Master's thesis and Internship : Strategies to Mitigate Market Re-Optimisation in Remedial Action Optimisation for Congestion Management in Transmission System Operators

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Strategies to Mitigate Market Re-Optimisation in Remedial Action Optimisation for Congestion Management in Transmission System Operators

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Summary

The increasing complexity of electrical transmission systems, driven by renewable energy integration, market liberalisation, and the growing number of controllable assets, increases the challenges of congestion management for transmission system operators (TSOs). To support operational decision-making, remedial action optimiser (RAO) is used to identify cost-efficient combinations of remedial actions that ensure system security while limiting market interventions.

However, cost-based optimisation may trigger market re-optimisation. In some situations, negative redispatch costs make additional market redispatch economically attractive, even beyond what is required to relieve congestion. Consequently, the optimiser may favour excessive redispatch and neglect TSO-controlled remedial actions, leading to market adjustments that reduce costs without improving system security.

This thesis investigates this issue through both theoretical analyses and numerical simulations. Several mitigation strategies are proposed: arbitrary modifications of redispatch cost structures, prohibition of negative costs and adding operational constraints. These approaches are first analysed on simplified test cases to understand their behaviour and limitations, and then the promising methods, the ones inducing arbitrary modifications in the redispatch costs, are evaluated on large-scale simulations of the Belgian transmission grid using the existing PowSyBl OpenRAO tool.

The results show that these methods effectively prevent market re-optimisation. However, by modifying redispatch costs, they introduce a systematic bias in the optimisation process. Even when redispatch combinations resulting in low real operational costs exist, the optimiser may favour more costly alternative redispatch actions that provide more effective congestion relief under the modified cost formulation. Consequently, the selected solutions generally involve lower redispatch volumes but can become more expensive when evaluated using the original cost structure. No single method fully resolves the market re-optimisation issue while avoiding this trade-off in all configurations.

These findings highlight the challenges of achieving a perfect solution within RAO frameworks and underline the unavoidable trade-off between economic efficiency and robustness in effective congestion management.

Declaration of the utilisation of automatic tools and AI

For some English translations and vocabulary, *Reverso* has been used. Artificial intelligence tools were used as allowed in the charter of the University of Liège. They were used for language-related aspects of this work, such as enhancing spelling, grammar, vocabulary and sentence structures to improve the overall quality and clarity of the document. These tools have also been used for information search, but were never used to create analyses, graphics, figures or else. Analyses, simulations, interpretations and conclusions, are the propriety of the author solely. Specific AI tools used are *Copilot* and *Scotty*, which are AI tools available in Elia company, protecting the confidentiality of the information, and trained on Elia documents.

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Nomenclature

AC	Alternative current
CBCO	Critical branch and critical outage
CNEC	Critical network element and contingency
CRA	Curative remedial action
DC	Direct current
DSO	Distribution system operator
HVDC	High voltage direct current
LP	Linear programming
LRA	Linear remedial action
MILP	Mixed integer linear programming
NCC	National control center
OPF	Optimal power flow
PATL	Permanent admissible transmission loading
PC	Penalty cost
PRA	Preventive remedial action
PSDF	Phase shift distribution factor
PST	Phase shift transformer
PTDF	Power transfer distribution factor
RA	Remedial action
RAO	Remedial action optimiser
RD	Redispatch
RES	Renewable energy source
ROSC	Regional operational security coordination
TATL	Temporary admissible transmission loading
TSO	Transmission system operator

Presentation of the company

The company in which this work was carried out is Elia, a transmission system operator (TSO). Its main role is to manage the high-voltage electricity transmission grid and to ensure the secure and reliable transport of electricity from generation sites to distribution networks and large industrial consumers. Elia Group operates in Belgium through Elia Transmission Belgium, and in Germany via 50Hertz, which covers the north and east of the country. In addition, Elia Grid International provides consulting services to international clients [9]. The group employs approximately 4500 people [10] and reported total revenues of 4.76 billion euros in 2024 [11].

Elia is described in detail on their website [9]. It is important to know that Elia is a highly regulated natural monopoly, like other European transmission system operators. Due to the very expensive infrastructure and the critical importance of electricity transmission for public welfare, competition in this sector is not practical or desirable. It is the reason why this field is a monopoly where activities are strictly supervised by national regulatory authorities, such as the Belgian regulator (CREG), which defines the allowed revenue levels, investment frameworks and performance incentives [12]. This regulation aims to ensure that the company operates efficiently while guaranteeing fair and secure supply for consumers. As a result, the financial and operational performance of Elia is not determined by market competition, but rather by regulatory mechanisms. Moreover, Elia is a listed company. Being publicly traded imposes financial discipline and transparency requirements, as well as expectations from investors regarding long-term evolution. The company must therefore comply between regulations objectives, operational work, and financial performance. Therefore, it is important for the company to maintain a good reputation and credibility.

More than its regulated base activities, Elia is also focused and invests in the development and innovation of the grid to address the challenges of the energy transition. The increasing integration of renewable energy sources and the growing complexity of the electricity system require advanced technical solutions. The company is also actively involved in European collaborations, notably through ENTSO-E and various research programmes, contributing to the harmonisation and evolution of the high-voltage grid across Europe. These innovation efforts are directly linked to operational challenges, such as congestion management, and form the basis for the development of tools like the Remedial Action Optimiser studied in this work [1].

From a human resources perspective, Elia employs around 4500 people. The majority of employees are involved in technical and operational roles, including engineers, technicians, and IT specialists, reflecting the technical nature of the company's core activities. Approximately 47% of employees work in finance and operations, 34% in engineering roles, and 20% in sales and marketing functions [10].

This work was more specifically done in the Power System Operations and Security service, an expert team working next to the National Control Center, where real-time operations of the Belgian transmission grid are applied.

[1] Some information provided here comes from some visits, meetings, and experience inside the company

Chapter 1

Introduction and power system context

1.1 Introduction

1.1.1 Context

This master's thesis examines the development of electrical transmission grid management as its complexity increases. The operation of power transmission systems has undergone some profound changes over the last decades. In the past, electricity systems were managed in a vertically integrated way [13], which means that the same actors controlled generation, transmission, distribution and supply [14]. At that time, production was strongly centralised in large conventional power plants. This structure allowed easy and straightforward planning, with predictable power flows. From this structure, three fundamental transformations arrived in Belgium:

- the liberalisation of electricity markets (fully completed in 2007) [15],
- the change of energy sources with the massive rise of renewable energy sources (RES) and
- the new technologies applied to the transmission network.

The liberalisation of electricity markets changed the main structure of the electricity industry, from one company producing, transporting, and selling to an unbundled model. Generation became competitive, while transmission (Elia) and distribution stayed regulated. Liberalisation has brought new market players, making the system more open and complex. Today, the market is highly dynamic and no longer managed by the transmission system operator (TSO). Instead, numerous market participants, such as decentralised generators or active consumers ("prosumers") play a significant role, and market operation has become a large and important business [13, 15]. The consequence of this liberalisation for the TSOs is the rise in complexity to ensure a secure network, by following the decisions of the market operators.

In parallel, the generation mix has strongly changed and continues to do so, with a large increase in RES. RES are often not ideally situated compared to grid infrastructure and consumption areas, e.g. offshore wind turbines far away in the sea, and are less predictable than traditional power plants due to their intermittent nature, which makes managing the grid increasingly complex [16].

Furthermore, today, new technologies such as batteries, phase-shifting transformers and HVDC links are being integrated into the grid, alongside a growing number of cross-border interconnections and a rising total electricity demand driven by the ongoing electrification of society. These technologies increase the number of control variables available to TSOs, thereby adding to the complexity of decision-making for various aspects of system stability management. With these new assets, TSOs can manage grid flexibility and reliability more effectively, but the range of possible actions and strategies they need to consider has grown significantly, making stability management even more challenging.

Transmission system operators must manage several security objectives such as voltage, frequency, congestion, short-circuit current and stability. This work will focus on one of them: congestion management, which consists of ensuring that all transmission elements operate within their physical and thermal limits in order to avoid overloading. Managing congestion in the high-voltage grid is a complex task for TSOs, as it involves a large number of variables, as outlined above. Two types of action can be implemented to relieve congestion: costly and non-costly measures. Non-costly measures are prioritised; however, they are not always sufficient to fully secure the grid. In such cases, costly measures must be employed. Given the economic implications of these cost-related actions, it is desired to optimise congestion management in order to identify the most efficient and economically viable solutions, while remaining consistent with market outcomes in the context of electricity market liberalisation.

1.1.2 Aim of this work

This thesis focuses on a smart and optimised congestion management, and more specifically on addressing a problem related to this optimisation and its unintended interactions with the market when using costly measures. This specific objective will be reformulated in Section 2.5, once the necessary background on power systems and optimisation frameworks has been presented. To tackle this specific issue, several techniques are first proposed and developed from a theoretical perspective. These analyses help to highlight the advantages and drawbacks of the proposed methods, guiding the selection of the most promising solutions for testing on a real transmission grid. The selected solutions are then implemented in a specific configuration of the Belgian grid, which is artificially modelled to create a relevant scenario.

1.1.3 Thesis outline

This work begins with a reminder of the fundamentals of the power system, aiming to familiarise the reader with concepts related to power systems and congestion management. Chapter 2 then introduces the principle of remedial actions and the remedial action optimiser, which forms the basis of this study. The core issue addressed in this document is discussed once the optimiser is explained. An overview of the previous studies on this topic is included at the end of the chapter. Chapter 3 details various theoretical solutions and small-scale case studies that address the issue, starting with the method proposed in the previous chapter, and then develops new ideas. The final chapter, Chapter 4, presents the Belgian grid and the software environments used, followed by large-scale grid simulations of some proposed methods. The work concludes with a summary and perspectives for future research.

1.2 Power system fundamentals

The fundamental knowledge needed to introduce the context of this work is developed in this section. It serves as a reminder for specialists in this subject, and as an introduction to the transmission of electricity and congestion management for others.

1.2.1 Power system overview

Basic structure of power grids

The structure of the electrical grid is similar around the world. It is composed of three primary segments: production, transmission and distribution [17]. The first segment, production, is where electricity is generated. Electricity can be produced by large power plants, which are typically located near industrial loads, but for safety reasons are placed farther from residential areas. Alternatively, electricity may be generated closer to residential areas, for example, by photovoltaic panels, or in completely isolated locations, as is often the case with wind power generation. Electricity is often produced at a voltage level of around 10 to 25 kV in large units. To deliver electricity from the distant generation sites to cities and other high-demand areas, the voltage is stepped up and (very) high-voltage lines, called transmission lines, are used. These lines have a voltage level between 70 kV and 400 kV (sub-transmission and transmission lines), a very high voltage to decrease the current in the lines, and therefore Ohmic losses during transport. Finally, once the electricity reaches consumption areas, to distribute it to small consumers, the voltage is stepped down (34 kV to 400 V) and the lower voltage level grid is called the distribution grid. It is powered by the transmission grid, and delivers electricity to houses, business and small industries [17].

Each part of the electricity supply process is managed by different organisations [18]. The distribution of electricity is handled by Distribution System Operators (DSOs), who are responsible for operating and maintaining medium- and low-voltage networks, typically at voltage levels below around 50 kV [19]. On the other hand, there is a single Transmission System Operator (TSO) in Belgium, Elia. The TSO is responsible for the operation, maintenance, and development of the high- and extra-high-voltage grid (above 70 kV) [9]. Elia ensures the secure transmission of electricity both within Belgium and across borders, connecting with neighbouring countries via high-voltage AC lines (with France and the Netherlands) and high-voltage DC links (with Germany (Alegro link) and the United Kingdom (Nemo link)).

Unlike DSOs, which operate at a regional level and are publicly owned [20, 21], the TSO operates at the national level and follows a more liberalised ownership structure, being a publicly listed company with private shareholders. Nevertheless, it remains a regulated monopoly, since electricity transmission is generally considered a natural monopoly in liberalised electricity markets [22], and is subject to strong regulatory oversight to ensure system security, reliability, and non-discriminatory access to the transmission network [23].

Role and responsibilities of transmission system operators

Transmission system operators (TSOs) are responsible for the operation of high-voltage electricity transmission networks. Their primary role is to ensure the secure and efficient transport of electricity from generation sources to distribution systems and large consumers, while maintaining system stability and reliability [24]. In Belgium, the TSO is also responsible for the development and maintenance of the grid. This is not the case for all TSOs, as in some countries these tasks are managed by other companies.

In Europe, TSOs operate within a common regulatory framework established by European Union legislation, notably the Third Energy Package (2009), which defines their roles and promotes coordination at the European level through ENTSO-E. This organisation facilitates cooperation between TSOs and supports key objectives such as market integration and security of supply [25].

TSOs must comply with binding network codes and regulations that define operational rules, including system security and cross-border coordination. For instance, the System Operation Guideline specifies requirements related to operational security and remedial actions. More recent frameworks, such as the Clean Energy Package (2019), have further strengthened the role of TSOs, particularly regarding regional coordination and the integration of renewable energy sources [23, 26].

Overall, this regulatory framework ensures that TSOs operate as neutral and independent entities under harmonised rules; however, a key drawback is the increased need for efficient congestion management strategies to maintain system security within technical limits [25].

1.2.2 Power system stability and security

As discussed, TSOs are responsible for ensuring the stability and security of the grid. To achieve this, several different operational constraints must be enforced to respect the network limits and guaranteeing that the network operates within its technical limits.

Operational constraints and network limits

The secure operation of a power system relies on both steady-state operating conditions and dynamic stability considerations. In steady-state operation, the system must satisfy three main types of operational constraints:

- voltage limits, maintaining acceptable voltage levels across the network,
- frequency control, ensuring the balance between generation and consumption, and
- current limits, ensuring that power flows do not exceed the thermal capacity of network components.

By ensuring that voltage and frequency remain within prescribed limits, that power flows do not exceed the capacity of network components and a good dynamic stability, the system remains both reliable and secure. Transmission is governed by strict regulatory rules designed to maintain security and stability under all operating conditions [27]. Following these principles helps prevent large-scale disturbances and guarantees a stable supply of electricity to all users.

N-1 security criterion

For steady-state security, mainly congestion and voltage management, a criterion is introduced to ensure the security of the grid. The "N-1" security criterion is a reliability standard used in power system operation and planning. It requires that the electrical grid remain secure and within operational limits even if any single network element, such as a transmission line, transformer, or busbar, unexpectedly becomes unavailable, i.e. is lost due to a fault or outage, which can happen at any time. This principle ensures that, after the failure of one component (the "minus one"), no other elements will become overloaded, and the system will continue to be stable without triggering a chain reaction of subsequent failures (a cascade effect) or a blackout. It is known as the principle of redundancy [28]. The "N-1" criterion is a fundamental requirement for TSOs to guarantee the reliability and security of the transmission grid for congestion safe operation. In more advanced assessments, the "N-k" criterion generalises this approach to consider the simultaneous loss of k elements, evaluating the resilience of the grid under multiple contingencies. It is stipulated by European rules that this principle must be respected at any time, in any situation. It includes also moments of maintenance and repair work, so it is important to coordinate them at right time [29].

To analyse the security of the grid, the "N" and the "N-1" state are analysed, to flag the operation state of the system. There are five different states in which the grid can be flagged (Figure 1.1) [1, 30].

