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The impact of the formation of Bidding Zones on Capacity allocation and Renewable penetration

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Introduction

Electricity markets play a fundamental role in our daily life, though it is an ‘invisible’ presence but essential to allow the shar of electricity good to everyone. Economic features are the same of every kind of market, and they are not the focus of this work, but unlike the others, electricity is a commodity and there is no distinction on quality or properties: a MW is always a MW, no matter who or where is produced! In this sense regulations have been important through years to arrive in the situation we are now: the liberalization of the energy sector, which allow the freely choose of the supplier with transparent and non-discriminatory conditions. During this process, improvements were made and two body were necessary: Transmission System Operators (TSOs) and the nominated electricity market operator, or Power Exchange (PXs), and still their importance is crucial to the whole process. The role of TSOs is to approve the tariffs, monitor congestion management, and behave as a dispute settlement authority, focusing then on the network and its operation and security; while PXs manage the market and provide a marketplace where wholesale buyers and sellers can exchange electricity, matching bids and offers and find the balanced energy price and quantity. These two bodies have the need to work together, exchanging information to ‘match’ the economic dispatch with physical (electrical) features of the network. As it can be imagined it isn’t easy and several aspects have to be taken into account, as geographical position, load request, type of generation, capacity allocations, cross-border transferability. Challenges which from the latest 10 years are growing exponentially and force the TSOs to reconsider the organization of the network and markets.

This work of thesis focuses on two of these aspects: capacity allocations and renewable penetration; with the goal to assess the impact that market areas and their formation can have on them in the Day-Ahead Markets. The final scope of the European Union, as well of this thesis though in a limited way, is to find the better configuration of the market areas, i.e. Bidding Zones, that maximize all the operation and exchange while reducing at its minimum the ‘waste’ of energy and the cost of re-dispatch. In this sense, capacity allocation and renewables are affected by the BZs' formation and in the thesis this impact will be evaluated and proof through a case study implemented with the use of MATLAB, and as well the consequences on the network and market outcomes. Moreover, two different capacity allocation methods are used and compared in the case study, the Available Transfer Capability (ATC) and the Flow-based Market Coupling (FBMC), the new method started in CWE region in 2015 and still under study to be implemented as well as possible.

The thesis is structured as follow: the first chapter is an overview of electricity markets, defining the role figures at stake and explaining how the day-ahead markets work and the implementation of its algorithm. Then the allocation methods are presented in the second chapter, enucleating its operation and providing all the features needful to face the case study. An overview of renewable penetration is made as well in the second chapter, presenting the effect of the growth of these sources on the market.

In the third chapter is reported the experience of the First Edition of Bidding Zone review, which define expert and model-based approach for the determination of areas, through several criteria assessed by Capacity allocation and congestion management (CACM) regulation and explained as well in this work. Finally, the fourth chapter presents a case study, where it will be used a benchmark network from the IEEE, the Reliability Test System (RTS-73B), formed by 73 buses, 120 branches and three market areas. It will be evaluated how changing nodes disposition and so bidding zones will impact on network and market outcomes, comparing the different capacity methods, real power flows respect to their limits, market prices and efficiency. The same procedure will be implemented considering a high share of renewable generation, solar and wind, set the power generated to its maximum, which will imply different committed generators. What is expected by varying the zonal configuration is to increase committed generators to better distribute the generation and so don't charge the lines and avoid congestion.

Then results will be presented at the end of the chapter with discussion and thoughts, which will confirm or not what said during all this work but will certainly be significant in one way or another.

CHAPTER 1
Electricity Markets: Overview and definitions

1.1. Towards a market integration

Liberalization of energy sector was the starting point to achieve the European electricity market, an unique market as a tool to reach the goals of supply security, affordability and sustainability.[1] The process of liberalization took place between the end of 80s and 90s.

The electricity industry has been organized as vertically integrated (VI) monopolies that were sometimes also state-owned. The idea firstly was to have only one "firm" owning every sector, so no competitiveness to ensure the growth of energy sector, building the grid and give energy to everyone. So then after settling of energy sector the VI became obsolete.

The first step was made in Great Britain, with the Electricity Act in 1989, that established the separation of generation (as competition) and transmission (regulated). Then other countries follow the example of Great Britain, but the beginning of the European electricity market was in 1996 with the directive 1996/92 approved by the European Parliament and the European Council. The principal instruments of the directive to reform the structure of electricity market was:

- abolition of exclusive rights in the electricity production;
- liberalization of retail and the possibility for larger customers to freely choose their supplier;
- guarantee (both for sellers and customers) to access in the market with transparent and non-discriminatory conditions.

The UE directive 2003/54 improves and replaces the previous. First, if the directive 96/92 introduced the concept of ''eligible consumers", consumers who have the legal

capacity to contract volumes of electricity from any supplier, with the new one the process was dramatically accelerated, with all non-household customers deemed eligible from July 1, 2004, and all consumers deemed eligible July 1, 2007.[2]
Second, about accessing in the market, the first directive wasn't clear about the third-party access models; instead with 2003 directive one regime was introduced, the regulated third-party access (rTPA), in such way to have a regulated prices to access to the network. This strengthened the necessity to have a regulator body, who has to approve the tariffs, monitor congestion management, and behave as a dispute settlement authority, acting in a partial way and with no interests: that's the role of Transmission System Operators (TSOs). Thus, to get transparency of the market and avoid discrimination, network activities and supply and generation activities must be separated: the directive 2003/54 requires financial unbundling of companies handling both. So, the other basic body in the market organization, which must be a different entity compared to the TSO, is the Power Exchange (PX) or nominated electricity market operator (NEMO) that manage the market and provide a marketplace where wholesale buyers and sellers can exchange electricity in an organized way, with a set of rules, at public prices. The principal roles of the NEMOs are to match the bids and the offers and find the balanced energy price and quantity, with a market clearing model that will be explain soon.
These were the first steps for the creation of an internal electricity market, but the process is still going on.

1.2. Overview of Electricity Market

Every PXs manage the complexity of a market serving million and million of citizen, providing a 'place' where to exchange electricity. Let's have a look of how energy market operates and how allocate cross-border transmission capacity in the most efficient way.
The European single market indeed is divided in several "sub-markets", each of them with national extension, as Italy, or intercontinental regional extension in which several countries join a unique market (i.e. NordPool that integrate the markets of Norway, Sweden, Finland, Denmark and Estonia).

Then these “sub-markets” can correspond to a single bidding zone (BZ) or can formed by several bidding zones, like the Italian market.

A definition of BZ is given by the ENTSO-E as: *“A bidding zone is the largest geographical area within which Market Participants are able to exchange energy without Capacity Allocation”*. Most bidding zones coincide with national borders; thus, any country is a bidding zone. However, some countries such as Norway and Italy are divided in several BZs, others are coupled in a single bidding zone such as Germany, Austria, and Luxembourg (DE-AT-LU). The different BZs are shown below:

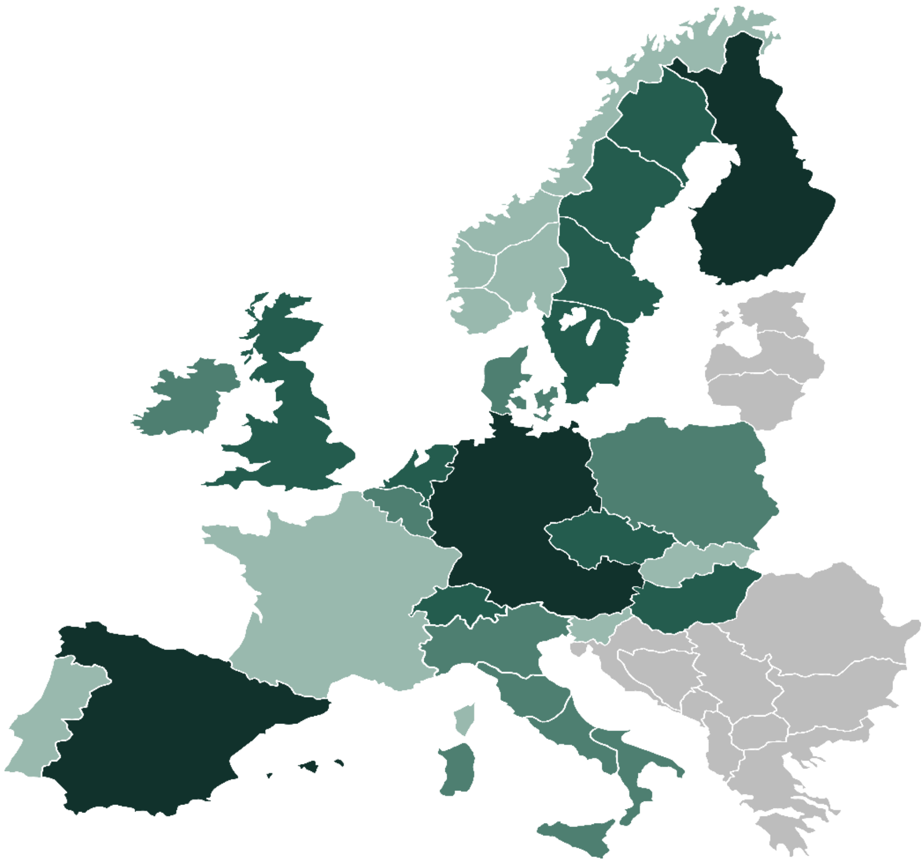


Figure 1. European Bidding Zones.

“Market Participants are able to exchange energy without Capacity Allocation”: within a zone, all transactions are allowed and there are any constraints on transmission capacity, unlike transactions between zones are limited to the available cross-zonal capacity. The links between different BZs are modeled through equivalent connections, characterized by a maximum transmission capacity. This is crucial point as market “output” depends on the possible congestion of the equivalent connections, which

suggests the importance of evaluating new configurations; however, other aspects and evaluation criteria will be explained further ahead.

An overview of market structure will be explained in this section. The Italian market system is used as reference, still the structure is quite similar for every country. Therefore, the day-ahead market will be thorough, being the object of study of this work for BZ reconfiguration.

1.2.1. Network Operator

As the directive of 1999 unbundled the Vertically Integrated Capacity (VIU), the electricity system was divided in four branches: production, transmission, distribution, and retail sale. While production, distribution and retail sale are free and with competition, transmission is a natural monopoly, managed by a unique Transmission System Operator (TSO). The urge to have a monopoly is that the only firm can focus better on management of the network without considering other competitors and economic consequences. The Italian TSO is TERNA, which has the tasks of management, maintenance and development of the high voltage transmission grid, performing the tasks of dispatching, or managing the energy flows on the grid at any time.

Another role of TSO is to release to the Market Operator before the start of Day-ahead Market, all the information about the network and capacity allocation. Below, the distinction in four sectors of the Italian electricity network:

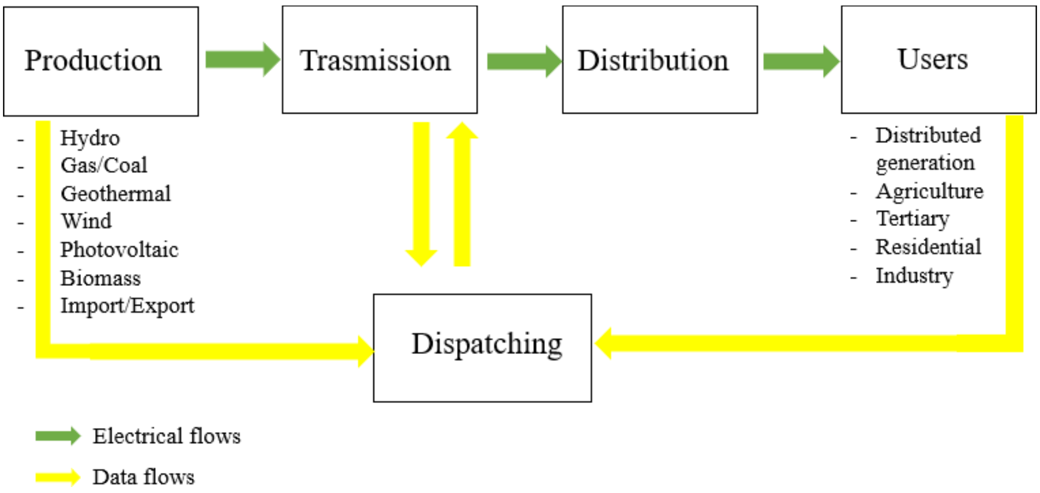


Figure 2. The 4 sectors of the Italian network.

The Italian market, as mentioned before, is divided in different bidding zones, both for geographical reason and heterogeneous nature of power grid. To ensure security of the network and minimum congestion, TERNA has divided the Italian transmission network in seven bidding zones, according to the European commission regulation 2015/2022.

Figure 3 shows the new bidding zones situation in Italy starting from 1° January 2021, where a new BZ is introduced (Calabria) and a region was moved from a zone to another.[3] The new configuration should maximize market efficiency because it will better reflect the criticalities of the network, allowing operators to optimize trading while avoiding network security problems.

Figure 3. Italian BZs.

1.2.2. Market Operator

The introduction of competition in wholesale markets led to the need of an entity managing the market, that's the nominated electricity market operator (NEMO). The mission of the market operator is to organize and manage the transaction in electricity market under criteria of neutrality, transparency, objectivity and competition between producers.

Transparency refers to the extent and way in which information related to the functioning of electricity wholesale markets is exchanged or disclosed between the involved market parties and focuses on transparency for the benefit of market participants. In economics a market is transparent if all market players have information about what products or services are available, at what price and where.

The Italian NEMO is Gestore Mercati Energetici (GME), set up in 2000 by Gestore Servizi Energetici (GSE), which is a joint stock company owned by the Ministery of ecological transition (MiTE). Other activities of GME are the publication of prices on GSE website, implementation of the EU directives and encourage the production of electricity from renewable source.

Electricity market managed by GME can be divided in "forward" and "spot" market.

Forward market is bilateral type (one-to-one), meaning an agreement is made between two parties to buy or sell an asset for the future. In this market in fact electricity is traded for “long time”. Let’s distinguish two types: physical, in which electricity is effectively delivered, and financial, about risk edging tools. Physical forward market is managed by GME and there is a platform in which every producer daily nominates the power plants with which it intends to fulfill the physical contracts closed. That’s important to mention that because the quantity traded from forward market will be add to volumes from IPEX giving the total electricity daily demand.

In spot market electricity is traded for the next day or the same day as well. It’s articulated in day-ahead market (DAM), based on an auctions mechanism, adjustment markets (AM), useful to re-adjust the offers/bids to be compliant with physical constraints, daily product markets, which allows trading of daily products with obligation of energy delivery and ancillary service market, which procures to the TSO the resources for managing, monitoring and control the system.

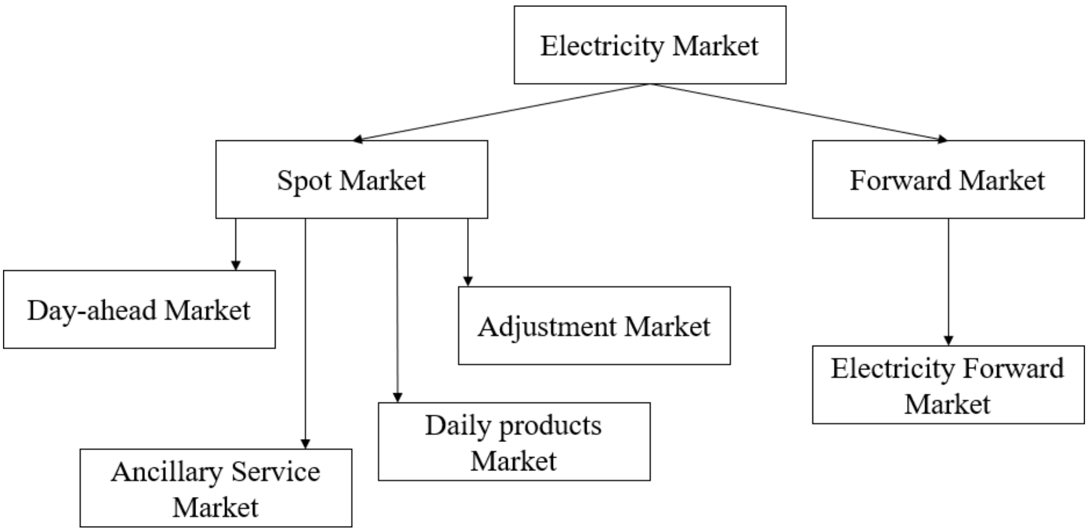


Figure 4. Italian electricity markets.

1.2.3. Market Time Horizon

As already mentioned, different markets operate in different times. Forward contracts can be made 1 year/month before the delivering time, while spot markets occur the day before or even the same day, as adjustment market.

The figure shows qualitatively the market time horizon:

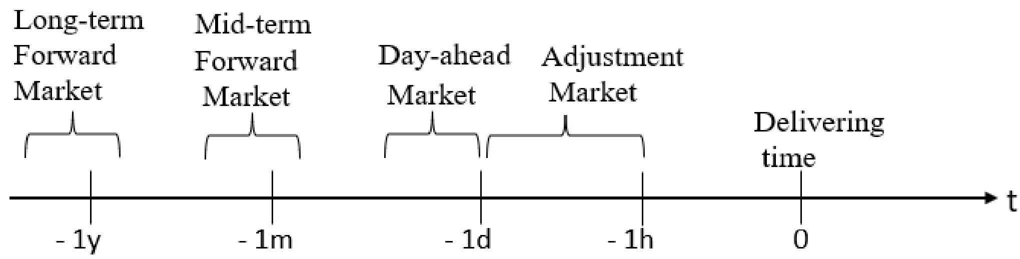


Figure 5. Market time horizon.

1.3. Day-Ahead Market (DAM)

Day-ahead market is the central part of the process, so long as the most part of transaction are made here, trading electricity for the day after. Day that is divided in 24-time step, one for each hour of the day, and for every hour a market clearing is needed. TSO (TERNA) and market operator (GME) have a fundamental role. TSO have to individuate constraints between zone, and communicates to GME, at least one hour before closing of DAM, hourly accepted energy trade between geographic zones and from foreign lines, and hourly demand for each geographic zone. While GME acts like a single buyer (Acquirente Unico) for buyers/sellers and communicate to TSO preliminary programs of injection and withdrawing for every delivery point. Then TSO can manage possible congestion occurs between zones.

The Italian network is represented with a zonal representation in which several nodes are grouped in the same zone, intra-zonal congestion can't occur and then price will be equal in the same zone. Zones are physical geographic areas and virtual areas as well, corresponding to connections with neighboring foreign countries.

The DAM opens at 8.00 AM of the ninth day before the delivery time and close at 12.00 AM of the day before the delivery. In this period, market participants submit their offers/bids in terms of quantity and maximum/minimum price they are willing to buy/sell. It can be distinguished different type of offers/bids:

- Simple: constituted by a couple of values (quantity, price);
- Multiple: constituted by series of simple offers (maximum 4 couples) introduced by the same operator;

- Balanced: sale offers with void price and purchase offers without price indication.

The mechanism of the market is based on an auction in which all offers/bids are ordered to obtain one upward and one downward curve. The reference market for the DAM is perfect competition and follows a non-discriminatory rule.

1.3.1. Non-discriminatory rule

It's related to the concept of uniforming pricing, meaning all sellers and buyers receive/pay the same price which is the price associated with the equilibrium. This is true in the Day ahead market if intra-zonal congestions don't occur.
Characteristics of non-discriminatory rule are:

- Incentive to producers and consumers to offer and bid their own marginal costs and benefits;
- Contribution to the system transparency;
- Incentives for entering of new competitors in the market;
- Possibility to recover fixed costs.

1.3.2. DAM Market Clearing

The offers presented by sellers reflect their marginal price, while purchasing offers reflects marginal utility of customers. At the end of DAM, all the offers are ordered but only a part will be accepted, based on economic merit and in the respect of transit limit.
Sale offers are ordered starting with the cheapest price offered, to create an aggregate offer curve with an upward sloping. Purchasing offers on the contrary are set from the expensive one, obtaining an aggregate demand curve with downward sloping.
The base mechanism is the system marginal price. The intersection between the offer curve and demand curve gives the system price and quantity and determines the accepted offers/bids, as the figure shows:

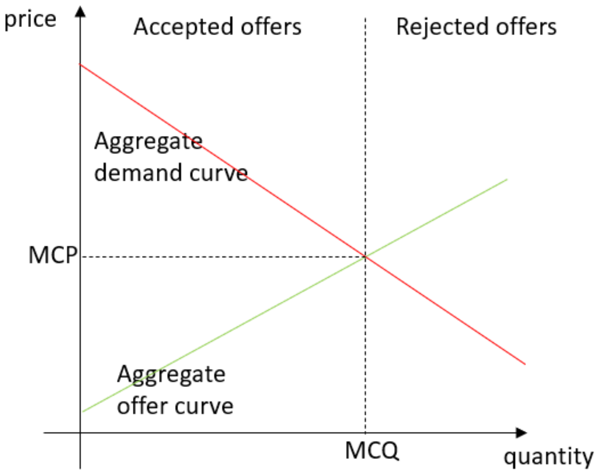


Figure 6. Demand and offer curves give the Market Clearing.

Where: MCP: market clearing price

MCQ: market clearing quantity

It's important to say that MCP represent the price of the whole system only if all transit constraints are respected. Differently, prices will be different zone by zone and will reflects zonal prices. So, if congestion occurs considering an equivalent connection between two zone, one zone will export energy and the other will import it. The maximum flow is viewed as a demand offer with no price indication, so the higher in merit order, in export zone; the same flow is considered as a sale offer with zero price in import zone. Then the market clearing process is made for every zone obtaining the zonal price.

Nevertheless, these differences in prices affect only the supply side, for which companies receive the zonal price; while for demand price it's applied a unique value of price, known as Prezzo Unico Nazionale (PUN), calculated as weighted average of geographic zonal prices:

$$PUN = \frac{\sum P_i \cdot u_i}{\sum P_i} \tag{1}$$

With: u_i: zonal price

P_i: bought quantity

i: referring zone

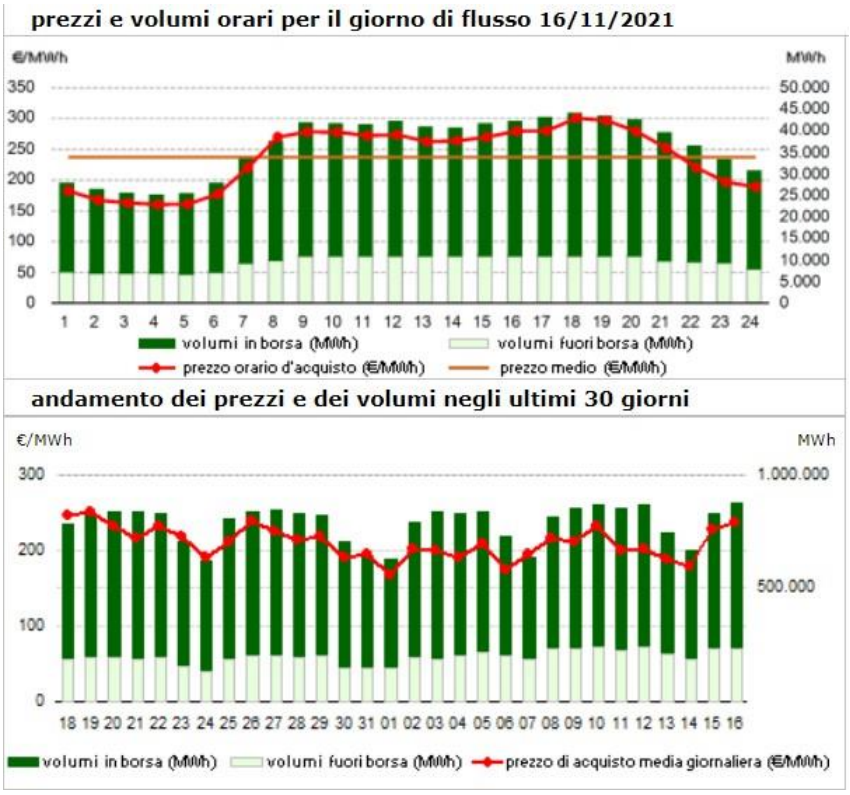


Figure 7. Prices and volumes of DAM drawn up by GME.

1.3.3. DAM Market Clearing Algorithm

The algorithm to clear the market has been thought to be robust, based on a merit economic order and transparent as possible. It allows to obtain the system price, total quantity to be traded, and quantity of each generator whose bids has been accepted. Furthermore, the algorithm gives information about possible congestion and consequent change of prices. The power flow limits are reported, reflecting the congestion between two zones, while the price of the zone is affected. In day ahead markets the offers are presented as couples of values, price and quantity, and the aggregate bids and offer curve is then a step-wise functions. Then, the clearing problem is formulated as linear programming (LP) optimization problem (OP). An OP maximizes or minimizes a goal choosing the values of a set of (decision) variables, subject to the constraints expressing limits on their possible values. For each constraint is associated a dual variable which reflects the rate of change in primal optimal value per unit increase from the given righthand-side value of the corresponding constraint. That means dual variables associated with flow constraints reflect change of prices of the zones.

The mechanism explained in the previous part correspond to the first phase of market clearing, meaning individuate accepted offers and give the total price if no congestion occurs. Secondly, the transit limit must be controlled, thanks to the information given by the TSO about constrains between zones according to the zonal representation of the network. Zones are physical geographic areas as already mentioned, and virtual area as well, corresponding to connections with neighboring foreign countries. So, for each zone it will be a power given by the sum of all accepted quantity (considering as positive the power injected and negative the power withdrawn), called net exchange position (NEX_z):

$$NEX_z = \sum_{i \in Z} P_{Gi} - P_{Di} \tag{2}$$

Where: P_{Gi}: quantity offered by sellers

P_{Di}: quantity offered by costumers

The goal to maximize is the social surplus or social welfare S^s. The optimization problem could be viewed also as a minimization of total cost, the results will be the same, but so long as the offers are presented in the form of (quantity P, price ρ), consider the social surplus is likely to be easier. Social surplus is the difference between the total marginal utility and the total marginal cost, which reflects respectively the aggregated demand curve and the aggregate offer curve. So, considering figure 8, social surplus is the area enclosed between the two curves:

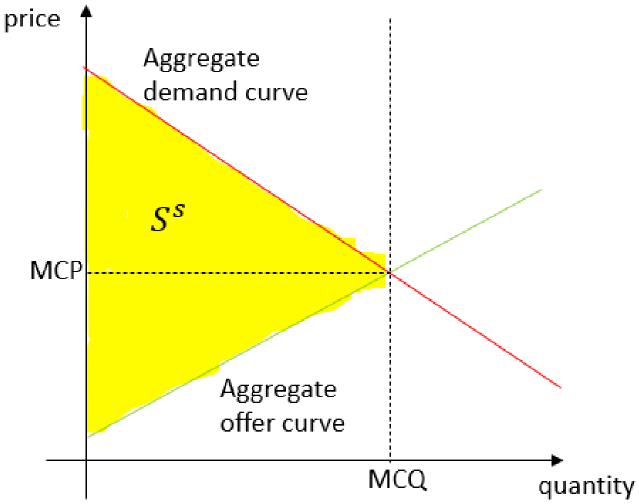


Figure 8. Social Surplus.

In electricity markets the offer and bids form aggregate curves that are step-wise functions, but the definition of S^s is the same and it's easier to write as:

$$S^s = \sum_{i=1}^{D} \rho_{Di} \cdot P_{Di} - \sum_{j=1}^{G} \rho_{Gj} \cdot P_{Gj} \tag{3}$$

That correspond to the objective function to maximize in the OP. Now we have to define the constraints of the problem. The first equality constraint refers to the global balance of the system, meaning the sum of the power injected must be equal to the sum of power withdrawn:

$$\sum_{j=1}^{G} P_{Gj} = \sum_{i=1}^{D} P_{Di} \tag{4}$$

written also as:

$$\sum_{j=1}^{G} P_{Gj} - \sum_{i=1}^{D} P_{Di} = 0 \tag{5}$$

Introducing the net exchange position of a zone, the equality constraint (equation 5) can also be written as:

$$\sum_{zgZ} NEX_z = 0$$

(6)

The inequality constraints reflect the limits of maximum and minimum power, with respect to the offers made, but above all they represent the power flow limits on the interconnections. They are formulated as:

$$P_{Gmin} < P_{Gj} < P_{Gmax} \qquad \forall j \in G$$

$$P_{Dmin} < P_{Di} < P_{Dmax} \qquad \forall i \in D$$

(7)

The inequality constraint is based on the ATC method, where TSO calculates the “market available capacity ex-ante" for each border separately. The available transfer capability (ATC) is the maximum directional exchange program between two zones compatible with operational security standards assuming that the future network conditions, generation, and load patterns were perfectly known in advance. That’s meaning the ATC values no longer depend on the real physical flows. Although the market clearing algorithm is rather simple with ATC market coupling, the calculation of the ATC values itself is rather opaque and non-transparent for regulators, considering forecasting to obtain them and all the variables that might change.
As $NEX_{z,max}$ is the maximum capacity between two zones calculated ex-ante by TSO, constraint for the OP is:

$$NEX_z < NEX_{z,max} \qquad \forall z \in Z$$

(8)

Then, the whole optimization problem is:

$$\max S^s = \sum_{i=1}^{D} \rho_{Di} \cdot P_{Di} - \sum_{j=1}^{G} \rho_{Gj} \cdot P_{Gj}$$

s.t.

$$\sum_{j=1}^{G} P_{Gj} - \sum_{i=1}^{D} P_{Di} = 0$$

$$P_{Gmin} < P_{Gj} < P_{Gmax} \qquad \forall j \in G$$

$$P_{Dmin} < P_{Di} < P_{Dmax} \qquad \forall i \in D$$

$$NEX_z < NEX_{z,max} \qquad \forall z \in Z$$

Then, if a constraint of maximum nex exchange position is blinded the market will be splitted. Split the market will provide different prices per zone, i. g. zonal price. First it's defined the direction of the power flow and it's fixed to its maximum value, so a zone is the exporting zone and the other the importing one. The market is cleared separately in the zones considering only the offers of that zone plus the binding value of the flow, as demand or generation bid depending on what zone is. In the exporting zone, binding value id considered as a demand bid with no price indication, while in the importing zone as a generation offer at zero price.
We can consider an example of a connection between two zone, A and B, where the power flow limit is binded so market splitting will be operated:

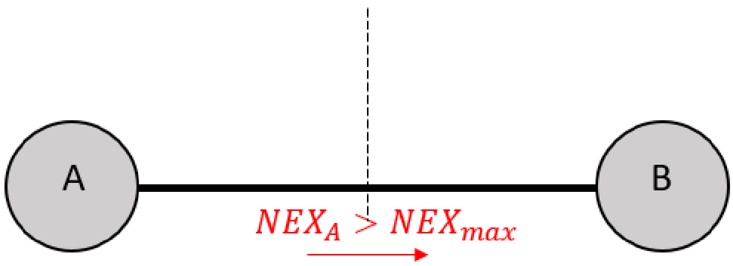


Figure 9. Example of two zones-one bus.

