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COST SHARING METHODOLOGIES FOR CROSS-BORDER REMEDIAL ACTIONS

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Abstract

The liberalization of the electricity market in Europe introduced competition among generators and suppliers not only within the national markets, but also at an international level. The interconnections between domestic networks have historically not been designed with the primary objective of facilitating international power transactions. Therefore, the integration of the national markets is limited by the amount of cross-border transmission capacity at several borders. Whenever cross-border interconnectors cannot accommodate all physical power flows following international power trades requested by market participants, congestion occurs. In this case, Transmission System Operators must take the necessary remedial actions to relieve the congestion before network security limits are violated. This thesis evaluates the technical aspects regarding cross-border power flows, and presents two different methodologies created to share the costs of the remedial actions necessary to relieve the congestion among the participating zones of the electricity market. The methodologies are then implemented in Matlab and tested on a real case of the European UCTE network, referred to the 5^{th} of July 2017 at 17.30.

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CHAPTER 1
INTRODUCTION

European electricity markets operate on various levels. Markets may vary in geographical scope, ranging from local offers on the retail market to transnational wholesale markets. Based on their time scale, wholesale markets range from real-time balancing markets to long-term contracts[1]. The electricity sold on the wholesale market can be sold either within a country or across borders. The interconnected European grid, which links the various grids from several countries by means of interconnection lines, is the basis of the cross-border electricity trade. The interconnected grid allows markets to be coupled to form a European internal electricity market[2].

The goal of setting up the internal energy market and ensuring its optimal functioning is taken up by the European Network System Operators for Electricity (ENTSO-E), which was established and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009. ENTSO-E is composed of 43 electricity Transmission System Operators (TSOs) from 36 countries across Europe[2].

European TSOs are entities operating independently from the other electricity market players and are responsible for the bulk transmission of electric power on the main high voltage electric networks. TSOs provide grid access to the electricity market players according to non-discriminatory and transparent rules. They are also responsible for the safe operation and maintenance of the system, in order to ensure security of supply. In some countries, TSOs are also in charge of development of the grid infrastructure[2].

Where an interconnection linking national transmission networks is not able to accomodate all physical flows resulting from international transactions from market participants, because of lack of capacity of the interconnectors and/or the national transmission systems concerned, congestion occurs. There is a variety of arrangements for transfer across national borders and for congestion management in Europe. The most attractive congestion management methods depend on the existence of well-developed, stable electricity markets[3].

Whenever a cross-border congestion occurs, some remedial measures need to be taken by the TSOs in order to relieve the congestion and ensure an adequate operation of the system. In case these measures are not cost free, the incurred costs need to be shared among the market zones. The main goal of this thesis is to apply and compare the results concerning two different methodologies that aim at sharing the responsibilities for the congestion among the different areas of the European network. This work is organized in the following way:

- In Chapter 2, the general concepts of capacity allocation mechanisms, that allow to define the amount of electricity that can be transmitted among bidding zones (regions or countries), are presented. Also, some congestion management methods aiming at allocating this capacity among generating companies within zones in an efficient way are reported.
- Chapter 3 presents the concepts of Power Flow Tracing and some of its methods found in the literature. The methods presented have the common goal of making available the information of how generators and loads contribute to the flows on the lines, and how generators are supplying the loads. This information may be used for several applications, one of which is to assign the responsabilities of a cross-border congestion in terms of power flows to all the zones of the network.
- Chapters 4 and 5 show the mathematical models for the two methodologies applied in this thesis.
- Chapter 6 reports the numerical results concerning the two methodologies, and some final considerations are given in Chapter 7.

CHAPTER 2
CONGESTION MANAGEMENT

In this chapter, the general concepts of capacity allocation mechanisms, that allow to define the amount of electricity that can be transmitted among bidding zones (regions or countries), are presented. Also, some congestion management methods aiming at allocating this capacity among generating companies within zones in an efficient way are reported.

2.1 Capacity Calculation

The recent liberalization of the electricity market in Europe aims at introducing competition not only among generators and suppliers within each European country in their respective domestic markets, but also at an internationl level among European countries competing within an efficient European Internal Electricity Market. However, TSOs have historically not designed their networks to operate in the most efficient way with respect to international power transactions at their borders, and therefore cross-border transmission capacities are not optimized, limiting negotiations between different zones[4]. The congestion may appear for several reasons under different time scopes[5][10] :

1. Not proper network reinforcements in the long term. Those reinforcements better favour the electricity trading between zones if common rules are applied among the zones involved when deciding for investments.
2. In the middle term, it may be caused by delay in transmission investments; not adequate market design, what would require a more efficient distribution of the bidding zones; and not well integrated regulations and policy rules among the

considered zones, like decisions on the handling of renewable sources and decommissioning of units.

3. In the short-term, the causes for the congestion may be a not efficient transmission capacity calculation method; uncertainties related to data quality as well as forecast errors; unforeseen events as power line outages; and behaviour of market players.

Following a congestion, some cost free measures can be taken in order to return the system to its adequate operation conditions. This measures include:

- Closing and/or opening of lines
- Operation of compensation devices
- Change of phase-shifter transformer angles
- Change of tap position of on load tap changer transformer
- Control of Flexible AC Transmission Systems (FACTS) devices

If those measures are not sufficient to relieve the congestion, money should be spent on further actions(redispatching, primary and secondary reserves etc.), and a cost-sharing mechanism must exist in order to share the costs for these actions among the market participants.

Different methods may be used in order to allocate capacity from a market perspective. Before introducing some of them, it is important to describe the general principles of the capacity calculation methods used to determine how much energy can be traded among countries without violating the operational limits of the network.

2.1.1 Net Transfer Capacity

One important matter that needs to be dealt with by the TSOs concerns the maximum power that can be transmitted from a given zone A to a given zone B , and vice-versa. This is equivalent to asking what is the Net Transfer Capacity (NTC) between A and B. This question is normally answered in three steps[6]:

a) Calculation of the Total Transfer Capacity (TTC)

The TTC is defined by the set of physical constraints of the network, which need to be respected in order to keep the security of the system. These constraints are given by the thermal, voltage and stability limits. Therefore, TTC represents the maximum possible power exchange between zones A and B under secure conditions. It is calculated ex-ante by means of power flow modelling and simulations, starting from the expected configuration of the network with respect to generation and load patterns and topological profile. Then, in order to calculate the TTC from zone A to zone B, for example, the generation in A is increased while the genereration in B decreased by the same amount in a stepwise manner, keeping the loads unchanged. These shifts of generation are stopped when security constraints are violated either within zones A or B, or on the tie-line interconnecting the two areas. In the former case, in order for the congestion to be considered an effective limiting factor, it is necessary to check that the congestion cannot be relieved by corrective measures, without reducing the electric system security level

b) Calculation of the Transmission Reliability Margin (TRM)

TRM takes into account the uncertainties related to the power exchanges at the borders of the considered zones due to forecast errors, data quality and unexpected real time events. TRM assessment may be performed by TSOs making use of historical data as well as probabilistic methods.

c) Calculation of the Net Transfer Capacity

NTC can be calculated by the following equation:

$$NTC = TTC - TRM \quad (1)$$

Therefore NTC represents the expected maximum power that can be exchanged between two given zones without violating technical security limits and taking into account uncertainties of the network conditions.

In highly meshed networks, as it is the case of the of the European one, the shifts in the generation patterns of two given areas will not only affect the power exchanges between them, but also of a number of other zones which do not necessarily share borders with the ones performing the power transaction. This phenomenon is in accordance with Kirchhoff's laws governing the flow of electricity.

As NTC is normally calculated in a bilateral manner and does not take into consideration the complexity of the meshed network, it should be used only as an indication by market participants when defining commercial transactions.

2.1.2 Flow Based Market Coupling

In face of the significant progress of market integration over the last years as well as the strong mutual support between TSOs during critical grid situations, it is possible to improve capacity calculation by means of the implementation of a Flow Based Market Coupling (FBMC) algorithm in order to determine the power capacity available for commercial transactions between bidding zones in a more accurate way[7].

The main enhancement of FBMC against the NTC algorithm is the direct consideration of physical transmission constraints in defining market prices and cross-border exchanges. The commercial transactions are therefore brought closer to the physical reality of the system because all critical elements relevant for the calculation of power exchanges between areas are taken into account.

Commercial exchanges between two bidding zones are calculated considering the feasible transactions among the other zones of the network. As a consequence of the more realistic representation of the network, it is possible to define less conservative amounts of power exchange between zones.

FBMC is based on the determination of two parameters:

a) Power Transfer Distribution Factors (PTDFs)

PTDFs give the incremental change of power flow through network branches due to the change of power exchange between zones.

Assuming that each load is fed by each generator of the system and each generator is feeding all loads proportionally to their individual repartition to the power balance of the entire system, we can interpret the horizontal network as a power pool that is filled by all generators and emptied by all loads. This assumption is entirely in line with the observations made in power grids and the high travel velocity of electric energy in relation to the spatial extension of the actual network[8].

Let the DC Power Flow equations be:

$$\mathbf{P} = \mathbf{B}^{\mathbf{bus}}\boldsymbol{\theta} \tag{2}$$

$$\mathbf{F} = \mathbf{B}^{\mathbf{branch}}\boldsymbol{\theta} \tag{3}$$

The matrix $\mathbf{B}^{\mathbf{bus}}$ has dimension n by n, the vector $\boldsymbol{\theta}$ is the vector of nodal phase angles of dimension n by 1 and the matrix $\mathbf{B}^{\mathbf{branch}}$ is of dimension k by n, being n the set of nodes in the system, and k the set of branches in the nodal network.

The DC power flow equation for active power injections is (2). The active power flow through transmission lines instead can be written as (3).

Since $\mathbf{B}^{\mathbf{bus}}$ is a rank deficient matrix, (2) can be solved only after removing the reference node. In this example, the first node is taken as the reference one.

An additional equation is added to the DC Power Flow equations to ensure a unique solution after having removed the reference node from (2). This equation imposes the sum of all power injections to be zero[9]:

$$\sum_{\mathbf{n}} \mathbf{P_n} = \mathbf{0} \tag{4}$$

After having removed the reference node the DC Power Flow equations become:

$$\mathbf{P}^{*} = \mathbf{B}^{\mathbf{bus*}}\boldsymbol{\theta}^{*} \tag{5}$$

$$\mathbf{F} = \mathbf{B}^{\mathbf{branch*}}\boldsymbol{\theta}^{*} \tag{6}$$

Substituting $\boldsymbol{\theta}^{*}$ from (6) gives the the DC line flows equations:

$$\mathbf{F} = \mathbf{ISF}^{*}\mathbf{P}^{*} \tag{7}$$

$$\mathbf{ISF}^{*} = \mathbf{B}^{\mathbf{branch*}}(\mathbf{B}^{\mathbf{bus*}})^{-1} \tag{8}$$

The full DC line flows are obtained by inserting a zero column in the position corresponding to the reference node into the reduced Injection Shift Factor matrix $\mathbf{ISF}^{*}$:

$$\mathbf{F} = \mathbf{ISF}\ \mathbf{P} \tag{9}$$

$$\mathbf{ISF} = [\mathbf{0} \quad \mathbf{ISF}^{*}] \tag{10}$$

In scalar format, the flow on a line l can be written as

$$F_{l} = \sum_{n} ISF_{l,n} P_{n} \tag{11}$$

An element $ISF_{l,n}$ gives the sensitivity of the active power flow through line *l* with respect to an additional power injection in node *n* as a sink. Given the properties of linearity and suerposition, the sensitivity of line flows to power injection in node n_1 with node n_2 as a sink can be written as a linear combination of the ISF elements[10]:

$$PTDF_{l,\, n_1 - n_2} = ISF_{l,n_1} - ISF_{l,n_2} \tag{12}$$

Formula (12) describes the so called Power Transfer Distribution Factors. It should be noted that, while the $\mathbf{ISF}$ matrix is dependent on the reference node that has been chosen, (12) actually remains always the same regardless of what node has been taken as a reference in the $\mathbf{ISF}$ matrix.

The Net Exchange Position of market zone z in [MW] is defined as

$$NEX_{z} = \sum_{l} A_{l,n} F_{l} \quad \forall z \tag{13}$$

A positive Net Exchange Position indicates net export, whereas a negative one indicates net import. $A_{l,n}$ is the network incidence matrix, which indicates whether a cross-border link is starting at a market zone ($A_{l,n} = 1$), ending at a market zone ($A_{l,n} = -1$), or not connected to a market zone ($A_{l,n} = 0$). The quantity F_l denotes the actual flow through transmission line l.

The zonal PTDFs, giving the linear relationship between Net Exchange Positions and flows through critical branches, can be derived from the nodal PTDFs by grouping nodes into zones by means of the Generation Shift Keys (GSKs), which give the nodal contribution to a change in the zonal balance. For a given set of n nodes, z zones and l lines, the zonal PTDF and the GSK matrices are calculated as follows[12]:

$$PTDF_{l,z}^{zonal} = \sum_{n} PTDF_{l,n}^{nodal} GSK_{n,z} \quad \forall l, \forall z \tag{14}$$

$$GSK_{n,z} = \frac{d\,P_n}{d\,NEX_z} \quad \forall n, \forall z \tag{15}$$

where P_n is the grid injection at node n. The zonal PTDF matrix represents an approximation of the real characteristics of the network, as a consequence of the loss of information of the exact nodal injections in the grid. Moreover, GSKs are based on predictions of the market outcome subject to forecast errors. In contrast to the NTC model, however, it has the goal of achieving the best possible approximation of the real network conditions despite the inevitable level of uncertainty.

b) Remaining Available Margin (RAM)

RAM represents the line capacity that can be used in the Day-Ahead Market. Its calculation is based on two steps. First, the critical branches and critical outages of the system are determined. Then, the RAM is determined for these critical branches and critical outages.

A critical branch is a network element (tie-lines, internal lines or transformers) which is significantly impacted by cross-border power exchanges.

For each one of a set of l critical branches , the RAM is calculated according to the following formula[12]:

$$RAM_l = F_l^{max} - F_l^{ref} - FAV_l - FRM_l \quad \forall l \tag{16}$$

where F_l^{max} is the maximum allowable power flow on the critical branch l in [MW]; F_l^{ref} is the reference flow on the critical branch l in [MW] caused by commercial transactions outside the Day-Ahead Market(bilateral trades, forward markets); FAV_l is the Final Adjustment Value on critical branch l in [MW], taking into account the knowledge and experience of the TSO which cannot be formally considered in the FBMC method; and FRM_l is the Flow Reliability Margin on critical branch l in [MW], acting as a safety margin due to the simplifications of the FBMC algorithm. F_l^{ref} is computed as

$$F_l^{ref} = F_l^{bc} - F_l \tag{17}$$

where F_l^{bc} is the transmission flow in [MW] referred to the Base Case, which is a forecast of the state of the grid at the moment of electricity delivery, performed two days before the delivery day. It is also referred to as the Day-2 Congestion Forecast (D-2CF). The transmission flow through the critical branch l can be written as

$$F_l = \sum_z PTDF_{l,n}^{zonal} NEX_z \quad \forall l \tag{18}$$

Figure 1 presents an schematic overview of the FBMC steps, showing the different parameters considered and their dependence to one another, up to the solution reached for the Day-Ahead (DA) market. The flow-based input parameters are determined by each TSO separately. The calculation of the flow-based capacity parameters is subsequently done by one entity that evaluates the parameters obtained by the TSOs. Finally, the FBMC algorithm is performed based on these parameters.

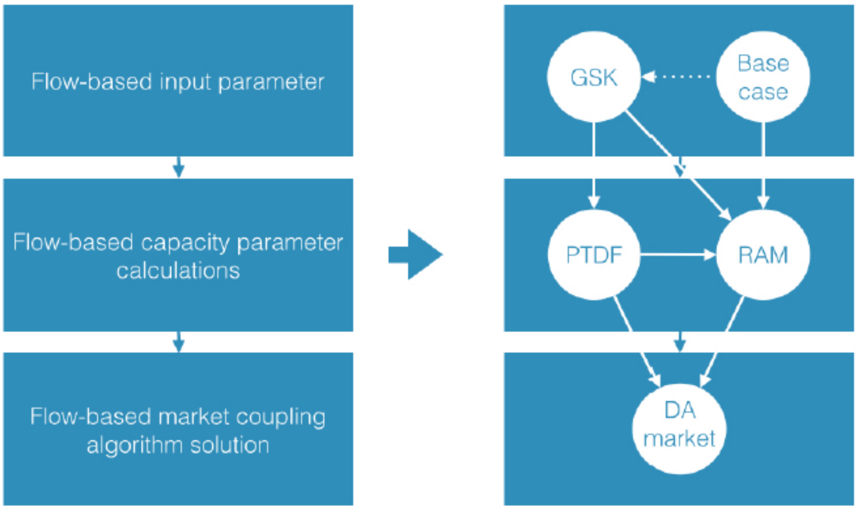

Figure 1 Schematic overview of the FBMC process[42]

In order to define a transaction between zones A and B, the FBMC approach allows to consider as inputs the amount of capacity being allocated at the other borders of the network. These inputs are not considered in the NTC approach, and as a result both methods coincide in the two area case, but the technical and consequently economic superiority of the PTDF based approach becomes evident when dealing with multilateral transactions, as it is the case in the European internal electricity market[4].

2.2 Congestion Management Methods

The criteria for choosing an appropriate strategy for cross-border congestion management should be in accordance with the regulations ruling the internal European electricity market. An efficient method should have the following characteristics[3][4]:

- Maximization of economic welfare
- Promotion of competition
- Non-discrimination among network users
- Security of network operation

Some congestion management methods are designed to allocate the available capacity while meeting security constraints of the network: priority based and pro rata, which are non-market based; explicit auctions, market splitting/implicit auctions and coordinated auctions, which are market based. Other methods must deal with already existing or expected congestion: redispatching and counter trading.

2.2.1 First come, first served

It is an example of priority based method where the capacity is granted to the first agents requesting it, and once the cross-border capacity limit is reached, the TSO no more accepts requests.

It encourages market participants to make longer forecasts and allows for the TSO to manage capacity volumes in advance with a proper security assessment, but this mechanism does not manage short-term trading in accordance with the principles of market dynamics.

2.2.2 Pro rata

All transaction requests are preliminarily accepted, but in case of congestion the TSO curtails the amount of capacity reserved according to the ratio existing capacity/requested capacity. Therefore, no economic incentives are given either to the TSO or to the market participants in order to avoid congestions.

2.2.3 Explicit auctions

It is a market based method for capacity allocation where capacity is traded among market participants through an auction mechanism independent of the electricity market. The transfer capacity between zones is evaluated through one of the approaches presented in section 2.1, for example, and this capacity is divided following an agreement between the TSOs of each zone. Then, the market participants make their bids in order to have access to part of the transmission capacity. The bids are accepted starting from the highest ones until all the capacity available is over, and the last bid can be partially accepted. The last accepted bid sets the marginal price for the transmission fee to be charged by the TSO and all the competitors are charged with it. Figure 2 illustrates the bidding concept. In case the available capacity is enough to cover all the bids, no fee is due.

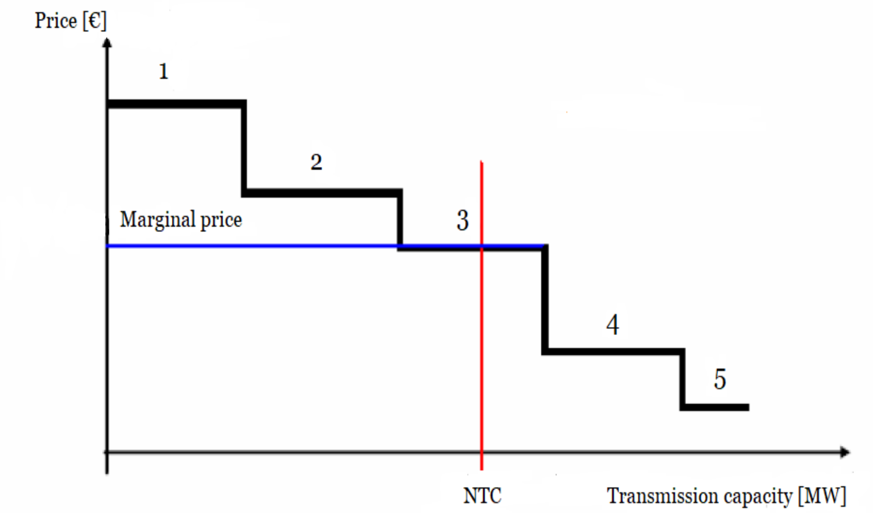

Figure 2 Explicit auction bidding mechanism[21]

The following remarks about explicit auctions hold:

- A balancing mechanism between the two areas making the transaction is not necessary for the auctions.
- Due to the independency between transmission and energy markets, a dominant participant could observe the outcome of the transmission allocation before deciding how to respond in the energy market. If the dominant player gains significant transmission capacity, it would have relatively more incentive to raise the energy price in the importing market, and vice-versa, being therefore able to capture rent through both markets.
- The money extracted by TSOs may be used for network reinforcements in order to increase transmission capacity.

2.2.4 Market splitting/implicit auctions

Under this method, the electricity and capacity markets are integrated. Market coupling and market splitting are very similar types of implicit capacity allocation mechanisms, therefore just the latter will be considered. They differ in the governance and market design when two or more markets(price/delivery zones) are linked with implicit allocation of capacity[12]. The method consists in splitting a power exchange (PEX) into geographical bid areas with limited capacities of exchange; power exchanges are cleared considering the markets disconnected. As a result, the pool prices of the market areas will be different from one another, otherwise there would be no need for transmission across the interconnectors. Then the TSO computes a load flow and identifies constrained interzonal lines. Geographical areas, composed of one or more bid areas, are defined on either side of the congested lines. In each geographical area, a new pool price is defined, flows across areas being limited to the capacity of the interconnection lines[5].

The congestion management relies partly on the market forces. Each area has its own pool price, with the areas downstream of a congestion having higher prices than the areas upstream of a congestion. The price-demand effect will make the demand increase in the low-priced areas and decrease in the high-priced ones, whereas generation will increase in the high-priced areas and decrease in the low-priced ones, thereby relieving the congestion.

Some of the implications of market splitting include :

- Market splitting is a convenient mechanism for market participants, because they only need to bid in or buy from their own markets. Bids are accepted until all demand, including demand from across congested interconnectors, is met.
- Trading is encouraged as long as market participants receive information about possibilities of congestions.
- Consumers may react to high prices in congested areas by substituting other forms of energy to electricity.
- Congested areas may attract new generators due to high prices, introducing more competition and decreasing the price.
- The economic rents are shared between customers and TSOs: no economic rents are available to generators.
- Participants must decide whether or not to exert market power prior to market outcomes being known.

The necessity for an integrated market structure among the participating zones is the biggest barrier for the application of this mechanism: there is a wide diversity of physical arrangements among areas(notification and balancing arrangemets, transmission pricing, half hour our hourly metering) and exchange trading arrangements(block bids, intraday markets, matching rules).