- Normal state: System within operational security limits in state "N" and "N-1".
- Alert state: System secure the "N" state but at least one "N-1" state is outside the operational limits. Some remedial actions (explained in more detail in the next chapter) must be applied to bring the system back to its normal state.
- Emergency state: The system is in emergency because it is outside its operational security limits in "N" states. Remedial actions need to be taken immediately to come back in an Alert state, and then in a normal state.
- Blackout state: In the blackout state, the voltage has been lost in a part of the system and at least 50% of the load has been lost. Once the blackout happens, the system must go to the next state, the restoration state.
- Restoration state: The system goes in restoration mode, where voltage and load are restored with restoration actions, and step by step coming back to a secure system.

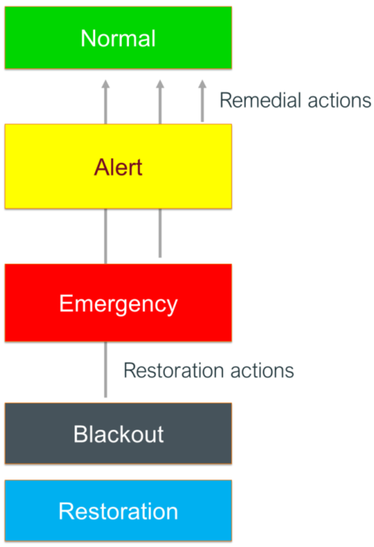


Figure 1.1: Power system security state (Source: course ELEC0449 [1])

In conclusion, the "N-1" criterion allows to analyse the security of the grid (a congestion-free network), and action must be taken to maintain it in a normal state.

1.2.3 Congestion management

This work will focus only on the congestion management. For that, the congestion is defined and the timeframes of congestion management are developed.

Definition of congestion

Grid congestion refers to a condition in which the current flowing through a power transmission element reaches or exceeds its safe operational limit, or maximum capacity. For lines, for example, as more electricity passes through it, its electrical resistance generates heat, resulting in increased energy losses due to the Joule effect, and causes physical expansion of the conductor (Figure 1.2). This heating limits how much current the line can safely carry: excessive sag can bring the line dangerously close to the ground and increase the risk of electrical arcing with the surrounding environment, resulting in safety hazards. Furthermore, overheating can damage the equipment or its insulation [24, 28].

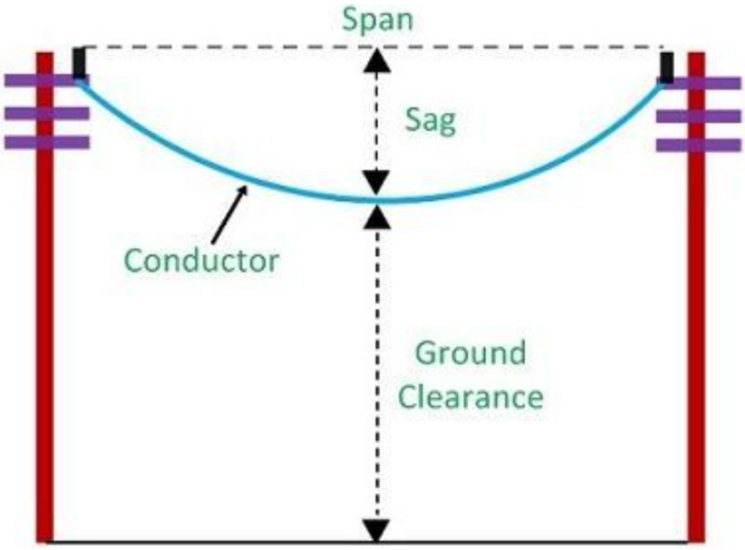


Figure 1.2: Visualisation of the sag and clearance on an overhead line (Source: Circuit globe [2]).

If safety thresholds are exceeded, the line can become inefficient, risk structural failure, or are disconnected from the grid by triggering circuit breakers. In severe cases, this can trigger a cascade of overloads on neighbouring lines, potentially resulting in widespread outages or blackouts. It is the reason why TSOs must ensure a secure "N-1" network in any case, to ensure a secure system and free of congestion. Although this phenomenon is commonly illustrated on overhead lines, similar physical limits apply to other network components such as transformers, underground cables and substation equipment, whose operation is also constrained by thermal ratings and electrical limits.

The growing electrification of the market and the development of the renewable energy sources have increased the complexity of keeping a congestion-free network. Grid congestion was always a concern for TSOs, but the risk of congestion increases sharply in the new society with this development. Indeed, the expansion of integration of RES adds a new challenge due to their distributed, decentralised, and intermittent nature, and the grid must handle a large increase in electricity demand due to the electrification process faced today [24]. Article [31] adds that the complexity comes from the high number of sellers and buyers of electricity on the market, the transmission network's limitations, and the mandatory uninterrupted balancing between demand and supply. This problem is called "Transmission Congestion".

Congestion management timeframes

Congestion management is implemented over several timeframes, each associated with a different level of system visibility and flexibility. Remedial actions are therefore selected and activated depending on the stage of operation and the available information.

Before the day-ahead timeframe, congestion management is influenced by long-term processes such as forward markets, transmission capacity allocation, and network planning. In particular, TSOs schedule maintenance and outages, which directly affect network availability and future congestion patterns.

In the day-ahead timeframe, congestion management is performed based on forecasts of load, generation, and network conditions. At this stage, planned remedial actions can be scheduled in advance, such as re-dispatching generation. In addition, certain non-costly remedial actions, such as predefined phase-shifting transformer (PST) settings or planned network configurations (topological changes), can also be used to manage expected congestion in a preventive manner. These actions aim to ensure that the system remains within its operational limits for the following day.

In the intraday timeframe, updates in system conditions, such as forecast errors in renewable generation, demand variations and market schedule, may lead to new or reinforced congestion situations. TSOs must therefore adapt their strategies by implementing new remedial actions. The measures allow the system to remain secure closer to real-time operation.

Finally, in the real-time timeframe, congestion management becomes more constrained due to limited time for intervention (a few minutes starting from the receipt of the alert). TSOs must rely on fast and reliable remedial actions to maintain system security. These actions include classical remedial actions (real-time redispatching, activation of balancing reserves, PSTs, topological actions), or, in extreme situations, emergency measures such as load shedding. At this stage, it is important to quickly ensure the stability and integrity of the power system.

1.2.4 Power system analysis: mathematical background

Finally, a small reminder of the power system mathematics is provided to further support the analysis and understanding of the developed tool.

Load Flow analysis

The first analysis is always the load flow analysis, to verify the electrical state of the network in a precise configuration and time step. This analysis is performed in steady-state. The transmission network is mainly operated with alternating current (AC), and only a few cross-border lines use direct current (DC), specifically high-voltage direct current (HVDC) lines. To calculate the load flow, equations are required. Firstly, the apparent power is defined as:

$$S = P + jQ \tag{1.1}$$

with P the active power (in Watts) and Q the reactive power (in Var). After a mathematical development (see reference book for more details [32]) the power flow equations are the following:

$$P_k = G_{kk}V_k^2 + V_k \sum_{m=1, m\neq k}^{n} V_m \left(G_{km}cos\theta_{km} + B_{km}sin\theta_{km}\right) \tag{1.2}$$

$$Q_k = -B_{kk}V_k^2 + V_k \sum_{m=1, m\neq k}^{n} V_m \left(G_{km}sin\theta_{km} - B_{km}cos\theta_{km}\right) \tag{1.3}$$

Where

- P_k is the active power injection at bus k (in W);
- Q_k is the reactive power injection at bus k (in var);
- V_k is the voltage magnitude at bus k (in p.u. or kV);
- V_m is the voltage magnitude at bus m;
- θ_k and θ_m are the voltage phase angles at buses k and m (in radians);
- $\theta_{km} = \theta_k - \theta_m$ is the voltage angle difference between buses k and m;
- G_{km} is the conductance between buses k and m (real part of the admittance);

- B_{km} is the susceptance between buses k and m (imaginary part of the admittance);
- G_{kk} and B_{kk} are the self-conductance and self-susceptance at bus k;
- $Y_{km} = G_{km} + jB_{km}$ is the element of the bus admittance matrix;
- n is the total number of buses in the network.

The power flow equations presented above are non-linear due to the trigonometric relationships between voltage magnitudes and angles. As a result, they cannot be solved using linear methods. To compute the load flow, iterative numerical methods are required. The Newton–Raphson algorithm is commonly used due to its quadratic convergence properties and its robustness when applied to large-scale power systems. This method iteratively updates voltage magnitudes and phase angles until convergence is achieved [32,33].

However, the non-linear nature of AC power flow equations makes them computationally demanding and less suitable for certain types of analysis. Consequently, simplified linear approximations of the network are often employed. In particular, DC load flow approximations are widely used, as they linearise the relationship between power flows and voltage angles [32, 34].

Security analysis

Also called contingency analysis, security analysis is an analysis of critical system conditions. It is a process for evaluating the network states resulting from unplanned outages of single elements ("N-1" criterion) such as transformers, busbars, transmission lines, etc. The security analysis can be based on AC power flow using iterative AC load flow calculations or on DC power flow approximations. In the most straightforward approach, a load flow is run for each contingency, where one element is disconnected ("N-1" state), in order to analyse the system behaviour and verify compliance with operational limits. However, this approach can be computationally intensive for large-scale systems. More advanced methods rely on sensitivity-based techniques, where the impact of contingencies is approximated using linear factors derived from the Jacobian matrix computed during the initial load flow. These methods, such as distribution factors, allow the fast screening of contingencies without recomputing a full load flow for each outage. This analysis enables the verification of the system security under the "N-1" criterion [35].

Optimal power flow

The Optimal Power Flow (OPF) problem extends classical load flow analysis by introducing an optimisation layer. Its objective is to determine an optimal steady-state operating point of the power system while satisfying both network and operational constraints. OPF is typically formulated as a constrained non-linear optimisation problem in which the objective function represents, for instance, generation costs or power losses [36, 37].

In its general form, the OPF problem can be written as:

$$\begin{aligned} \min_{x,u} \quad & f(x,u) \\ \text{s.t.} \quad & g(x,u) = 0 \\ & h(x,u) \leq 0 \end{aligned}$$

where x denotes the state variables (e.g., bus voltage magnitudes and angles) and u the control variables (e.g., generator active and reactive power outputs). The equality constraints $g(x,u)$ correspond to the non-linear power flow equations, which enforce the physical laws governing the network, while the inequality constraints $h(x,u)$ represent operational limits such as generator bounds, voltage limits, and line thermal limits [37, 38].

Chapter 2

State of the art for congestion management and specific objectives of this work

2.1 Remedial actions in transmission system operation for congestion management

In this section, remedial actions are defined and analysed. This work focuses only on congestion management, therefore only remedial actions useful for the management of congestion will be developed.

2.1.1 Definition of remedial actions

In the long term, TSOs can detect critical lines in the grid in case of outage, and therefore make investments by upgrading their infrastructure, such as constructing new transmission lines to increase power capacity on critical axes. In the short-term, upgrading the infrastructure is not feasible. Other actions are necessary to maintain grid stability. Operational decisions can be taken to relieve the grid from congestion [24]. These actions are called remedial actions (RAs). They are corrective measures applied to the network that redirect power flow to less critical lines. In Article 2(13) of CACM Regulation [39], remedial actions are defined as "any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security.".

2.1.2 Classification and types of remedial actions

Different types of actions are available. These actions differ in several parameters, such as reaction speed and cost. The RAs available for the TSOs are presented as follows [24, 40]:

- Generation-based action:
  Countertrading and Redispatch, generation curtailment.
- Network-based actions:
  Phase-shift transformer, topological modification and HVDC set point change.
- Demand-side actions:
  Load shedding.
- Energy storage:
  Battery park.

Some of these actions do not induce direct costs for TSOs, as their activation does not require any remuneration to external parties. These are referred to as non-costly measures, such as topology changes or phase-shifting transformer adjustments. In contrast, other actions involve interactions with market participants and require financial remuneration, in particular generation-based actions such as redispatch. These actions are therefore considered costly and their associated costs are paid by the TSOs [40].

2.1.3 Main remedial actions considered

In the rest of this work, only a specific selection of remedial actions is considered for the development of the study and is used in the analysis of congestion management presented later.

Phase shifting transformers

Firstly, a main remedial action currently used is the phase-shift transformer, known as PST. This RA enables to regulate the active power flow by changing the difference between voltage phase angles of two nodes, in an autotransformer [31]. The PSTs are non-costly RAs, which makes them some prior RA desired to implement. Indeed, a tap change does not induce a cost for the operator. In practice, a low cost will still be given to guide the optimiser (developed in next section) and not give random free PST if not needed.

Mathematically, it is known that the apparent power S is defined as:

$$S = P + jQ, \tag{2.1}$$

and active and reactive power, respectively P and Q, transport over a transmission line in a model, are given by the following equations [3]:

$$P = \frac{|U_s||U_r|}{X_L} sin\delta, \tag{2.2}$$

$$Q = \frac{|U_s||U_r|}{X_L} \left(cos\delta - \frac{|U_r|}{|U_s|} \right). \tag{2.3}$$

Where $|U_s|\angle\delta$ is the magnitude and angle of the voltage at the sending end of the line, $|U_r|\angle 0$ is the voltage at the receiving end, and X_L is the reactance of the transmission line (Figure 2.1).

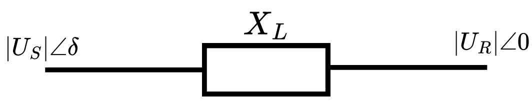


Figure 2.1: Modelling of the transmission line without a PST (Source: PST article [3]).

The active power with a PST follows some modifications, and the equation becomes:

$$P = \frac{|U_s||U_r|}{X_L + X_{PST}} sin(\delta + \alpha) \tag{2.4}$$

where X_{PST} is the leakage reactance of the PST and α an angle to shift the phase (can be positive or negative) [3] (Figure 2.2).

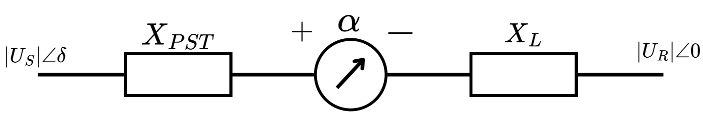


Figure 2.2: Modelling of the transmission line with a PST (Source: PST article [3]).

A change of the angle α using the PST will therefore induce a change of the power flow and allows the PST to control the active power flow (see Figure 2.3).

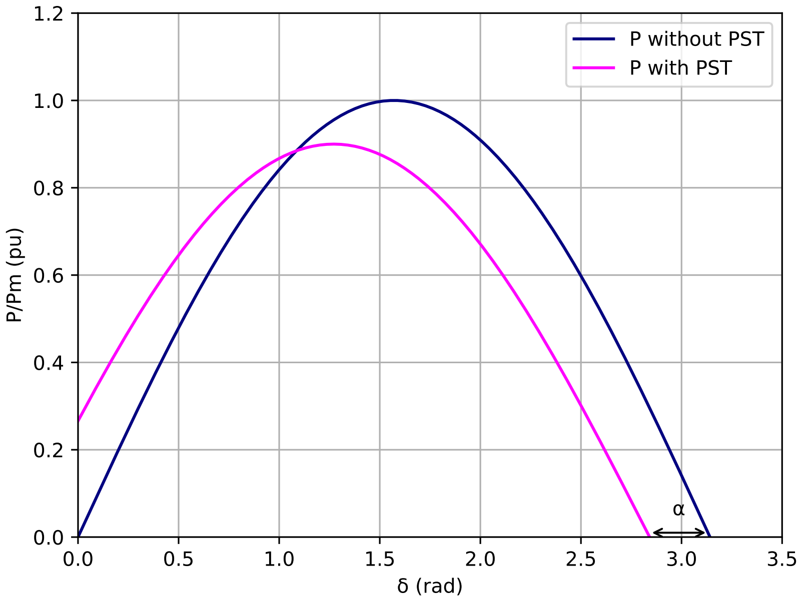


Figure 2.3: Impact of the PST on the active power curve (Source: PST article [3]).