The aggregate curves are linearized and qualitatively it is shown the different market clearing compared to the situation when no congestion occurs and there will be a unique price, the system price. Zone A is exporting zone and B is the importing zone, so the respective curves are translated of the maximum value of flow. Consequences of market splitting is a higher price in the importing zone (figure 11) respect to the price of exporting zone (figure 10).

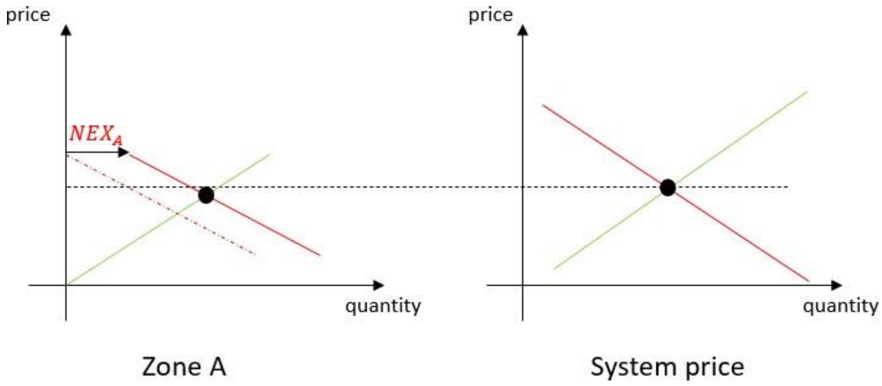


Figure 10. Consequences of market splitting: exporting zone.

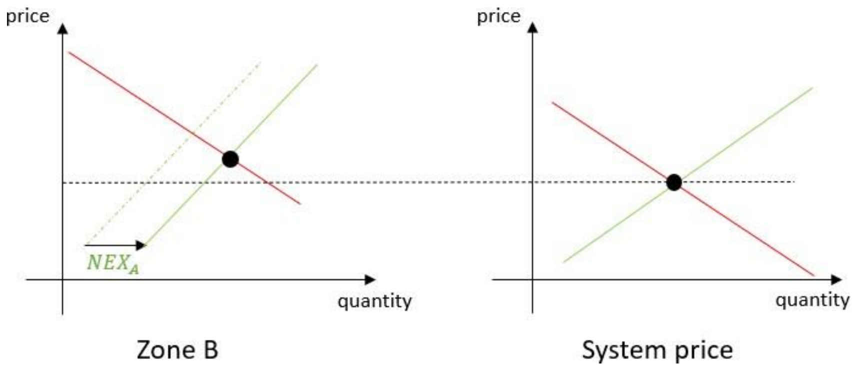


Figure 11. Consequences of market splitting: importing zone.

It has been said that the market clearing operate to match demand and offer to have the request power as equal to the power generated, in fact that is also the equality constraint of the optimization problem. However, in the real market, considering the italian DAM, it doesn't always happen: market clearing price doesn't correspond to the meet of the aggregate curve. It seems normal when congestion occurs and market is splitted, but there is this misalignment also when congestion doesn't happen and the price is the same for all the zone.

To explain that, let's consider a market clearing taken by the GME website, related to a certain day and hour in which the price is the same, so quantity bought and sold should be equal.

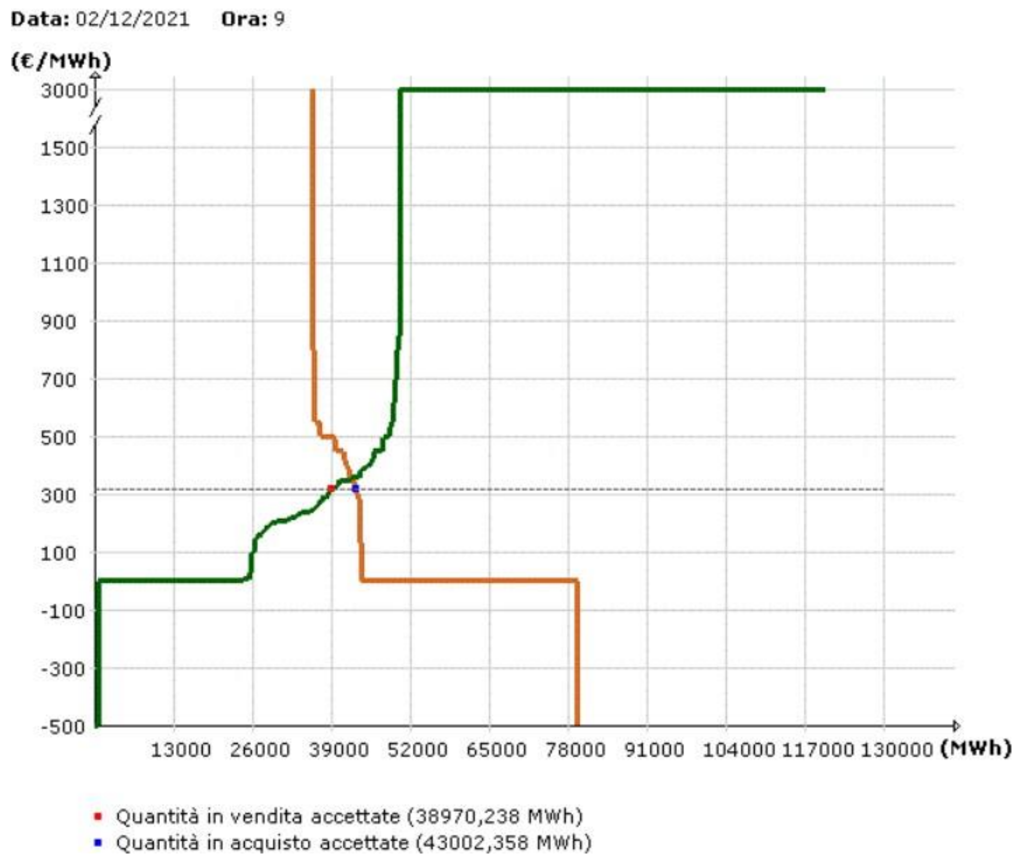


Figure 12. DAM market clearing on GME website.

What is cleary shown is the clearing doesn't correspond to the meet of aggregate curves and quantity is not the same. How is it possible? Why is there this difference, even if no market splitting was made?

The answer is yes, that is possible and actually it happens always. The italian market, in fact, take into account not only the offers of the seven geographical bidding zone, but also the virtual interconnection with neighboring countries. Italy has began, beside the PCR initiative (explained in the next session), a market coupling with France, Greece, Slovenia, Austria, with the principle of move energy to the country that need and try to reduce prices. So the difference between bought and sold quantity is due to the quantity that moves from these country, and their offers will have always the higher merit-order to entry in the accepted bids for sure. Let's prove what said, calling the difference of bought and sold quantity ΔP:

$$\Delta P = 43002.358 - 38970.238 = 4032.12\ MWh \tag{9}$$

The sum of the quantity exported from France, Greece, Slovenia and Austria will be equal to ΔP:

Prezzi Zona: **XFRA**

prezzo di vendita (€/MWh)	acquisti (MWh)	vendite (MWh)
320,00	00,00	2.971,00

Prezzi Zona: **XGRE**

prezzo di vendita (€/MWh)	acquisti (MWh)	vendite (MWh)
320,00	00,00	306,60

Prezzi Zona: **XAUS**

prezzo di vendita (€/MWh)	acquisti (MWh)	vendite (MWh)
320,00	00,00	144,83

Prezzi Zona: **bsp**

prezzo di vendita (€/MWh)	acquisti (MWh)	vendite (MWh)
320,00	00,00	609,70

Figure 13. Exported quantity from neighboring countries.

Firstly notice that the price is the same for all the zone, while no congestion occurs. Italy imports respectively:

$P_{XFRA} = 2971.00\ MWh$

$P_{XGRE} = 306.60\ MWh$

$P_{XGRE} = 144.83\ MWh$

$P_{bsp} = 609.70\ MWh$

And their sum will be equal to ΔP. That explain the not perfectly right intersection of the curves.

1.4. Price Coupling of Region (PCR)

One of the purposes of the IEM is to improve the cross-border transmission capacity in the wholesale markets among member states. The European regulation (European Commission (2009)) states that *"network congestion problems shall be addressed with non-discriminatory market-based solutions"* and implicit auction has been selected by the Agency for the Cooperation of Energy Regulators (ACER) as the target mechanism to be implemented in Europe, due to its greater efficiency. In an implicit auction, the allocation of both capacity and energy occurs at the same time, and the market clearing sets prices and quantities in such a way as to make the optimal use of the available transmission capacity.

Now we are considering a multi-national electricity market (i.e. IEM), so each country is a market zone with no intra-zonal congestion. There are two possible approaches to implement implicit auctions: market splitting and market coupling.

With market splitting, a single central PX clears the market, setting quantities, zonal prices (that differ in case of congestion) and cross-border flows, by applying uniform matching rules. This solution clearly requires a high level of integration among the involved national markets.

With market coupling, the different national PXs coordinate themselves through a coupling algorithm that is run by a central body, but they retain the pricing authority and may have different matching rules. The method of market clearing used and preferred for the implementation of the IEM is the price coupling. In price coupling the calculation of cross-border volumes and prices are coordinated in a single mechanism, this guarantees the robustness of the results and avoids price and flow discrepancies.

There are advantages of a price coupling solution over a conventional explicit auction for transmission capacity with a subsequent energy trading:

- it simplifies the access to the market, requiring bidding only on the PX for energy;
- it reduces the risks for market players, since they don't need to buy transmission capacity before knowing its real value, that will be set on the energy market;
- transmission capacity is fully used, even when the sign of the zonal price difference is uncertain in advance; moreover, a full netting of opposite transactions is accomplished, and no capacity withholding can be carried out;
- the uncertainty about the final use of transmission capacity is therefore reduced: in this way, the involved TSOs could reduce security margins and make available a larger amount of transmission capacity, and even more in case a "flow-based" market coupling is implemented, where a detailed grid modelling is used to calculate more precisely power flows and better account for network security constraints;
- the allocation of transmission capacity is non-transaction based: it is fairly allocated to the transactions that value it most;
- in case of congestion, it provides a correct price signal: the value of transmission capacity is the difference of the prices of the connected zones;

- when no congestion occurs, zonal prices fully converge, as required by a single integrated Internal Electricity Market.

In this context two scenarios (with and without Market Coupling) are compared to appreciate the impact on the day-ahead Italian electricity market of a possible price coupling with northern neighboring countries. Results show that the use of market coupling could allow for a more optimized used of the available transmission capacity and avoiding adverse flows. This would benefit Italian producers, increasing the amount of their generation, as well as the prices at which such generation can be sold.[4]
Price coupling has been chosen as the standard method for the implementation of a single internal electricity market, so called pan-European day-ahead electricity market. According to this, starting from 2012 seven PXs launched the Price Coupling of Region (PCR) initiative, arriving in 2016 which included the interconnections in 30 of 42 EU borders (fig. 14).[1] The PCR is based on the development of a single market clearing algorithm, named the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA). The use of a common algorithm allows a fair and transparent determination of prices and optimizes the overall welfare. It's clear that high degree harmonization among local markets is needed and it means that some or all parties had to modify some of their characteristics, creating conflicts between parties. However the benefits are multiple: efficient day-ahead capacity allocation, higher liquidity, wider relevant market, reduced information asymmetry across regions and the already mentioned transparency of prices and optimization of welfare.[1]

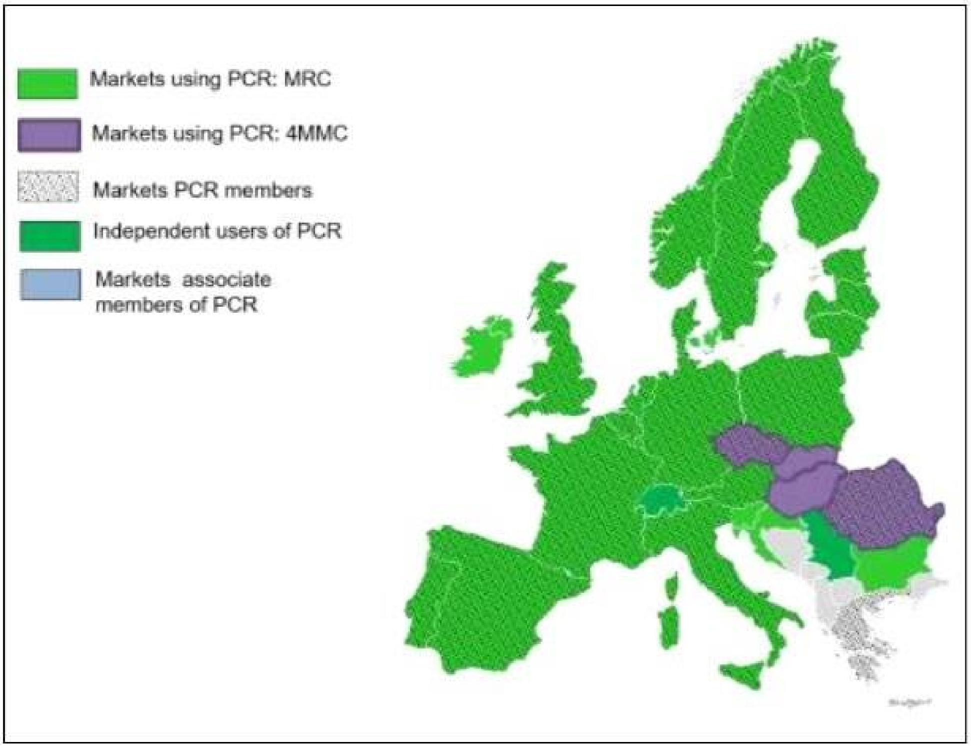


Figure 14. PCR initiative.

CHAPTER 2

New Challenges on Bidding Zone Configuration

2.1. Capacity calculation and implication on BZ reconfiguration

Considering the day ahead market algorithm explained in the previous section, maximum net exchange position has been considered as inequality constraints on flow lines, following the ATC method. This approach, used as well in the Italian market, is the most applied in electricity markets among Europe.

Actually, other transmission capacity allocations method exists, based on a flow-based approach. In this context, a fundamental step was the implementation of the Flow Based Market Coupling (FBMC), started in 2015 in the CWE region, replacing the Available Transfer Capability (ATC) approach. Anyway, further market areas are still connected by the ATC method, and both are part of the EUPHEMIA algorithm. Consider the FBMC means to take account of real physical power flows, that maximize the transmission capacity available to the market. The implementation of this method influences the process of bidding zone configuration and vice versa.

2.2. The 'Available Transfer Capability' (ATC) Allocation Method

Available Transfer Capability or ATC is the most used capacity allocation method by the TSOs in Europe. It can be defined as the amount of available capability which exists in the transmission paths for further transactions. In other words, it is the remaining capability of the transmission network for further transactions.

It's based on the experiences of TSO considering forecasting on network conditions, generation, and load patterns, that meaning values of ATC can't be so accurate and they

are strongly dependent on the conditions of network. In the following, a way implemented by TSO and used as well in this work, will be explained in details.
The process to obtain the ATC constraints in the case study, between the three zones starts with the formation of the zonal representation and the identification of the virtual interconnectors among the zones. In the study case, since between Area 2 and 3 and Area 1 and 3 there are only one branch, the virtual interconnectors correspond to the actual branches; while connection between Area 1 and 2 is given by three branches. Then, to obtain the single connector for the ATC model these branches are considered as in parallel.
Firstly, the network must be represented, and in this sense the reactances gives all the information needed. Knowing them and the position of the nodes, bus admittance matrix B and the H matrix can be built, that's a fundamental way to achieve then the PTDF. These two matrices fully represent the network and can be determined regardless the power flow and market transaction. Now the network is set, the following step is to run a dc power flow, thanks to MATPOWER, to determine the amount of power for each zone, i.e. NEX, as the difference of the total power injection and withdrawing.
There are different ways to calculate ATC domain; in this case study a PTDF algorithm has been implemented. The algorithm is described below:

1. Identify the bus data and line data of the system
2. Calculate bus admittance matrix and eliminate reference bus number row and column to get bus reactance matrix.
3. Solve power flow
4. Determine PTDF matrix
5. Calculate the transfer limit for each line
6. Estimate ATC

The first three steps have been already mentioned. Before explaining step 4, a clarification is helpful: the PTDF matrix is not univocal, and his values depends on the chosen slack node. While in an optimization problem the choose of the slack node doesn't matter for the results, in this ATC determination have the right slack node is crucial to obtain the correct ATC. That's why in here, five PTDF matrices are considered, one for each branch, changing the slack node, to obtain the values of ATC for the zones. Therefore, the procedure to determine PTDF matrix consist in delete a raw and a column from B, and a column from H, corresponding to the raw and column of the slack node. Then PTDF has been calculated as:

$$PTDF = H' \cdot B'^{-1} \tag{10}$$

The transfer limit (step 5) for each line is estimated using:

$$TL_l = \begin{cases} \dfrac{P_l^{max} - P_l}{PTDF_l} & if\ PTDF_l > 0 \\ \dfrac{-P_l^{max} - P_l}{PTDF_l} & if\ PTDF_l > 0 \end{cases} \tag{11}$$

Where:

P_l^{max} is the highest possible transmitting power that is the thermal constraint;

P_l is the real power transmitted through the line.

The values of ATC are given by the lowest value (not zero) of the transfer limit TL_l. That's meaning the ATC on a certain branch (interconnector among zones in our case) depends on the limitation of the flow on another branch, and that's reported in the results table.

When there is more than one branch between two zones, the determination of ATC has been different, adding to the lowest value of TL_l the power transmitted through the other lines between these zones. Then the unique ATC has been chosen as the lowest value between these three.

$$ATC_l = \min|TL_l| + \sum_{1}^{L_{zz^F}} P_i \qquad l = 1, .. L_{zz^F}; i = 1, .. L_{zz^F}\ i \neq l$$

$$ATC_{zz'} = \min ATC_l \tag{12}$$

With L_{zz^F}: lines between zone z and z'.

2.3. Overview of Flow-based Market Coupling

The Flow Based Market Coupling is the new capacity allocation method started in 2015 in CWE region. The advantage of this method is that in one run it gives both constraints on interconnectors among zones and simultaneously consider these constraints to make the market clearing and have the market outcomes. It is more accurate than ATC, with a wider domain of transmission capacity allowed, but still harder to implement.

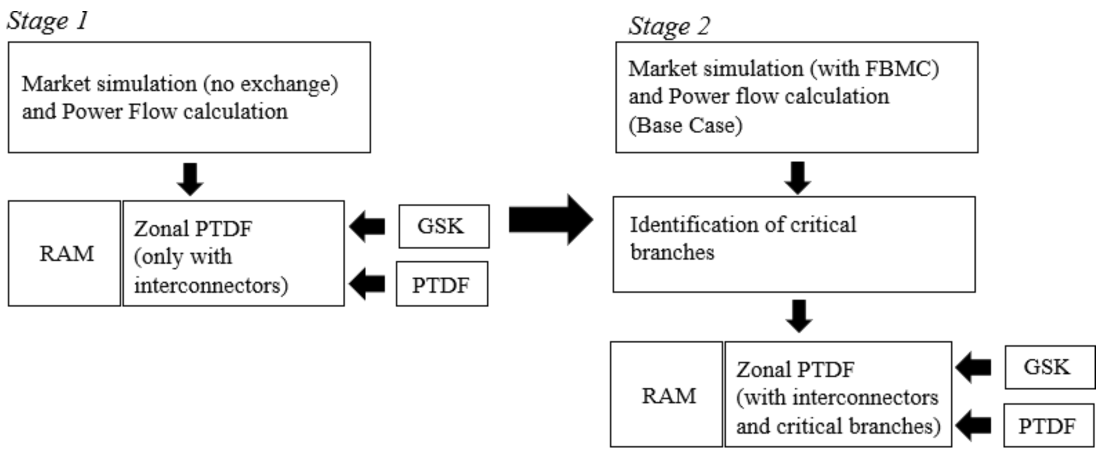


Figure 15. FBMC parameters calculation.

The FBMC is based on a zonal representation of the network, but some physical transmission intra-zonal constraints are considered in the market clearing. Still the capacity allocation in FBMC happens partly ex ante the market clearing, and partly simultaneously with the market clearing.

The first thing to understand is that commercial flows don't correspond to physical flow. The FBMC then map every commercial transaction to a physical flow and subsequently impose the physical constraint, that's a flow constraint. Only some lines, called as critical branches, are considered in a reduced network model, while in the ATC virtual interconnector between zones are taken into account. This is a main different of the two approaches. The figure illustrates the differences of the network considered in ATC and FBMC, where the black lines correspond to critical branches in FBMC and to virtual connections between zones.

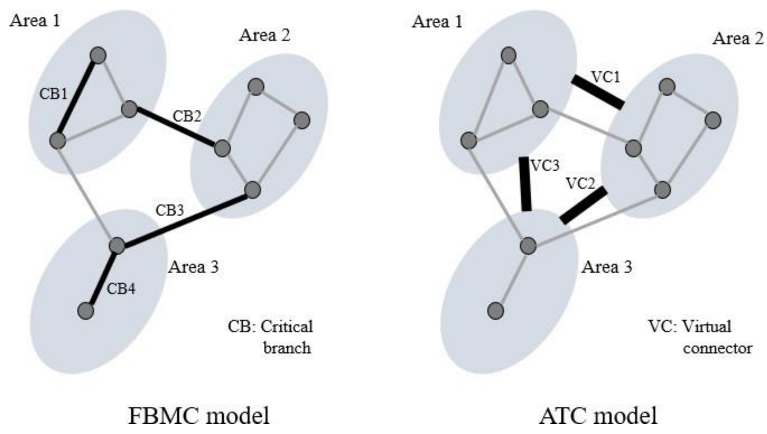


Figure 16. FBMC and ATC model.

Looking at figure 15, two parameters are introduced, the zonal Power Transfer Distribution Factors ($PTDF_z$) and the Remaining Available Margin (RAM). They are calculated both ex-antes, but there is a circular problem. The FBMC parameters are needed to clear the day- ahead market, but the day-ahead market outcome is needed to determine the FBMC parameters. This circular problem is settled by determining the $PTDF_z$ and the RAM based on a forecast of the state of the electricity system at the moment of delivery. These FBMC parameters are then communicated to the day-ahead market clearing algorithm.

The FBMC follows a zonal approach, that means all the nodes within a zone are considered as one node. So, the representation of the zones is given by the $PTDF_z$.

$PTDF_z$ is a matrix that describes the relation between the flow through a line and the NEX_z. It has dimension L x Z, and it maps the influence of a change in the NEX_z of a zone z to a flow in line l.

To determinate it, the first forecasted parameter is used: the generation shift keys (GSK), a matrix with dimension N x Z. So, from the nodal PTDF, the zonal PTDF is founded:

$$PTDF_z\,(\mathrm{l,z}) = \sum_{n=1}^{N} PTDF_n(\mathrm{l,n}) \cdot \mathrm{GSK(n,z)} \quad \forall l \in L, \forall z \in Z \tag{13}$$

Or in matrix notation:

$$\begin{bmatrix} PTDF_z(1,1) & \cdots & PTDF_z(1,Z) \\ \vdots & \ddots & \vdots \\ PTDF_z(L,1) & \cdots & PTDF_z(L,Z) \end{bmatrix} = \begin{bmatrix} PTDF_n(1,1) & \cdots & PTDF_n(1,N) \\ \vdots & \ddots & \vdots \\ PTDF_n(L,1) & \cdots & PTDF_n(L,N) \end{bmatrix} \times \begin{bmatrix} \mathrm{GSK}(1,1) & \cdots & \mathrm{GSK}(1,\mathrm{Z}) \\ \vdots & \ddots & \vdots \\ \mathrm{GSK}(\mathrm{N},1) & \cdots & \mathrm{GSK}(\mathrm{N},\mathrm{Z}) \end{bmatrix}$$

The determination of GSKs is a key element on the implementation of FBMC. Generation shift keys defines how a change in net position is mapped to the generating units in a bidding area. It contains the relation between the change in net position of a zone and the change in output of every generating unit within the same market zone. Mathematically it can be written as:

$$GSK(n,z) = \frac{dP_n}{dNEX_z} \qquad \forall n \in N, \forall z \in Z \tag{14}$$

To clearly understand, for instance, a GSK of 0.5 for node n in zone z indicates that the generation at node n increases with 0.5 MW if the zonal balance of zone z increases with 1 MW.

Determination of GSK is different in every zone, according to the TSOs methods. The impact of different strategies of GSK on FBMC method and generator dispatch are evaluated.

Six different GSK strategies are analyzed and their impact on the outcome of FBMC and the resulting unit commitment in the CEE region. The results show that the differences between the applied GSK in the yearly scope remain marginal on a market zone level, compared to the difference between the ATC approach and the FBMC. FBMC allows for larger cross-border trading capacities, which lead to different unit commitment in the market zones. For single power plants however, the difference can be much more severe than on an aggregated level. [5]

The second FBMC parameter is the Remaining Available Margin. The RAM is the line capacity that can be used in the DAM. The RAM is then calculated as the maximum allowable power flow reduced by three factors:

- the reference flow caused by commercial transactions outside the day-ahead power exchange (i.e., bilateral trades, forward markets, intra-day markets, and real-time balancing);
- the Final Adjustment Value (FAV). The FAV allows TSOs to take account of knowledge and experience that cannot be introduced in the formal FBMC

method, such as an additional margin due to complex remedial actions or active topology control. The FAV can be positive or negative;

- the Flow Reliability Margin. The FRM is a safety margin that needs to compensate for approximations and simplifications made in the FBMC methodology such as the assumptions inherent to a zonal PTDFs, the use of a linear grid model with a simplified topology.

Therefore, RAM is written as:

$$RAM = F_{max} - F_{ref}' - FAV - FRM \tag{15}$$

The procedure to define these parameters consist in two parts. In the first stage, a market simulation without any electricity exchange ("ATC = 0" calculation) is carried out (called base case) and thus balanced net positions are established in all zones. RAM and $PTDF_z$ values are determined but so long as no internal critical branches are known in the first stage, the first RAM and $PTDF_z$ only contain interconnectors.

Then, these two parameters from the first stage are used to run a market simulation taking into account the FBMC as market coupling mechanism in stage two. The resulting load and generation time series and the physical flows resulting from a power flow calculation serve as a base case for the final determination of the FBMC parameters and the critical branches.

Determination of critical branches is crucial, because only critical elements are considered for the FMBC. To find critical elements, the task is to identify which grid elements are affected by trade between zones. If an element is substantially affected, it is considered critical.

Mathematically the zonal PTDF values of one zone are subtracted from the zonal PTDF values of another zone and it’s done for all zone-to-zone combinations:

$$|PTDF_{l,z} - PTDF_{l,z^F}| \geq \alpha \qquad \forall z \in Z, \forall z' \in Z \setminus \{z\} \quad \forall l \in L \tag{16}$$

The decision of what threshold α is considered is a choice made by TSOs. This parameter determines the sensitivity of the zone-to-zone criterion and influence the determination of critical lines. With lower values, more lines are included, while if it's chosen high enough, only cross-border lines remain as critical network elements.

Therefore, the zonal PTDF matrix is reduced to only contain critical lines and represents the "reduced network" which is considered as inequality constraint in flow-based market coupling.[6]

The already explained procedure has been used to individuate the critical branches and implement the constraints on them, but some clarification on the method are needed.