2.2.5 Redispatching and counter trading

Redispatching means that the TSO needs to request generators to deviate from their generation schedules for the sake of network security, as it is the case when a congestion needs to be relieved. Interruptible loads may also be used in addition to generators for redispatching. The TSO requires information on prices to adjust the schedules, and additional costs are normally generated for the TSO. These costs could be allocated to the responsible parties for the sake of economic efficiency[13].

Counter trading is a market based form of redispatching where the shift of generation schedules is achieved by the TSO trading power among different generators and/or interruptible loads by means of a bidding system, where the TSO needs to buy and sell electricity to balance demand in each area. The first step is for generators in the zones affected by the congestion to offer the amount they wish to supply into the combined markets of both zones, and the lowest price they are willing to offer; a similar approach is performed for the energy that needs to be sold back, and the highest prices offered are considered. The TSO then calculates the unsconstrained system price.

The precise generation or load pattern alteration is not predefined under counter trading: through open bidding processes, the TSOs purchase and sell electricity in the opposite direction of the flow through the congested interconnector and, because physical flows of electricity are netted, in this way they can reduce the flow on the interconnector. Under redispatching, however, the TSO requests for alterations of specific generators/loads.

As an example of counter trading, assume that all the generators offer their capacity at marginal cost to the unsconstrained dispatch and to the counter trading market, and consider an interconnector between zones A and B with a flow limit of 150 MW. The unconstrained dispatch, however, amounts to 300 MW from zone A to zone B. Therefore, the TSO must undertake a 150 MW redispatch. This can be achieved by selling 150 MW to generators in zone A and buying 150 MW from generators in zone B. The least cost redispatch requires the TSO to buy electricity from zone B at the lowest possible price and sell it to zone A at the highest possible price (e.g. the TSO buys at 60 €/MWh and sells at 40 €/MWh). Some considerations follow:

- Under counter trading, instead of collecting rents, costs are due to the TSO as a result of the congestion. This gives a clear economic signal to the TSO about the seriousness of the constraint, which indicate how necessary it is to invest in network upgrades.

- Counter trading removes the difference in the final electricity price in the two areas. If TSOs recover the cost due to the constraint evenly from system users, the system price is likely to be between the two prices under market splitting.
- Counter trading requires a common balancing mechanism in both areas, whereas in theory redispatching only requires the knowledge of generator's costs. However, in practice there is little difference between counter trading and redispatching on an economic basis.
- These mechanisms provide no funds to the TSO to upgrade the network.

It is the extension of the bilateral explicit auction mechanism

2.3 Conclusion

An efficient cross-border transmission management must fulfill two main targets: the available capacity must be accurately calculated and efficiently allocated among market participants through a mechanism that incentivizes competition and the maximum utilization of this capacity without creating congestion.

The allocation of cross-border transmission capacity should be multilaterally coordinated in order to increase economic efficiency by reducing uncertainties of the network users. Furthermore, multilateral coordination is the prerequisite for the application of a transmission capacity model based on PTDFs. For a two area case, FBMC and NTC methods give the same results[4]. However, the greater the number of areas participating in the market, the greater the benefits yield by the PTDF approach.

With respect to the congestion management methods, priority based ones like first come, first served and pro rata are not market based and do not allow competition for the transmission capacity in an economically efficient way.

The most economically efficient method is the market splitting/implicit auctions, but it finds obstacles due to the fact that it requires a coordination between the markets of the different participating zones. Therefore, explicit auctions have an advantage in terms of practical feasibility, although its disadvantages like the higher possibility of unfair competition between bidders and the separated transmission capacity market from the energy market are relevant. A solution would be to start from the explicit auctions mechanism and gradually change it to the implicit auctions one, as coordination between market zones are increased. For that purpose hybrid implicit/explicit auctions models have been proposed[4].

Redispatching and counter trading are remedial mechanisms that need to be activated in order to relieve a congestion, and only the latter is a market based solution. These mechanisms incur costs to the involved TSOs.

CHAPTER 3
POWER FLOW TRACING

This chapter presents the concepts of Power Flow Tracing (PFT) and some of its methods found in the literature. The methods presented have the common goal of making available the information of how generators and loads contribute to the flows on the lines, and how generators are supplying the loads. This information may be used for several applications, one of which is to assign the responsabilities of a cross-border congestion in terms of power flows to all the zones of the network, when a zonal approach is considered; and to all the generators and/or loads within a given zone, when a nodal approach is considered[14]. The due charges and/or compensations can then be computed making use of the PFT results. Other usages that can benefit from PFT algorithms include: loss allocation[15]; grid assessment with a high share of renewable sources[16]; intentional controlled islanding[17]; under frequency load shedding[18]; system splitting in case of faults[19]; probabilistic pricing[20].

3.1 Types of Flows

As explained in Chapter 2, a bilateral evaluation of the transmission capacity available on a cross-border line is generally not accurate in a meshed network. This is due to the fact that normally the two neighbouring areas are not the sole responsibles for the flow on that line. Moreover, a transaction may happen between two zones that do not share a common border. Even if the two area case is considered, PFT is important in order to allow the TSOs to accurately charge the generators and/or loads within each zone the transmission costs.
ENTSO-E has defined different types of flows, as follows:

- An Internal Flow is defined as the physical flow on a network element where the source and the sink and the complete element are located in the same zone (this does not affect the tie-lines).
- An Import/Export Flow is the physical flow on a line or part of a tie-line that belongs either to the zone with the source or the sink.
- A Loop Flow is the physical flow on a line where the source and the sink are located in the same zone and the network element is located in a different zone including tie-lines.
- A Transit Flow is the physical flow on a network element where the source, the sink and the line or part of the tie-line are all located in different zones.

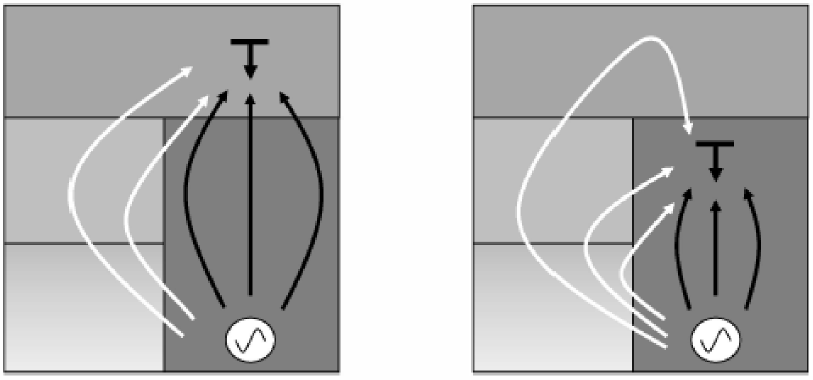

Figure 3 Transit Flows(left) and Loop Flows(right) represented by the white arrows[22]

Figure 3 illustrates the concept of Transit and Loop Flows. A Transit Flow can be either an allocated or an unallocated flow:

- It is an unallocated flow when the exchange, causing the Transit Flow, is not subject to the same cross-border allocation mechanism as the zone facing the Transit Flow.
- It is an allocated flow when the exchange, causing the Transit Flow, is subject to the same cross-border allocation mechanism as the zone facing the Transit Flow.

A Loop Flow is by definition an unallocated flow, as the source and the sink are located within the same bidding zone and the intrazonal exchange is not subject to an allocation mechanism.

3.2 Proportional Sharing

The proportional sharing mechanism relies on the Proportional Sharing Principle(PSP) introduced by J. Bialek in 1996[23]. The PSP states that the nodal inflow is proportionally distributed among the nodal outflows. The Kirchhoff's Current Law (KCL) is obeyed, ensuring that the power injected into the bus equals the power leaving that bus. As an illustration, it means that, in Figure 4, Line 1 has a share of 40/100 and Line 2 has a share of 60/100 in the other lines. This gives the following contributions:

- Line 1 injects $\frac{40}{100}$.70=28 into Line 3 and $\frac{40}{100}$.30=12 into Line 4.
- Line 2 injects $\frac{60}{100}$.70=42 into Line 3 and $\frac{60}{100}$.30=18 into Line 4.

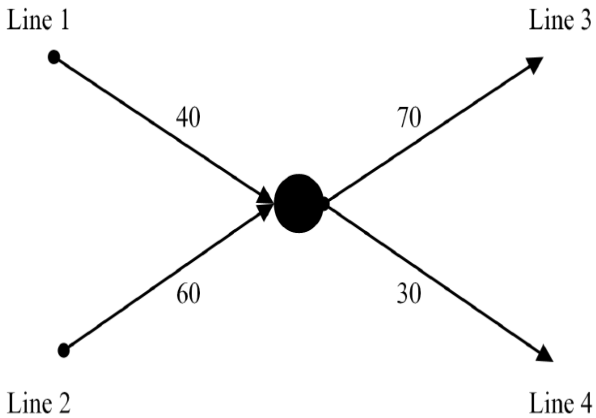

Figure 4 Illustration of PSP[23]

Two basic methods using PSP are well known in the literature: the linear equation based approach presented by Bialek in 1996[23] and the graph based approach presented by Kirschen *et al* in 1997[24]. A third method which relies on a participation factors matrix to determine the contribution of generators to line flows and loads is proposed by Abdelkader in 2007[25] and it will also be shown. All the three approaches claim to be able to handle active and reactive flows in an analogous way, but the authors report some difficulties that may arise when tracing the path of reactive flows, due to the higher collinearity of the reactive subproblem.

3.2.1 Linear equation based method

This method only works on lossless networks, when the flow is the same at both ends of the line. It may be used with an upstream looking algorithm, which looks at the inflows of a node(incoming lines and generation), or with an downstream looking algorithm, which looks at the outflows of a node(outgoing lines and loads). Three different kinds of equivalent networks can be built in order to apply these algorithms using the concepts of gross flows, net flows or average flows:

- With gross flows, an equivalent lossless network is created in which the line flow equals the sending end power of the actual line. Therefore the generation is the same as in the actual grid, and the loads are increased in order to fulfill KCL.
- With net flows, the equivalent lossless network has the line flow equal to the receiving end power of the actual line. Therefore the load is the same as in the actual grid, and generation is increased in order to fulfill KCL.
- With average flows, the line flow of the equivalent network is the average value of the actual line flow. Generation and load need to be changed accordingly in order to fulfill KCL.

Grossflows are only used with the upstream looking algorithm, whereas net flow are only used with the downstream algorithm. Average flows on the other hand can be used with both algorithms. The methods presented in this section have been used in [ex-ante] as the basis for deriving a mathematical model used to allocate transmission costs ex-ante by means of statistical analysis of a set of system operating conditions.

a) Upstream looking algorithm using gross flows

It aims at determining which generators are contributing to the loads and lines in the system. The total gross flow through node i, when looking at the inflows, can be expressed as

$$P_i^{gross} = \sum_{j \in \alpha_i^u} |P_{ij}^{gross}| + P_{G_i} \qquad \forall i \tag{19}$$

where α_i^u is the set of nodes that supply node i, P_i^{gross} is the gross nodal flow through bus i, P_{ij}^{gross} is the gross flow on line i-j and P_{G_i} is the generation at bus i. As the losses have been eliminated, $P_{ji}^{gross} = P_{ij}^{gross}$.

By defining $c_{ji}^{gross} = \dfrac{|P_{ji}^{gross}|}{P_j^{gross}}$, (15) can be written as

$$P_i^{gross} - \sum_{j \in \alpha_i^u} c_{ji}^{gross} P_j^{gross} = P_{G_i} \qquad \forall i \tag{20}$$

It is assumed that the transmission losses are small, so that $\dfrac{|P_{ji}^{gross}|}{P_j^{gross}} \approx \dfrac{|P_{ji}|}{P_j}$, where P_{ij} is the actual flow from node j through line ji, and P_j is the actual total flow through node j. This corresponds to assuming that the distribution of gross flows at any node is the same as the distribution of actual flows. (20) can be written in vector form as

$$\mathbf{A_u} \mathbf{P^{gross}} = \mathbf{P_G} \tag{21}$$

where $\mathbf{P^{gross}}$ is the vector of gross nodal flows through buses, $\mathbf{P_G}$ is the vector of nodal generations, and $\mathbf{A_u}$ is the upstream distribution matrix, where its elements are determined as

$$A_{u_{ij}} = \begin{cases} 1, & \text{for} \quad i = j \\ -c_{ji} = \dfrac{|P_{ji}|}{P_j}, & \text{for} \quad j \in \alpha_i^u \\ 0, & \text{otherwise} \end{cases} \tag{22}$$

When the gross nodal flows have been determined from (21), the gross line flows can be found using PSP as

$$|P_{ij}^{gross}| = \frac{|P_{ij}^{gross}|}{P_i^{gross}} P_i^{gross} \approx \frac{|P_{ij}|}{P_i} \sum_{k=1}^{n} \left[\mathbf{A_u^{-1}}\right]_{ik} P_{Gk} = \sum_{k=1}^{n} D_{ij,k}^{G} P_{Gk} \qquad , j \in \alpha_i^d \tag{23}$$

where $D_{ij,k}^{G}$ is the topological generation distribution factor, α_i^d is the set of nodes supplied by bus i, and n is the number of buses.

The contribution of generators to a load at node i can be derived in an analogous way, resulting in:

$$P_{Li}^{gross} = \frac{P_{Li}^{gross}}{P_i^{gross}} P_i^{gross} \approx \frac{P_{Li}}{P_i} \sum_{k=1}^{n} \left[\mathbf{A_u^{-1}}\right]_{ik} P_{Gk} \tag{24}$$

where P_{Li}^{gross} is the gross load at node i.

The total usage of the network U_{G_k} by k-th generator can now be calculated assuming that the charge for a particular line will be paid proportionally to the actual use of that line by k-th generator. Defining the gross weight w_{ij}^{gross} of line ij as a charge per MW due to gross flows,

$w_{ij}^{gross} = \dfrac{C_{ij}}{P_{ij}^{gross}}$, where C_{ij} is the total supplement charge in [€] for the use of the line.

The supplement charge is an additional charge on top of the marginal cost transmission charge, and it may be as high as 70% of the total transmission charge (fixed capital charges plus some Operation and Maintenance costs that are practically independent of the actual network operation). It is used to alleviate the problem of the high volatility of the marginal pricing of the transmission service, which fails to recover the total incurred network costs. The supplement transmission charge for the use of the k-th generator can then be calculated by adding up individual shares (multiplied by line weights) of the generator in all the lines of the system[26]:

$$
\begin{aligned}
U_{G_k} &= \sum_{i=1}^{n}\sum_{j\in\alpha_i^d} w_{ij}^{gross} D_{ij,k}^{G} P_{G_k} = \sum_{i=1}^{n}\sum_{j\in\alpha_i^d} \frac{C_{ij}}{P_i^{gross}} \left[\mathbf{A_u^{-1}}\right]_{ik} P_{G_k} \\
&= P_{G_k} \sum_{i=1}^{n} \left\{ \frac{\left[\mathbf{A_u^{-1}}\right]_{ik}}{P_i^{gross}} \sum_{j\in\alpha_i^d} C_{ij} \right\}
\end{aligned} \tag{25}
$$

To determine the charges, it is necessary to invert matrix $\mathbf{A_u}$ and calculate vector $\mathbf{P^{gross}}$ from (21).

b) Downstream looking algorithm using net flows

Its goal is to determine how each load contributes for the generation and line flows of the grid. The total net flow through node i, when looking at the outflows, can be expressed as

$$
P_i^{net} = \sum_{j\in\alpha_i^d} |P_{ij}^{net}| + P_{L_i} = \sum_{l\in\alpha_i^d} c_{ji}^{net} P_j^{net} + P_{L_i} \qquad \forall i \tag{26}
$$

where $c_{ji}^{net} = \dfrac{|P_{ji}^{net}|}{P_j^{net}}$ and α_i^d is the set of nodes supplied by node i, P_i^{net} is the net nodal flow through bus i, P_{ij}^{net} is the net flow on line ji and P_{L_i} is the demand at bus i . As the losses have been eliminated, $P_{ji}^{net} = P_{ij}^{net}$. Rearranging the terms of (22) gives

$$
P_i^{net} - \sum_{l\in\alpha_i^d} c_{ji}^{net} P_j^{net} = P_{L_i} \qquad \forall i \tag{27}
$$

The transmission losses are assumed so small, so that $\dfrac{|P_{ji}^{net}|}{P_j^{net}} \approx \dfrac{|P_{ji}|}{P_j}$. (22) can be written in vector form as

$$
\mathbf{A}_d\, \mathbf{P}^{net} = \mathbf{P}_L \tag{28}
$$

where $\mathbf{P}^{net}$ is the vector of net nodal flows, $\mathbf{P}_L$ is the vector of nodal demands and $\mathbf{A}_d$ is the downstream distribution matrix. The elements in the matrix are decided as

$$
A_{d_{ij}} = \begin{cases} 1, & \text{for} \quad i = j \\ -c_{ji} = \dfrac{|P_{ji}|}{P_j}, & \text{for} \quad j \in \alpha_i^d \\ 0, & \text{otherwise} \end{cases} \tag{29}
$$

When the net nodal flows have been determined from (28), the net line flows can be determined by applying PSP and rearranging the terms of (26):

$$|P_{ij}^{net}| = \frac{|P_{ij}^{net}|}{P_i^{net}} P_i^{net} \approx \frac{|P_{ij}|}{P_i} \sum_{k=1}^{n} |A_d^{-1}|_{ik} P_{Lk} = \sum_{k=1}^{n} D_{ij,k}^{L} \quad P_{Lk} \qquad , j \in \alpha_i^u \tag{30}$$

where D_{ij}^{L} is the topological load distribution factor. The contribution of loads to generation at bus i can be derived in the same manner, giving:

$$P_{G_i}^{net} = \frac{P_{G_i}^{net}}{P_i^{net}} P_i^{net} \approx \frac{P_{G_i}}{P_i} \sum_{k=1}^{n} |A_d^{-1}|_{ik} P_{Lk} \tag{31}$$

where $P_{G_i}^{net}$ is the net generation at node i.

By defining the net weight w_{ij}^{net} of line ij as a charge per MW due to net flows, $w_{ij}^{net} = \frac{C_{ij}}{P_{ij}^{net}}$, the total usage of the network U_{L_k} by the k-th load can then be calculated by adding up individual shares of the load (multiplied by line weights) in all the lines in the system:

$$\begin{aligned} U_{Lk} &= \sum_{i=1}^{n} \sum_{j \in \alpha_i^u} w_{ij}^{net} D_{ij,k}^{L} P_{Lk} = \sum_{i=1}^{n} \sum_{j \in \alpha_i^u} \frac{C_{ij}}{P_i^{net}} \left[\mathbf{A_d^{-1}}\right]_{ik} P_{Lk} \\ &= P_{Lk} \sum_{i=1}^{n} \left\{ \frac{\left[\mathbf{A_d^{-1}}\right]_{ik}}{P_i^{net}} \sum_{j \in \alpha_i^u} C_{ij} \right\} \end{aligned} \tag{28}$$

To determine the charges, it is necessary to invert matrix $\mathbf{A_d}$ and calculate vector $\mathbf{P^{net}}$ from (28). This is the dual methodology of a).

3.2.2 Graph based method

This method consists in organizing the buses and branches of the grid into homogeneous groups starting from a solved power flow or state estimation computation[24]. From that, it is possible to represent the state of the system by means of a directed, acyclic graph. The original concepts used in this method are listed below.

1. Domain of a generator: it is defined as the set of buses which are reached by the power produced by a given generator.
2. Common: it is defined as the set of buses supplied by the same generators. A bus therefore belongs to one and only one common. The rank of a common is defined as the number of generators supplying power to the buses comprising this common, and it can never be lower than one or higher than the number of generators in the system
3. Link: each branch of the system is either internal or external to a common. Internal means that it connects two buses which are part of the same common, and external means that it connects two buses which are part of different commons. A link is defined as the set of one or more

external branches connecting the same commons to each other. The direction of the actual flows on every branch of a link is the same.

In the 6-bus example of Figure 5, it gives:

- All the buses are part of the domain of generator A; the domain of generator B comprises buses 3, 4, 5 and 6; the domain of generator C comprises only bus 6.
- Common 1 includes buses 1 and 2, which are supplied by generator A only (rank 1); common 2 includes buses 3, 4 and 5, which are supplied by generators A and B (rank 2); common 3 includes only bus 6, which is supplied by all three generators (rank 3).
- Link 1 connects commons 1 and 2 and consists of branches 1-3 and 2-5; link 2 connects commons 2 and 3 and consists of branches 4-6 and 5-6; link 3 connects commons 1 and 3 and consists of branch 2-6.

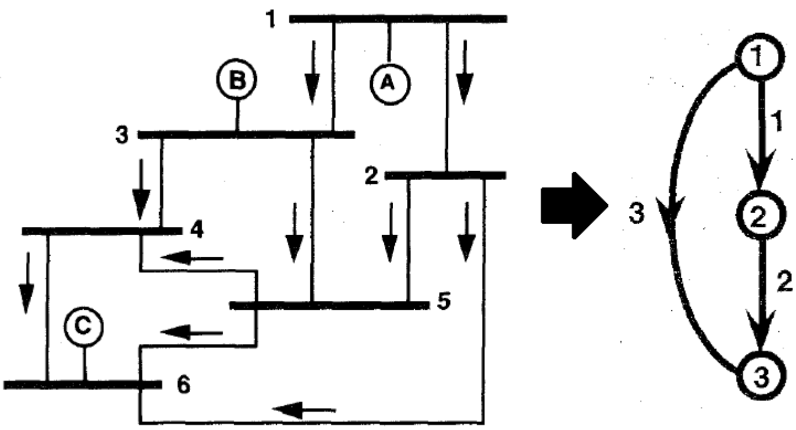

Figure 5 6-bus system example(left) and state graph generated(right)[24]

The state graph generated is shown in Figure 5. One difficulty of the application of this method is that a single change in the topology of the network may change the composition of commons and links. A recursive method is used to calculate the contributions of generators and loads, which alternates between computing the flow on a line due to a generator, and the relative contribution of a generator to the outflow of a common. The contribution of a generator i to a link jk is determined by:

$$F_{jk}^{i} = C_{j}^{i} F_{jk} \tag{33}$$

where F_{jk}^{i} is the flow on link j-k due to generator at bus i, C_{j}^{i} is the relative contribution of generator at bus i to the outflow of common j, and F_{jk} is the flow on link jk. The relative contribution of generator at bus i to the outflow of common k is determined by:

$$C_k^i = \begin{cases} \dfrac{P_{Gi}}{F_i} & \text{if} \quad i = j \\ \dfrac{\sum_{j \in D} P_{jk}^i}{F_k} & \text{otherwise} \end{cases} \tag{34}$$

where C_k^i is the relative contribution of generator at bus i to the outflow of common k, P_{Gi} is the generation at node i, F_k is the flow through common k, and D is the set of commons supplying common k.