Although it is modelled as an additional angle in the equations, physically, a phase-shifting transformer does not directly impose a phase change. Instead, it operates by injecting an additional voltage in series with the transmission line. This injected voltage is generated by a shunt transformer and applied through a series transformer. The voltage is typically in quadrature, i.e. shifted by 90°, with respect to the system voltage, and its vectorial addition modifies the overall voltage phasor. As a result, the phase angle difference between the sending and receiving ends is modified [41].

One characteristic of the PST is the possibility to model this RA as linear remedial action in a DC-based model. When the phase shift angle (α) is small, the effect of PST tap changes on power flows can be closely approximated by a linear relationship, as $\sin\alpha \approx \alpha$ for small angles. This simplification is valid only when the phase angle shift remains limited. Additionally, for the sake of linearisation, the discrete tap positions of PSTs are treated as continuous variables and then rounded. While these approximations simplify the analysis, they may introduce errors when applied to real-world systems.

Topological modifications

Topological modifications of the grid have a very low marginal cost and, like PSTs, can be considered as non-costly remedial actions [40]. Therefore, the use of this type of RAs is expected to increase, as it allows a reduction of congestion management costs. The main difficulty related to this action is its non-linearity [4]. Several approaches to manage the non-linearity behaviour in congestion management have been proposed, such as in the article of Andrea Ewerszumrode [42], where an iterative approach separating linear remedial actions (PST and RD) from topology, is developed. The challenge associated with non-linearity is the ability to meet computation time requirements. Indeed, congestion management requires a short-term process so a smart management of non-linearity optimisation is needed.

Topological RAs can have a large impact on congestion management costs. Indeed, their use can avoid or significantly reduce the need for costly remedial actions such as redispatching. Based on the article of M.Dorfer [43], the use of topological actions can reduce the redispatching volume by up to 60%.

An approach to manage topological changes has been implemented in PowSybBI software, through the CASTOR algorithm (Calculation with Scalable and Transport Optimiser) [4]. There, two types of RAs are considered: linear remedial actions (later called LRAs) like PSTs, RD and HVDC set points, and non-linear actions for the topological RAs (change of switch and circuit breaker position like line opening or busbar coupler opening/closing). The problem becomes combinatorial because of its non-linearity, non-convexity and discretisation. Therefore, the CASTOR algorithm is based on a search-tree algorithm.

In Figure 2.4, an overview of the search-tree is illustrated with three available topological RAs and a set of LRAs. The root node corresponds to the initial network configuration without any remedial action. At each node, an LRAs optimisation is first performed using a linear optimisation problem (typically a linear (LP) or mixed-integer linear programming (MILP)). Then, each possible non-linear remedial action is applied, creating new network configurations. For all configurations, the LRAs are re-optimised, since a re-optimisation can bring to a new optimal set-point of LRAs in the specific new topology. To explore the tree, the branch corresponding to the configuration with the lowest objective function value is selected. For example, the objective function OF 1.2 is lower than OF 1.1 and OF . The process is repeated until a stopping criterion is reached, usually the maximum depth of the tree for congestion management. The final configuration corresponds to the optimal set of remedial actions.

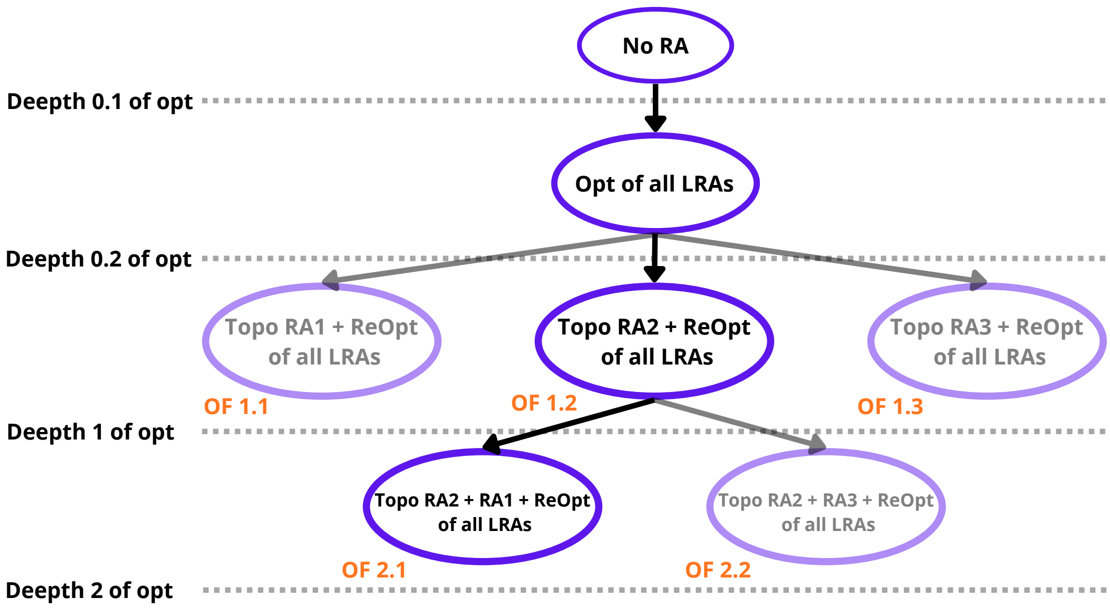


Figure 2.4: Search-tree of the CASTOR algorithm (Source: PowSyBI description [4]).

Generation redispatch

Generation redispatch (RD) is defined as a measure implemented by one or more transmission system operators through the adjustment of generation levels, with the objective of modifying physical power flows in the transmission network and relieving congestion [44]. When this action is carried out by a single operator, it is referred to as internal redispatch, and when multiple operators coordinate their actions across different control areas, it is known as cross-border redispatch [6]. The principle of the redispatching is to increase (respectively decrease) the production of certain generation units, and, to maintain a production equal to consumption for balancing, other units must decrease (respectively increase) their productions. The net cost of these actions is usually positive, which is why redispatch is considered a costly RA.

To exemplify a redispatch action, a configuration of a redispatch between unit 1 and unit 2 is considered (Figure 2.5). Prior to the application of the redispatch, the line is loaded at 105%, which exceeds its operational limit of 5%. This redispatch action results in a reduction in line loading of 0.05% per MW transferred, a value referred to as the remedial action sensitivity. The initial production levels, redispatch prices, as well as the downward redispatching potential (RDP-) and upward redispatching potential (RDP+) of units 1 and 2 are set to 200 MW. In this situation, the necessary redispatch to solve the congestion is 100 MW between the two units.

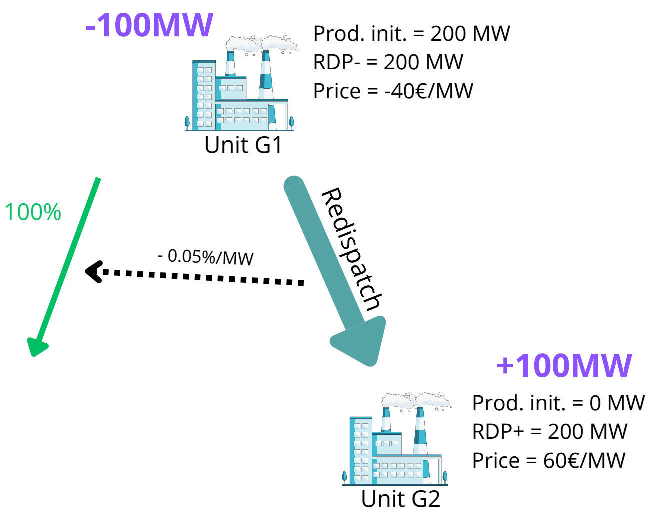


Figure 2.5: Redispatch of 100 MW between two production units with a sensitivity of -0.05% per MW redispatched to relieve an overload of 5% of a transmission line.

In Belgium, the costs of RD are based on real and avoided production costs. It is not a market logic with supply and demand, but rather an economic neutrality logic for the activated unit. The upward RD cost is the compensation for the fuel costs paid by the TSO to the electricity producer. It is a positive price. On the other hand, a decrease in production avoids some fuel usage, and therefore the downward RD cost for thermal power plants is often negative, representing that the producer gives money back to the TSO. However, with regard to renewable energy sources, the marginal cost is very low and a production decrease can induce some losses of green certificates (and associated revenue); therefore, the downward RD cost for RES is positive.

This total RD process is usually a costly RA [44], since downward costs are often lower in absolute value than up-regulation costs, and it starts from a market schedule that aims to optimise its decisions.

In this example, the total cost of redispatch is calculated as follows:

$$\begin{aligned} c_{tot} &= 100MW * -40€/MW + 100MW * 60€/MW \\ &= -4000€ + 6000€ \\ &= 2000€ \end{aligned} \tag{2.5}$$

This remedial action is already used in the National Control Center (NCC) when non-costly remedial actions like PSTs or topological changes are not sufficient or less effective. As PSTs, redispatch RA can be considered as a linear remedial action [4].

2.1.4 Preventive and curative remedial actions

Two categories can be defined for the remedial action activation methods: preventive and curative RAs. In the framework [40], these two categories are defined as follows:

- A preventive remedial action is applied before the occurence of a potential contingency. It is determined through the operational planning process and must be implemented in advance of the considered timeframe to ensure the system complies with the "N-1" security criterion.
- A curative remedial action is applied immediatly after the occurence of a critical contingency for which the need of the actions has been identified during operational planning. It is applied in order to re-establish compliance with the "N-1" criterion, after contingency, in the permissible violation duration of the critical element.

In Figure 2.6, preventive remedial actions (PRA) and curative remedial actions (CRA) are illustrated with respect to the occurrence of a contingency (PRA is pre-fault and CRA is post-fault). These actions are closely linked to the thermal limits of transmission lines, namely the permanent admissible transmission loading (PATL) and the temporary admissible transmission loading (TATL). In a basic RA management, the preventive actions aim to ensure that, under normal operation and in anticipation of a contingency, line loadings remain below the PATL, therefore guaranteeing continuous compliance with security constraints. However, following a contingency, line loadings may temporarily exceed the PATL while remaining below the TATL, which represents a short-term thermal margin. Therefore, for more developed RA management, preventive action aims to ensure limits under TATL, when curative actions are activated only if a contingency occurs and bring back the critical element(s) below their PATL. The advantages of using curative measures is a lower RAs usage while maintaining a secure network. Indeed, curative remedial actions are required to exploit this temporary overload capability while ensuring that the system is brought back within permanent limits within an acceptable time frame, and are exploited only if the contingency really appears, which has a very low probability. This combination of preventive and curative measures enables a lower action sets of RAs and a more efficient use of the grid while maintaining system security [4, 45].

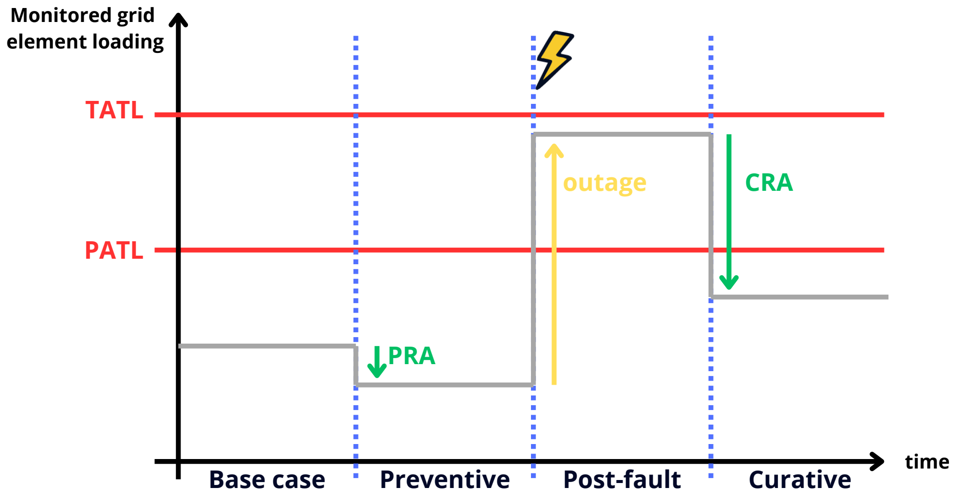


Figure 2.6: Preventive and curative remedial actions in relation to thermal line limits (PATL and TATL) (Source: presentation Elia [5]).

PSTs, RD and topological modifications can be used as both preventive RAs and curative RAs. However, for CRA, the range of actions is typically more limited. This work focuses principally on the usage of preventive remedial actions, considering permanent limits.

2.1.5 Current congestion management and costs

Current management of the congestion in the NCC

Short-term congestion management in transmission grids is manually handled by operators in the control room. These operators monitor the grid for short-temr management, from day-ahead to real-time and take actions when needed to ensure secure operation. In Belgium, this activity is carried out in the National Control Centre (NCC). Other aspects related to system stability are also managed there, but they are outside the scope of this work.

Currently, in case of an "N" or "N-1" violation, the selection of remedial actions (RAs) is entirely based on the operators' expertise and knowledge of the grid. As a result, the decision-making process is not automated and depends on human judgment, although it is supported by significant operational experience.

Redispatch activations and costs

In this work, the focus is mainly on the analysis of the behaviour of redispatching. A study of the frequency of use and costs is conducted using the Elia open data website [6]. First, numerous internal redispatch activations can be observed (Figure 2.7). It can be seen that in 2024, there was a peak in redispatching, with more than 45 GW activated in a single month. Otherwise, the average activation per month is about 6 GW. A redispatch activation corresponds to a change in the production for 15 minutes, and varies between 10 and 600 MW, with a mean of about 150 MW of redispact per action.