In this work it has been choosing a GSK strategy used in [5], and they are determined pro rata to the share of each node in the ATC based result of the base case:

$$GSK_{n,z} = \frac{P_{Gen,n}}{P_{Gen,z}} \qquad \forall n \in N, \forall z \in Z \tag{17}$$

With:

N: number of buses, 73 in our case;

Z: number of zones, 3 in our case.

Therefore, the zonal PTDF is obtained as equation (13) and from equation (16) critical branches are founded. In this work it has been chosen different values of threshold α, in the base case a low value has been necessary to appreciate the presence of critical branches in the problem, while for other cases a higher value has been enough to individuate some critical branches (B_c). The number of B_c will be used then in the optimization problem, as number of inequality constraints to consider, and it will be explained in the next paragraph.

In this context it's important to have some clarification. These branches won't for sure exceed the flow constraints, but they are the more likely to. Besides, to these B_c it should be added the branches between the areas, considered as inequality constraint, since as said before, the FMBC is based upon a zonal approach of the network and that imply a particular attention to the flow among zones. The second FBMC parameter, the Remaining Available Margin, is determined as in equation (15):

$$RAM = F_{max} - F_{ref}' - FAV - FRM$$

Where:

– F_{max} is given directly by the data input in the branch information (last column of Table A.1 in Appendix A);

– FAV and FRM have been chosen arbitrarily as 15% and 20% of F_{max} respectively;

– F_{ref}' has been determined following the approach of [5] as:

$$F'_{ref} = F_{ref} - PTDF_z \cdot NEX \tag{18}$$

and F_{ref} is the line loading in the base case determined running a DC power flow.

RAM values correspond to the flow limit on real branches, but it's needed a cross-border limit between zones, to compare to ATC approach. Then a procedure like the one used for ATC is applied. Selecting two zones with more than one branch connecting, the cross-border limits is obtained adding to the RAM of the line, the power flow on the other branches between these two zones. So, for each branch, it will be a value and finally the higher has been selected as flow limit.

$$RAM'_l = RAM_l + \sum_{1}^{L_{zz^F}} P_i \qquad l = 1,..L_{zz^F}; i = 1,..L_{zz^F}\ i \neq l$$

$$RAM_{zz'} = \max_{RAM'_l}$$

Finally, some advantages of using the flow-based approach instead than ATC model:

- More price convergence between zones as the trade potential between zones increases;
- A more efficient allocation of the day-ahead interconnection capacity with respect to the economic value of commercial transactions;
- A better cooperation between TSOs since FB forces TSOs and power exchanges to work together;
- More transparency regarding critical transmission lines which could lead to better decisions about investments in new infrastructure;
- A better understanding of network behavior, which contributes to the safe operation of the interconnected network.

[7], [8], [9], [10]

2.4. Implication on BZ reconfiguration

Flow-based market coupling is a concept designed for close-to-real-time operation. Information on the electricity system which is available with relatively short lead times of less than two days is translated into market properties and constraints. This leads to an efficient use of the grid infrastructure since the market obtains the most recent and precise information on where and to which extent the grid can be used and operates within these boundaries.

In a future simulation environment, as in the First Review of BZ, such close-to-real-time information is not available. Then consider the flow-based approach is a very difficult challenge, so long as the major features should be forecasted, leading to uncertainty of results. First, the base case is determined based on a representation of the actual grid situation two days before real time. This information on the actual grid situation is not available when modelling a future market environment, especially if the future scenarios under assessment are characterized by significant variations in demand and generation patterns as well as in the grid structure. Determination of critical branches, PTDF/GSKs and RAM depends too much on information in real time as well. It has been necessary to design and implement assumptions and simplifications replacing the operational information, but which are particularly sensitive, since small changes to the input data and modelling assumptions can have a significant impact on the results obtained in a flow-based market coupling simulation. That suggests not using the flow-based market coupling results as a quantitative element in the BZ Review but to dedicate further work on enhancing flow-based simulations in a future environment.

Another aspect to consider is the incompatibility of FBMC with clustering methods and OP described above. In fact, they are based on a nodal representation of the network, calculating LMPs for each node, then merging together to obtain new zones. The constraints on each line are obtained from the PTDF nodal matrix (considering the line as link between two nodes). The FBMC approach is different. First, the network is viewed as a zonal representation and the determination of further parameters is based on this crucial aspect. Some lines within a zone are taken into account as well, as critical branches, but their determination comes from the zonal PTDF matrix. Moreover, the entire process of FBMC begins considering a base case. The incompatibility is that the base case is a zonal representation, while what we want, is a new configuration of the zone, then the necessity is to start the process with a nodal representation.

In conclusion, to combine FBMC with a model-based approach is quite difficult and, as said before, requests further studies.

On the contrary, integrate the FBMC with an expert-based approach is possible and easier, using a new configuration proposed by TSOs. It can be evaluated how the FBMC approach is influenced by the number of zones or compare it with the ATC method. FBMC leads to significant improvements and higher efficiency. The result is an increase of social welfare, respect to ATC, and increasing the number of zones as well; in fact, FBMC domain is wider than more transactions are allowed. Furthermore, redispatch costs are always lower than in an ATC method and they reduce while number of zones is higher.

2.5. RES penetration and implication on BZ reconfiguration

2.5.1. European Statements

One of the targets of EU is the reduction of greenhouse gas (GHG) emission, together with the increase of the share of renewable energy source (RES) and energy efficiency. In these terms, with the Directive 2009/28/EC, the EU has identified the strategic plans to combat climate change by proposing short and medium-term measures to be realized by 2020: the 20/20/20 targets, related to the 1990 situation. That was the situation in 2012:

- Greenhouse gas emissions in 2012 decreased by 18% relative to emissions in 1990;
- The share of renewable energy has increased to 13% in 2012 as a proportion of final energy consumed;
- The EU had installed about 44% of the world's renewable electricity (excluding hydro) at the end of 2012;
- The carbon intensity of the EU economy fell by 28% between 1995 and 2010.

These targets have been achieved. The European Environment Agency (EEA) estimates, in 2020, EU-27 greenhouse gas emissions were 31 % lower than in 1990, constituting a substantial overachievement of the 20 % reduction target. That is shown by the graph in figure 17 (for the period 1990-2016) (source: *CAIT Climate Data Explorer via.Climate Watch*). The share of renewables target has been achieved as well, with a 21.3 % share of renewables in EU energy consumption in 2020. But the process is still going, with new energy targets for 2030 and 2050.

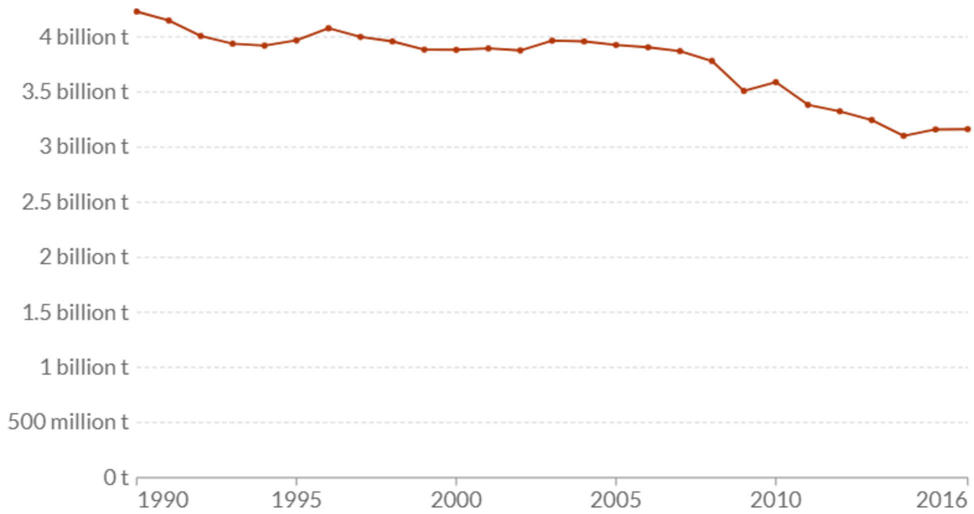


Figure 17. Greenhouse gas emissions.

At the end of 2019 the European commission proposed the ‘Green Deal’, setting new ambitious targets for 2030 and with the goal for EU to become climate-neutral by 2050. Then in July 2021 the ‘European Climate Law’ writes into law the goal set out in the ‘Green Deal’ for Europe’s economy and society. Climate neutrality by 2050 means achieving net zero GHG emissions for EU countries, mainly by cutting emissions, investing in green technologies, and protecting the natural environment.

The law aims to ensure that all EU policies contribute to this goal and that all sectors of the economy and society play their part.

This will create new opportunities for innovation and investment and jobs, as well as:

- Create jobs and growth;
- Address energy poverty;
- Reduce external energy dependency;
- Improve health and wellbeing.

In particular, targets for 2030 are:

- Reduce GHG emission of 55%;
- Increase share of renewable of 40%;
- Increase energy efficiency of 36-39%.

According to EU Directive 2018/2001, RES refers to energy from renewable non-fossil sources, namely wind, solar (both solar thermal and solar photovoltaic) and geothermal energy, wave and other ocean energy, hydropower, biomass, landfill gas. It is important to note that renewable and non-GHG emitting energy sources are not synonyms. For example, nuclear power plants do not pollute the air or emit GHG when producing electricity, but the material most often used to generate nuclear energy, uranium, is generally a non-renewable resource and, consequently, nuclear energy is not considered renewable.

Since 2010 there was a huge growth of solar and wind generation, while hydropower is almost constant. It has been achieved an important goal in 2020, with renewable source becoming the most produced source in EU, overcoming the source from fossil fuel (source: *Statistical Review of World Energy & Ember*):

Figure 18. Energy sources produced in EU.

2.5.2. Renewable Energy generation

Energy generation from renewable, in terms of TWh, was 653 TWh in 2010 with 57% (373 TWh) from hydropower source. While in 2020, not only generation from renewable increased, with 1052 TWh, but increase the quote as well from solar and wind, being respectively about 14% and 37% of total. In particular generation from solar has been passed from 23 TWh in 2010 to 146 TWh in 2020, with an increase of 634%; while wind generation from 139 TWh to 395 TWh, with an increase of 284%.
The figure below explains what just said, taking into account also other renewables, as geothermal, biomass, waste, wave and tidal (source: *BP-2021 Statistical Review of Global Energy*):

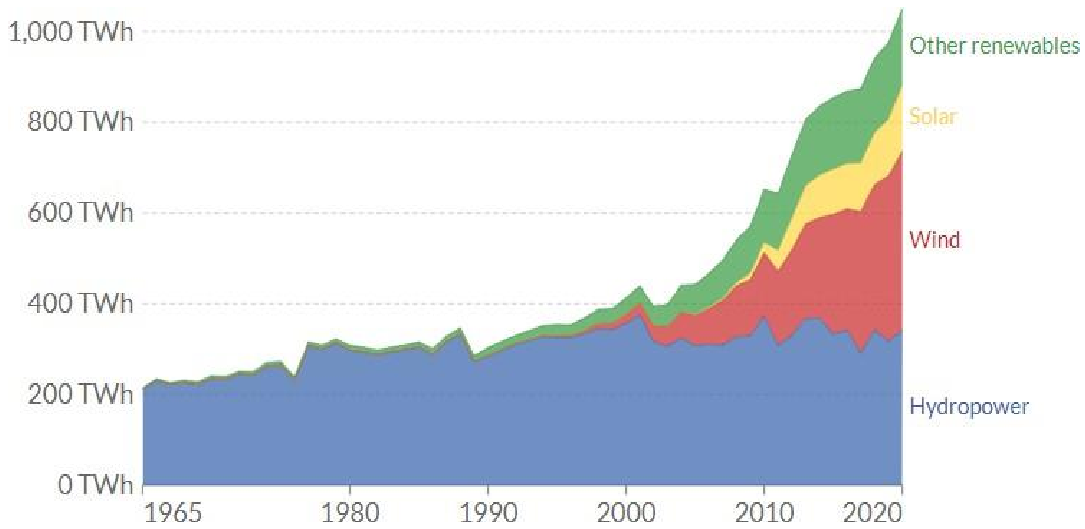


Figure 19. Renewable energy generation in EU.

2.5.3. Solar Energy Capacity

The graph reports the growth of installed solar energy capacity in terms of GW. It can be seen that, starting from 2010, the growth was strong, with an increase of about 550%, from 30.12 GW to 167.81 GW in 2020 (*BP-2021 Statistical Review of Global Energy*):

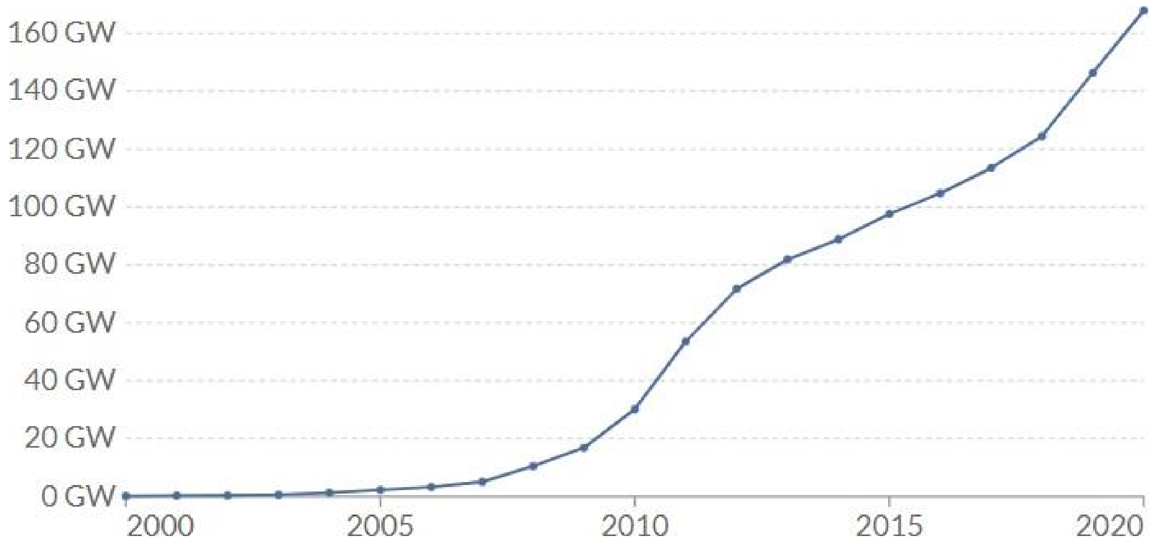


Figure 20. Installed solar energy capacity.

2.5.4. Wind Energy Capacity

The graph reports the growth of installed wind energy capacity in terms of GW. With respect to solar energy capacity, the growth is more linear, so long as wind factories were more widespread also before 2010. However, wind capacity passed from 86.24 GW installed in 2010 to 216.58 GW in 2020, with an increase of 250% (*BP-2021 Statistical Review of Global Energy*):

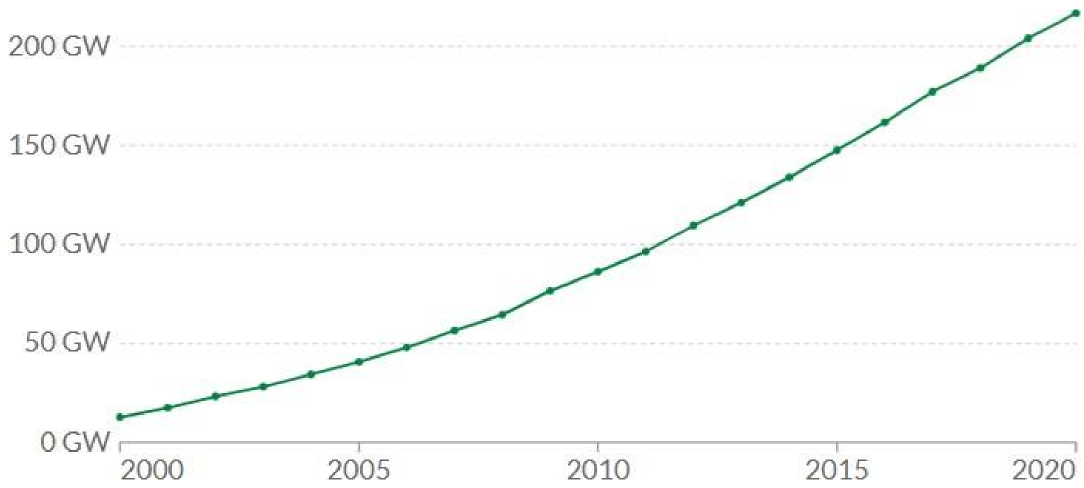


Figure 21. Installed wind energy capacity.

2.6. Role of RES in Electricity Market

The development of electricity produced from renewable sources has a decisive impact, in Italy and in other European countries, both on the operation of electrical systems and on the results of the energy markets.

The renewed energy context is made more complex by the presence of some economic factors, such as the gradual reduction in electricity consumption, a constant increase in the contribution of renewable sources - especially on the distribution networks on which most photovoltaic and wind plants are located - and a significant decrease in the hours of use of traditional combined cycle plants. In this new scenario, destined to evolve further to the advantage of renewables, the consequences that occur in the electricity market become interesting.

The behavior of RES, which differs from the conventional sources, requires each country to adapt its energy policy. The main features of renewables are:

- Intermittency: RE production needs priority of dispatch because it can hardly be foreseen, and electricity generated cannot be stored. This may also lead to an increased need for spare peak production capacities to be available to cope with the increased intermittency in the grid,
- Segmentation: most RE plants are small and widely distributed within a country, which requires grid reinforcement works.

The effects of RE generation on electricity markets are still unclear and certainly dependent on each country's energy mix.

In Italy, in the sessions of the day-ahead market (MGP) organized according to the criterion of economic merit and with the enhancement of energy to the marginal offer, renewable sources, characterized by marginal production costs almost null, displace the curve of fossil-based plants, thus helping to reduce the price of energy on the market. This phenomenon defined as "Merit Order Effect" (MOE), becomes more and more evident as the contribution of RES increases with respect to energy needs.

Generators offer their marginal cost during the DAM, and so long as RES have very low marginal costs, their offers place always at the beginning of the aggregate curve. This led to a translation to the right of the aggregate offer curve (fig. 22). So, offers

from RES are surely accepted, selling energy at market clearing price, while offers from conventional source could be rejected, moving to the right in the merit order curve.
That can bring an advantage because system price reduces, but at the same time affects the competitiveness of other energy sources that will continue to be fundamental for the EU's energy system: they could be out of the market, but their generation is still needed as backup when the variable output of intermittent RES is low.
It's true that RES penetration could led to a reduction of system price, but on the other hand due to the variable and inflexible nature of electricity production from RES, price volatility increases.

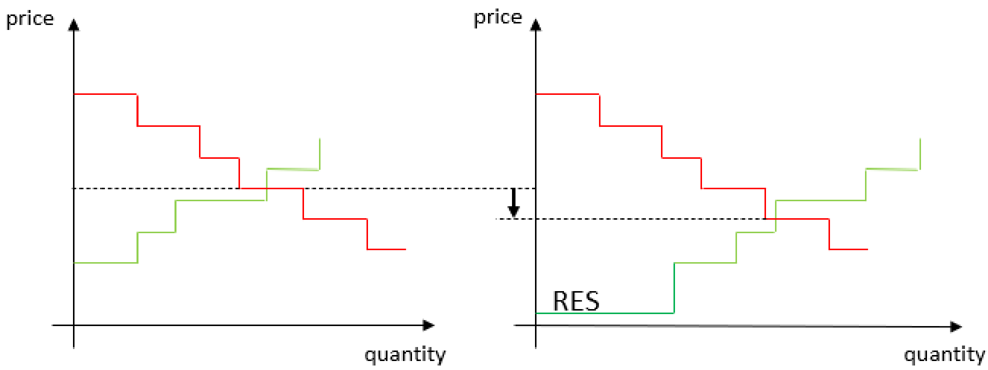


Figure 22. Price reduction thanks to RES penetration.

However, this large-scale integration of renewables into the electricity grid creates problems. The European electricity grid and market had been largely designed for large, controllable conventional generators that use fossil fuels. Variable, inflexible and uncertain electricity production from renewables challenge this system because it disrupts the conventional methods for planning the daily operations of the electric grid. it is still unclear how the market design must be modified to further encourage investments in low-carbon technologies, while at the same time safeguarding security of supply and keeping the costs of electricity at an affordable level for consumers.
An aspect to consider is that traditionally, dispatchable thermal capacity is used to balance any supply-demand mismatch, provide backup capacity, and Ancillary Services (AS) such as frequency and voltage control to maintain grid stability. With the advent of RES this situation is changing. The integration of increased amounts of RES into the electricity grid have imposed additional challenges by disrupting the conventional

methods of maintaining the supply-demand balance. This can threaten network stability and the process to maintain system stability is projected to get increasingly difficult. Furthermore, RES growth leads to increased events of supply-demand mismatch, meaning higher and new need for flexibility, which is defined as the ability of a given resource to adjust its production or consumption within a given timeframe and consequently higher cost of redispatch.

Moreover, RES penetration can hinder market integration, occurring when prices among different nodes/zones follow similar patterns over a long period of time. Due to their variable nature differences in price can frequently occurs. In this context it can assess whether renewables increase the occurrence of congestion and evaluate the impact of wind and photovoltaics on congestion costs.

When a region is importing power, increasing local renewable supply decreases the probability of congestion and the level of congestion costs. A rise in local demand, on the contrary, increases the probability of congestion in the entry due to larger import needs. At the same time if the renewable output rises in the already exporting region the probability of congestion increases because the exporting region has a larger efficient output. A rise in the demand in the exporting region however has the opposite effect of lowering the probability of congestion and its costs because more power is consumed locally. Moreover, importing regions are less likely to produce congestion in the exit and more likely to suffer congestion in entry due to less efficient local supply. Therefore, a larger RES production in these regions is expected to bring more balances in interzonal flows. Increasing RES supply in exporting regions, instead, may exacerbate the problem of congestion, adding efficient supply where is relatively less needed. [11]

Therefore, the design of the European electricity market must carefully take into account the impact of localization choices of renewable production on the efficiency of the overall market and transmission electricity systems, together with the need of additional transmission capacity.

CHAPTER 3
Definition of BZs through model-based and expert-based approaches

In general, there are two approaches to define bidding zone configurations. The first one is the expert-based approach, which relies mainly on the experience and knowledges of the relevant Transmission System Operators (TSOs). In this context, the first part of this chapter presents the expert approach used in the Bidding Zone Review, a document released to evaluate new possible configuration. Furthermore, the more important criteria will be presented.

The second part of the chapter focuses on the other approach, the so called model-based. It relies on mathematic models, and thanks to clustering methods new configuration can be found.

3.1. Bidding Zone Review

In 2018 the European Union Agency for the Cooperation of Energy Regulators (ACER) released the First Edition of the Bidding Zone Review [12]. This process lasted 15 months and ending on 21 March 2018, with the help of participating TSOs, which were tasked to:

- specify the configurations subject to the review;
- consult with the national regulatory authorities regarding the assessment methodology, assumptions and configurations, and with stakeholders regarding the alternative configuration proposals;
- draw a final conclusion on whether to maintain or amend the bidding zone configuration for submission to the Member States.

The goal of the Review is to evaluate different bidding zone configurations and, in line with the CACM code network [15], possible benefits respect to criteria. On this basis, Member States are obliged to reach an agreement on whether to maintain or amend the bidding zone configuration.

The review explores both the expert-based and the model-based approach. For the first the process starts defining ex ante different configurations and then various criteria are applied. For the model-based, it's explained how to form the network indicators and the clustering methods to obtain a new configuration.

This paragraph introduces the expert-based approach used in the Review and then the evaluation criteria to estimate possible benefits.

3.2. Expert-based approach to define BZs

This paragraph introduces the expert-based approach used in the Review and then the evaluation criteria to estimate possible improvements or worsening. The approach to define new BZs is based on a selection of ex ante defined configurations including splitting or merging of the existing bidding zones. Since these configurations are defined by the concerned TSOs based on their expert assessment, they are called as expert-based configurations. In total, five configurations (fig. 23) have been identified and studied:

- **Status Quo**: the current situation, used as benchmark to be compared to new configurations;
- **DE/AT split**: considers a separation of the Austrian (AT) zone from the German-Luxembourgian (DE, LU) zone;
- **Big Country Split and Big Country Split 2**: extend the configuration DE/AT Split by the additional splits of France (FR), Germany (DE) and Poland (PL);
- **Small Country Merge**: considers a merge of the Belgian (BE) and Dutch (NL) bidding zones and a merge of the Czech (CZ) and Slovak (SK) bidding zones.

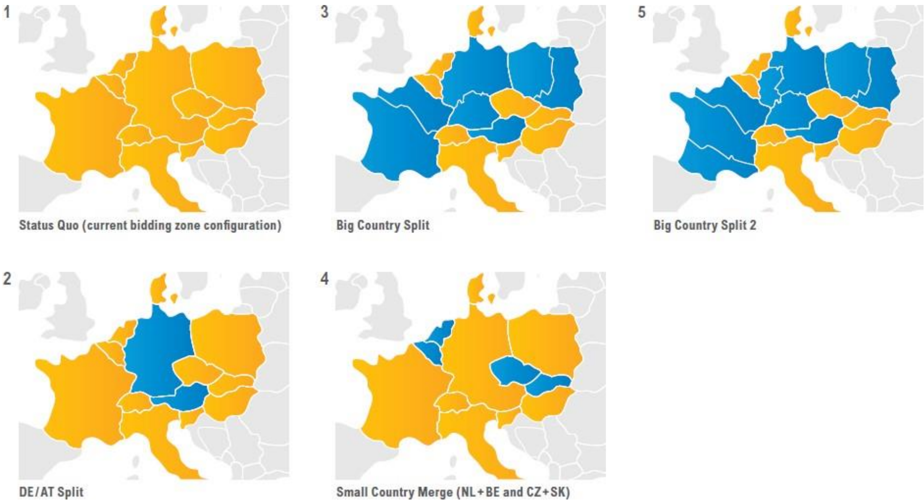


Figure 23. Different BZs configurations.

On these expert-based configurations, the evaluation criteria were applied, and a comparison was made respect to the Status Quo. It's important to clarify that this evaluation has been conducted in comparative terms, and criteria analyses are mainly qualitative and, hence, are not supported by comprehensive quantitative simulations. The Table shows the results from the review, where the ratings can be understood as follows:

- (+): better than the current bidding zone configuration (Status Quo)
- (0): no significant difference compared to the current bidding zone configuration
- (-): worse than the current bidding zone configuration

BZ configuration	**DE/AT Split**	**Big Country Split**	**Big Country Split 2**	**Small Country Merge**
Operational Security	(+)	(+)	(+)	(-)
Security of Supply	(0)	(0)	(0)	(0)
Degree of uncertainty in cross-zonal capacity calculation	(0)	(0)	(0)	(0)
Economic Efficiency	(0)	(0)	(0)	(0)

Market Liquidity	(-)	(-)	(-)	(+)
Market Power	(-)	(-)	(-)	(+)
Transition and transaction cost	(-)	(-)	(-)	(-)
Stability and robustness of BZ	(0)	(-)	(-)	(0)
Location and frequency of congestion (market and grid)	(+)	(+)	(+)	(-)

Table 1. Criteria applied to different configuration of BZs.

Status Quo represents the actual situation (March 2022) of delineation of bidding zones, which consist mostly in national borders but there are bidding zones larger than borders. Germany, Austria and Luxembourg constitute one single bidding zone, instituted in 2005. However, the width of this zone causes an insufficiency of transmission capacities within the zone, resulting in the power flows thought neighbor countries, Czech and Poland. [13][14]. That's explain the necessity and the urge to provide different solution to overcome this problem. The first edition of the bidding zone review deal with this theme, studying four different configurations evaluating all criteria.

In Northern Europe the settlement is the opposite, BZ are smaller than national borders. Sweden was divided into four bidding zones in 2011. This process was based upon decision of European Commission that resulted from appeals of market participants in Denmark. Norway is divided into several bidding zones as well. Still the number of bidding zones is not fixed and can be changed according to the development of transmission grid or in case of grid failures. The exact configuration of bidding zones in Norway is based on detailed analysis of the transmission lines. TSO submits to Nord Pool Spot quarterly in-depth analysis with 5-year outlook.

Figure 24 shows the Status Quo BZs in exam in the review, focused on central Europe:

Figure 24. Center Europe Status Quo.

3.3. Evaluation Criteria

The new possible assessments of bidding zones require a long and complicated process that have to face a lot of different aspects, in some case in contrast and an algorithm covering a time frame of 24 daily set of values for at least a year. Necessity to find new configuration comes out from problems as in the DE-AT-LU zone. A first reason to why adopt new solution is the increase in consumption that the current society is facing; then a higher demand and a consequently higher offer. That means the network must deal with stronger power flows and with higher probability of congestion. Another reason and problem that will increase in further years, is the continuous change in networks due to RES penetration, following the European directives on sustainability and reach of certain level of emissions. On the other hand, RES penetration brings new challenges for TSOs, as the increase in redispatch costs or not using all the generated power.