3.2.3 Participation factors matrix based method

This method was proposed in [25], and makes use of a single matrix to calculate the contributions of generators to loads and line flows, without needing matrix inversion as the upstream and donwstream looking algorithms. The nodal concepts used are listed below.

1. Source node: the power flows of all the lines connected to it are directed outwards of the node.
2. Sink node: the power flows of all the lines connected to it are directed inwards the node.
3. Generation node: the power flows of all the lines connected to it are directed both outwards and inwards, but the net power injected into the node is positive.
4. Load node: the power flows of all the lines connected to it are directed both outwards and inwards, but the net power injected to into the node is negative.

Every system has at least one source node and one sink node, that represent the terminal nodes of the flow path. Intermediate paths are composed of generation nodes and load nodes. Figure 6 illustrates these concepts.

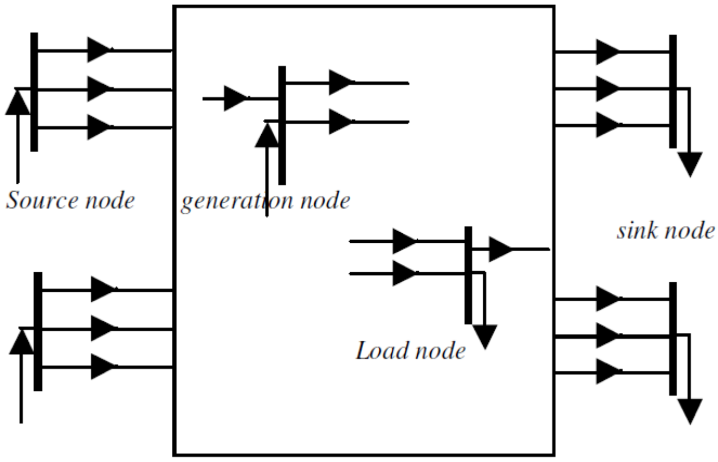

Figure 6 Node types[25]

The participation factor of node to the flow through a line is defined as the flow on the line caused by the generator at the considered node, divided by the total flow on the line, and it can be positive, negative or zero, depending on the direction of the flow with respect to the node. Applying the Propportional Sharing Principle to a given node n, the participation factor of node i to the flow through line l can be written is a general form as

$$A_{i,l} = \sum_{k \in \lambda_n} A_{i,k} A_{n.k} \quad , l \in \mu_n \tag{35}$$

where λ_n is the set of lines carrying flows directed inwards node n, and μ_n is the set of lines carrying flows directed outwards node n.

The method makes use of a line flow matrix, which has its rows corresponding to the buses of the system and the columns corresponding to the branches of the system. The columns are made of zeros except at the rows corresponding to the end buses of the branch being represented by the considered column. Each element has the value of the power entering or leaving the branch at the bus. The line matrix can be written in compact for as

$$\mathbf{F} = | f_{il} | \quad i = 1, N_B \quad l = 1, N_L \tag{36}$$

where f_{il} is the power extracted(outflow) or injected(inflow) by branch l at bus i, N_B is the number of buses of the system and N_L the number of lines of the system. Outflows are considered positive and inflows are considered negative; f_{il} is zero if line l is not connected to bus i. The type of a given node i can be deduced by looking at the nonzero elements of the row corresponding to that node in the line flow matrix, as shown in Table 1.

Table 1 Node types

Node type	Condition
Sink node	$f_{il} \le 0, \quad l = 1, N_L$
Load node	$\sum_{l=1}^{N_L} f_{il} \le 0, \quad \exists l : f_{il} > 0$
Generation node	$\sum_{l=1}^{N_L} f_{il} > 0, \quad \exists l : f_{il} < 0$
Source node	$f_{il} \ge 0, \quad l = 1, N_L$

Then a participation factors matrix $\mathbf{A}$ is built from the line flow matrix. Each nonzero element of the rows of $\mathbf{F}$ corresponding to source nodes are replaced with ones in $\mathbf{A}$, since the flows on the lines connected to a source node are entirely provided by the source node itself: each nonzero element of $\mathbf{F}$ corresponding to sink nodes are replaced with zeros in $\mathbf{A}$, since sink nodes do not provide power to any line. For generation nodes,

$$A_{il} = \begin{cases} \dfrac{P_i}{\sum_{m \in \alpha_P} f_{im}}, & f_{il} > 0 \\ 0, & f_{il} = 0 \\ \dfrac{f_{il}}{\sum_{m \in \alpha_P} f_{im}}, & f_{il} < 0 \end{cases} \tag{37}$$

where α_P is the set of positive elements in the i^{th} row, and P_i is the net power injected at bus i. For load nodes,

$$A_{il} = \begin{cases} \alpha, & f_{il} > 0 \\ 0, & f_{il} = 0 \\ \dfrac{f_{il}}{\sum_{m \in \alpha_N} | f_{im} |}, & f_{il} < 0 \end{cases} \tag{38}$$

where α_N is the set of negative elements in the i^{th} row, and α is a very small positive number (e.g. 10^{-8}). The power flow tracing procedure makes use of the matrix $\mathbf{A}$ to determine the contribution of generators to lines and loads. The complete stepwise algorithm can be found in [25]. Transmission losses are implicitly accounted for since the method uses the information of the flow on both ends of the lines in the computations.

3.3 Equivalent Bilateral Exchanges

One drawback of the methods based on the PSP is the exclusion of the consideration of counterflows, which are the power flow components opposite to the direction of the net flow in a line. This exclusion can result in transmission use rates that are highly volatile with respect to the power flow operating point[27]. Transmission cost allocation based on Equivalent Bilateral Exchanges (EBE) claims to be able to deal with this issue. Furthermore, it is independent of the choice of the slack bus and yields transmission use charges that are stable and always positive. The EBE principle states that, starting from the solution of an optimal power flow where no system constraints are violated, Kirchhoff's laws are respected and each generator injects flows towards all the loads. Therefore each load is supplied by a fraction of each generator uniformly divided among all generators, and each generator supplies a fraction of each load uniformly divided among all the loads.

Assuming a generator i and a load j, the individual contribution from generator i to the load j is given by

$$\mathrm{GD}_{ij} = \frac{P_{G_i}^{DC}}{P^{total}} P_{D_j} \tag{39}$$

where P^{total} is the sum of all power demands, P_{D_j} is the demand at bus j and $P_{G_i}^{DC}$ is the power generated in any bus i considering a lossless system. The contribution of each EBE to the power flow on each line of the system can be determined by

$$\mathbf{F} = \boldsymbol{\alpha}\mathbf{P} \tag{40}$$

Where $\mathbf{P}$ is a vector representing the active power injection at each bus, and $\boldsymbol{\alpha}$ represents the sensitivity matrix of the system. The vector of power injections $\mathbf{P}$ describes a generic EBE with one injection GD_{ij} at bus i and one extraction GD_{ij} at bus i, so that:

$$\mathbf{P} = \left(0 \cdots \underset{\uparrow}{\mathrm{GD}_{ij}} \cdots -\mathrm{GD}_{ij} \cdots 0\right)^T \tag{41}$$

The vector $\mathbf{F}$ expresses the flow on each line due to the EBE formed by generator i and load j. In order to determine the network usage allocated to generator k for line l, half of the sum of all EBEs containing generator k must be considered:

$$U_l^{Gk} = \frac{1}{2}\sum_{j=1}^{N_G} F_l^{kj} \tag{42}$$

Analogoulsy, for load k:

$$U_l^{Dk} = \frac{1}{2}\sum_{j=1}^{N_D} F_l^{jk} \tag{43}$$

where F_l^{kj} is the flow through line l due to the EBE composed of generator k and load j, and N_G and N_D are respectively the number of generators and loads of the system. Considering the cost rates of line l allocated to generators and loads, respectively, as

$$r_l^G = \frac{C_l^G}{U_l^G} \tag{44}$$

$$r_l^D = \frac{C_l^D}{U_l^D} \tag{45}$$

where C_l^G and C_l^D are the total costs allocated to generators and loads, respectively; and U_l^G and U_l^D are the total network usage of line l by generators and loads, respectively. Then, the cost of line l allocated to generators and loads located at bus k is

$$C_l^{Gk} = r_l^G U_l^{Gk} \tag{46}$$

$$C_l^{Dk} = r_l^D U_l^{Dk} \tag{47}$$

3.4 Z bus based method

The Zbus method makes use of the impedance matrix Z_{bus} in order to allocate the usage of the lines to generators and loads. This method does not depend on the choice of the slack bus; it is claimed to show a desirable proximity effect, meaning that a significant share of a the usage of a given line is assigned to buses close to that bus; and it does not require an artificial imposition of the proportion of usage of the line by generators and loads, but relies solely on circuit theory. In order to present an appropriate numerical behaviour, all transmission lines must be modeled including actual shunt admittances[28][29].

Assuming that the complex power injected through transmission line is given by

$$S_{jk} = E_j \; I_{jk}^* \tag{48}$$

where S_{jk} is the complex power flow through line jk, E_j is the nodal voltage at bus j and I_{jk} is the current through line jk. Using the impedance matrix Z_{bus}, obtained as the inverse of the admittance matrix ($Y_{bus}^{-1} = Z_{bus}$), the voltage at bus j can be calculated as

$$E_j = \sum_{i=1}^{n} z_{ij} \; I_i \tag{49}$$

where z_{ij} is the element (j,i) of the Z_{bus} matrix. The current through line jk is obtained as

$$I_{jk} = \left(E_j - E_k\right) y_{j\to k} + E_j \; y_{j\to k}^{sh} \tag{50}$$

where $y_{j\to k}$ is the series admittance of the π equivalent circuit of line jk, and $y_{j\to k}^{sh}$ is half of the total shunt admittance of the π equivalent circuit of the line jk. After some manipulations, (50) can be written as

$$I_{jk} = \sum_{i=1}^{n} a_{jk}^{i} I_i \tag{51}$$

where

$$a_{jk}^{i} = \left(z_{ji} - z_{ki}\right) y_{j\to k} + z_{ji} \; y_{j\to k}^{sh} \tag{52}$$

The magnitude of a_{jk}^{i} provides a measure of the electrical distance between bus i and line jk. Substituting (51) into (48):

$$S_{jk} = E_j \; \sum_{i=1}^{n} \left(a_{jk}^{i} I_i \right)^* \tag{53}$$

Then, the active power through line jk is

$$P_{jk} = \sum_{i=1}^{n} \Re\left\{E_j \; a_{jk}^{i*} I_i^*\right\} \tag{54}$$

The active power flow through any transmission line can then be split and associated to the nodal current injection at each bus. The power flow through line jk associated to current i can be written as

$$P_{jk}^{i} = \Re\left\{E_j \; a_{jk}^{i*} I_i^*\right\} \tag{55}$$

In order to reach a better measure of the usage of line jk, the average of the contribution from bus i to line jk is used, with the power flow calculated at the beginning and at the end of the line:

$$U_{jk}^{i} = U_{l}^{i} = \frac{|P_{jk}^{i}| + |P_{kj}^{i}|}{2} \quad , \forall l \in \Omega_L \tag{56}$$

where U_{jk}^{i} is the usage of line jk associated with the current injection at bus i, also referred to as U_{l}^{i}; and Ω_L the set of lines of the system. The total usage of any line l is equal to the power flow through this line and it is denoted as

$$U_l = \sum_{i=1}^{n} U_l^i \tag{57}$$

Without loss of generality, is considered at least a single generator and a single load at each bus of the network. If bus i contains only generation, the usage of line l allocated to generator G_i is

$$U_l^{G_i} = U_l^i \tag{58}$$

On the other hand, if bus i contains only demand, the usage of line l allocated to demand D_i is

$$U_l^{D_i} = U_l^i \tag{59}$$

If instead bus i contains both generation and demand, the usage allocated to the generator and load at bus i belonging to line l are, respectively:

$$U_l^{G_i} = \frac{P_{G_i}}{P_{G_i} + P_{D_i}} U_l^i \tag{60}$$

$$U_l^{D_i} = \frac{P_{D_i}}{P_{G_i} + P_{D_i}} U_l^i \tag{61}$$

Finally, considering the cost rate as expressed in (44) and (45), the cost of line l allocated to generators and loads located at bus k is, respectively:

$$C_l^{G_k} = r_l^G U_l^{G_k} \tag{62}$$

$$C_l^{D_k} = r_l^D U_l^{D_k} \tag{63}$$

3.5 Cross-border Tracing

In order to assign the responsibilities in terms of power flow to the respective zones of the network, which may be regions or countries, individual generators and loads of each zone are grouped into a single node that takes into account the sum of cross-border net imports and exports of the considered zone. The total zonal net import/export represents the balance between generation and demand of the area. The equivalent node is treated as a generator if it exports energy (net exporter) and as a load if it imports energy (net importer).

Tracing cross-border flow making use of the complete representation of the network is also possible[30][31], but there are a series of possible drawbacks in this approach:

1. Disclosure of possibly commercially sensitive information: detailed information of the internal networks and the knowledge of individual nodal injections are needed, and countries may be unwilling to disclose it.
2. Different allocation mechanisms in each zone: it is realistically unlikely that the same transmission cost allocation mechanisms due to line usage would be applied in all the countries. Therefore the utilization of the zonal approach allows for the TSOs of each country to apply their own allocation methods. In the European scenario, this is in accordance with the principle of subsidiarity, that "*it is the principle whereby the European Union does not take action (except in the areas that fall within its exclusive competence), unless it is more effective than action taken at national, regional or local level* "[2].
3. Charges to countries with balanced generation and demand: even in the case of zones with net import/export equals zero, some charges could be allocated to different generators/loads within a given zone when considering the impact of a balanced group of closely connected generators and loads on the external network. In [31], an example is used to illustrate this issue: Figure 7 shows 1000 MW being transferred from node 1 to node 2, being the power through lines 1-2 and 3-4 also equal to 1000 MW. A closely connected balanced group composed of a load at node 2 and a generator at node 3 exists. PFT would allocate 300/1000 of the cost of losses in line 1-2 to the load at node 2 and 300/1000 of the cost of losses in line 3-4 to the generator at node 3. However if they are grouped into a zone and their net effect on the external network was considered, no charges would be allocated to them.

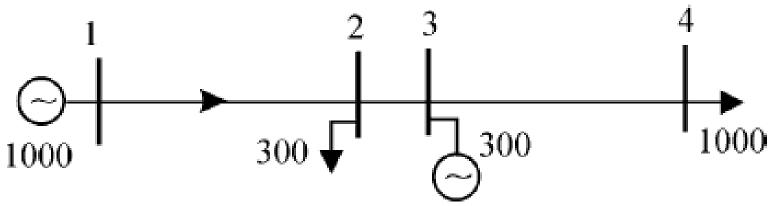

Figure 7 Example of a balanced group[4]

3.6 Conclusion

This chapter discussed the importance of correctly identifying the different types of flows and addressing them to the generators and loads causing it. Some methods found in the literature used for that purposes were then presented. The ones based on the PSP rely on the assumption that the nodal inflow is proportionally distributed among the nodal outflows. The EBE approach is based on another principle that states that each load of the system is supplied by a fraction of each generator uniformly divided among all generators, and an analogous reasoning applies in the opposite way. The Z_{bus} method on the other hand relies entirely on circuit theory and does not make use of an assumption of proportionality of usage of lines by generators and loads. For a comparison between those methods based on implementative results, the reader may refer to [14][29].

Modifications to the methods presented and different procedures can be found in the literature[32][33][34]. For specific purposes other methodologies exist, as it is the case of cost allocation, where there are methodologies which consider market variables alongside technical variables of the electrical system, for example making use of optimization algorithms[35][36].

Finally, some considerations regarding the use of the zonal and the complete network approach in order to assign responsabilities for a cross-border congestion were presented. It was shown that the zonal approach may have some advantages like the possibility of each country use its own allocation mechanism, no need for disclosure of possibly commercially sensitive information and no undue charges to balanced zones.

CHAPTER 4
COST SHARING METHODOLOGY I

This chapter gives a description of the cost sharing methodology considered by RTE for coordinated countertrading and redispatching actions, pursuant to requirements set by Capacity Allocation and Congestion Management CACM) and System Operations (SO) Guidelines (GL). It has been developed with the aim of being usable in the Capacity Calculation Regions (CCRs) concerning the Italian north borders .In this thesis, however, it was implemented in the whole European UCTE network. The method assumes that the costs to be shared are the ones corresponding to the costs of the coordinated countertrading and redispatching actions that have been agreed by the relevant TSOs in order to relieve the constraint on a given internal or interzonal congested grid element[37].

4.1 Area of Common Interest

The Area of Common Interest (ACI) is the set of assets for which the TSOs agree to share costs in the case they decide to implement coordinated countertrading and redispatching relieving the constraint on one of these assets (i.e. the congested grid element). This methodology thus does not apply to the costs related to remedial actions relieving the constraint on the other assets.

According to SO FL Art. 76, only costs of remedial actions relieving cross-border relevant congestions are subject to sharing between TSOs; and cross border relevance of a congestion is determined according to the influence of energy exchanges on it.

Thus, ACI assets shall be the elements that are mostly influenced between zones the considered network. It is assumed that the ACI contains the Critical Branches-Critical Outages (CBCO) used in the capacity calculation since they limit the maximum level of commercial exchanges.

4.2 Influence Factors of Exchange Variations

According to SO GL Art. 76, the costs shall be shared in proportion to the aggravating impact of energy exchange between given control areas on the congested grid element (referred to as L). Therefore, the base element used in the cost sharing is the influence factor of exchange variation between two zones on the congested grid element L, considered in the relevant state (N or N-1 depending on the congestion). The influence factor $\mathrm{Infl.}_{A\rightarrow B}(L)$ between a given zone A and a given zone B is defined as

$$\mathrm{Infl.}_{A\rightarrow B}(L) = \frac{\mathrm{Flow}(L)_{\mathrm{shift}} - \mathrm{Flow}(L)_{\mathrm{base\ case}}}{100} \tag{64}$$

where $\mathrm{Flow}(L)_{\mathrm{shift}}$ is the flow through the grid element L in a shifted situation and $\mathrm{Flow}(L)_{\mathrm{base\ case}}$ is the flow through the grid element L in the base case. The base case used for the calculation of influence factors is the network model used to decide the need for coordinated countertrading and redispatching measures: it is the grid situation corresponding to the latest available Common Grid Model (CGM), depending on the time of application, used during the coordination and considered in the N or N-1 state. The shifted situation corresponds to an increase of 100 MW of power transferred from zone A to zone B starting from the base case (independent of which buses are used for that purpose), using the relevant Generation Shift Keys (GSKs). Some GSK strategies are described in Appendix 2.
The right-hand side of equation (64) is divided by 100 because $\mathrm{Infl.}_{A\rightarrow B}(L)$ represents a coefficient between 0 and 1, and it can be denoted as a percentage when multiplied by 100. For example, if the flow through the congested grid element in the shifted situation increases by 100 MW with respect to the base case, the influence factor of (64) would be equal to 1 (100%), therefore meaning that the whole increase of 100 MW of exchanges from zone A to zone B is translated into an increase of flow through the congested grid element. The influence factor $\mathrm{Infl.}_{A\rightarrow B}(L)$ can thus be defined as the increase (or decrease if the value is negative) of flow through the grid element L for 100 MW increase of exchanges from zone A to zone B in the relevant state.

Considering the case of the network comprising Italy and its neighboring countries, seven influence factors would be calculated when coordinated countertrading and/or redispatching relieving actions on one asset of the ACI have been applied:

- $Infl._{France \rightarrow Italy}$ and $Infl._{France \rightarrow Switzerland}$
- $Infl._{Switzerland \rightarrow Italy}$ and $Infl._{Switzerland \rightarrow Austria}$
- $Infl._{Austria \rightarrow Italy}$ and $Infl._{Austria \rightarrow Slovenia}$
- $Infl._{Slovenia \rightarrow Italy}$

4.3 Determination of the Distribution per Type of Flows

In order to determine the aggravating impact of a given energy exchange on an overloaded grid element, it is needed to identify the types of flows and associated amounts on this element. As discussed in 3.1, ENTSO-E has defined different types of flows, as follows:

- An Internal Flow is defined as the physical flow on a network element where the source and the sink and the complete element are located in the same zone(this does not concern the tie-lines).
- An Import/Export Flow is the physical flow on a line or part of a tie-line that belongs either to the zone with the source or the sink.
- A Loop Flow is the physical flow on a line where the source and the sink are located in the same zone and the network element is located in a different zone including tie-lines.
- A Transit Flow is the physical flow on a network element where the source, the sink and the line or part of the tie-line are all located in different zones.

Table 2 summarizes the types of flows applicable to tie-lines and internal lines:

Table 2 Type of flows applicable to tie-lines and internal lines

Type of flows	Tie-line	Internal line
Internal flow	No	Yes
Iimport/Export flow	Yes	Yes
Loop flow	Yes	Yes
Transit flow	Yes	Yes

Figure 8 describes the different types of flows on a given overloaded grid element, where PATL stands for Permanent Admissible Transmission Loading, which is the "*loading in Amps, MVA or MW that can be accepted by a network branch for an unlimited duration without any risk for the material*"[2] and RA stands for Remedial Actions.

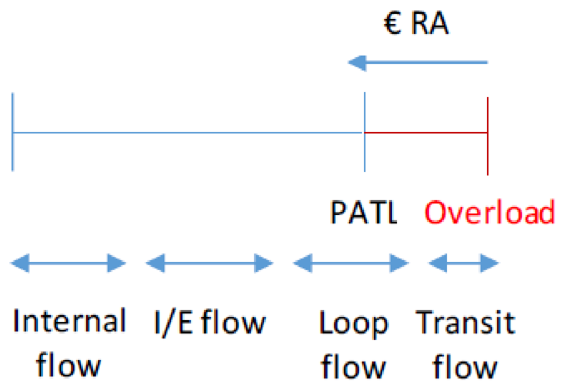

Figure 8 Types of flows on a given overloaded grid element

4.3.1 Determination of Transit and Import/Export Flows

Transit and Import/Export flows must be divided between zones, proportionally to their influence factors and commercial exchanges. The flows on a grid element L (being either an internal line or a tie-line), due to the exchanges between zone A and zone B are calculated as follows:

$$\mathrm{Part}_{A/B}(L) = \mathrm{Infl.}_{A \to B}(L) \times \mathrm{CommercialFlows}(A \to B) \tag{65}$$

with $\mathrm{Part}_{A/B}(L) = \mathrm{Part}_{B/A}(L)$, because if both the directions of the calculated influence factor and the considered commercial flow are reversed, the result in equation (65) would remain unchanged. The commercial flows used in the calculations are inputs referred to the base case. On the grid element L, the part of Import/Export flows is thus equal, with linear approximations, to the sum:

- If L is an internal line in zone A,

$$\mathrm{ImpExp}(L) = \sum_{i \neq A} \mathrm{Part}_{A/i}(L) \tag{66}$$

- If L is a tie-line between zones A and B,

$$\mathrm{ImpExp}(L) = \mathrm{Part}_{A/B}(L) \tag{67}$$

The Import/Export Flows considered in equations (66) and (67), for an internal line and a tie-line, respectively, are illustrated in Figure 9, with respect to a 3 area case. The red lines represent the congested grid element, and the blue and the green lines represent the relevant flows (which could flow in either direction) that affect the considered congested element.