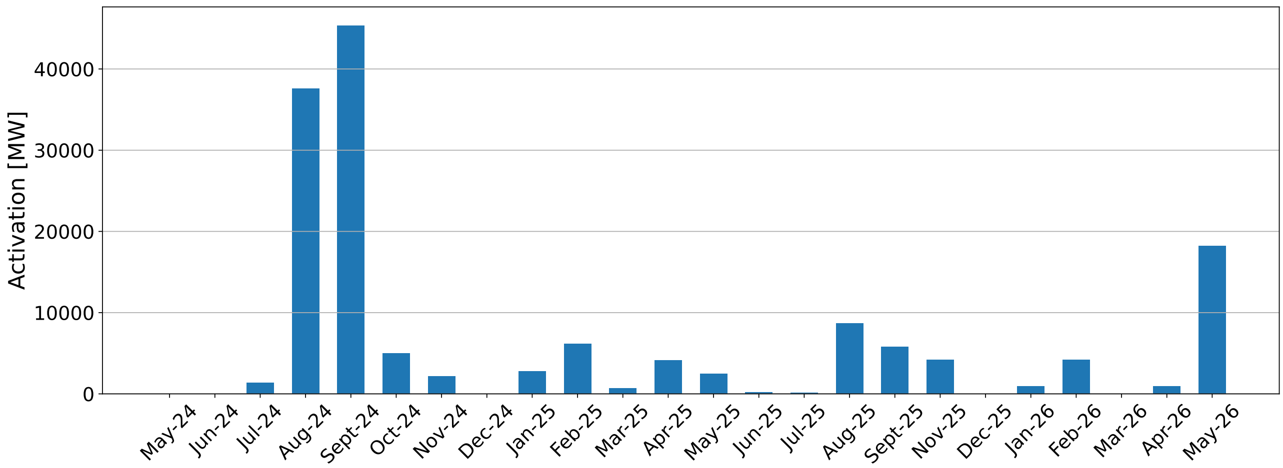


Figure 2.7: Internal redispatching activation in Belgium (Source: Elia website [6]).

In Figure 2.8, the monthly cost of redispatching applied to Belgian congestion is represented, from 2019 to 2026. In the past, the cost reached its highest point in February 2022 at around one million euros. On average, from March 2019 to February 2026, the RD costs 84 k€ per month. These costs are not significant compared to Elia's annual revenue, which has exceeded three billion euros per year since 2022 [11]. Nevertheless, according to Commission Regulation 2017/1485 [23], Article 21, the primary criterion for selecting remedial actions is their effectiveness and economic efficiency. Therefore, the process for selecting appropriate remedial actions must be based on their cost. In Belgium, redispatch costs are relatively low due to the country's smaller size; however, these costs are higher in other countries. Across Europe, the total cost of remedial actions to mitigate grid congestion in 2024 reached 4.3 billion euros, representing an increase of 5% compared to the previous year [46]. This cost is expected to continue increasing over the years, which makes the focus on cost minimisation relevant.

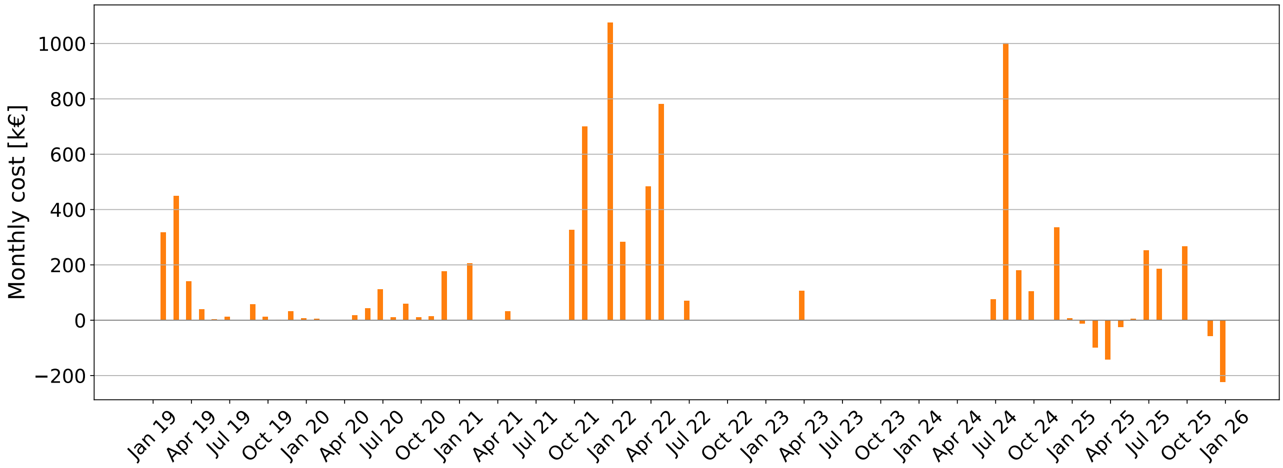


Figure 2.8: Internal redispatching cost in Belgium (Source: Elia website [6]).

Moreover, some negative prices can be observed in 2025 on Figure 2.8. This behaviour will be part of the main focus of this document and will be explained later.

N.B. Costs linked to remedial action for congestion management are the responsability of the TSOs. When the redispatching is performed to solve a Belgian congestion, Elia pays 100% of the price. But when congestion occurs on cross-border lines, the price is shared between the two TSOs involved.

2.1.6 Limitation and motivation for advanced remedial action coordination

Current congestion management practices present several limitations. As highlighted previously, the cost of the redispatching can be significant (main costly RA, with counter-trading but this action is not studied here). Moreover, the decision-making process is still largely based on operator experience/feeling and heuristic rules, rather than on systematic and optimised approaches. As a result, the selection of remedial actions does not guarantee an economic and technical optimum. In addition, the current congestion management is often performed at a local level, within the control area of the TSO. A lack of coordination between TSOs may lead to an inefficient global outcomes, such as displacement of the congestion to neighbouring regions. Finally, as explained in section 1.1.1, the increasing complexity of the process, due to a growing number of congestions and remedial actions, makes the overall process increasingly difficult to manage.

With the increasing complexity of power systems, the increasing number of operational constraints, and the large-scale integration of renewable energy sources, traditional approaches to remedial action management are progressively approaching their limits. These methods may no longer be sufficient in the future to ensure global optimality, coordinated decision-making, and cost-efficiency. This context motivates the development of advanced optimisation tools for remedial action coordination.

2.2 Remedial action optimiser: Concept and principles

As observed in the previous section, the rapid increase in network management complexity means traditional congestion management methods are gradually reaching their limits. Therefore, the remedial action optimiser tool has been developed.

2.2.1 Definition and objectives of the RAO

The remedial action optimiser (referred to as RAO) is a decision-support tool used by TSOs to identify and evaluate optimal solutions for managing congestion, performing capacity calculation, or even controlling voltage levels on the grid. Although the RAO has several applications, this work focuses exclusively on its use for congestion management.

More specifically, the RAO for congestion management identifies and evaluates congestion on the grid (through security analysis), then selects the most effective measures, known as remedial actions, to relieve congestion and secure the grid [47]. It ingests network data such as power flows, topology, contingency analysis, operational limits and more, and runs an optimisation to determine the set of options which resolves congestion at the lower prices. Decision variables of the optimiser are the remedial actions (later called RAs), which can be either non-costly or costly as explained in the previous section. For each set of RAs, the optimiser evaluates technical feasibility, expected effect on power flows, asset availability and economic impact, and then computes the combination that most effectively reduces grid stress for both current conditions and "N-1" contingencies [48]. Optimising remedial actions is crucial because, in some countries, annual congestion costs due to the use of costly RAs can reach millions of euros [49]. Currently, this decision-making tool is in development, and in test period.

The RAO helps TSOs to make faster, more transparent and consistent decisions in complex environments, notably since networks become more and more complex with the renewables, cross-border flows and limited network expansion increase operational challenges. Furthermore, a development of a cross-zonal RAO for a coordination between multiple RAO may lead to a further optimum. In conclusion, the RAO will support the TSOs operational planning in real-time and intra-day, improve their efficiency and security by resolving congestion preventively and cost-effectively to maintain the security of the network [48].

2.2.2 Mathematical formulation

The Remedial Action Optimiser (RAO) for congestion management can be interpreted as a specialised variant of the Optimal Power Flow (OPF), specifically designed for this purpose. Unlike a standard OPF, which optimises generation dispatch over the entire system, the RAO focuses on identifying the optimal combination of remedial actions (such as redispatch and PST adjustments) to ensure network security.

The RAO is a static optimisation problem. At a given time step, the electrical network is assumed to be in a steady-state operating condition, and no dynamic behaviour of the system is explicitly modelled. Therefore, the optimisation problem is based on equations representing power flows and operational constraints. The RAO problem is typically formulated as a constrained optimisation problem, which can be expressed as a mixed-integer linear program (MILP). Continuous variables are generally used to represent quantities such as power flows or redispatch levels, while discrete variables may be introduced to model the activation of specific remedial actions (e.g., position of the PSTs). The optimisation problem is solved using dedicated mathematical solvers such as Cbc (Gurobi and CPLEX can also be used with a licence), which are capable of handling large-scale problems under strict computational time constraints [50, 51].
In practical applications, the complexity of the RAO problem requires the use of simplified network models. In particular, DC load flow approximations are often employed in order to linearise power flow equations and ensure computational tractability. This simplification introduces a trade-off between accuracy and

computational efficiency, which is critical in operational contexts where solutions must be obtained within tight time limits. Furthermore, the RAO optimisation must be performed repeatedly throughout the day, requiring robust and scalable solution methods capable of delivering high-quality solutions within limited execution times. For this reason, some optimisers perform the optimisation using DC power flow approximations and a linearised formulation of the problem. The impact of remedial actions is then represented through sensitivity factors, such as Power Transfer Distribution Factors (PTDFs), which enable a linear approximation of the network behaviour. To ensure the validity of the optimisation results and verify their consistency with the actual network behaviour, an AC power flow calculation and security analysis are subsequently performed.

The description of the algorithm presented here is based on the PowSyBl documentation, which is one of the software tools used in this work. PowSyBl is an open-source framework that provides a comprehensive description of the OpenRAO implementation [4]. A more detailed presentation of PowSyBl and its functionalities is provided later in this work, in Section 4.2. The objective function, the main constraints and the control variables are described to have a global overview of the algorithm.

Objective function

The objective function of the RAO studied here is a minimisation of the cost of remedial actions, since the goal is to solve the congestion in the more economic way. The equation is divided in two main parts: the remedial actions expenses, and the penalty for a violation of the loading constraints. The main part of the algorithm ideas and equations are described by PowSyBl for the OpenRAO [52]. All the following equations are taken from this documentation. The objective function is constructed as follows:

$$\text{Minimize} \quad \underbrace{\sum_{r\in\mathcal{RA}}\sum_{s\in\mathcal{S}} c(r,s)}_{\text{Functional cost = remedial actions expenses}} \quad + \quad \underbrace{P_{\text{overload}} \times MMV}_{\text{Virtual cost = penalty on minimal margin violation}} \tag{2.6}$$

Where

- $r \in \mathcal{RA}$ is the index of remedial actions is the set of all remedial actions $\mathcal{RA}$;
- $s \in \mathcal{S}$ is the index of network situations for which remedial actions are optimised in the total set of state $\mathcal{S}$;
- c is the functional cost of the RAs (developed later).
- $P_{overload}$ is the penalty cost of not having a secured network;
- MMV is the minimal margin violation which reprents the shortfall (in MW or A) needed to satisfy the required margin.

Constraints

The constraints are also developed in PowSyBl documentation [52]. The main constraints of the optimisation problem are developed as follows:

- Functional costs:

$$c(r,s) = \begin{cases} c^{act}(r)\,\delta(r,s) & \text{if } r \text{ is a network action,} \\ c^{act}(r)\,\delta(r,s) + c_{\Delta}^{+}(r)\,\Delta^{+}(r,s) + c_{\Delta}^{-}(r)\,\Delta^{-}(r,s) & \text{if } r \text{ is a range action.} \end{cases} \tag{2.7}$$

With

- $c^{act}(r)$ is the activation costs of a remedial action r;
- $c_{\Delta}^{-}(r)$ is the cost of negative variation of remedial action r, such as shifting an HVDC or RD's set point by -1 MW, or to decrease of one tap for the PSTs;
- $c^{+}(r)$ is the cost of positive variation of remedial action r, such as shifting an HVDC or RD's set point by +1 MW, or to increase of one tap for the PSTs;
- $\delta(r, s)$ is a binary variable showing if the remedial action r is activated or not in state s;
- $\Delta^{-}(r, s)$ is the variable representing the amount of negative variation of remedial action r in state s;
- $\Delta^{+}(r, s)$ is the variable representing the amount of positive variation of remedial action r in state s.

This constraint highlights the two types of RAs: network actions and range actions. The network actions can only be active or inactive, e.g. topological action, and on the other side, range actions have degree of freedom, e.g. PST tap position, RD or HVDC setpoint where the set-point choices are in a given ranges.

- Impact of a RA on flows:

$$F(c) = f_n(c) + \sum_{r \in \mathcal{RA}(s)} \sigma_n(r, c, s) \left[A(r, s) - \alpha_n(r, s)\right], \quad \forall c \in \mathcal{C} \tag{2.8}$$

with

- $\mathcal{C}$ is the set of Critical Network Element and Contingency, also called CNEC (all the couple critical branch and critical outage, called CBCO) and c the index of the current CNEC studied;
- F(c) is the flow of the element c;
- $f_n(c)$ is the reference flow of the element c at the beginning of the current iteration of the MILP, around which the sensitivities are computed;
- $\sigma_n(r, c, s)$ is the sensitivity of the RA r on CNEC c for state s;
- A(r,s) is the set-point of the RA r on state s;
- $\alpha_n(r, s)$ is the set-point of the RA at the beginning of the current iteration of the MILP, around which the sensitivities are computed.

Sensitivity: The parameter $\sigma_n(r, s)$ in the previous equation is the sensitivity of the remedial action. For redispatch, the sensitivity is also known as the power transfer distribution factor (PTDF). The PTDF is defined in the article of R. Baldick by "the relative change in power flow on a particular line due to a change in injection and corresponding withdrawal at a pair of busses" [53]. The impact of a RA on the CNEC depends on the topology, therefore is calculated for the reference set-point [53]. Mathematically, the sensitivity of one redispatching remedial action r can be visualised as the change of active power on the CNEC for one 1 MW of modification of production of this RA (Equation 2.9) [54]. The unit of the PTDF is MW/MW.

$$\Delta P(c, s) = \sigma_n(c, s) * 1MW \tag{2.9}$$

The sensitivity of the PST is called the PSDF (phase shift distribution factor) and is almost similar to PTDF. Its unit is in MW/tap and is the impact on a CNEC for a change of one tap of the PST.

- Set point variations:

$$A(r,s) = A(r,s') + \Delta^+(r,s) - \Delta^-(r,s), \quad \forall (r,s) \in \mathcal{RA} \tag{2.10}$$

with A(r,s') is the set-point of the range action r, but at a state preceding s.

The set-point of a range action in a given state s is obtained by starting from its previous value and adding the upward adjustment while subtracting the downward adjustment applied in that state.

- Injection balance constraints:

$$\sum_{r \in \mathcal{IRA}(s)} \left(\Delta^+(r,s) - \Delta^-(r,s)\right) * \sum_{d \in \mathcal{DK}(r)} d = 0, \quad \forall s \tag{2.11}$$

where d is the injection distribution keys, binary indicators to indicate if an RA r has an impact of the production units.

- Maximum loading constraints:

$$F(c) \leq f_{max}(c) - MM, \quad \forall c \in \mathcal{C} \tag{2.12}$$

where f_{max} is the maximum flow capacity limit of an element and MM is the minimal margin available on all monitored network elements.

- Security margin:

$$MM + MMV \geq \Delta_{\text{secure}}, \qquad MMV \geq 0, \tag{2.13}$$

where Δ_{secure} is the security shift. It is a parameter of security forcing the load of a line to be lower from its maximum of a certain value.

