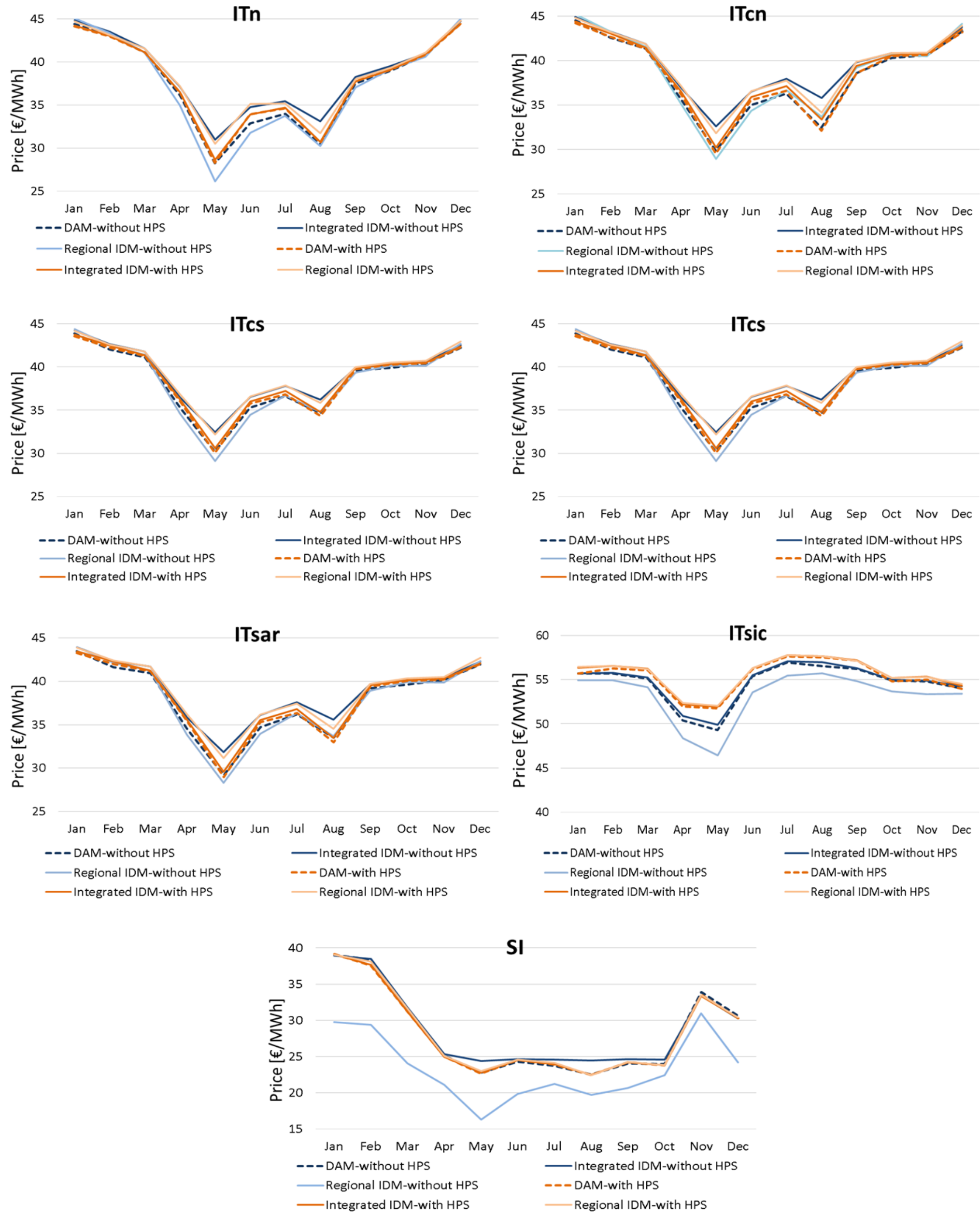

Figure 4.14: Monthly average DAM and IDM prices inside Italy and Slovenia, under regional and integrated IDM, with/without HPS (2030)

The crucial role of hydro-pumped storage units on day-ahead and intraday market performance cannot be neglected. According to the EUCO 2030 Scenario developed by ENTSOE-E in TYNDP 2018, it is anticipated to have above 58 GW installed capacity of hydro pumped-storage generators in Europe by 2030, mostly concentrated in Spain, Germany, Austria, France, and Italy. Comparing the market performance with and without the market participation of these units imply on their major contribution in balancing system in the intraday markets. From one side, performing a Europe-wide intraday market without additional flexibility provided by hydro pumped-storage generators cannot terminate the planned RES curtailment in the market due to the lack of adequate flexibility in the system. Form the other side, the integration of hydro pumped-storage in the market reduces the potential impact of market integration on the market performance within the systems with high RES penetration.

The simulation results during different time intervals of the year 2030 indicates that even-though market integration leads to the reduction of the average intraday prices in all test cases during the year, it may lead to price increment or decrement during individual time intervals. Higher prices in one or more countries during some market time units may happen to keep prices lower in other countries to achieve a minimum total operation cost. However, this support also happens in the opposite direction among the countries such that the average prices in all test cases reduces as a result of market integration. In other words, market integration provides a platform for bidirectional support among countries to share their resources and reduce the total operation cost of the system. Furthermore, the resulted price variations during different time intervals proves that in order to analyse the impact of new policies regarding revision of the electricity market structure, e.g. market integration, one should perform the analysis on a sufficiently long time period rather than one snapshot, in order to be able to capture all the aspects of the new market structure, precisely.

Finally, the market performance results under the assumption of unconstrained inter-zonal network capacities imply that network expansion increases the total generators' surplus within Europe, while it reduces the total operation cost of the system. However, to make an economic decision on the European inter-zonal grid expansion, one should compare the achieved savings in total operation cost of the system resulted from individual transmission expansion plans with their required investment and operations costs. In general, any other plan for improving the market performance and facilitating the integration of RESs should be assessed through a cost benefit analysis before being implemented. Similarly, while market integration is expected to bring financial benefits in terms of reducing the total operation cost of the system and improving the utilization of RESs, it arises additional variable and fixed cost for the system operation including the installation and operation of the required ICT technologies. From the other side, some of the potential benefits of intraday market integration can be provided through alternative solutions such as increasing the integration of storage technologies and activating demand response programs in the market which can provide additional flexibility to the system operation. The optimum solution to improve the market performance under high RES penetration might be a combination of different approaches with respect to their costs and potential benefits. This rises a new research question to investigate the optimum combination of various flexibility resources in the European electricity markets, in line with the EU target model and the European market regulations.

4.5.1 Outlook

Market integration is expected to decrease the opportunity of generator companies to exercise market power and increase market prices. This characteristic is specifically of great importance in the power systems with high penetration of intermittent RESs which require more power trade on the intraday markets. Nevertheless, policy makers will have to accept that the increase in prices in some periods of scarcity is fundamental to ensure investment in a market with low marginal cost RESs [170]. In this context, the appropriate pricing of the reserve markets will inevitably result in adjustments of the energy prices, due to the unavoidable link between system operation and reserve capacity.

The theory [170] advocates for the establishment of a demand function for the demand capacity. This function will require new policies and rules (not yet developed in Europe) for the trading of reserve capacity in real time and the simultaneous clearing of energy and reserves. This situation of variability and flexibility will also benefit from a much more integrated coordination of the operations of the transmission and distribution systems operators. Generation resources at the distribution level are gaining importance with the wide deployment of RESs, and one can foresee their integration in the overall system and market operation. This will not be simple, neither from the policy nor the technical viewpoints, but it will be worth exploring.

An open question is whether the requirement for coordination across European zones will demand the setting up of a new entity entrusted with the arrangement of processes and contracts, prequalification tests and requirements, and monitoring of operations. This supervision will not just be an evolution of the current one, but will see new functions, management mechanisms, data flows and harmonisation among the various TSOs. The net result might be a better frequency quality in the European interconnected power system, based on the development of more balanced and effective technical and market means.

The potential role of flexible demand has also been the object of detailed analyses, e.g. with aggregator business models [171]. Although Europe aims at a market design that will incorporate flexibility on the supply and demand sides, those residual periods with highly volatile prices might need new approach to scarcity pricing and risk reduction. A market that favours variable renewable energy sources, and therefore dependent on weather conditions and subject to forecasting uncertainties, will have to accept variability in prices for energy and services. Scarcity is a characteristic of well-functioning markets, and the varying prices will send signal to the market actors for improving the allocation of resources and investments.

Two key elements that policies should foster in order to facilitate the flexibility of the power system are sector coupling (e.g. with the heating and transport systems), and flexibility in the demand side. The electrification of society should increase the availability of flexible loads with ramping capabilities. The interrelationship between flexible demand and scarcity is one of the crucial topics for future research and consideration for policy makers. This will require a deeper understanding of the preferences of consumers and of the incentives that might be used for shaping their response, linking the management of the demand side to the available capacities [172].

Nomenclature

Superscripts, Sets and Indices

$\mathcal{N}$	Set of zones, indexed by n
$\mathcal{L}$	Set of interconnections, indexed by l
$\mathcal{G}$	Set of conventional generators, indexed by i
$\mathcal{T}$	Set of time periods, indexed by t
$\mathcal{J}$	Set of customers, indexed by j
$\mathcal{W}$	Set of wind generators, indexed by w
$\mathcal{S}$	Set of solar generators, indexed by s
$\mathcal{E}$	Set of uncertainty scenarios, indexed by e
$\mathcal{H}$	Set of hydro pumped storage units, indexed by h
$\mathcal{G}_I \subseteq \mathcal{G}$	Subset of conventional generators capable of providing primary reserve, indexed by i
$\mathcal{G}_I I \subseteq \mathcal{G}$	Subset of conventional generators capable of providing secondary reserve, indexed by i
$\mathcal{L}_n \subseteq \mathcal{L}$	Set of interconnections connected to zone n, indexed by l
$\mathcal{G}_n \subseteq \mathcal{G}$	Subset of conventional generators connected to zone n, indexed by i
$\mathcal{J}_n \subseteq \mathcal{J}$	Subset of customers connected to the zone n, indexed by j
$\mathcal{W}_n \subseteq \mathcal{W}$	Subset of wind generators, located at zone n, indexed by w
$\mathcal{S}_n \subseteq \mathcal{S}$	Subset of solar generators, located at zone n, indexed by s
$\mathcal{H}_n \subseteq \mathcal{H}$	Subset of hydro pumped storage units, located at zone n, indexed by h

M_1 Superscript denoting the day-ahead market

M_2 Superscript denoting the intraday market

Parameters

$\vec{A}_{l,t}$ ATC of the interconnection l, in its default direction, at time t [MW]

$\overleftarrow{A}_{l,t}$ ATC of the interconnection l, in the opposite direction, at time t [MW]

$D^{M_1}_{j,t}$ Predicted electric demand of customer j, at time t, in day-ahead market [MWh]

$D^{M_2}_{j,t,e}$ Predicted electric demand of customer j, at time t, under scenario e, in intraday market [MWh]

$d_{n,l}$ Network incident matrix,$d_{n,l} = 1$ if interconnector l is incident to and oriented away from zone n, $d_{n,l} = -1$ if interconnector l is incident to and oriented towards zone n, and $d_{n,l} = 0$ if interconnector l is not incident to zone n

$\underline{g}_{i,t}$ Minimum output power of conventional generator i at time t in day-ahead market [MW/h]

$\overline{g}_{i,t}$ Dispatchable capacity of conventional generator i at time t in day-ahead market [MW/h]

$p^{M_1}_{i,t}$ Offer price of conventional generator i for electrical power at time t in day-ahead market [€/MWh]

$p^{M_1}_{w,t}$ Offer price of wind generator w for electrical power at time t in day-ahead market [€/MWh]

$p^{M_1}_{s,t}$ Offer price of solar generator s for electrical power at time t in day-ahead market [€/MWh]

$p^{II,M_1}_{i,t}$ Offer price of conventional generator i for secondary reserve at time t in day-ahead market [€/MW]

$p^{U,M_2}_{i,t}$ Upward adjustment power price offered by conventional generator i at time t in intraday market [MW/h]

$p^{D,M_2}_{i,t}$ Downward adjustment power price offered by conventional generator i at time t in intraday market [MW/h]

$p_{i,t}^{II,M_2}$ Offer price of conventional generator i for secondary reserve at time t in intraday market [€/MW]

$p^{W,Sp}$ Penalty for wind power spillage [€/MW]

$p^{S,Sp}$ Penalty for solar power spillage [€/MW]

$\overline{r}_i^{I}$ Maximum primary reserve capacity of conventional generator i [MW]

$\overline{r}_i^{II}$ Maximum secondary reserve capacity of conventional generator i [MW]

R_n^{II} Secondary reserve requirement of zone n [MW]

R_n^{I} Primary reserve requirement of zone n [MW]

$V_{n,t}$ Value of lost load/unserved energy [€/MWh]

$V_{n,t}^{II}$ Value of secondary reserve capacity shortage [€/MW]

$X_{W,t}^{M_1}$ Predicted output power of wind generator w at time t in day-ahead market [MWh]

$X_{s,t}^{M_1}$ Predicted output power of solar generator s at time t in day-ahead market [MWh]

$X_{w,t,e}^{M_2}$ Predicted output power of wind generator w at time t ,under scenario e, in intraday market [MWh]

$X_{s,t,e}^{M_2}$ Predicted output power of solar generator s at time t, under scenario e, in intraday market [MWh]

π_e Probability of uncertainty scenario e [p.u.]

$\overline{\Lambda}_h^{head}$ Energy storage capacity of the head reservoir of hydro pumped storage unit h [MWh]

$\overline{\Lambda}_h^{tail}$ Energy storage capacity of the tail reservoir of hydro pumped storage unit h [MWh]

$\Lambda_h^{0,head}$ Initial energy stored in the head reservoir of hydro pumped storage unit h at the first time interval of the day-ahead market [MWh]

$\Lambda_h^{0,tail}$ Initial energy stored in the tail reservoir of hydro pumped storage unit h at the first time interval of the day-ahead market [MWh]

$\overline{p}_h^{g}$ Maximum power production by the hydro pumped storage unit h in generation mode

$\overline{p}_h^p$ Maximum power consumption by the hydro pumped storage unit h in pumping mode

η_h Cycle efficiency of hydro pumped storage unit h [%]

Day-ahead Variables

C^{M_1} Total cost of energy and reserve provision in day-ahead market [€/day]

$E_{n,t}^{M_1}$ Unserved energy at zone n, at time t, in day-ahead market [MWh]

$f_{l,t}^{M_1}$ Power flow on the interconnection l, at time t, in day-ahead market [MW]

$g_{i,t}^{M_1}$ Accepted output power of conventional generator i, at time t, in day-ahead market [MW/h]

$g_{i,t}^{M_1}$ Scheduled power production/consumption of hydro pumped storage unit h in generation/pumping model, at time t, in day-ahead market [MW/h]; $P_{h,t}^{M_1} \geq 0$: generating mode, $P_{h,t}^{M_1} < 0$: pumping mode

$\Lambda_{h,t}^{head,M_1}$ Energy stored in the head reservoir of hydro pumped storage unit h, at time t, based on the day-ahead market schedules [MWh]

$\Lambda_{h,t}^{tail,M_1}$ Energy stored in the tail reservoir of hydro pumped storage unit h, at time t, based on the day-ahead market schedules [MWh]

$g_{w,t}^{M_1}$ Accepted output power of wind generator w, at time t, in day-ahead market [MW/h]

$g_{s,t}^{M_1}$ Accepted output power of solar generator s, at time t, in day-ahead market [MW/h]

$r_{i,t}^{II,M_1}$ Accepted secondary reserve capacity of conventional generator i at time t, in day-ahead market [MW]

$r_{i,t}^{I,M_1}$ Capacity of generator i for primary reserve, at time t, in day-ahead market [MW]

$r_{h,t}^{II,M_1}$ Accepted secondary reserve capacity of hydro pumped storage generator h at time t, in day-ahead market [MW]

$r_{h,t}^{I,M_1}$ Capacity of pumped storage generator h for primary reserve, at time t, in day-ahead market [MW]

$u_{i,t}^{M_1}$ Binary state variable, indicating acceptance of generation offer of conventional generator i at time t, in day-ahead market

$\Phi_{n,t}^{II,M_1}$ Secondary reserve shortage capacity at zone n, at time t, in day-ahead market [MW]

$\lambda_{n,t}^{M_1}$ Day-ahead market clearing price in zone n, at time t [€/MWh]

Intraday Variables

$C_e^{M_2}$ Total cost of generation adjustment in the intraday market under scenario e [€/hour]

$E_{n,t,e}^{M_2}$ Unserved energy at zone n, at time t, under scenario e, in intraday market [MWh]

$f_{l,t,e}^{M_2}$ Power flow on the interconnection l, at time t, under scenario e, in intraday market [MW]

$g_{i,t,e}^{U,M_2}$ Accepted upward power adjustment of conventional generator i, at time t, under scenario e, in intraday market [MW/h]

$g_{i,t,e}^{D,M_2}$ Accepted downward power adjustment of conventional generator i, at time t, under scenario e, in intraday market [MW/h]

$g_{i,t,e}^{D,M_2}$ Adjustment power of hydro pumped storage unit h, at time t, under scenario e, in intraday market [MW/h]; $\Delta P_{h,t,e}^{M_2} \geq 0$: upward adjustment, $\Delta P_{h,t,e}^{M_2} < 0$: downward adjustment

$\Lambda_{h,t,e}^{head,M_2}$ Energy stored in the head reservoir of hydro pumped storage unit h, at time t, under scenario e, based on the intraday market schedules [MWh]

$\Lambda_{h,t,e}^{tail,M_2}$ Energy stored in the tail reservoir of hydro pumped storage unit h, at time t, under scenario e, based on the intraday market schedules [MWh]

$r_{i,t,e}^{II,M_2}$ Accepted secondary reserve capacity of conventional generator i, at time t, under scenario e, in intraday market [MW]

$r_{i,t,e}^{I,M_2}$ Capacity of conventional generator i for primary reserve at time t, under scenario e, in intraday market[MW]

$r_{h,t,e}^{II,M_2}$ Accepted secondary reserve capacity of hydro pumped storage generator h, at time t, under scenario e, in intraday market [MW]

$r_{h,t,e}^{I,M_2}$	Capacity of conventional hydro pumped storage generator h for primary reserve at time t, under scenario e, in intraday market[MW]
$S_{w,t,e}^{M_2}$	Power spillage of wind generator w, at time t, under scenario e, in intraday market [MW/h]
$S_{s,t,e}^{M_2}$	Power spillage of solar generator s, at time t, under scenario e, in intraday market [MW/h]
$u_{i,t,e}^{U,M_2}$	Binary state variable, indicating acceptance of upward adjustment offer of conventional generator i, at time t, under scenario e, in intraday market
$u_{i,t,e}^{D,M_2}$	Binary state variable, indicating acceptance of downward adjustment offer of conventional generator i, at time t, under scenario e, in intraday market
$\Phi_{n,t}^{II,M_2}$	Secondary reserve shortage capacity at zone n, at time t, in intraday market [MW]
$\lambda_{n,t,e}^{M_2}$	Intraday market clearing price in zone n, at time t, under scenario e [€/MWh]

Chapter 5

Multi-Regional Coordinated Risk-Preparedness Plan in Europe

Typically, power systems are operated in a secure manner such that the system can withstand the contingency of loss of one or two components. Loss of a system components can be considered as an accidental threat against system operation. However, accidental components failures are not the only causes jeopardizing power systems. Even in a well-functioning power system and electricity market, the risk of an electricity crisis due to a variety of causes, e.g. extreme weather condition, malicious attack, and fuel shortage, which can threaten system security, cannot be neglected. Although these system threats have relatively low probability of occurrence, their impact on the system operation can go far above N-1 security criteria and may cause the affected system to experience a crisis situation in which all or most of the internal tools fail to withstand the issue. Currently, European countries implement national rules for preventing, preparing for, and managing crisis situations and behave very differently under crisis circumstance. The European Commission's proposal on risk-preparedness in the electricity sector, as a part of the new legislative package "Clean Energy for All Europeans", published on the 30^{th} November 2016, sets out how member states should cooperate to prevent and manage crisis situations, while ensuring that even under crisis, the electricity is delivered where it is most needed. In this proposal, one foreseen tool to cope with crisis is regional load shedding. Accordingly, this chapter of the thesis investigates the impact of regional cooperation on crisis management in power systems. Without loss of generality, in this study risk is modelled as dry season with its impact of increasing load and reducing dispatchable capacity of generators. A decision-making algorithm is proposed to manage crisis, aiming at continuous supply of protected demands and essential reliability services, i.e. reserves in this study, at minimum cost and with the least social impact on non-protected consumers. Due to the lack of detailed and open-source network model of the European power systems, the model is tested on the 3-region IEEE RTS-96 network, modified by Washington

University by adding renewables to the system. Different scenarios are modelled to provide a wide view on the impact of different levels of cooperation among regions for managing crisis.

List of the abbreviations used in this chapter is provided at the end of the chapter.

5.1 Introduction

If a critical situation for the transmission system happens, a country or region could experience a situation of crisis, in which all or many of the internal tools prepared to withstand the possible issues could not be enough. In this case, the solutions include load shedding and the request of assistance sent to neighbouring countries or regions. The assistance refers to the provision of energy only to run the essential services. This process may avoid the evolution of the crisis towards a complete blackout and the consequent need of exploiting the black start capability of the systems.

The purpose of risk preparedness plan and regulations in Europe is to ensure that all member states put in place appropriate tools to prevent, prepare for, and manage electricity crisis situation [173]. The risk of an electricity crisis due to a variety of circumstances, e.g., extreme weather condition, malicious attack and fuel shortage, can remain as a threat to power systems, even where market and system function well. In the strongly interconnect power system, like the European power systems, crisis situations often have a cross-border effect and might affect several member states simultaneously. Currently, member states implement different actions to prevent, prepare for, and manage crisis situations. The National rules for risk preparedness tend to disregard what happens across borders. Furthermore, the transparency and sharing of information for handling crisis situations are very limited among member states. Hence, the European Commission has proposed regulation for risk preparedness across Europe with the aim of improving the cooperation of TSOs at regional level via creation of regional operational centers. The proposed regulation sets out what member states should do to prevent and manage crisis situations and how they should cooperate with each other.