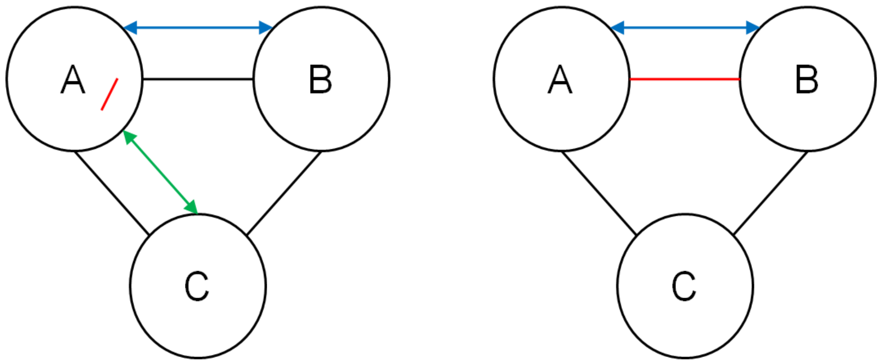

Figure 9 Relevant flows for the calculation of Import/Export Flows for an internal line (left) and a tie-line (right)

The part of Transit Flows is equal to the sum:

- If L is an internal line in zone A,

$$\text{Transit Flow}(L) = \sum_{i, i \neq A} \mathrm{Part}_{i/j}(L) \tag{68}$$

- If L is a tie-line between zones A and B,

$$\text{Transit Flow}(L) = \sum_{(i,i) \neq (A,B)} \mathrm{Part}_{i/j}(L) \tag{69}$$

The Transit Flows considered in equations (68) and (69), for an internal line and a tie-line, respectively, are illustrated in Figure 10, with respect to a 3 area case. The red lines represent the congested grid element, and the blue and the green lines represent the relevant flows (which could flow in either direction) that affect the considered congested element.

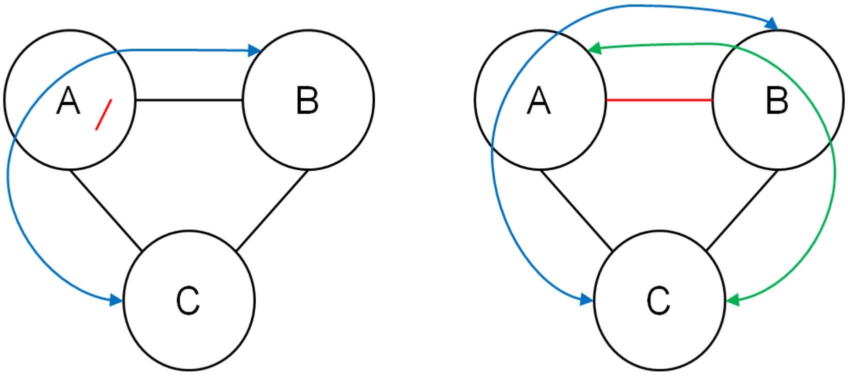

Figure 10 Relevant flows for the calculation of Transit Flows for an internal line (left) and a tie-line (right)

4.3.2 Determination of Loop Flows

The first step is the determination of the influence of each zone on the Loop Flows. For a given zone A, $\mathrm{Infl.}_A^{LF}(L)$ represents the increase (or decrease if the value is negative) of flow through the grid element L for 1000 MW increase of generation in zone A balanced by 1000 MW increase of demand in the same zone, considered in the relevant state of the grid. It is calculated in an analogous way to the influence factors of exchange variations presented in 4.2:

$$\mathrm{Infl.}_A^{LF}(L) = \frac{\mathrm{Flow}(L)_{shift} - \mathrm{Flow}(L)_{base\ case}}{1000} \tag{70}$$

where $\mathrm{Flow}(L)_{shift}$ is the flow through the grid element L in a shifted situation and $\mathrm{Flow}(L)_{base\ case}$ is the flow through the grid element L in the base case. From the base case, on shifted situation is defined by increasing both the generation and the load in zone A by 1000 MW using the relevant GSK and Load Shift Keys (LSK).

The right-hand side of equation (70) is divided by 1000 because $\mathrm{Infl.}_A^{LF}(L)$ represents a coefficient between 0 and 1, and it can be denoted as a percentage when multiplied by 100. For example, if the flow through the congested grid element in the shifted situation increases by 1000 MW with respect to the base case, the influence factor of (70) would be equal to 1 (100%), therefore meaning that the whole increase of 1000 MW of both the generation and demand of zone A is translated into an increase of flow through the congested grid element.

The amount of increase of 1000 MW is higher than for the influence factors of exchange variations in order to avoid obtaining very low values for the difference of power flowing through the grid element L. Indeed, the influence of loop flows is assumed to be generally lower, and the amount of increase could be adapted depending on the network considered, which comprises the countries adopting this cost sharing methodology.

The second step is the determination of the share of Loop Flows yield by each zone. The source and the sink of a Loop Flow are located in the same zone, and the common amount of power whose source and sink are located in the same given zone is considered as the minimum power between load consumed in the zone and generation produced in the zone: this corresponds to the source and sink power of loop flows yield by this zone.

In Figure 11, it is assumed that zone A has a positive Net Position (zonal generation higher than zonal demand). The right block represents the whole generation of zone A, the upper part of the left block the whole demand of zone A, and the lower part of the left block the surplus of generation of zone A. Therefore, the amount of power corresponding to the demand of zone A may yield Loop Flows, because this power is generated and consumed in the same zone, but its trajectory is not necessarily limited to this zone. On the other hand, the amount of power corresponding to the surplus of generation may contribute to Import/Export Flows and Transit Flows, because this power is generated in zone A, but it is not consumed in this zone.

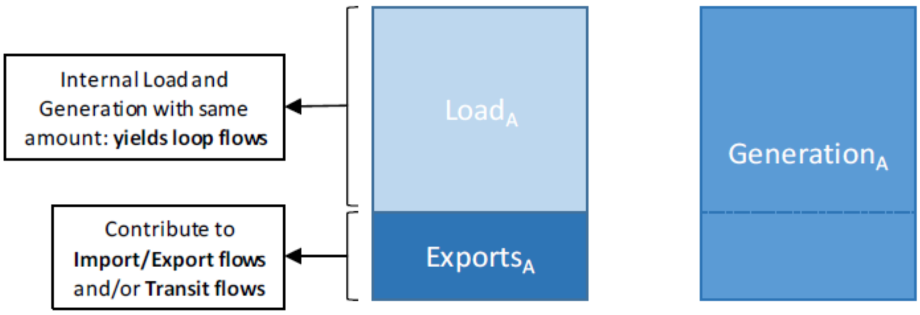

Figure 11 Equilibrium in zone A and Loop Flows

The flows on a grid element L, due to the loop flows from zone A are calculated as

$$\mathrm{LoopFlow}_A(L) = \mathrm{Infl.}_A^{LF}(L) \times \min(\mathrm{Load}_A ; \mathrm{Generation}_A) \quad , L \in A \tag{71}$$

The flows on a grid element L due to the Loop Flows yield by other zones than the one to which L belongs to are calculated as follows:

- If L is an internal line in zone A:

$$\mathrm{LoopFlow}(L) = \sum_{i \neq A} \mathrm{LoopFlow}_i\ (L) \tag{72}$$

- If L is a tie-line between zones A and B,

$$\text{LoopFlow(L)} = \sum_{i} \text{LoopFlow}_{i}\ (\text{L}) \tag{73}$$

The Loop Flows considered in equations (72) and (73), for an internal line and a tie-line, respectively, are illustrated in Figure 12, with respect to a 3 area case. The red lines represent the congested grid element, and the blue, the green and the orange lines represent the relevant flows (which could flow in either direction) that affect the considered congested element.

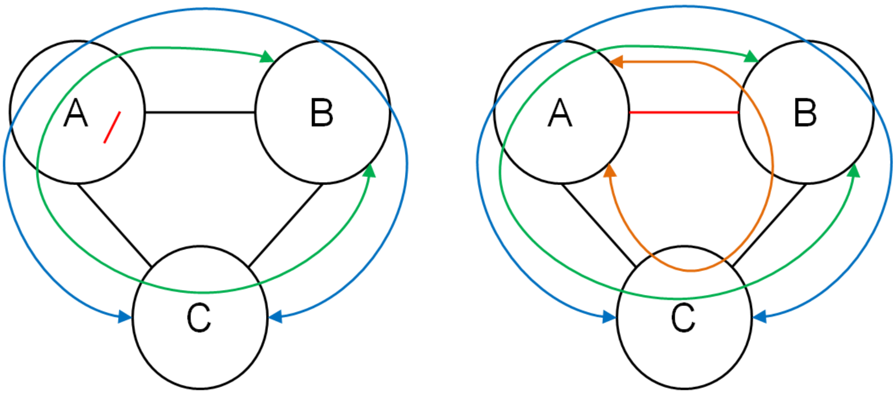

Figure 12 Relevant flows for the calculation of Loop Flows for an internal line (left) and a tie-line (right)

4.3.3 Determination of Internal Flows

The sum of Import/Export, Transit and Loop Flows shall be interpreted as External Flows, which are flos yield by other countries than the one to which the grid element L belongs:

$$\text{ExternalFlow(L)} = \text{TransitFlow(L)} + \text{ImpExp(L)} + \text{LoopFlow(L)} \tag{74}$$

Finally, for internal lines, the Internal Flow is determined as the Loop Flows yield by the zone to which L belongs, and it may have a negative value, which means that it would relieve the constraint. If L is an internal line in zone A:

$$\text{InternalFlow(L)} = \text{LoopFlow}_{A}(\text{L}) \tag{75}$$

It has to be noted that Internal Flow is set to zero in case L is a tie-line.

4.3.4 Overview of flow calculation

The following table summarizes the calculation to be performed in order to assess the amount of the different types of flows for each type of line:

Table 3 Formulas for flow evalution for each type of line

Type of flows	Tie-line between A and B	Internal line in A
Internal flow	-	$\mathrm{LoopFlow}_A(L)$
Import/Export flow	$\mathrm{Part}_{A/B}(L)$	$\sum_{i \neq A} \mathrm{Part}_{A/i}(L)$
Loop flow	$\sum_{i} \mathrm{LoopFlow}_i(L)$	$\sum_{i \neq A} \mathrm{LoopFlow}_i(L)$
Transit flow	$\sum_{(i,i) \neq (A,B)} \mathrm{Part}_{i/j}(L)$	$\sum_{i,i \neq A} \mathrm{Part}_{i/j}(L)$

4.4 Cost Sharing

The cost sharing is calculated only if the External Flows represent a positive amount, i.e. they tend to aggravate the congestion on the considered element L: this sets the rules to determine the cross-border relevance of the congestion on the considered congested element L. This rule could be further generalized, by defining a threshold for the External Flows for example. It has to be noted that congestion on tie-lines will always be considered as cross-border relevant ones.

4.4.1 Case 1: ExternalFlow(L)<0

The External Flows relieve the constraint: the congestion is not a cross-border relevant one and it is due to internal zonal problems. All the costs shall be taken care of by the zone of the grid element L:

$$\text{If } \mathrm{ExternalFlow}(L) \leq 0 \;\&\; L \in A \Rightarrow \mathrm{Sharing}_A = 100\% \tag{76}$$

4.4.2 Case 2: ExternalFlow(L)>0

In this case, the congestion is a cross-border relevant one, and the costs shall be shared in proportion to the aggravating impact of energy exchange between given control areas on the congested grid element. The sharing cost factor assigned to a given zone is thus depending on:

1. For the zone of the overloaded grid element
- Weight of all Internal Flows.
- Weight of Import/Export Flows, shared with the other neighboring zones.
2. For the other zones (or in case of a tie-line).
- If it is a neighboring zone, weight of all Import/Export flows yield by this zone on the overloaded grid element, shared with the zone of the the overloaded grid element.
- Weight of Transit Flows yield by each of these zones on the overloaded grid element, shared with the other zones.
- Weight of Loop Flows, yield by each of these zones on the overloaded grid element

By default, an equal sharing between two neighboring zones is applied. The above principles are summarizes in Table 4, for the case of an internal line belonging to zone A:

Table 4 Cost sharing principles for an internal line belonging to zone A

Zone	Weight from Internal Flow	Weight from Transit Flow	Weight from Import/Export Flow	Weight from Loop Flow
A	100%	50%	50%	-
Each of the other zones (B)	0%	50% of the part of Transit Flow where B is involved (the other 50% being attributed to the neighbors of B different from A)	50% of the part of Import/Export Flow from B (only if B is a neighboring zone of A)	100% of the part of Loop Flow yield by B
All	100%	100%	100%	100%

The sharing cost factor of a zone B due to remedial actions to relieve constraints on an internal grid element L belonging to the zone A is thus defined as follows:

- If B=A:

$$\text{Sharing}_A(L) = \frac{\text{InternalFlow}(L) - \frac{1}{2} \times \text{ImpExp}(L)}{\text{TotalFlow}(L)} \tag{77}$$

- If $B \neq A$:

$$\text{Sharing}_B(L) = \frac{\frac{1}{2} \times \sum_{i \neq A,B} \text{Part}_{B/i}(L) + \frac{1}{2} \times \text{Part}_{A/B}(L) + \text{LoopFlow}_B(L)}{\text{TotalFlow}(L)} \tag{78}$$

For a tie-line between zones A and B, the cost sharing principles can be summarized in Table 5:

Table 5 Cost sharing principles for an internal line belonging to zone A

Zone	Weight from Internal Flow	Weight from Transit Flow	Weight from Import/Export Flow	Weight from Loop Flow
A	-	50% of the part of Transit Flow where A is involved (the other 50% being attributed to the neighbors of A different from B)	50%	100% of the part of Loop Flow yield by A
B	-	50% of the part of Transit Flow where B is involved (the other 50% being attributed to the neighbors of B different from A)	50%	100% of the part of Loop Flow yield by B
Each of the other zones (C)		50% of the part of Transit Flow where C is involved (the other 50% being attributed to the neighbors of C)	0%	100% of the part of Loop Flow yield by C
All	-	100%	100%	100%

The cost sharing factor of each zone due to remedial actions to relieve constraints on a grid element L between zones A and B is thus defined as follows:

- For A:

$$\text{Sharing}_A(\text{L}) = \frac{\frac{1}{2} \times \sum_{i \neq A,B} \text{Part}_{A/i}(\text{L}) + \frac{1}{2} \times \text{ImpExp}(\text{L}) + \text{LoopFlow}_A(\text{L})}{\text{TotalFlow}(\text{L})} \tag{79}$$

- For B:

$$\text{Sharing}_B(\text{L}) = \frac{\frac{1}{2} \times \sum_{i \neq A,B} \text{Part}_{B/i}(\text{L}) + \frac{1}{2} \times \text{ImpExp}(\text{L}) + \text{LoopFlow}_B(\text{L})}{\text{TotalFlow}(\text{L})} \tag{80}$$

- For $C \neq A/B$:

$$\text{Sharing}_C(\text{L}) = \frac{\frac{1}{2} \times \sum_{i} \text{Part}_{C/i}(\text{L}) + \text{LoopFlow}_C(\text{L})}{\text{TotalFlow}(\text{L})} \tag{81}$$

4.5 Conclusion

This chapter presented a methodology proposed by RTE to assign the cost sharing factors to the participating zones of the electrical grid considered, and the different steps of the method are described in Figure 13. This methodology takes into account only the most recent grid situation in order to assign the responsibilities to the relevant areas in terms of active power flow: this represents an advantage in terms of implementation and computational aspects, because operations involving different grid models do not need to be performed, and no equivalence between these grid models is required.

The inputs of the Capacity Calculation Process considered are the GSKs and the commercial exchanges defined in the Market Coupling Process. The influence of each zone on the congested element is calculated based on the impact of the increase in the physical flow transferred between two given zones. Therefore the topological configuration of the areas is not explicitly taken into account.

In the explanatory note [37] concerning this methodology, different timeframes for the activation of redispatching and countertrading remedial actions are defined, and it is said that, in case of sudden critical situations that lead to an overload of a critical grid element and that require very fast actions, a different cost sharing methodology may be defined for the costs arisen therefrom: this represents a loss of generality for the method shown in the present chapter.

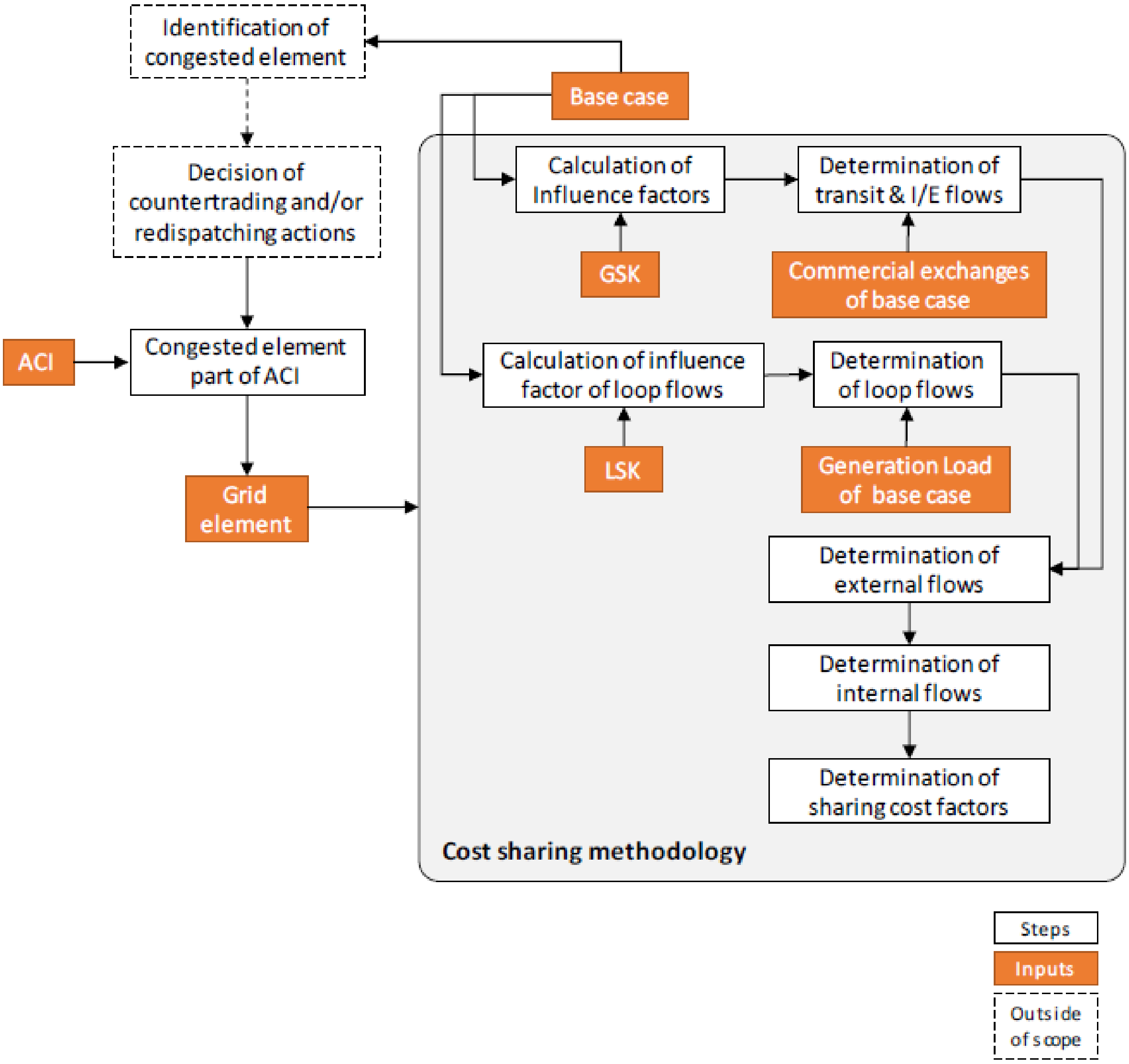

Figure 13 Different steps of RTE's methodology

CHAPTER 5
COST SHARING METHODOLOGY II

The operational planning process of the European electrical grid has become more complex in the past years, due to some reasons like the increase in the penetration of non programmable renewable sources and an unknown ex-ante market based self-dispatch of generating units. In this framework, high quality forecasts of future generation/consumption patterns have become vital for a safe and economically efficient operation of the electricity infrastructure. This chapter gives a description of a cost sharing methodology developed by Terna for coordinated countertrading and redispatching actions. One of the main motivations behind this methodology is to incentivize the market participants to increasingly carry out better hypothesis and forecasts, and ultimately to facilitate the long-term development of the European internal energy market. Basically, this is achieved by penalizing the control areas of the grid for their real-time power flow deviations with respect to the scheduled energy exchanges carried out in the planning process.

The method takes into account that topological changes and generation pattern variations of the network are the main responsibles for changes in the line flows, and therefore the main reasons that could lead to a congestion. That being considered, the main idea of the method is to assign zonal responsibilities in terms of power flow due to a given congestion in the network, by modelling an "ideal" congestion-free situation of the grid based on the security assessment carried out during the Capacity Calculation Process (CCP), and then, to compare this congestion-free model to the grid situation where the congestion is actually present, which could be a Day-Ahead Congestion Forecast (DACF), an IntraDay Congestion Forecast (IDCF), or a SnapShot (SN). The topological and generation pattern variations are evaluated, one at a time, and another model which has the generation pattern of the actual grid, and the topology of the “ideal” grid, is built for that purpose. A DC load flow model is used for the sake of clarity, and it is assumed that the nodes in the grid, during the time window analyzed, do not vary. However, generalization of the principles applied in the method to a lossy network and to time-varying grid nodes should also be possible[38][39].

5.1 Single Topology Variation Assessment

The Single Topology Variation Assessment quantifies the impact of the topology variation on the flows of the lines by comparing two different grid models, and it is assumed in this thesis that the nodes do not vary between these two models. Also, a DC load flow will be used (see Appendix 1), which is a linear approximation of the AC power flow equations based on the following assumptions:

1. Resistances of lines and transformers are neglected: losses are neglected.
2. All voltages are assumed equal to 1 pu.
3. Shunt branches of lines and transformers are neglected.
4. The voltage angle difference between adjacent nodes is small.