Constraints can be hard or soft. In the case of hard constraints, the solver searches for any feasible solution, regardless of cost. If no solution exists, the problem is declared infeasible, and the solver stops. To ensure that the RAO can always propose a solution, constraints are often defined as soft constraints. A penalty is associated with the violation of these constraints. This penalty is set to be very costly in order to force the optimiser to accept constraint violations only when no feasible solution exists without them (price about 150 k€/percent of violation).

Soft constraints can be either linear or non-linear. Non-linear soft constraints enable the optimiser to impose a higher penalty for significant violations, while being more permissive (lower penalty) for minor violations. Unlike linear constraints, where the penalty is directly proportional to the magnitude of the violation, non-linear penalties increase more rapidly as violations grow. Therefore, it favours solutions with a larger number of small constraint violations rather than solutions with only a few large magnitude violations. This reflects the fact that from a network security perspective, a small number of large overloads are more dangerous than several small ones. Non-linear soft constraints are therefore implemented.

Control variables

The number of control variables in the RAO problem can be very large, depending on the set of remedial actions (RAs) considered. Each remedial action introduces one or several decision variables representing its activation or set-point level. Consequently, the size of the optimisation problem increases significantly as more remedial actions are included, enlarging the solution space available to the RAO.

The control variables typically correspond to the adjustable parameters of the power system that can be used to mitigate congestion. In this thesis, the set of RAs is limited to:

- tap position of PSTs, which influence active power flows by modifying phase angles,
- redispatch levels of generation units, used to reallocate power injections across the network, and
- topological modifications of the network (e.g., line disconnections or busbar reconfigurations), which alter the network configuration and redistribute power flows.

Other remedial actions and therefore control variables can be taken into account in other RAO.

Example of an RAO proposition

To better understand the operating principle of this optimiser, a simple example is presented (Figure 2.9). First, the network is analysed through a security analysis to detect potential congestion under both "N" and "N-1" conditions (see Section 1.2.4 and Section 1.2.3). If congestion is identified, for example, a transmission line loaded at 105%, i.e. 5% above its thermal limit, the optimisation process is triggered. The RAO then explores different combinations of remedial actions to relieve the congestion, while maintaining the overall system secure and minimising the associated cost. In the example below, the optimiser proposes adjusting two PST tap positions and performing a 50 MW redispatch. Finally, a security analysis is carried out to verify that the solution ensures safe operation. With the RAO solution, the operator knows the most economical way to relieve congestion and, while taking into account additional security criteria such as voltage management, can implement the proposed set of remedial actions in the network.

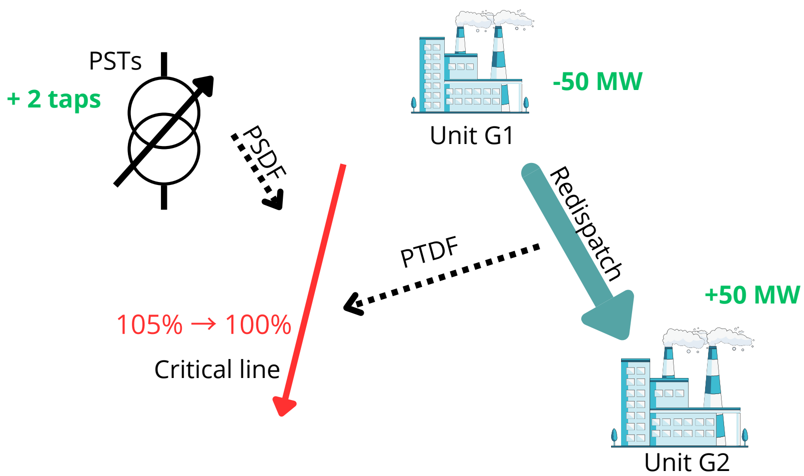


Figure 2.9: Proposed remedial actions by the RAO after one overload of 5% has been detected on a line by the security analysis.

2.3 One of the challenges of the current RAO

Using a remedial action optimiser for congestion management in Belgium is new and therefore still in development and currently improving. Different problems have been identified in the actual implementation of the optimiser, and this work tackles one specifically: the problem called market re-optimisation.

The issue on the RAO presented here is called the market re-optimisation. As explained above, the objective function of the RAO is a cost minimisation of the set of remedial actions applied. For this reason, it can happen that some redispatching is interesting purely for economical gain, rather than for the management of the congestion. In an internal analysis of the desired and undesired RAO behaviours [55] made by Elia and the TSOs from the CORE region for the ROSC project (a multi-TSO projects to create an international RAO), this feature is called the Profit-driven redispatch, i.e. the RAO will always search for the least-cost solution. For this reason, some unnecessary RD can appear because a down-regulation will be more profitable than an up-regulation of a cheaper generator. The net result will be a negative cost, a profit.

Actually, the redispatch applied is not necessary to relieve a congestion. It is only proposed by the RAO to allow the objective function to obtain a lower value than without it. The behaviour is undesirable and unacceptable because the transmission system operators are subject to legal obligation given by the European Union (as explained in Section 1.2.1). The optimisation of the market is the role of the market operators and not the TSOs, which must focus on the security of the grid. Therefore, the TSOs have the possibility to do some variation in the production, only for the sake of the stability of the grid, and not for economic reasons only. In the European Union, the legal statements that TSOs must follow are developed in the Commission Regulation. There, it is indeed specified according to the System Operation Guideline (SOGL), in Recital (5) of Regulation (EU) 2017/1485, than:

> « All TSOs should comply with the common minimum requirements on procedures necessary to prepare real-time operation, to develop individual and deliver common grid models, to facilitate the efficient and coordinated use of remedial actions which are **necessary for real-time operation in order to maintain the operational security, quality and stability** of the interconnected transmission system, and to support the efficient functioning of the European internal electricity market and facilitate the integration of renewable energy sources ('RES'). » [23]

Moreover, in Article 20 of the Commission Regulation [23], it is specified that TSOs shall design, prepare, and activate RAs to prevent or manage operational security violations. The two regulations highlight that the TSOs have the responsibility of the security of the grid, and for that have the possibility to change the market, but only for that reason and not for economic reasons only.

The problem of market re-optimisation is specific to European countries, due to the liberalisation of energy. In Europe, today, market activities and network security are managed by separate entities, meaning that TSOs do not have direct control over electricity generation and cannot initially optimise the market to address grid congestion. As a result, any interventions by TSOs in the market must be minimised and applied only when no other measures are possible. This separation between market operations and system operation is uncommon worldwide and is a specific characteristic of the European electricity system.

Market re-optimisation issues may arise in different configurations. Two illustrative examples are developed. First, in a network with a single congestion that can be resolved solely through phase-shifting transformer actions, the optimiser may still propose additional redispatch actions in addition to the tap changes. These redispatch actions have little to no impact on relieving the congestion but are selected by the RAO because they generate profit, thereby reducing the value of the objective function. A second example occurs when a certain level of redispatch between several units is sufficient to alleviate congestion, yet the optimiser proposes a larger amount of redispatch, leading to a significantly negative objective function. In both cases, additional and unnecessary redispatch actions are selected by the optimiser with the aim of decreasing the overall cost of the problem.

This phenomenon can be observed in large-scale power systems, where unusually high redispatch volumes (in MW) combined with significantly negative total costs may appear for a congestion that is relatively easy to resolve. In such situations, it becomes relatively straightforward to identify that the set of remedial actions selected by the optimiser includes elements of market re-optimisation. However, in more complex configurations, where the optimal solution for congestion management alone is less obvious, it becomes more difficult to determine whether profit-driven redispatch actions have been selected by the RAO.

Finally, the market re-optimisation issue has an undesired side effect. When some redispatching have negative cost, these ones are prioritised by the RAO compared to non-coslty remedial actions, own by the TSO, such as PSTs and topological changes. These non-costly measures must be prioritised, as RD must remain an exceptional measure, and used only when non-costly actions are not sufficient on their own to relieve congestion.

2.4 State of the research about market re-optimisation issue

The objective of this thesis is to identify a solution to the problem of market re-optimisation described above. This issue was highlighted in studies conducted for the ROSC project, where experts, in collaboration with Elia, observed this unwanted behaviour and initiated the search for potential solutions. As this research has not yet been published, the material presented here is based on internal studies carried out within the company. Since this issue is specific to Europe, where market operations and network security are managed by separate entities, and given that RAO is still under development, there are currently no published sources that directly address the market re-optimisation problem. This section therefore presents the work of these experts in order to analyse the current state of research on this issue.

This theoretical analyses of this issue was conducted in the ROSC project, supported by FGH [7]. In this study, a simple configuration was used to investigate the theoretical effects of market re-optimisation and of introducing a penalty on redispatch, aimed at discouraging exchanges between generation units. Initially, a line is overloaded by 5% (Figure 2.10) and two redipsatch units are available. The intuitive solution to solve the congestion is to redispatch 100 MW between the two units, that decrease the line loading of 5% and solve the congestion (Figure 2.11).

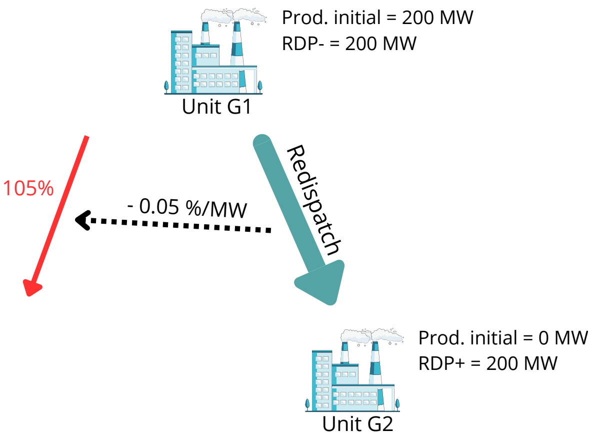


Figure 2.10: Base case schematic of a line congested with two available redispatch units.

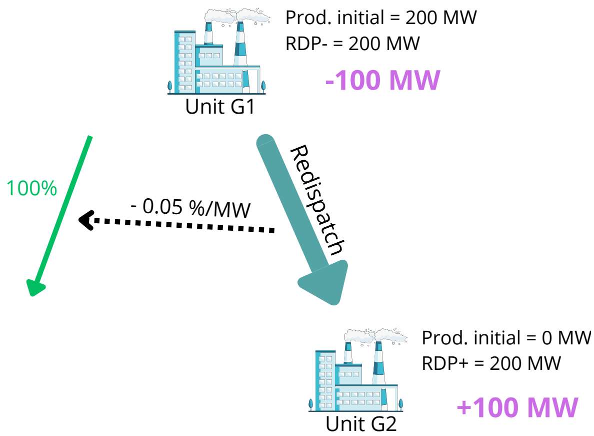


Figure 2.11: Intuitive solution to solve perfectly the congestion by using the redispatch units.

But due to the prices of the units, if market re-optimisation is possible, the RAO choose unexpected high redispatch to decrease as much as possible its objective function (Figure 2.12). It can be observed that a certain amount of redispatch is required to resolve congestion. However, the remedial action optimiser makes use of the entire available volume, as this leads to a higher negative cost. To prevent this behaviour, the experts proposed introducing a penalty cost of 5 €/MW on the redispatched volume. This penalty shifts the objective function towards positive values, effectively making redispatch artificially costly (Figure 2.13). As a result, it discourages excessive redispatch and prevents additional adjustments that would otherwise appear beneficial from the perspective of the objective function. With this penalty cost, the optimal redispatch come back to the expected value, as described above (Figure 2.11). In addition to avoid costly RD, it tends to minimise the volume. This behaviour of the RAO, is, in this configuration, interesting and desired.

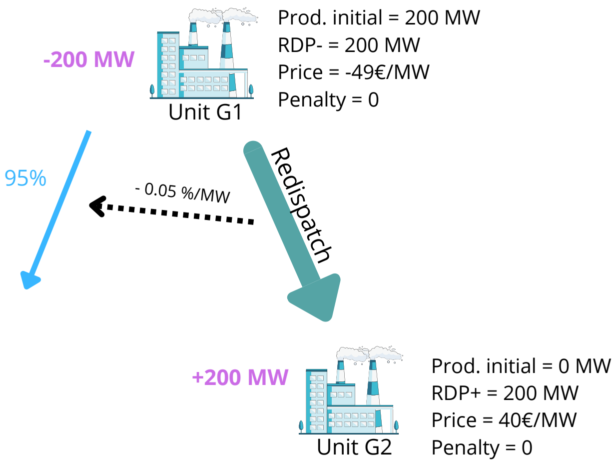


Figure 2.12: Cost minimisation results without penalty cost [7]
(Objective function = -1800€,
Total cost = -1800€,
Total penalty = 0€).

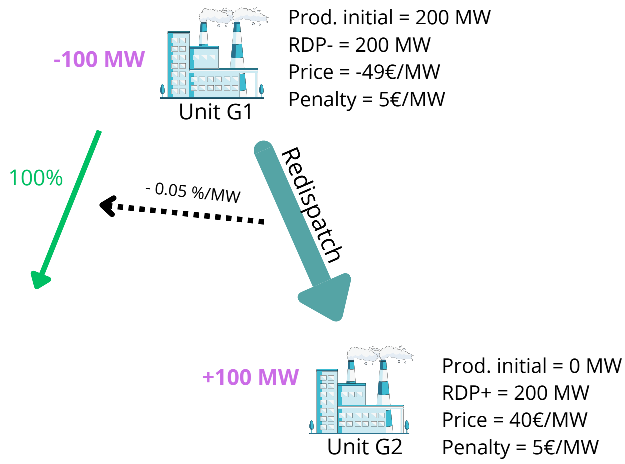


Figure 2.13: Cost minimisation results with penalty cost [7]
(Objective function = 100€,
Total cost = -900€,
Total penalty = 1000€).

Another situation is examined in the experts' presentation [7], where the introduction of a penalty cost again leads to volume minimisation, even in the absence of market re-optimisation. When no penalty cost is applied, the most intuitive and cost-effective redispatch is selected to resolve the congestion (Figure 2.14). However, when a significant penalty is introduced (here 500 €/MW), the redispatch instead involves a more efficient but more expensive unit (Figure 2.15,). This choice reduces the total volume of redispatched power, but results in higher actual costs. The inclusion of ths virtual cost forces the optimiser to favour units with a greater impact on the congestion, rather than cheaper units with lower impact. Consequently, while the total RD volume is minimised, the real costs become higher than in the case without a penalty. In certain situations, this behaviour may become problematic, as it can lead to significantly increased prices.

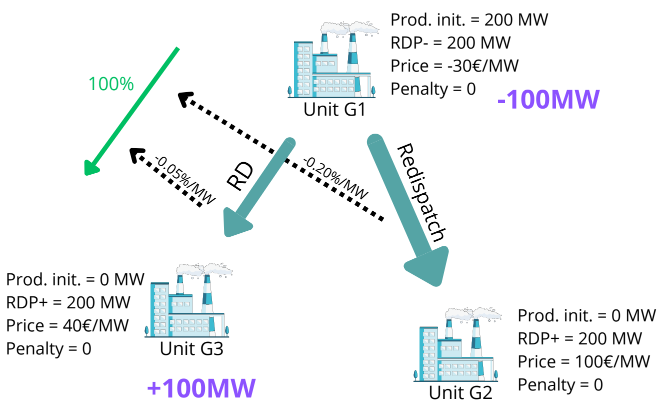


Figure 2.14: Cost minimisation results without penalty cost [7]
(Objective function = 1000€,
Total cost = 1000€,
Total penalty = 0€).