ENTSO-E in 2012 published a guideline, the Network Code Capacity Allocation and Congestion Management (CACM) which provide a set of rule and devices on capacity allocation and congestion management methods and issues. Moreover, it establishes a review of the BZ configuration, that may be launched by the National Regulatory Authorities or the TSO. The participating System Operators involved in the review of the BZ configuration shall: perform the assessment of the BZ configuration, propose the alternative BZ configurations, assess the current and each alternative BZ configuration and finally perform a public consultation regarding the alternative configuration proposals.[12]

To assess the alternative BZ the guideline [15] state criteria that must be followed on reconfiguration. In particular, article 38 divides criteria in 3 categories:

CRITERIA TO ASSESS THE EFFICIENCY OF ALTERNATIVE BIDDING ZONE CONFIGURATIONS

"When the Bidding Zone configuration is reviewed, at least the following criteria shall be considered:

(a) In respect of network security: - the ability of the Bidding Zone configuration to ensure Operational Security and the security of supply; and - the size of uncertainties in the cross Bidding Zone Capacity Calculation.

(b) In respect of overall market efficiency: - the increase or decrease in Economic Surplus arising from the change; - market efficiency, including, at least, firmness costs, market liquidity, market concentration and market power, the facilitation of effective competition, the accuracy and robustness of price signals and transition costs, including costs of amending existing contractual obligations, incurred by Market Participants, Nominated Electricity Market Operators and System Operators; - the need to ensure the feasible market outcome without an extensive application of economically inefficient corrective measures; - any adverse effects of internal transactions on other Bidding Zones; and - the impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes.

(c) In respect of the stability and robustness of Bidding Zones: - the need for Bidding Zones to be sufficiently stable and robust over time; - the need for Bidding Zones to be consistent for all Capacity Calculation Timeframes; - the need for each generation and load unit to belong to only one Bidding Zone for each Market Time Period; and - the location and frequency of congestion, provided that: Structural Congestions influence the delimitation of Bidding Zones; and taking into account investments which may relieve existing congestions."

Before to explain them, a clarification is needed. These criteria are valid and used for both the approach, to estimate and understand the results. While in this case, as the reference is The First Edition of Bidding Zone Review, they have been considered only for the expert-based approach, with the outcomes shown in the above table.

3.3.1. Network security

Keeping the network secure is the main target of the reconfiguration. The continuous growing of the grid and the process of creating an internal European market had bought an urge to evaluate new configuration to improve security for the network while balancing all the sub-criteria.

Some definitions of security are given, provided by the EU and international policy, regulatory, and scientific sources:

For the International Electrotechnical Commission (IEC) Security is *"the ability of an electric power system to operate in such a way that credible events do not give rise to loss of load, stresses of system components beyond their ratings, bus voltages or system frequency outside tolerances, instability, voltage collapse, or cascading"*.

For ENTSO-E Security is *"the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements"*.

The Institute of Electrical and Electronics Engineers (IEEE) define Security as *"the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service"*.

It's clear that, despite few differences in definitions, the target is to keep the network operating in a secure way and in terms to ensure supply to all consumers. In respect to network security CACM code establish three criteria: operational security, security of supply and degree of uncertainty in cross-zonal capacity calculation.

3.3.2. Operational Security

The guidelines on electricity transmission system operation (Commission regulation (EU) 2017 / 1485) defines 'operational security' as *"the transmission system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterized by operational security limits"*. Hereby, 'normal state' means "*a situation in which the system is within operational security limits in the N-situation and after the occurrence of any contingency"*. A contingency is the loss or failure of a small part of the power system (e.g. a transmission line), or the loss/failure of individual equipment such as a generator or transformer.[12]

To be clearer, a transmission system is in the normal state when all the following conditions are fulfilled: (article 18 of the guideline)

- voltage and power flows are within the operational security limits defined in accordance with Article 25 by every TSO;
- the steady state system frequency deviation is within the standard frequency range;
- active and reactive power reserves are sufficient to withstand contingencies from the contingency list defined without violating operational security limits;
- operation of the concerned TSO's control area is and will remain within operational security limits after the activation of remedial actions following the occurrence of a contingency from the contingency list defined.

3.3.3. Security of Supply

Security of supply is straightly connected to the adequacy of the network, in terms to cover all the energy demand in a zone and so related to capacities and flows though lines. Furthermore, this topic need careful evaluations since RES penetration can lead to consistent discrepancies between predicted and real power flows. Adequacy can be defined as "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements" (ENTSO-E).

In particular, security of supply focuses on generation adequacy, representing the availability of large-sized generation and storage capacity to meet demand in the various timeframes, meaning that ensuring security of supply is not a TSO task, while grid security is. Well-known indicators for the measurement of generation adequacy can be based on probabilistic modelling, as loss of load expectation (LOLE) and expected energy not served (EENS), or on more static indicators such as remaining capacity margins.[12]

EENS is the share of the demand of electricity not supplied to the final uses, in a given timeframe, while LOLE is the number of hours for which EENS is different from zero, considering the same timeframe, meaning the time for which offer doesn't match electricity demand. It's evident as lower these two parameters are, as more the system is adequate.

3.3.4. Degree of uncertainty in cross-zonal capacity calculation

The introduction of Flow-Based capacity calculation process, already in operation in CWE region, has led to an increase of deviation between day-ahead (as used for FBMC) and real-time flows. That's due to inaccuracy of zonal PTDFs, but to intraday changes and forecast errors in RES and load as well.

It isn't clear yet how bidding zone configuration could impact on uncertainty in cross-zonal capacity calculation. Two aspects can be value. On the one hand, uncertainty results from the accuracy of zonal PTDFs. Let's consider two BZs, one smaller and one bigger; if generation and load in the smaller bidding zone are distributed more equally than in the bigger bidding zone, the uncertainty arising from the zonal PTDF error is lower in the smaller bidding zone. On the other hand, uncertainty also arises from RES and load forecast errors, but here the uncertainty increases more in the smaller bidding zones.[12] The problem is that it's yet unclear which of these reverse impacts will be higher. Therefore, more studies should be conducted to evaluate which of these reverse impacts will be higher and if the splitting of a bidding zone will bring to a lower or higher overall degree of uncertainty in cross-zonal capacity calculation.

3.3.5. Market efficiency

The concept of market efficiency is very wide and includes various aspects and different criteria. In this section some evaluation criteria of CACM code will be overview and how the definition of new BZ could impact on them will be explained. In economic terms Market efficiency refers to the degree to which market prices reflect all available, relevant information. Then if markets are efficient, all information is already incorporated into prices. But this definition in electricity systems is not quite complete. As we know, market prices reflects only if there is some congestions, but all relevant information misses. Markets outcome are the quantity to be sold and the correspondent price. Market efficiency definition have to be a bit changed for Electricity Markets. So, it can be viewed as a set of criteria, which check the effective overall market efficiency.

First of all, market efficiency is straightly connected to the welfare concept. In optimization problems maximize the social welfare is the objective function, written as:

$$S^s = \sum_{1}^{B} b_i \cdot P_{Di} - \sum_{1}^{C} c_i \cdot P_{Gi} \tag{19}$$

Where:

$b_i \in B$: accepted bids [€/MWh]

$c_i \in C$: accepted offers [€/MWh]

P_{Di}, p_{Gi}: demand and offer quantity [MWh]

Practically, it reflects the benefits given by the market both for suppliers and customers. That's why in optimization theory the objective function can be replaced with the minimization of total cost, that's the same objective and the same output will results. So, market efficiency is defined as the change in the total system costs (i. e. variable production costs in the day-ahead market model) plus the corresponding redispatch costs. About redispatch costs, while in a nodal market design, redispatch costs are considered as already implicit in the total system costs, this is only partly the case for a zonal market design, that's why they must be considered, specially where a specific auction is made. Another consideration is that redispatch costs are extremely variable and difficult to forecast, even more with growth of RES penetration, because of their strong dependence on previous dispatch results.

So, use only total system costs as indicator of market efficiency is useless, first because they are derived by models that do not exactly represent reality, but also because some aspects like market liquidity or market power could affect the overall efficiency.[12]

3.3.6. Market liquidity

Market liquidity can be defined as the degree to which any market party can quickly source and/or sell any volume of energy (implicit) or capacity (explicit) without affecting the involved market price. It's a key tool for measuring effectiveness and competition level in energy markets.

A high level of liquidity brings several benefits to the markets and market participants as well:

- the participation of a large number of market players in energy markets, who will be willing to negotiate at any time;
- high liquidity reflects an efficient distribution of relevant supply and demand information, leading to an efficient market dispatch;
- high liquidity is attractive for traders and new market participants, so long as it reduces entry barriers;
- open trading positions are closed more quickly, facilitating the trading and hedging process, minimizing the risks
- liquidity may result in greater price transparency which can then provide opportunities for increased competition across the market.

Indicators to assess liquidity are:

- Bid-offer spread: defined as the amount by which the ask price exceeds the bid. This is essentially the difference in price between the highest price that a buyer is willing to pay for a product and the lowest price for which a seller is willing to sell it:

$$Bid - offer\ spread = \max(b_i) - \min(c_i) \tag{20}$$

  The bid-offer spread is interpreted as a measure of liquidity, for which low level of spread means more liquidity, and as measure of "cost of liquidity" as well. In fact, the larger the spread, the more a trader will have to adjust their price expectations in order to make a trade, effectively adding costs to the trade.

- Churn rate: calculated as the ratio of the total volume of power trade and electricity consumption in a given time period. In other words, the churn rate measures how many times a unit of electricity is traded before it is finally consumed.

$$Churn\ rate = \frac{volume\ trade}{\text{physical consumption}} \tag{21}$$

A high value of churn rate means a more liquid market. As example the churn factors in major European forward markets (in 2014-2016 period) is shown in figure 25, provided by the ACER Market Monitoring Report 2016:

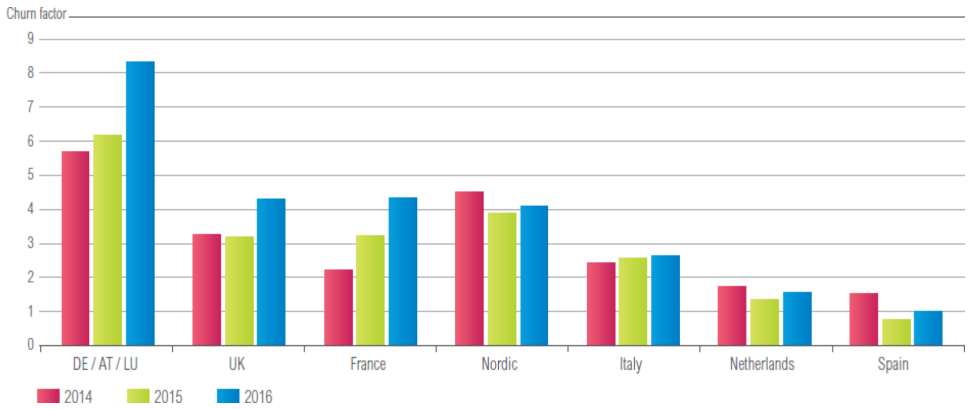


Figure 25. Churn factor in European forward markets.

It can be noticed that the larger the zone is, the higher churn rate is: in the large zone of DE/AT/LU, the churn factor is nearly twice as high as in the other zones. The size of a bidding zone is actually a key element on the understood of how much liquid is that market. A bigger BZ would mean more market participants and more participants are equivalent to more trades, i.g. more volume traded. Moreover, high connectivity (or improved congestion management) between BZs is beneficial for liquidity as it assures more trading possibilities. More electricity can be shifted from one zone to another, allowing for more interactions between the market participants. That's also explain why DE/AT/LU market, which have been implemented the more efficient flow-based calculation method, is so much liquid.[12]

The above-mentioned indicators rely on detailed empirical data of existing markets. However, such data is not available for the future or for alternative bidding zone configurations. All empirical data is linked to specific evolutions, and each bidding zone is unique due to its own characteristics of generation, demand, market structure, etc. They are also hard to be simulated by any model, whereby in most cases, the impact of future bidding zone reconfigurations on market liquidity can therefore hardly be predicted. Consequently, the evaluation of market liquidity is mainly a qualitative one. Finally, from the Bidding Zone Review emerged that reducing size of the bidding zones in the split configurations makes a decrease of liquidity very probable, the number of products will likely double, whereas the number of market participants remains equal, meaning less trades. This effect could be mitigated by the exchanges between BZs, which still will be smaller than exchanges within BZ. On the contrary merging different BZs would have the opposite effect.

3.3.7. Market power

Market power is the ability of a single firm or a group of competing firms in a market, to profitably raise prices above and restrict output below competitive levels for a sustained period of time. Two types of market power exist: vertical when a firm is involved in two related activities and uses its dominance in one area to raise prices and increase profits, and horizontal when the firm controls a significant share of the total capacity available to the market so it can drive up prices.

It is useful mentioning that, compared to other markets, some of the economic characteristics of electricity markets are potentially beneficial for the increase of market power: mainly the existence of transmission constraints, entrance barriers, inelastic demand, peak demand conditions and instantaneous balancing needs. The benchmark of the market is perfect competition, that allows to high efficiency and perfect information, and clearly market power approach more to an oligopoly situation. The BZs reconfiguration targets to reduce market power, but as well as market liquidity, some predictions and forecasting on future and possible new BZs are needed.

The concept of market power is strongly connected to the definition of market concentration, occurs when large share of capacity is owned by one or few companies. Market concentration, and consequently market power, can be computed by various indicators, most important and used are:

- **Herfindal-Hirschmann Index** (HHI)

  Considering a market with N_g firms, where each firms has a maximum capacity p_g^{max}, and the total capacity of the market is $p_T^{max} = \sum_{g=1}^{N_g} p_g^{max}$;

the market share of a firm is defined as:

$$a_g = \frac{p_g^{max}}{p_T^{max}} \tag{22}$$

Then the HHI is:

$$HHI = \sum_{g=1}^{N_g} (a_g)^2 \tag{23}$$

It ranges from $\frac{1}{N_g}$, meaning equal share, to 1, meaning a monopoly situation. So low values of HHI lead to low level of market concentration and hence market power.

- **Residual Supply Index (RSI)**

  The RSI measures how much capacity remains in the market, when one provider retains its capacity:

$$RSI = \frac{Total\ Supply - Largest\ Seller's\ Supply}{Total\ Demand} \tag{24}$$

  This indicator also considers potential imports, in fact:

$$Total\ supply = Total\ domestic\ supply\ capacity\ + Total\ net\ import \tag{25}$$

  An RSI above 100 % indicates that sufficient capacity remains in the market to meet the demand. An RSI below 100 % indicates that the remaining capacity does not meet the demand.

3.3.8. Transition and transaction costs

Transition costs are the 'one-time' costs directly related to a configuration change, such as required investments due to market changes or investments or assets due to price changes or costs for rearranging established trade deals between market participants. The level of transition costs can depend on the time span since the new configuration

comes into effect, so determine the time frame for the evaluation is fundamental but complicated as well, since all other factors influencing structure, scope and effectiveness of the power market should remain approximately stable.
Transaction costs refer to the costs of participating in the market. They are permanent costs for search and information, bargaining, policing and enforcement. Transaction costs are, to some extent, specific to a given bidding zone configuration. The evaluation considers the current bidding zone configuration as a reference point and refers only to increase or decrease of transaction costs that are expected due to the new configuration.
However, stakeholders and TSOs were not able to provide a reliable estimation of such costs in euros, due to the high uncertainties and the complexity of the changes caused by a new bidding zone configuration. Still TSOs provided an overview on the necessary adaptations which they consider as being relevant for transition and transaction costs:

- An adaptation of BZ areas in a manner meaning they no longer correspond to control zones would make an adaptation of all related grid contracts necessary;
- In the case of adapted bidding zones no longer corresponding to control zones, adaptations of the grid tariffs might be required;
- The splitting of a national BZ into two, implicates changes with regard to the settlement process of balancing areas. Contracts need to be redrafted and adjusted to reflect the new configuration;
- Splitting a zone controlled by a TSO, lead to the calculation and the procurement that need to be done separately for both market areas. That means higher costs of the overall process.

  [12]

  Finally, it is quite obvious that any adaptation of bidding zones, either through a merge or a split, would yield transition and transaction costs which would not occur in the event of maintaining the Status Quo. Therefore, the impact for all assessed bidding zone configurations is assessed to be negative. For Big Country Split, the related transition and transaction costs are estimated higher compared to the DE/AT Split and the Small Country Merge. The reason for this is that the first considers the splitting of countries and control zones. Then, a greater amount of adaptation is necessary compared to splitting along a control zone border. [12]

3.3.9. Stability and robustness of bidding zones

Last set of criteria focus more on market design and market structure influence. First evaluation is on stability and robustness of BZs over time, asserting that a BZ is stable and robust if the congestions that the bidding zone borders reflect are sufficiently stable and robust over time, that's, in general, the case of structural congestion. To be robust over time requires that the structural congestions occur in the same grid area and to be sufficiently predictable. If they aren't a robust definition of bidding zone borders becomes challenging.

Secondly, the clear assignment of generation and load units to bidding zones can be interpreted as a requirement for the definition of alternative bidding zone configurations. The target is to assign generation and load units to a BZ, but it becomes critic when units are assigned to more than one bidding zone yielding very distortive effects since the allocation would be arbitrary. So, it's crucial, in terms of reconfiguration, to evaluate the assignment of units located close to a bidding zone border since the high relevance for the efficiency of the market coupling in general.

This is the example of the German-Austrian border, where some units are geographically located in Austria but are considered as generators in Germany due to specific contracts.

It's fair to say that the assignment of units and loads in a new bidding zone configuration cannot become easier or better compared to the Status Quo, because the current configuration already considers a clear assignment of every generation and load unit.

3.3.10. Location and frequency of congestion (market and grid)

As the CACM article 33 states: "*the location and frequency of congestion, if structural congestion, influences the delimitation of bidding zones, taking into account any future investment which may relieve existing congestion*". Structural congestion means, according to CACM, *"congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently recurring under normal power system conditions"*.

This criterion is strongly linked to the requirement for bidding zones to be 'sufficiently stable and robust over time'. The assessment of the location and frequency of congestion forms the basis for evaluate if reconfigured bidding zones can be considered as sufficiently stable and robust over time.

3.4. Other indicators

To assess the effectiveness of the new configuration of BZ it can be introduced other quantitative indicators, which reflect economic or physical aspects. Hereby some of them are explained.

- **Congestion Rent**

  It can be defined as "the amount collected by the owners of the rights to the transmission line. Considering one line, these rights would typically pay the owners an amount equal to the line's capacity times the difference between the prices at the two ends of the line. Congestion rent is a transfer payment from line user to line owner, as using the line has no actual cost."

  Then, the mathematical equation expressing the congestion rent, considering p_A and p_B (with $p_A > p_B$) the marginal price of two interconnected zones and F_{AB} the power flow on the line, is:

  $$CR = (p_A - p_B) \cdot F_{AB} \tag{26}$$

  It's clear that if there is no congestion, the price will be equal and congestion rent is null.

- **Price Volatility**

  Price volatility is used to describe price fluctuations of electricity, considering a specified period. It's calculated as standard deviation of prices in zones or within zone. Electricity markets are often more volatile than others since price of primary energies are more floatable. Besides price volatility is used as indicators or even for zonal formation similarly to marginal price. The higher the volatility, the riskier the security and efficiency of markets.

- **Price Convergence**

Price convergence is often used to measure the overall efficiency of the interconnections. A large price convergence reflects a small occurrence of congestion.

To compute the price convergence for each interconnection in the system it has been defined an indicator. The indicator will consider the price difference for hour t and interconnector L between two bidding zones. The first step is calculating the convergence for each time step:

$$PC(b,t) = \begin{cases} 1 & if\ \Delta p_{b,t} = 0 \\ 0 & if\ \Delta p_{b,t} > 0 \end{cases}$$

(27)

Where $\Delta p_{b,t}$ is the price difference across the interconnector b at hour t.

Hereby, the price convergence indicator is computed as:

$$PCI_b = \frac{\sum_{t=1}^{T} PC(b,\ t)}{T}$$

(28)

- **Price Divergence**

  Price divergence indicator (PDI) assesses if a change in the zonal configuration is beneficial by bringing the whole system closer to the target model, the copper plate model, i.e. the capacity of the transmission lines inside the zone are set to infinity so there aren't constraints on the line. The indicator is based on a root-mean square deviation which aggregates the magnitudes of difference between the market configuration after market splitting and the copper plate model into a single measure.

$$PDI_z = \sqrt{\frac{\sum_{t=1}^{T} \sum_{z=1}^{Z} (p_z - p_{CP})^2}{2T}}$$

(29)

Where p_z is the price of zone z and p_{CP} is the price in the copper plate model.

- **Loop flows**

A commercial exchange realized between two bidding zones does not only affect the flow between these BZs. It also has a significant influence on other zones: it can be defined loop flows and transit flows.

Loop flows and transit flows can decrease the available transmission capacity of neighboring price zones even if they are not involved in the scheduled exchanges. Remedial actions (like redispatching) are the only way to get rid of them, but it induces extra cost for the system operator.

The figure below helps to understand the definition of loop and transit flow, considering a situation with three bidding zones:

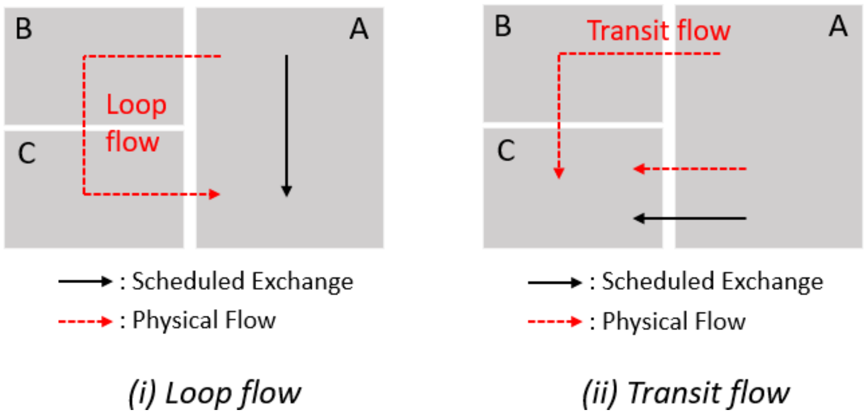


Figure 26. Loop and Transit flows.

Loop flow can be defined as the flow over bidding zones (zones B and C) caused by a scheduled exchange within another bidding zone (origin and destination in zone A). Transit flow can be defined as the flow over bidding zones (zone B) caused by origin (in zone A) and destination (in zone C) in two different bidding zones.

3.5. Model-based approach to define BZs

In general, there are two approaches to define bidding zone configurations. The first one was already mentioned as the expert-based approach in the first review of bidding zone, which relies mainly on the experience and knowledges of the relevant Transmission System Operators (TSOs). In fact, BZ configurations are formed ex-ante based on

TSOs' experiences, as the figure shows, and then all the evaluation are made based on criteria.

The other approach is called model-based and relies on mathematic models, supporting TSOs with highly automated and wide computations. In this section an overview of this approach is explained, so long as it won't be the approach used in the case study.

The model-based approach typically involves two steps:

- calculate, based on the complete network model, appropriate indicators for the electric network's components;
- use them as inputs for clustering algorithms that define the market bidding zones as areas of the network characterized by similar values of the selected indicators.

Furthermore, several numbers of indicators and cluster algorithms can be used, but the most used one will be explained in details, in line with [16] .

The main indicators used are the Power Transfer Distribution Factor (PTDF) and the Locational Marginal Price (LMP). The compute of the indicators isn't univocal. In fact, they can depend on previous assumption and the obtained values depend strongly on these assumption and factors. It's important to choose them right to setting up a correct optimization problem. In the next session factors impacting the formulation of model-based approach are reported, and then the following paragraph will be focused on the explanation of the two indicators.

3.5.1. Network model

There are two possible approaches to represent the transmission network:

- models based on the DC power flow (PF) equations;
- models based on the AC power flow equations.

from which a DC or AC optimization problem is derived.

In AC model it's considered both real and reactive power, voltage magnitude and phase angles, while in DC PF only real power and phase angles are taken into account. That means AC is not linear and with much more constraints to consider. That's why in most of the literature, a DC PF model is adopted.[17] This choice is due to the following advantages:

- reduced set of input data, since only partial information on the reactive part of the problem are necessary;
- linear problem, faster to solve;
- robust in term of convergence.

Anyhow, choosing a DC model, the resulting bidding zone configuration will not incorporate any information regarding potential voltage problems. This could be a relevant issue in Power Systems where voltage regulation problems are relevant.

3.5.2. Objective function

Two different objective functions can be adopted for LMP computation: minimization of production costs or maximization of social welfare. In first approximation it could seem the same what to use, but it’s not like that.
In the case of cost minimization, it must estimate the short-run marginal costs of each generation unit. These costs could be approximated based on the technologies and the fuel type. However, this approach can carry to solutions with prices that are too uniform across the network, since it would be really hard to correctly represent real differences between power plants and in addition, deviations are observed in real electricity markets anyway. Then, assuming cost minimization, in case of network indicators sensitive to this aspect (such as LMPs), could produce unrealistic bidding zone configurations.
For these reasons, using maximization of social welfare is more advantageous. However, a handicap of this approach is that the offer price for a specific generating unit can’t be assumed constant over long time periods and it is also potentially affected by the bidding zone configuration.

3.5.3. Time resolution and time horizon

Another important factor that influences the outcomes of a bidding zone configuration algorithm is the time resolution (hourly, etc.) and span (day, month, year etc.) for which the network indicators are determined. The choice is fundamental to achieve a zonal structure that is robust and stable over time. Assessing longer time horizons allows to determine zonal structures as "compromise" between different system conditions (in terms of load, RES infeed, grid status, etc.), but this could lead to solutions which don’t fit well with specific operating conditions. This issue could be mitigated by adopting a high number of bidding zones. In most of literatures, time resolution is hourly and time horizon is one-step, day, or year. [17]

3.6. Input features and Optimization Problem

The determination of a new configuration with the model-based has a different approach since a nodal representation of the network is needed. That means this method, being more accurate, requires some more input features, not considered in a expert approach. First, the network must be all represented, so all branches and nodes have to give all relevant information, reactances and resistances of branches, voltage magnitude and phase angle for each node. That at least considering an AC model of the network, still reactances are necessary as well for AC and DC model, to determine the PTDF matrix, essential not only to set up the OP, but used as well as input for clustering methods.

The optimization problem is similar to the one used in the day-ahead market, with the difference of a nodal representation of the network, so long as the purpose of the OP is to find LMPs for each node, then the clustering methods can be applied.

The objective function as explained before, is advantageous to choose to maximize social welfare. It's interesting to say that the OP can be set with a minimization of the objective function, simply changing the sign of the social welfare; mathematically the results will be the same:

$$\max S^s = \min -S^s \tag{30}$$

What change respect to the DAM algorithm are the constraints used. As a nodal representation is applied, constraints must be on each element of the network (nodes, lines). Then equality constraint concerns nodal injection P_n, that corresponds to the net injection into the grid of a node n as:

$$P_n = P_{Gn} - P_{Dn} \tag{31}$$

the difference of power injected and withdrawn on that node. A first approach could be considering the total sum of nodal injection equal to zero, that is the global balance associate with the global system price. It can be useful, in BZs configuration and remembering we want LMPs in each node, to use the nodal balance, so from obtain the nodal prices:

$$P_n = P_{Gn} - P_{Dn} = 0 \qquad \forall\, n \in N \tag{32}$$

The inequality constraints refer to maximum line flows, such as DAM algorithm, with the difference of considering real lines instead of virtual interconnector. In this process, PTDF matrix is helpful to obtain the equation of the flow. As we already define PTDF, the inequality constraints are expressed by:

$$F_l = \sum_{n=1}^{N} PTDF(l,n) \cdot \; P_n \leq F_{max,l} \qquad \forall l \in L \tag{33}$$

The OP is then written as follow:

$$\max S^s$$

$$\text{s.t.}$$

$$P_n = P_{Gn} - P_{Dn} = 0 \qquad \forall\, n \in N$$

$$F_l = \sum_{n=1}^{N} PTDF(l,n) \cdot \; P_n \leq F_{max,l} \qquad \forall l \in L$$

3.7. Network Indicators: PTDF and LMPs

3.7.1. Power Transfer Distribution Factor (PTDF)

The PTDF is the change of an energy transit on a branch following the variation of the power injected into a node, so it is a function of the network elements and the topology. Considering the whole network, the PTDF is a matrix of L x N, where each element *PTDFn*(*l, n*) contains the influence on the flow through a line l of an injection of 1 MW in node n and a withdrawal in the reference node.

For example, considering a DC model, for a connection between nodes i and j, the transit depends on the phases of the nodal voltages δ_i and δ_j as follow:

$$F_{ij} = f(\delta_i, \delta_j) \tag{34}$$

Then the PTDF is expressed by the derivative of the transit respect to the nodal injection in node n, P_n :

$$PTDF_{ij,n} = \frac{\partial F_{ij}}{\partial P_n} \tag{35}$$

The PTDF matrix is crucial to determinate the transit flow on each line, to compare with the maximum flow and so understand which are the critical branches.