Applying a regional approach for risk preparedness plan results in economic benefits due to better utilization of power system resources (power plants, interconnection capacity, storage facilities, and demand response) and mitigating the probability of loss of protected loads under crisis. In the proposed regulations by European Commission, the risk preparedness plans should include measures to ensure that simultaneous crisis situations are properly prevented and managed. The plans must include at least:

i. the designation of a regional crisis manager team;

ii. mechanism to share, inform, and cooperate within a region;

iii. measures to mitigate the impact of a crisis, including a simultaneous crisis situation; for instance, regional load shedding plans or other mutual assistance arrangements regarding mutual assistance to ensure that electricity can be delivered where it is most needed and in an optimal manner;

iv. any cost compensation schemes linked to the assistance arrangements;

v. procedures to carry out annual tests of the plans.

The EU's risk preparedness proposal complements the prescriptions of the revised Third Package, composed by Directive (EC) No 2009/72/EC of the European Parliament, which aims at improving the functioning of the internal electricity market in Europe, as well as improving the system security by better cooperation among European TSOs at regional level and creation of regional operational centres [173]. The proposed risk preparedness plan contributes to the Third Package through assuring that even if a crisis situation occurs in a system, market-based measures are given the highest priority and electricity markets keep working as long as possible.

According to Article 13 of the EU's risk preparedness proposal [173], when a reliable information source, e.g. by seasonal adequacy outlooks, provides predictions on an event which is occurrence is likely to have significant impact on degradation of electricity supply in a country, the country under the risk of crisis should immediately give warning to the European Commission and Electricity Coordination Group. The affected country should provide information to the competent authorities of the neighbouring countries on all the possible measures planned to mitigate the crisis and the possible need for assistance from other countries. After the electricity crisis is declared by a Member State, all the actions set out in the risk preparedness plan should be fully followed.

In this chapter of the thesis, the impact of regional coordination and multi-area assistance to manage electricity crisis in an interconnected system is investigated. A decision making algorithm is proposed and formulated as an optimization problem to be undertaken by the Electricity Coordination Group or any kind of regional risk management coordinator to ensure that electricity is delivered where it is more needed, while allowing market-based measures to be undertaken as long as possible. Crisis in this study is modelled by an extreme weather condition as dry season. Taking into account the time-dependent impact of such crisis on the system, as well as the variable production of renewable generators, there might be hours with adequate generation sources in the system to supply demand and operation services, as well as hours with supply shortage, leading to crisis. Accordingly, the proposed optimization problem covers both normal and abnormal operation of the system. Under the assumption of a well-functioning integrated electricity market, the model emulates market operation in normal conditions. However, in case of a severe abnormal situation, the market operation may be disrupted as a result of the inadequate available supply resources in providing energy and essential reliability services. At this point, the model implements load shedding in the affected region, as well as the supporting regions, to mitigate the propagation of the electricity crisis to a wider area and to prevent a possible blackout. Load shedding is taken as a last-resort action to be activated when no other solutions to maintain the system operation within its security margins are available.

Load shedding schemes are necessary to prevent phenomena such as voltage collapse, line overload, etc., which may lead to cascade outages and successive blackout. Load shedding is considered as a powerful tool to avoid the system wide blackouts [174]. Load shedding can be defined as the amount of load that can be instantly removed from a power grid to keep the remainder operational. This load reduction is in response to a system disturbance that results in a generation shortage condition. The benefits of load shedding originate from limitations when all available generation has been exhausted and only load reductions can help restore system reliability to acceptable levels [175]. Load shedding has been studied to solve different network issues, such as under-frequency [176, 177], under-voltage and voltage stability [178–181], and vulnerability [182]. The time scale of the application of load shedding ranges from a few seconds to a few minutes. As such, the time scale of load shedding practices referring to voltages and frequency falls in the short-term security time scale. However, the concepts relevant to the application of load shedding for regional risk-preparedness plans refer to a longer time scale, i.e., the one relevant for mid-term adequacy [93]. As such, preventive strategies to organise how to perform load shedding in case of need are of interest.

In this study, load is divided into three categories, according to its priority to be continuously supplied, including: protected loads, non-protected non-interruptible loads, and interruptible loads. However, the model is formulized parametrically, considering k load categories which allows us to prioritize consumers more precisely by defining more load categories. In case of a shortage in electricity supply, load shedding on the least sensitive consumers would be started in order to ensure the continuous supply of sensitive loads and provision of fast-response reserves in the system. The focus of this study is on the provision of Frequency Containment Reserve (FCR) and Automatic Frequency Restoration Reserve (aFRR) as currently these services are mostly provided by conventional generators. The model ensures provision of adequate FCR and FRR reserves even under electricity crisis situation, within the affected and supporting regions. The objective is to keep the system operating in a secure manner, under the N-1 security criteria, such that even under crisis, it can withstand the failure of one component.

5.2 Regional security coordination

Currently in European power systems, the operational flexibility and reserves are provided in each control area by the corresponding Transmission System Operator (TSO), independently. However, inter-area coordination for reserve procurement is highly recommended to enhance the security of supply. According to the study performed in [183], assessing the security of a multi-area interconnected power system individually inside each area, with no coordination among areas, may fail to ensure the security of the total interconnect power system. In other words, without exchanging the information among areas, it may happen that each area is N-1 secure, but the total system is not. It is because the impact of contingencies inside each area on the power flow of tie-lines cannot be considered in the security assessment of its interconnected areas.

In Europe, the rise of cross-national power flows has called for stronger cooperation among TSOs in system operation. There are emerging actors which started performing regional electricity security analysis and actions at a regional (cross-national) level. Accordingly, Regional Security Coordinator (RSC) entities are formed by TSOs to support them in preserving security of supply in their electricity system. The five core services provided by RSCs include: operational planning security analysis, outage planning coordination, coordinated capacity calculation, short term adequacy forecast, and providing a common grid model. Although RSCs perform the regional security analysis, but they are not equipped to directly control the grid and the final decision to implement the actions proposed by the RSCs remains under the responsibility of TSOs.

At present, there are four active RSCs in Europe, including TSCNET, CORESO, SCC, and the Nordic RSC, represented in Figure 5.1. TSCNET is one of the leading regional security coordinators in Europe, which is based in Munich and covers 15 TSOs of 12 European countries including: 50Hertz, TransnetBW, Amprion, and TenneT in Germany, APG in Australis, CEPS in Czech, ELES in Slovenia, Energinet in Denmark, HOPS in Croatia, MAVIR in Hungary, PSE in Poland, SEPS in Slovakia, Swissgrid in Switzerland, TenneT in The Netherlands, and Transelectrica in Romania [184]. CORESO is another European RSC, based in Belgium, which covers TSOs including: Eirgrid and SONI in Ireland, Elia in Belgium, RTE in France, National Grid in the UK, Terna in Italy, 50Hertz, in Germany, REN in Portugal, and REE in Spain [185]. SCC is the first RSC in the Southeast Europe founded by EMS in Serbia, CGES in Montenegro, and NOSBiH in Bosnia and Hercegovinia [186]. Finally, the most recently established ECS in Europe is the Nordic RSC, covering the four TSOs of the Nordic countries: Finglrid in Finland, Statnett in Norway, Svenska Kraftnat in Sweden, and Energinet in Denmark [187].

The crisis management algorithm developed in this study is a network-constrained generation and load dispatch model in which security of supply is considered by provision of adequate reserve capacity in each region. The model also reserves a portion of cross-border interconnection capacities for sharing reserve services among the regions under crisis, while the post contingency power flows are not assessed. It is assumed that the feasibility of generation and reserve schedules within each zone to withstand the contingency of a single equipment failure (N-1 security criteria) would be assessed independently by each TSO. This assumption follows the current security assessment procedure in most of the European countries. However, with respect to the EU's trend toward increasing the coordination among European TSOs in performing security analysis is a regional level, the algorithm is also further supplemented by regional N-1 security assessment. Therefore, two models for multi-regional coordinated crisis management are provided in this chapter: ① a network constrained decision making problem with regional reserve requirement constraints; ② a security constrained decision making problem with implicit feasibility assessment of the generation and load schedules in post-contingency conditions.

5.3 Model representation and mathematical formulatioin

This Section introduces the decision-making algorithm developed in this study to manage crisis situation in power systems through a multi-area assisted rotational load shedding approach. The proposed algorith is formulated as an optimization problem, based on Mixed Integer Linear Programming (MILP) approach. Crisis is modelled by its time-dependent impact on available generation capacity and load in the affected region. As already discussed in Section 5.2, two models are provided for modelling security of supply in the crisis management algorithm, as follows:

1. Network constrained crisis management algorithm
2. Security constrained crisis management algorithm

In what follows, the mathematical formulation of both models as a MILP problem are represneted in detail.

5.3.1 Network-constrained crisis management algorithm

The network constrained decision making algorithm for crisis management, presented in this section, is the base model which follows the current European approach for providing FCR and FRR reserves and performing ex-post security analysis, locally by individual TSOs. In this approach, the FCR and FRR reserve capacity requirement within each region/zone are calculated explicitly and used as the input parameter within the crisis-management algorithm. The optimization problem formulated to solve the decision-making algorithm finds the optimum

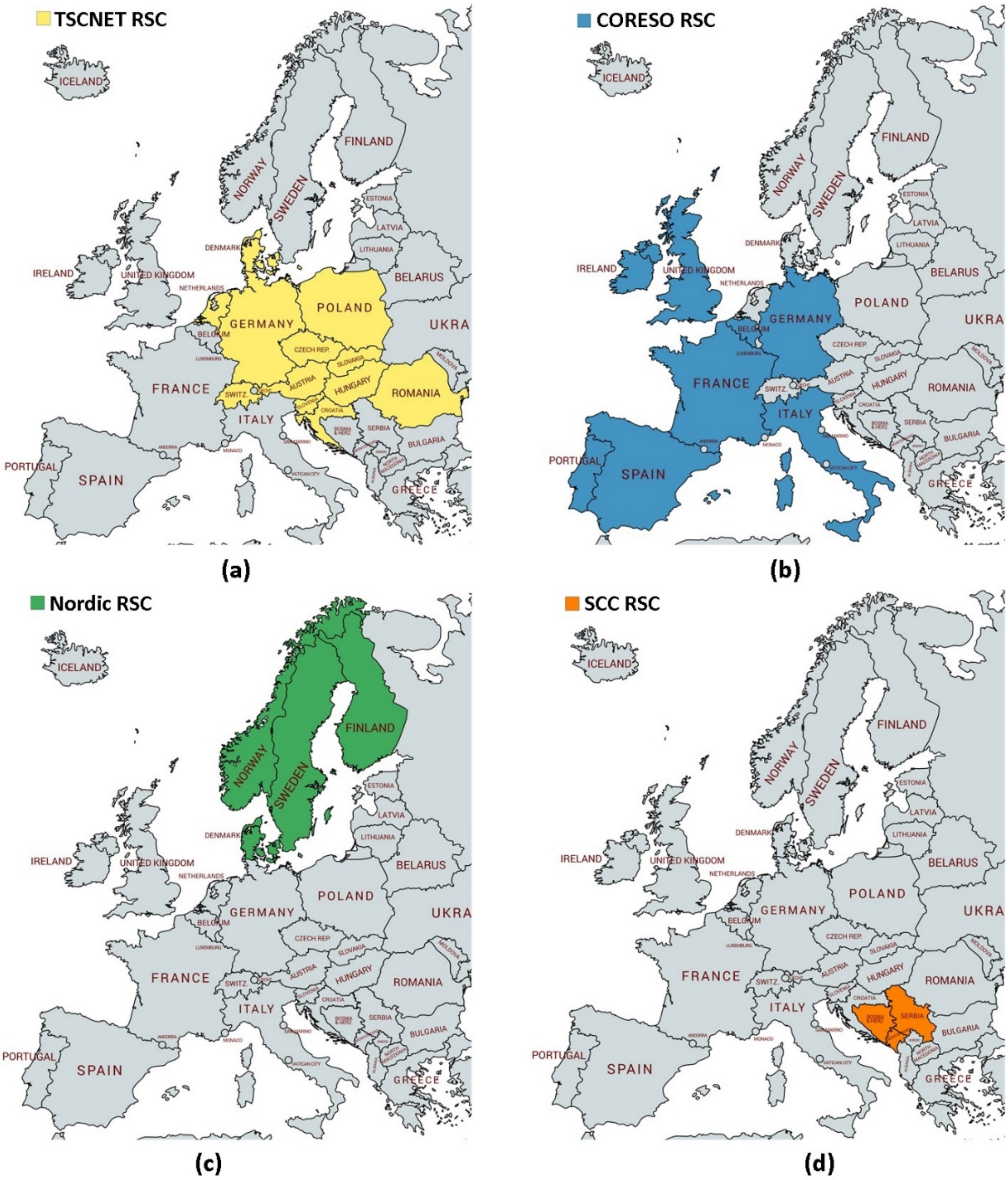

Figure 5.1: Countries covered by different Regional Security Coordinators in Europe; (a): TSCNet RSC, (b): CORESO RSC, (c): Nordic RSC, and (d): SCC RSC

generation and interruptible load schedules to supply non-interruptible loads and provide FCR and FRR reserve, both under normal conditions and under crisis. In line with ENTSO-E's short-term adequacy forecasts, the model uses week-ahead predictions of load and renewable production to assess the adequacy of available supply resources under potential upcoming abnormal situations. Under severe conditions, generators may be not adequate to supply all consumers and provide FCR and FRR requirements. It might be not only due to the shortage of available generation capacity, but also resulted by technical limits of generators and network limits to export energy where it is needed. As the model deals with the short-term planning for crisis management and not the real-time operation of the system, it uses deterministic approach for modelling renewables. The idea is to find a reliable solution which can withstand the most extreme predicted condition. Accordingly, the analysis is performed for the most unfavourable predicted renewable production (wind power in this study).

The optimization problem is formulated as follows. Furthermore, to make the general procedure of the decision making algorithm, Figure 5.2 illustrates the flowchart of the model.

A. Objective function:

The objective function (5.1) minimizes the total operation cost of the system including generation/fuel cost and start-up cost of conventional generators, penalty for renewable curtailment (wind spillage in our case study), penalty for FCR and FRR reserve shortage in each zone, and an equivalent penalty factor for load curtailment on different load types. The penalty factors for load curtailment on different load types are set according to the sensitivity of the load to be curtailed within the zone affected by the abnormal situation or the unaffected neighboring zones.

$$\begin{aligned} &\min_{g_{i,t}, q_{s,t}, E^{spil}_{w,t}} C^{TOT} \\ &= \sum_{t\in\mathcal{T}} \Bigg[\sum_{i\in\mathcal{J}} (C^{opr}_{i,t} + C^{SU}_{i,t}) \\ &+ \sum_{w\in\mathcal{W}} E^{spil}_{w,t}\, \varphi^{spil} + \sum_{z\in\mathcal{Z}} \varphi^{FCR}_z r^{FCR,sh}_{z,t} + \sum_{z\in\mathcal{Z}} \varphi^{FRR}_z r^{FRR,sh}_{z,t} \\ &\Psi\Bigg(\sum_{z\in\mathcal{Z}} \mu_{k,z} \sum_{n\in\mathcal{N}_z} \sum_{d\in\mathcal{D}_n} E^{int}_{k,d,t} \Bigg) \Bigg] \end{aligned} \tag{5.1}$$

B. Constraints

B.1. Generators' constraints

Equations (5.2)–(5.5) represent the conventional and wind generators' constraints in the normal operation of the system.

$$C^{opr}_{i,t} = \rho^{fix}_i u_{i,t} + \sum_{b\in\mathcal{B}} \rho^{var}_{b,i} P_{b,i,t} \tag{5.2}$$

$$g_{i,t} = \sum_{b\in\mathcal{B}} P_{b,i,t} \tag{5.3}$$

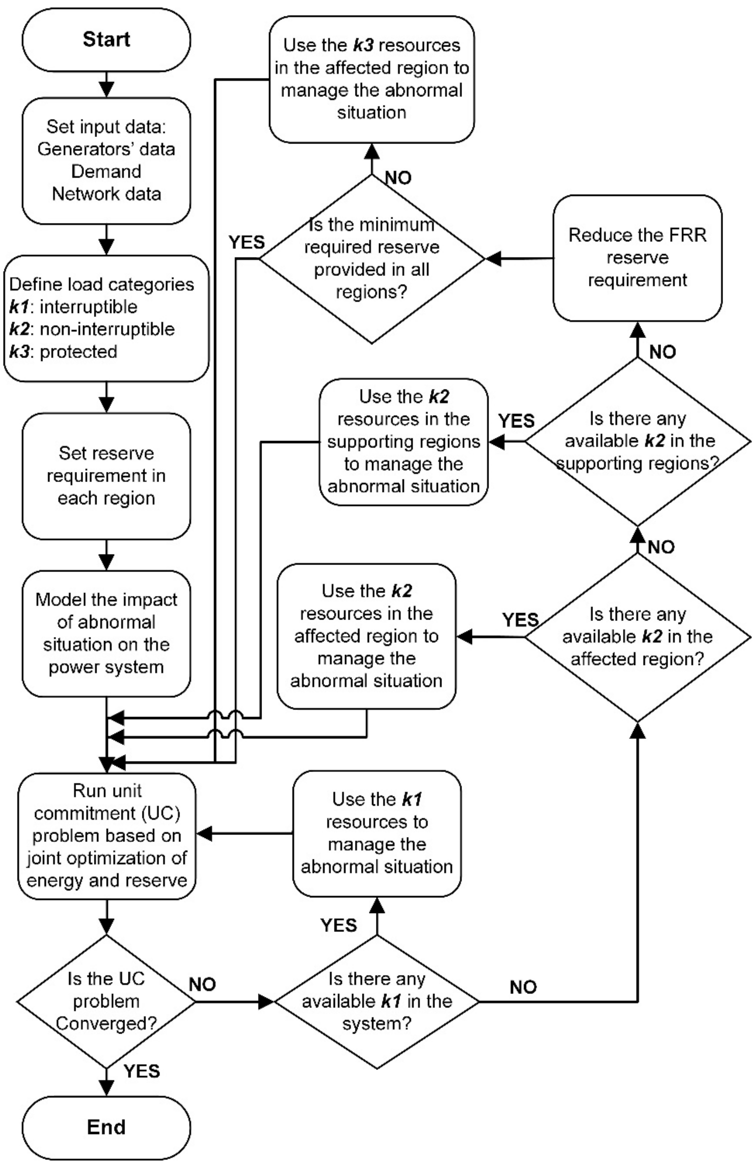

Figure 5.2: Flowchart of the decision making algorithm

$$P_{b,i,t} \leq u_{i,t} H_{i,t}^{Gen} P_{b,i,t}^{max} \tag{5.4}$$

$$u_{i,t} H_{i,t}^{Gen} g_i^{min} \leq g_{i,t} \leq u_{i,t} H_{i,t}^{Gen} g_i^{max} \tag{5.5}$$

Equation (5.2) indicates the operation/production cost of conventional generators including fixed and variable costs. Fixed costs are no-load costs which depend on the ON/OFF state of generators. Binary variable $u_{i,t}$ defines the ON/OFF state of generation unit i at each time interval. Incremental production cost curve of conventional generators is modelled by the so-called step/staircase function. In a market algorithm, it is equivalent to submit block offers into the market. According to (5.3), the aggregated power production under different generation/offer blocks represents the total production of each generator. Accepted generation from each block cannot exceed the block size in term of maximum power quantity, as presented by (5.4). Furthermore, as indicated by (5.5), the aggregated power production of each generator by different blocks is limited by its minimum and maximum technical limit, in normal conditions and after the occurrence of an abnormal situation affecting generators' operational limits.

Generators' state variable ($u_{i,t}$) is defined by two additional binary variables, indicating Start-up state ($y_{i,t}$) and shut-down state ($z_{i,t}$) of the unit in each time interval, in (5.6)-(5.8).

$$u_{i,t} - u_{i,t-1} = y_{i,t} - z_{i,t} \quad ; \quad \forall t > 1 \tag{5.6}$$

$$u_{i,t} - u_{i,0} = y_{i,t} - z_{i,t} \quad ; \quad \forall t = 1 \tag{5.7}$$

$$y_{i,t} + z_{i,t} \leq 1 \tag{5.8}$$

Equation (5.6) indicates that the generation unit i is in start-up state at time interval t if and only if the unit has been OFF in the previous time interval while it is ON in time interval t. As stated by (5.8), a unit cannot be in Start-up and Shut-down states simultaneously.

Start-up cost of conventional generators is represented by (5.9). In this study, $\overline{X}_i$ start-up time blocks are considered for each generator according to the time period the unit was OFF before starting up again ($\overline{X}_i = 8$). Different costs are assumed for each start-up time interval, implying on the hot to cold start-up costs. A binary variable is defined for each start-up time block ($\mathcal{Y}_{i,x,t}$). $\mathcal{Y}_{i,x,t}$ equals one if generator i starts up at time interval t under its x^{th} start-up block which means after x hours being OFF. The binary variable $\mathcal{Y}_{i,x,t}$ is defined by (5.10). $T^{OFF}_{i,t}$ in (5.10) indicates the total number of hours that the generation unit i have been OFF before time interval t. To rewrite the implicit equation (5.10) to its distinct form, the three conditions in (5.10) are defined by (5.11)-(5.13), respectively. According to (5.11), if and only if generation unit i is ON in $t = t'$, while it has been OFF during all the x time intervals before and one interval before that (at $t = t' - x - 1$) it was ON again, the left side of equality constraint (5.11) becomes zero which implies on $\mathcal{Y}_{i,x,t'} = 1$. However, the maximum number of start-up time blocks for conventional generators is limited to $\overline{X}_i = 8$ which mean that if a unit turns on after being off for more than $\overline{X}_i$ time intervals, its start-up cost does not change any more. This condition is defined by the second constraint in equation (5.10) and rewritten to a distinct form by (5.12). Finally, the third condition of $\mathcal{Y}_(i, x, t)$ determination in (5.10) is rewritten by (5.13). Inequality constraint (5.13) indicates that is a unit is

OFF at time interval $t = t'$ or it has not been continuously OFF during the period of x intervals before, then $\mathcal{Y}_{i,x,t'}^{=}0$. The ON/OFF state of generation units before the first time interval of the optimization are determined by (5.14) and (5.15). Finally, equation (5.16) correlates the start-up time block variables to the binary variable of start-up state, defined by $y_{i,t}$. Furthermore, it implies that if a generation unit is in start-up state at t, only one of its start-up time block variables is non-zero.

$$C_{i,t}^{SU} = \sum_{x \in \mathcal{X}} \mathcal{Y}_{i,x,t} C_{x,i}^{SU} \tag{5.9}$$

$$\begin{cases} \mathcal{Y}_{i,x,t} = 1; \quad if\ T_{i,t}^{OFF} = x\ \ and\ \ u_{i,t} = 1 \\ \\ \mathcal{Y}_{i,\overline{X}_i,t} = 1 \quad if\ T_{i,t}^{OFF} \geq \overline{X}_i\ \ and\ \ u_{i,t} = 1 \\ \\ \mathcal{Y}_{i,x,t} = 0; \quad if\ T_{i,t}^{OFF} \leq x\ \ or\ \ u_{i,t} = 0 \end{cases} \tag{5.10}$$

$$\sum_{t=t'-x}^{t'-1} u_{i,t} + (1 - u_{i,t'-x-1}) + (1 - u_{i,t'}) \geq 1 - \mathcal{Y}_{i,x,t'} \quad ; \forall x \neq \overline{X}_i, t', i \tag{5.11}$$

$$\sum_{t=t'-\overline{X}_i}^{t'-1} u_{i,t} + (1 - u_{i,t'}) \geq 1 - \mathcal{Y}_{i,\overline{X}_i,t'} \quad \forall t', i \tag{5.12}$$

$$\sum_{t=t'-x}^{t'-1} u_{i,t} + (1 - u_{i,t'}) \leq M(1 - \mathcal{Y}_{i,x,t'}) \quad \forall x, t', i \tag{5.13}$$

$$\sum_{t=-T_{i,0}^{on}+1}^{0} u_{i,t} = T_{i,0}^{on} \tag{5.14}$$

$$\sum_{t=-T_{i,0}^{off}+1}^{0} (1 - u_{i,t}) = T_{i,0}^{off} \tag{5.15}$$

$$\sum_{x \in \mathcal{X}} \mathcal{Y}_{i,x,t} = y_{i,t} \tag{5.16}$$

The nomination of $\mathcal{Y}_{i,x,t}$ and equations (5.11)-(5.13) are further explained by a numerical example in Figure 5.3.