Therefore only active power flows are considered in the DC load flow. Its basic equations are obtained under the assumptions listed above:

$$\mathbf{P} = \mathbf{B}^{\mathbf{bus}}\boldsymbol{\theta} \tag{82}$$

$$\mathbf{F} = \mathbf{B}^{\mathbf{branch}}\boldsymbol{\theta} \tag{83}$$

where $\mathbf{P}$ is the vector of nodal active power injections, $\mathbf{F}$ is the vector of active power flows through transmission lines, $\boldsymbol{\theta}$ is the vector of nodal voltage angles, and $\mathbf{B}^{\mathbf{bus}}$ and $\mathbf{B}^{\mathbf{branch}}$ are, respectively, the bus and branch coefficient matrices. The variation in the admittance of a line between two adjacent nodes ij can be formalized, under the mathematical point of view, with a matrix $\Delta\mathbf{B}^{\mathbf{bus}}$. This conjecture can be confirmed since $\mathbf{B}^{\mathbf{bus}}$ is a symmetrical matrix which can be built from direct inspection. Its diagonal terms are composed of the sum of the admittances adjacent to the node whose number is identified by the row number (which is equal to the column number) considered. Its off-diagonal terms instead are defined as the admittances, preceded by a minus sign, that directly connect the nodes corresponding to the rows and columns considered. The shunt parameters are always neglected.

Thus, a single variation in the topology of the network which consists in a change of admittance between two adjacent nodes ij denoted by Δy_{ij} is represented by the matrix

$\Delta\mathbf{B}^{\mathbf{bus}}$ having the following structure: the elements in the positions (i,i) and (j,j) are equal to $-\Delta y_{ij}$ while the elements in the positions (j,i) and (i,j) are equal to Δy_{ij}. The rest of the elements are equal to zero.

The scenario of interest is the situation where the generation/load patterns of the two grid models are the same, but the topologies are different:

$$\mathbf{P} = \mathbf{B}_1^{\mathbf{bus}}\boldsymbol{\theta}_1 \tag{84}$$

$$\mathbf{F}_1 = \mathbf{B}_1^{\mathbf{branch}}\boldsymbol{\theta}_1 \tag{85}$$

$$\mathbf{P} = \mathbf{B}_2^{\mathbf{bus}}\boldsymbol{\theta}_2 \tag{86}$$

$$\mathbf{F}_2 = \mathbf{B}_2^{\mathbf{branch}}\boldsymbol{\theta}_2 \tag{87}$$

Equations (84) and (85) represent the first grid scenario, and (86) and (87) represent the second grid scenario. The only term which does not change in these equations t is the vector $\mathbf{P}$ which represents the nodal power injections. It has to be noted that the matrices $\mathbf{B}_1^{\mathbf{branch}}$ and $\mathbf{B}_2^{\mathbf{branch}}$ do not have the same dimension: $\mathbf{B}_1^{\mathbf{branch}}$ is a k_1 by n matrix and $\mathbf{B}_2^{\mathbf{branch}}$ is a k_2 by n matrix, being k_1 the set of lines in the first scenario, k_2 the set of lines in the second scenario and n the set of nodes in the scenarios which is assumed to be the same. As a result, the vectors $\mathbf{F_1}$ and $\mathbf{F_2}$ have different dimensions.

In order to make $\mathbf{F_1}$ and $\mathbf{F_2}$ comparable, it is possible to build the matrices $\mathbf{B}_1^{\mathbf{branch}}$ and $\mathbf{B}_2^{\mathbf{branch}}$ in such a way so they have the same dimensions: this is done by representing, with a row of zeros, the components that appear in one of the two scenarios and not in the other. Since most of the lines will not be subject to a loss nor to a return nor to a change in its admittance in the time window analyzed, the matrices $\mathbf{B}_1^{\mathbf{branch}}$ and $\mathbf{B}_2^{\mathbf{branch}}$ will have most of the rows correspondent to one another. Applying this procedure the active power flow through transmission lines become:

$$\overline{\mathbf{F}}_1 = \overline{\mathbf{B}}_1^{\mathbf{branch}}\boldsymbol{\theta}_1 \tag{88}$$

$$\overline{\mathbf{F}}_2 = \overline{\mathbf{B}}_2^{\mathbf{branch}}\boldsymbol{\theta}_2 \tag{89}$$

where $\overline{\mathbf{B}}_1^{\mathbf{branch}}$ and $\overline{\mathbf{B}}_2^{\mathbf{branch}}$ are the branch coefficient matrices having the same dimensions, after the components that appear in one scenario and not in the other are represented by a a row zeros. As a result the vectors $\overline{\mathbf{F}}_1$ and $\overline{\mathbf{F}}_2$ which contain the power flow through the lines, also have the same dimensions. Furthermore, it is possible to define the following terms:

$$\Delta\mathbf{B}^{\mathbf{bus}} = \mathbf{B}_2^{\mathbf{bus}} - \mathbf{B}_1^{\mathbf{bus}} = \sum_{k=1}^{N_L} \Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus}} \tag{90}$$

$$\Delta\boldsymbol{\theta} = \boldsymbol{\theta}_2 - \boldsymbol{\theta}_1 \tag{91}$$

where $\Delta\mathbf{B}^{\mathbf{bus}}$ is a k by n reduced bus admittance matrix, N_L is the number of branches in the network, and $\Delta\boldsymbol{\theta}$ is a n vector with nodal voltage angles.

$$\Delta\overline{\mathbf{B}}^{\mathbf{branch}} = \overline{\mathbf{B}}_2^{\mathbf{branch}} - \overline{\mathbf{B}}_1^{\mathbf{branch}} \tag{92}$$

$$\Delta\overline{\mathbf{F}} = \overline{\mathbf{F}}_2 - \overline{\mathbf{F}}_1 \tag{93}$$

where $\Delta\overline{\mathbf{B}}^{\mathbf{branch}}$ is a k by n branch admittance matrix and $\Delta\overline{\mathbf{F}}$ is a k by 1 vector with line flows. The assumption made in (90) is that the matrix $\Delta\mathbf{B}^{\mathbf{bus}}$, denoting the overall variation of the grid topology, can be decomposed into the sum of single admittances variations between two adjacent nodes, represented by the sparse matrix $\Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus}}$. Applying (90) and (91), the active power flow injection expression of (82) can be written as

$$\mathbf{P} = \left(\mathbf{B}_1^{\mathbf{bus}} + \sum_{k=1}^{N_L} \Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus}}\right)\left(\boldsymbol{\theta}_1 + \Delta\boldsymbol{\theta}\right) \tag{94}$$

It has to be noted that the matrices $\mathbf{B}_1^{\mathbf{bus}}$ and $\mathbf{B}_2^{\mathbf{bus}}$ are rank-deficient and the inversion of the matrx can not be performed directly. A reference node has to be adopted for both models, and its corresponding row and column have to be deleted, in order to solve this issue. Doing so and applying the active power flow injection expression of (86) and (90) through (91), (94) can be further simplified into

$$\Delta\boldsymbol{\theta}^* = -\left(\mathbf{B}_2^{\mathbf{bus}*}\right)^{-1}\left(\sum_{k=1}^{N_L} \Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus}*}\right)\boldsymbol{\theta}_1^* \tag{95}$$

where the superscript * indicates that the row and column corresponding to the reference node have been deleted. Making use of the distributive property of the matrix multiplication, (95) can be written as

$$\Delta\boldsymbol{\theta}^{*} = \sum_{\mathbf{i,j}} -\left(\mathbf{B}_{2}^{\mathbf{bus*}}\right)^{-1}\left(\Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus*}}\right)\boldsymbol{\theta}_{1}^{*} \tag{96}$$

Basically, in (96) the variation of the nodal voltage angles $\Delta\boldsymbol{\theta}^{*}$ is decomposed into the sum of terms $-\left(\mathbf{B}_{2}^{\mathbf{bus*}}\right)^{-1}\left(\Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus*}}\right)\boldsymbol{\theta}_{1}^{*}$. Thus, it is possible to arbitrarily define

$$\Delta\boldsymbol{\theta}_{\mathbf{k}}^{*} = -\left(\mathbf{B}_{2}^{\mathbf{bus*}}\right)^{-1}\Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus*}}\boldsymbol{\theta}_{1}^{*} \tag{97}$$

where $\Delta\boldsymbol{\theta}_{\mathbf{k}}^{*}$ is a n-1 by 1 reduced vector with nodal angles deviations due to an admittance variation in line k. Note that:

$$\Delta\boldsymbol{\theta}^{*} = \sum_{k=1}^{N_L}\Delta\boldsymbol{\theta}_{\mathbf{k}}^{\mathbf{bus*}} \tag{98}$$

From equation (97) it is possible to deduce that the $\Delta\boldsymbol{\theta}_{\mathbf{k}}^{*}$ terms are a function of the following inputs:

1. Variation of the admittance between two adjacent nodes ij represented by the matrix $\Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus*}}$.
2. The first grid scenario, represented by $\boldsymbol{\theta}_{1}^{*}$.
3. The second grid scenario, represented by $\left(\mathbf{B}_{2}^{\mathbf{bus*}}\right)^{-1}$.

The vector $\Delta\boldsymbol{\theta}_{\mathbf{k}}^{*}$ should be interpreted as the reduced vector of nodal voltage angle variations due to an admittance variation in line k. Substituting (88) through (91) into (93), we obtain:

$$\Delta\overline{\mathbf{F}} = \overline{\mathbf{B}}_{2}^{\mathbf{branch*}}\boldsymbol{\theta}_{2}^{*} - \overline{\mathbf{B}}_{1}^{\mathbf{branch*}}\boldsymbol{\theta}_{1}^{*} = \overline{\mathbf{B}}_{2}^{\mathbf{branch*}}\Delta\boldsymbol{\theta}^{*} + \Delta\overline{\mathbf{B}}^{\mathbf{branch*}}\boldsymbol{\theta}_{1}^{*} \tag{99}$$

$$\Delta\overline{\mathbf{F}} = \sum_{k=1}^{N_L}\mathbf{B}_{2}^{\mathbf{branch*}}\Delta\boldsymbol{\theta}_{\mathbf{k}}^{*} + \Delta\overline{\mathbf{B}}^{\mathbf{branch*}}\boldsymbol{\theta}_{1}^{*} \tag{100}$$

By using equation (97), we can define the vector $\Delta\overline{\mathbf{F}}_{\mathbf{ij}}$, which is the vector of line flows deviations due to an admittance variation between nodes ij:

$$\Delta\overline{\mathbf{F}}_{\mathbf{i,j}} = \overline{\mathbf{B}}_{2}^{\mathbf{branch*}}\Delta\boldsymbol{\theta}_{\mathbf{k}}^{*} \tag{101}$$

$$\Delta\overline{\mathbf{F}}_{\mathbf{i,j}} = \overline{\mathbf{B}}_{2}^{\mathbf{branch*}}\left[-\left(\mathbf{B}_{2}^{\mathbf{bus*}}\right)^{-1}\left(\Delta\mathbf{B}_{\mathbf{k}}^{\mathbf{bus*}}\right)\boldsymbol{\theta}_{1}^{*}\right] \tag{102}$$

Thus, the expression of the active flows difference between the two grid scenarios becomes:

$$= \sum_{\mathbf{i,j}}\Delta\overline{\mathbf{F}}_{\mathbf{i,j}} + \Delta\overline{\mathbf{B}}^{\mathbf{branch*}}\boldsymbol{\theta}_{1}^{*} \tag{103}$$

It is now possible to quantify how much the single admittance variation between two generic buses i and j modifies the active power flows in the grid, by means of the vector $\Delta\overline{\mathbf{F}}_{\mathbf{i,j}}$. From now on, the vector $\overline{\mathbf{\Delta F}}_{\mathbf{i,j}}$ will be identified as the vector with the line flows deviations due to an admittance variation between nodes i and j. Instead, the term $\overline{\mathbf{\Delta B}}^{\mathbf{branch*}}\boldsymbol{\theta}_1^*$ is important only for the lines that have changed their admittance between the two scenarios analyzed, as the rows of $\overline{\mathbf{\Delta B}}^{\mathbf{branch*}}$ corresponding to unchanged elements is composed of zeros. It should be noted that a line outage is represented with a variation resulting in an admittance equals to zero, whereas a line return is represented by an admittance that changes from zero to a certain value.

All the algeibraic passages of the present section have the ultimate goal to address the responsibilities for the active power flow differences represented by $\overline{\mathbf{\Delta F}}$ to the control areas where the admittance variation between the generic nodes i and j has occurred.

5.2 Grid Models

Three grid models, from which two are artificially built, are used in this methodology for the assessment of the impact of topological and generation pattern variations on the congested element in terms of power flows. In order to build the required grid models, the following inputs are necessary:

- Data from the Capacity Calculation Process (CCP), which are obtained from the security assessment of the power system. From these data, the so-called Capacity Calculation Model of the grid is obtained. The GSKs that will be used to translate the zonal net position variations into nodal ones are also defined in the CCP.
- Commercial exchanges between the areas of the CCP, defined in the Market Coupling Process (MCP).
- Grid model based on which the costly remedial actions to be carried out have been decided (which could be a DACF, an IDCF or a SN). This grid model is referred to as the Final Model.

All these inputs are then used to artificially build two new models of the grid, namely the Congestion Free Model and the Generation/Load Patterns Model. These two new models, alongside the Final Model, are used to perform the generation/load and the topological assessment of the real-time power flow deviations with respect to the power exchanges that were scheduled in the MCP. An overview of the schematic of the methodology is presented in Figure 14.

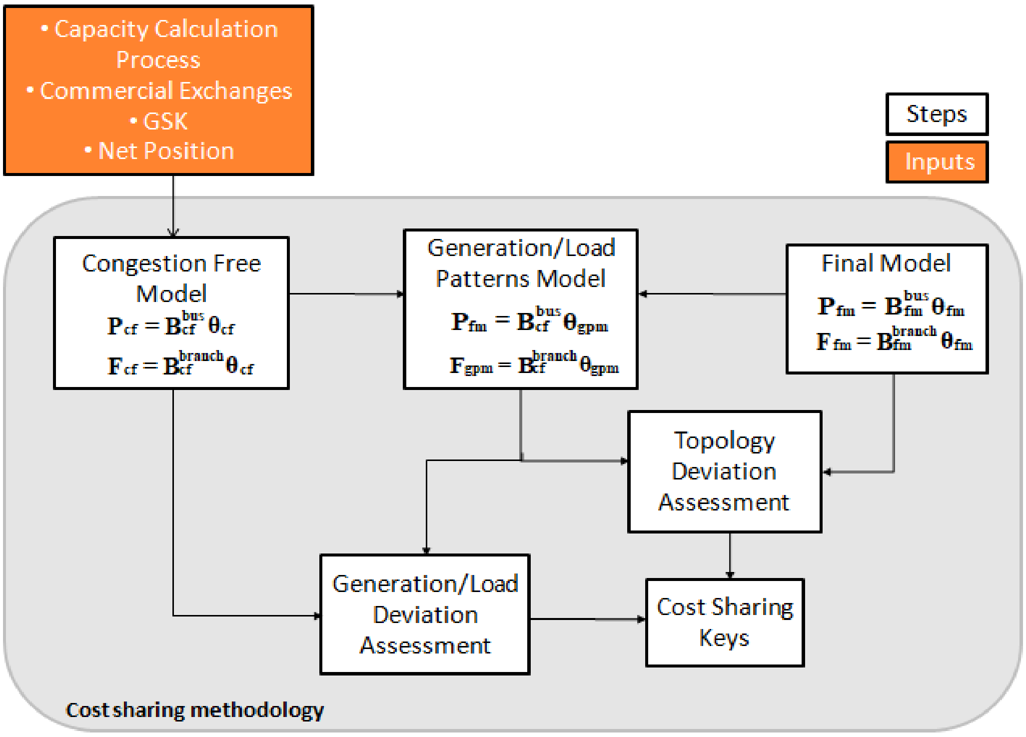

Figure 14 Different steps of Terna's methodology

5.2.1 Congestion Free Model

The Congestion Free Model represents and ideal operating point of the system in which the forecasts made in the Capacity Calculation Process turn out to be correct. Basically, the methodology quantifies the deviations of the actual generation and topology patterns from the ideal ones of the Congestion Free Model, and assigns the cost sharing keys (with respect to the congestion observed in the Final Model) based on these deviations.

The Congestion Free Model is built by shifting the net positions of the areas of the Capacity Calculation Region, from the commercial exchanges simulated in the Capacity Calculation Process, to the ones determined by the Market Coupling Process, at the borders included in the Capacity Calculation Region. The shifting procedure is realized by means of the GSKs defined in the Capacity Calculation Process, and impacts only the areas that have at least one border belonging to the Capacity Calculation Region. The building procedure of the Congestion Free Model can be summarized in the following steps:

1. Take as input the Capacity Calculation Model.
2. Take as input the GSKs of the Capacity Calculation Model.

3. Take as input the scheduled commercial exchanges, defined in the Market Coupling Process, between the areas involved in the Capacity Calculation Region, at the borders included in the Capacity Calculation Region.
4. Shift the net positions of the areas involved in the Capacity Calculation Region in such a way that the commercial schedules of step 3 are respected. Make use of the GSKs of step 2 to translate a variation in the zonal net positions into nodal ones.

Doing so, the Congestion Free Model is yielded, and it has the physical flows equal to the commercial flows defined in the Market Coupling Process. Its equations, describing the active nodal power injections and the flow on the lines, obtained by means of a DC load flow, can be respectively written as

$$\mathbf{P_{cf}} = \mathbf{B_{cf}^{bus}} \boldsymbol{\theta}_{\mathbf{cf}} \tag{104}$$

$$\mathbf{F_{cf}} = \mathbf{B_{cf}^{branch}} \boldsymbol{\theta}_{\mathbf{cf}} \tag{105}$$

Where $\mathbf{P_{cf}}$ is a n-1 by 1 reduced vector with nodal power injections, $\mathbf{B_{cf}^{bus}}$ is a n-1 by n-1 reduced bus admittance matrix, $\mathbf{B_{cf}^{branch}}$ is a k by n-1 reduced branch admittance matrix, $\boldsymbol{\theta}_{\mathbf{cf}}$ is a n-1 by 1 reduced vector with nodal voltage angles, and $\mathbf{F_{cf}}$ is a k by 1 vector with line active power flows. All these matrices containing the subscript cf are referred to the Congestion Free Model.

5.2.2 Generation/Load Patterns Model

The Generation/Load Patterns Model has the topology of the Congestion Free Model described in 5.2.1, and the generation/load patterns corresponding to the most recent grid situation used in this methodology, where the congestion is actually present (the congestion is not necessarily present, but then this methodology does not need to be applied), referred to as the Final Model, which is described in subsection 5.2.3. The topology of the Generation/Load Patterns Model is therefore represented by matrices $\mathbf{B_{cf}^{bus}}$ and $\mathbf{B_{cf}^{branch}}$, which are referred to the Congestion Free Model; whereas the generation/load patterns is represented by the vector of active power injections $\mathbf{P_{fm}}$, referred to the Final Model.

Therefore, the Generation/Load Patterns Model can be described by the following equations:

$$\mathbf{P_{fm}} = \mathbf{B_{cf}^{bus}} \boldsymbol{\theta}_{\mathbf{gpm}} \tag{106}$$

$$\mathbf{F_{gpm}} = \mathbf{B_{cf}^{branch}} \boldsymbol{\theta}_{\mathbf{gpm}} \tag{107}$$

where $\mathbf{F_{gpm}}$ is a k by 1 vector with line active power flows, and $\boldsymbol{\theta}_{\mathbf{gpm}}$ is a n-1 by 1 reduced vector with nodal voltage angles. Both of them contain the subscript gpm, which indicates that they are referred to the Generation/Load Patterns Model.

5.2.3 Final Model

The Final Model is the one based on which the remedial actions to be carried out have been decided and where the congestion is actually present, which could be a Day-Ahead Congestion Forecast, an Intraday Congestion Forecast or a Snapshot. This is the model in which the congestion is present, and it can described by the following equations:

$$\mathbf{P_{fm}} = \mathbf{B_{fm}^{bus}} \boldsymbol{\theta}_{\mathbf{fm}} \tag{108}$$

$$\mathbf{F_{fm}} = \mathbf{B_{fm}^{branch}} \boldsymbol{\theta}_{\mathbf{fm}} \tag{109}$$

where $\mathbf{P_{fm}}$ is a n-1 by 1 reduced vector with nodal power injections, $\mathbf{B_{fm}^{bus}}$ is a n-1 by n-1 reduced bus admittance matrix, $\mathbf{B_{fm}^{branch}}$ is a k by n-1 reduced branch admittance matrix, $\boldsymbol{\theta}_{\mathbf{fm}}$ is a n-1 by 1 reduced vector with nodal voltage angles, and $\mathbf{F_{fm}}$ is a k by 1 vector with line active power flows. All these matrices containing the subscript fm are referred to the Final Model.

5.3 Assessment of Deviation

In this section, it is assumed that there is only one element to be relieved with remedial actions, and thus only one limiting element to analyze. However, the extension to cases with more than one limiting element can be performed simply by superimposing the results obtained for each single element, because of the linear characteristic of the problem.
The Congestion Free Model, described in subsection 5.2.1, is the one that has to be taken as the reference point for all the following computations. Indeed, this model represents an ideal scenario where all the forecasts made in the Capacity Calculation Process, alongside the commercial exchanges defined in the Market Coupling Process, turn out to be correct and to reflect the actual physical situation of the grid.

It should be noted that the sum of responsibilities assigned to each area, in terms of the additional active power flow through the congested element, is exactly the difference of the active power flow through the congested element between the Final Model and the Congested Free Model.

5.3.1 Generation/Load Deviation Assessment

The Generation/Load Deviation Assessment evaluates the influence of the generation/load pattern deviations on the congested element. The main idea is to compare the Congestion Free Model with the Generation/Load Patterns Model, which have the same topology but different generation/load patterns. Starting from (104) through (107), the following quantities are defined:

$$\Delta \mathbf{P}_{\mathbf{fm-cf}} = \mathbf{P}_{\mathbf{fm}} - \mathbf{P}_{\mathbf{cf}} \tag{110}$$

$$\Delta \boldsymbol{\theta}_{\mathbf{gpm-cf}} = \boldsymbol{\theta}_{\mathbf{gpm}} - \boldsymbol{\theta}_{\mathbf{cf}} \tag{111}$$

$$\Delta \mathbf{F}_{\mathbf{gpm-cf}} = \mathbf{F}_{\mathbf{gpm}} - \mathbf{F}_{\mathbf{cf}} \tag{112}$$

Subtracting (104) from (106) a new DC power flow injection model is obtained:

$$\Delta \mathbf{P}_{\mathbf{fm-cf}} = \mathbf{B}_{\mathbf{cf}}^{\mathbf{bus}} \Delta \boldsymbol{\theta}_{\mathbf{gpm-cf}} \tag{113}$$

$$\Delta \mathbf{F}_{\mathbf{gpm-cf}} = \mathbf{B}_{\mathbf{cf}}^{\mathbf{branch}} \Delta \boldsymbol{\theta}_{\mathbf{gpm-cf}} \tag{114}$$

Equation (113) represents the unscheduled part of the nodal active power injections: every component of the vector $\Delta \mathbf{P}_{\mathbf{fm-cf}}$ different from zero represents a node which has deviated from its scheduled net position define in the CCP.