To be clearer let's consider an example of a three nodes network:

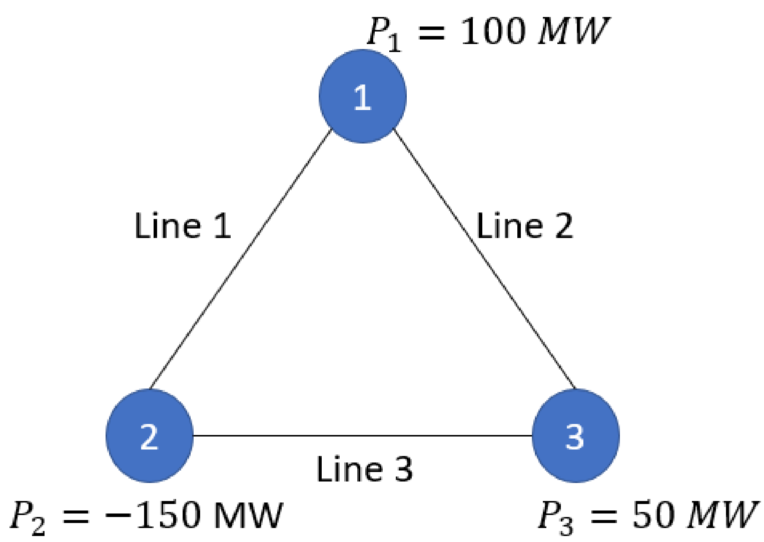


Figure 27. A three nodes network.

In which, in the node 2 a demand of 150 MW needs to be fulfilled and generation is given by node 1 and node 2. The PTDF matrix gives the relation between the power injection in the nodes and the flow occurring in the line. Assuming line impedances equal to 1, the resulting PTDF is:

$$PDF = \begin{bmatrix} 0.667 & 0 & 0.333 \\ 0.333 & 0 & -0.333 \\ -0.333 & 0 & -0.667 \end{bmatrix}$$

(36)

As mentioned before, the obtained PTDF matrix relates power injection with power flows:

$$F_l = \sum_{n=1}^{N} PTDF(l,n) \cdot P_n \leq F_{max,l} \qquad \forall l \in L$$

(37)

And in this example, it will be:

$$\begin{bmatrix} F_1 \\ F_2 \\ F_3 \end{bmatrix} = \begin{bmatrix} 0.667 & 0 & 0.333 \\ 0.333 & 0 & -0.333 \\ -0.333 & 0 & -0.667 \end{bmatrix} \times \begin{bmatrix} 100 \\ -150 \\ 50 \end{bmatrix} = \begin{bmatrix} 83.3 \\ 16.6 \\ -66.6 \end{bmatrix}$$

(38)

3.7.2. Local Marginal Price (LMP)

LMPs are determined starting from the Lagrange multipliers associated to the equality and inequality constraints of the OPF. Their calculation is based on a weighted combination of the Lagrange multipliers associated with the balance constraint and the inequality constraints that define the security conditions of the grid. In the case of an OPF using a DC representation of the grid, the nodal price of node n, p_n, can be calculated as follows:

$$p_n = \lambda + \sum_{l=1}^{L} \mu'_l \frac{\partial F_l}{\partial P_n} - \sum_{l=1}^{L} \mu''_l \frac{\partial F_l}{\partial P_n}$$

(39)

Where:

λ: marginal price of the slack node, equal to the Lagrange multiplier of the energy balance constraint, when limits are not blinded $p_n = \lambda$;

μ'_l, μ''_l: Lagrange multipliers of the inequality constraints that limit the flows on the branches;

F_l: flow on the line l;

P_n: power injection of node n.

3.8. Clustering Methods

The obtained indicators are used as input of the clustering methods, where the goal is to group nodes with similar LMPs (or PTDFs) to create a different configuration of zones which could bring benefits. In general, clustering methods are used for grouping a number of entities on the basis of data that represent their characteristics or behaviors. The process applied in the electricity sector has the following phases:

- *data gathering and processing*: measurement and calculation of the data for the entities under study (i.e. nodes), and treatment of missing data;
- *pre-clustering*: data pre-screening, selection of representative features, and formation of the input data matrix;
- *clustering*: selection of the clustering algorithm to be used, formation of the clusters and of the cluster centroids, and computation of the clustering validity indicators;
- *post-clustering*: formation of the final groups considering possible external constraints or links among the entries belonging to the resulting clusters.

3.8.1. Pre-clustering

A pre-clustering phase is necessary with the aim to find possible simplifications and avoid useless executions. In the following, it will refer to LMPs as indicators.

One of the relevant aspects is the number of time steps at which LMPs differ in the nodes. The number of time steps is reduced calculating the standard deviation at each time steps, and then removing all time-steps with standard deviation null or lower than a predefined threshold, so long as they don't give useful information.[18]

In this way, the LMPs in the remaining time steps can be used directly as clustering features and the input data matrix is then formed.

3.8.2. Clustering and post-clustering phases

The clustering algorithms have been executed by using as features the LMPs or the PTDFs of the most critical elements. Focusing on the use of LMPs, specific clustering algorithms have provided good performance in the study implemented on a reduced model of the European transmission network, namely:

- *k-means* (KM) clustering, adopting the squared Euclidean distance metric and using the k-means++ algorithm for cluster center initialization to attenuate the problem of random initialization;
- *hierarchical* clustering with different linkage criteria, that is, different ways to calculate the distance between clusters to decide how to merge pairs of clusters based on the minimum distance.

However, these versions form the zones only based on the numerical values of the LMPs, not considering the connections among the nodes. Therefore, it is very probable to obtain non-connected zones. This issue can be solved in different ways.[18] One possibility is to operate a postprocessing of the clustering results: starting from the predefined number of clusters, the non-connected zones are splitted, leading to an increase in the number of final zones. Another way is to modify the code of the clustering algorithm, by incorporating the node connection check inside the algorithm, in which a distance matrix is used to represent how the pairs of nodes are connected, and a penalty factor is applied to the entries of a distance matrix when the nodes are not connected. This makes less likely to merge non-connected nodes in the clustering procedure.

Next chapter consists in a study case of a known network. Thus, it has been followed an expert-based approach changing position of nodes in order to form a new disposition of the zones.

CHAPTER 4
Case Study: the IEEE Reliability test system 73-bus

4.1. Overview of Case study

In this chapter a case study is presented, starting from a well-known network structure [19] [20], and using it as starting framework for further analysis.
The network model is based on the IEEE Reliability test system of 1996, as called also RTS96, formed of 73 buses and it will be explained in more detail in next paragraph. It will be used a DC power flow, so network is represented by reactances and only real power and phase angles are taken into account; that to reduce constraints and linearize the problem.
The analysis can be divided in two sections. First it has been implemented a way to calculate the transmission capacity allocations with the ATC and FBMC methods, comparing the results to individuate all pros and cons of both and which one might be the better solution. Moreover, of course the determination of the transmission limits depends on the configuration of the zones. A simulation of the Day-Ahead Market has been done to compare market outcomes as well. Therefore, it has been evaluated how changing the configuration of the network impacts on the determination of parameters of the methods and on final results.
In the second part of the study the impact of the renewable generation sources is taken into account. As explained in the previous chapter, RES penetration can lead to a decrease of zonal prices, but on the other hand new challenges emerge. The analysis is focused on find the best configuration of bidding zones to handle the growth of RES and its consequences, comparing the two situation and evaluating the possible improvements.
The following table summarizes the cases to be analyzed:

Case	Description
‘BC’	The base case, all the input data are directly given by the IEEE RTS-96 and reported in the tables in Appendix A. The configuration of the zones doesn’t change and as well the generated power. Generators from renewable sources are set ‘not working’.
‘ZB’	As the base case, inputs don’t vary and are the same of *‘BC’*. The configuration has been changed to compare to *‘BC’* results. Generators from renewable sources are set ‘not working’ as well.
‘R1’	The configuration and input are the same of the base case. It has been considered their maximum capacity for renewable generators, then they enter in the market with all implication which have been evaluated. So, all generators are working.
‘ZR’	It’s the case of *‘R1’*, that is maximum generated power from renewables, but with the same configuration of *‘ZB’*.

Table 2. Description of study cases.

MATLAB R2018b is the benchmark program used to compute and analyze the data, with the help of MATPOWER Tool, which provide all the network and market features. In particular, functions of the program, which have been used are the following:

- *‘makeincidence’*: form the incidence matrix L;
- *‘makeBdc’*: form the matrix B;
- *‘makePTDF’*: form the PTDF matrix;
- *‘rundcpf’*: run a DC power flow;
- *‘linprog’*: used for the optimization problem;
- *‘geoscatter’*, *‘geobubble’* and *‘geoplot’*: to plot the network, as well the results, on a geographic map.

4.2. Topology of the Network

The first version of the IEEE Reliability Test System (RTS-79) was developed and published in 1979 by the Application of Probability Methods (APM) Subcommittee of the Power System Engineering Committee. It was developed to satisfy the need for a standardized data base to test and compare results from different power system reliability evaluation methodologies. In 1986 a second version of the RTS was developed (RTS-86) and published with the objective of making the RTS more useful in assessing different reliability modeling and evaluation methodologies. RTS-86 expanded the data system primarily relating to the generation system. The last update to the RTS came in 1996 (RTS-96). This update provided a substantial increase in model complexity and size, and add operating costs and constraints related to the generating units.

The RTS-96 is substantially composed by three RTS-79 systems with specific interconnection. Thus, the system is divided in 3 areas, which are the Bidding Zones in examination, and it's formed by 73 buses, divided in such way:

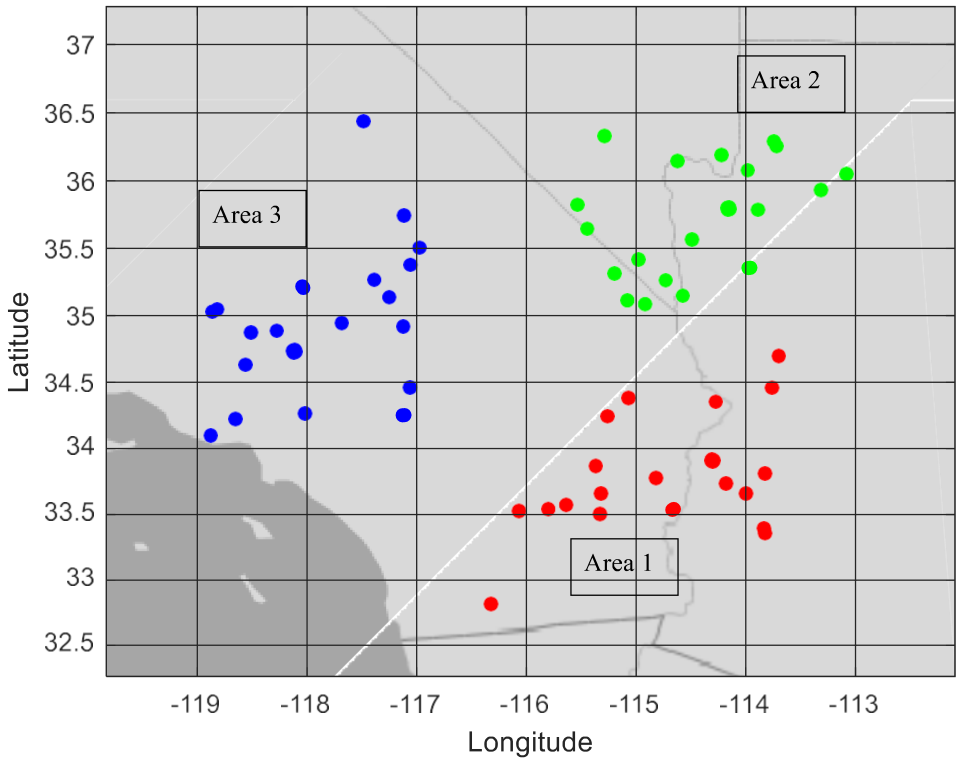


Figure 28. Distribution of the nodes in the network.

- From 101 to 124 in Area 1;
- From 201 to 224 in Area 2;
- From 301 to 325 in Area 3.

They can also be classified according to their type as:

- 32 PV buses;

- 40 PQ buses;
- Bus 113 as reference bus (slack node).

Or by the magnitude of voltage:

- 30 buses of 138 kV;
- 43 buses of 230 kV.

Figure 29. The IEEE 73-bus RTS-96.

4.2.1. Branches information

For the further analysis, the topology of the network is essential and straightly connected to the results. For example, changing connections between nodes or varying impedance, can give different results in terms of ATC constraints.
Then, it's quite important to assess these values and give and unique footprint of the network. In this sense, RTS-96 provide all branches information in a table format of 120 rows, meaning there are 120 branches. The columns of interest report the identification code of the branch, the starting and the arrival point and the parameters of the line. As said before, the network is composed by three areas. For the

determination of ATC constraints, lines connecting zones play a fundamental role, so long as they are useful to determine the virtual interconnectors among the areas. Branches information are reported in the following table:

UID	From Bus	To Bus	R (p.u.)	X(p.u.)	Areas
'AB1'	107	203	0.0420	0.1610	1-2
'AB2'	113	215	0.0100	0.0750	1-2
'AB3'	123	217	0.0100	0.0740	1-2
'CA1'	325	121	0.0120	0.0970	3-1
'CB1'	318	223	0.0130	0.1040	3-2

Table 3. Relevant information of cross-border branches.

4.2.2 Load and Generation Data

The data reported in the table in the Appendix A were provided directly by the RTS-96 and refer to a benchmark situation of the network, used then to calculate capacity constraint with both methods.

The load of each bus is in the last column, and it's also reported the correspondent voltage, type, name and ID of the buses. As can be noticed, some buses have zero load, as bus '111', meaning they can be a generation bus, or even only a transit node. The distribution of the load is expressed in following figure, obtained by the MATLAB function *'geoscatter'*, where the size of the markers represents the amount of power request, and the colors indicate the belonging zone in this way:

- RED: for the nodes belonging to Area 1;
- GREEN: for the nodes belonging to Area 2;
- BLUE: for the nodes belonging to Area 3.

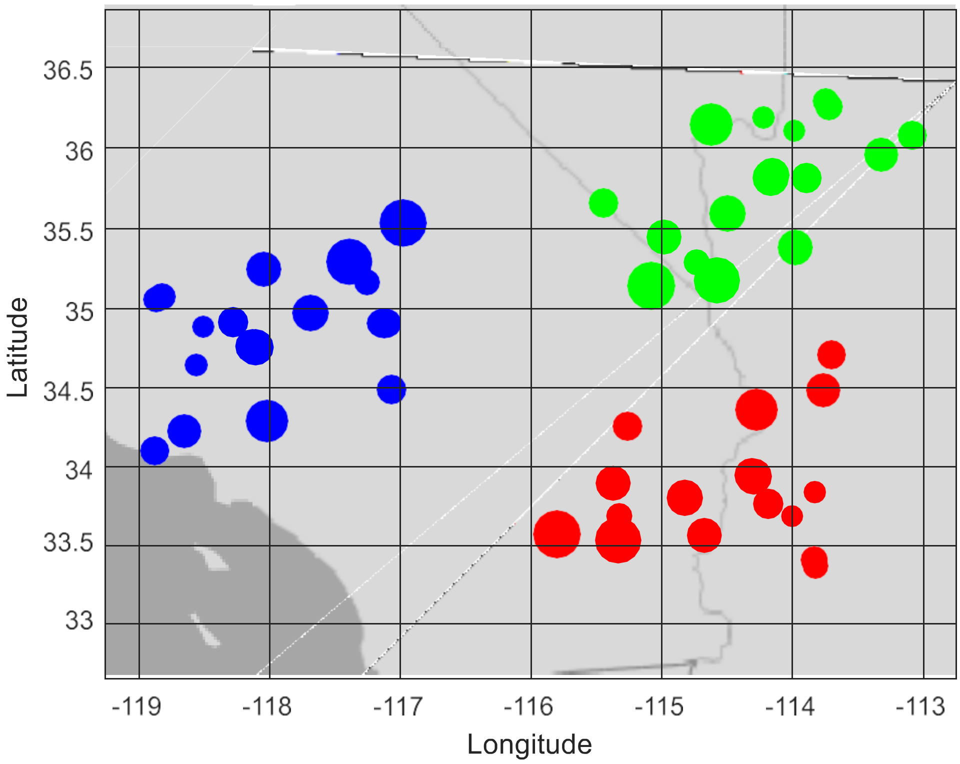


Figure 30. Distribution of the Loads.

As the Load, Generation data are provided by the RTS-96. In this case, for a bus it could be more than one power injected into the network, as well as it could be zero. Moreover, it's provided the generator type and the constraints of minimum and maximum power that could be injected. Important to say that, at the beginning of the analysis, solar and wind generators are set to 0, then to its maximum value.

It can be distinguished as well by the type of generation. On the total of 158 generators, more of 50 % are from renewable sources, i.e. hydro, wind and solar, although solar generation for the initial analysis are set to 0. Then, the non-renewable generators consist in coal, oil and natural gas, which are the majority and divided in combustion turbine and combined cycle.

Generator type	**N°**	**%**

Coal	16	10.13
Natural Gas (NG)	37	23.42
Oil	19	12.03
Hydro	20	12.66
Solar	57	36.08
Wind	4	2.53
Others	5	3.17

Table 4. Type of Generation.

The algorithm used for simulating the DAM, for both approach is structured as mentioned in Chapter 1 using the equation (3), (6), (7) and (8), with the difference in the FBMC of consider flows limit over the critical branches and not only on the virtual interconnector. Inequality and equality constraints has been already explained, and remembering that the objective function is to maximize the social surplus:

$$S^s = \sum_{i=1}^{D} \rho_{Di} \cdot P_{Di} - \sum_{j=1}^{G} \rho_{Gj} \cdot P_{Gj}$$

The offers ρ_{Di} from the loads are set equal for each of them at $400\ €/MWh$.

The bids ρ_{Gj} on the generation unit have been considered as the marginal cost, always in $€/MWh$. Marginal cost is obtained by deriving the cost function, considered as piecewise linear it is:

$$c(p) \begin{cases} m_1(p - p_1) + c_1 & p \leq p_1 \\ m_2(p - p_2) + c_2 & p1 < p \leq p_2 \\ \vdots & \vdots \\ m_n(p - p_n) + c_n & p_{n-1} < p \end{cases} \tag{40}$$

Where m_j denotes the slope of the j-th segment:

$$m_j = \frac{c_j - c_{j-1}}{p_j - p_{j-1}} \qquad j = 1,2, \ldots . n \tag{41}$$

Then marginal cost corresponds to the coefficient m_j of each piecewise. To simplify it has been considered only the two borders power, the ones in the last two column in the table of generation data, P_{min} and P_{max}, while the cost coefficient are provided as data input.
For the optimization problem, it has been chosen a linear programming solver with the use of *'linprog'* function of MATLAB.

4.3. Results

In this section the results of all the analyzed cases are presented. For each of them, the Load data has never been changed, using the input data of Appendix A. The base case, called as '*BC*', corresponds to the starting data, as reported in 4.2. Then the renewable generation has been changed (case '*R1*'), set to P_{max} and making them part of the process of the market and power flows. Moreover, the position of some nodes was changed (case '*ZB*' and '*ZR*'), to create new zone and estimate how can impact on network and market efficiency.

4.3.1. Cases with $P_{RES} = 0$

4.3.1.1. Base case *'BC'*

For the Base Case branches connecting the zones are five, respectively three between 1-2, and one between 1-3 and 2-3. Their value of reactants is reported:

Areas	**Branches**	**X(p.u.)**
1-2	107-203	0.1610
1-2	113-215	0.0750
1-2	123-217	0.0740
2-3	223-318	0.1040
1-3	121-325	0.0970

Table 5. Reactance of cross-border branches.

The results obtained support what is already knew, that is the strongness of the flow-based approach respect to the ATC. In fact, the FBMC lead to a wider range of cross-border capacity, in particular by a factor of about 4. That means more 'soft' constraints on the border lines and then a higher possibility to exchange power between zones. In the last column the limiting factor is given, about the ATC approach and define the branch that reached the limit and give the cross-border limit.

Areas	Flow-based approach (MW)	ATC approach (MW)	Limiting factor
1-2	618.19	145.31	107-108
2-3	404.51	84.75	107-108
1-3	327.51	71.37	107-108

Table 6. Cross-border Capacity results for *'BC'*.

The following figures help to understand even better how the situation changes with the different approaches. The markers always represent the Load as explained in 4.2.2, while one node for each zone has been chosen to represent the whole zone, calculated as the average of latitude and longitude of the nodes belonging to that zone. Instead, lines represent the virtual interconnector among zones, and their widths is the ratio between capacity on the line and the highest of both approaches.

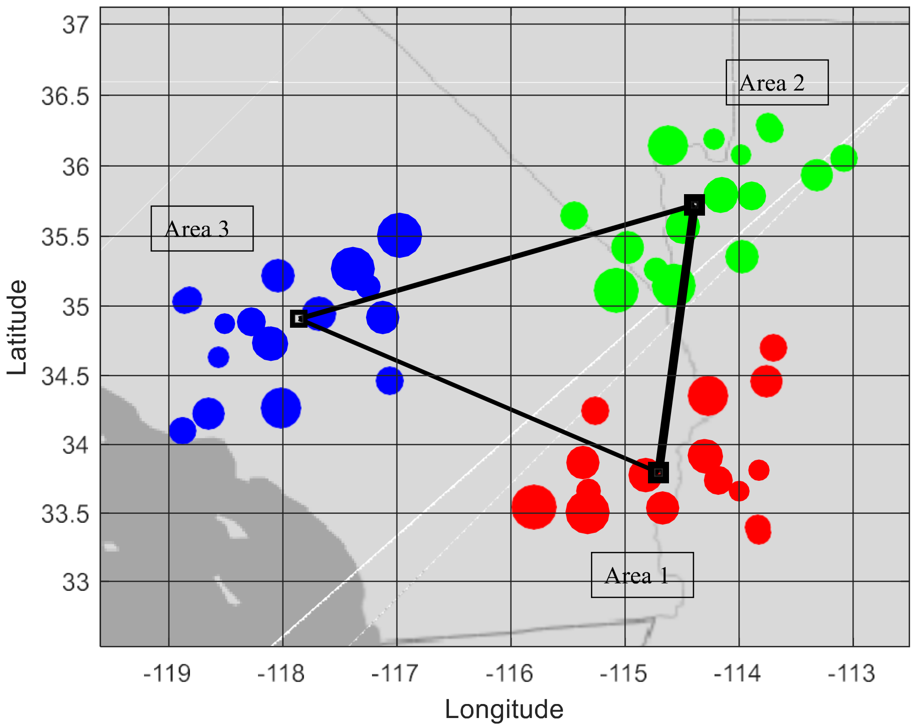


Figure 31. *'BC'* Cross-border Capacity with ATC approach.

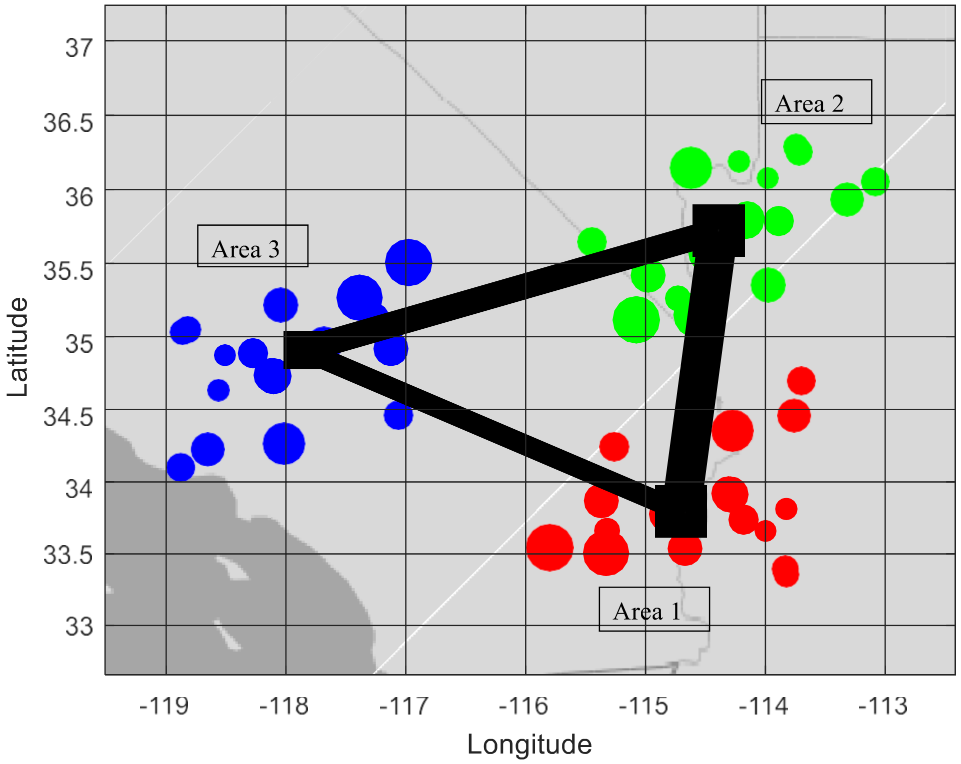
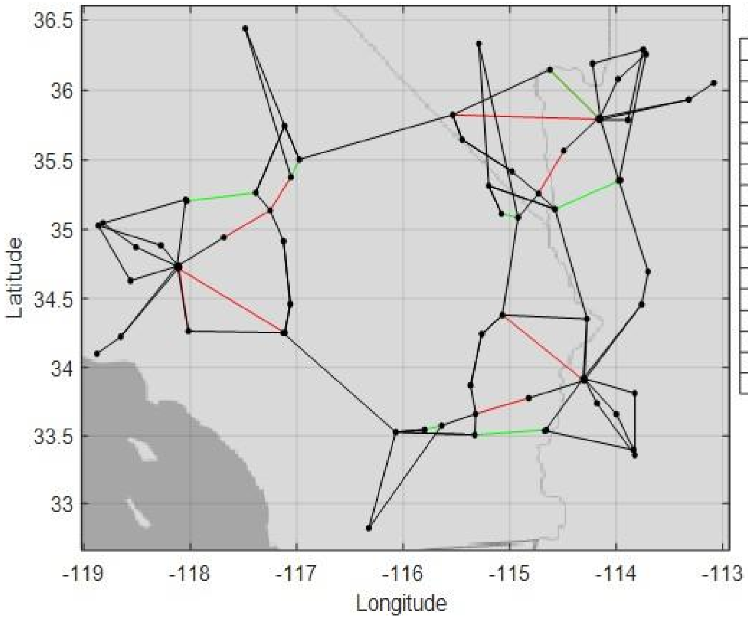


Figure 32. *'BC'* Cross-border Capacity with Flow-based approach.

Besides, for flow-based case critical branches are determined, choosing a very low threshold of $\alpha = 0.005$. The resulted critical branches are 17, as reported in the graphic and they will be added to the inequality constraints. 10 on 17 will exceed the limits.



Critical Branches	Real Flow [MW]	Flow Limit [MW]	
112-123	-203.82	184.71	O
114-116	-253.51	119.85	O
115-124	185.34	206.80	R
117-118	-96.34	280.03	R
211-213	-206.98	179.90	O
212-213	-146.27	255.91	R
212-223	-242.67	174.34	O
214-216	-308.72	140.96	O
215-224	205.58	223.67	R
217-218	-133.51	296.51	R
303-324	-279.78	138.76	O
311-313	-213.80	207.98	O
312-323	-310.97	127.56	O
315-324	-356.18	75.798	O
316-317	154.65	154.65	C
317-318	-298.66	127.36	O
112-123	-32.53	268.72	R

Figure 33. *'BC'* Critical branches representation.

On the other hand, in the ATC methods, only the virtual interconnectors are considered as constraints. For sure this is an approach more approximate since flows on real branches are not taking into account, thus possible overcoming of the flow limits are firstly ignored, and then considered in the second phase of the market, but that isn’t the scope of this work. In this case, two of three ATC constraints are reached, so among zones 1-2 and 2-3 the maximum available power is transferred. In FBMC, limits over the interconnector are reached only between area 2 and 3, while for other two transaction, the power flow is quite lower than the limit.

	ATC Approach		FBMC Approach	
Areas	**Flow limit (MW)**	**Real Flow (MW)**	**Flow limit (MW)**	**Real Flow (MW)**
1-2	145.31	145.31	618.19	24.51
2-3	84.75	84.75	404.51	404.51
1-3	71.37	66.69	327.51	236.51

Table 7. Flow limit and Real flow for *'BC'*.

Inequality constraints in the flow-base OP are more tighten, since critical branches are considered, and as it can be view from results constraints are overreached on 10 branches over 17. That means the need to reconsider the market problem and some adjustments are needed: it could lead to an increase of marginal costs for producers and of price for consumers. However, comparing market efficiency as equation (10), flow-based presents a slightly higher social surplus than ATC. Price as well is lower in the FBMC, the OP gives the system price, though some more actions can barely change the price for each zone. The following table presents the results, underlining these are the DAM's results so not the final dispatching situation:

	ATC Approach			**FBMC Approach**		
Areas	1	2	3	1	2	3
λ (€$/MWh$)	32.77	29.60	33.77	30.56	30.56	30.56
S^S (€$/h$)	3220400			3220800		

Table 8. Market outcomes for *'BC'*.

The power generated for both approach is quite similar, less than some differences due to branch limit. All the generators are committed, 93, while the others are from renewable sources and not working. The following maps show the distribution of all the generators, working and not, in ATC and FBMC approach.