The maximum FCR and FRR reserve constraint of conventional generation units are presented by (5.17)-(5.20). Both FCR and FRR can only be provided by flexible spinning generators, usually by thermal and hydro units. FCR reserve is provided by spinning generators equipped with governor droop control system and the maximum FCR provision is constrained by the droop gain. Similar to the argumentation provided in Section 3.4 and Section 4.3.3, in this model also it is

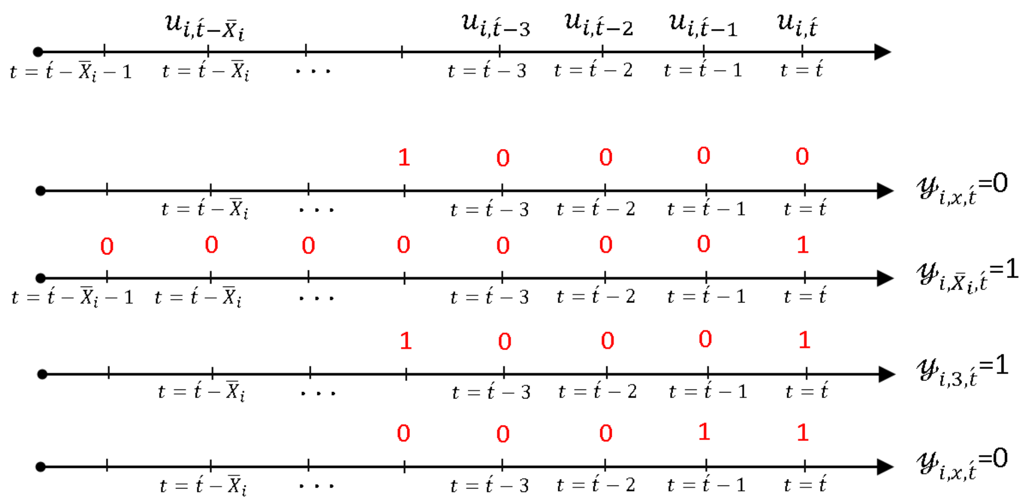

Figure 5.3: Illustrative example of start-up time block's definition

assumed that thermal and hydro generators can provide up to 8% of their dispatchable capacity for FCR services. The maximum FCR constraint of generation units is presented by (5.17). Furthermore, the final output power of conventional generators after providing upward or downward FCR in emergencies cannot exceed the minimum and maximum production limit of the unit, as indicated by (5.18). FRR reserve provision is considered less restricted as spinning generators can provide their remained capacity, i.e. the difference between their dispatchable generation and their scheduled generation and FCR capacity, for upward FRR service. Downward FRR can also be provided by dispatchable generators through reducing their output power to their minimum production limit, considering also the reserved downward FCR capacity. The FRR reserve constraints are also presented by (5.19) and (5.20). For the sake of simplicity and without loss of generality, FCR is assumed symmetric product. Hence, a unique variable is defined for both upward and downward FCR reserve.

$$r_{i,t}^{FCR} \leq \gamma_i \ u_{i,t} H_{i,t}^{Gen} g_i^{max} \tag{5.17}$$

$$u_{i,t} H_{i,t}^{Gen} g_i^{min} + r_{i,t}^{FCR} \leq g_{i,t} \leq u_{i,t} H_{i,t}^{Gen} g_i^{max} - r_{i,t}^{FCR} \tag{5.18}$$

$$g_{i,t} + r_{i,t}^{FRR,Up} \leq u_{i,t} H_{i,t}^{Gen} g_i^{max} - r_{i,t}^{FCR} \tag{5.19}$$

$$g_{i,t} - r_{i,t}^{FRR,Dn} \geq u_{i,t} H_{i,t}^{Gen} g_i^{min} + r_{i,t}^{FCR} \tag{5.20}$$

Ramp up/down constraint of conventional generation units are provided by (5.21) and (5.22).

$$-R_i^{Dn} \leq g_{i,t} - g_{i,t-1} \leq R_i^{Up} \quad ; \forall t > 1 \tag{5.21}$$

$$-R_i^{Dn} \leq g_{i,t} - g_{i,0} \leq R_i^{Up} \quad ; \forall t = 1 \tag{5.22}$$

Equations (5.23) and (5.24) represent the minimum up time and minimum down time limit of conventional generators, respectively. As indicated by (5.23), due to the technical minimum up time of generation units, the time distance between two successive start-up states of a unit cannot be shorter than its minimum up time limit. Also according to (5.24), the time distance between two shut-downs of a generation unit should be longer than its minimum down time limit.

$$\sum_{t=t'-T_i^{min,Up}+1}^{t'} y_{i,t} \leq u_{i,t'} \tag{5.23}$$

$$\sum_{t=t'-T_i^{min,Dn}+1}^{t'} z_{i,t} \leq (1 - u_{i,t'}) \tag{5.24}$$

Finally, the energy curtailment limit of wind generators is represented by (5.25). Note that μ^{spill} is the percentage of allowed wind spillage with respect to the predicted wind production ($g_{w,t}^{max}$) in each time interval.

$$E_{w,t}^{spill} \leq \mu^{spill} g_{w,t}^{max} \tag{5.25}$$

B.2. Hydro pumped storage constraints

The production and storage constraints of hydro pumped storage generators are represented by (5.26)-(5.30). Hydro pumped storage generators are define by two reservoirs in different elevations (head and tail reservoirs), a maximum pumping up/down power, and a cycling efficiency. Similar to any other storage technologies, hydro pumped storage units can operate in two modes: generating mode ($q_{s,t} \geq 0$) and pumping mode ($q_{s,t} < 0$). Maximum power production/consumption limit of hydro pumped storage units is represented by (5.26). The maximum energy storage in the head and tail reservoirs of each hydro pumped storage generator is limited by the reservoir's capacity, as shown by (5.27) and (5.28). The hourly energy level in head and tail reservoirs are affected by the cycling efficiency (η_s) of hydro pumped storage units. The cycling efficiency is modelled on the pumping mode of the generator, under consumption mode. Accordingly, the energy stored in head and tail reservoirs are represented by (5.29) and (5.30).

$$-q_s^{max} \leq q_{s,t} \leq q_s^{max} \tag{5.26}$$

$$E_{s,t}^{H} \leq E_{s}^{max,H} \tag{5.27}$$

$$E_{s,t}^{T} \leq E_{s}^{max,T} \tag{5.28}$$

$$\begin{cases} E_{s,t}^{H} = E_{s,t-1}^{H} - q_{s,t} & ;if\ q_{s,t} \geq 0 \\ E_{s,t}^{H} = E_{s,t-1}^{H} - \eta_s q_{s,t} & ;if\ q_{s,t} < 0 \end{cases} \tag{5.29}$$

$$\begin{cases} E_{s,t}^{T} = E_{s,t-1}^{T} + q_{s,t} & ;if\ q_{s,t} \geq 0 \\ E_{s,t}^{T} = E_{s,t-1}^{T} + \eta_s q_{s,t} & ;if\ q_{s,t} < 0 \end{cases} \tag{5.30}$$

Equations (5.29) and (5.30) should be re-written to a distinct linear. To this aim, first we need to determine the operating mode of hydro pumped storage units. To find out if a pumped storage unit is operating in generating or pumping mode, a binary variable $x_{s,t}$ is defined such that $x_{s,t} = 1$ if storage is in consuming power for pumping up water from tail reservoir to its head reservoir and $x_{s,t} = 0$ if the storage is in generating mode, i.e. releasing water from head reservoir to the tail reservoir. The binary operating state variable of hydro pumped storage units is defined by (5.31). Inequality constraint (5.32) represents the linear distinct form of equation (5.31). Next, using $x_{s,t}$ variable defined by (5.32), equations (5.29) and (5.30) are rewritten by (5.33)-(5.39).

$$x_{s,t} = \begin{cases} 1 & ;if\ q_{s,t} < 0 \\ 0 & ;if\ q_{s,t} \geq 0 \end{cases} \tag{5.31}$$

$$-\left(\frac{1}{M}\right) q_{s,t} \leq x_{s,t} \leq 1 - \left(\frac{1}{M}\right) q_{s,t} \tag{5.32}$$

$$-x_{s,t}M \leq E_{s,t}^{H} - E_{s,t-1}^{H} + q_{s,t} \leq 0 \quad ;\forall t > 1 \tag{5.33}$$

$$-(1 - x_{s,t})M \leq E_{s,t}^{H} - E_{s,t-1}^{H} + \eta_s q_{s,t} \leq 0 \quad ;\forall t > 1 \tag{5.34}$$

$$-x_{s,t}M \leq E_{s,t}^{H} - E_{s,0}^{H} + q_{s,t} \leq 0 \quad ;c \tag{5.35}$$

$$-(1 - x_{s,t})M \leq E_{s,t}^{H} - E_{s,0}^{H} + \eta_s q_{s,t} \leq 0 \quad ;\forall t = 1 \tag{5.36}$$

$$0 \leq E_{s,t}^{T} - E_{s,t-1}^{T} - q_{s,t} \leq x_{s,t}M \quad ;\forall t > 1 \tag{5.37}$$

$$0 \leq E_{s,t}^{T} - E_{s,t-1}^{T} - \eta_s q_{s,t} \leq (1 - x_{s,t})M \quad ;\forall t > 1 \tag{5.38}$$

$$0 \leq E^{T}_{s,t} - E^{T}_{s,0} - q_{s,t} \leq x_{s,t}M \quad ; \forall t = 1 \tag{5.39}$$

$$-x_{s,t}M \leq E^{H}_{s,t} - E^{H}_{s,t-1} + q_{s,t} \leq 0 \quad ; \forall t > 1 \tag{5.40}$$

Equations (5.41)-(5.42) indicate the FCR and FRR reserve constraints of hydro pumped storage generators. It should be noted that the impact of reserve provision by hydro pumped storage generators on the energy storage in the reservoirs is neglected in this study, as it depends on the expected reserve activation under contingencies and the probability of contingency occurrence is supposed to be very low.

$$r^{FCR}_{s,t} + r^{FRR,Up}_{s,t} \leq q^{max}_{s} - q_{s,t} \tag{5.41}$$

$$r^{FRR,Dn}_{s,t} \leq q^{max}_{s} + q_{s,t} \tag{5.42}$$

B.3. Network and System Balance Constraints

The supply-demand balance constraint of the system in each node is represented by (5.43). Equation (5.43) implies that sum of energy produced in each network node (by conventional and wind generators and hydro pumped storage units) and the energy curtailed form load, should be equal to the total demand on the same node plus the energy exported to the other network nodes. Equation (5.44) indicates the power flow on each line based on DC power flow equations. Maximum flow limit on each line in different directions is indicated by (5.45). Equation (5.46) implies on the voltage angle limit of each network node. The slack bus for power flow calculations is defined by (5.47).

$$\begin{aligned} \sum_{i \in \mathcal{J}_n} g_{i,t} + \sum_{s \in \mathcal{S}_n} q_{s,t} + \sum_{w \in \mathcal{W}_n} (g^{max}_{w,t} - E^{spill}_{w,t}) - \sum_{l \in \mathcal{L}} d_{n,l} f_{l,t} - \sum_{d \in \mathcal{D}_n} H^{Dem}_{d,t} L_{d,t} \\ + \sum_{d \in \mathcal{D}_n} \sum_{k \in \mathcal{K}} E^{int}_{k,d,t} = 0 \end{aligned} \tag{5.43}$$

$$f_{l,t} = \frac{1}{X_l} \left(\sum_{n \in \mathcal{N}} d_{n,l} \theta_{n,t} \right) \tag{5.44}$$

$$-f^{max-}_{l} \leq f_{l,t} \leq f^{max+}_{l} \tag{5.45}$$

$$-\pi \leq \theta_{n,t} \leq \pi \quad ; \forall n \neq 1 \tag{5.46}$$

$$\theta_{n,t} = 0 \quad ; \forall n : n_{slack} \tag{5.47}$$

B.4. Regional reserve requirement constraints

Minimum FCR and FRR reserve requirement in each region is represented by (5.48)-(5.50). It is assumed that each region/zone has a minimum reserve requirement to be provided by its internal resources which is defined by operational regulations within that region. This assumption is in line with the current reserve provision rules in Europe. While the total FCR requirement in each synchronous area is provided by all the countries belonged to that area, each country has a minimum reserve requirement which defines its share to the total reserve requirement. Upward FCR and FRR capacity shortage in each zone are also considered in (5.48) and (5.49).

$$\sum_{n\in\mathcal{N}_z}\left(\sum_{s\in\mathcal{S}_n} r_{s,t}^{FCR} + \sum_{i\in\mathcal{J}_n} r_{i,t}^{FCR}\right) + r_{z,t}^{FCR,sh} \geq r_z^{FCR} \tag{5.48}$$

$$\sum_{n\in\mathcal{N}_z}\left(\sum_{s\in\mathcal{S}_n} r_{s,t}^{FRR,Up} + \sum_{i\in\mathcal{J}_n} r_{i,t}^{FRR,Up}\right) + r_{z,t}^{FRR,sh} \geq r_z^{FRR,Up} \tag{5.49}$$

$$\sum_{n\in\mathcal{N}_z}\left(\sum_{s\in\mathcal{S}_n} r_{s,t}^{FRR,Dn} + \sum_{i\in\mathcal{J}_n} r_{i,t}^{FRR,Dn}\right) \geq r_z^{FRR,Dn} \tag{5.50}$$

B.5. Load interruption constraints

Maximum load interruption constraints of each load type are indicated by (5.51) and (5.52). Equation (5.51) indicates the maximum energy interruption while (5.52) indicates the maximum duration of interruption on each load category per day. Inequality constraint (5.52) limits the maximum duration of interruption on a single customer according to its load category. However, a customer in transmission network model can be either a very large consumer directly participating in the model or an entity aggregating the load of smaller customers, e.g. load aggregators, distribution companies, or load serving entities. Typically, the maximum permitted duration of interruption is set by regulators within each region or country. However, it implies on the duration of interruption on a single end users. As the share of each end-user in the total aggregated demand is not known by the decision-maker in our model, we model this constraint in a flexible manner as in (5.52). According to (5.52), if all the available capacity of interruptible load on a customer participated in the model is interrupted, the interruption duration cannot exceed its maximum limit ($T^{max,int}$). However, if only half of the available capacity is interrupted, then this duration can be increased up to twice its maximum limit ($2 \times T^{max,int}$), assuming that the interruption can be performed rotationally on the smaller end-users. The similar reasoning applies to any share of load interruption on each aggregated customer, and on all the load categories.

$$E_{k,d,t}^{int} \leq H_{d,t}^{Dem}\eta_{d,k}L_{d,t} \tag{5.51}$$

$$\sum_{t\in\mathcal{T}^{Day}} \frac{E^{int}_{k,d,t}}{H^{Dem}_{d,t}\eta_{d,k}L_{d,t}} \leq T^{max,int}_{k} \tag{5.52}$$

5.3.2 Security-constrained crisis management algorithm

In this section, the optimization problem presented in Section 5.3.1 is reformulated to a security-constrained model by taking into consideration the regional N-1 security assessment within the crisis management model. The whole set of contingencies representing the failure of one transmission line or generation unit, within all regions, is taken into account. The mathematical formulation of the modified security-constrained decision making algorithm is presented in what follows. The constraints are divided into pre-contingency and post-contingency equations, covering the system states under abnormal situation (possible crisis), before and after the occurrence of a contingency as a component failure.

A. Objective function:

$$\begin{aligned}
&\min_{g_{i,t},q_{s,t},E^{spill}_{w,t}} C^{TOT} \\
&= \sum_{t\in\mathcal{T}}\Bigg[\sum_{i\in\mathcal{J}}(C^{opr}_{i,t} + C^{SU}_{i,t}) \\
&+ \sum_{w\in\mathcal{W}} E^{spill}_{w,t}\varphi^{spill} + C^{Res}\Big(\sum_{i\in\mathcal{J}} r^{Up,Res}_{i,t} + \sum_{s\in\mathcal{S}} r^{Up,Res}_{s,t}\Big) \\
&+ \sum_{e\in\mathcal{E}}\sum_{z\in\mathcal{Z}}\sum_{n\in\mathcal{N}_z}\varphi^{Res}_{z} r^{sh}_{n,t,e} + \Psi\Big(\sum_{z\in\mathcal{Z}}\mu_{k,z}\sum_{n\in\mathcal{N}_z}\sum_{d\in\mathcal{D}_n} E^{int}_{k,d,t}\Big)\Bigg]
\end{aligned} \tag{5.53}$$

The objective function (5.53) minimizes the total operation cost of the system including generation/fuel cost and start-up cost of conventional generators, penalty for renewable curtailment (wind spillage in our case study), cost of reserve capacity from conventional and hydro pumped storage generators, penalty for reserve shortage under contingencies, and an equivalent penalty factor for load curtailment on different load types. The cost of reserve provision in the objective function is considered as the payment to reserve providers for their readiness and capacity reservation, while it is assumed that in case of reserve activation the energy would be settled according to the marginal cost of generators.

B. Normal operation constraints

B.1. Generators' constraints

$$C^{opr}_{i,t} = \rho^{fix}_{i} u_{i,t} + \sum_{b\in\mathcal{B}} \rho^{var}_{b,i} P_{b,i,t} \tag{5.54}$$

$$g_{i,t} \ = \ \sum_{b\in\mathcal{B}} P_{b,i,t} \tag{5.55}$$

$$E^{spill}_{w,t} \leq \mu^{spill} g^{max}_{w,t} \tag{5.56}$$

$$P_{b,i,t} \leq u_{i,t} H^{Gen}_{i,t} P^{max}_{b,i,t} \tag{5.57}$$

$$u_{i,t} \ - \ u_{i,t-1} \ = \ y_{i,t} \ - \ z_{i,t} \quad ; \forall t > 1 \tag{5.58}$$

$$u_{i,t} \ - \ u_{i,0} \ = \ y_{i,t} \ - \ z_{i,t} \quad \forall t = 1 \tag{5.59}$$

$$y_{i,t} \ + \ z_{i,t} \ \leq 1 \tag{5.60}$$

$$C^{SU}_{i,t} \ = \ \sum_{x\in\mathcal{X}} \mathcal{Y}_{i,x,t} C^{SU}_{x,i} \tag{5.61}$$

$$\sum_{t=t'-x}^{t'-1} u_{i,t} \ + \ (1-u_{i,t'}) \leq M(1-\mathcal{Y}_{i,x,t'}) \tag{5.62}$$

$$\sum_{t=t'-x}^{t'-1} u_{i,t} \ + \ (1-u_{i,t'-x-1}) \ + \ (1-u_{i,t'}) \geq 1-\mathcal{Y}_{i,x,t'} \tag{5.63}$$

$$\sum_{t=t'-\overline{X}_i}^{t'-1} u_{i,t} \ + \ (1-u_{i,t'}) \geq 1-\mathcal{Y}_{i,\overline{X}_i,t'} \tag{5.64}$$

$$\sum_{x\in\mathcal{X}} \mathcal{Y}_{i,x,t} \ = \ y_{i,t} \tag{5.65}$$

$$u_{i,t} H^{Gen}_{i,t} g^{min}_i \leq g_{i,t} \leq u_{i,t} H^{Gen}_{i,t} g^{max}_i \tag{5.66}$$

$$g_{i,t} \ + \ r^{Up,Res}_{i,t} \leq u_{i,t} H^{Gen}_{i,t} g^{max}_i \tag{5.67}$$

$$u_{i,t} H^{Gen}_{i,t} g^{min}_i \leq g_{i,t} - r^{Dn,Res}_{i,t} \tag{5.68}$$

$$r^{Up,Res}_{i,t} \leq r^{Up,max}_i \tag{5.69}$$

$$r^{Dn,Res}_{i,t} \leq r^{Dn,max}_i \tag{5.70}$$

$$r^{Up,Act}_{i,t,e} \leq I^{Gen}_{e,i} r^{Up,Res}_{i,t} \tag{5.71}$$

$$r_{i,t,e}^{Dn,Act} \leq I_{e,i}^{Gen} r_{i,t}^{Dn,Res} \tag{5.72}$$

$$-R_i^{Dn} \leq g_{i,t} - g_{i,t-1} \leq R_i^{Up} \quad ;\forall t > 1 \tag{5.73}$$

$$-R_i^{Dn} \leq g_{i,t} - g_{i,0} \leq R_i^{Up} \quad ;\forall t = 1 \tag{5.74}$$

$$\sum_{t=t'-T_i^{min,Up}+1}^{t'} y_{i,t} \leq u_{i,t'} \tag{5.75}$$

$$\sum_{t=t'-T_i^{min,Dn}+1}^{t'} z_{i,t} \leq (1 - u_{i,t'}) \tag{5.76}$$

Equations (5.54)–(5.76) represent the conventional and wind generators' constraints in the normal operation of the system. Equation (5.54) indicates the operation/production cost of conventional generators including fixed and variable cost terms. Conventional generators' offers are divided into several blocks. According to (5.55), sum of production under different blocks represents the total generation of each generator. Equation (5.56) indicates the maximum wind curtailment which cannot exceed the available wind production at each time interval. Equation (5.57) constraints the maximum dispatched power of conventional generators under each block according to the maximum offer quantity of the same block, taking into account the impact of crisis. The binary state variable of conventional generators implying on their ON/OFF status, start-up and shut-down states, are defined by (5.58)-(5.60). Start-up cost of conventional generators is represented by (5.61). Binary variable $y_{i,x,t}$ indicates the start-up time block of generator i at time interval t. Start-up time block for each generator is set according to the time period the unit was OFF before turning it ON. The time duration a generation unit was OFF before its start-up implies on the hot to cold start-up conditions and the start-up cost is calculated accordingly. $y_{i,x,t}$ equals one if generator i starts up at time interval t under its xth start-up block which means after x hours being OFF. The binary variable $y_{i,x,t}$ is defined by (5.62)-(5.65). Minimum and maximum production limit of conventional generators with/without crisis are defined by (5.66). The reserve capacity provided by each conventional generator is constrained by (5.67)-(5.70). Accordingly, the reserve energy activated by each generator under different contingencies cannot not exceed the reserved capacity of the same generator, as indicated by (5.71) and (5.72). Maximum ramp up and ramp down constraint of generators are shown by (5.73) and (5.74). Finally, equations (5.75) and (5.76) represent the minimum up time and minimum down time of conventional generators.