The next step is to assign the shares of the aggravating impact on the congested element to each node which has deviated from the schedule. In order to do so, it is assumed in this methodology that each node with a negative net position is supplied by a fraction of each node with a positive net position, uniformly divided among all nodes with positive net positions: it is the EBE principle described in 3.3. Therefore, a share of the deviation of the active power flows represented by $\mathbf{\Delta F^{i}_{gpm-cf}}$, is assigned to each node i that has a net position different from zero in equation (113). In particular, the following relation is valid:

$$\mathbf{\Delta F_{gpm-cf}} = \sum_{\mathbf{i}} \mathbf{\Delta F^{i}_{gpm-cf}} \tag{115}$$

The component to be taken into account in the vector $\mathbf{\Delta F_{gpm-cf}}$, in order to assign the cost sharing factors, is the one corresponding to the congested element. The zonal configuration of the network is then obtained, by grouping the nodes according to the areas which they belong to (even the areas not involved in the CCR), allowing to obtain the responsibilities of each area for the congestion in terms of power flow through the congested element.
Applying the EBE principle, it is possible to identify the counterflows, which are the flows that are actually relieving the congestion, and it is left open the possibility to include them or not in the calculation of the cost sharing keys.

5.4 Topology Deviation Assessment

This assessment is based on the comparison between the Generation/Load Patterns Model and the Final Model, which have the same generation/load patterns but different topologies. Starting from (106) through (109), it is possible to define the following quantities:

$$\mathbf{\Delta B^{branch}_{fm-cf}} = \mathbf{\overline{B}^{branch}_{fm}} - \mathbf{\overline{B}^{branch}_{cf}} \tag{116}$$

$$\mathbf{\Delta F_{fm-gpm}} = \mathbf{\overline{F}_{fm}} - \mathbf{\overline{F}_{gpm}} \tag{117}$$

The reasoning applied is the same as in 5.1: the overall topology variation is decomposed into single admittances variations between adjacent nodes ij and, after having grouped the single admittances variations according to the areas in which they lie, the correspondent responsibilities in terms of power flow due to the congestion are assigned to each area, even the ones not involved in the Capacity Calculation Region. Equations (106) and (107) can be rewritten in order to represent the grid models considered as

$$\mathbf{\Delta\overline{F}_{i,j}} = \mathbf{\overline{B}^{branch*}_{fm}} \left[-\left(\mathbf{B^{bus*}_{fm}}\right)^{-1} \left(\mathbf{\Delta B^{bus*}_{k}}\right) \boldsymbol{\theta}^{*}_{\mathbf{gpm}} \right] \tag{118}$$

$$\mathbf{\Delta\overline{F}_{fm-gpm}} = \sum_{\mathbf{i,j}} \mathbf{\Delta\overline{F}_{i,j}} + \mathbf{\Delta\overline{B}^{branch*}_{fm-gpm}} \boldsymbol{\theta}^{*}_{\mathbf{gpm}} \tag{119}$$

Basically, (118) is the one to be used in order to assess the admittance variation between adjacent nodes ij. The component of the vector $\overline{\mathbf{\Delta F}}_{\mathbf{i,j}}$ to be taken into account in order to evaluate the aggravating impact in terms of power flows is the one corresponding to the congested element.

After having evaluated the topological and generation/load impacts on the congested eleement in terms of power flows, the cost sharing keys can be the determined to all the areas. For the sake of clarity and conciseness, the congested element l is supposed to not have changed its admittance between the Congestion Free Model and the Final Model, so that the corresponding row of the matrix $\overline{\mathbf{\Delta B}}^{\mathbf{branch*}}_{\mathbf{fm-cf}}$ contains only zeros. The aggravating impact of an area A on the congested element l is

$$\Delta F^l_A = \sum_{i,j\in A} \Delta F^l_{i,j} + \frac{1}{2}\sum_{i\vee j\in A} \Delta F^l_{i,j} + \sum_{i\in A} \Delta F^l_i \tag{120}$$

where the term $\Delta F^l_{i,j}$ is the deviation of the flow through the congested element due to an admittance variation between adjacent nodes ij, and ΔF^l_i is the deviation of the flow through the congested element due to a variation in the net position of node i. The vector $\Delta F^l_{i,j}$ is used in the first two summation terms of the right-hand side of equation (120): the first one corresponds to the adjacent nodes that are in the same zone, whereas the second one corresponds to two adjacent nodes that are located in different zones, which is an interconnector line. The latter one is therefore divided by 2 in order to assign half the responsibility for the power flow deviation through the interconnector to each area. Thus, the sharing key of an area A is determined as

$$S_A = \begin{cases} \dfrac{\Delta F^l_A}{\sum_A \Delta F^l_A}, & \text{if} \quad \Delta F^l_A > 0 \\ 0, & \text{otherwise} \end{cases} \tag{121}$$

5.5 Conclusion

This chapter presented a methodology proposed by Terna to assign the cost sharing factors to the participating zones of the grid considered. The method ensures a distribution of costs and benefits in terms of the aggravating impact that each TSO imposes to the congested element with respect to a congestion free scenario. In practice the sharing keys are proportional to the impact of wrong forecasts made for each area. This latter principle aims to incentivize these areas to carry out better forecasts and, ultimately, to facilitate the long term development of the pan-European interconnected systems.

CHAPTER 6
NUMERICAL RESULTS

In this chapter, numerical results concerning the two methodologies presented in Chapter 4 and Chapter 5 are shown and, based on these results, some of their differences are discussed. Both mehods were applied on the same European UCTE grid situation on the 5^{th} of July 2017 at 17.30. The two networks used as inputs for the analysis (referred as Capacity Calculation Model and Final Model) were provided by Terna S.p.A. and imported through DigSILENT Power Factory. Then, the data was converted to Matlab format.

Three different grid scenarios were analyzed:

- N situation, where the network is intact.
- N-1 situation, where the contingency is on line LN_LN3000154 connecting nodes SROBBI12-SY_PUN11 belonging to the Switzerland area.
- N-1 situation, where the contingency is on line LN_LN3000155 connecting nodes SFILIS11- SROBBI11 belonging to the Switzerland area.

In all the three scenarios, the congested element, which is the one that should be monitored, is always the same: it is the line LN_LN300086, connecting node SSOAZZ1, belonging to the Switzerland area, to node XSO_BU11, belonging to the so-called Fictitious area, which represents the intermediary nodes connecting one area to the other. Node XSO_BU11 is connected to node IBULM111, which belongs to the Italian area. Therefore, in practice the congested element is a tie-line connecting Switzerland to Italy.

The input data used for the analysis are:

1. The Capacity Calculation Model, which is the grid scenario derived from the Capacity Calculation Process (CCP).

2. The Final Model (also referred as Common Grid Model), which is the grid scenario used to decide the need for coordinated countertrading or redispatching measures (which could be a DACF, IDCF or a SN).
3. The commercial exchanges defined in the Market Coupling Process (MCP).
4. The Net Position (NP) of all the areas of interest.

The data from input 3 concerning the actual and the reference commercial exchanges of the Italian borders are shown in Table 6 and Table 7, respectively. Table 8 and Table 9 contain, respectively, the actual and the reference Net Position data from all the areas considered in input 4, and the Net Position of the following countries are considered together:

- SHB: Slovenia + Croatia + Bosnia Herzegovina
- SMM: Serbia + Montenegro + Macedonia
- PL&UA: Poland + Ukraine

Table 6 Reference Commercial Exchange

From	To	Active Power [MW]
Switzerland	Italy	2725
France	Italy	2260
Italy	Austria	-268
Italy	Slovenia	-478

Table 7 Actual Commercial Exchange

From	To	Active Power [MW]
Switzerland	Italy	2458
France	Italy	2279
Italy	Austria	-238
Italy	Slovenia	586

Table 8 Reference Commercial European Net Position

Country	Net Position [MW]	Country	Net Position [MW]
Belgium	-348	Netherlands	-891
Bosnia Herzegovina	-614	Poland	667
Bulgaria	717	Portugal	385
Czech Republic	306	Romania	499
Montenegro	66	Switzerland	1328
Germany	10960	Albania	-374
Spain	-2227	Slovenia	-614
France	619	Slovakia	-392
Greece	-473	Serbia	66
Croatia	-614	Ukraine	667
Italy	-5655	Austria	-2600
Macedonia	66	Hungary	-1901

Table 9 Actual Commercial European Net Position

Country	Net Position [MW]	Country	Net Position [MW]
Belgium	-37	Netherlands	-1384
Bosnia Herzegovina	-865	Poland	327
Bulgaria	794	Portugal	-877
Czech Republic	1266	Romania	-535
Montenegro	-46	Switzerland	3553
Germany	7237	Albania	-365
Spain	-965	Slovenia	-865
France	622	Slovakia	-26
Greece	-698	Serbia	-46
Croatia	-865	Ukraine	327
Italy	-4313	Austria	-2065
Macedonia	-46	Hungary	-1921

6.1 Network Analysis

The initial grid models that were provided for the application of the methodologies refer to the complete European UCTE network, and they contain some issues that need to be addressed before actually using the models as inputs in the two methodologies. These issues prevent the application of the DC power flow, and they are basically two:

1. There exist some isolated parts in the network,
2. The breakers/switches are modelled as zero impedance branches in Matlab.

The first grid model considered is the Capacity Calculation Model, which is derived from the Capacity Calculation Process. From DIgSILENT it is possible to read the components of the network:

- 12017 terminals, 565 of them isolated.
- 5703 loads.
- 1741 synchronous machines, 12 out of service.
- 13026 lines, 1389 out of service.
- 2391 2 winding transformers, 259 out of service
- 2606 breakers/switches, 355 of them open.

The second grid model to be considered is the one used to decide the need for coordinated countertrading and/or redispatching measures: it is referred in this thesis as the Common Grid Model or Final Model (which could be a DACF, an IDCF or a SN). From DIgSILENT it is possible to read the components of the network:

- 12017 terminals, 565 of them isolated.
- 5700 loads.
- 1744 synchronous machines, 11 out of service.
- 13027 lines, 1382 out of service.
- 2139 2 winding transformers, 249 out of service.
- 2605 breakers/switches, 368 of them open.

In order to obtain a DC power flow on Matlab, the following procedure was applied to both networks: the isolated parts of the network and the open breakers were deleted, and the closed breakers/switches were merged into single buses (as they are modelled as zero impedance lines). Doing so, on Matlab the following data is obtained for the Capacity Calculation Model:

- 11438 buses.
- 17930 branches.
- 1733 generators.

And for the Final Model:

- 11438 buses.
- 17930 branches.
- 1737 generators.

For both grids, out of the 17930 branches, 2583 are breakers/switches. These breakers/switches are modelled like zero impedance lines. In order to obtain a convergent

DC power flow, two distinct parallel approaches were adopted with respect to these breakers/switches:

1. The null impedances of these lines were replaced with very small values (of the order of 10^{-6}).
2. The breakers/switches were eliminated from the network by using the following merging procedure:
    - The buses connecting closed breakers/switches were merged into a single bus. In this case all the loads and generators connected to the initial buses are also put together into the merged bus.
    - The open breakers/switches were eliminated.

The flows through the branches in common in the two grid situations (all the branches except the ones representing breakers/switches) were then compared, for the Capacity Calculation Model and the Final Model. The pu values of the errors were analyzed, with the base power equal to 100 MVA. Significant errors occurred due to the inclusion of the small impedance lines, and their relevant quantities can be read from Table 10.

The reason for the occurrence of the errors can be explained by analyzing how the power flow through the branches of the electrical grid are calculated in the DC power flow: in pu values, the flows are equal to the voltage angles difference between the two buses connecting a given branch, divided by the reactance of this branch (see Appendix 1). These two quantities are ideally zero for a breaker/switch. Therefore, any small change in the voltage angles difference or in the reactance value can lead to high variations on the flow through the breaker/switch, thus leading to a change in the power balance of the buses connecting this element, and hence in the power flowing through the other lines. As an example, consider a breaker/switch with the following parameters:

- Series reactance assumed equal to 0.3 Ω/km and line length equal to 1 m.
- Voltage angles difference equal to 10-6 radians.
- Base power equal to 100 MVA and base voltage equal to 220 kV.

The calculated reactance in pu is equal to 6.1983*10-7, and the power flow through the breaker/switch is equal to 161.3 MW. If the series reactance is otherwise assumed equal to 0.25 Ω/km, the calculated pu reactance becomes 5.1653*10-8, and the power flow through the breaker/switch increases to 1936 MW.

In order to reduce the errors caused by the breakers/switches, the following procedure was adopted:

1. Starting from the complete network with 2583 breakers/switches, all of these elements went through the merging procedure, except the ones that have different

status between the Capacity Calculation Model and the Final Model. In this way only 198 breakers/switches were left.

2. Considering the remaining 198 breakers/switches, the looped elements were reduced into equivalent ones. A simple example is illustrated in Figure 15: the initial situation (on the left) contains three grid nodes connected by three zero impedance lines (breakers/switches), that were reduced to a situation (on the right) where the two equivalent nodes are connected by one zero impedance line (breaker/switch), with nodes 2 and 3 being merged into a single node. This operation is only possible because the impedances of the breakers/switches are equal to zero. After that the number of breakers/switches is reduced to 90.

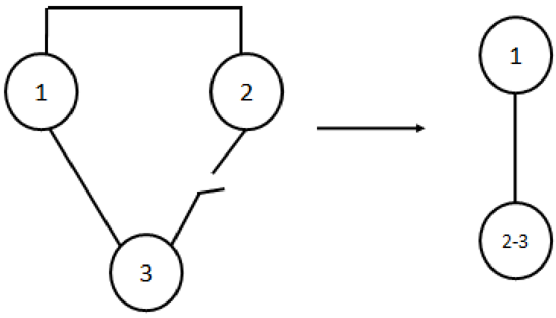

Figure 15 Equivalent breaker example

Again, the flows difference between the completely merged network and the one with the remaining 90 breakers/switches was analyzed. The evolution of some error quantities can also be read from Table 10, and as it can be noted they underwent a significant reduction and can be considered acceptable. Therefore the network model with 90 equivalent breakers that change status between the two grid scenarios was used to evaluate the effect of the topological changes on the congested grid element.

Table 10 Flows Difference Error Quantities in pu (baseMVA=100 MVA) 2583 → 90 breakers/switches

Grid Model	Absolute Max. Error	Absolute Min. Error	Standard Deviation	Mean Absolute Error
CC Model	2.0562 → 3.5623x10-6	0 → 0	0.0536 → 6.7635x10-8	0.0086 → 5.7511x10-9
Final Model	1.2570 → 5.7527x10-5	0 → 0	0.0222 → 1.0342x10-6	0.0020 → 1.1368x10-7

The final configuration of the Capacity Calculation Model used in the analysis becomes:

- 9351 buses.

- 15437 branches.
- 1087 generators.

And of the Final Model:

- 9351 buses.
- 15437 branches.
- 1081 generators.

6.2 Cost Sharing Methodology I

This section presents the numerical results of the methodology described in Chapter 4, applied to the European network, considering 3 different grid scenarios. The grid model used for the analysis is the Final Model, which is referred in Chapter 4 as the Common Grid Model.

6.2.1 Flows Determination Case N

In this case the responsibilities due to the flows on the congested element L (line LN_LN300086) are evaluated when no contingency is present in the network. The flow on the congested element, obtained by means of a DC power flow, is

$$\text{Flow}(L)_{\text{base case}} = 936.3\,\text{MW}$$

The power flow limits through a power line vary, depending on several factors like thermal limits of the line, voltage regulation and stability of the system. For the purposes of this thesis, it is considered that the flow above of 936.3 MW represents a congestion, and therefore some remedial actions need to be taken in order to decrease this value.

The first step is to apply the procedure described in section 4.2 in order to increase the energy exchanges between two neighboring countries, and see the impact this increase has on the congested element. Doing so, it is possible to obtain the influence factors of exchange variations. The procedure used to change the generation and load patterns of the nodes within each zone was the one described in section 4.2. For the Italy-Switzerland border, after increasing the exchanges by 100 MW from Switzerland to Italy, the flow on the congested element becomes

$$\text{Flow}(L)_{\text{shift}} = 949.9\,\text{MW}$$

The same was done for all the other areas and, making use of (64), all the influence factors were calculated. The results obtained for the Italian borders are shown in Table 11.

Table 11 Influence Factors For the Italian Borders

From	To	Influence Factor [%]
Switzerland	Italy	0.1364
France	Italy	0.0914
Austria	Italy	0.0918
Slovenia	Italy	0.0755

With (65), the flows on the congested grid element L, due to the exchanges between two given zones, are calculated. Then, making use of (67) and (69), the share of Import/Export Flow and Transit Flow on the congested grid element is calculated:

$$\mathrm{ImpExp(L)} = 365.9\,\mathrm{MW}$$

$$\mathrm{TransitFlow(L)} = 209.8\mathrm{MW}$$

It has to be noted that, as the congested grid element is a tie-line, the Internal Flow is set to zero. The next step is to increase the generation and load patterns of each country by 1000 MW, one country at a time, in order to calculate the influence factors related to the Loop Flows. Formula (70) is used for that purpose, and the results are presented in Table 12. Actually, as the DC power flow is used, the problem is linear and, if the increase of the generation and load patterns of each country is 100 MW instead of 1000 MW, the results of Table 12 would be the same, provided that the right-hand side of equation (70) is also divided by 100 instead of 1000.

Table 12 Influence Factors Loop Flows

Country	Influence Factor [%]	Country	Influence Factor [%]
Belgium	0.0017	Netherlands	-0.00001
Bosnia Herzegovina	-0.00001	Poland	-0.00012
Bulgaria	-0.00013	Portugal	-0.00001
Czech Republic	-0.00006	Romania	-0.00051
Montenegro	0.00072	Switzerland	0.02040
Germany	0.00039	Albania	0.000035
Spain	0.00019	Slovenia	0.00240
France	-0.00061	Slovakia	-0.00054
Greece	0.000003	Serbia	0.00031
Croatia	0.00081	Ukraine	-0.00007
Italy	0.00810	Austria	-0.00340
Macedonia	-0.00004	Hungary	-0.00073

Applying (71) and making use of the results contained in Table 12, the Loop Flows yield by each country on the congested grid element are obtained, and the values are presented in Table 13.

Table 13 Loop Flows yield by each Country

Country	Loop Flow [MW]	Country	Loop Flow [MW]
Belgium	1,6132	Netherlands	-0,0423
Bosnia Herzegovina	-0,0135	Poland	-2,0070
Bulgaria	-0,4045	Portugal	-0,0449
Czech Republic	0,2969	Romania	-2,9952
Montenegro	0,1873	Switzerland	67,0223
Germany	8,2850	Albania	0,0100
Spain	2,8075	Slovenia	2,5734
France	-25,6653	Slovakia	-1,1158
Greece	0,0167	Serbia	1,0825
Croatia	0,2942	Ukraine	-0,0331
Italy	178,8646	Austria	-1,3789
Macedonia	-0,0220	Hungary	-2,1076

The total value of Loop Flow on the congested element is the sum of the values in Table 13:

$$LoopFlow(L) = 227.2MW$$

Finally, the sum of Import/Export, Transit and Loop Flows, which shall be interpreted as External Flows, is

$$ExternalFlow(L) = 802.9MW$$

6.2.2 Flows Determination Case N-1 SROBBI12-SY_PUN11

In this case the responsibilities due to the flows on the congested element L (line LN_LN300086) are evaluated when there is a contingency on line LN_LN3000154, belonging to the Switzerland area. The flow on the congested element, obtained by means of a DC power flow, becomes:

$$Flow(L)_{basecase} = 1115.5\ MW$$

The first step is to apply the procedure described in subsection 4.2 in order to increase the energy exchanges between two neighboring countries, and see the impact this increase has on the congested element. Doing so, it is possible to obtain the influence factors of exchange variations. The procedure used to change the generation and load patterns of the nodes within each zone was the one described in section 4.2. For the Italy-Switzerland border, after increasing the exchanges by 100 MW from Switzerland to Italy, the flow on the congested element becomes:

$$Flow(L)_{shift} = 1131.7\ MW$$

The same was done for all the other areas and, making use of (64), all the influence factors were calculated. The results obtained for the Italian borders are shown in Table 14.

Table 14 Influence Factors For the Italian Borders

From	To	Influence Factor [%]
Switzerland	Italy	0.1623
France	Italy	0.1120
Austria	Italy	0.1123
Slovenia	Italy	0.0916

With (65), the flows on the congested grid element L, due to the exchanges between two given zones, are calculated. Then, making use of (67) and (69), the share of Import/Export Flow and Transit Flow on the congested grid element is calculated:

$$\mathrm{ImpExp(L)} = 435.4\,\mathrm{MW}$$

$$\mathrm{TransitFlow(L)} = 270.1\mathrm{MW}$$

It has to be noted that, as the congested grid element is a tie-line, the Internal Flow is set to zero. The next step is to increase the generation and load patterns of each country by 1000 MW, one country at a time, in order to calculated the influence factors related to the Loop Flows. (70) is used for that purpose, and the results are presented in Table 15.

Table 15 Influence Factors Loop Flows

Country	Influence Factor [%]	Country	Influence Factor [%]
Belgium	0.0092	Netherlands	-0.0001
Bosnia Herzegovina	0.0232	Poland	-0.0007
Bulgaria	-0.0007	Portugal	0.0004
Czech Republic	-0.0025	Romania	0
Montenegro	0.0031	Switzerland	0.0009
Germany	0.0008	Albania	-0.0002
Spain	0.0001	Slovenia	-0.0001
France	-0.0009	Slovakia	0
Greece	-0.0007	Serbia	0
Croatia	0.0022	Ukraine	0
Italy	0.0011	Austria	0
Macedonia	-0.0002	Hungary	0.0002

Applying (71) and making use of the results contained in Table 15, the Loop Flows yield by each country on the congested grid element are obtained, and the values are presented in Table 16.