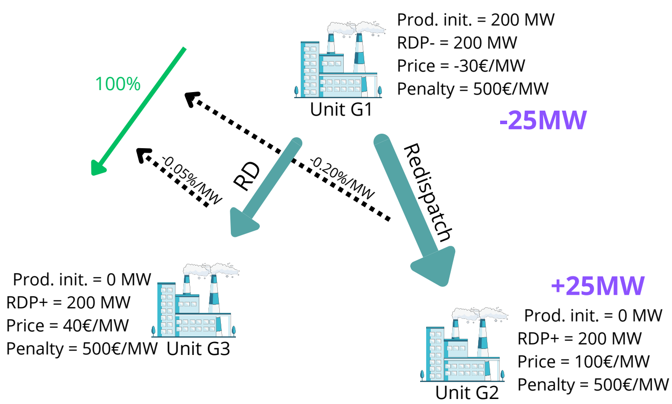


Figure 2.15: Volume minimisation results with penalty cost [7]
(Objective function = 26750€,
Total cost = 1750€,
Total penalty = 25000€).

The second study conducted by the experts focused on the research and development of an large scale optimiser for the Core ROSC model [56]. As part of this research, some simulations were performed to assess the performance of the RAO optimiser within the ROSC model. In these simulations, a grid model was used to specifically study the impact of penalty costs and sensitivities applied to the RAs. The objective was to evaluate the behaviour of the optimiser under different scenarios and to identify the effects of these parameters. For the analysis of market re-optimisation behaviour in this document, particular attention is given to the penalties applied to redispatch. The results showed that, in the absence of a penalty on redispatch, a large volume of redispatch is activated. To mitigate this undesired behaviour, the introduction of a sufficiently high penalty reduces its utilisation. The experts estimated that an appropriate value for the penalty cost lies around the mean of the highest and lowest marginal costs. This level was found to be sufficient to limit significant market re-optimisation, without requiring higher penalty values. The simulations confirmed that the total volume of redispatch was significantly reduced under this approach. However, the study did not extend beyond this initial analysis. In particular, the precise determination of the optimal penalty value was not further investigated, and potential negative impacts or unintended behaviours resulting from its introduction were not explored [56].

2.5 Specific objectives

Therefore, the objective of this work is to determine a solution that prevents profit-driven redispatch proposed by the remedial action optimiser in the context of congestion management. In addition, the aim is to compare the proposed solutions in order to identify the most effective approach to limit volume optimisation behaviour. Once the most promising solutions have been identified through theoretical analyses, the final objective is to test them on large-scale cases, here, the Belgian grid, in order to assess their overall behaviour.

Chapter 3

Proposed solutions against market re-optimisation issue

The goal of this chapter is to explore solutions to the issue of market re-optimisation, using both theoretical perspectives and small-scale models. This chapter begins with a comprehensive analysis of the proposed method in the state of the art, before exploring new ideas, while identifying the advantages and disadvantages of all methods.

3.1 Penalty costs - the idea proposed in the state of the art

The first analysis is based on the solution of adding a penalty cost, as proposed by experts. Adding a sufficiently large constant value to all redispatch costs ensures that any redispatch between units is always associated with a positive cost, thereby preventing market re-optimisation. Indeed, with a sufficiently large penalty, downward regulation can no longer generate more profit than upward regulation driven by mandatory balancing requirements.

First, the method is tested on a basic model, after which the potential drawbacks it may introduce are discussed. Finally, the most robust value for the penalty cost is calculated and explained. The case studies are fictional and are designed to highlight potential issues that the proposed solution may cause.

3.1.1 Test experimentation

To study the different proposed solutions, the analyses are done in an Excel sheet calculator for a fundamental comprehension in a largely simplified network, involving only one line and a few generators available for RD. In some simulations, one phase shift transformer will be added. In the simplified model in Excel, the objective function corresponds to the sum of the RD cost and the penalty cost for the maximum loading constraint violation. Few constraints are also implemented:

- soft constraints of maximum loading,
- limitations for generation unit range actions, from Table 3.2, and
- a balancing constraint:
$$\Delta^+ + \Delta^- = 0 \tag{3.1}$$
where Δ^+ is the amount of increased MW production (up-regulation), and Δ^- is the amount of decreased MW production (down-regulation).

To highlight the behaviour of penalty costs, a first study consists of a line congested, with two generation units and a phase shift transformer available as remedial actions (Figure 3.1). This situation is inspired by a real case observed in some testing in the Elia RAO in development for the Belgian system.

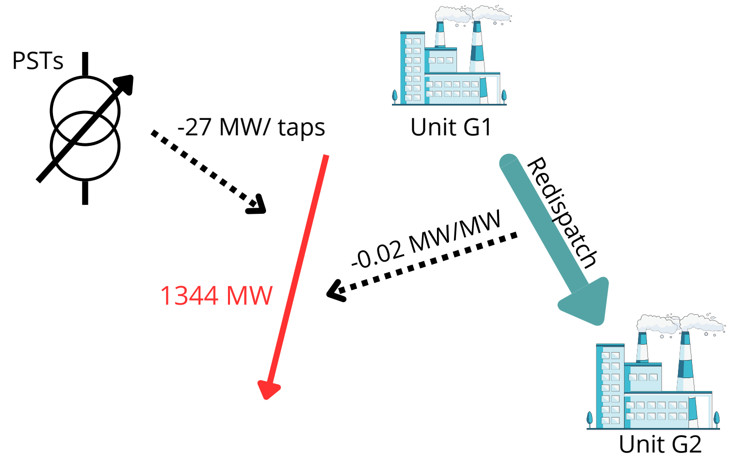


Figure 3.1: Schematic reproduction of a real case in initial "N-1" situation, with a 380 kV line congestion (maximum loading of 1301.5 MW).

In this configuration, there is a 380 kV line congested in "N-1" situation. Due to the high efficiency and non-costly nature of the PST, the optimiser is expected to select some tap changes as remedial actions. In contrast, redispatch is a costly action with very low effectiveness in relieving the congestion, so it is no expected in the solution. Two tap changes are sufficient to decrease the line below its thermal limit.

In case of a possibility of market re-optimisation (Table 3.1), the RAO proposes unnecessary redispatch. It proposes to apply two taps on a transformer and do some redispatching between the two units (Figure 3.2). The last RA provides only marginal congestion relief, but primarily enables the creation of negative costs because one generation unit incurs a higher cost when reducing its output than another unit does when increasing its production. For this reason, some market re-optimisation is observed, with negative cost results from the RAO of about -1570 €.

Table 3.1: Cost parameters for redispatch in the base case.

Units	Costs
Unit G1	Down: -78€/MW
Unit G2	Up: 72€/MW

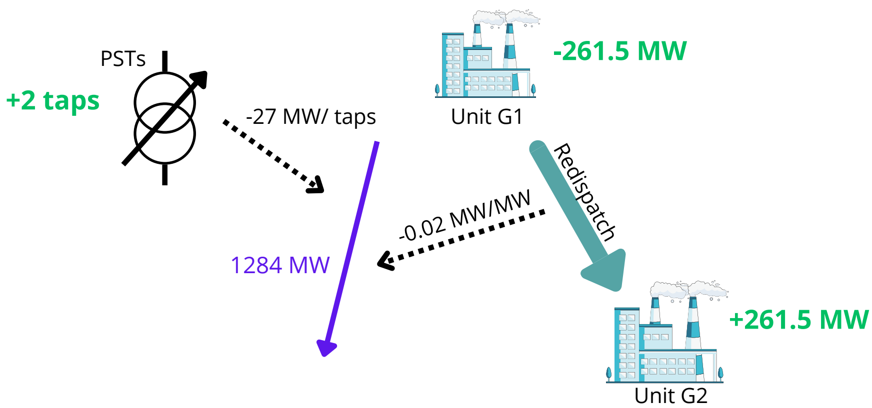


Figure 3.2: Schematic reproduction of the real case after actions taken by the RAO.

To prevent this behaviour, the addition of a penalty cost, as proposed by the experts, is added to the initial cost of all generation units G1 and G2. Its value is initially set at 10 €/MW. This additional cost has the expected behaviour and prevents correctly market re-optimisation. Indeed, since the RD had very low sensitivity on the congestion, it does not appear in the solution now that it is a costly measures. The same results are obtained when this method is tested on some specific RAO softwares. More developments on the Belgian grid with one of these software tools are developed in the next chapter.

When non-costly measures are included in the optimisation, they are correctly prioritised over redispatch, provided that a sufficient penalty cost is added to prevent market re-optimisation issues. Indeed, this additional penalty ensures that all redispatch actions incur a positive cost, eliminating the possibility of negative values in the objective function. As a result, non-costly measures become economically more attractive than any redispatch, whether its cost is real or artificially increased.

3.1.2 Drawback of the methods

Unfortunately, the addition of a constant penalty cost to all units involved in the redispatch is not perfect and can induce some undesired behaviour.

Volume optimisation

As described by the existing study, the addition of a constant penalty cost can shift the focus from cost optimisation to volume optimisation. When volume is optimised, redispatch actions may end up being more expensive than expected, which is not desirable for TSOs, as the costs of congestion management ultimately becomes their responsibility. The key questions are under what conditions this shift to volume optimisation occurs, and whether it is possible to determine an optimal value for the penalty cost that minimises the risk of volume-based optimisation, keeps redispatch costs reasonable on average, and still effectively prevents market re-optimisation.

A base case has been created to analyse this issue (Figure 3.3). One line with a maximum capacity of 1500 MW (100%) is overloaded by 75 MW (5%). Several different cases are subsequently analysed using an Excel sheet calculator to relieve this congestion. Three generators are available. The RD can be applied between G1 and G2, with a sensitivity of -0.1 MW/MW, or between G1 and G3, with a sensitivity of -0.5 MW/MW. Naturally, if the RD with G3 is less expensive, this unit will be used and no problem of volume optimisation arises, since it is both the least costly solution and the one requiring the lowest amount of MW transfer (Table 3.2).

Table 3.2: Characteristics of the three generation units available for redispatch, in the simplify case for the excel analysis.

Production units	Sensitivity	Range of production [MW]	Initial production point
Unit G1	-0.1 MW/MW	[0; 1200]	1200 MW
Unit G2	-0.2 MW/MW	[0; 600]	0 MW
Unit G3	-0.6 MW/MW	[0; 600]	0 MW

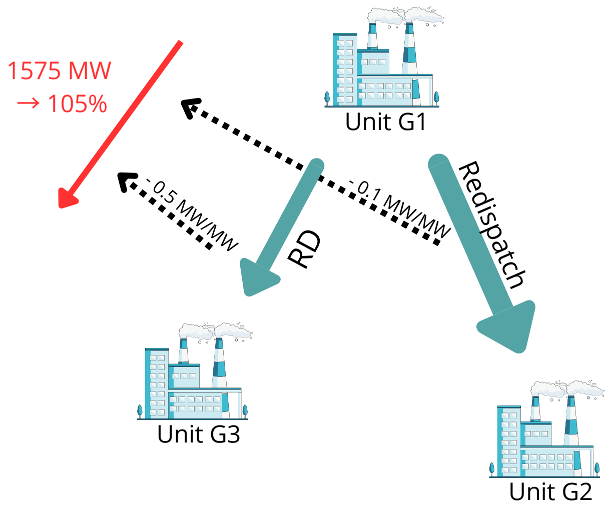


Figure 3.3: Schematic of base case for an excel analysis, with a line overloaded by 75 MW (thermal limit = 1500 MW).

Three situations have been analysed, with different RD costs data. In the first, the cost of up-regulation for G2 and G3 is lower than the cost of down-regulation for G1. Then, in case 2, only the cost for G2 is lower. And finally, in case 3, both units have a higher cost compared to the down-regulation, which means that even without a penalty cost, the redispatch is costly (Table 3.3). The penalty cost threshold is determined with the simulations. This value corresponds to the penalty cost where volume optimisation happens.

Table 3.3: RD costs of the units for the three test cases and their penalty cost threshold.

Cases	Production units	Cost of production unit [€/MW]	Penalty cost threshold [€]
1	Unit G1	-70	5.625
	Unit G2	60	
	Unit G3	65	
2	Unit G1	-70	6.875
	Unit G2	60	
	Unit G3	75	
3	Unit G1	-70	-1.25
	Unit G2	75	
	Unit G3	85	

To determine when volume optimisation occurs, the optimal redispatch, with the three cases, is analysed while increasing the penalty cost (Figure 3.4). The first graphs highlight the optimal RD configuration by showing the production of G2 and G3 (Figure a and b). The production of G1 is not represented since it is the opposite of the sum of the change of production of G2 and G3 by the equation of balancing. More than that, the line loading is also visible on the graph, represented by the red points, for each penalty cost applied to the optimisation problem. On the other hand, the second graphs highlight the evolution of the objective function value (total cost) and the real cost (without virtual cost induced by the addition of the penalty cost) in function of the penalty cost applied to the optimisation problem (Figure c and d).

With the cost of case 1, to relieve this congestion, the redispatch initially selected by the RAO induce a market re-optimisation, with an unnecessary large production of G2 (Figure 3.4a and Figure 3.4c). The addition of a penalty cost larger or equal to 3 €/MW prevents this behaviour, since the up-regulated generator G2 will have a lower price than the down-regulation happening in G1 for the balancing. The up-regulated cost of G2 is still lower, but the optimal solution includes a complete use of this unit, whether a redispatch with it induces a positive or negative prices, because it is not sufficient to completely solve the congestion by itself. There, the penalty cost works as designed, the loading of the line comes back to 100% and does not go further. But with a penalty cost higher than five, the RAO no longer chooses to use generation unit 2, even if it is less costly per MW, and instead prefers to use a lower amount of MW production from generator G3 (from 30 to 150 MW produced by G3). This choice is driven by the fact that it is more cost-effective to use a smaller volume of MW at a higher price per MW, resulting in a lower overall cost. This simulation highlights the replacement of a cost optimisation by a volume optimisation. The real cost of this volume optimisation is higher with a total RD cost from -6150 € to -750 € with a penalty cost higher than 5.625 €/MW.