B.2. Hydro pumped storage constraints

$$-q_s^{max} \leq q_{s,t} \leq q_s^{max} \tag{5.77}$$

$$r_{s,t}^{Dn,Res} \leq q_{s,t} + q_s^{max} \tag{5.78}$$

$$r_{s,t}^{Up,Res} \leq q_s^{max} - q_{s,t} \tag{5.79}$$

$$r_{s,t,e}^{Up,Act} \leq r_{s,t}^{Up,Res} \tag{5.80}$$

$$r_{s,t,e}^{Dn,Act} \leq r_{s,t}^{Dn,Res} \tag{5.81}$$

$$E_{s,t}^{H} \leq E_S^{max,H} \tag{5.82}$$

$$E_{s,t}^{T} \leq E_s^{max,T} \tag{5.83}$$

$$-(\frac{1}{M})q_{s,t} \leq x_{s,t} \leq 1-(\frac{1}{M})q_{s,t} \tag{5.84}$$

$$-x_{s,t}M \leq E_{s,t}^{H} - E_{s,t-1}^{H} + q_{s,t} \leq 0 \quad ;\forall t > 1 \tag{5.85}$$

$$-(1-x_{s,t})M \leq E_{s,t}^{H} - E_{s,t-1}^{H} + \eta_s q_{s,t} \leq 0 \quad ;\forall t > 1 \tag{5.86}$$

$$-x_{s,t}M \leq E_{s,t}^{H} - E_{s,0}^{H} + q_{s,t} \leq 0 \quad ;\forall t = 1 \tag{5.87}$$

$$-(1-x_{s,t})M \leq E_{s,t}^{H} - E_{s,0}^{H} + \eta_s q_{s,t} \leq 0 \quad ;\forall t = 1 \tag{5.88}$$

$$0 \leq E_{s,t}^{T} - E_{s,t-1}^{T} - q_{s,t} \leq x_{s,t}M \quad ;\forall t > 1 \tag{5.89}$$

$$0 \leq E_{s,t}^{T} - E_{s,t-1}^{T} - \eta_s q_{s,t} \leq (1-x_{s,t})M \quad ;\forall t > 1 \tag{5.90}$$

$$0 \leq E_{s,t}^{T} - E_{s,0}^{T} - q_{s,t} \leq x_{s,t}M \quad ;\forall t = 1 \tag{5.91}$$

$$0 \leq E_{s,t}^{T} - E_{s,0}^{T} - \eta_s q_{s,t} \leq (1-x_{s,t})M \quad ;\forall t = 1 \tag{5.92}$$

The constraints of hydro pumped storage generators are represented by (5.77)-(5.94). Hydro pumped storage generators are define by two reservoirs in different elevations (head and tail reservoirs), a maximum pumping up/down power, and a cycling efficiency. Hydro pumped storage generators can operate in two modes: generating mode ($q_{s,t} \leq 0$) and pumping mode ($q_{s,t} < 0$). Maximum power production/consumption limit of hydro pumped storage units is represented by (5.77). Equations (5.78)-(5.81) indicate the reserve capacity/energy constraints of hydro pumped storage generators. The maximum energy storage in the head and tail reservoirs of each hydro pumped storage generator is limited by the reservoir's capacity, as shown by (5.82) and (5.83). The inefficiency of hydro pumped storage unit is modelled on its water pumping cycle. Binary variable $x_{s,t}$ indicates the storage unit's operating mode such that $x_{s,t} = 1$ if storage is in consuming power for pumping up water and $x_{s,t} = 0$ if the storage is in generating mode. The equations (5.84)-(5.92) are defined to calculate the hourly energy level in the head and tail reservoirs of each hydro pumped storage unit as a mixed integer linear problem.

B.3. Network and system balance constraints

$$\begin{aligned} &\sum_{i \in \mathcal{I}_n} g_{i,t} + \sum_{s \in \mathcal{S}_n} q_{s,t} \\ &+ \sum_{w \in \mathcal{W}_n} (g_{w,t}^{max} - E_{w,t}^{spill}) - \sum_{l \in \mathcal{L}} d_{n,l} f_{l,t} - \sum_{d \in \mathcal{D}_n} H_{d,t}^{Dem} L_{d,t} \\ &+ \sum_{d \in \mathcal{D}_n} \sum_{k \in \mathcal{K}} E_{k,d,t}^{int} = 0 \end{aligned} \tag{5.93}$$

$$f_{l,t} = \frac{1}{X_l} \Big(\sum_{n \in \mathcal{N}} d_{n,l}\, \theta_{n,t} \Big) \tag{5.94}$$

$$- f_l^{max-} \leq f_{l,t} \leq f_l^{max+} \tag{5.95}$$

$$- \pi \leq \theta_{n,t} \leq \pi \quad ; \forall n \neq 1 \tag{5.96}$$

$$\theta_{n,t} = 0 \quad ; \forall n : n_{slack} \tag{5.97}$$

The nodal energy balance constraint of the system under normal operation (without contingencies) is represented by (5.93). Equation (5.94) indicates the power flow on each line based on DC power flow equations. Maximum flow limit on each line in different directions is indicated by (5.95). Equation (5.96) implies on the voltage angle limit of each network node. The voltage angle of slack bus is set by (5.97).

B.4. Load interruption constraints

$$E_{k,d,t}^{int} \leq H_{d,t}^{Dem} \eta_{d,k} L_{d,t} \tag{5.98}$$

$$\sum_{t\in\mathcal{T}^{Day}} \frac{E^{int}_{k,d,t}}{H^{Dem}_{d,t}\eta_{d,k}L_{d,t}} \leq T^{max,int}_{k} \tag{5.99}$$

Maximum load interruption constraints of each load type are indicated by (5.98) and (5.99). Equation (5.98) indicates the maximum energy interruption while (5.99) indicates the maximum duration of interruption on each customer.

C. Post-contingency constraints

$$\begin{aligned} \sum_{i\in\mathcal{J}_n} (I^{Gen}_{e,i} g_{i,t} + r^{Up,Act}_{i,t,e} - r^{Dn,Act}_{i,t,e}) + \sum_{s\in\mathcal{S}_n} (q_{s,t} + r^{Up,Act}_{s,t,e} - r^{Dn,Act}_{s,t,e}) \\ + \sum_{w\in\mathcal{W}_n} (g^{max}_{w,t} - E^{spill}_{w,t} - E^{spill}_{w,t,e}) - \sum_{l\in\mathcal{L}} d_{n,l} f^{emg}_{l,t,e} \\ - \sum_{d\in\mathcal{D}_n} H^{Dem}_{d,t} L_{d,t} + \sum_{d\in\mathcal{D}_n} \sum_{k\in\mathcal{K}} E^{int}_{k,d,t} + r^{sh}_{n,t,e} = 0 \end{aligned} \tag{5.100}$$

$$E^{spill}_{w,t,e} \leq \mu^{spill} g^{max}_{w,t} - E^{spill}_{w,t} \tag{5.101}$$

$$f^{emg}_{l,t,e} = \frac{1}{X_l}\left(\sum_{n\in\mathcal{N}} d_{n,l}\,\theta^{emg}_{n,t,e}\right) \tag{5.102}$$

$$-(1+\mu^{ovl}) I^{Lin}_{e,l} f^{max-}_{l} \leq f^{emg}_{l,t,e} \leq (1+\mu^{ovl}) I^{Lin}_{e,l} f^{max+}_{l} \tag{5.103}$$

$$-\pi \leq \theta^{emg}_{n,t,e} \leq \pi \quad ;\forall n \neq 1 \tag{5.104}$$

$$\theta^{emg}_{n,t,e} = 0 \quad ;\forall n : n_{slack} \tag{5.105}$$

The post-contingency state of the system is constrained by (5.100)-(5.105). The set of contingencies include outage of all generators and lines, while the system should be N-1 secure which means that it should remain stable following each of the defined contingencies. The post contingency energy balance constraint is represented by (5.100). If necessary, additional wind curtailment can be implemented following a contingency as a downward reserve capacity (equation (5.101)). Post-contingency power flow of each line under individual contingencies is defined by (5.102). It is assumed that in post-contingency state the power flow on the transmission lines can be slightly overloaded compared to the normal operation constraint, as indicated by (5.103). In this study it is assumed that in emergency operation states up to 10% overload on the transmission lines is permitted ($\mu^{ovl} = 0.1$). Finally, equation (5.104) and (5.105) indicate the post contingency voltage angle limit of the network nodes.

5.3.3 No multi-area load shedding assistance

In both of the models presented in Sections 5.3.1 and 5.3.2, there might be a situation where interconnected areas provide support to the affected area only by their excess generation capacities, and not through load interruption services. This condition does not necessarily lead to no load interruption in the supporting regions; but it means that interruptible loads can only be used for local services. To demonstrate this scenarios, a binary variable ($j_{z,t}$) is defined to represent the import/export state of each region. If the sum of power flows on the interconnections connected to zone z , in the direction flowing out zone z is positive, i.e. zone z is exporting power to the neighboring zones, $j_{z,t} = 1$. Else if zone z is importing power, then $j_{z,t} = 0$. The implicit equation to define $j_{z,t}$ in (5.106) is transformed to a linear distinct form by (5.107). Then equation (5.108) is defined to restrict load interruption in the exporting zones, such that if a zone is exporter, sum of the load interruption on all load categories within this zone is zero. However, this constraint is relaxed for importing zones. This means that other zones not under crisis can only export power from their generation and storage sources and not from interruption of loads.

$$j_{z,t} = \begin{cases} 1 \quad ; if \sum\limits_{\substack{l \in \mathcal{L}_z \\ n \notin \mathcal{N}_z}} d_{n,l} f_{l,t} < 0 \\ \\ 0 \quad ; if \sum\limits_{\substack{l \in \mathcal{L}_z \\ n \notin \mathcal{N}_z}} d_{n,l} f_{l,t} \geq 0 \end{cases} \tag{5.106}$$

$$-(\frac{1}{M})\left(\sum_{\substack{l \in \mathcal{L}_z \\ n \notin \mathcal{N}_z}} d_{n,l} f_{l,t}\right) \leq j_{z,t} \leq 1 - (\frac{1}{M})\left(\sum_{\substack{l \in \mathcal{L}_z \\ n \notin \mathcal{N}_z}} d_{n,l} f_{l,t}\right) \tag{5.107}$$

$$M(1 - j_{z,t}) \geq \sum_{n \in \mathcal{N}_z} \sum_{d \in \mathcal{D}_n} \sum_{k \in \mathcal{K}} E^{int}_{k,d,t} \tag{5.108}$$

5.4 Test case and scenarios

In order to verify the applicability and efficiency of the proposed multi-area assisted load shedding approach for managing crisis in interconnected regions, the model is tested on a conceptual test case. As the model requires detailed network and generator's model of the system under test and due to the lack of accurate open source data of the European power systems, the standard IEEE RTS 96 is selected as the test case. Furthermore, in order to analyse the impact of different levels of coordination among regions to manage crisis situation, a set of scenarios are defined in this study. The network model and proposed scenarios by details in the following subsections.

5.4.1 Network model

The standard IEEE RTS 96 test system includes 3 analogous interconnected regions with totally 73 buses, 120 transmission lines, and 96 conventional generation units. However, in this study we used the updated version of the system which has been modified by Washington University in [188] by adding 19 wind power plants. Furthermore, the number of conventional generators are reduced from 96 units to 82 units[1] in our model. There are also hydro pumped-storage generators in the model which are added to the test system by replacing the hydro generation units in region 2, with 6 pumped-storage units, each having 50MW capacity [132]. The network topology of the test system is illustrated in Figure 5.4.

The network and generators' data, as well as the hourly demand for one year, are provided by Washington University in [188]. However, in this study, the simulation is performed on the summer peak week of the year. The Washington University's data source also provides 2 scenarios for wind production: 1) Favorable, and 2) Unfavorable. The aggregated wind production within each the three regions (R1, R2, and R3), during the simulation week, is shown by Figure 5.5.

The minimum requirement of FCR and FRR reserves in each region, under the network-constrained crisis management approach, are presented in Table 5.1. It is assumed that the FCR reserve is shared among the countries belonging to a synchronous area, based on their total generation during a year. This assumption is according to the current regulations for sharing of reserves in the continental European synchronous area. The regions under study (R1-R3) are supposed to be members of a more geographically dispersed synchronous area. However, FRR reserve is supposed to be provided regionally and its minimum requirement is defined by the size of the largest generation unit for upward reserve and the largest load for downward reserve, in each region.

Table 5.1: Minimum reserve requirement in each region

Region	FCR[MW]	Upward FRR[MW]	Downward FRR[MW]
R1	80	400	300
R2	70	400	300
R3	50	400	300

The share of different load categories, i.e. interruptible load, non-interruptible load, and protected loads, in the total electricity demand in each region is shown by Figure 5.6. Note that these values correspond to the average share of each load

[1]The following generation units are removed from the IEEE RTS-96 system modified by Washington University: i5, i7, i22, i23, i30, i31, i37, i39, i54, i55, i65, i67, i86, and i87

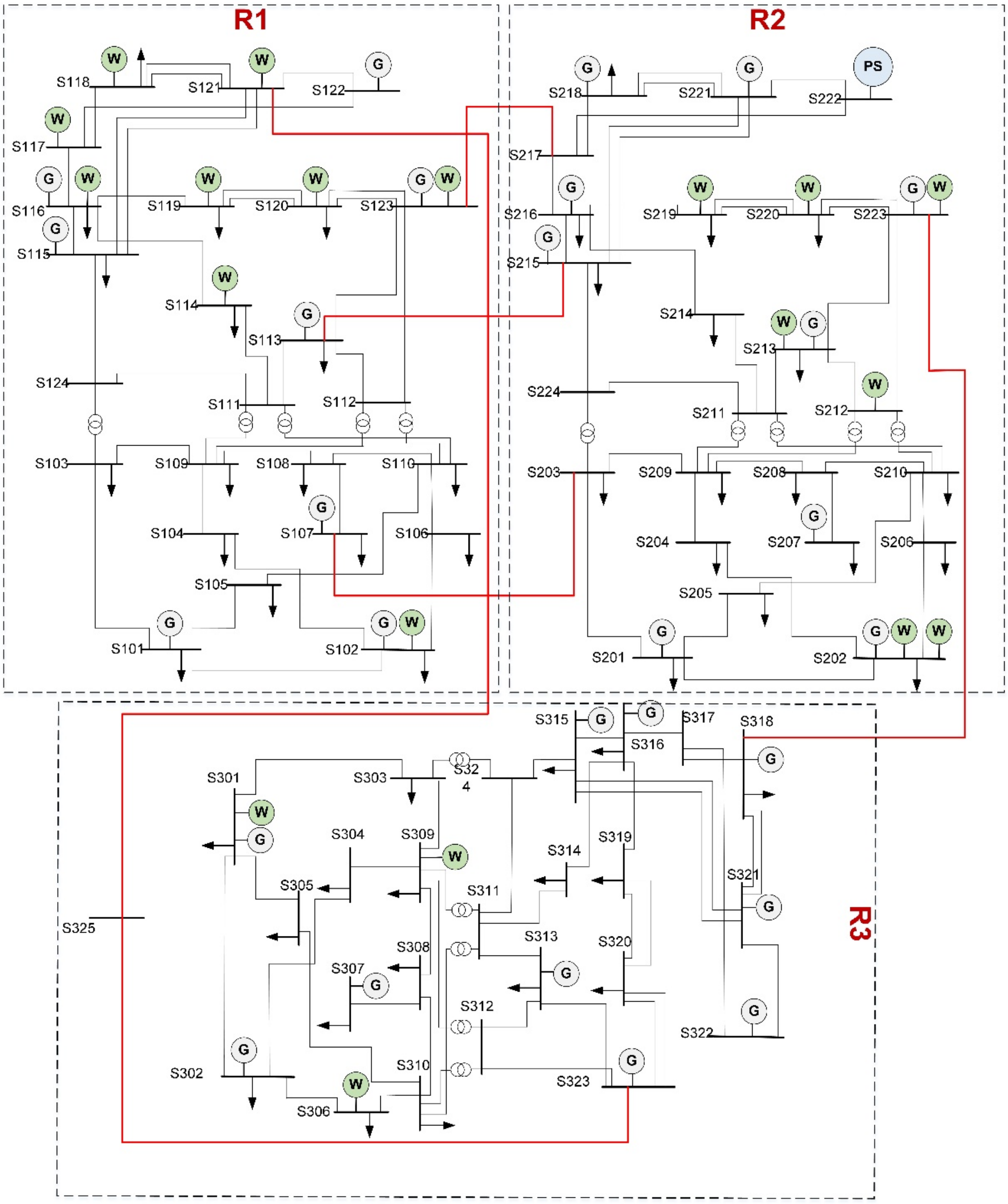

Figure 5.4: Network topology of modified IEEE RTS 96 test system

category on all the network nodes within a region, while the share of load categories on each individual node is set randomly.

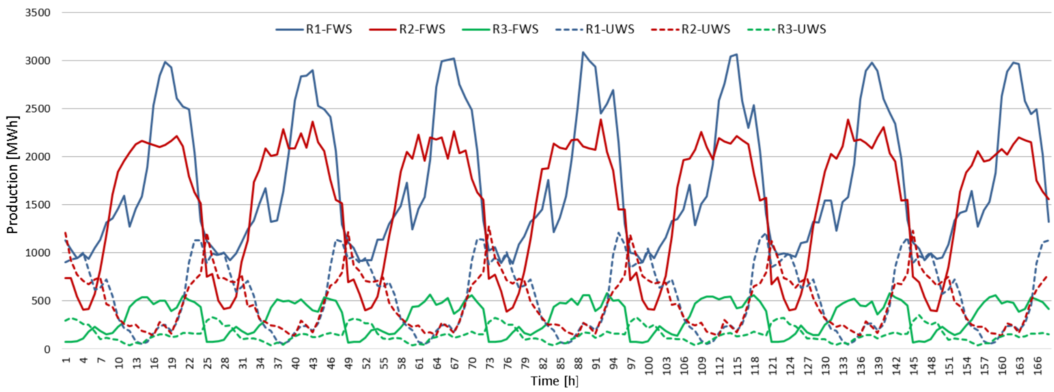

Figure 5.5: Hourly wind production in each region under Favorable Wind Scenario (FVS) and Unfavorable Wind Scenario (UWS)

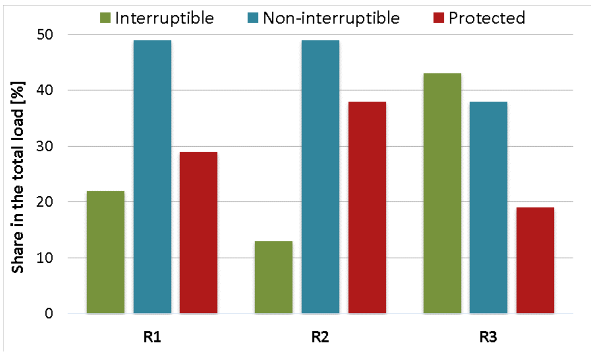

Figure 5.6: Share of different load categories in the total electricity demand within each region

5.4.2 Crisis model

Crisis in this study is considered as an extreme weather condition led to dry season in one region. However, the proposed model is generalized to be applied on any other type of system threats, by small modifications. It is assumed that water shortage caused by dry season disrupts the cooling system of thermal generators in the affected region. Furthermore, the limited water in the water reservoirs reduces the production of hydro generators. Consequently, the dispatchable capacity of conventional generators, including hydro and thermal units, reduces. As these units are supposed to be the main providers of FCR and aFRR reserves in the system, the extreme weather condition may turn into a crisis for the system in some time intervals with higher demand and lower wind production. The limited flexibility of generators and their other technical limits, e.g. minimum up/down time and ramp rate limits, as well as network constraints, are among the other reasons that intensify the impact of abnormal situation on the system's operation.

The impact of dry season on total dispatchable capacity of conventional generators within the affected region is shown in Figure 5.7. It is assumed that the dispatchable capacity of generators gradually reduces during the simulation week, to 20% reduction at the end of the week. Dry season is also expected to increase the electricity demand, during day time intervals. This increase is caused by using more cooling system by the end users. In this study it is assumed that the electricity consumption during day time hours, i.e. 8 A.M. to 10 P.M., in the region affected by dry season, increases gradually up to 10% at the end of the simulation week. Figure 5.8 shows the impact of the dry season on the load profile within the affected region. Note that as the three regions are identical in terms of installed generation capacity of conventional generators and also the electricity demand, the impact of crisis on their generation and load is also the same for all regions.