Table 16 Loop Flows yield by each Country

Country	Loop Flow [MW]	Country	Loop Flow [MW]
Belgium	2.0655	Netherlands	0.1318
Bosnia Herzegovina	-0.0178	Poland	-2.5009
Bulgaria	-0.5216	Portugal	-0.0533
Czech Republic	0.4241	Romania	-3.8568
Montenegro	0.2423	Switzerland	76.0906
Germany	16.0749	Albania	0.01290
Spain	3.3286	Slovenia	3.3615
France	-28.0029	Slovakia	-1.3994
Greece	0.0216	Serbia	1.3902
Croatia	0.3838	Ukraine	-0.0415
Italy	203.2736	Austria	-1.038
Macedonia	-0.0285	Hungary	-2.7035

The total value of Loop Flow on the congested element is the sum of the values in Table 16:

$$\text{LoopFlow}(L) = 266.6\text{MW}$$

Finally, the sum of Import/Export, Transit and Loop Flows, which shall be interpreted as External Flows, is

$$\text{ExternalFlow}(L) = 972.1\text{MW}$$

6.2.3 Flows Determination Case N-1 SFILIS11-SROBBI11

In this case the responsibilities due to the flows on the congested element L (line LN_LN300086) are evaluated when there is a contingency on line LN_LN3000155, belonging to the Switzerland area. The flow on the congested element, obtained by means of a DC power flow, is

$$\text{Flow}(L)_{\text{basecase}} = 1142.4\text{MW}$$

The first step is to apply the procedure described in section 4.2 in order to increase the energy exchanges between two neighboring countries, and see the impact this increase has on the congested element. Doing so, it is possible to obtain the influence factors of exchange variations. The procedure used to change the generation and load patterns of the nodes within each zone was the one described in section 4.2. For the Italy-Switzerland border, after increasing the exchanges by 100 MW from Switzerland to Italy, the flow on the congested element becomes

$$\mathrm{Flow}(L)_{shift} = 1159.2\,\mathrm{MW}$$

The same was done for all the other areas and, making use of (64), all the influence factors were calculated. The results obtained for the Italian borders are shown in Table 17.

Table 17 Influence Factors For the Italian Borders

From	To	Influence Factor [%]
Switzerland	Italy	0.1680
France	Italy	0.1184
Austria	Italy	0.1131
Slovenia	Italy	0.0909

With (65), the flows on the congested grid element L, due to the exchanges between two given zones, are calculated. Then, making use of (67) and (69), the share of Import/Export Flow and Transit Flow on the congested grid element is calculated:

$$\mathrm{ImpExp}(L) = 450.6\,\mathrm{MW}$$

$$\mathrm{TransitFlow}(L) = 279.0\mathrm{MW}$$

It has to be noted that, as the congested grid element is a tie-line, the Internal Flow is set to zero. The next step is to increase the generation and load patterns of each country by 1000 MW, one country at a time, in order to calculated the influence factors related to the Loop Flows. (70) is used for that purpose, and the results are presented in Table 18.

Table 18 Influence Factors Loop Flows

Country	Influence Factor [%]	Country	Influence Factor [%]
Belgium	0.0077	Netherlands	-0.0001
Bosnia Herzegovina	0.0304	Poland	-0.0007
Bulgaria	-0.0007	Portugal	0.0004
Czech Republic	-0.0049	Romania	0
Montenegro	0.0033	Switzerland	0.0010
Germany	0.0005	Albania	-0.0002
Spain	0.0001	Slovenia	-0.0001
France	-0.0010	Slovakia	0
Greece	-0.0007	Serbia	-0.0001
Croatia	0.0019	Ukraine	0
Italy	0.0011	Austria	0
Macedonia	-0.0002	Hungary	0.0002

Applying (71) and making use of the results contained in Table 18, the Loop Flows yield by each country on the congested grid element are obtained, and the values are presented in Table 19.

Table 19 Loop Flows yield by each Country

Country	Loop Flow [MW]	Country	Loop Flow [MW]
Belgium	1.8056	Netherlands	-0.3475
Bosnia Herzegovina	-0.0184	Poland	-2.7957
Bulgaria	-0.5554	Portugal	-0.0533
Czech Republic	0.3870	Romania	-4.1145
Montenegro	0.2570	Switzerland	99.7086
Germany	9.6431	Albania	0.0137
Spain	3.33170	Slovenia	3.5207
France	-29.6519	Slovakia	-1.548
Greece	0.0230	Serbia	1.4884
Croatia	0.4027	Ukraine	-0.0460
Italy	171.4148	Austria	-2.0222
Macedonia	-0.0302	Hungary	-2.8992

The total value of Loop Flow on the congested element is the sum of the values in Table 19:

$$LoopFlow(L) = 247.9MW$$

Finally, the sum of Import/Export, Transit and Loop Flows, which shall be interpreted as External Flows, is

$$ExternalFlow(L) = 977.5MW$$

6.2.4 Cost Sharing Keys

The Aggravating Impact (AI) in terms of power flows of each country on the congested element, can be calculated by using the weights determined in Table 5, applied to the different types of flows. Table 20 and 21 shows, respectively, the results obtained for Case N and for Case N-1, with the contingency on line LN_LN3000155.

Table 20 Aggravating Impact Case N - Methodology I

Country	AI [MW]	Country	AI [MW]
Belgium	7.6129	Netherlands	6.4230
Bosnia Herzegovina	1.9764	Poland	60.38
Bulgaria	0.1199	Portugal	-0.0888
Czech Republic	25.2252	Romania	-2.4428
Montenegro	0.3810	Switzerland	241.2623
Germany	43.4930	Albania	0.1163
Spain	10.0703	Slovenia	35.8361
France	-6.4054	Slovakia	10.9723
Greece	0.3331	Serbia	1.4326
Croatia	9.2468	Ukraine	1.4826
Italy	361.1578	Austria	33.9143
Macedonia	0.1801	Hungary	8.4036

Table 21 Aggravating Impact Case N-1 - Methodology I

Country	AI [MW]	Country	AI [MW]
Belgium	8.6408	Netherlands	6.4824
Bosnia Herzegovina	2.7118	Poland	13.0720
Bulgaria	0.1647	Portugal	-0.1054
Czech Republic	35.2719	Romania	-3.3554
Montenegro	0.5226	Switzerland	313.5514
Germany	63.6757	Albania	0.1596
Spain	11.9710	Slovenia	45.2327
France	-12.5616	Slovakia	15.1265
Greece	0.4572	Serbia	1.9698
Croatia	12.6907	Ukraine	2.0407
Italy	396.1005	Austria	50.5371
Macedonia	0.2472	Hungary	11.5251

Figure 16 compares the responsibilities assigned to all the areas in case N and N-1, and shows the results in the same order as they are presented in Tables 20 and 21. It can be noted that the magnitude of the responsibilities assigned to almost all the countries have increased, including the ones referred to Italy and Switzerland (numbers 11 and 17 of the x axis in Figure 16, respectively).

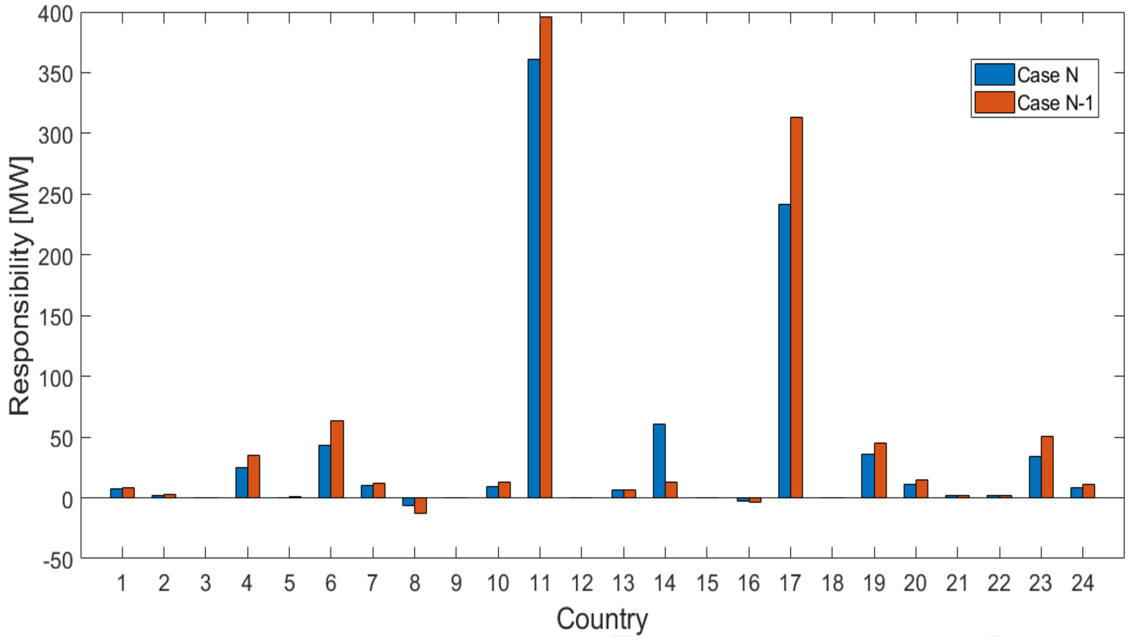

Figure 16 Responsibilites methodology I for cases N and N-1

Applying (79) through (81), the cost sharing factors of each zone due to remedial actions to relieve constraints on a grid element L are defined. Only the countries that represent a positive impact on the congested element are considered, in such a way that the countries that actually relieve the constraint have a sharing factor equal to zero. Tables 22 and 23 show the results for the sharing keys obtained for different status of the system (N and N-1).

Table 22 Sharing Keys Case N - Methodology I

Country	S_A	Country	S_A
Belgium	0.0089	Netherlands	0.0075
Bosnia Herzegovina	0.0023	Poland	0.0702
Bulgaria	0.0001	Portugal	0
Czech Republic	0.0293	Romania	0
Montenegro	0.0004	Switzerland	0.2805
Germany	0.0506	Albania	0.0001
Spain	0.0117	Slovenia	0.0417
France	0	Slovakia	0.0128
Greece	0.0004	Serbia	0.0017
Croatia	0.0108	Ukraine	0.0017
Italy	0.4199	Austria	0.0394
Macedonia	0.0002	Hungary	0.0098

Table 23 Sharing Keys Case N-1 - Methodology I

Country	S_A	Country	S_A
Belgium	0.0087	Netherlands	0.0065
Bosnia Herzegovina	0.0027	Poland	0.0132
Bulgaria	0.0002	Portugal	0
Czech Republic	0.0356	Romania	0
Montenegro	0.0005	Switzerland	0.3160
Germany	0.0642	Albania	0.0002
Spain	0.0121	Slovenia	0.0456
France	0	Slovakia	0.0152
Greece	0.0005	Serbia	0.0020
Croatia	0.0128	Ukraine	0.0021
Italy	0.3992	Austria	0.0509
Macedonia	0.0002	Hungary	0.0116

6.3 Cost Sharing Methodology II

This section presents the numerical results of the methodology described in Chapter 5, applied to the European network, considering 3 different grid scenarios.

6.3.1 Congestion Free Model

This model represents and ideal operating point of the system in which the forecasts made in the CCP turn out to be correct.

The Congestion Free Model is built by shifting the net positions of the areas of the Capacity Calculation Region, from the commercial exchanges simulated in the Capacity Calculation Process, to the ones determined by the Market Coupling Process, at the borders included in the Capacity Calculation Region. The building procedure of the Congestion Free Model can be summarized in the following steps:

1. Take as input the Capacity Calculation Model.
2. Take as input the GSKs of the Capacity Calculation Model.
3. Take as input the scheduled commercial exchanges, defined in the Market Coupling Process, between the areas involved in the Capacity Calculation Region, at the borders included in the Capacity Calculation Region.

4. Shift the net positions of the areas involved in the Capacity Calculation Region in such a way that the commercial schedules of step 3 are respected. Make use of the GSKs of step 2 to translate a variation in the zonal net positions into nodal ones.

Table 24 shows the active flows between Italy and its neighboring countries, computed with a DC power flow.

Table 24 Actual Cross-Border Exchange

From	To	Active Power [MW]
Switzerland	Italy	3675.0
France	Italy	132.7
Austria	Italy	211.5
Slovenia	Italy	1379.2

In order to obtain the same cross-border flows as the commercial exchanges defined in the MCP, the following procedure was applied:

1. The difference between the real commercial exchange and the reference commercial exchange is calculated as

$$\Delta = \frac{F_{real} - F_{reference}}{2} \tag{122}$$

2. If this difference is positive, all the loads belonging to the from-zone are increased and the generator production decreased according to

$$P_{load} = P_{load} + \Delta \frac{P_{load}}{\sum_{P \in zone} P_{load}} \tag{123}$$

$$P_{gen} = P_{gen} - \Delta \frac{P_{gen,min} - P_{gen}}{\sum_{P \in zone} P_{gen,min} - P_{gen}} \tag{124}$$

while all the loads belonging to the to-zone should be decreased and all the generator production increased according to

$$P_{load} = P_{load} - \Delta \frac{P_{load}}{\sum_{P \in zone} P_{load}} \tag{125}$$

$$P_{gen} = P_{gen} + \Delta \frac{P_{gen,max} - P_{gen}}{\sum_{P \in zone} P_{gen,max} - P_{gen}} \tag{126}$$

3. If the difference is negative, all the loads belonging to the from-zone should be decreased and all the generator production increased, while all the loads belonging to the to-zone should be increased and the generator production decreased. This is done by applying (123) through (126) with a negative Δ.

Doing so, it is possible to shift the generation and the consumption of all the terminals belonging to a given area in a proportional way, instead of using the GSK's list and all the different methods applied in every zone. The real Net Position of all the areas considered in the CC model are shown in Table 25.

Table 25 Actual Commercial European Net Position

Country	Net Position [MW]	Country	Net Position [MW]
Belgium	-38.18	Netherlands	-848.67
Bosnia Herzegovina	352.71	Poland	17.60
Bulgaria	773.76	Portugal	-229.06
Czech Republic	877.98	Romania	90.01
Montenegro	-221.18	Switzerland	1129.28
Germany	9842.16	Albania	-363.07
Spain	-1301.06	Slovenia	-1743.12
France	949.77	Slovakia	-196.44
Greece	-737.42	Serbia	587.16
Croatia	-1262.01	Ukraine	372.63
Italy	-1088.06	Austria	-2138.34
Macedonia	-142.51	Hungary	-1864.41

After having shifted the real exchanges to the commercial ones defined in the MCP, the difference between the real and the reference Net Position occurs partly because in the MCP the network's losses referred to the single areas are included, while they are neglected in the DC power flow. The consumption of those areas are shifted, by considering their losses spread with the loads, in the following way:

$$\Delta = \frac{NP_{real} - NP_{reference}}{2} \tag{127}$$

$$P_{load} = P_{load} + \Delta \frac{P_{load}}{\sum_{P \in zone} P_{load}} \tag{128}$$

6.3.2 Generation/Load Deviation Assessment

In this section, the influence of the generation/consumption patterns deviations on the congested element is evaluated. The models to be considered are the Congestion Free Model and the Generation/Load Patterns Model, which has the generation/consumption pattern of the Final Model, and the topology of the Congestion Free Model.
The values of the flow on the congested element for both the models, obtained by means of a DC power flow, are:

$$F_{cfm} = 716.2\,\mathrm{MW}$$

$$F_{gpm} = 891.3\,\mathrm{MW}$$

From (112) and (114), the difference of flow on the congested element is obtained. Both equations give the same result:

$$\Delta F_{gpm\text{-}cf}\,EFF = 175.1\,\mathrm{MW}$$

$$\Delta F_{gpm\text{-}cf} = 175.1\,\mathrm{MW}$$

With (115), it is then possible to assign the responsibilities of each area in terms of power flow through the congested element. The results are reported in Table 26, and the sum of these values represents the active flow through the congested element due to the generation/consumption deviation.

Table 26 Responsibilities Generation/Load Deviation Assessment

Country	Active Power Flow [MW]	Country	Active Power Flow [MW]
Belgium	-0.08	Netherlands	-0.39
Bosnia Herzegovina	-0.62	Poland	1.46
Bulgaria	-0.90	Portugal	15.16
Czech Republic	-1.52	Romania	7.07
Montenegro	-1.25	Switzerland	61.35
Germany	17.68	Albania	-0.17
Spain	-25.07	Slovenia	-33.97
France	-50.53	Slovakia	-1.65
Greece	-6.58	Serbia	5.47
Croatia	1.73	Ukraine	0.47
Italy	241.80	Austria	-0.30
Macedonia	-1.05	Hungary	-0.37

The Ficititious Border area has a responsibility of -52.61 MW, but since this area represents the nodes that connect one area to the other, this value should be shared with the other areas.

6.3.3 Topology Deviation Assessment Case N

In this section the impact that the topology variation has on the congested element is evaluated in the case where no contingency is present in the network. The models to be considered are the Generation/Load Pattern Model, which has the generation/consumption pattern of the Final Model, and the Final Model.

The values of the flow on the congested element for both the models, obtained by means of a DC power flow, are:

$$F_{fm} = 936.3\,\mathrm{MW}$$

$$F_{gpm} = 891.3\,\mathrm{MW}$$

Applying (117), the difference of flow on the congested element is

$$\Delta F_{fm\text{-}gpm}EFF = 44.9\,\mathrm{MW}$$

While applying (119), the result obtained is

$$\Delta F_{fm\text{-}gpm} = 54.1\,MW$$

The percentage error of the difference of flow through the congested element is

$$\varepsilon_{\%} = \frac{|44.9 - 54.1|}{44.9} * 100 = 20.49\%$$

This error occurs because of the DC load flow approach adopted, and therefore it could be reduced by using an AC power flow procedure. Table 27 contains the responsibilities in terms of power flow of each area on the congested element, due to an admittance variation on line l, with:

$$F_{zone} = \sum_{i,j \in zone} \Delta F_{i,j}^{l} \tag{129}$$

$$F_{border-zone} = \frac{1}{2} \sum_{i \vee j \in zone} \Delta F_{i,j}^{l} \tag{130}$$

The sum of these values represents the active flow through the congested element due to the topology deviation, and it is exactly equal to the value obtained with (119).

Table 27 Responsibilities Topology Assessment Case N

Country	F_{zone} [MW]	$F_{border-zone}$ [MW]
Fictitious Border	0	1.43
Belgium	-0.27	0
Bosnia Herzegovina	-0.06	0.09
Bulgaria	0.01	0
Czech Republic	0	0
Montenegro	0	0
Germany	-0.06	0
Spain	-0.09	0
France	1.44	0.06
Greece	0.03	0
Croatia	-1	0
Italy	40.69	0
Macedonia	0	0
Netherlands	-0.16	0
Poland	-0.04	0
Portugal	0	0
Romania	0.02	0
Switzerland	12.75	0.58
Albania	0	0
Slovenia	-0.03	0
Slovakia	0	0
Serbia	-0.07	0
Ukraine	-0.11	0
Austria	-2.12	0.58
Hungary	0.31	0.12

The first column of Table 27 represents the responsibilities assigned to the areas when the nodes that connect the line where the admittance variation occurs are located in the same zone. On the other hand, the second column represents the responsibilies assigned to the areas for admittance variations referred to the interconnectors between two given zones. The total responsibility due to the admittance variation of the interconnector is then divided equally between the two zones.

Exactly 22 interconnectors change their status between the Generation/Load Patterns Model and the Final Model. All these interconnectors are connected by nodes located in the areas which have nonzero values in the second column of Table 27 plus the Italian area, which is represented by a zero value because its border-zone responsibility is negligible (of the order of 10-8 MW). This statement is also valid for the topology assessment performed in the subsequent subsections 6.3.4 and 6.3.5, because the status of all the interconnectors remain unchanged with respect to the present subsection.

6.3.4 Topology Deviation Assessment Case N-1 SROBBI12-SY_PUN11

In this section the impact that the topology variation has on the congested element is evaluated in the case where no contingency is present in the network. The models to be considered are the Generation/Load Pattern Model, which has the generation/consumption pattern of the Final Model, and the Final Model.

The values of the flow on the congested element for both the models, obtained by means of a DC power flow, are:

$$F_{fm} = 1115.5\,\text{MW}$$

$$F_{gpm} = 891.3\,\text{MW}$$

Applying (117), the difference of flow on the congested element is

$$\Delta F_{fm\text{-}gpm}EFF = 224.1\,\text{MW}$$

While applying (119), the result obtained is

$$\Delta F_{fm\text{-}gpm} = 232.8\,\text{MW}$$

The percentage error of the difference of flow through the congested element is

$$\varepsilon_{\%} = \frac{|224.1 - 232.8|}{224.1} * 100 = 3.88\%$$

Table 28 contains the responsibilities in terms of power flow of each area on the congested element, due to an admittance variation on line l. The sum of these values represents the active flow through the congested element due to the topology deviation, and it is exactly equal to the value obtained with (119).

Table 28 Responsibilities Topology Assessment Case N-1 SROBBI12-SY_PUN11

Country	F_{zone} [MW]	$F_{border-zone}$ [MW]
Fictitious Border	0	1.76
Belgium	-0.34	0
Bosnia Herzegovina	-0.08	0.12
Bulgaria	0.01	0
Czech Republic	0	0
Montenegro	0	0
Germany	-0.27	0
Spain	-0.11	0
France	1.69	0.07
Greece	0.04	0
Croatia	-1.29	0
Italy	37.69	0
Macedonia	0	0
Netherlands	-0.22	0
Poland	-0.06	0
Portugal	0	0
Romania	0.03	0
Switzerland	194.96	0.68
Albania	0	0
Slovenia	-0.04	0
Slovakia	0	0
Serbia	-0.10	0
Ukraine	-0.14	0
Austria	-2.94	0.73
Hungary	0.41	0.15

6.3.5 Topology Deviation Assessment Case N-1 SFILIS11-SROBBI11

In this section the impact that the topology variation has on the congested element is evaluated in the case where no contingency is present in the network. The models to be considered are the Generation/Load Pattern Model, which has the generation/consumption pattern of the Final Model, and the Final Model.

The values of the flow on the congested element for both the models, obtained by means of a DC power flow, are:

$$F_{fm} = 1142.4\,\mathrm{MW}$$

$$F_{gpm} = 891.3\,\mathrm{MW}$$

Applying (117), the difference of flow on the congested element is

$$\Delta F_{fm\text{-}gpm}EFF = 251.0\,\mathrm{MW}$$

While applying (119), the result obtained is

$$\Delta F_{fm\text{-}gpm} = 260.5\,\mathrm{MW}$$

The percentage error of the difference of flow through the congested element is

$$\varepsilon_{\%} = \frac{|251.0 - 260.5|}{251.0} * 100 = 3.78\%$$

Table 29 contains the responsibilities in terms of power flow of each area on the congested element, due to an admittance variation on line l. The sum of these values represents the active flow through the congested element due to the topology deviation, and it is exactly equal to the value obtained with (119).