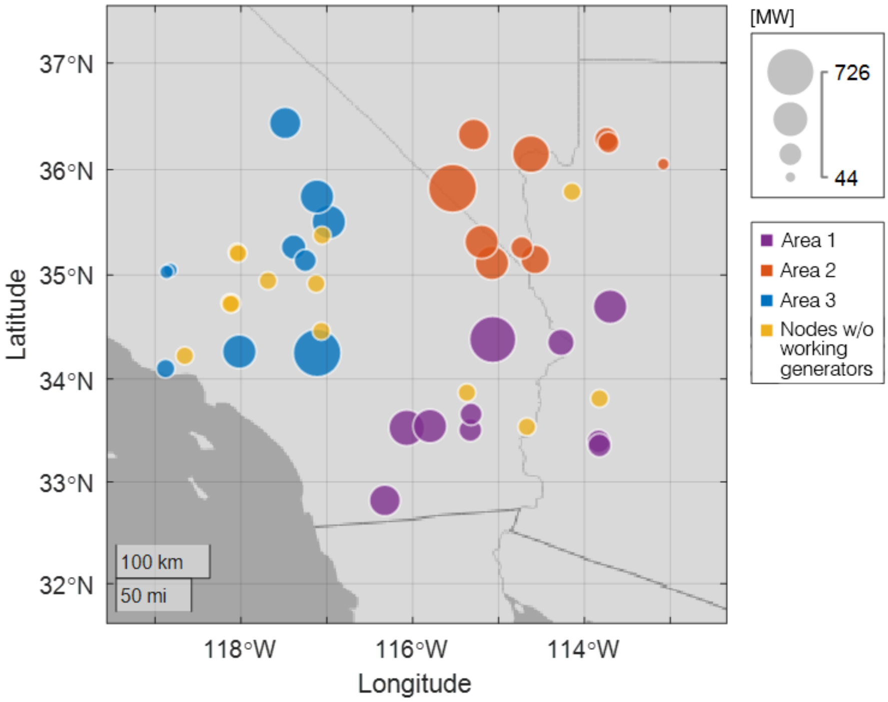


Figure 34. *'BC'* Distribution of generated Power (ATC approach).

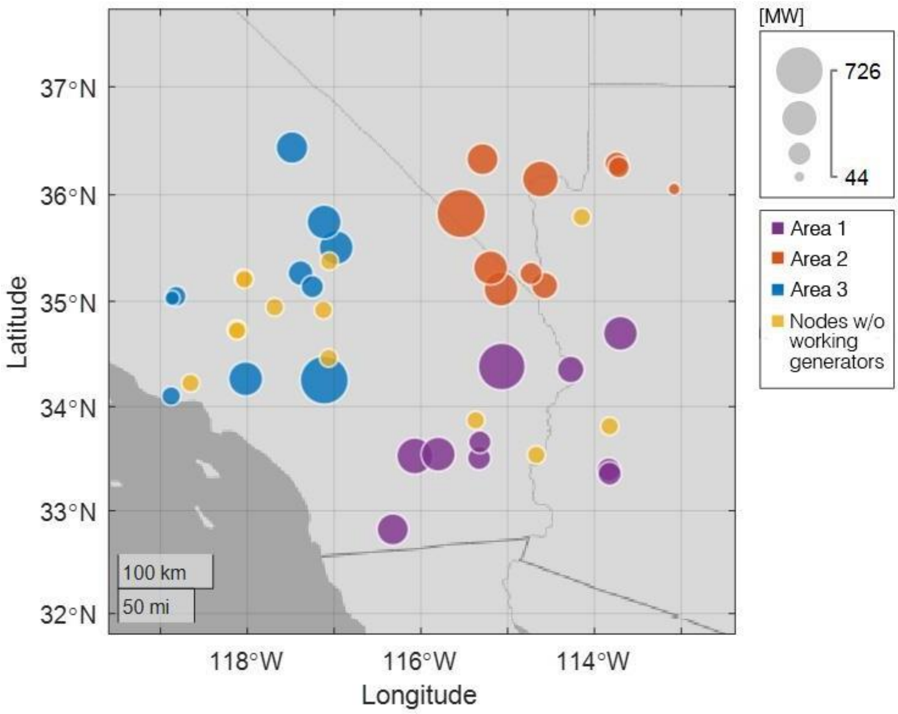


Figure 35. *'BC'* Distribution of generated power (FBMC approach).

4.3.1.2. Case *'ZB'*

In this section, the topology of the network is changed varying the position of some nodes respect to the belonging area. It has been studied how these changes on formation of bidding zones can impact the capacity allocation and the economic and physical dispatch as well. Of course, changing position of the nodes have an impact also on branches among zones; thus, virtual interconnector will correspond to other branches than *'BC'* case and this could bring advantages or not. Moreover, if in *'BC'* only between area 1 and 2 there were more than one branch connecting the zones, with the new disposition all the area are connecting to each other with at least two branches. How it can be seen in figure 40, the choice of what nodes move to another zone was not casual, it has been picked those nodes geographically closer to that area, so:

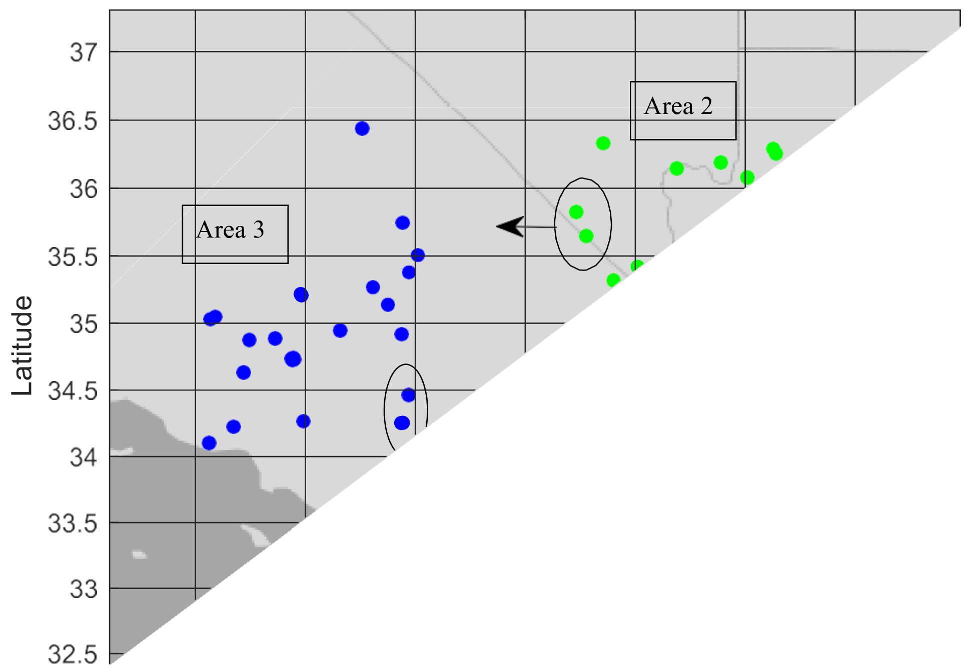


Figure 36. New disposition of BZs.

In particular:

- Nodes 107 and 108 from Area 1 to Area 2;

– Nodes 220 and 223 from Area 2 to Area 3;
– Nodes 320, 323 and 325 from Area 3 to Area 1;

In this way new border branches are:

Areas	**Branches**	**X(p.u.)**
1-2	108-109	0.1650
1-2	108-110	0.1650
1-2	113-215	0.0750
1-2	123-217	0.0740
2-3	212-223	o.2030
2-3	213-223	0.1820
2-3	219-220	0.0415
1-3	312-323	0.2030
1-3	313-323	0.1820
1-3	319-320	0.0415

Table 9. Reactance of new cross-border branches.

Then, the new cross-border capacity limits are calculated with the same procedure, changing the flow considered in the process and this led to different results. This third case uphold the results of previous cases, being flow-based capacity such bigger than the one obtained in ATC.

Areas	**Flow-based approach (MW)**	**ATC approach (MW)**	**Limiting factor**
1-2	583.68	111.62	107-108
2-3	785.31	455.59	107-108
1-3	921.34	459.14	107-108

Table 10. Cross-border Capacity results for *'ZB'*.

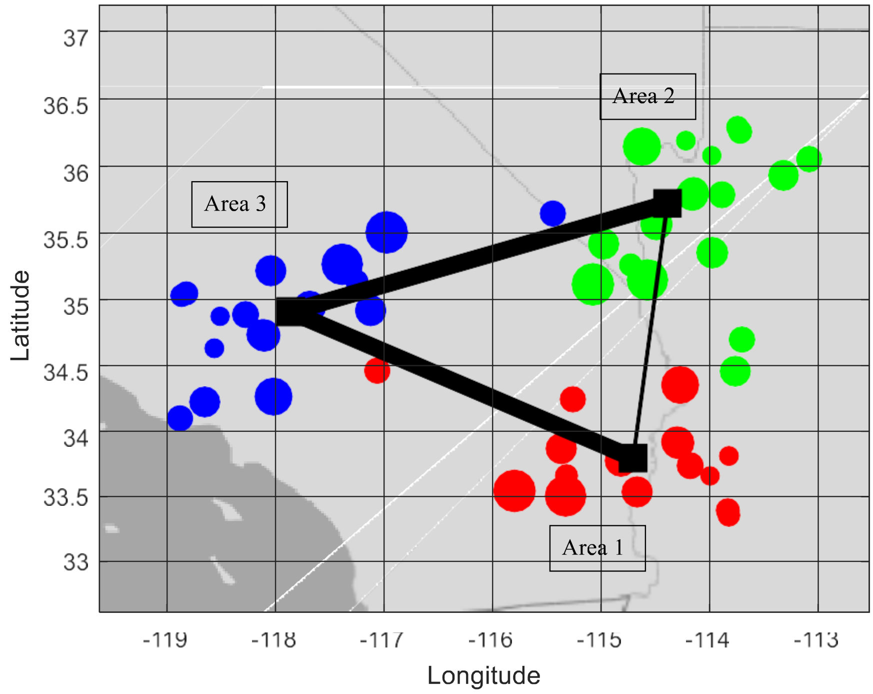


Figure 37. '*ZB'* Cross-border Capacity with ATC approach.

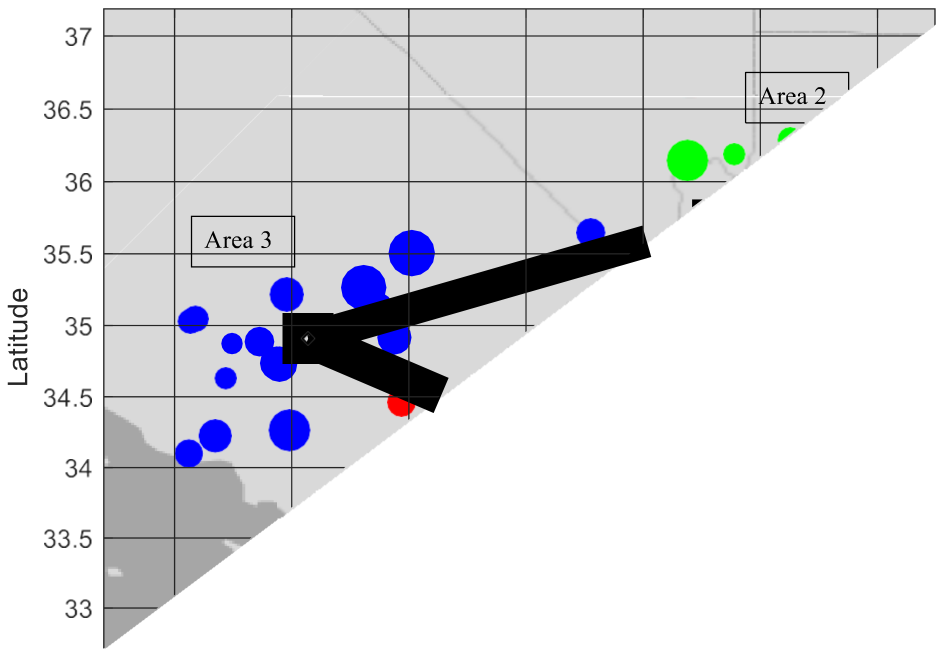
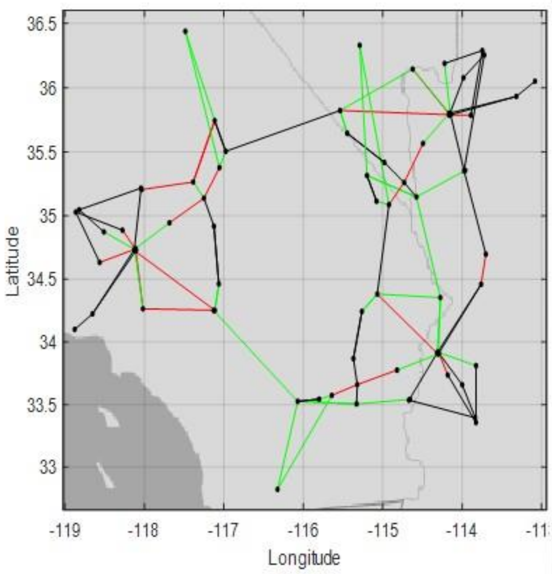


Figure 38.*'ZB'* Cross-border Capacity with FBMC approach.

For the determination of critical branches, a threshold of $\alpha = 0.005$ has been chosen. The choice to use the same α of *'BC'* was made to better compare these two cases. Though the number of critical branches of *'ZB'* is much higher than in the base case, it's important to clarify that a very low value of α has been picked for to appreciate the presence of critical branches. In fact, with normal values of α, like the one used in other case, no critical branches emerged. So, with the new disposition of the areas, critical branches founded are 70, and 22 of them overcome their limit.



Critical Branches	Real Flow [MW]	Flow Limit [MW]		Critical Branches	Real Flow [MW]	Flow Limit [MW]	
103-124	-184.72	186.97	R	214-216	-308.72	134.81V	O
104-109	-41.43	100.76	R	215-221	-202.36	213.60	R
106-110	-92.26	37.41	O	215-221	-202.36	213.60	R
107-108	39.20	39.20	C	215-224	205.58	217.08	R
109-112	-133.85	265.87	R	216-217	-280.12	169.10	O
110-111	-132.27	260.66	R	217-218	-133.51	290.42	R
110-112	-170.80	225.61	R	217-222	-136.90	270.27	R
111-113	-169.88	279.28	R	220-223	-121.79	243.67	R
111-114	-58.89	310.75	R	220-223	-121.79	243.67	R
112-113	-101.44	341.55	R	221-222	-162.47	236.70	R
112-123	-203.82	178.89	O	303-324	-279.78	133.21	O
113-123	-171.28	188.45	R	304-309	-93.44	75.11	O
113-215	-100.66	231.87	R	305-310	-73.19	99.18	R
114-116	-253.51	113.22	O	306-310	-131.01	18.71	O
115-121	-168.26	211.06	R	309-311	-155.76	246.28	R
115-121	-168.26	211.06	R	309-312	-194.90	208.39	R
115-124	185.34	199.69	R	310-311	-218.95	191.73	O
116-117	-226.83	139.20	O	310-312	-258.70	153.29	O
117-118	-96.34	274.18	R	311-313	-213.80	201.81	R
117-122	-131.10	267.74	R	311-314	-161.56	265.17	R
120-123	-141.97	279.92	R	312-313	-143.25	270.09	R
120-123	-141.97	279.92	R	312-323	-310.97	120.55	O
121-122	-168.27	239.23	R	313-323	-267.68	162.83	O
203-224	-204.96	204.36	O	314-316	-356.18	67.63	O
204-209	-43.43	96.01	R	315-316	27.09	370.64	R
206-210	-88.26	35.65	O	315-321	-217.55	195.88	O
209-211	-133.11	262.09	R	315-321	-217.55	195.88	O
209-212	-166.79	219.16	R	315-324	145.92	145.92	C
210-211	-187.36	214.11	R	316-317	-298.66	120.85	O
210-212	-221.53	170.55	O	317-318	-158.28	261.64	R
211-213	-206.98	172.82	O	317-322	-141.01	261.92	R
211-214	-114.11	332.35	R	320-323	-143.13	267.48	R
212-213	-146.27	250.19	R	320-323	-143.13	267.48	R
212-223	-242.67	168.49	O	321-322	-168.38	234.75	R
213-223	-189.86	227.26	R	325-121	98.10	323.96	R

Figure 39. *'ZB'* Critical branches representation.

Presenting the OP outcomes, in this case, results give the same information: in fact, one of three constraints is reached, among zones 2-3, so the maximum available power is transferred. While for the connection between 1-2 the flow is lower than his constraints, but for 1-3 in both cases the flow limits are overreached. It can be meant that equality constraints are not respected, so generated power of a zone don't match with the power request of the same zone. Of course, changing position of some nodes influenced the results about flow and there il clearly a problem between capacity on 1-3, since in both approach limit is overreached. Thus, adjustments are needed.

	ATC Approach		**FBMC Approach**	
Areas	**Flow limit**	**Real Flow**	**Flow limit**	**Real Flow**

	(MW)	(MW)	(MW)	(MW)
1-2	111.62	107.59	583.68	437.31
2-3	455.59	455.59	785.31	785.31
1-3	459.14	1365.6	921.34	1695.3

Table 11. Flow limit and Real flow for *'ZB'*.

The new configuration of the zones had practically no consequences on the market dispatch, while capacity constraint and flows dispatch changed a lot with the new conformation. In particular, in FBMC nothing changes with a social surplus identical and the system price as well. What concern now it's a different flow of the power among zones, meaning a higher re-dispatch costs, since within zone equality constraints are not respected, precisely between zone 1 and 3. The same considerations can be made for ATC approach, but in this case, there is a slight reduction of the price and social surplus improve as well.

	ATC Approach			FBMC Approach		
Areas	1	2	3	1	2	3
λ (€$/MWh$)	30.89	29.89	31.89	30.56	30.56	30.56
S^S (€$/h$)	3220800			3220800		

Table 12. Market outcomes for *'ZB'*.

The power generated is not presented, since although the bidding zones changed power doesn't or at least not as much quantitatively to be shown. For flow based is identical, while in ATC approach it barely changes in some nodes.

4.3.2. Cases with $\boldsymbol{P_{RES} = P_{RES.max}}$

4.3.2.1. Case *'R1'*

In this study case it has been considered the renewable generators working at them maximum power. That will lead to a higher on-line capacity, then the cross-borders limits will change due to a stronger flow on the branches. Furthermore, the results of optimization problem will change, since renewable generators will be committed as higher as possible, due to their marginal cost, that is zero because none of these costs occurs in renewable sources.

The network is still the same of *'BC'*, so branches connecting the zones are equal:

Areas	Branches	X(p.u.)
1-2	107-203	0.1610
1-2	113-215	0.0750
1-2	123-217	0.0740
2-3	223-318	0.1040
1-3	121-325	0.0970

Table 13. Reactance of cross-border branches.

As well as *'BC'*, the cross-border capacity is wider for FBMC but in this case in a non-linear way. For example, in area 1-2 the ATC-limit is hardly the double of the FB, while between 2-3 switch from 154 to 1024.

Areas	Flow-based approach (MW)	ATC approach (MW)	Limiting factor
1-2	900.92	587.26	113-215
2-3	1024.4	154.78	318-223
1-3	346.71	223.34	303-309

Table 14. Cross-border Capacity results for *'R1'*.

Following the ladder of the previous section, the figures allow to visualize and compare the founded cross-border limits, where the features used are the same of *'BC'*.

Figure 40. *'R1'* Cross-border Capacity with ATC approach.

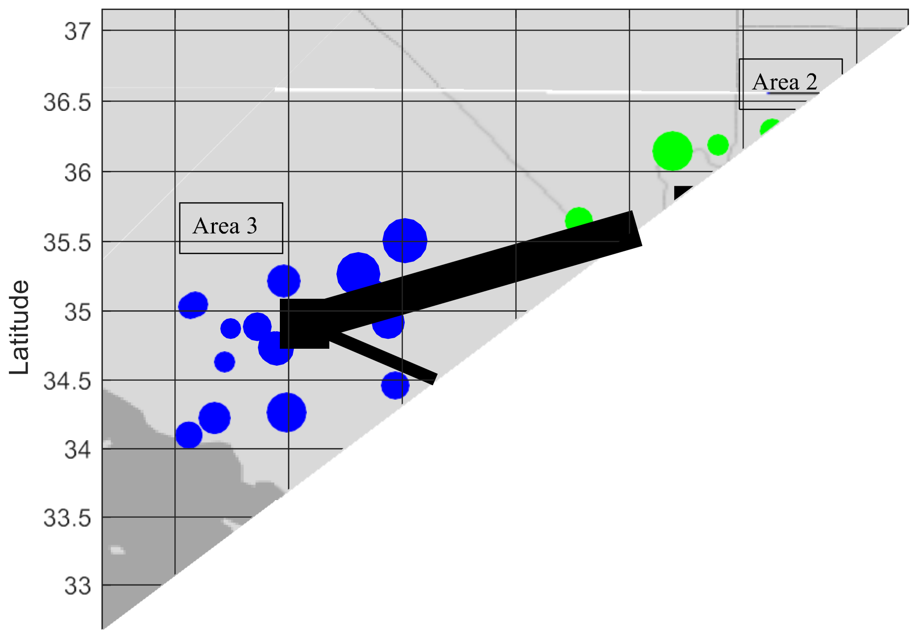
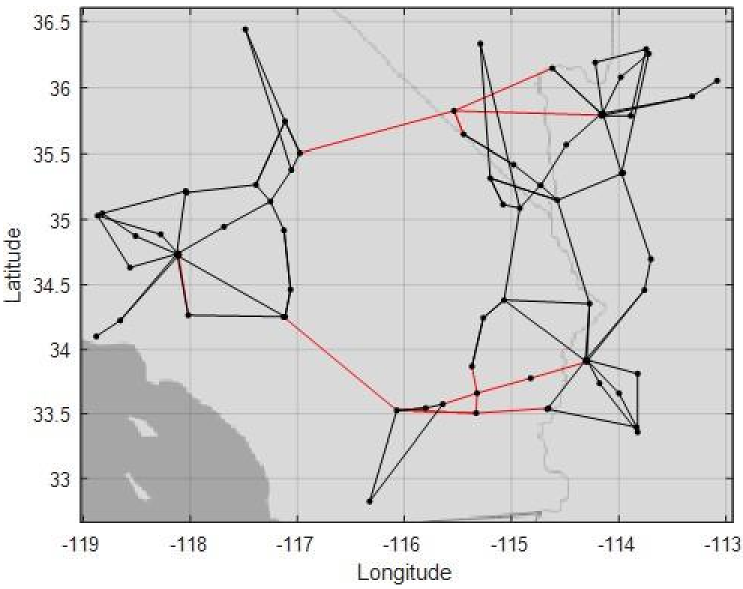


Figure 41. *'R1'* Cross-border Capacity with FBMC approach.

Besides, for flow-based case critical branches are determined, choosing this time a threshold of $\alpha = 0.1$, since using as lower as in 'BC', practically all branches resulted as critical. Then critical branches are in total 21, as reported in the graphic and they will be added to the inequality constraints.



Critical Branches	Real Flow [MW]	Flow Limit [MW]	
111-114	69.03	69.03V	C
114-116	248.07	248.07	C
115-116	109.85	109.85	C
115-121	276.76	276.76	C
115-121	276.76	276.76	C
115-124	168.74	168.74	C
116-117	565.61	565.61	C
116-119	346.54	346.54	C
117-118	252.93	252.93	C
211-213	93.57	93.57	C
212-223	216.46	216.46	C
213-223	175.85	175.85	C
216-219	101.57	101.57	C
220-223	23.69	23.69	C
220-223	23.69	23.69	C
311-313	155.44	155.44	C
312-313	80.55	80.55	C
317-318	561.78	561.78	C
325-121	346.70	346.70	C
318-223	1024.43	1024.43	C
323-325	295.61	295.61	C

Figure 42. *'R1'* Critical branches representation.

Presenting the OP outcomes, in this case, results give the same information: in fact, two of three constraints are reached, among zones 1-2 and 1-3, so the maximum available power is transferred. While for the connection between 2-3 in both cases the flow limits are overreached. It can be meant that equality constraints are not respected, so generated power of a zone don't match with the power request of the same zone. Thus, adjustments are needed. While, concerning critical branches, none of them overcome his RAM, but on every branch the maximum available capacity is flowing.

	ATC Approach		FBMC Approach	
Areas	**Flow limit (MW)**	**Real Flow (MW)**	**Flow limit (MW)**	**Real Flow (MW)**
1-2	587.26	587.26	900.92	900.92

2-3	154.78	1397.90	1024.4	2148.60
1-3	223.34	223.34	346.71	346.71

Table 15. Flow limit and Real Flow for *'R1'*.

Now the economic results are presented. With the introduction of RES, for sure prices will be lower than the previous case, but on the other hand, presence of RES lead to a higher price volatility, meaning the differences of the prices of the zones are consistent. Then using the flow-based approach didn't bring to a such improvement on price, considering is equal to the highest of ATC; that is due to presence of RES since lines are more stressed and the economic flow can be very different respect to the real physical flow. However, comparing market efficiency as equation (10), flow-based presents a higher social surplus than ATC. Price as well is lower in the FBMC, the OP gives the system price, though some more actions can barely change the price for each zone. The following table presents the results, underlining these are the DAM's results so not the final dispatching situation:

	ATC Approach			**FBMC Approach**		
Areas	1	2	3	1	2	3
λ $(€/MWh)$	27.84	12.42	13.42	27.55	27.55	27.55
S^S $(€/h)$	3360800			3363600		

Table 16. Market outcomes for *'R1'*.

The power generated for both approach is quite similar, less than some differences due to branch limit. In here, committed generators are substantially all, 154 without considering synchronous condensors and the storage. The following maps show the distribution of all the generators, working and not, in ATC and FBMC approach.

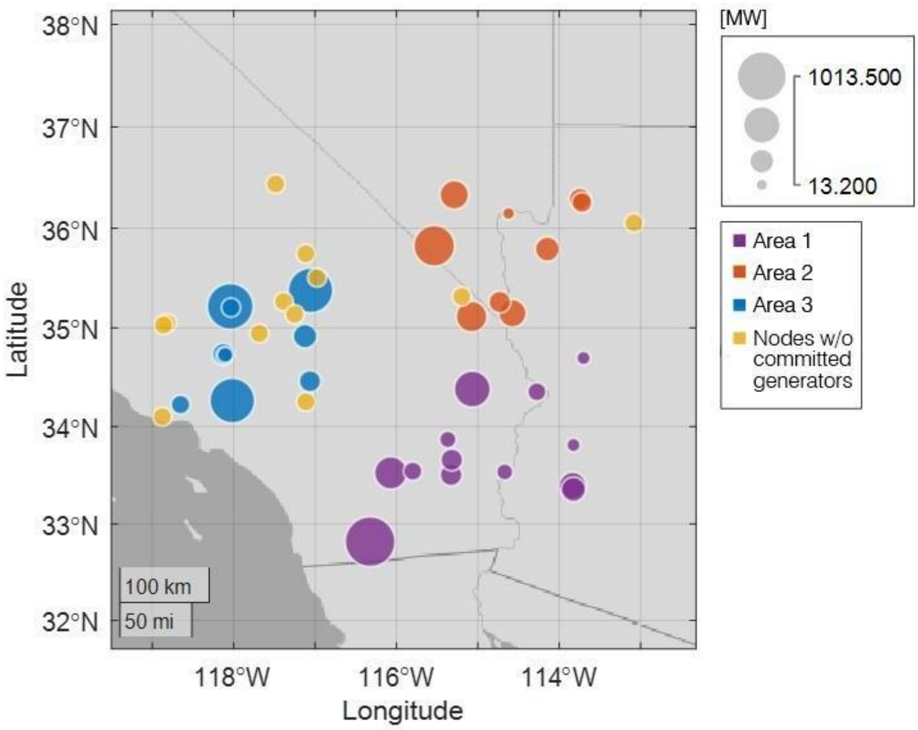


Figure 43. '*R1'* Distribution of generated Power (ATC approach).

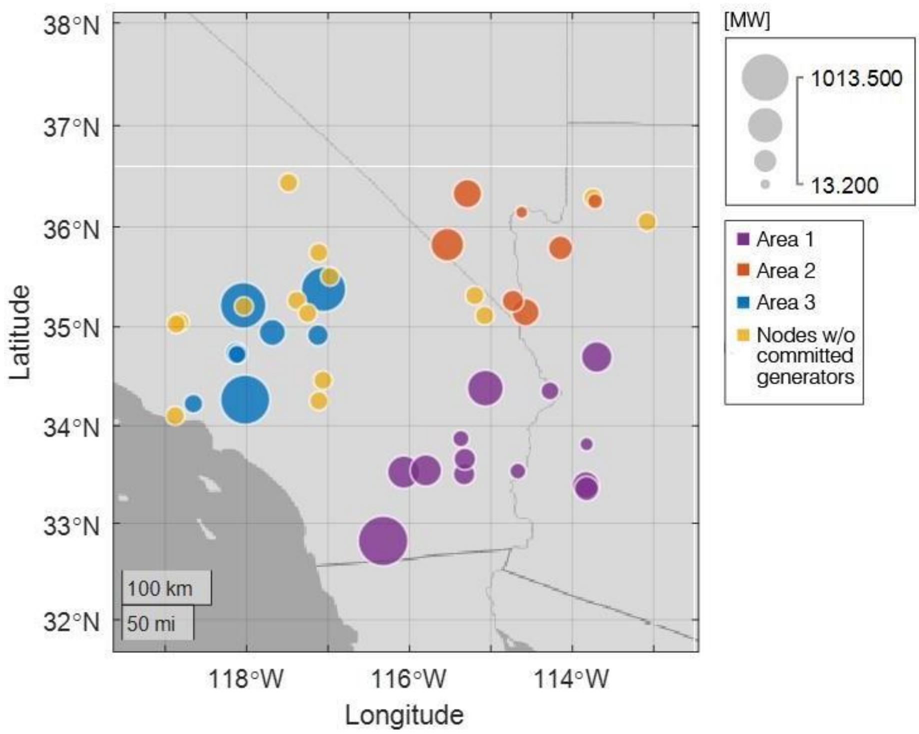


Figure 44. *'R1'* Distribution of generated Power (FBMC approach).