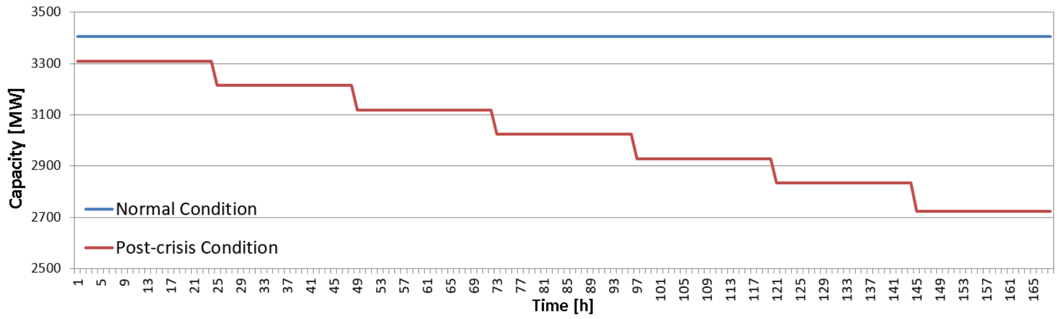

Figure 5.7: Impact of crisis on the dispatchable generation capacity within the affected region

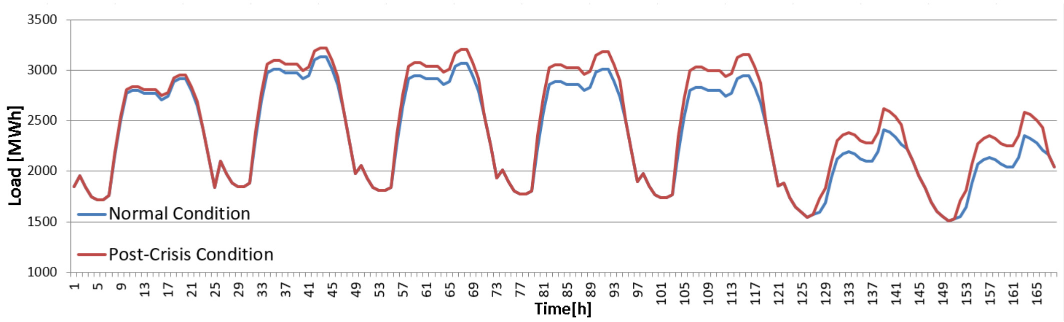

Figure 5.8: Impact of crisis on the hourly load profile within the affected region

5.4.3 Simulation scenarios

In order to shed more light on the impact of multi-area assisted rotational load shedding to manage crisis, in this study it is assumed that abnormal situation affects only one region and the other regions will/won't support the affected region.

Two general scenarios are considered for the affected region: crisis in Region1 or crisis in Region3. Crisis in Region2 is not modelled as the situation is very close to the case of crisis in Region1, both in terms of generation adequacy and interconnections' capacity. However, Region1 and Region3 in these regards, such that Region3 has very low wind generation capacity and limited interconnection to the other regions. Another division on the scenarios is in terms of the level of multi-regional assistance. The other regions may support the affected region with their excess generation capacities and also by curtailing their interruptible loads. In the worst case, they can fully stop assisting the affected region through limiting their export capacity to that region. All these possible scenarios are modelled with favourable and unfavourable wind scenarios which totally results in 30 scenarios as shown in Figure 5.9.

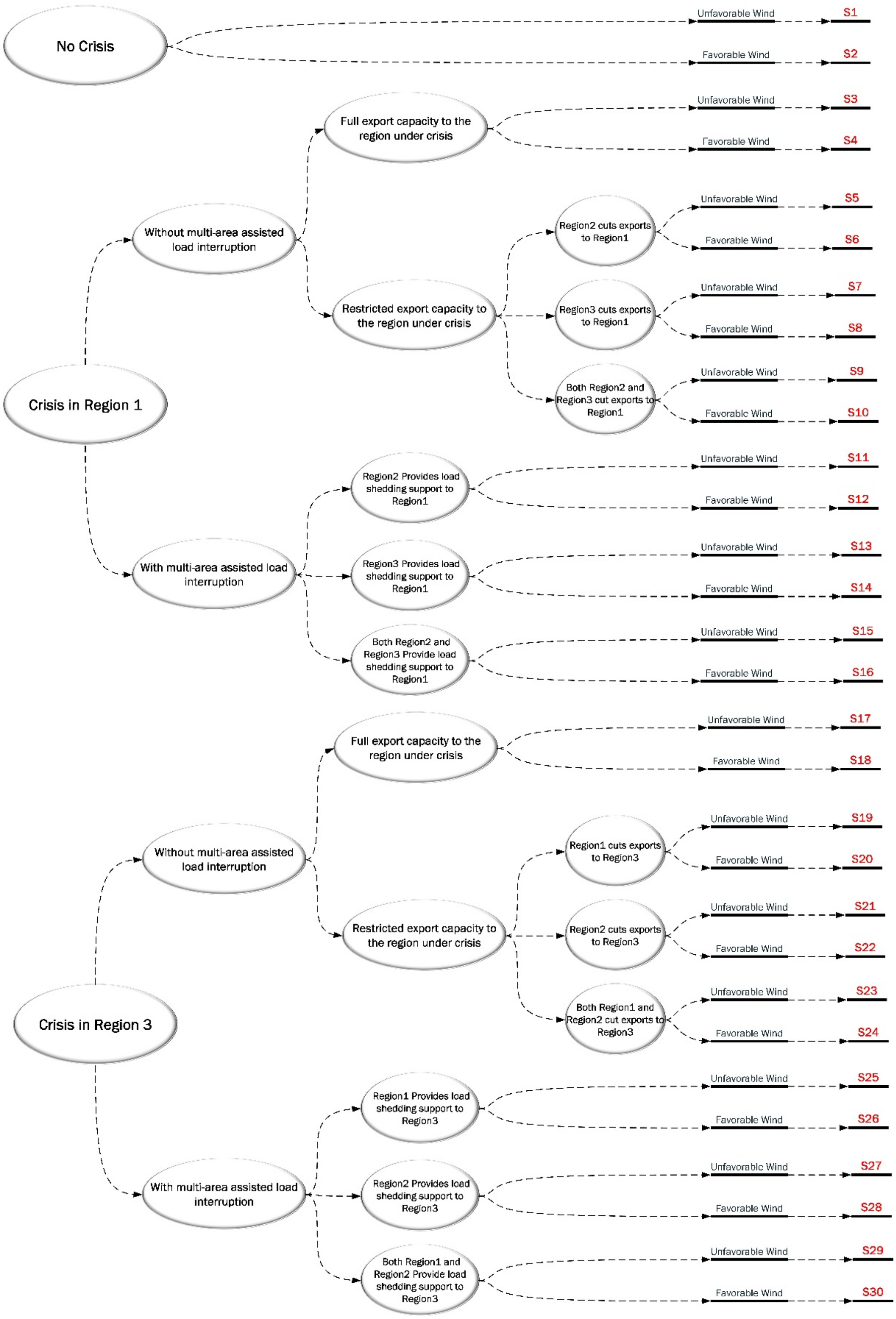

Figure 5.9: Scenario tree

5.5 Simulation results

This section presents the simulation results of the proposed multi-regional coordinated risk-preparedness plan, on the modified IEEE-RTS96 test case (Figure 5.4), and under different scenarios corresponding to the different levels of coordination among regions (as indicated in Figure 5.9). The proposed scenarios (S1-S30) are modelled through the network-constrained crisis management algorithm, which better represents the current European approach; while the application of the security-constrained crisis management algorithm is also verified on some scenarios. The input parameters corresponding to the penalty factors for load shedding and reserve shortage within the region which is affected by the abnormal situation, as well as the supporting neighbouring regions, are presented in Table 5.2. Please note that these values do not have an actual economic implication, but are use as weighting factors for different terms of the objective function (5.1) to prioritize the actions and are calculated through the try and error approach. The proposed optimization problem which has been formulated as Mixed Integer Linear Programming (MILP) problem in Section 5.3, is solved using CPLEX solver in GAMS.

Table 5.2: Input parameters of penalties for load curtailment and reserve shortage

Parameter	Value[€/MWh]	
	Affected Region	Supporting Region
Ψ	100,000	
$\mu_{k1,z}$	0.1	0.1
$\mu_{k2,z}$	0.2	0.3
$\mu_{k3,z}$	0.9	1
φ_z^{Res}	40,000	50,000

5.5.1 Base-case: Normal operation state

The net electricity production and consumption within each region, under normal operation state, i.e. without the occurrence of any abnormal situation, are shown in Figure 5.10 and Figure 5.11. The regional net production values in Figure 5.10 and Figure 5.11 correspond to the total electricity produced by conventional and wind generators (taking into account the wind curtailment) in the region, plus the output power of the hydro pumped storage unit under generating mode. Similarly, the net consumption values in each region correspond to the hourly base load minus interrupted load (if any), plus the energy consumed by hydro pumped storage units in their pumping mode.

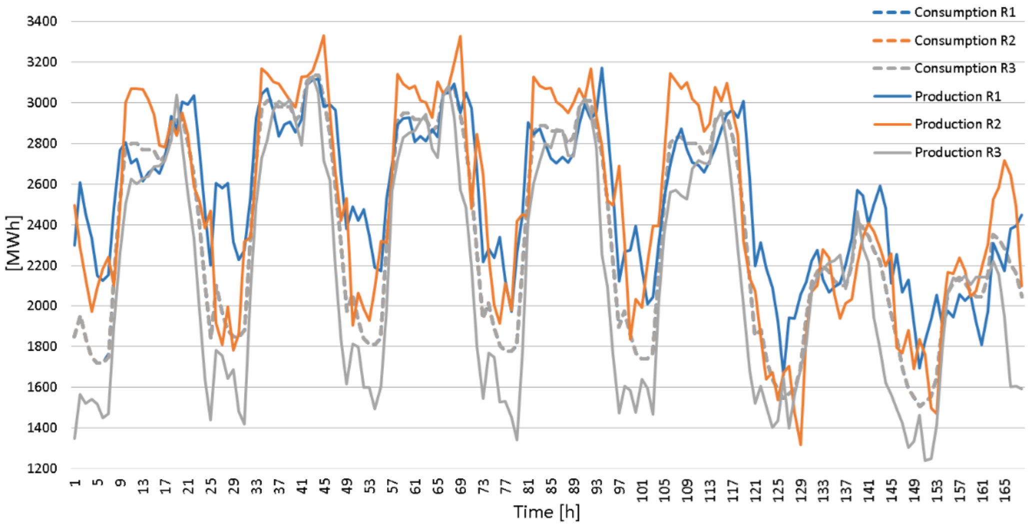

Figure 5.10: Net electricity production/consumption within each region under normal operation and unfavorable wind production (S1)

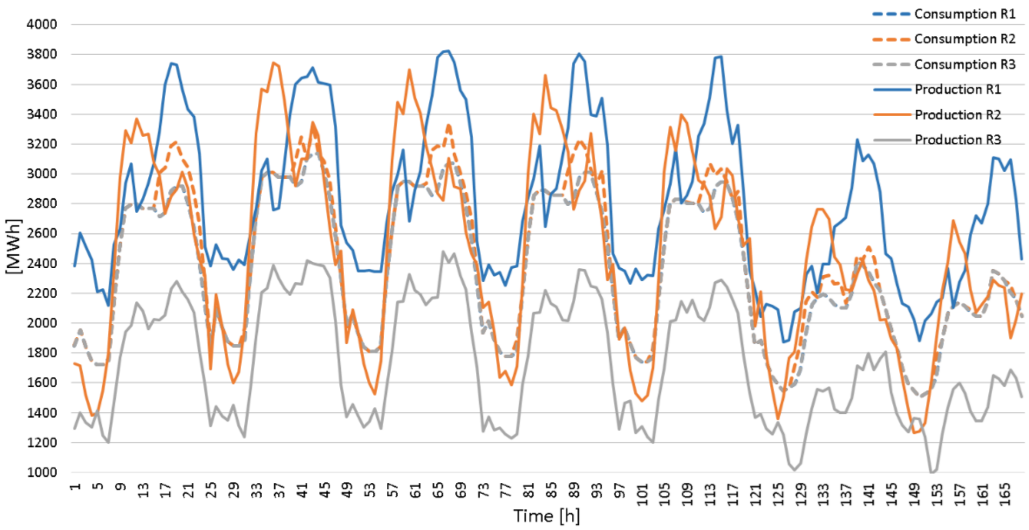

Figure 5.11: Net electricity production/consumption within each region under normal operation and favorable wind production (S2)

Comparing the regional net production and consumption values in Figure 5.10 indicates that under the unfavourable wind production scenario (S1), Region 3 is a net electricity importer, while Region 2 is the main exporters during peak hours and Region 1 in the main exporter during off-peak hours. Taking into account that under the unfavourable wind scenario, wind production in Region 1 and Region 2 are pretty close (as shown in Figure 5.5), the relatively high difference of peak and off-peak production in Region 2 is likely to be resulted by the role of the hydro pumped storage generators in this region.

Contrarily to the unfavourable wind scenario, Figure 5.11 shown that under the favourable wind scenario (S2), Region 1 becomes the man electricity exporter during the peak and off-peak hours, as it has the highest installed capacity of wind generators. Region 3 relies on the exports form Region 1 and also Region 2 (in the peak morning hours).

5.5.2 Abnormal situation in Region 1

The simulation results indicate that the assumed extreme weather condition in Region 1 can be managed without interrupting the supply of protected loads, in all scenarios. However, the provision of operating reserves in the affected region (R1), under unfavourable wind production, is highly dependent on the support from the neighbouring regions, especially Region 2. Accordingly, under the unfavourable wind production, if Region 2 cuts its export capacity to Region 1, as modelled in scenario S5, there would be 26 hours of reserve shortage in Region 1 with the maximum shortage capacity of 220 MW. In the worst case, if both Region 2 and Region 3 stop providing support to Region 1 by cutting their export capacity to this region, as represented by scenario S9, the affected region (R1) would face 39 hours of operating reserves' shortage with maximum shortage capacity of 364 MW.

Due to the large installed capacity of wind power plants in Region 1, totally 3900 MW, the abnormal situation under all scenarios with favourable wind production (S4, S6, S8, S10, S12, S14, and S16) can be managed solely by supply-side resources and without curtailing any type of loads. However, under unfavourable wind production scenarios (S3, S5, S7, S9, S11, S13, and S15), the crisis in Region 1 cannot be managed without the active/passive participation of demand-side resources through load interruption. The total energy curtailment from interruptible and non-interruptible loads in each region are shown in Figure 5.12 and Figure 5.13, respectively. As indicated by Figure 5.13, non-interruptible load curtailment only occurs within the affected region (R1) and under the two most severe scenarios, i.e. with no support (S9) or very limited support (S5) from the neighbouring regions. Figure 5.12 also approves that these two scenarios lead to the maximum unsupplied energy from interruptible loads. Comparing the simulation results of S3 and S9 leads to the conclusion that the support provided by the neighbouring countries, only through their excess generation capacity and without interrupting their internal services, can help the affected region to avoid loss of its non-interruptible loads and also reduces the total unsupplied interruptible loads by 52%. Another notable conclusion from the results presented in Figure 5.12 is that cutting the export capacity from the neighbouring regions to the affected region during the crisis period, with the aim of not getting affected by the crisis, may lead to adverse results within the neighbouring regions, such that they might experience load interruption during some hours. This effect can be seen in scenario S9, with load interruption in both

Region 2 and Region 3 (Figure 5.12), which is resulted by the complexity of the network and the generators' technical limits across the interconnected regions.

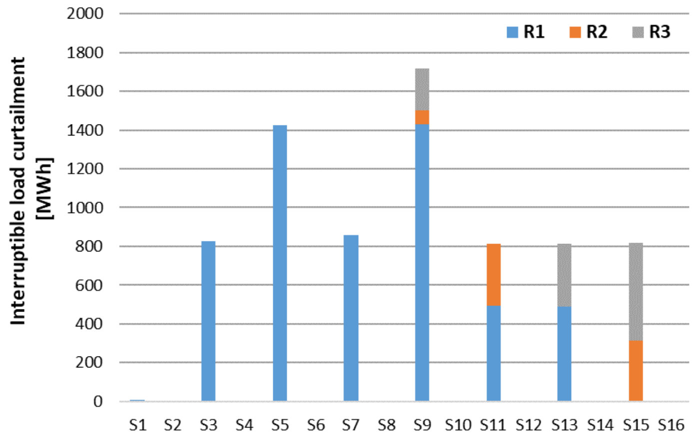

Figure 5.12: Regional energy curtailment from interruptible loads under abnormal situation in Region 1

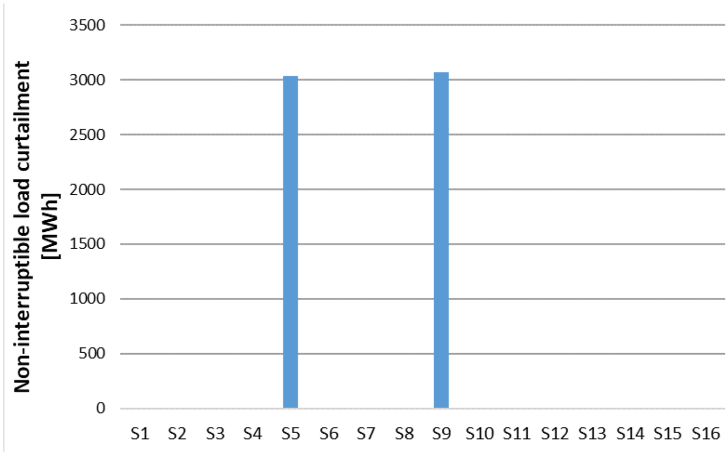

Figure 5.13: Energy curtailment from non-interruptible loads in Region 1, under abnormal situation in this region

To shed more light on the impacts of crisis under different scenarios, in terms of the customers' supply interruption, the maximum curtailed power in each region and maximum duration of load interruption during the 1-week simulation period, are shown in Figure 5.14 and Figure 5.15, respectively. As expected, no regional support in scenario S9, leads to the most intensive impact on the consumers within the affected region, resulting in maximum 350 MW concurrent load interruption and totally 20 hours of supply interruption in the week.

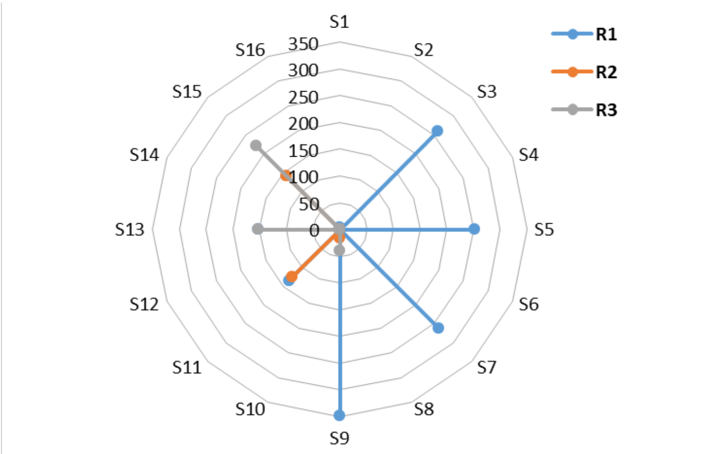

Figure 5.14: Maximum curtailed power in MW from interruptible loads in each region under abnormal situation in Region 1

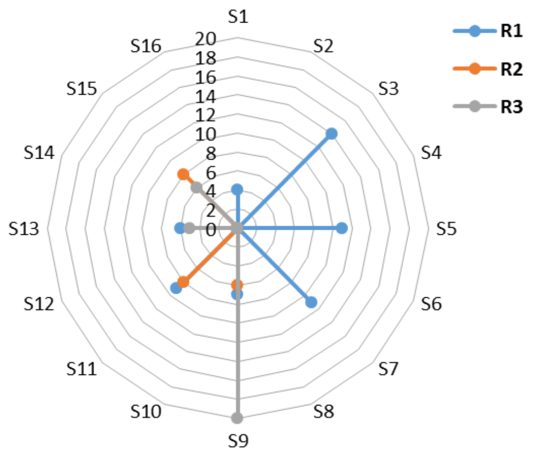

Figure 5.15: Total duration [h] of supply interruption within each region under abnormal situation in Region 1

Finally, the total operation cost of the system under different scenarios, including the generation costs and penalties for the interruption of loads, wind curtailment, and reserve shortage, is shown in Figure 5.16. It should be noted that the cost values represented in Figure 5.16 do not have a pure economic implication, but are more used as an indicator for comparing the scenarios in terms of socio-economic impacts of the crisis, and depend strongly on the assumptions made on the penalty factors. In other words, these costs are equal to the value of the objective function in (5.1). The remarkable spike of the cost values in scenarios S5 and S9 is due to the occurrence of both non-interruptible load curtailment and reserve shortage, with relatively high penalty factors, in these scenarios. Blocking all the potential supports form the neighboring regions, especially Region 2, through cutting the export capacity, results in the increase of total costs up to 4.5 times more in S5 and 12.9 times more in S9, compared to the scenario S3. Furthermore, the simulation results imply on a slight reduction of the total operation costs due to the application of regional load shedding (less than 0.5% cost reduction in S15/S16 compared to S4/S5), while it mostly impacts the duration and maximum size of the interruption in each region, as shown in Figure 5.14 and Figure 5.15.

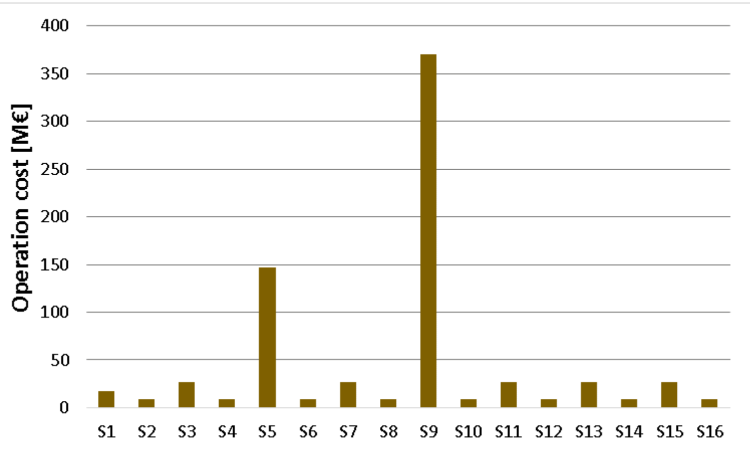

Figure 5.16: Total operation cost of the system under abnormal situation in Region 1

5.5.2.1 Security-constrained crisis management algorithm

In order to examine the performance of the proposed security-constrained crisis management approach, this section provides a comparison of this approach with the results of the network-constrained approach, on some scenarios. To this aim, three more representative scenarios are selected: base case with no crisis (S1), no cross-regional support to the region under crisis (S9), and the highest level of cooperation among the regions to manage the crisis, through sharing of supply and demand side resources (S15). The simulation results, in terms of the regional unsupplied energy from interruptible/ non-interruptible load and the total operation cost of the system, are provided in Figure 5.17 - Figure 5.19.