Table 29 Responsibilities Topology Assessment Case N-1 SFILIS11-SROBBI11

Country	F_{zone} [MW]	$F_{border-zone}$ [MW]
Fictitious Border	0	1.90
Belgium	-0.31	0
Bosnia Herzegovina	-0.08	0.12
Bulgaria	0.01	0
Czech Republic	0	0
Montenegro	0	0
Germany	0.03	0
Spain	-0.11	0
France	1.72	0.07
Greece	0.04	0
Croatia	-1.37	0
Italy	37.25	0
Macedonia	0	0
Netherlands	-0.13	0
Poland	-0.06	0
Portugal	0	0
Romania	0.03	0
Switzerland	222.41	0.74
Albania	0	0
Slovenia	-0.04	0
Slovakia	0	0
Serbia	-0.10	0
Ukraine	-0.16	0
Austria	-2.84	0.80
Hungary	0.43	0.16

6.3.6 Cost Sharing Keys

The Aggravating Impact (AI) in terms of power flows of each country on the congested element, can be calculated from (120), and they are equal to the sum of the impacts of each zone with respect to the generation/consumption and topology deviations. Table 30 and 31 shows, respectively, the results obtained for Case N and for Case N-1, with the contingency on line LN_LN3000155.

Table 30 Aggravating Impact Case N - Methodology II

Country	AI [MW]	Country	AI [MW]
Belgium	-0.35	Netherlands	-0.54
Bosnia Herzegovina	-0.59	Poland	1.41
Bulgaria	-0.90	Portugal	15.16
Czech Republic	-1.52	Romania	7.10
Montenegro	-1.25	Switzerland	74.69
Germany	17.61	Albania	-0.17
Spain	-25.16	Slovenia	-34.00
France	-49.03	Slovakia	-1.65
Greece	-6.55	Serbia	5.40
Croatia	0.73	Ukraine	0.36
Italy	282.48	Austria	-1.83
Macedonia	-1.05	Hungary	0.06

Table 31 Aggravating Impact Case N-1 - Methodology II

Country	AI [MW]	Country	AI [MW]
Belgium	-0.39	Netherlands	-0.52
Bosnia Herzegovina	-0.58	Poland	1.40
Bulgaria	-0.89	Portugal	15.16
Czech Republic	-1.52	Romania	7.10
Montenegro	-1.25	Switzerland	284.50
Germany	17.71	Albania	-0.17
Spain	-25.18	Slovenia	-34.01
France	-48.74	Slovakia	-1.65
Greece	-6.54	Serbia	5.37
Croatia	0.36	Ukraine	0.31
Italy	279.05	Austria	-2.34
Macedonia	-1.05	Hungary	0.22

Figure 17 compares the responsibilities assigned to all the areas in case N and N-1, and shows the results in the same order as they are presented in Tables 30 and 31. It can be noted that the magnitude of the responsibilities assigned to all the countries remained roughly the same, except for Switzerland which had its responsibility increased by approximately 210 MW (number 17 of the x-axis in Figure 17).

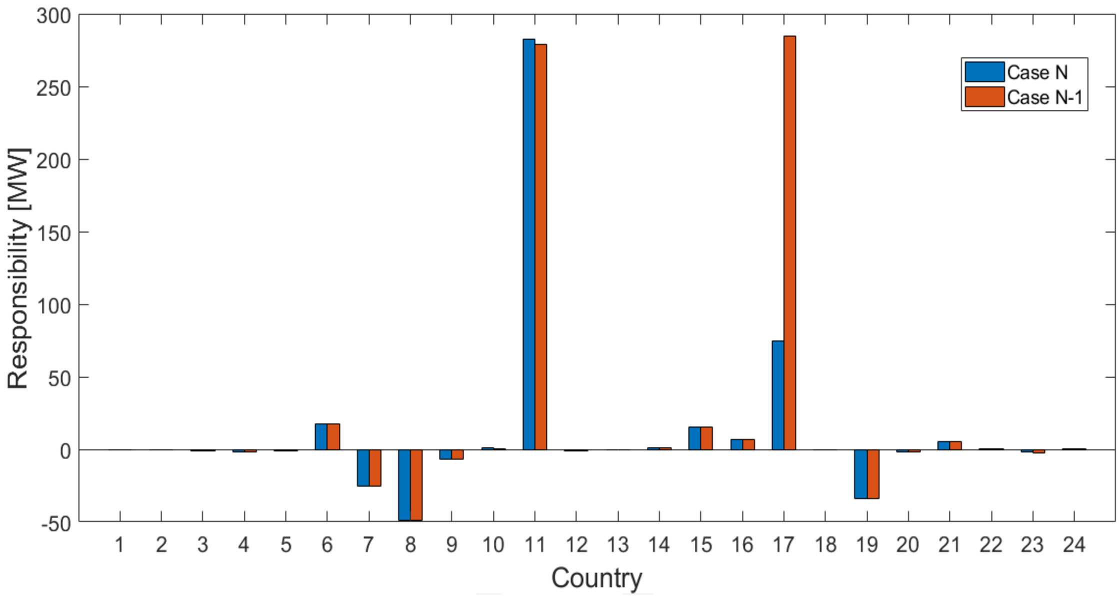

Figure 17 Responsibilites methodology II for cases N and N-1

Applying (121), the cost sharing factors of each zone due to remedial actions to relieve constraints on the congested element are defined. Only the countries that represent a positive impact on the congested element are considered, in such a way that the countries that actually relieve the constraint have a sharing factor equals zero. The results are reported in Tables 32 and 33.

Table 32 Sharing Keys Case N - Methodology II

Country	S_A	Country	S_A
Belgium	0	Netherlands	0
Bosnia Herzegovina	0	Poland	0.0035
Bulgaria	0	Portugal	0.0374
Czech Republic	0	Romania	0.0175
Montenegro	0	Switzerland	0.1844
Germany	0.0435	Albania	0
Spain	0	Slovenia	0
France	0	Slovakia	0
Greece	0	Serbia	0.0133
Croatia	0.0018	Ukraine	0.0009
Italy	0.6975	Austria	0
Macedonia	0	Hungary	0.0001

Table 33 Sharing Keys Case N-1 - Methodology II

Country	S_A	Country	S_A
Belgium	0	Netherlands	0
Bosnia Herzegovina	0	Poland	0.0023
Bulgaria	0	Portugal	0.0248
Czech Republic	0	Romania	0.0116
Montenegro	0	Switzerland	0.4655
Germany	0.0290	Albania	0
Spain	0	Slovenia	0
France	0	Slovakia	0
Greece	0	Serbia	0.0088
Croatia	0.0006	Ukraine	0.0005
Italy	0.4566	Austria	0
Macedonia	0	Hungary	0.0004

6.4 Conclusion

The increase of flow through the congested element in the Final Model between Case N and Case N-1 SFILIS11-SROBBI11 is 206 MW, and this increase occurs only due to an outage in the Switzerland area. The value of the aggravating impact of this area from the first case to the second one, in methodology I, goes from 241 MW to 313 MW but, as it can be seen in Figure 16, an increase in the aggravating impact also occurs for the majority of the other areas. As a result, the cost sharing factor assigned to the Switzerland area does not change significantly between the two scenarios, and therefore the responsibilities due to the congestion are not reflected correctly. On the other hand, when methodology II is used, the increase of the aggravating impact of the Switzerland area is 210 MW, which is approximately equal to the actual increase of flow of 206 MW through the congested element, however, differently from methodology I, the aggravating impacts of the other areas remain approximately the same in both scenarios, what is reflected in the increase of the cost sharing factor assigned to the Switzerland area. Figures 18 and 19 reports the results commented in the present paragraph, comparing the cost sharing keys defined by the two methodologies for cases N and N-1. Table 34 presents the results referred specifically to Italy and Switzerland.

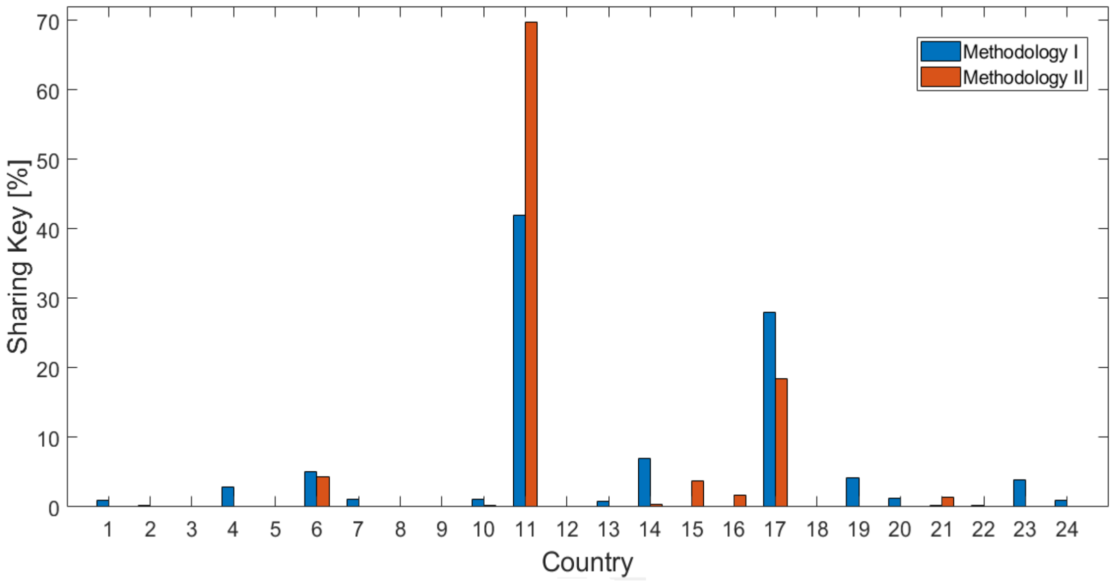

Figure 18 Cost sharing factors case N

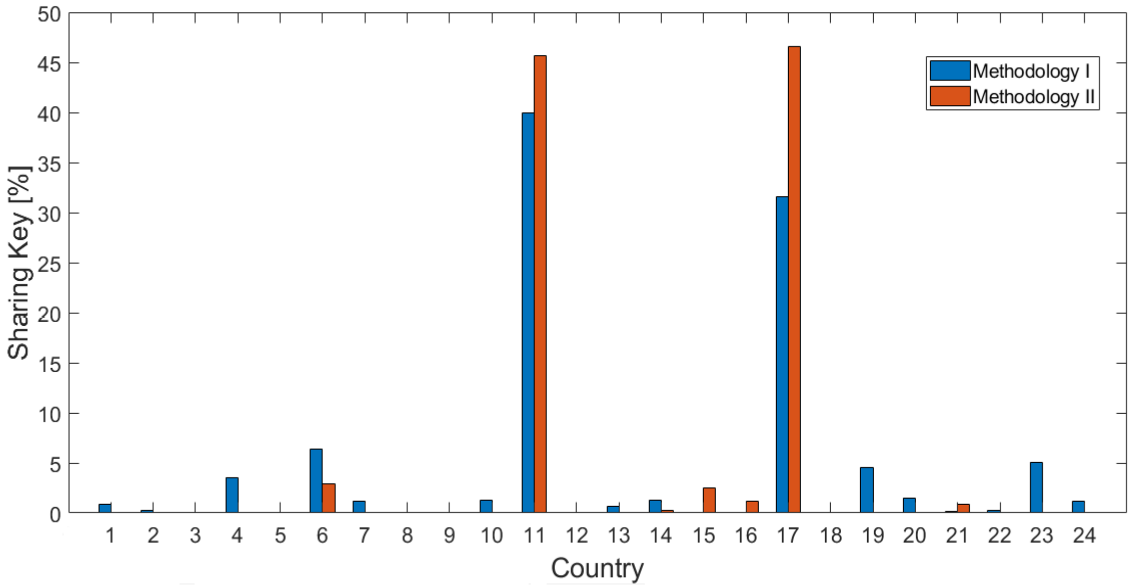

Figure 19 Cost sharing factors case N-1

Table 34 Responsibilities Switzerland-Italy Case N $\rightarrow$ Case N-1 SFILIS11-SROBBI11

Methodology	Country	AI [MW]	S_A
I	Switzerland	241.26 $\rightarrow$ 313.55	0.2805 $\rightarrow$ 0.3160
I	Italy	361.16 $\rightarrow$ 396.10	0.4199 $\rightarrow$ 0.3992
II	Switzerland	74.69 $\rightarrow$ 284.50	0.1844 $\rightarrow$ 0.4655
II	Italy	282.48 $\rightarrow$ 279.05	0.6975 $\rightarrow$ 0.4566

In the explanatory note of methodology I[37], different timeframes for the activation of redispatching and countertrading remedial actions are defined, and it is said that, in case of sudden critical situations that lead to an overload of a critical grid element and require very fast actions, a different cost sharing methodology may be defined for the costs arisen therefrom. The results of this chapter suggest that this should be the case if the responsibilities for the critical situation are to be assigned to the zone where the situation takes place.

The results concerning the aggravating impact and the cost sharing factors obtained in both methodologies for Case N, when there is no contingency in the grid, represent a more adequate comparison. From Figure 18 it can be noted that methodology I yields a more homogeneous distribution of the cost sharing factors among the countries when compared to methodology II, and as a consequence the difference between the sharing keys assigned to

Italy and Switzerland is smaller in the first method (numbers 11 and 17 of the x-axis in Figure 18, respectively) . The different outcomes of the two methodologies may be justified by their distinct characteristics:

- Methodology I takes into account only the most recent grid situation in order to assign the responsibilities to the relevant areas in terms of active power flow. The inputs of the Capacity Calculation Process considered are the GSKs and the commercial exchanges defined in the Market Coupling Process. The influence of each zone on the congested element is calculated based on the impact of the increase in the physical flow transferred between two given zones. Therefore the topological configuration of the areas is not explicitly taken into account.
- Methodology II is based on the comparison between the Congestion Free Model, which represents the grid situation where the commercial exchanges defined in the Capacity Calculation Process are equal to the physical flows between the areas considered in the Market Coupling Process, and the Final Model, which represents the actual scenario of the grid. The responsibilities for the congestion are then assigned to the relevant areas, based on the topological and generation/consumption deviations with respect to the scheduled ones. This principle aims to incentivize the control areas to increasingly carry out better hypothesis and forecasts[38].

From the implementation perspective, the assumption that the grid nodes do not change between the Congestion Free Model and the Final Model scenarios may be a limiting factor for methodology II. If, for example, some parts of the network are disconnected or connected within the timeframe analyzed, the method could not be applied as it is. However, a generalization of the concepts applied should also be possible in case time-varying grid nodes are considered.

CHAPTER 7
CONCLUSION

The main goal of this thesis was to apply and compare the results of two different cost sharing methodologies. They are based on two distinct approaches, but both analyze the impact that each area of the European network considered has on the congested element in terms of active power flow.

The first methodology takes into account only the most recent grid situation in order to assign the responsibilities to the relevant areas, and it is based on the calculation of influence factors, which evaluate the impact that an increase in the exchanges between two given zones, as well as the impact that an increase in the generation and consumption patterns within a single zone, have on the congested element.

The second methodology is based on the comparison between two different grid scenarios, the first one representing the congestion free grid situation where all the forecasts were made during the Capacity Calculation Process, and the second one representing the actual scenario of the grid where the congestion may be actually present. The responsibilities for the congestion are then assigned to the relevant areas, based on the topological and generation/consumption deviations between the two considered networks. This principle aims to incentivize the control areas to increasingly carry out better hypothesis and forecasts.

With respect to the first method, from the results obtained it does not seem to translate into an increase of responsibilities to a given area, if this same area suffers a sudden critical situation (e.g. an unplanned outage) that ends up overloading a grid element, causing a congestion. Therefore, a different approach could be considered in this case. The methodology should otherwise yield coherent results if no contingency occurs in the network.

The second method has a limitation that comes from the assumption that the grid nodes do not vary during the timeframe of the two scenarios analyzed. In practice, this means that the generation/load patterns and the topology can freely change, as long as the same nodes and the same branches are present in the two scenarios: the single opening/closing operation of a breaker within the timeframe analyzed could isolate or include a part of the network and prevent the application of the method as it was applied in this thesis. A generalization procedure that enables the analysis for time-varying nodes could therefore be considered as a future development.

The implementation of the actual Generation Shift Keys of each zone, defined in the Capacity Calculation Process in order to change the zonal generation/consumption patterns, instead of doing it in a proportional way, could be done for both methodologies.

APPENDIX 1

The following quantities are used in the description of the DC power flow[41]:

- $\overline{V_N}$: voltage at node N in [V]. Another way to write the voltage is $\overline{V_N} = |V_N| e^{j\delta_N}$ with δ_N the voltage angle at node N in [radians], relative to a reference node with zero reference angle.
- P_N : active power injection in the grid at node N in [W].
- R_L : resistance of transmission line L in [Ω].
- X_L : reactance of transmission line L in [Ω].
- $\overline{Z_L} = R_L + jX_L$: impedance of transmission line L in [Ω].
- G_L : conductance of transmission line L in [S].
- B_L : susceptance of transmission line L in [S].
- $\overline{Y_L} = G_L + jB_L$: admittance of transmission line L in [S].

A DC power flow is a linearization of an AC power flow, based on three assumptions:

1. Line resistances are negligible compared to line reactances ($R_L << X_L$ for all lines). This assumption implies that grid losses are neglected and line parameters are simplfied.

$$G_L = \frac{R_L}{R_L^2 + X_L^2} \approx 0 \tag{A.1}$$

$$B_L = \frac{-X_L}{R_L^2 + X_L^2} \approx -\frac{1}{X_L} \tag{A.2}$$

$$\overline{Z_L} \approx jX_L \tag{A.3}$$

$$\overline{Y_L} \approx jB_L \tag{A.4}$$

The diagonal matrix with line admittances $\mathbf{Y_d}$ can now be written as a diagonal matrix with line susceptances $\mathbf{B_d}$.

2. The voltage profile is flat, meaning that the voltage amplitude is equal for all nodes (in per unit values):

$$|V_N| \approx 1 \text{ pu} \tag{A.5}$$

3. Voltage angle differences between adjacent nodes are small. This assumption results in a linearization of the sine and cosine terms in the AC power flow equations:

$$\sin(\delta_N - \delta_Q) \approx \delta_N - \delta_Q \tag{A.6}$$

$$\cos(\delta_N - \delta_Q) \approx 1 \tag{A.7}$$

Therefore, the DC power flow only considers active power flows, assumes perfect voltage support and reactive power management, and neglects transmission losses.

The active power flow through a lossless transmission line is given by

$$P_L = \frac{|V_N||V_Q|}{X_L} \sin(\delta_N - \delta_Q) \tag{A.8}$$

With the DC power flow assumptions in mind, (A.8) simplifies to the DC power flow equations for nodal active power balances (respectively, for one node and in matrix format for all nodes):

$$P_L = B_L(\delta_N - \delta_Q) \tag{A.9}$$

$$\mathbf{p_L} = \mathbf{B_d}\,\mathbf{A}\ \boldsymbol{\delta_N} \tag{A.10}$$

The static AC power flow equation for active power injections at a node simplifies to the DC power flow equation for nodal active power balances (respectively, for one node and in matrix format for all nodes):

$$P_N = \sum_Q B_L(\delta_N - \delta_Q) \tag{A.11}$$

$$\mathbf{p}_N = \mathbf{A}^T \mathbf{B}_\mathbf{d} \mathbf{A}\ \boldsymbol{\delta}_\mathbf{N} \qquad \text{(A.12)}$$

The positive direction of the active power flow p_L is from node N to node Q, and B_L refers to the susceptance of line L between node N and node Q. Substituting the nodal voltage angles δ_N from (A.9) through (A.12) gives the DC power flow equations:

$$\mathbf{p}_\mathbf{L} = \left(\left(\mathbf{B}_\mathbf{d}\mathbf{A}\right)\left(\mathbf{A}^T \mathbf{B}_\mathbf{d}\mathbf{A}\right)^{-1}\right)\mathbf{p}_\mathbf{N} \qquad \text{(A.13)}$$

The DC power flow equations for nodal power balances are (A.11) and (A.12) are linearly dependent. As a result, the matrix $\left(\mathbf{A}^T \mathbf{B}_\mathbf{d}\mathbf{A}\right)$ is singular and its inverse does not exist. To overcome this issue, one node has to be designated as a reference node and removed from the DC power flow equations. In the matrix $\left(\mathbf{B}_\mathbf{d}\mathbf{A}\right)$ the column corresponding to the reference node has to be removed while in the matrix $\left(\mathbf{A}^T \mathbf{B}_\mathbf{d}\mathbf{A}\right)$ both the column and row corresponding to the reference node have to be removed. With respect to voltage angles, only the difference in voltage angles between two adjacent nodes matters. Therefore the voltage angle of the reference node has to be set to zero. Finally, one additional relationship has to be added to the set of equations to make sure that the DC power flow has one unique solution. This relationship expresses that the sum of all nodal injections equals zero:

$$\sum_N p_N = 0 \qquad \text{(A.14)}$$

APPENDIX 2

Generation Shift Keys (GSKs) are needed to transform any change in the balance of one control area into a change of injections in the nodes of that control area. GSKs are elaborated on the basis of the forecast information about the generating units and loads. TSOs apply different GSK strategies within the aim of reflecting market conditions in their zone best. This does not necessarily have to be limited to generation. GSKs are therefore also referred to as Injection Shift Keys (ISKs) or Demand Shift Keys (DSKs). Some strategies adopted for defining GSKs are listed below[41].

1. As a reference, a flat strategy is used, where the share of each node n is proportional to the number of generators installed at the respective zone:

$$GSK1_{n,z} = \frac{n_{Gen,n}}{n_{Gen,z}} \quad \forall z, n \in z \tag{A.15}$$

where n and z refer to node and zone, respectively.

2. In the second strategy the shift keys are determined pro rata to the share of each node in the capacity allocation result of the base case:

$$GSK2_{n,z} = \frac{P_{Gen,n}}{P_{Gen,z}} \quad \forall z, n \in z \tag{A.16}$$

3. For GSK3, only generators with available free of charge capacity participate in a change of the Net Position to determine the zonal PTDF. If no free of charge conventional capacity is available, the ten most expensive generators in the base case have an equal share on the injection change:

$$GSK3_{n,z} = \frac{n_{free,n}}{n_{free,z}} \quad \forall z, n \in z \tag{A.17}$$

4. GSK4 is based on the active power outputs of each node in the annual minimum and annual maximum Net Positions in the yearly base cases. The GSK for each hour is then determined as a linear function of the Net Position between these two extremes:

$$GSK4_{n,z} = \frac{P_{sum,n}^{NP_{max,z}} - P_{sum,n}^{NP_{min,z}}}{NP_{max,z} - NP_{min,z}} \quad \forall z, n \in z \tag{A.18}$$

5. For GSK5, only nodes with flexible generation units (gas, oil and pump storage plants) participate in the Net Position change. The share is divided equally among the participating nodes:

$$GSK5_{n,z} = \frac{n_{flex,n}}{n_{flex,z}} \quad \forall z, n \in z \tag{A.19}$$

6. In GSK6, the share for each node is calculated as the ratio of installed capacity at the node to the installed capacity in the market zone:

$$GSK6_{n,z} = \frac{P_{max,n}}{P_{max,z}} \quad \forall z, n \in z \tag{A.20}$$

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