4.3.2.2. Case 'ZR'

In this last case, it's used the new configuration, like *'ZB'*, while making renewable generators working at their P_{max}. Then the 'renewable' cases will be compared to appreciate if there can be some improvements on changing bidding zone configurations.

The new cross-border capacity limits are:

Areas	Flow-based approach (MW)	ATC approach (MW)	Limiting factor
1-2	1135.54	713.26	318-223
2-3	705.63	589.14	318-223
1-3	571.05	402.98	303-309

Table 17. Cross-border Capacity results for *'ZR'*.

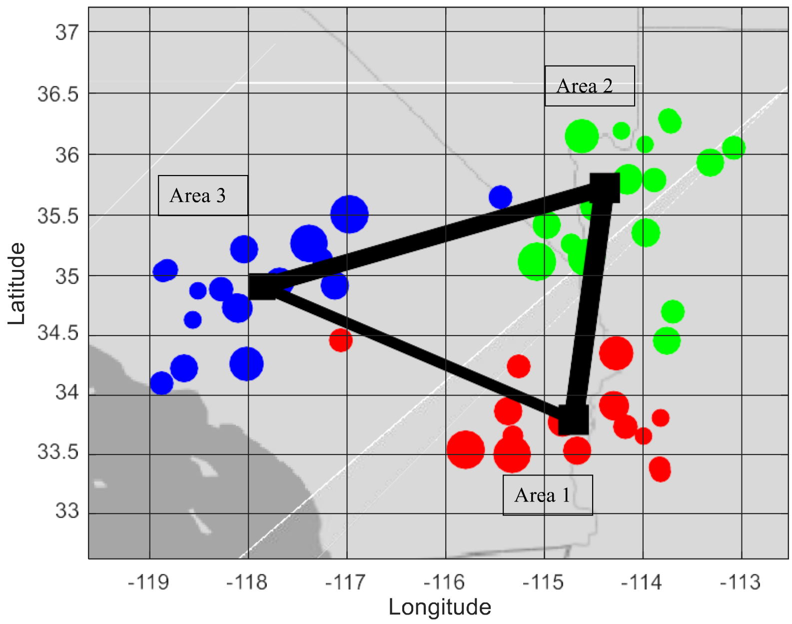
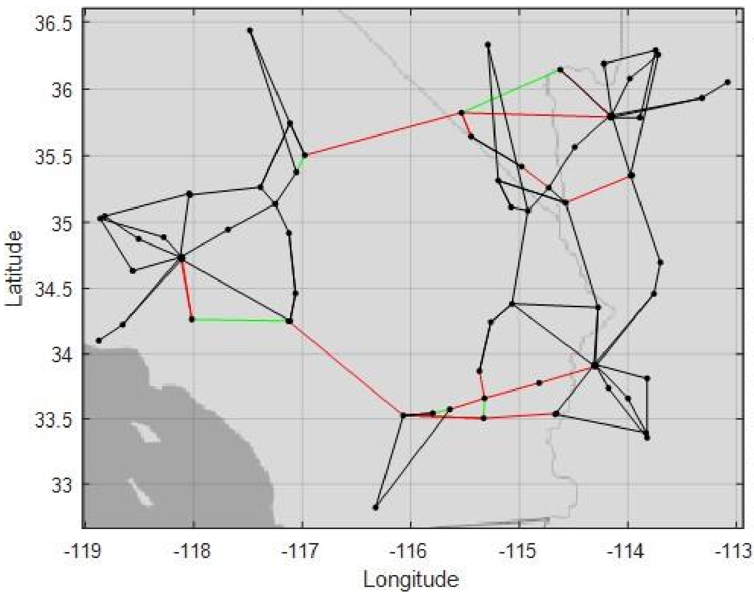


Figure 45. *'ZR'* Cross-border Capacity with ATC approach.

Figure 46. *'ZR'* Cross-border Capacity with FBMC approach.

Concerning the determination of critical branches, a threshold of $\alpha = 0.1$ has been chosen, the same of *'R1'*, with which will be compared. This time critical branches founded are 25. By running the OP, only 1 critical branch on 25 overcome the RAM.



Critical Branches	Real Flow [MW]	Flow Limit [MW]	
103-124	104.04	104.04	C
111-114	15.39	15.39	C
114-116	321.36	321.36	C
115-116	175.78	175.78	C
115-121	343.01	343.01	C
115-121	343.01	343.01	C
115-124	230.55	230.55	C
116-117	663.78	663.78	C
116-119	430.50	430.50	C
117-118	333.22	333.22	C
210-212	209.17	209.17	C
211-213	145.12	145.12	C
212-223	270.20	270.20	C
213-223	223.47	223.47	C
215-224	146.94	146.94	C
216-219	46.76	46.76	C
220-223	70.75	70.75	C
220-223	70.75	70.75	C
311-313	204.67	204.67	C
312-313	127.76	127.76	C
313-323	41.60	41.60	C
317-318	646.30	646.30	C
325-121	-7262.02	438.93	O
318-223	1171.37	1171.37	C
323-325	407.49	407.49	C

Figure 47. *'ZR'* Critical branches representation.

In this case, results give different information on the network: on one side, in the ATC constraints are overreached in 1-2 and 1-3 while between 2-3 the limit is blinded; on the other hand, in FBMC approach happens the opposite and only between 2 and 3 the limit is overreached.

	ATC Approach		**FBMC Approach**	
Areas	**Flow limit (MW)**	**Real Flow (MW)**	**Flow limit (MW)**	**Real Flow (MW)**
1-2	713.26	4269.3	1135.54	1135.54
2-3	589.14	589.14	705.63	2842.1
1-3	402.98	4948.5	571.05	571.05

Table 18. Flow limit and Real flow for *'ZR'*.

Prices and market efficiency had a great improvement in this way, the results are presented here while comparison between different cases will take place in next section.

	ATC Approach			**FBMC Approach**		
Areas	1	2	3	1	2	3
λ (€$/MWh$)	23.31	22.31	24.31	17.56	17.56	17.56
S^S (€$/h$)	3380300			3374400		

Table 19. Market outcomes for *'ZR'*.

The generated power presents some changes. With the same ladder of the previous cases, the graphs of the generated power for each node are shown, then in next section all comparisons will be made.

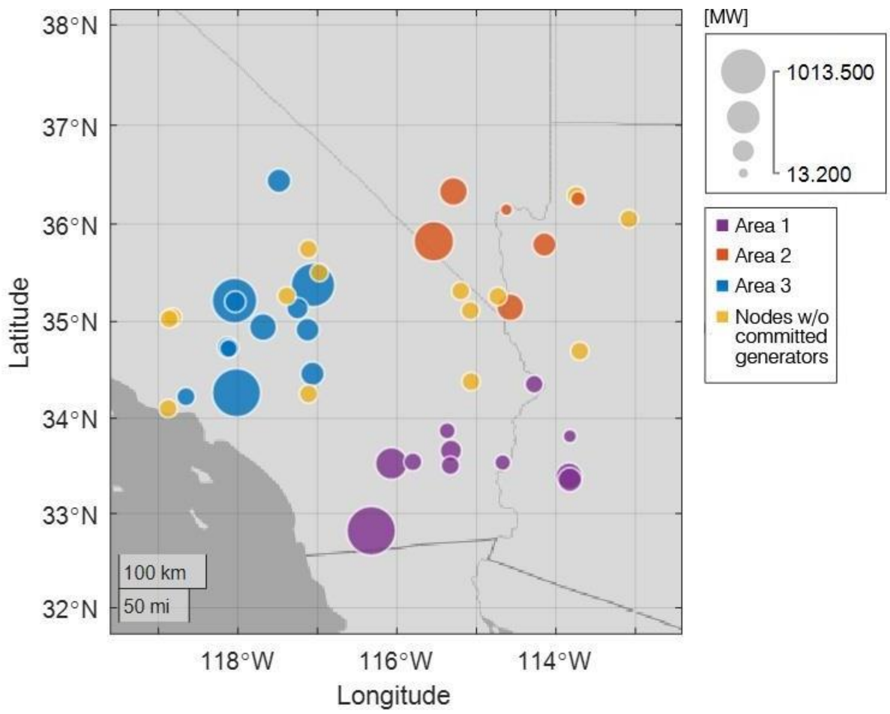


Figure 48. *'RZ'* Distribution of generated Power (ATC approach).

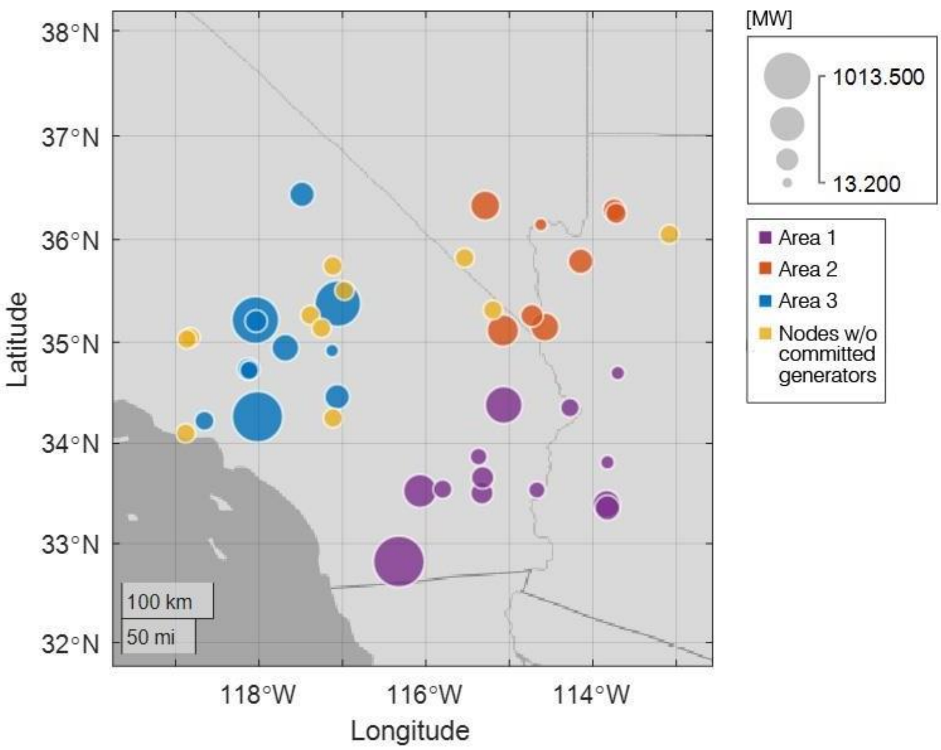


Figure 49. *'RZ'* Distribution of generated Power (FBMC approach).

4.4. Results discussion

This section concerns the analysis of the obtained results, in order to compare the different studied cases to get outcomes and conclusion that could be useful in further studies. In particular, in all cases ATC and FBMC approaches are confronted; then base case is compared to *'ZB'* case and *'R1'* to *'ZR'*, to estimate the impact of changing the bidding zone configuration on physical flow, meaning cross-border capacity and the flow OP results, and market outcomes as well.

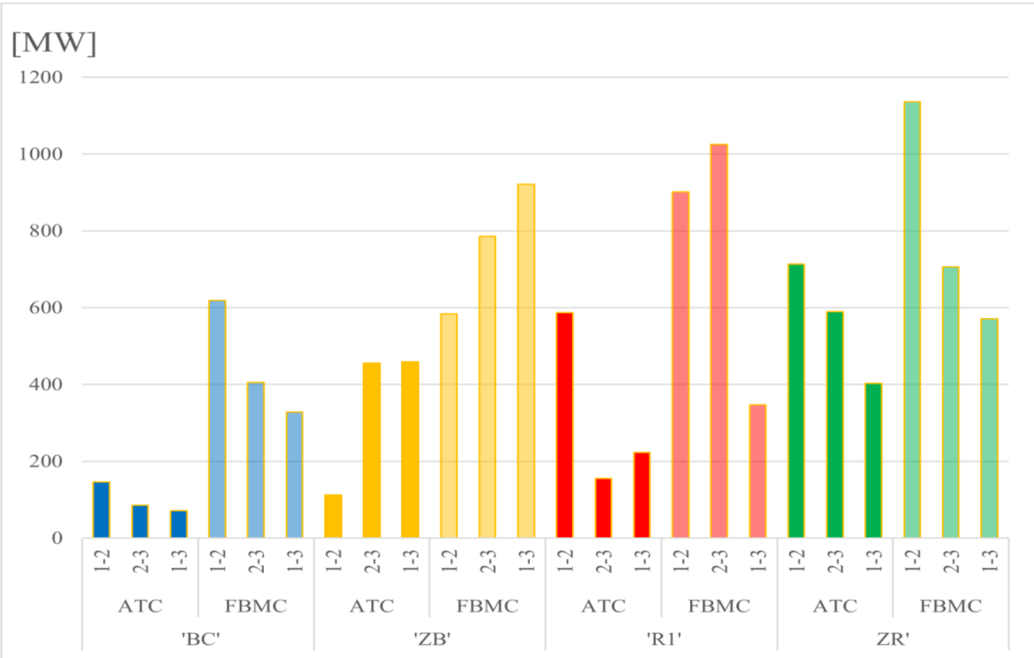


Figure 50. Cross-border Capacity for all cases.

Firstly, the cross-border results are presented. More colors are used to differentiate the cases. As it can be seen, using the flow-based approach led to a very higher capacity for all interconnections and in all studied cases. This was already known, since FBMC is more accurate and consider a zonal approach but taking in account all nodes of the network. Moreover, changing the configuration of the zone as in *'ZB'* and *'ZR'*, in general improve the cross-border capacity: in the first two cases that is true for capacity among 2-3 and 1-3, while between 1-2 it slightly decreases; while in the 'renewable' cases change the configuration has a bigger impact since lead to an increase of capacity in almost all areas. Finally, in the cases of renewable generation at its 100%, i.e. *'R1'* and *'ZR'*, cross-border capacity is for sure wider because in each node power injected is much higher, that means lines have to endure a stronger flow and that lead to the increase of capacity.

Now a comparison between capacity and real flow through the virtual interconnector, obtained by the optimization problem, is made. To better understand the impact of changing configuration two cases at a time have been analyzed. Red bars will represent the cross-border capacity and the blue bars the real flow.

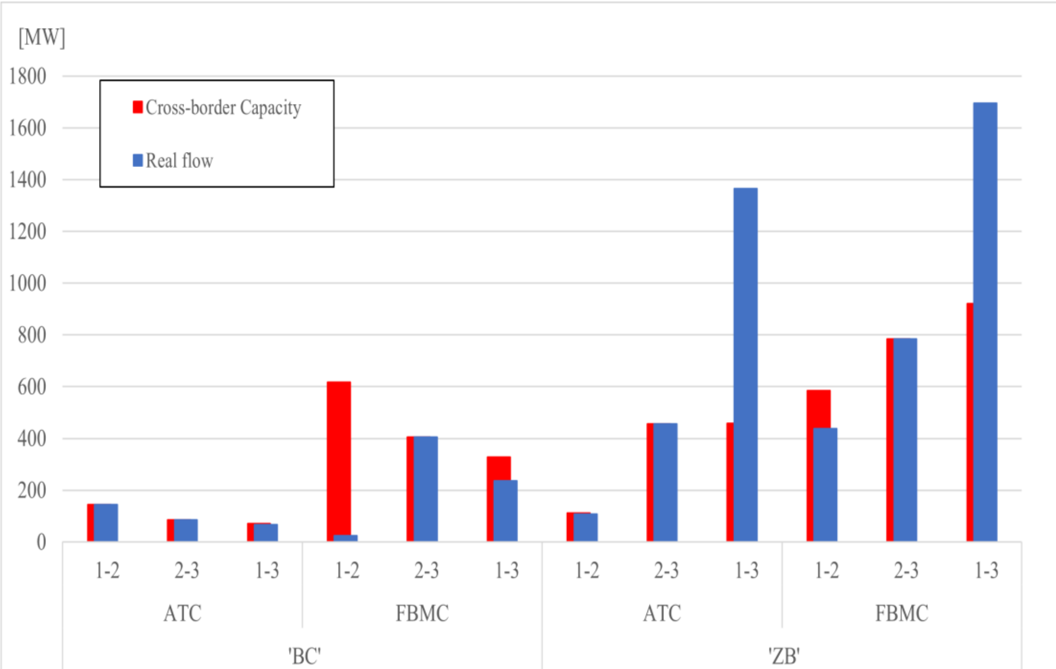


Figure 51. Real flow and cross-border capacity in *'BC'* and *'ZB'*.

Looking at figure 48, in the base case limits are never overreached, blinded them at most: in ATC approach in fact flow through 1-2 and 2-3 is equal to the maximum allowed, while in 1-3 it is a little lower; in FBMC it's even better since only between 2-3 the limit is blinded. The situation is different considering the new configuration of zones. It is true that the capacity grows, respect to *'BC'*, and more power is allowed to pass between areas, but at the same time flow is much higher than its limit. In both approach, outcomes are the same so long as in 1-2 there aren't problem and in 2-3 the limit is blinded, but between areas 1-3 the real flow is about three times higher than cross-border capacity (with ATC approach); the situation barely gets better with FBMC, since limit get higher, and flow is 'only' about two times bigger. A solution can be split the market and consider two-by-two the areas, but it will be led to a difference in prices among zones and possibly to a not completely use of injected power. A better solution is resolving the problem to its root, meaning change again the configuration, at least for zones 1 and 3, and try to do this since acceptable solution are obtained.

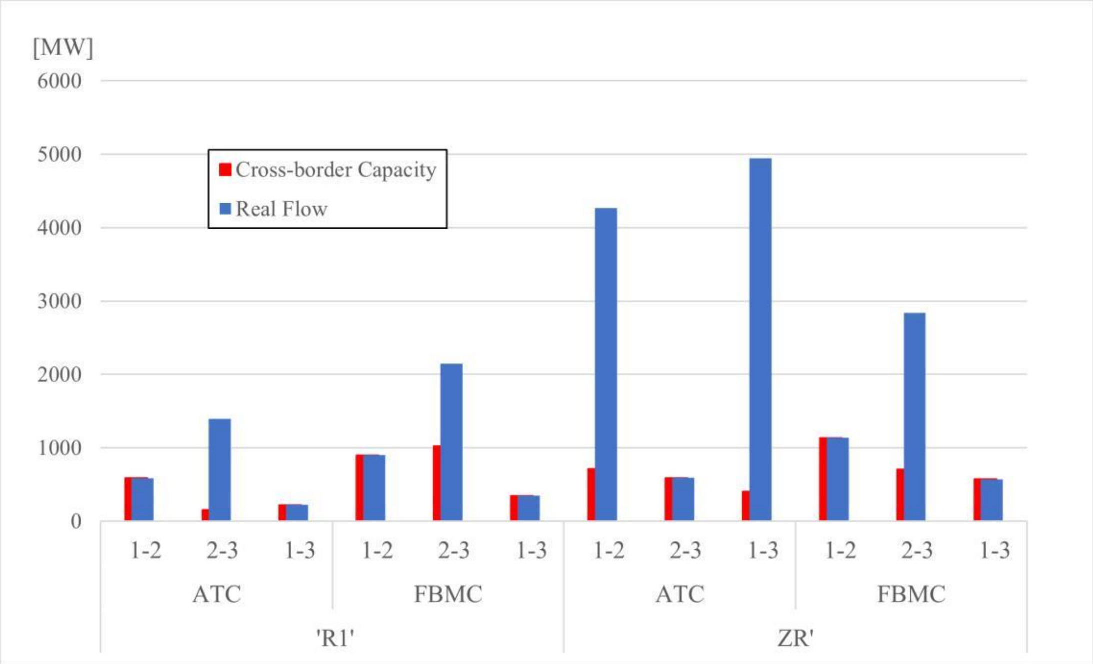


Figure 52. Real flow and cross-border capacity in *'R1'* and *'ZR'*.

The same changes in the configuration as *'ZB'* were made in *'ZR'*, but in these two cases renewable generation is working. As said before, that have led to a higher cross-border capacities, but to a higher flow as well. The limits are overreached already in the starting BZ's configuration, since between 2-3 flow is respectively about 8 times and 2 times than its limit in the different approach. Of course, considering the FBMC, capacity grows up, so the flow is 2 times higher, but that doesn't correspond to an improvement. The situation doesn't get better with the new disposition of the zones. If in the flow-based approach limits is overcome in 2-3 as the starting case 'R1', in ATC it's even worst and real flow exceed its maximum value in both 1-2 and 1-3. In this case change the configuration of the zones had a harmful impact and didn't bring any improvements in a physical point of view.

So, as in the first two analyzed cases, conclusion is that this change of zones is not acceptable with no gain to any interested parties.

The critical branches are reported and results show that with the new configuration they increase, though in first two cases a very low threshold has been chosen, and in the renewable cases the situation is better and only 1 branch exceed the limit in the new disposition.

	'BC' ($\alpha = 0.005$)	**'ZB'** ($\alpha = 0.005$)	**'R1'** ($\alpha = 0.1$)	**'ZR'** ($\alpha = 0.1$)
Critical branches	17	70	21	25
Congested critical branches	1	2	21	24
Overloaded critical branches	10	23	0	1

Table 20. Critical branches for all cases.

The results of the optimization problem give information on commitment of generators, allowing to understand the impact of introducing renewables and new configuration. So, the following table shows all generators pointing out the working, committed and not. As it can be seen *'BC'* and *'ZB'* presents the same numbers, while they change considering renewable sources and varying the position of some nodes in *'ZR'*, where the not committed ones correspond to non-renewables and in particular oil coal and natural gas, which don't enter in the market.

	'BC'		**'ZB'**		**'R1'**		**'ZR'**	
	ATC	**FBMC**	**ATC**	**FBMC**	**ATC**	**FBMC**	**ATC**	**FBMC**
Working generators	96	96	96	96	154	154	154	154
Committed	96	96	96	96	86	82	93	96
Not committed	0	0	0	0	68	72	61	58

Table 21. Committed generators for all cases.

The market outcomes are now shown, lingering on social surplus and prices. About prices, in the ATC approach different prices for the three zones has been calculated, while for the flow-based approach it has been considered the system price (SP in figure 54), meaning all zones has the same price at the beginning, since constraints on critical branches are overcome and for sure it should re-consider the market process with a re-dispatch.

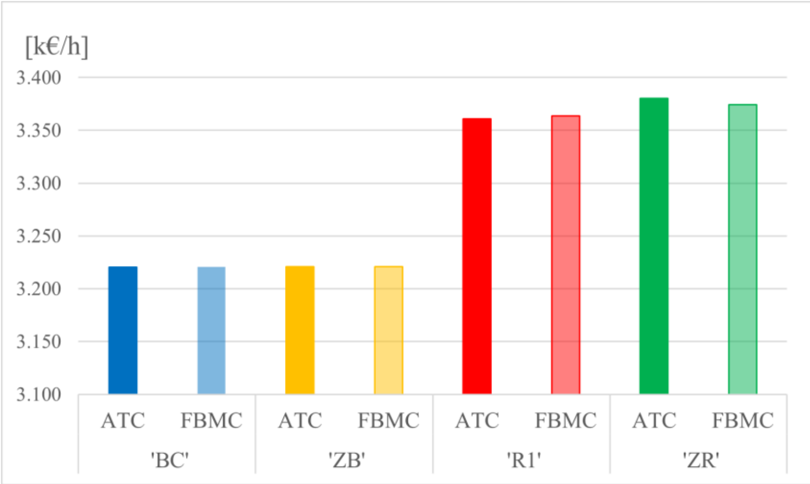


Figure 53. Social Surplus for all cases.

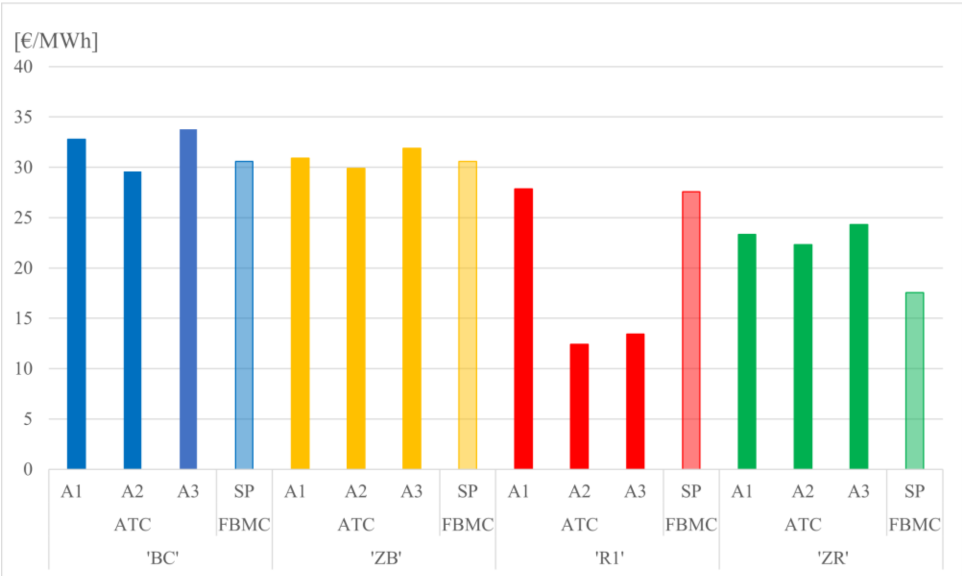


Figure 54. Selling prices for all cases.

Looking at figure 53, social surplus gets improvements using the flow-based approach, even if there is a very low difference and almost imperceptible in the graphs. With the new configuration, in *'ZB'* it's the same since all injected power are equal than *'BC'* and the network outcomes then don't change. In the other two cases, social surplus gets higher, that could mean more renewable generation enters in the market thanks to the new disposition of the zones. So, in a market point of view change the configuration carry to improvements in social welfare, and that can be

also viewed in figure 54, where prices in *'ZR'* are lower and /or well-distributed than in *'Z1'*. Furthermore, comparing the cases with and without renewable sources it's remarkable how the social surplus is higher: that is quite obvious so long as RES have marginal cost equal to 0 and no variable costs occurs to them.
In figure 51, prices are presented and as for social surplus the new configuration and the presence of renewable sources led to lower prices. In particular, cases 'BC' and 'ZB' have small differences in prices and in flow-based they are even the same. Better improvements can be seen in the other two cases, where in ATC approach prices become steadier among zones and in the flow-based it even felt of about 10 €/MWh, a great gain both for sellers and buyers.
In the next section some conclusions are exposed, and an overview of the whole work is made.

4.5. Conclusions

This work of thesis was focused on assess the impact of the formation of Bidding Zones on Capacity Allocation and Renewable penetration.
Firstly, an overview of how the electricity market works is made, lingering on the Italian market as benchmark of the explanation and on the day ahead market, which is the topic argument of the analyzed cases. The market clearing and its algorithm is presented. Every PXs have a different way to achieve the clearing, but as the aim to European Union is trying to create a unique market, necessity to reinforce connections among TSOs is crucial. In a world more and more global and connected one to each other, all the barriers should be deleted, and electricity markets are following this road, nonetheless all the difficulties may be occurring. One of them is certainly differences in capacity allocation methods used by different TSOs. As in 2015 CWE region started the Flow-based Market Coupling, the new and more performing methods, challenges on integration of the markets have been increased. Flow based leads to some improvements: more price convergence between zones and a wider cross border capacity domain, meaning trade potential between zones increases, a more efficient allocation of the day-ahead interconnection capacity with respect to the economic value of commercial transactions, a better cooperation

between TSOs since they have to work together, lower redispatch costs. All these benefits at the cost of a harder algorithm to implement due to a forecasting of the state of the electricity system to determine some keys elements of this approach. Anyhow, it's worth the risk since pros are more than cons and benefits of flow-based has been proof in the case of study in chapter 4 as well.