On the contrary to the network-constrained model, the security-constrained crisis management approach does not result in the shortage of operating reserve capacity in scenario S9, where the interconnected neighbouring regions stop providing any support to the affected region (R1) by cutting their export capacity to this region. This is mainly because the security-constrained model applies the free sharing of reserves across the borders, while in the network-constrained model,

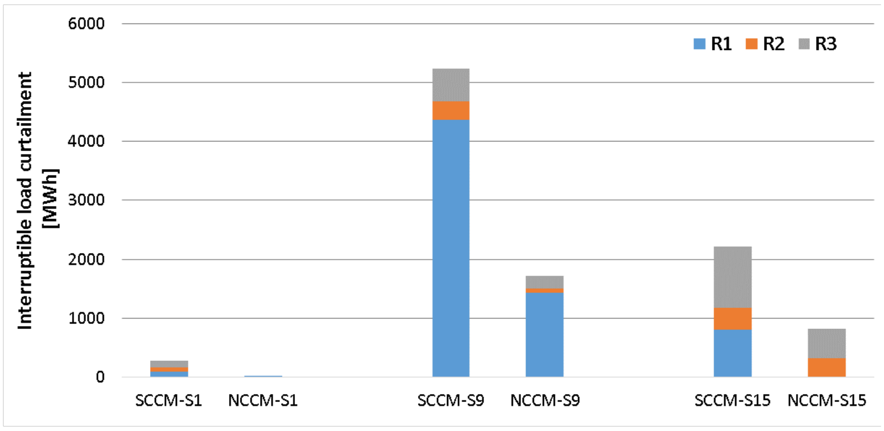

Figure 5.17: Regional energy curtailment from interruptible loads under Security-Constrained Crisis Management (SCCM) and Network-Constrained Crisis Management (NCCM) models

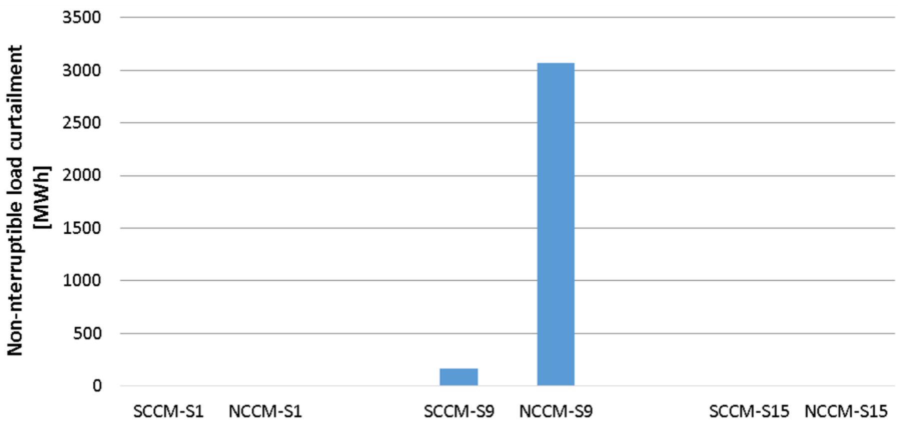

Figure 5.18: Energy curtailment from non-interruptible loads in Region 1, under Security-Constrained Crisis Management (SCCM) and Network-Constrained Crisis Management (NCCM) models

the minimum requirement of operating reserves in each region is set as a hard constraint.

As shown in Figure 5.17, under the normal operating condition, i.e. without occurrence of the abnormal situation, and unfavourable wind production scenario (S1), the security-constrained model results in curtailment of interruptible loads in all regions (totally 271 MW). The main reason for having load interruption under normal conditions is that although there are enough installed generation capacity to supply all the loads and reserves, the network constraints limits the dispatch of generators for providing reserves in post-contingency states. It should be noted that in

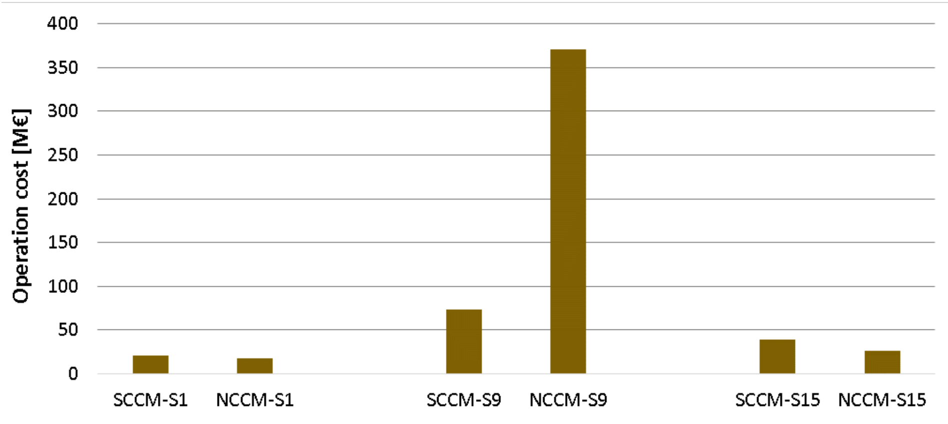

Figure 5.19: Total operation cost of the system under Security-Constrained Crisis Management (SCCM) and Network-Constrained Crisis Management (NCCM) models

this analysis the contingency list includes the set of all transmission lines and generation units. Altogether, Figure 5.17 indicates that the security-constrained crisis management approach (SCCM) increases the curtailment of interruptible loads in all the scenarios. However, in contrary to the scenarios S1 and S15, the SCCM improves the operation of the system in scenario S9, which is the most extreme scenario in terms of the level of cooperation among the regions. This conclusion is based on the comparison of results on the total energy unsupplied from non-interruptible loads in Figure 5.18 and the total operation cost of the system in Figure 5.19. As shown in Figure 5.18, the security-constrained approach reduces the total energy curtailment form non-interruptible loads in Region 1, by 94.5% compared to the network-constrained approach, in scenario S9. The main advantage of this approach is the unbound provision of reserve capacities across the region in the optimization algorithm, while there is no minimum requirement in the regions. This feature allows the model to allocate the reserve capacities to the regions with excess supply resources and use all of the available generation capacity within the region under crisis, to supply its loads. Consequently, the country under crisis experiences the minimum curtailment on its non-interruptible loads in pre-contingency state and relies on the cross-border reserve capacities in the post-contingency state.

Total operation cost of the system under the security-constrained and the network-constrained approaches, is represented in Figure 5.20. The results indicate that the security-constrained approach leads to 80% reduction of the total costs compared to the network-constrained approach, in scenario S9, which is due to the avoided reserve shortage and non-interruptible load curtailment in this scenario.

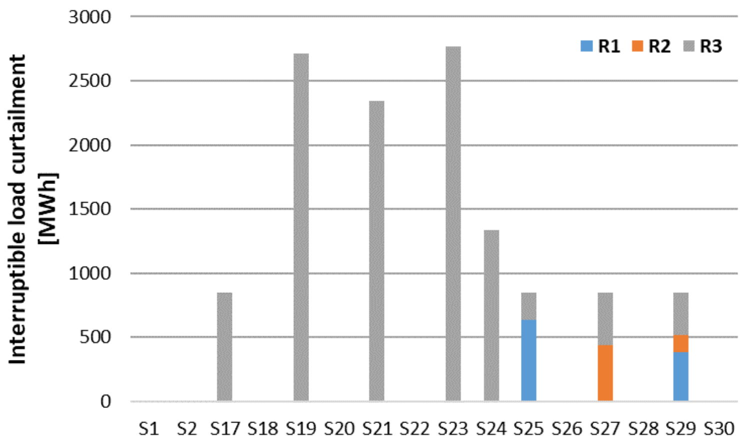

Figure 5.20: Regional energy curtailment from interruptible loads under abnormal situation in Region

5.5.3 Abnormal situation in Region 3

In this section, a similar analysis is performed on the test case with the crisis in Region 3, as Region 3 has different characteristics compared to Region 1 and Region 2 in terms of the total interconnection capacity and the installed wind generation capacity. The simulation results on the different scenarios, corresponding to different levels of regional coordination under favourable and unfavourable wind production (S17 – S30), are presented by Figure 5.20 - 5.24. Please note that the scenarios S1 and S2 which represent the case with no crisis in any region, are also provided in the results as the base case for benchmarking. According to the simulation results, the extreme weather condition in Region 3 can also be managed without loss of protected loads during the simulation period (168 hours) in all scenarios (S17-S30). However, under the unfavourable wind production in all regions and without any support from the neighbouring regions (R1 and R3), the abnormal situation leads to 42 hours of operating reserves' shortage with maximum shortage capacity of 393 MW.

Total energy curtailment from interruptible and non-interruptible loads under scenarios S17 - S30 are shown in Figure 5.20 and Figure 5.21, respectively. As shown in Figure 5.20, crisis in Region 3 leads to the maximum energy curtailment of interruptible loads in this region under scenarios S19 and S23, indicating that under crisis conditions, Region 3 is mostly dependent on the energy exports from its interconnections to Region 1. On the contrary to the case of crisis in Region 1in scenario S9, if crisis occurs in Region 3 and all the neighbouring regions cut their export capacity to this region, they will won be affected; while Region 3 will experience around 2330 MWh curtailment of its non-interruptible loads and 42 hours of reserve shortage (S23). Furthermore, as the total installed capacity

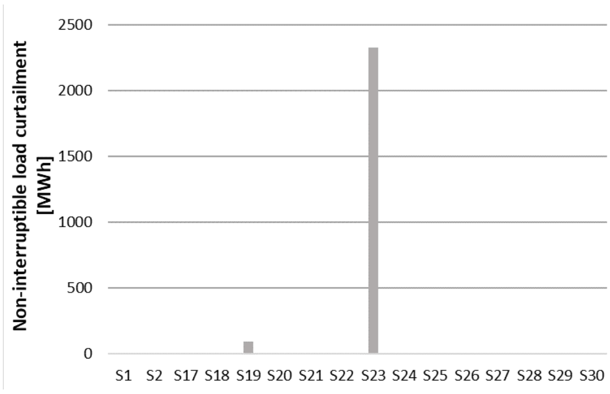

Figure 5.21: Energy curtailment from non-interruptible loads in Region 3, under abnormal situation in this region

of wind power plants in Region 3 is limited to 600 MW, even under favourable wind production scenario represented by S24, Region 3 would be dependent on the energy exports from the neighbouring regions to manage crisis without curtailing loads.

The maximum curtailed power in each region and maximum duration of load interruption during the simulation period (168 hours), are shown in Figure 5.22 and Figure 5.23, respectively. As shown in Figure 5.22, the maximum power interruption in Region 3 occurs under scenario S23, where wind production in unfavorable and both Region 1 and Region 2 stop providing support to the affected region (R3). However, the maximum duration of supply interruption occurs in scenarios S19 and S21, where one of the neighboring regions stops exporting power through its interconnections to the region affected by the crisis.

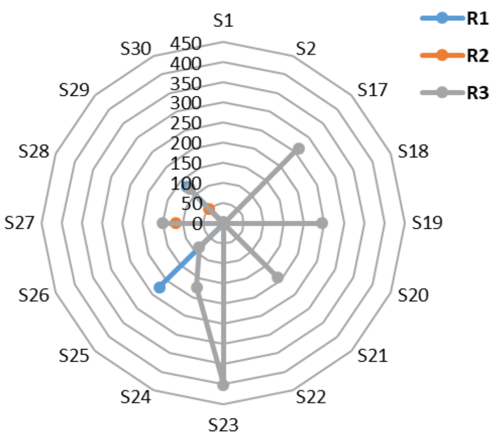

Figure 5.22: Maximum curtailed power in MW from interruptible loads in each region under abnormal situation in Region 3

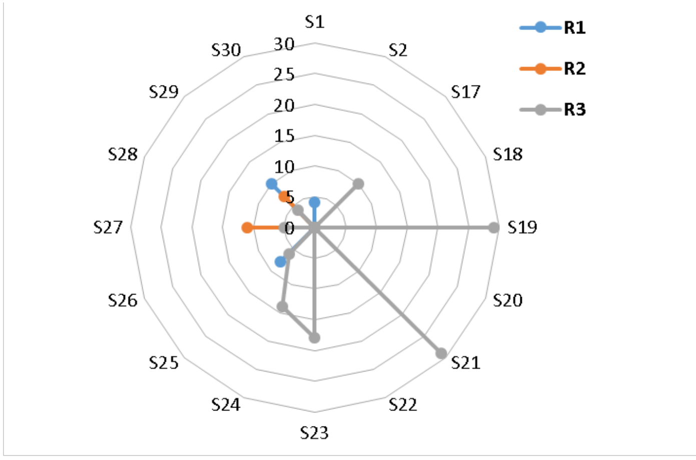

Figure 5.23: Total duration [h] of supply interruption within each region under abnormal situation in Region 3

Finally, the total operation cost of the system under scenarios S17 – S30 is presented in Figure 5.24. Comparing the total cost of operating system under crisis in Region 1 in Figure 5.16, and the one with crisis in Region 3 in Figure 5.24 indicates that an identical crisis leads to 9.2% higher operating costs when in happens in Region 3 with no inter-regional support. This is in contrast to the assumption that the flexibility of customers in Region 3, in terms of the share of interruptible loads (shown in Figure 5.6), are significantly higher than the one in Region 1. The reason for this high operating cost is probably the strong dependence of Region 3 on the energy exports form the interconnected neighbouring regions.

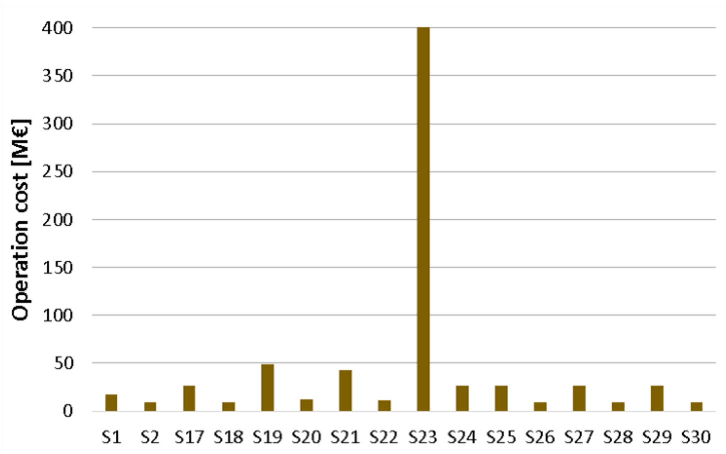

Figure 5.24: Total operation cost of the system under abnormal situation in Region 3

5.6 Conclusions and discussion

In this chapter of the thesis, the impact of strengthening cooperation among the interconnected regions for managing abnormal situation more efficiently have been assessed. The decision making problem for multi-area assisted crisis management have been proposed and formulated as an optimization problem with Mixed Integer Linear Programing approach. The proposed model performs multi-regional assisted load shedding in a rotational manner with the aim of minimizing the socio-economic impact of the crisis on the continuity of essential services in the affected region.

Two approaches are presented for considering the security of supply in the decision making algorithm: 1) a network-constrained crisis management approach, and 2) a security-constrained crisis management approach. The objective function in both approaches is to minimize the total operation cost of the system, taking into account the weighted penalty factors for reserve shortage, renewable curtailment, and load interruption. The model has been examined on a conceptual test case with three interconnected regions, i.e. the modified IEEE RTS-96 network. Totally 30 scenarios have been defined, implying on different levels of cooperation among regions to manage crisis, under favorable and unfavorable wind production schemes.

The simulation results on the test case imply on the important role of cross-regional coordination under crisis situation for preventing interruption of essential services within the affected region. However, the level of dependence of the affected region to the support provided by each of its neighboring interconnected regions depends on the available interconnected capacities to the affected region and the un-dispatched generation capacity within each region. If a crisis happens within a region which have been energy exporter under normal conditions, cutting the export capacity form the interconnected regions to the affected region may lead to adverse results in terms of load interruption, within the interconnected regions. In any case, suspending any mutual support to the affected region is likely to increases the total operating costs of the system and also lead to reserve shortage within the affected region which in turn can be considered as a threat to the security of the whole interconnected region. Finally, comparing the simulation results of the security-constrained and the network-constrained models indicates that the unconstrained procurement of reserves across the borders can significantly improve the operation of the system, especially under crisis situation. The main advantage of this approach is that the affected region can utilize all of its available supply side resources to serve the loads and rely on the support of neighboring regions in case of the contingencies which are less likely to occur.

Nomenclature

Sets and Indices

$\mathcal{T}$	Set of simulation time intervals, indexed by t and t';
$\mathcal{Z}$	Set of system zones, indexed by z;
$\mathcal{N}$	Set of network nodes, indexed by n;
$\mathcal{L}$	Set of transmission lines, indexed by l;
$\mathcal{D}$	Set of customers, indexed by d;
$\mathcal{I}$	Set of conventional generators, indexed by i;
$\mathcal{S}$	Set of hydro pumped storage generators, indexed by s;
$\mathcal{W}$	Set of wind generators, indexed by w;
$\mathcal{I}_n \subset \mathcal{I}$	Set of conventional generators connected to node n, indexed by i;
$\mathcal{S}_n \subset \mathcal{S}$	Set of hydro pumped storage generators connected to node n, indexed by s;
$\mathcal{W}_n \subset \mathcal{W}$	Set of wind generators connected to node n, indexed by w;
$\mathcal{N}_z \subset \mathcal{N}$	Set of network nodes located at zone z, indexed by n;
$\mathcal{D}_n \subset \mathcal{D}$	Set of customers connected to node n, indexed by d;
$\mathcal{L}_z \subset \mathcal{L}$	Set of cross-zonal interconnections connected to zone z, indexed by l;
$\mathcal{K}$	Set of load categories, indexed by k;
$\mathcal{E}$	Set of generator/line contingencies, indexed by e;
$\mathcal{B}$	Set of conventional generators' offer blocks, indexed by b;
$\mathcal{X}$	Set of conventional generators' start-up time blocks, indexed by x;

Parameters

M	A relatively large number;
Ψ	Weighing factor of load shedding penalty in the objective function;
$\mu_{k,z}$	Penalty factor of interruption on load category k, located in zone z, used for prioritizing interruption on different load types in affected and supporting zones;
C^{Res}	Incentive to reserve providers for capacity reservation;
$T_k^{max,int}$	Maximum permitted duration of interruption on load category k per day;
φ_z^{Res}	Penalty of reserve shortage at zone z;
φ^{spill}	Penalty of wind spillage;
$\eta_{d,k}$	Share of the load category k in the electricity demand of customer d;
$P_{b,i,t}^{max}$	Maximum power quantity offered by conventional generator i under generation block b;
g_i^{max}	Dispatchable capacity of conventional generator i under normal operation;
g_i^{min}	Minimum production limit of conventional generator i under normal operation;
$r_i^{Up,max}$	Maximum upward reserve capacity which can be provided by generator i;
$r_i^{Dn,max}$	Maximum downward reserve capacity which can be provided by generator i;
f_l^{max+}	Available transfer capacity of transmission line l under normal operation of the system, in the pre-defined direction;
f_l^{max-}	Available transfer capacity of transmission line l under normal operation of the system, in the opposite direction;
X_l	Admittance of transmission line l;
$d_{n,l}$	Elements of the network incident matrix, $d_{n,l} = 1$ if line l is oriented away from node n, $d_{n,l} = -1$ if line l is oriented towards node n, and $d_{n,l} = 0$ if line l is not incident to node n;

$\rho_{b,i}^{var}$ Variable cost of energy production by conventional generator i under generation block b;

ρ_i^{fix} Fixed operation cost of conventional generator i;

$H_{i,t}^{Gen}$ Impact factor of crisis on the dispatchable capacity of conventional generator i at time t; $(0 \leq H_{i,t}^{Gen} \leq 1)$

$H_{d,t}^{Dem}$ Impact factor of crisis on the energy demand of customer d at time t; $(H_{d,t}^{Dem} \geq 1)$

$I_{e,i}^{Gen}$ Binary value correlating contingency e with the failure of generator i; ($I_{e,i}^{Gen} = 0$ if generator i is failed under contingency e, else $I_{e,i}^{Gen} = 1$)

$I_{e,l}^{Lin}$ Binary value correlating contingency e with the failure of transmission line l; ($I_{e,l}^{Lin} = 0$ if line l is failed under contingency e, else $I_{e,l}^{Lin} = 1$)

$C_{x,i}^{SU}$ Step-wise start-up cost of generator i at step x;

$\overline{X}_i$ Maximum number of start-up time blocks of conventional generator i;

$T_{i,o}^{off}$ Initial number of time periods (hours) generator i has been OFF;

$T_{i,o}^{on}$ Initial number of time periods (hours) generator i has been ON;

$g_{i,o}$ Initial production of generator i at time $t = 0$;

$u_{i,o}$ Initial ON/OFF status of generator at time $t = 0$;

$r_z^{FRR,Up}$ Upward FRR reserve capacity requirement of region/zone z;

$r_z^{FRR,Dn}$ Downward FRR reserve capacity requirement of region/zone z;

r_z^{FCR} FCR reserve capacity requirement of region/zone z;

R_i^{Up} Ramp up limit of conventional generator i;

R_i^{Dn} Ramp down limit of conventional generator i;

$T_i^{min,Up}$ Minimum up time of generator i;

$T_i^{min,Dn}$ Minimum down time of generator i;

q_s^{max} Maximum power production/consumption limit of hydro pumped storage generator s in generating/pumping mode;

$E_s^{max,H}$	Capacity of the head storage of hydro pumped storage generator s;
$E_s^{max,T}$	Capacity of the tail storage of hydro pumped storage generator s;
$E_{s,0}^{H}$	Initial level of energy stored in the head storage of hydro pumped storage generator s;
$E_{s,0}^{T}$	Initial level of energy stored in the tail storage of hydro pumped storage generator s;
η_s	Cycle efficiency of hydro pumped storage generator s;
μ^{spill}	Maximum permitted wind curtailment of wind generator w as a percentage of available power production;
μ^{ovl}	Maximum permitted overload on transmission network lines in post-contingency operation, as a percentage of line thermal limit;
$l_{d,t}$	Hourly demand of customer d at time t;
$g_{w,t}^{max}$	Available power production of wind generator w at time t;