With a penalty cost between 3 and 5.625 €/MW, the overload is managed as follows:

$$1575 - 0.1 * (-630) - 0.2 * 600 - 0.6 * 30 = 1500. \tag{3.2}$$

With a penalty cost above 5.625 €/MW, the overload is managed as follows:

$$1575 + 0.1 * 150 - 0.2 * 0 - 0.6 * 150 = 1500. \tag{3.3}$$

To determine the penalty cost threshold, the situation where the cost of the two configurations is equal must be found:

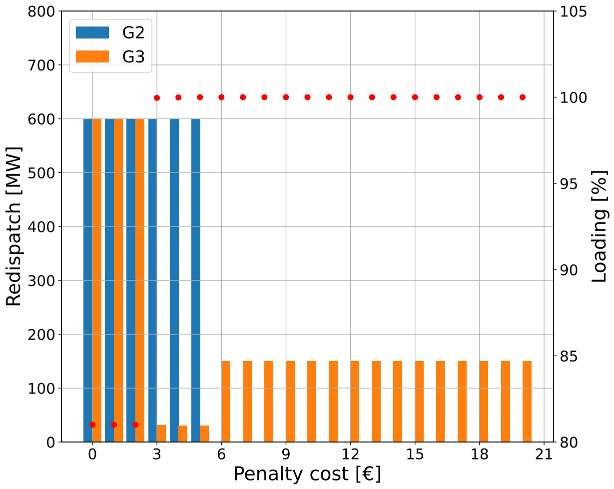
$$\begin{aligned} &\Delta G2_1(c_{G2} + pc) + \Delta G3_1(c_{G3} + pc) \\ &\quad + (\Delta G2_1 + \Delta G3_1)(c_{G1} + pc) = \Delta G2_2(c_{G2} + pc) + \Delta G3_2(c_{G3} + pc) + (\Delta G2_2 + \Delta G3_2)(c_{G1} + pc) \\ &600(60 + x) + 30(65 + x) + 630(-70 + x) = 0(60 + x) + 150(65 + x) + 150(-70 + x) \\ &\iff x = 5.625 \end{aligned} \tag{3.4}$$

Where

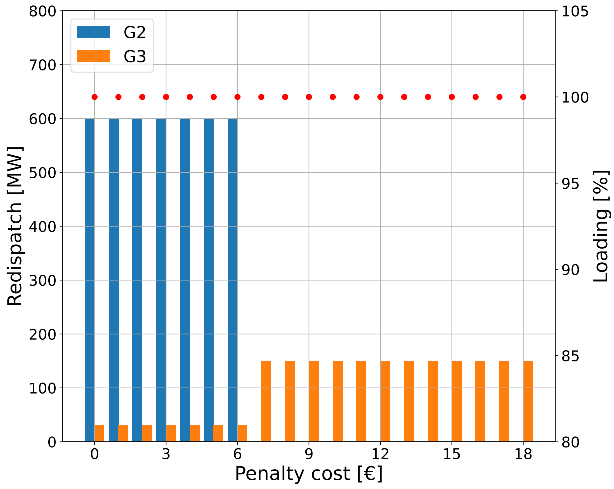
- pc and x are the penalty cost;
- c_{Gi} is the cost associate to a change of production on the generation unit i;
- ΔGi_j is the variation of production of the generator i in situation j.

In conclusion, in case 1, the acceptable value of the penalty cost is in the interval between 2.5 (limit for the market re-optimisation of generator G2) and 5.625 €/MW (limit of volume optimisation). Notice that in this situation, no market re-optimisation happens on generator G1 since the expected behaviour of RD of it corresponds to its maximal production. If the maximum upward flexibility of the unit was exceeding the amount of power required to relieve the congestion, the minimum penalty cost would be estimated at 5 €/MW, corresponding to the value needed to align the up-regulation cost of Unit G2 with the down-regulation cost of Unit G1.

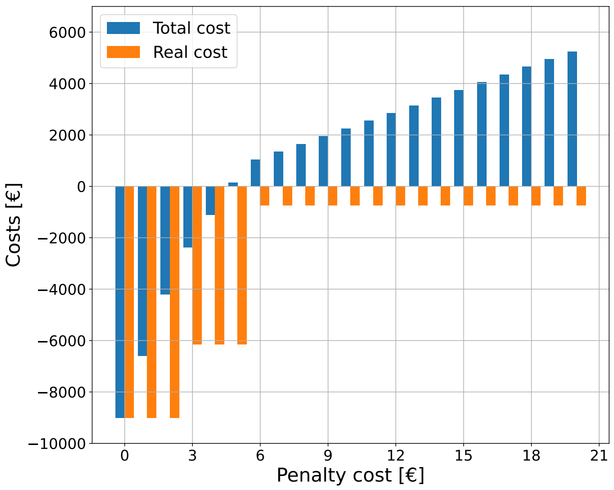
By comparison, in the second case, the generation units G3 is not be used to re-optimise the market since its price is larger than the price to decrease the production of G1 (Figure 3.4b and 3.4d). Therefore, the value of the penalty cost must be at least bigger than 5 €/MW to prevent the production of G2 to be exaggerated (force the cost of G2 to become higher than the cost of G1). But here since the maximum capacity range is taken in the optimal RD in G2, no market re-optimisation is visible, as with case 1. The threshold of the penalty cost is calculated in this situation to be 6.875 €/MW. The range of acceptable value is even lower than in the previous case, with a real expected cost of -5850 €, compared to a cost of RD of +2250 € with volume optimisation.



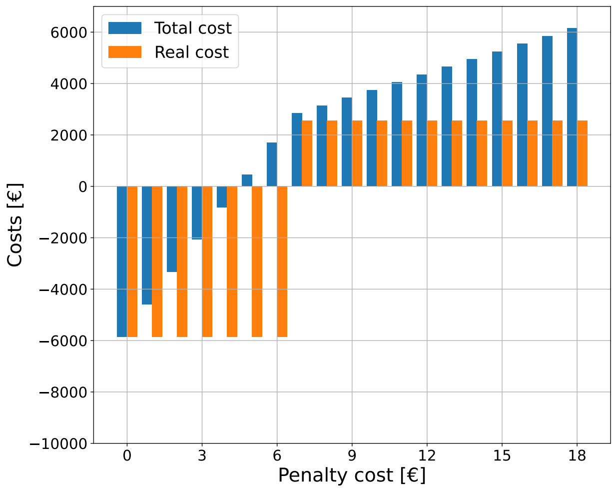
(a) Evolution of optimal redispatch and line loading with respect to the penalty cost, for the first test case.



(b) Evolution of optimal redispatch and line loading with respect to the penalty cost, for the second test case.



(c) Evolution of the objective function and redispatch cost with respect to the penalty cost, for the first test case.



(d) Evolution of the objective function and redispatch cost with respect to the penalty cost, for the second test case.

Figure 3.4: Impact of the penalty cost on redispatch volume and associated costs for two test cases.

In the third case, the initial costs do not lead to any market re-optimisation issues, so no measures are required. Nevertheless, even if a penalty cost is introduced, the penalty threshold in this configuration is negative, indicating that G3 is already more attractive than G2. Therefore, adding a constant penalty cost will not trigger any undesirable volume optimisation behaviour in the remedial action optimiser.

Mathematically, the change of the cost induce a volume optimisation because the proportionality between the RD cost is not preserved when a constant value is added to them. Indeed, the addition of a constant value to a fraction change the proportionality ratio.

$$\frac{a}{b} \neq \frac{a+x}{b+x} \tag{3.5}$$

If we compare the cost of RD between G0 and G1 or G2, and the additional term of penalty cost (pc):

$$\frac{c_{G0}+c_{G1}}{c_{G0}+c_{G2}} \neq \frac{(c_{G0}+pc)+(c_{G1}+pc)}{(c_{G0}+pc)+(c_{G2}+pc)} = \frac{c_{G0}+c_{G1}+2pc}{c_{G0}+c_{G2}+2pc} \tag{3.6}$$

The RAO does not directly compare costs only, but rather evaluates each candidate action based on the product of cost and sensitivity, i.e. the efficiency of the action in relieving the constraint. In the case where sensitivities are identical, the optimiser naturally selects the unit with the lowest cost. However, when sensitivities differ, the decision is driven by a trade-off between cost and effectiveness: a unit with a higher cost may still be selected if it provides sufficiently higher sensitivity. More precisely, a unit is selected if the increase in effectiveness compensates for its higher cost, meaning that the cost ratio must remain lower than the inverse of the sensitivity ratio. Therefore, the addition of a constant penalty cost modifies this balance by shifting the relative cost ratios between units, which in turn changes the selection thresholds. This explains why the proportionality observed without penalty is no longer preserved when a constant term is introduced.

To understand quickly this problem, here is an numerical example (Table 3.4). We have three units where the redispatch from G0 to G1 or G2 with respectively a cost of -60 €/MW, 70 €/MW and 80 €/MW. A redispatch between these units gives a cost of 10 €/MW and 20 €/MW, without penalty cost. Initially, the proportionality is 10/20 = 1/2. Therefore, if the amount of RD is more than 2 times bigger for G1 than from G2, G2 will be selected. Otherwise G1 will be less expensive. On the other hand, if a penalty cost of 10 €/MW is added, the proportionality is now 30/40 = 3/4. When more than 4/3 times more RD are needed in G1 than in G2, a RD with G2 will be the cheapest. This example illustrates the break of proportionality with the addition of a constant penalty cost.

Table 3.4: Example of the change of proportionality with the addition of a penalty cost.

Production units	**Initial cost of RD [€/MW]**	**Cost with PC = 10€/MW**
Unit G0	-60	-50
Unit G1	70	80
Unit G2	80	90
RD G0 - G1	10	30
RD G0 - G2	20	40
Report of proportionality	10/20 = 1/2	30/40 = 3/4

The parameters that influence the penalty cost threshold for volume optimisation are the initial cost of units and the sensitivity of units to congestion.

In small simulation like executed above, the threshold value can be found easily by comparing the situation with and without volume optimisation (Equation 3.4). However, in larger simulations, the complexity of the solution grows, and it becomes hard to define what is the global optimum of RD and when volume optimisation occurs. The main challenge remains therefore to be able to determine whether or not the addition of the penalty cost which remove the market re-optimisation will induce some volume optimisation or not.

In conclusion, the addition of a constant penalty cost breaks the proportionality relation between the different generation unit costs, which can induce a volume optimisation. In these situations, the RAO therefore proposes a range of RAs with a higher cost than the optimal value, without market-optimisation.

Penalty cost approaching soft constraint violation cost

The previous section highlights that setting a high value for the penalty costs is the most reliable way to prevent market re-optimisation in all cases. However, it has already been demonstrated that excessively high penalty costs can lead to an undesirable behaviour: volume optimisation, rather than cost optimisation. Additionally, another risk of using very high penalty costs emerges: if the penalty becomes too large, the cost of redispatch (RD) could become comparable to, or even higher than, the penalty associated with violating the soft constraints for the maximum loading of critical network elements.

Congestion constraints are typically treated as hard constraints. However, to ensure that the optimiser always produces a solution and avoids infeasibility, these constraints can be relaxed and treated as soft constraints. In this approach, violating a constraint incurs a penalty violation cost, rather than making the problem unsolvable. This cost is set to a large, but not infinite, value. In the current RAO, the penalty for violating a congestion constraint is set at 1500 k€ per unit of violation, where a 'unit' corresponds to the percentage overload above the maximum allowed capacity of a critical element, such as a transmission line. With this setup, the system's behaviour is well understood, and logical outcomes can be anticipated.

An example illustrates this risk (Figure 3.5), where a costly redispatch RA is available to reduce an overload on a critical line, initially loaded at 105%. It is important to note that this RA is not able to completely eliminate the congestion. The blue curves in the figure represent the RD prices as the penalty cost increases. For curve 1, the penalty cost is not too high, so the optimiser makes full use of the available redispatch resources to reduce the overload as much as possible. In this case, the total cost is the sum of the RD1 cost plus the penalty violation cost "cost 1" for the remaining overload. However, for line 3, the penalty cost is too significant, leading to a solution in which it is less expensive for the optimiser to accept a larger overload (2% instead of 1%) rather than applying additional redispatch. The threshold value is shown by situation 2, where the cost of applying the maximum available redispatch equals the cost of violating the constraint for the remaining congestion. This threshold depends on several factors, such as the sensitivity of redispatch actions on the congestion, the initial RD price, the available MW for redispatch, and the penalty cost for constraint violations.

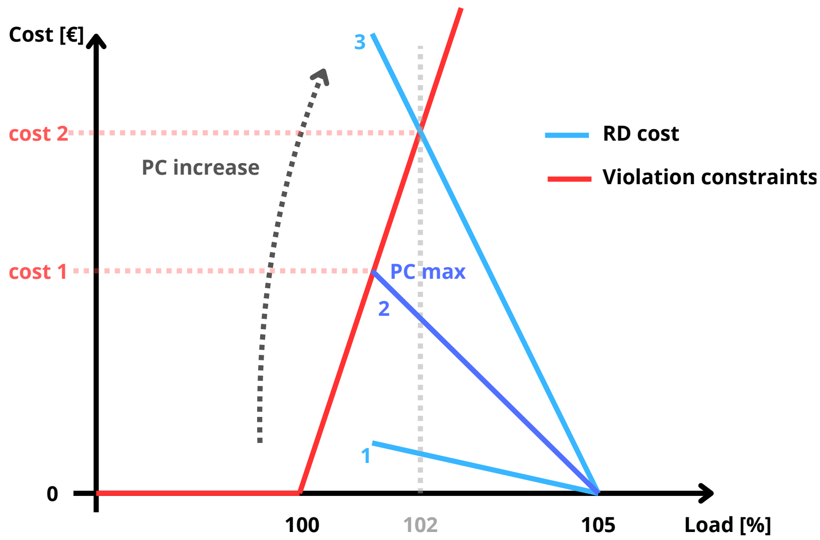


Figure 3.5: Evolution of the RD and violation of constraint cost in function of the load.

The threshold value of the penalty cost is calculated in several configurations of the base case (Section 3.1.1), with the PSTs disabled (Figure 3.6 and Table 3.5).

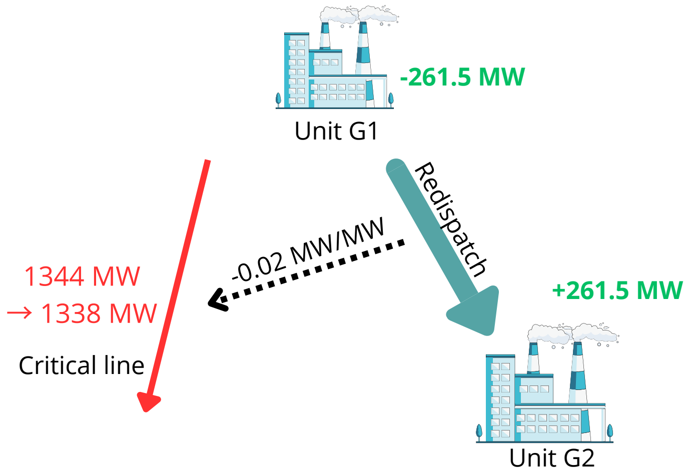


Figure 3.6: Recall: Schematic reproduction of a real case in initial n-1 situation, with a 380 kV line congestion (maximum loading of 1301.5%) and cost parameters in Table 3.5, without PST.

Table 3.5: Recall: Parameters of the real small case (Figure 3.6).