The other aspect which could be affected by the formation of bidding zone is the renewable penetration. Since one of the targets of EU is the reduction of greenhouse gas (GHG) emission, together with the increase of the share of RES, and several short and medium-term measures to be realized have been proposed, renewable sources have exponentially grown, mostly in the latest 15 years. The presence of RES and its growth has a considerable impact on the market and on sharing of generated power. Since renewables have no variable costs to face and impossibility to storage all generated power, they enter always in the market clearing, following the merit-order effect. It leads to a lower overall selling price, but it has some consequences as well. At one hand, renewable production is variable and inflexible, as it depends on solar and wind presence and 'strongness', and this discontinuity must be evaluated for network stability and security considering flow passing through lines. If before there was the certainty of how much power could pass on a certain line, with RES forecasting is necessary and the network had to be strengthened and improved, a process that should continue in the future considering and hoping a further increase of renewables. On the other hand, looking at figure 22, with RES the aggregate offer curve is moving to the right and that means some generation units are kicked out the market without selling energy. It affects the competitiveness of other energy sources that will continue to be fundamental for the EU's energy system: they could be out of the market, but their generation is still needed as backup when the variable output of intermittent RES is low. That's why capacity pricing was introduced, that represent a remuneration that non-renewable power plants receive based on their capacity availability, since in short term they could not get enough profit from the electricity market to stay in the market; while in long term capacity pricing can provide incentives to keep operating/invest in new thermal or in general non-renewable capacity. That's a way to avoid bankruptcy of these power plants since they could be still useful as backup when renewable

generation is low. Besides, it's true that RES penetration led to a reduction of system price, but due to their variable and inflexible nature of production, price volatility can increase, and it is another aspect not to be underestimated.
The third chapter was focused on explain the process to define new bidding zones. As said, flow-based approach and renewable sources are affected to the formation of zones and so the need to clearly study and consider with empirical data this process. It was the focus of the First Edition of Bidding Zone Review, a document released in 2018 by ACER, which explore different configuration of BZs in the Center Europe regions to find the better situation to be used for the future. In general, there are two ways to achieve this aim, considering an expert-based or model-based approach, both processed in the Review.
In the model-based, new zones are formed with empirical process starting from network and market input. As explained in the chapter, PTDFs or LMPs are two of network indicators used as input to the clustering methods, that merges nodes with similar values of PTDFs (or LMPs) to form new zones. However, this approach is only introduced in this work since the other one is used in the study case. The expert-based is implemented on a selection of ex ante defined configurations including splitting or merging of the existing BZs, defined by the expert assessment of the concerned TSOs. In particular, in the Review five different configuration, including the Status Quo, are evaluated using those criteria well-explained in the chapter. Yet, this approach is based on a forecasting as well and can't give the absolute certainty of the effectiveness of the new formation. That's why further studies and a continuous review is needed, since new challenges to be face are arising more and more. This work tries to focus on some of them, as in Chapter 4 with the use of IEEE Reliability test system different possibility have been studied and compared to perceive the impact of a new disposition of the zones. In total four cases have been analyzed with the use of MATLAB R2018b and the MATPower Tool. Each of these have been approached ATC and Flow-based methods for capacity allocation. In this sense, a first comparison can be made between these methods, and it founds out the advantage of the flow-based approach in the terms of maximum inter-zonal capacity, as might be expected, being wider at least of a factor 2 and even more respect to the ATC values. Another one of the first foregone consideration concern the economic

results considering working or not renewable generation units and reflects what said in second chapter. In fact, looking at cases *'BC'* and *'Z1'* economic efficiency increase of about $140.000\ €/h$ and even of $160.000\ €/h$ in the cases with different zones configuration. In addition, zonal prices and system price get benefits from the introduction of renewable since they come down, although price volatility arises in *'Z1'*.

However, the main purpose of this document was evaluating different configuration and its consequences on network and market features. What has been done is confronting the base case (*'BC'*) and the base case with renewable presence (*'R1'*) with the same cases with the same input but changing some nodes position and so their belonging to a zone. The choice of what nodes move from a zone to another was purely geographically since they were nearer to the selected new zone. Only one different configuration has been evaluated and although outcomes strongly depend on the arbitrary choice of these nodes, results can give significant and interesting information. Focusing on cross-border capacity, overally methods to allocate benefits from the new disposition give wider domains. In the base case *'BC'* and in the case *'ZB'* the values of maximum capacity increase from 84.75 MW to 455.59MW and from 71.37 MW to 459.14 MW respectively between zones 2-3 and 1-3 in the ATC approach. The same situation arises with the flow-based approach, where it rises of about 2 and 3 times respectively in zones 2-3 and 1-3, passing from 404.51 MW and 327.51 to 785.31 MW and 921.34 MW. On the contrary, among zones 1-2 it stays quite constant, decreasing only a bit. Instead, it's interesting how the real flow results changing between the first two cases. In fact, if in *'BC'* two of three connections are congested in ATC, and one of three in the FBMC while the others respect the limits, in *'ZB'* running optimization problem from ATC gives one congested line, one which respect its limits and the last overloaded. In particular connection 1-2 is within the limit (before was congested) and connection 1-3, which was within the limits before, in *'ZB'* became overloaded. The same situation happens facing the flow-based approach, where connection between 1-3 became overloaded, while between 1-2 flow stays in its limits in both cases. It's not a coincidence, and looking to generated power of the 'moving' nodes, it can be realized that in Area 3 it decreases and that means a higher power to be imported in zone 3 to satisfy demand and it causes the overcoming of the limit.

Almost the same consideration can be made with the other two cases, *'R1'* and *'ZR'* where the new configuration brings benefits as well, since transfer capacities increase in both approaches for all connections, except among 2-3 in flow-based. On the contrary, about real flow the situation is even worst. The starting situation of *'R1'* is of two lines congested and one overloaded, for both approaches. Changing the configuration in this case doesn't bring improvements, indeed it gets worse: in ATC in fact, now two lines overcome their limits, while in FBMC nothing changes but flow on overloaded line became even higher. It's clear how this new disposition affects negatively both operational security and security of supply. However, the improvements achieved in cross-border capacity values give hopes to find a configuration in which network security criteria can be fully respect.

Another aspect to consider in renewable cases is how the number of committed generation units changes varying the configuration, growing up from 86 and 82 to 93 and 96, and looking carefully the more committed generators corresponds to solar generation. In this sense, the impact of the configuration is beneficial since no energy waste is made. In the first two case, instead committed generators remain the same.

Furthermore, from an economic point of view new configuration allows to lower prices and higher economic efficiency, then a positive impact, at least apparently. Apparently since in new arrangements flows overcome their imposed limits more times and, even if it wasn't studied in this study, lead to a higher redispatch costs and to a change of committed power as well. Still, focusing on day-ahead market results benefits are noticeable, at least in last two cases: In ATC approach prices among zones become more constant and reduces in area 1 as well, while in flow-based it drops of $10\ €/MWh$, that can be considered a great achievement. As well market efficiency increases of $20.000\ €/h$ and $11.000\ €/h$ in two approaches, due to a well distribution of committed generators.

The analysis of results brings out different aspects, expressed below. First, capacity allocation gets clearly benefits for new configuration, rising in all analyzed cases, and maybe exploring other configuration more improvements can be obtained. Anyhow it has to be considered the position of the nodes to choose how can be moved, taking into account the geographically and network feasibility of that choice. This aspect could reduce the possible configuration to form.

In addition, it emerges a crucial difference between network outcomes and market outcomes. The economic results in fact, give the idea that the new configuration have a positive impact, more committed generators, lower prices and higher social surplus with benefits for both consumers and producers. Still, from the point of view of feasibility these changes don't lead to a better situation, even worst considering renewable generators working. That is an aspect not to be underestimated, since matching network and economic feasibility could become more and more difficult in the future.

In conclusion, although the results of this study do not fully satisfy the expectation, formation of bidding zones can have a higher positive impact, pleasing both explained aspects and in particular this network can be studied further in the future using these results as starting point and exploring new possible configuration and/or different percentage of renewable generation.

Appendix A: Network Data

The IEE RTS96 73-bus is a well-known network used in many works. The RTS-96 is substantially composed by three RTS-79 systems with specific interconnection. Thus, the system is divided in 3 areas, which are the Bidding Zones in examination, and it's formed by 73 buses. In this Appendix all relevant data of the network are reported.

A.1. Branches features

RTS-96 provide all branches information in a table format of 120 rows, meaning there are 120 branches. The columns of interest report the identification code of the branch, the starting and the arrival point and the parameters of the line:

UID	From Bus	To Bus	R	X	F_{max}
'A1'	101	102	0.0030	0.0140	200
'A2'	101	103	0.0550	0.2110	220
'A3'	101	105	0.0220	0.0850	220
'A4'	102	104	0.0330	0.1270	220
'A5'	102	106	0.0500	0.1920	220
'A6'	103	109	0.0310	0.1190	220
'A7'	103	124	0.0020	0.0840	600
'A8'	104	109	0.0270	0.1040	220
'A9'	105	110	0.0230	0.0880	220
'A10'	106	110	0.0140	0.0610	200
'A11'	107	108	0.0160	0.0610	220
'AB1'	107	203	0.0420	0.1610	220
'A12-1'	108	109	0.0430	0.1650	220
'A13-2'	108	110	0.0430	0.1650	220
'A14'	109	111	0.0020	0.0840	600
'A15'	109	112	0.0020	0.0840	600
'A16'	110	111	0.0020	0.0840	600
'A17'	110	112	0.0020	0.0840	600
'A18'	111	113	0.0060	0.0480	625
'A19'	111	114	0.0050	0.0420	625
'A20'	112	113	0.0060	0.0480	625
'A21'	112	123	0.0120	0.0970	625

'A22'	113	123	0.0110	0.0870	625
'AB2'	113	215	0.0100	0.0750	625
'A23'	114	116	0.0050	0.0590	625
'A24'	115	116	0.0020	0.0170	625
'A25-1'	115	121	0.0060	0.0490	625
'A25-2'	115	121	0.0060	0.0490	625
'A26'	115	124	0.0070	0.0520	625
'A27'	116	117	0.0030	0.0260	625
'A28'	116	119	0.0030	0.0230	625
'A29'	117	118	0.0020	0.0140	625
'A30'	117	122	0.0140	0.1050	625
'A31-1'	118	121	0.0030	0.0260	625
'A31-2'	118	121	0.0030	0.0260	625
'A32-1'	119	120	0.0050	0.0400	625
'A32-2'	119	120	0.0050	0.0400	625
'A33-1'	120	123	0.0030	0.0220	625
'A33-2'	120	123	0.0030	0.0220	625
'A34'	121	122	0.0090	0.0680	625
'AB3'	123	217	0.0100	0.0740	625
'B1'	201	202	0.0030	0.0140	200
'B2'	201	203	0.0550	0.2110	220
'B3'	201	205	0.0220	0.0850	220
'B4'	202	204	0.0330	0.1270	220
'B5'	202	206	0.0500	0.1920	220
'B6'	203	209	0.0310	0.1190	220
'B7'	203	224	0.0020	0.0840	600
'B8'	204	209	0.0270	0.1040	220
'B9'	205	210	0.0230	0.0880	220
'B10'	206	210	0.0140	0.0610	200
'B11'	207	208	0.0160	0.0610	220
'B12-1'	208	209	0.0430	0.1650	220
'B13-2'	208	210	0.0430	0.1650	220
'B14'	209	211	0.0020	0.0840	600
'B15'	209	212	0.0020	0.0840	600
'B16'	210	211	0.0020	0.0840	600
'B17'	210	212	0.0020	0.0840	600
'B18'	211	213	0.0060	0.0480	625
'B19'	211	214	0.0050	0.0420	625
'B20'	212	213	0.0060	0.0480	625
'B21'	212	223	0.0120	0.0970	625
'B22'	213	223	0.0110	0.0870	625
'B23'	214	216	0.0050	0.0590	625
'B24'	215	216	0.0020	0.0170	625
'B25-1'	215	221	0.0060	0.0490	625
'B25-2'	215	221	0.0060	0.0490	625
'B26'	215	224	0.0070	0.0520	625
'B27'	216	217	0.0030	0.0260	625
'B28'	216	219	0.0030	0.0230	625

'B29'	217	218	0.0020	0.0140	625
'B30'	217	222	0.0140	0.1050	625
'B31-1'	218	221	0.0030	0.0260	625
'B31-2'	218	221	0.0030	0.0260	625
'B32-1'	219	220	0.0050	0.0400	625
'B32-2'	219	220	0.0050	0.0400	625
'B33-1'	220	223	0.0030	0.0220	625
'B33-2'	220	223	0.0030	0.0220	625
'B34'	221	222	0.0090	0.0680	625
'C1'	301	302	0.0030	0.0140	200
'C2'	301	303	0.0550	0.2110	220
'C3'	301	305	0.0220	0.0850	220
'C4'	302	304	0.0330	0.1270	220
'C5'	302	306	0.0500	0.1920	220
'C6'	303	309	0.0310	0.1190	220
'C7'	303	324	0.0020	0.0840	600
'C8'	304	309	0.0270	0.1040	220
'C9'	305	310	0.0230	0.0880	220
'C10'	306	310	0.0140	0.0610	200
'C11'	307	308	0.0160	0.0610	220
'C12-1'	308	309	0.0430	0.1650	220
'C13-2'	308	310	0.0430	0.1650	220
'C14'	309	311	0.0020	0.0840	600
'C15'	309	312	0.0020	0.0840	600
'C16'	310	311	0.0020	0.0840	600
'C17'	310	312	0.0020	0.0840	600
'C18'	311	313	0.0060	0.0480	625
'C19'	311	314	0.0050	0.0420	625
'C20'	312	313	0.0060	0.0480	625
'C21'	312	323	0.0120	0.0970	625
'C22'	313	323	0.0110	0.0870	625
'C23'	314	316	0.0050	0.0590	625
'C24'	315	316	0.0020	0.0170	625
'C25-1'	315	321	0.0060	0.0490	625
'C25-2'	315	321	0.0060	0.0490	625
'C26'	315	324	0.0070	0.0520	625
'C27'	316	317	0.0030	0.0260	625
'C28'	316	319	0.0030	0.0230	625
'C29'	317	318	0.0020	0.0140	625
'C30'	317	322	0.0140	0.1050	625
'C31-1'	318	321	0.0030	0.0260	625
'C31-2'	318	321	0.0030	0.0260	625
'C32-1'	319	320	0.0050	0.0400	625
'C32-2'	319	320	0.0050	0.0400	625
'C33-1'	320	323	0.0030	0.0220	625
'C33-2'	320	323	0.0030	0.0220	625
'C34'	321	322	0.0090	0.0680	625
'CA-1'	325	121	0.0120	0.0970	625

'CB-1'	318	223	0.0130	0.1040	625
'C35'	323	325	0	0.0090	893

Table A. 1. Branches information.

A.2. Load Data

The data reported in the table were provided directly by the RTS-96 and refer to a benchmark situation of the network, used then to calculate capacity constraint with both methods.

The load of each bus is in the last column, and it's also reported the correspondent voltage, type, name and ID of the buses. As can be noticed, some buses have zero load, as bus '111', meaning they can be a generation bus, or even only a transit node.

Bus ID	Bus Name	Base kV	Bus Type	Load (MW)
101	Abel'	138	'PV'	108
102	'Adams'	138	'PV'	97
103	'Adler'	138	'PQ'	180
104	'Agricola'	138	'PQ'	74
105	'Aiken'	138	'PQ'	71
106	'Alber'	138	'PQ'	136
107	'Alder'	138	'PV'	125
108	'Alger'	138	'PQ'	171
109	'Ali'	138	'PQ'	175
110	'Allen'	138	'PQ'	195
111	'Anna'	230	'PQ'	0
112	'Archer'	230	'PQ'	0
113	'Arne'	230	'Ref'	265
114	'Arnold'	230	'PV'	194
115	'Arthur'	230	'PV'	317
116	'Asser'	230	'PV'	100
117	'Aston'	230	'PQ'	0
118	'Astor'	230	'PV'	333
119	'Attar'	230	'PQ'	181
120	'Attila'	230	'PQ'	128
121	'Attlee'	230	'PV'	0
122	'Aubrey'	230	'PV'	0
123	'Austen'	230	'PV'	0
124	'Avery'	230	'PQ'	0
201	'Bach'	138	'PV'	108
202	'Bacon'	138	'PV'	97
203	'Baffin'	138	'PQ'	180

204	'Bailey'	138	'PQ'	74
205	'Bain'	138	'PQ'	71
206	'Bajer'	138	'PQ'	136
207	'Baker'	138	'PV'	125
208	'Balch'	138	'PQ'	171
209	'Balzac'	138	'PQ'	175
210	'Banks'	138	'PQ'	195
211	'Bardeen'	230	'PQ'	0
212	'Barkla'	230	'PQ'	0
213	'Barlow'	230	'PV'	265
214	'Barry'	230	'PV'	194
215	'Barton'	230	'PV'	317
216	'Basov'	230	'PV'	100
217	'Bates'	230	'PQ'	0
218	'Bayle'	230	'PV'	333
219	'Bede'	230	'PQ'	181
220	'Beethoven'	230	'PQ'	128
221	'Behring'	230	'PV'	0
222	'Bell'	230	'PV'	0
223	'Bloch'	230	'PV'	0
224	'Bordet'	230	'PQ'	0
301	'Cabell'	138	'PV'	108
302	'Cabot'	138	'PV'	97
303	'Caesar'	138	'PQ'	180
304	'Caine'	138	'PQ'	74
305	'Calvin'	138	'PQ'	71
306	'Camus'	138	'PQ'	136
307	'Carew'	138	'PV'	125
308	'Carrel'	138	'PQ'	171
309	'Carter'	138	'PQ'	175
310	'Caruso'	138	'PQ'	195
311	'Cary'	230	'PQ'	0
312	'Caxton'	230	'PQ'	0
313	'Cecil'	230	'PV'	265
314	'Chain'	230	'PV'	194
315	'Chase'	230	'PV'	317
316	'Chifa'	230	'PV'	100
317	'Chuhsi'	230	'PQ'	0
318	'Clark'	230	'PV'	333
319	'Clay'	230	'PQ'	181
320	'Clive'	230	'PQ'	128
321	'Cobb'	230	'PV'	0
322	'Cole'	230	'PV'	0
323	'Comte'	230	'PV'	0
324	'Curie'	230	'PQ'	0
325	'Curtiss'	230	'PQ'	0

Table A. 2. Load Data.

A.3. Generation Data

As the Load, Generation data are provided by the RTS-96. In this case, for a bus it could be more than one power injected into the network, as well as it could be zero. Moreover, it's provided the generator type and the constraints of minimum and maximum power that could be injected. Important to say that, at the beginning of the analysis, solar and wind generators are set to 0, then to its maximum value.

Bus ID	Generator type	Power injected (MW)	P_{max} (MW)	P_{min} (MW)
101	'Oil'	8	20	8
101	'Oil'	8	20	8
101	'Coal'	76	76	30
101	'Coal'	76	76	30
102	'Oil'	8	20	8
102	'Oil'	8	20	8
102	'Coal'	76	76	30
102	'Coal'	76	76	30
107	'NG'	355	355	170
113	'NG'	55	55	22
113	'NG'	55	55	22
113	'NG'	55	55	22
113	'NG'	55	55	22
115	'Oil'	5	12	5
115	'Oil'	5	12	5
115	'Coal'	155	155	62
116	'Coal'	155	155	62
118	'NG'	355	355	170
123	'Coal'	155	155	62
123	'Coal'	350	350	140
123	'NG'	55	55	22
123	'NG'	55	55	22
123	'NG'	55	55	22
201	'Oil'	8	20	8
201	'Oil'	8	20	8
201	'Coal'	76	76	30
202	'Oil'	8	20	8
202	'Oil'	8	20	8
202	'Coal'	76	76	30
202	'Coal'	76	76	30

207	'NG'	55	55	22
207	'NG'	55	55	22
213	'NG'	355	355	170
213	'NG'	55	55	22
213	'NG'	55	55	22
215	'NG'	55	55	22
215	'NG'	55	55	22
216	'Coal'	155	155	62
218	'NG'	355	355	170
221	'NG'	296.97	355	170
223	'Coal'	155	155	62
223	'Coal'	155	155	62
223	'Coal'	350	350	140
223	'NG'	22	55	22
223	'NG'	22	55	22
223	'NG'	22	55	22
301	'Oil'	8	20	8
301	'Oil'	8	20	8
301	'NG'	44	55	22
301	'NG'	44	55	22
302	'Oil'	8	20	8
302	'Oil'	8	20	8
302	'NG'	55	55	22
302	'NG'	55	55	22
307	'NG'	55	55	22
307	'NG'	55	55	22
313	'NG'	355	355	170
315	'Oil'	5	12	5
315	'Oil'	5	12	5
315	'Oil'	5	12	5
315	'Oil'	5	12	5
315	'Oil'	5	12	5
315	'NG'	55	55	22
315	'NG'	55	55	22
315	'NG'	55	55	22
316	'Coal'	155	155	62
318	'NG'	355	355	170
321	'NG'	355	355	170
322	'NG'	55	55	22
322	'NG'	55	55	22
323	'NG'	355	355	170
323	'NG'	355	355	170
114	'Sync_Cond'	0	1	0
121	'Nuclear'	400	400	396
122	'Hydro'	50	50	0
122	'Hydro'	50	50	0

122	'Hydro'	50	50	0
122	'Hydro'	50	50	0
122	'Hydro'	50	50	0
122	'Hydro'	50	50	0
201	'Hydro'	50	50	0
214	'Sync_Cond'	0	1	0
215	'Hydro'	50	50	0
215	'Hydro'	50	50	0
215	'Hydro'	50	50	0
222	'Hydro'	50	50	0
222	'Hydro'	50	50	0
222	'Hydro'	50	50	0
222	'Hydro'	50	50	0
222	'Hydro'	50	50	0
222	'Hydro'	50	50	0
314	'Sync_Cond'	0	1	0
322	'Hydro'	50	50	0
322	'Hydro'	50	50	0
322	'Hydro'	50	50	0
322	'Hydro'	50	50	0
320	'Solar'	0	51.60	0
314	'Solar'	0	51.60	0
314	'Solar'	0	51.60	0
313	'Solar'	0	95.10	0
314	'Solar'	0	92.70	0
314	'Solar'	0	51.60	0
313	'Solar'	0	93.30	0
310	'Solar'	0	51.70	0
324	'Solar'	0	49.70	0
312	'Solar'	0	94.10	0
310	'Solar'	0	51.60	0
324	'Solar'	0	51.60	0
324	'Solar'	0	51	0
113	'Solar'	0	93.60	0
319	'Solar'	0	188.20	0
215	'Solar'	0	125.10	0
102	'Solar'	0	25.60	0
101	'Solar'	0	25.90	0
102	'Solar'	0	25.30	0
104	'Solar'	0	26.80	0
212	'Solar'	0	200	30
101	'Solar'	0	26.70	0
101	'Solar'	0	26.20	0
101	'Solar'	0	25.80	0
103	'Solar'	0	61.50	0
119	'Solar'	0	66.60	0

308	'Solar'	0	100.90	0
313	'Solar'	0	101.70	0
313	'Solar'	0	63.10	0
313	'Solar'	0	65.40	0
313	'Solar'	0	67	0
313	'Solar'	0	64.80	0
313	'Solar'	0	63.80	0
313	'Solar'	0	64.10	0
313	'Solar'	0	66.60	0
313	'Solar'	0	62.40	0
313	'Solar'	0	66.90	0
313	'Solar'	0	65.20	0
313	'Solar'	0	27.80	0
320	'Solar'	0	27.30	0
320	'Solar'	0	27	0
320	'Solar'	0	28.30	0
313	'Solar'	0	27.20	0
320	'Solar'	0	27	0
320	'Solar'	0	28.20	0
118	'Solar'	0	9.30	0
118	'Solar'	0	9.70	0
118	'Solar'	0	9.40	0
118	'Solar'	0	9.10	0
118	'Solar'	0	9.10	0
118	'Solar'	0	9.70	0
320	'Solar'	0	9.40	0
118	'Solar'	0	11.80	0
118	'Solar'	0	11.20	0
118	'Solar'	0	10.30	0
118	'Solar'	0	4.50	0
213	'Solar'	0	13.20	0
309	'Wind'	0	148.30	0
317	'Wind'	0	799.10	0
303	'Wind'	0	847	0
122	'Wind'	0	713.50	0
313	'Storage'	0	50	0

Table A. 3. Generation Data.

The marginal cost coefficient in table A.4. were used to implement the total cost function of the generators, which has been used to set the objective function in the case study.

Bus ID	P_{min}		P_{max}	
101	8	1085.77	20	2298.06
101	8	1085.77	20	2298.06
101	30	841.579	76	1596.51
101	30	841.579	76	1596.51
102	8	1212.03	20	2344.92
102	8	1212.03	20	2344.92
102	30	735.097	76	1683.09
102	30	735.097	76	1683.09
107	170	4772.49	355	9738.36
113	22	1122.43	55	2075.88
113	22	1122.43	55	2075.88
113	22	1122.43	55	2075.88
113	22	1122.43	55	2075.88
115	5	897.292	12	1791.41
115	5	897.292	12	1791.41
115	62	1500.19	155	3668.44
116	62	1735.06	155	3751.14
118	170	4795.62	355	9901.24
123	62	1437.41	155	3775.85
123	140	3582.87	350	8137.67
123	22	1088.22	55	2046.97
123	22	1088.22	55	2046.97
123	22	1088.22	55	2046.97
201	8	1157.22	20	2269.08
201	8	1157.22	20	2269.08
201	30	823.758	76	1918.39
202	8	1131.23	20	2196.47
202	8	1131.23	20	2196.47
202	30	751.269	76	1819.68
202	30	751.269	76	1819.68
207	22	1116.10	55	2366.39
207	22	1116.10	55	2366.39
213	170	5170.31	355	10458.8
213	22	1122.43	55	2075.88
213	22	1122.43	55	2075.88
215	22	1216.84	55	2160.80
215	22	1216.84	55	2160.80
216	62	1426.14	155	3412.47
218	170	7523.51	355	11987.1
221	170	4551.11	355	9828.37
223	62	1422.99	155	3256.43
223	62	1422.99	155	3256.43
223	140	3323.31	350	7981.70
223	22	1692.75	55	2996.75
223	22	1692.75	55	2996.75
223	22	1692.75	55	2996.75
301	8	1208.23	20	2377.50
301	8	1208.23	20	2377.50

301	22	1119.44	55	2235.93
301	22	1119.44	55	2235.93
302	8	1208.23	20	2377.50
302	8	1208.23	20	2377.50
302	22	1316.56	55	2535.46
302	22	1316.56	55	2535.46
307	22	1141.93	55	2160.41
307	22	1141.93	55	2160.41
313	170	5243.00	355	9944.47
315	5	745.674	12	1445.52
315	5	745.674	12	1445.52
315	5	745.674	12	1445.52
315	5	745.674	12	1445.52
315	5	745.674	12	1445.52
315	22	884.435	55	1821.12
315	22	884.435	55	1821.12
315	22	884.435	55	1821.12
316	62	1552.62	155	3712.68
318	170	5254.89	355	10536.7
321	170	4775.79	355	9868.71
322	22	1031.69	55	1886.71
322	22	1031.69	55	1886.71
323	170	4877.56	355	10331.0
323	170	4877.56	355	10331.0
114	0	0	1	0
121	396	3208.98	400	3208.98
122	0	0	50	0
122	0	0	50	0
122	0	0	50	0
122	0	0	50	0
122	0	0	50	0
122	0	0	50	0
201	0	0	50	0
214	0	0	1	0
215	0	0	50	0
215	0	0	50	0
215	0	0	50	0
222	0	0	50	0
222	0	0	50	0
222	0	0	50	0
222	0	0	50	0
222	0	0	50	0
222	0	0	50	0
314	0	0	1	0
322	0	0	50	0
322	0	0	50	0
322	0	0	50	0
322	0	0	50	0
320	0	0	51.60	0
314	0	0	51.60	0

314	0	0	51.60	0
313	0	0	95.10	0
314	0	0	92.70	0
314	0	0	51.60	0
313	0	0	93.30	0
310	0	0	51.70	0
324	0	0	49.70	0
312	0	0	94.10	0
310	0	0	51.60	0
324	0	0	51.60	0
324	0	0	51	0
113	0	0	93.60	0
319	0	0	188.2	0
215	0	0	125.1	0
102	0	0	25.60	0
101	0	0	25.90	0
102	0	0	25.30	0
104	0	0	26.80	0
212	30	0	200	0
101	0	0	26.70	0
101	0	0	26.20	0
101	0	0	25.80	0
103	0	0	61.50	0
119	0	0	66.60	0
308	0	0	100.90	0
313	0	0	101.70	0
313	0	0	63.10	0
313	0	0	65.40	0
313	0	0	67	0
313	0	0	64.80	0
313	0	0	63.80	0
313	0	0	64.10	0
313	0	0	66.60	0
313	0	0	62.40	0
313	0	0	66.90	0
313	0	0	65.20	0
313	0	0	27.80	0
320	0	0	27.30	0
320	0	0	27	0
320	0	0	28.30	0
313	0	0	27.20	0
320	0	0	27	0
320	0	0	28.20	0
118	0	0	9.30	0
118	0	0	9.70	0
118	0	0	9.40	0
118	0	0	9.10	0
118	0	0	9.10	0
118	0	0	9.70	0
320	0	0	9.40	0

118	0	0	11.80	0
118	0	0	11.20	0
118	0	0	10.30	0
118	0	0	4.50	0
213	0	0	13.20	0
309	0	0	148.3	0
317	0	0	799.1	0
303	0	0	847	0
122	0	0	713.5	0
313	0	0	50	0

Table A. 4. Generation Cost Data.

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Sitography

GME- Gestore Mercati Energetici: https://www.mercatoelettrico.org/it/

CAIT Climate Data Explorer via.Climate Watch: http://cait.wri.org/

Statistical Review of Word Energy & Ember: https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html

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