Variables

$C_{i,t}^{opr}$	Operation cost of generator i at time t;
$g_{i,t}$	Dispatched power of generator i at time t;
$E_{w,t}^{spill}$	Curtailed energy of wind generator w at time t under normal operation;
$E_{k,d,t}^{int}$	Interrupted energy on load category k of customer d at time t;
$r_{z,t}^{FCR,sh}$	FCR reserve shortage in zone z at time t;
$r_{z,t}^{FRR,sh}$	FRR reserve shortage in zone z at time t;
$r_{i,t}^{FCR}$	Upward and downward FCR reserve capacity provided by generator i at time t;
$r_{i,t}^{FRR,Up}$	Upward FRR reserve capacity provided by generator i at time t;
$r_{i,t}^{FRR,Dn}$	Downward FRR reserve capacity provided by generator i at time t;
$r_{s,t}^{FCR}$	Upward and downward FCR reserve capacity provided by hydro pumped storage generator s at time t;

$r_{s,t}^{FRR,Up}$	Upward FRR reserve capacity provided by hydro pumped storage generator s at time t;
$r_{s,t}^{FRR,Dn}$	Downward FRR reserve capacity provided by hydro pumped storage generator s at time t;
$r_{i,t}^{Up,Res}$	Upward reserve capacity provided by generator i at time t to manage emergency situation;
$r_{i,t}^{Dn,Res}$	Downward reserve capacity provided by generator i at time t to manage emergency situation;
$r_{s,t}^{Up,Res}$	Upward reserve capacity provided by hydro pumped storage generator s at time t to manage emergency situation;
$r_{s,t}^{Dn,Res}$	Downward reserve capacity provided by hydro pumped storage generator s at time t to manage emergency situation;
$r_{i,t,e}^{Up,Act}$	Upward reserve power activated by generator i at time t to manage emergency situation caused by contingency e;
$r_{i,t,e}^{Dn,Act}$	Downward reserve power activated by generator i at time t to manage emergency situation caused by contingency e;
$r_{s,t,e}^{Up,Act}$	Upward reserve power activated by hydro pumped storage generator s at time t to manage emergency situation caused by contingency e;
$r_{s,t,e}^{Dn,Act}$	Downward reserve power activated by hydro pumped storage generator s at time t to manage emergency situation caused by contingency e;
$r_{n,t,e}^{sh}$	Reserve shortage at node n under contingency e, at time t;
$E_{s,t}^{H}$	Energy stored in the head storage of hydro pumped storage generator s at time t;
$E_{s,t}^{T}$	Energy stored in the tail storage of hydro pumped storage generator s at time t;
$q_{s,t}$	Power production/consumption of hydro pumped storage generator s in generating/ pumping mode at time t;
$P_{b,i,t}$	Dispatched power of generation block b offered by conventional generator i at time t;
$C_{i,t}^{SU}$	Start-up cost of conventional generator i at time t;

$u_{i,t}$	Binary variable indicating the ON/OFF state of the conventional generator i at time t;
$y_{i,t}$	Binary variable indicating the start-up of the conventional generator i at time t;
$\mathcal{Y}_{i,x,t}$	Binary variable indicating the start-up time block of the conventional generator i at timet; $\mathcal{Y}_{i,xt} = 1$ if generator i starts up under its x^{th} block at time t and $\mathcal{Y}_{i,x,t} = 0$ else.
$z_{i,t}$	Binary variable indicating the shut-down of the conventional generator i at time t;
$x_{s,t}$	Binary variable indicating the pumping mode of the hydro pumped storage generator s at time t; $x_{s,t} = 1$ if storage is in consuming power for pumping up water and $x_{s,t} = 0$ if the storage is in generating mode.
$j_{z,t}$	Binary variable indicating the exporting mode of zone z at time t; $j_{z,t} = 1$ if electricity is exported from zone z to the neighboring zones and $j_{z,t} = 0$ if electricity is imported to zone z from the neighboring zones.
$f_{l,t}$	Power flow on transmission line l under normal operation of the system, in the pre-defined direction at time t;
$\theta_{n,t}$	Voltage angle of node n at time t for power flow computations under normal operation;
$f_{l,t,e}^{emg}$	Post-contingency power flow on transmission line l at time t under contingency e, in the pre-defined direction;
$\theta_{n,t,e}^{emg}$	Post-contingency voltage angle of node n at time t under contingency e;
$E_{w,t,e}^{spill}$	Post-contingency wind energy curtailment of wind generator w at time t under contingency e;

Chapter 6

Conclusions and Recommendations

6.1 Conclusions of this dissertation

The goal of the research in this PhD dissertation was to assess the impacts of increasing the integration of the EU electricity systems, form market and network operation perspectives, to prepare the European power system for coping with the emerging operational challenges. To this aim, this thesis has focused on three evolving scenarios in European electricity systems: eradicating the dependence of EU power systems on non-EU systems, accelerated growth of renewable energy sources in electricity systems, and the more efficient utilization of cross-border interconnection infrastructures in operating the European electricity system under normal and crisis situation. Increasing the integration among the EU electricity systems has been considered as a unique solution which can contribute in managing all these evolving scenarios. Accordingly, this thesis addressed three arising research questions regarding how to create a more integrated European electricity system.

As the first research question addressed in this thesis, the integration of Baltic States to the EU electricity system has been studied in Chapter 3. After joining to the European Union, Baltic States have been asked by the Union to get desynchronized from the non-European IPS/UPS system and to strengthen their interconnection with the European electricity system, with the aim of enhancing the energy security and independency in Europe. ENTSO-E had proposed three scenarios for Baltic-EU synchronization after desynchronizing from IPS/UPS system. In the study developed in Chapter 3 of this thesis, the three prospective scenarios have been compared from market performance and network congestion's perspective. The simulation results indicated that Baltic synchronization with Continental European Synchronous area through Lithuania-Poland interconnection leads to minimum operation and investment costs within the Baltic States.

The second research question addressed in this thesis was the impact of increasing the integration among the European electricity markets, under high penetration of renewable energy sources. Chapter 4 of this thesis provided a stochastic optimization problem for modelling a network-constrained Europe-wide day-ahead and intraday market, based on the predicted generation mix and interconnection capacities in Europe by 2030. The simulation results indicated that market integration reduces the total surplus of generator companies within the Europe while providing economic benefits for consumers. Market participation of hydro pumped storage generators play important role in terminating the renewable energy curtailment and increasing the hosting capacity of renewables in European electricity systems. Furthermore, the simulation results indicated that the flexibility provided by hydro pumped storage generators reduces the potential benefits of integrating intraday markets in Europe. In other words, the additional flexibility provided to the market through integrating intraday electricity markets for managing renewables' uncertainty and variability, can also be provided by the storage technologies or demand side flexibility.

While the focus of the studies performed in Chapter 3 and Chapter 4 were on the normal operating conditions of the system, Chapter 5 addresses the potential benefits of increasing cooperation and coordination among the integrated regions to manage abnormal situations. In this chapter, a decision making algorithm for multi-regional coordinated risk preparedness planning was developed which applied circular load shedding on less sensitive loads, as the last resort for operating the system under abnormal conditions and prevent interruption of essential reliability services in the affected region. Different scenarios corresponding to different levels of coordination among regions to manage crisis were modelled and analysed. The results on the test case confirmed the effectiveness of the proposed multi-regional coordinated risk preparedness plan on reducing the total operation cost of the system and preventing load interruption under crisis situation, whereas uncoordinated suspension of energy exports to the region under crisis may lead to adverse effects in the supporting region itself. Consequently, the analysis strongly suggests the continuity of market-based and coordinated approaches to manage crisis situation through more efficient utilization of the available generators and cross-border infrastructures. Furthermore, by comparing the results under two different approaches for providing operating reserve, the simulation results approved that market-based provision of reserves across the border and without minimum requirement constraints, can perform as an effective tool in managing crisis situation with lower operating costs and less impacts on the continuity of supply in the affected region.

6.2 Recommendation for future works

The following recommendations can be done in the direction of this dissertation:

- Implementing flow-based market coupling model instead of the ATC-based approach used in this thesis, to model the Europe-wide integrated market model. The flow-based approach leads to more efficient utilization of generation and transmission resources. However, to generate the model, the full transmission network model of the participating European countries is required.

- Optimum design of market zones in European electricity system. The Europe-wide integrated market model used in this thesis is based on the current division of market zones in the European electricity system. However, increasing penetration of variable renewable energy sources strongly impacts the optimum design of market zones. The reason is that these resources are generally located far from the consumption points and their production does not follow load variations. Hence, increasing their penetration complicates the intra-zonal congestion management and requires more efficient design of the market zones.

- Stochastic modelling of crisis management approach, based on the different scenarios of load and renewable production. The crisis management approach in this thesis considered two scenarios for wind production as favourable (best case) and unfavourable (worst case) scenarios, while a stochastic approach can lead to more economic decisions.

- Assessing the impact of integrating reserve markets in Europe. In the integrated European electricity market model presented in this thesis, the operating reserve requirements have been set based on the current regulations within different synchronous areas in Europe. Performing a Europe-wide integrated market model for free provision of operating reserves across the borders can further reduce the total operation cost of the system and increase the hosting capacity of renewables within European electricity system.

- Performing a sensitivity analysis on the impact of different levels of demand-side flexibility (share of different load categories) on the performance of the multi-regional integrated risk-preparedness plan.

- Assessing the environmental impact of integrating electricity markets across Europe, within individual European countries.

Bibliography

[1] European Commission Website. *Energy Topics*. Available on:https://ec.europa.eu/energy/en/topics.

[2] ENTSOE website. *Current situation with operation of Baltic States in synchronous mode with IPS/UPS power system*. Available on:https://tyndp.entsoe.eu/2016/insight-reports/baltic-synchronisation/.

[3] The European Parliament and the Council of the European Union. *DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the promotion of the use of energy from renewable sources*. Official Journal of European Union. Available on:https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN. 11 December 2018.

[4] European Parliament. *EU Legislation in progress-Briefing. Third edition*. Available on:http://www.europarl.europa.eu/RegData/etudes/BRIE/2017/595925/EPRS_BRI(2017)595925_EN.pdf. 14 March 2019.

[5] ENTSO-E. *Cross-zonal intraday capacity pricing methodology-explanatory note*. On://docstore.entsoe.eu/Documents/Network%20codes%20documents/Implementation/cacm/170810_CZIDCP_Methodology_Explanatory_Note_AllTSOs.pdf. 10 August 2017.

[6] R. Bolton, V. Lagendijk, and A. Silvast. “Grand visions and pragmatic integration: Exploring the evolution of Europe’s electricity regime”. In: *Environmental Innovation and Societal Transactions* 32 (Sept. 2019), pp. 55–68.

[7] E. M. Carlini et al. “EU transition in power sector: How RES affects the design and operations of transmission power systems”. In: *Electric Power Systems Research* 169 (Apr. 2019), pp. 74–91.

[8] P. Ringler, D. Keles, and W. Fichtner. “How to benefit from a common European electricity market design”. In: *Energy Policy* 101 (Feb. 2017), pp. 629–643.

[9] J. Abrell and S. Rausch. “Cross-country electricity trade, renewable energy and European transmission infrastructure policy”. In: *Journal of Environmental Economics and Management* 79 (Sept. 2016), pp. 87–113.

[10] J. Torriti. “Provatization and cross-border electricity trade: from internal market to European supergrid?” In: *Energy* 77 (Dec. 2014), pp. 635–640.

[11] C. Jullien et al. “Coordinating cross-border congestion management through auctions: an experimental approach to European solutions”. In: *Energy Economics* 34 (Jan. 2012), pp. 1–13.

[12] D. Peng and R. Poudineh. “Electricity market design under increasing renewable energy penetration: Misalignments observed in the European Union”. In: *Utilities Policy* 61 (Dec. 2019).

[13] T. Schittekatte, V. Reif, and L. Meeus. *The EU electricity network codes (2019 ed.)* Florence School of Regulation (FCR) Technical Report, Feb. 2019.

[14] *ENTSO-E Network Codes.* (online) Available on:https://www.entsoe.eu/network_codes/.

[15] J. J. Sanchez et al. “Dynamics in forward and spot electricity markets”. In: *IEEE Transactions on Power Systems* 24 (May 2009), pp. 582–591.

[16] T. S. Chung, S. H. Zhang, and K. P. Wong. “Electricity market risk management using forward contracts with bilateral options”. In: *IEE Proceeding-Generation, Transmission and Distribution* 150 (Sept. 2003), pp. 588–594.

[17] R. R. Ernstsen et al. “Hedging local volume risk using forward markets: Nordic case”. In: *Energy Economics* 68 (Oct. 2017), pp. 490–514.

[18] C. Redl et al. “Price formation in electricity forward markets and the relevance of systematic forecast errors”. In: *Energy Economics* 31 (May 2009), pp. 356–364.

[19] *Website of the NordPool market.* (online) Available on:https://www.nordpoolspot.com/.

[20] *Website of the EPEX SPOT market.* (online) Available on:https://www.apxgroup.com/about-us/about-us/profile/.

[21] NEMO Committee. *EUPHEMIA Public Description: Single price coupling algorithm.* Available on:file:///D:/Shooka/PhD%20Thesis/Chap%202/References/CurrentEUOperation/euphemia-2019.pdf. 10 April 2019.

[22] C. Weber. “Adequate intraday market design to enable the integration of wind energy into the European power systems”. In: *Energy Policy* 38 (July 2010), pp. 3155–3163.

[23] C. Pape. “The impact of intraday markets on the market value of flexibility-Decomposing effects on profile and the imbalance costs”. In: *Energy Economics* 76 (Oct. 2018), pp. 186–201.

[24] S. Zalzar et al. "The impacts of an integrated European adjustment market for electricity under high share of renewables". In: *Energy Policy* 136 (Jan. 2020).

[25] M. Sarfati, M. R. Hesamzadeh, and P. Holmberg. "Production efficiency of nodal and zonal pricing in imperfectly competitive electricity markets". In: *Energy Strategy Reviews* 24 (2019), pp. 139–206.

[26] D. Newbery, M. G. Pollitt, and R. A. Ritz. "Market design for a high-renewables European electricity system". In: *Renewable and sustainable Energy Reviews* 91 (Aug. 2018), pp. 695–707.

[27] M. Weibelzahl and A. Martz. "On the effects of storage facilities on optimal zonal pricing in electricity markets". In: *Energy Policy* 113 (Feb. 2018), pp. 778–794.

[28] ENTSO-E Help Center. *What is the difference between Bidding Zone (BZN) and Control Area (CTS)?* (online) Available on:https://entsoe.zendesk.com/hc/en-us/articles/115000151326-What-is-the-difference-between-Bidding-Zone-BZN-and-Control-Area-CTA-.

[29] J. Egerer, J. Weibezahn, and H. Hermann. "Two price zones for the German electricity market- Market implications and distributional effects". In: *Energy Economics* 59 (Sept. 2016), pp. 365–381.

[30] K. Janda, J. Malek, and L. Recka. "Influence of renewable energy sources on transmission networks in Central Europe". In: *Energy Policy* 108 (Sept. 2017), pp. 524–537.

[31] M. Weibelzahl and Nodal. "Zonal, or uniform electricity pricing: how to deal with network congestion. Review article". In: *Frontiers in Energy* 11 (June 2017), pp. 210–232.

[32] T. Felling and C. Weber. "Consistent and robust delimitation of price zones under uncertainty with an application to central Western Europe". In: *Energy Economics* 75 (Sept. 2018), pp. 583–601.

[33] L. H. Lam, V. Ilea, and C. Bovo. "European day-ahead electricity market coupling: Discussion, modelling, and case study". In: *Electric Power Systems Research* 155 (Feb. 2018), pp. 80–92.

[34] PSE website. *Polskie Sieci Elektroenergetyczne (Transmisison system operator of Poland), Trends and market context.* Available on:http://raport.pse.pl/en/trends-and-market-context$#$trends-and-market-context.

[35] L. J. De Vries, J. De Joode, and R. Hakvoort. "The regulation of electricity transmission networks and its impact on governance". In: *European Review of Energy Markets* 3 (Oct. 2009).

[36] European Parliament and the Council of the European Union. *REGULATION (EC) No 1228/2003 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity*. Official Journal of European Union. 15/07/2003.

[37] European Commission. *COMMISSION REGULATION (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management*. Official Journal of European Union. 25/07/2015.

[38] A. Marinakis, A. G. Bakirtzis, and T. V. Cutsem. "Energy and transmission allocation in the presence of overlapping electricity markets". In: *IEEE Transactions on Power Systems* 25 (Aug. 2010), pp. 1402–1414.

[39] MIT Energy Initiative. *Utility of the Future, An MIT Energy Initiative response to an inductry in transition. Massachusetts Institute of Technology.* Available on:https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf. December 2016.

[40] A. Yousefi et al. "Congestion management using demand response and FACTS devices". In: *Electric Power and Energy Systems* 37 (May 2012), pp. 78–85.

[41] S. Dutta and S. P. Singh. "Optimal rescheduling of generators for congestion management based on particle swarm optimization". In: *IEEE Transactions on Power systems* 23 (Nov. 2008), pp. 1560–1569.

[42] K. V. Bergh et al. "Redispatching in an interconnected electricity system with high renewable penetration". In: *Electric Power systems Research* 127 (Oct. 2015), pp. 64–72.

[43] European Commission. *COMMISSION REGULATION (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council*. Official Journal of European Union. 15/06/2013.

[44] H. Schermeyer, C. Vergara, and W. Fichtner. "Renewable energy curtailment: A case study on today's and tomorrow's congestion management". In: *Energy Policy* 112 (Jan. 2018), pp. 427–436.

[45] K. Trepper, M. Bucksteeg, and C. Weber. "Market splitting in Germany-New evidence from a three-stage numerical model of Europe". In: *Energy Policy* 87 (Dec. 2015), pp. 199–215.

[46] Operation handbook UCTE. *European network of transmission system operators for electricity*. Available on:https://www.entsoe.eu/publications/system-operations-reports/operation-handbook/Pages/default.aspx.

[47] K. Morison, L. Wang, and P. Kundur. "Power system security assessment". In: *IEEE Power and energy magazine* 2 (Oct. 2004).

[48] T. Slot et al. "Options for future European electricity system operation. European Commission's report". In: *Luxembourg: Publications Office of the European Union* (Dec. 2015).

[49] ENTSO-E. *Network Code on Operational Security*. Available on:https://www.entsoe.eu/fileadmin/user_upload/_library/resources/OS_NC/130227-AS-NC_OS_final_.pdf. 27 February 2013.

[50] European Commission. *COMMISSION REGULATION (EU) 2017/1485 of 2 August 2017 on establishing a guideline on electricity transmission system operation*. Official Journal of European Union. 25/08/2017.

[51] CEPS and MAVIR. *PSE Operator and SEPS, Bidding Zones Definition, Response to the study commissioned by Bundesnetzagentu*. Available on:https://www.pse.pl/documents/20182/51490/17225Position_of_CEPS_MAVIR_PSEO_SEPS-Bidding_Zones_Definition.pdf/3f9865bc-8c32-48a2-aa33-b141f042a830. March 2012.

[52] D. I. Chatzigiannis et al. "European day-ahead electricity market clearing model". In: *Electric Power systems Research* 140 (Nov. 2016), pp. 225–239.

[53] ENTSO-E Website. "TYNDP 2018, Europe's Network Development Plan to 2025, 2030 and 2040". In: (). URL: %5Curl%7Bhttps://tyndp.entsoe.eu/tyndp2018/%7D%20,.

[54] A. Purvins and S. Zalzar T. Huang. "Integration of the Baltic States into the EU electricity system: A technical and economic analysis, JRC Science for Policy Report". In: *Luxemburg: Publication Office of the European Union* (2017). URL: https://op.europa.eu/en/publication-detail/-/publication/8d3b7da2-562e-11e7-a5ca-01aa75ed71a1/language-en.

[55] ENTSO-E. *Electricity in Europe 2017*. Available on:https://docstore.entsoe.eu/Documents/Publications/Statistics/electricity_in_europe/entso-e_electricity_in_europe_2017_web.pdf.

[56] European Environment Agency. *Renewable energy in Europe-2018, Recent growth and knock-on effects*. Publication Office of the European Union, EEA Report No 20/2018.

[57] M. Joos and I. Staffell. "Short-term integration costs of variable renewable energy: wind curtailment and balancing in Britain and Germany". In: *Renewable and sustainable Energy Reviews* 86 (Apr. 2018), pp. 45–65.

[58] T. Lv X. Deng. "X. Deng, T. Lv, Power system planning with increasing variable renewable energy: A review of optimization models". In: *Journal of Cleaner Production* In Press (Oct. 2019).

[59] H. Khatib and C. Difiglio. “Economics of nuclear and renewables”. In: *Energy Policy* 2016 (Sept. 96), pp. 740–750.

[60] G. Bachner et al. “The economy-wide effects of large-scale renewable electricity expansion in Europe: The role of integration costs”. In: *Renewable Energy* 134 (Apr. 2019), pp. 1369–1380.

[61] A. Stiphout, K. Vos, and G. Deconinck. “The impact of operating reserves on investment planning of renewable power systems”. In: *IEEE Transactions on Power Systems* 32 (May 2016).

[62] B. Zhang, R. Rajagopal, and D. Tse. “Network Risk Limiting Dispatch: Optimal Control and Price of Uncertainty”. In: *IEEE Transactions on Automatic Control* 59 (Sept. 2014), pp. 2442–2456.

[63] J. Abrell, S. Rausch, and C. Streitberger. “Buffering volatility: Storage investments and technology-specific renewable energy support”. In: *Energy Economics* (Aug. 2019).

[64] J. B. Bejerano and E. T. Baute. “Impacts of intermittent renewable generation on electricity system costs”. In: *Energy Policy* 94 (July 2016), pp. 411–420.

[65] K. N. Hasan, R. Preece, and J. V. Milanovic. “Existing approaches and trends in uncertainty modelling and probabilistic stability analysis of power systems with renewable generation”. In: *Renewable and Sustainable Energy Reviews* 101 (Mar. 2019), pp. 168–180.

[66] W. Wei, F. Liu, and S. Mei. “Real-Time Dispatchability of Bulk Power Systems With Volatile Renewable Generations”. In: *IEEE Transactions on Sustainable Energy* 6 (July 2015), pp. 738–747.

[67] D. A. Ciupăgeanu, G. Lăzăroiu, and L. Barelli. “Wind energy integration: variability analysis and power system impact assessment”. In: *Energy* 185 (Oct. 2019), pp. 1183–1196.

[68] Q. Wang and B. Hodge. “Enhancing Power System Operational Flexibility With Flexible Ramping Products: A Review”. In: *IEEE Transactions on Industrial Informatics* 13 (Aug. 2017), pp. 1652–1664.

[69] W. A. Bukhsh, C. Zhang, and P. Pinson. “An Integrated Multiperiod OPF Model With Demand Response and Renewable Generation Uncertainty”. In: *IEEE Transactions on Smart Grid* 7 (May 2016), pp. 1495–1503.

[70] A. Roos and T. F. Bolkesjø. “Value of demand flexibility on spot and reserve electricity markets in future power system with increased shares of variable renewable energy”. In: *Energy* 144 (Feb. 2018), pp. 207–217.

[71] R. Domínguez, G. Oggioni, and Y. Smeers. “Reserve procurement and flexibility services in power systems with high renewable capacity: effects on integration on different market designs”. In: *International Journal of Electrical Power and Energy Systems* 113 (Dec. 2019), pp. 1014–1034.

[72] H. Karbouj et al. “Non-synchronous fast frequency reserves in renewable energy integrated power systems: a critical review”. In: *International Journal of electrical Power and Energy Systems* 106 (Mar. 2019), pp. 488–501.

[73] N. Navid and G. Rosenwald. “Market Solutions for Managing Ramp Flexibility With High Penetration of Renewable Resource”. In: *IEEE Transactions on Sustainable Energy* 3 (Oct. 2012), pp. 784–790.

[74] M. A. Mirzaei et al. “Consideration of Hourly Flexible Ramping Products in Stochastic Day-Ahead Scheduling of Integrated Wind and Storage Systems”. In: *2018 Smart Grid Conference (SGC)*. Nov. 2018, pp. 1–6.

[75] M. Marzband et al. “Non-cooperative game theory based energy management systems for energy district in the retail market considering DER uncertainties”. In: *IET Generation, Transmission Distribution* 10.12 (2016), pp. 2999–3009.

[76] N. Gholizadeh et al. “An innovative energy management framework for cooperative operation management of electricity and natural gas demands”. In: *Energy Conversion and Management* 200 (Nov. 2019).

[77] H. Gholinejad et al. “A hierarchical energy management system for multiple home energy hubs in neighborhood grids”. In: *Journal of Building Engineering* 28 (Mar. 2020).

[78] W. Wei et al. “Robust Energy and Reserve Dispatch Under Variable Renewable Generation”. In: *IEEE Transactions on Smart Grid* 6 (Jan. 2015), pp. 369–380.

[79] J. Haas et al. “Challenges and trends of energy storage expansion planning for flexibility provision in low-carbon power systems-a review”. In: *Renewable and Sustainable Energy Reviews* 80 (Dec. 2017), pp. 603–619.

[80] F. Nadeem et al. “Comparative Review of Energy Storage Systems, Their Roles, and Impacts on Future Power Systems”. In: *IEEE Access* 7 (2019), pp. 4555–4585.

[81] L. Fiorini et al. “Sizing and Siting of Large-Scale Batteries in Transmission Grids to Optimize the Use of Renewables”. In: *IEEE Journal on Emerging and Selected Topics in Circuits and Systems* 7 (June 2017), pp. 285–294.

[82] S. Lumbreras, A. Ramos, and F. Banez-Chicharro. “Optimal transmission network expansion planning in real-sized power systems with high renewable penetration”. In: *Electric Power Systems Research* 149 (Aug. 2017), pp. 76–88.

[83] W. Zappa, M. Junginger, and M. Broek. "Is a 100% renewable European power system feasible by 2050?" In: *Applied energy* 233-234 (Jan. 2019), pp. 1027–1050.

[84] S. Boeck et al. "Review of defence plans in Europe: current status, strengths and opportunities". In: *Cigre Science and Engineering* 5 (June 2016).

[85] European Commission. *Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC, COM/2016/0862 final - 2016/0377 (COD)*. Available on:https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX$%$3A52016PC0862.

[86] European Commission. *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European investment Bank 'Clean Energy for all Europeans'.* Brussels, 30.11.2016 COM (2016) 860 final.

[87] Spark Legal Network, VVA Europe, European Commission, and Directorate General for Mobility and Transport. *Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply final report.* Luxembourg: Publications Office, 2014.

[88] *Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment.* Official Journal of the European Union. 4/2/2006.

[89] *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.* Official Journal of the European Union. 14/8/2009.

[90] S&P Global Platts, EU Electricity markets in January and February 2017. *-Understanding the Impact of the Cold Spell and the Special Measures Introduced in Select Member States and Concerned Energy Community Contracting Parties, A report to DG Energy.* December 20, 2017.

[91] ENTSO-E. *Managing critical grid situations- a market analysis- Annex to the ENTSO-E May 2017 report on managing critical grid situations: success and challenges.* November 2017.

[92] ENTSO-E Seasonal Outlooks. *Winter outlook 2018/2019-summer review 2018.* 28 November 2018.

[93] ENTSO-E. *Mid-Term Adequacy Forecast, 2019 Edition.* Available on: https://www.entsoe.eu/outlooks/midterm/.

[94] M. P. Blanco et al. *Generation adequacy methodologies review.* JRC Science for Policy Report, EUR 27944 EN. 2016.

[95] ENTSO-E. *Short-term and Seasonal adequacy assessments methodology proposal in accordance with Article 8 of the REGULATION (EU) 2019/941 of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC*. 8 July 2019.

[96] European Commission. *COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT accompanying the document Commission Regulation (EU) No .../... establishing a Guideline on Electricity Balancing, SWD/2017/0383 final, Brussel*. Available on: https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX$%$3A52017SC0383. 23/11/2017.

[97] EPEXSpot website. *Negative Prices Q&A*. Available on: https://www.epexspot.com/en/company-info/basics_of_the_power_market/negative_prices.

[98] Clean Energy wire website. *The causes and effects of negative power prices*. Available on: https://www.cleanenergywire.org/factsheets/why-power-prices-turn-negative.

[99] E. Bompard et al. "Baltic power system's integration into the EU market coupling under different desynchronization schemes: a comparative market analysis". In: *Energies* 11 (2018).

[100] A. L'Abbate et al. "Long-term HVDC developments in the European power system: The Baltic case in GridTech analysis". In: *2015 IEEE 5th International Conference on Power Engineering, Energy and Electrical Drives (POWERENG)*. May 2015, pp. 283–290.

[101] V. Radziukynas et al. "Challenges for the Baltic Power System connecting synchronously to Continental European Network". In: *Electrical Power System Research* 140 (2016), pp. 54–64.

[102] Nord Pool Website. Available on: http://www.nordpoolspot.com/How-does-it-work/.

[103] E. Bompard et al. "Electricity independence of the Baltic States: Present and future perspectives". In: *Sustainable Energy, Grids , and Networks* 10 (2017), pp. 55–64.

[104] European Commission. *Integration of the Baltic States into the EU Electricity System*. Available on: https://publications.europa.eu/en/publication-detail/-/publication/8d3b7da2-562e-11e7-a5ca-01aa75ed71a1/language-en/format-PDF/source-31392329.

[105] FinGrid, Statnett, Svenska, Kraftnat, Evengrinet.dk. *Impact of Baltic Synchronization on the Nordic Power System Stability*. Available on: https://www.svk.se/siteassets/om-oss/rapporter/impact-of-baltic-synchronization-on-the-nordic-power-system-stability.pdf. 2016.

[106] D. Newbery, G. Strbac, and I. Viehoff. “The benefits of integrating European electricity markets”. In: *Energy Policy* 94 (2016), pp. 253–263.

[107] ENTSO-E. “Regional Investment Plan 2015—Baltic Sea”. In: *ENTSO-E: Brussels, Belgium* (2015).

[108] ENTSO-E. *Baltic Synchronization.* Available on: http://tyndp.entsoe.eu/insight-reports/baltic-synchronisation/.

[109] ENTSO-E. “rincipals for Determining the Transfer Capacities in the Nordic Power Market”. In: *ENTSO-E: Brussels, Belgium* (2017).

[110] Feng Ding and J. D. Fuller. “Nodal, uniform, or zonal pricing: distribution of economic surplus”. In: *IEEE Transactions on Power Systems* 20 (May 2005), pp. 875–882.

[111] ENTSO-E. *Nordic Balancing Philosophy.* Available on: https://www.entsoe.eu/Documents/Publications/SOC/Nordic/Nordic_Balancing_Philosophy_160616_Final_external.pdf. June 2016.

[112] ENTSO-E. “Then-Year Network Development Plan 2010–2020, Non-Binding Community-Wide Ten-Year Network Development Plan Pilot Project Final Report”. In: *ENTSO-E: Brussels, Belgium* (June 2010).

[113] UCTE. “Policy 1: Load-Frequency Control and Performance”. In: *UCTE, Ottawa, Canada* (2009).

[114] ENTSO-E. “TYNDP 2016 Scenario Development Report”. In: *ENTSO-E: Brussels, Belgium* (2015).

[115] O.S. Grande, G. Doorman, and B. H. Bakken. “Exchange of Balancing Resources between the Nordic Asynchronous System and the Netherlands/Germany/Poland”. In: *SINTEF Energiforskning AS: Trondheim, Norway* (2008).

[116] *EUPHEMIA Public Description, PCR Market Coupling Algorithm. Version 1.5.* Available on: https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf. December 2016.

[117] E. Bjorndal, M. Bjorndal, and V. Gribkovskaia. “A Nodal Pricing Model for the Nordic Electricity Market, Discussion Paper, Department of Business and Management Science”. In: *Norwegian School of Economics: Bergen, Norway* (Dec. 2014).

[118] I. Aravena and A. Papavasiliou. “Renewable Energy Integration in Zonal Markets”. In: *IEEE Transactions on Power Systems* 32 (Mar. 2017), pp. 1334–1349.

[119] G. Oggioni and Y. Smeers. “Market failure of market coupling and counter-trading in Europe: An illustrative model based discussion”. In: *Energy Economics* 35 (2013), pp. 74–87.

[120] M. Beus et al. “Electricity market design in Croatia within the European electricity market- recommendations for further development”. In: *Energies* 11 (2018).

[121] S. Ellenbeck et al. “Security of supply in European electricity markets-determinants of investment decisions and the European Energy Union”. In: *Energies* 8 (2015), pp. 5198–5216.

[122] M. Poncela, A. Purvins, and S. Chondrogiannis. “Pan-European analysis on power system flexibility”. In: *Energies* 11 (2018).

[123] E. Bompard et al. “Congestion-management schemes: a comparative analysis under a unified framework”. In: *IEEE Transactions on Power Systems* 18 (Feb. 2003), pp. 346–352.

[124] S. Delikaraoglou, J. M. Morales, and P. Pinson. “Impact of Inter- and Intra-Regional Coordination in Markets With a Large Renewable Component”. In: *IEEE Transactions on Power Systems* 31 (Nov. 2016), pp. 5061–5070.

[125] Energy Exemplar Website. *PLEXOS Simulation Software*. Available on: www.energyexemplar.com.

[126] Tennet. “Model for Capacity Calculation”. In: *TenneT: Arnhem, the Netherlands* (July 2012).

[127] European commission. “Energy, Transport and GHG Emissions Trends to 2050, EU Reference Scenario”. In: *Publication office of the European Commission* (2016).

[128] ENTSO-E. “Scenario Outlook and Adequacy Forecast 2014–2030”. In: *ENTSO-E: Brussels, Belgium* (2014).

[129] ENTSO-E. *Ten-Year Network Development Plan*. Available on: http://tyndp.entsoe.eu/2016/reference/downloads. 2016.

[130] I. Staffell and S. Pfenninger. “Using bias-corrected reanalysis to simulate current and future wind power output”. In: *Energy* 114 (Nov. 2016), pp. 1224–1239.

[131] S. Zalzar et al. “A smart charging algorithm for integration of EVs in providing primary reserve as manageable demand-side resources”. In: *International Transactions on Electrical Energy Systems* 27 (Apr. 2017).

[132] S. Zalzar et al. “The impacts of an integrated European adjustment market for electricity under high share of renewables”. In: *Energy Policy* 136 (Jan. 2020).

[133] European Commission. “A policy framework for climate and energy in the period from 2020 to 2030”. In: *Communication from the commission to the European parliament, the council, the European economic and social committee and the committee of the regions, Brussels* (Jan. 2014).

[134] European Commission. “Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources”. In: *EU publications, Official Journal of the European Union, Document 32018L2001* (Dec. 2018).

[135] J. Blazquesz et al. “The renewable energy policy paradox”. In: *Renewable and Sustainable Energy Reviews* 82 (2018), pp. 1–5.

[136] S. Zalzar and E. Bompard. “A Day-Ahead Joint Energy and Uncertainty Reserve Market Clearing Model to Manage VRE Uncertainty”. In: *2018 IEEE International Conference on Environment and Electrical Engineering and 2018 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I CPS Europe)*. June 2018, pp. 1–5.

[137] F. Abbaspourtorbati et al. “Three- or Two-Stage Stochastic Market-Clearing Algorithm?” In: *IEEE Transactions on Power Systems* 32.4 (July 2017), pp. 3099–3110.

[138] M. Amelin. “An Evaluation of Intraday Trading and Demand Response for a Predominantly Hydro-Wind System Under Nordic Market Rules”. In: *IEEE Transactions on Power Systems* 30.1 (Jan. 2015), pp. 3–12. ISSN: 1558-0679. DOI: 10.1109/TPWRS.2014.2324632.

[139] S. Fattler and C. Pellinger. “The value of flexibility and the effect of an integrated European intra-day market”. In: *13th international conference on the European Energy Market (EEM)*. 2016.

[140] P. N. Biskas et al. “High-level design for the compliance of the Greek wholesale electricity market with the target model provisions in Europe”. In: *Electric Power Systems Research* 12 (2017), pp. 323–341.

[141] ENTSO-E. *Network Codes Development Process*. Available on:https://www.entsoe.eu/fileadmin/user_upload/_library/Association/120217_Network_Codes_Development_Process.pdf.. February 2012.

[142] ENTSO-E. *Cross-zonal intraday capacity pricing methodology-explanatory note*. . 10 August 2017.

[143] J. Lago, F. D. Ridder, and B. D. Schutter. “Forecasting day-ahead electricity prices in Europe: the importance of considering market integration”. In: *Applied Energy* 211 (2018), pp. 890–903.

[144] Tong Wu et al. “Pricing energy and ancillary services in integrated market systems by an optimal power flow”. In: *IEEE Transactions on Power Systems* 19.1 (Feb. 2004), pp. 339–347.

[145] ENTSO-E. *P5 – Policy 5: Emergency Operations*. V 3.1, Continental Europe Operation Handbook, 43rd RG CE Plenary Meeting 26 of September of 2017, Available on:https://www.entsoe.eu/publications/system-operations-reports/operation-handbook/Pages/default.aspx.

[146] E. Bompard, T. Huang, and L. Yang. "Market Equilibrium Under Incomplete and Imperfect Information in Bilateral Electricity Markets". In: *IEEE Transactions on Power Systems* 26 (Aug. 2011), pp. 1231–1240.

[147] ENTSO-E. *Ten-Year Network Development Plan 2018*. Available on:https://tyndp.entsoe.eu/tyndp2018/.

[148] Omie Website. Available on:www.omel.es/en/home/markets-and-products/electricity-market/our-electricity-markets/intraday-market.

[149] Epexspot website. Available on:https://www.epexspot.com/en/product-info/intradayauction.

[150] J. Glachant. "Tacking stock of the EU Power Target Model... and steering its future course". In: *Energy Policy* 96 (2016).

[151] F. Bouffard and F. D. Galiana. "Stochastic Security for Operations Planning With Significant Wind Power Generation". In: *IEEE Transactions on Power Systems* 23 (May 2008), pp. 306–316.

[152] ENTSO-E. *System Operation Report*. Available on:https://www.entsoe.eu/publications/system-operations-reports/Pages/default.aspx.

[153] A. Mazza, E. Bompard, and G. Chicco. "Applications of power to gas technologies in emerging electrical systems". In: *Renewable and Sustainable Energy Reviews* 92 (2018), pp. 794–806.

[154] DG Energy. *Impact assessment study on downstream flexibility, price flexibility, demand response & smart metering*. European Commission publications, Available on:https://ec.europa.eu/energy/en/studies/impact-assessment-study-downstream-flexibility-price-flexibility-demand-response-smart. July 2016.

[155] R. A. Verzijlbergh et al. "Institutional challenges caused by the integration of renewable energy sources in the European electricity sector". In: *Renewable and Sustainable Energy Reviews* 75 (Aug. 2017), pp. 660–667.

[156] M.G. Gutierrez and R. L. Arantegui. "Assessment of the European potential for pumped hydropower energy storage- A GIS-based assessment of pumped hydropower storage potentials". In: *Scientific and Policy Report by the Joint Research Centre of the European Commission, EU Publications* (2013).

[157] P. Nikolaidis and A. Poullikkas. "A comparative review of electrical energy storage systems for better sustainability". In: *Journal of Power Technologies* 97 (2017).

[158] Eurostat website. Available on:http://ec.europa.eu/eurostat/data/database.

[159] A. Purvins et al. "Integration of the Baltic States into the EU electricity system", Science for Policy report by the Joint Research Centre (JRC), Project No: 2017.3516". In: *Publication Office of the European Union* (2017).

[160] Monitoring Analytics. *State of the market report for PJM, 2016 State of the Market Report for PJM*. Available on:. 2017.

[161] P. Vogler-Finck and W. Fruh. "Evolution of primary frequency control requirements in Great Britain with increasing wind generation". In: *Electrical Power and Energy Systems* 73 (2015), pp. 377–388.

[162] SONI EIRGRID. "Operational Constraints Update". In: *Reported by TSOs of Ireland and Northern Ireland* (Aug. 2017).

[163] S. Just. "The German market for system reserve capacity and balancing energy". In: *Chair for management sciences and energy economics, University of Duisburg-Essen, EWL Working Paper No. 06/15, 2015* ().

[164] U.S. Department of Energy National Renewable Energy Laboratory IBM TJ Watson Research Center. "Metrics for evaluating the accuracy of solar power forecasting". In: *3rd International Workshop on Integration of Solar Power into Power Systems, London, England* (Oct. 2013).

[165] J. Zhang et al. "Baseline and target values for PV forecasts: Toward improved solar power forecasting". In: *2015 IEEE Power Energy Society General Meeting*. July 2015, pp. 1–5.

[166] R. Doherty and M. O'Malley. "A new approach to quantify reserve demand in systems with significant installed wind capacity". In: *IEEE Transactions on Power Systems* 20.2 (May 2005), pp. 587–595.

[167] B. A. Bowen. "An alternate proof of the central limit theorem for sums of independent processes". In: *Proceedings of the IEEE* 54.6 (June 1966), pp. 878–879.

[168] Omie website. *Main Results of the electricity market 2018", Omie publications*. Annual Report, Available on:http://www.omie.es/files/omie_diptico_pantalla_en.pdf..

[169] Statista website. *Hydropower pumped storage capacity in Europe 2018.* , Available on:https://www.statista.com/statistics/690032/pumped-storage-capacity-europe/.

[170] W. Hogan. "Electricity Scarcity Pricing through Operating Reserves". In: *Economics of Energy & Environmental Policy* 2 (2013), pp. 65–86.

[171] A. Papalexopoulos, J. Beal, and S. Florek. "Precise Mass-Market Energy Demand Management Through Stochastic Distributed Computing". In: *IEEE Transactions on Smart Grid* 4.4 (Dec. 2013), pp. 2017–2027.

[172] K. Margellos and S. Oren. "Capacity Controlled Demand Side Management: A Stochastic Pricing Analysis". In: *IEEE Transactions on Power Systems* 31.1 (Jan. 2016), pp. 706–717.

[173] European Commission. "REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC". In: *Brussels* (Nov. 2016).

[174] S. S. Reddy. "Multi-Objective Based Congestion Management Using Generation Rescheduling and Load Shedding". In: *IEEE Transactions on Power Systems* 32.2 (Mar. 2017), pp. 852–863.

[175] H. Mortaji et al. "Load Shedding and Smart-Direct Load Control Using Internet of Things in Smart Grid Demand Response Management". In: *IEEE Transactions on Industry Applications* 53.6 (Nov. 2017), pp. 5155–5163.

[176] V. V. Terzija. "Adaptive underfrequency load shedding based on the magnitude of the disturbance estimation". In: *IEEE Transactions on Power Systems* 21.3 (Aug. 2006), pp. 1260–1266.

[177] M. Marzband et al. "Adaptive load shedding scheme for frequency stability enhancement in microgrids". In: *Electric Power Systems Research* 140 (Nov. 2016), pp. 78–86.

[178] C. W. Taylor. "Concepts of undervoltage load shedding for voltage stability". In: *IEEE Transactions on Power Delivery* 7.2 (Apr. 1992), pp. 480–488.

[179] T. Q. Tuan et al. "Emergency load shedding to avoid risks of voltage instability using indicators". In: *IEEE Transactions on Power Systems* 9.1 (Feb. 1994), pp. 341–351.

[180] C. Moors, D. Lefebvre, and T. Van Cutsem. "Load shedding controllers against voltage instability: a comparison of designs". In: *2001 IEEE Porto Power Tech Proceedings (Cat. No.01EX502)*. Vol. 2. Sept. 2001, 6 pp. vol.2-.

[181] B. Otomega, M. Glavic, and T. Van Cutsem. "Distributed Undervoltage Load Shedding". In: *IEEE Transactions on Power Systems* 22.4 (Nov. 2007), pp. 2283–2284.

[182] J. Jung et al. "Adaptation in load shedding under vulnerable operating conditions". In: *IEEE Transactions on Power Systems* 17.4 (Nov. 2002), pp. 1199–1205.

[183] O. Mäkelä and G. Andersson. "On pitfalls of current security assessment practice in multi-area power systems". In: *2012 IEEE International Energy Conference and Exhibition (ENERGYCON)*. Sept. 2012, pp. 427–432.

[184] TSCNET Services Website. , Available on:https://www.tscnet.eu/.

[185] CORESO website. , Available on:https://www.coreso.eu/mission/history-of-coreso/.

[186] SCC Website. , Available on:http://www.scc-rsci.com/.

[187] Nordic RSC website. , Available on:https://nordic-rsc.net/.

[188] H. Pandzic et al. *Unit Commitment under Uncertainty - GAMS Models*. Library of the Renewable Energy Analysis Lab (REAL), University of Washington, Seattle, USA, Available on:http://www.ee.washington.edu/research/real/gams_code.html.

This Ph.D. thesis has been typeset by means of the TEX-system facilities. The typesetting engine was pdfLATEX. The document class was `toptesi`, by Claudio Beccari, with option `tipotesi=scudo`. This class is available in every up-to-date and complete TEX-system installation.