Units	**Costs**
G1	Down: -78€/MW
G2	Up: 72€/MW
Violation of constraints	1500 k€/pu

The RD are used as their maximum to reduce the overload. With 261.5 MW redispatched, the congested line loading goes from 1344 MW to 1338 MW, corresponding to a decrease of 6 MW. In this situation, when the penalty cost exceeds a threshold of 933 €/MW, no RD are taken anymore. This threshold value can be found with this formula:

$$\begin{aligned}
& c_{RD,tot} = c_{violation\ constraints} \\
\iff & \Delta RD^+(c^+_{RD} + PC_{max}) + \Delta RD^-(c^-_{RD} + PC_{max}) = c_{violation\ constraints} \\
\iff & PC_{max} = \frac{\Delta RD^+ * c_{RD^+} + \Delta RD^- * c^-_{RD} - c_{violation\ constraints}}{\Delta RD^+ + \Delta RD^-} \\
\iff & PC_{max} = \frac{\Delta RD^+ * c_{RD^+} + \Delta RD^- * c^-_{RD} - (load_{init,pu} - load_{afterRD,pu}) * c_{violation}}{\Delta RD^+ + \Delta RD^-}
\end{aligned} \tag{3.7}$$

Where:

- $c_{RD,tot}$ is the total cost due to redispatch;
- $c_{violation\ constraints}$ is the total cost induce to a violation of maximum loading constraint;
- ΔRD^+ is the variation of production for up-regulation;
- ΔRD^- is the variation of production for down-regulation;
- c^+_{RD} is the cost of the unit for an up-regulation RD;
- c^-_{RD} is the cost of the unit for a down-regulation RD;
- PC_{max} is the threshold value of the penalty cost which will lead to an equality between the cost of RD and the cost of violation of the constraint;

- $load_{init,pu}$ is the initial load of the critical line, per unit;
- $load_{afterRD,pu}$ is the load of the critical line after the application of the RD. In case of market re-optimisation, this value must be taken to the maximal loading capacity of the line and not the value inferior to its due to the re-optimisation of the market, since there is no additional cost to go from the maximal capacity to a lower value of it;
- $c_{violation}$ is the cost of violation of constraints per unit of violation.

This threshold value highly depends on the sensitivity of the RD to the congestion. Using the same use case test with different sensitivity of the RD, it can be shown that the dependence is almost linear (Figure 3.7).

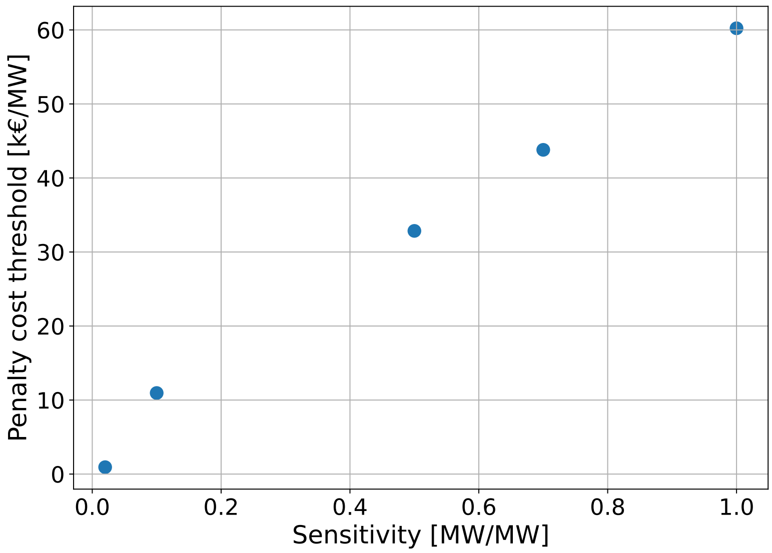


Figure 3.7: Linear evolution of the penalty cost thresholds for the real small use case without PSTs, depending on the sensitivity of the redispatch RA.

In conclusion, extremely high penalty costs should be strictly avoided to prevent issues such as unintended congestion acceptance and volume optimisation. The penalty cost should be set as low as possible, while still preventing market re-optimisation, to minimise these risks. With a limited value, it is unlikely that the penalty cost becomes comparable to the actual costs of constraint violations. Moreover, the study demonstrates that the penalty cost threshold increases significantly with sensitivity. But, if a redispatch action has very low sensitivity to the congestion, the optimiser will typically select another solution. As a result, redispatch options with bigger sensitivity are generally used, corresponding to very high threshold, avoiding this soft constraint violation cost risk.

3.1.3 Optimal penalty cost

The experts proposed calculating a penalty cost value as the mean between the lowest and highest marginal cost. A more detailed value is developed here. The most robust way to implement the penalty cost is to determine the minimum value that still effectively prevents market re-optimisation. To achieve this, all down-regulation costs (in absolute value) must be lower than all up-regulation costs. Mathematically, the required penalty cost can be found by calculating the difference between the highest down-regulation cost (absolute value) and the lowest up-regulation cost. Since the penalty is applied uniformly to all costs, only half of this difference needs to be added. For security, an addition of one unit is included to avoid equality between the costs, which could otherwise induce some random choice by the RAO, since redispatch between two units with the same cost would be invisible in the objective function. This penalty cost can be calculated as follows:

$$a = -min(RDdown_{neg}) \tag{3.8}$$
$$b = min(RDup_{pos}) \tag{3.9}$$
$$pc = \frac{a-b}{2} + 1 \tag{3.10}$$

$$c_{RD,update} = \begin{cases} c_{RD}, & \text{si } pc < 0, \\ c_{RD} + pc, & \text{si } pc \geq 0. \end{cases} \tag{3.11}$$

Where

- $RD_{down_{neg}}$ is the set of all the negative cost of down-regulation RD;
- $RD_{up_{pos}}$ is the set of all the positive cost of up-regulation RD;
- pc is the penalty cost;
- c_{RD} is the initial cost of the RD;
- $c_{RD,update}$ is the update cost of the RD.

Equation 3.11 specifies that a penalty cost must be applied only if it is positive. Otherwise, it means that no market re-optimisation was possible with the initial cost. Here is an example of the computation an application of this cost (Table 3.6):

$$\begin{aligned} a &= 100, \\ b &= 70, \\ pc &= \frac{100-70}{2} + 1 = 16, \\ c_{RD,update} &= c_{RD} + 16. \end{aligned} \tag{3.12}$$

Table 3.6: Transformation of the RD costs with an optimal penalty cost.

Generator name	**Type of regulation**	**Initial cost**	**Updated cost**
G1	Down	-50 €/MW	-34 €/MW
G2	Down	-65 €/MW	-49 €/MW
G3	Down	-75 €/MW	-59 €/MW
G4	Down	-100 €/MW	-84 €/MW
G5	Up	70 €/MW	86 €/MW
G6	Up	100 €/MW	116 €/MW

This penalty cost could still induce volume optimisation but decrease as much as possible the probability of happening. The second drawback, the risk of approaching soft constraint violation cost, is very unlikely, given that the cost associated with soft constraint violations is often much higher than the small penalty cost considered here.

3.2 Other modifications of the input parameters of redispatching

Following the analysis of how adding a constant penalty cost to the redispatch input parameters affects the RAO choices, a key undesired effect has been identified: the minimisation of redispatch volume. The remainder of this chapter explores alternative approaches to address market re-optimisation issue and observing the volume minimisation effect. In this section, three other methods that involve modifying these parameters are examined.

3.2.1 Rescaling of negative costs

The first new trick on the input parameters, latter called method 1, is a rescaling of the negative cost. This proposition was the first idea of some Elia expert, after observing market re-optimisation in a real Belgian case. Since the market re-optimisation comes from the importance of some negative costs, this method proposes to inverse the negative cost of the down-regulation of the units. To preserve the priority order between units for down-regulation, the costs are rescaled so that the unit initially identified as the most attractive remains the one with the lowest cost. The rescaling is performed such that the most negative value is set equal to the highest PST cost, while the least negative value is aligned with the cost of the cheapest up-regulating generator. The remaining units are then scaled proportionally between these two values. Finally, to avoid the more interesting down-regulation units to be set at the equal value of the more interesting unit of up-regulation, the up limit of the rescaling range is decreased by one unit. Otherwise the optimiser sees a free redispatch and some undesired behaviour could appear. Mathematically, the costs become:

$$c_{i,update} = \begin{cases} c_i, & \text{if } c_i \geq 0, \ \forall i \in GU, \\ ll + \left(c_i - \max(c^-)\right) \cdot \left(\dfrac{\min(c^+) - 1 - ll}{\min(c^-) - \max(c^-)}\right), & \text{if } c_i < 0, \ \forall i \in GU, \end{cases} \tag{3.13}$$

With

- c_i initial cost of the generator i for redispatch;
- $c_{i,update}$ updated cost of the generator i;
- GU is the set off all the generator units available for redispatching and i is the index of the generator;
- ll = lower limit = value of the more costly PSTs ≈ 0.1€;
- c^+ set of all the positive cost;
- c^- set of all the negative cost.

After the transformation (Table 3.7), all costs are positive, which correctly prevents any profit-driven redispatching. A machine is often available for up-regulation or down-regulation only. To prevent this undesired regulation from being selected, a high cost of 99999 €/MW is assigned to it. With such a value, this regulation will never be chosen. When this new method is applied, this cost remains unchanged, as it is already a positive value. Therefore, it is not be presented in the table, and only the costs of the available regulation are presented.

Table 3.7: Transformation of the RD costs with a rescaling of the negative costs.

Generator name	Type of regulation	Initial cost	Updated cost
G1	Down	-50 €/MW	69 €/MW
G2	Down	-65 €/MW	48.303 €/MW
G3	Down	-75 €/MW	34.505 €/MW
G4	Down	-100 €/MW	0.01 €/MW
G5	Up	70 €/MW	70 €/MW
G6	Up	100 €/MW	100 €/MW

This method is also subject to volume optimisation, and therefore a risk to reach higher total cost of redispatch than the real optimum. The proportionality between the values is highly changed, which leads to predominant volume minimisation issue, worst than low penalty cost.

3.2.2 Proportional decrease of the negative costs

Another method is proposed (later called method 2): divide all the costs of the generation units for down-regulation by a constant factor, e.g. 10, to force them to always be lower than the cost for up-regulation. The lower the factor is, the better the preservation of proportionality and the lower the volume minimisation.

In the reduced model, this method is effective. Indeed, if the cost to reduce production at generation unit G1 is divided by 10, it becomes lower than the cost of increasing production at G2. As a result, the total cost of the redispatch becomes positive, and the redispatch is no longer profit-driven. Consequently, market re-optimisation does not occur (Table 3.8).

Table 3.8: Transformation of the RD cost with a proportional decrease of the negative costs, with a factor 10.

Production units	Initial cost of regulation units [€/MW]		Modified cost of regulation units [€/MW]	
	Down cost	Up cost	Down cost	Up cost
Unit G1	-50	99999	-5	99999
Unit G2	-65	99999	-6.5	99999
Unit G3	-75	99999	-7.5	99999
Unit G4	-100	99999	-10	99999
Unit G5	99999	70	9999	70
Unit G6	99999	100	9999	100

This method allows the same priority order to be maintained between power plants for down-regulation. For example, the cost of a power plant might have a down cost of 99999 €/MW when a decrease in production is to be prevented, while other units might have a price of -50 and -100 €/MW. If all the down prices are divided by the same factor, the first unit remains significantly higher than the other units (9999 compared to -5 and -10 €/MW), and therefore is not used to decrease production. On the other hand, the unit with a cost of -50 €/MW remains more attractive than one at -100 €/MW. For this reason, all down prices must be divided by the same factor; otherwise, this priority order will no longer be respected, creating inappropriate behaviour in the RAO decision.

The value of 10 is arbitrary. A value that is too low will not bring all the down costs below the up costs, so the lower limit of the factor must be chosen such that the highest down cost (in absolute value) becomes smaller than the lowest cost for up-regulation. A value that is too high may have two potential problems. One is that it may make some down-regulation costs negligible, which can be problematic if the costs fall below the perception threshold of the optimiser. In this case, the priority order of the generation units for decreasing production will not be respected, and the optimiser will not be able to find the correct optimal objective value. Another is that the higher the factor, the higher the break of proportionality and therefore the bigger the risk of volume optimisation.

As with the penalty cost explained in the previous section, the proportionality between all the costs is not preserved, which will result in a possibility of volume optimisation. To avoid this problem as much as possible, the lowest possible value of the division factor should be used, and can be calculated as follows:

$$c_{i,update} = c_i \frac{U-1}{D}. \tag{3.14}$$

Where

- c_i is the initial cost;
- $c_{i,update}$ is the updated cost;
- U is the lowest cost in up-regulation;
- D is the highest down regulation cost in absolute value.

In the case presented in Table 3.8, the factor is

$$\frac{U-1}{D} = \frac{70-1}{100} = 0.69. \tag{3.15}$$

The value of the input parameters can be adapted by this factor (Table 3.9).

Table 3.9: Transformation of the RD costs with a proportional decrease of the negative costs, with an optimal factor.

Production units	**Modified cost of regulation units [€/MW]**	
	Down cost	**Up cost**
Unit G1	-34.5	99999
Unit G2	-44.85	99999
Unit G3	-51.75	99999
Unit G4	-69	99999
Unit G5	68999.31	70
Unit G6	68999.31	100

This method correctly prevent the market re-optimisation issue. It also alters less the RD costs than the previous methods, and therefore, maintains the proportionality between them more closely. Volume optimisation is expected to occur less frequently.

3.2.3 Modification of the too high cost of down-regulation

The last idea, later called method 3, is to only change the costs that can lead to a market re-optimisation, if there are any. For this, all the down-regulation costs with an absolute value greater than the minimum cost of up-regulation are modified. They are set to the opposite of this minimum upward regulation cost. To prevent the optimiser from choosing a random RD when the total price of RD between two units is zero (i.e. when up- and down-regulation costs are equal), the price is increased by one unity. The formula is detailed as follows:

$$c_{i,update} = \begin{cases} c_i, & \text{if } |c_i| \leq min(c^+),\ \forall i \in GU_{down}, \\ -|min(c^+)| + 1, & \text{if } |c_i| > min(c^+),\ \forall i \in GU_{down}. \end{cases} \tag{3.16}$$

With

- c_i initial cost of the generator i for down-regulation;
- $c_{i,update}$ updated cost of the generator i for down-regulation;
- GU is the set off all the generator units available for down-regulation RD and i is the index of the generator;
- c^+ set of all the positive costs of up-regulation units.

When applied to the set of generator prices, this method modifies only a few prices (Table 3.10). In this example, only two prices are affected by the change, while the others retain their original values. As a result, fewer redispatch proportionality changes occur, making this method promising for avoiding issues related to volume minimisation.

Table 3.10: Transformation of the RD costs with a modification of high down-regulation costs.

Generator name	Type of regulation	Initial cost	Updated cost
G1	Down	-50€/MW	-50€/MW
G2	Down	-65€/MW	-65€/MW
G3	Down	-75€/MW	-69€/MW
G4	Down	-100€/MW	-69€/MW
G5	Up	70€/MW	70€/MW
G6	Up	100€/MW	100€/MW

3.2.4 Properties of all these methods

All these methods, like the penalty cost approach, should avoid modifying the initial input parameters when market re-optimisation is not possible. Therefore, a conditional criterion must be applied before making any changes, to identify whether there are any critical costs that could lead to market re-optimisation. If no such risk exists, no modifications should be made, in order to minimise any unnecessary risks of volume minimisation by disrupting the proportionality. All this modifications can be appplied thanks to a script reading and updating the input costs before setting to the RAO. There the conditional criteria verifying the risk of market re-optimisation should be set, as follows:

$$c_{i,final} = \begin{cases} c_{i,update} & \text{if } \ min(c^+) + max(|c^-|) \leq 0 \\ c_i & \text{otherwise} \end{cases} \tag{3.17}$$

Moreover, phase-shift transformers and other non-costly remedial actions should be prioritised over redispatching. All these proposed methods are designed to ensure that only costly redispatching is used, thereby eliminating the possibility of profit-driven or free actions. As a result, in theory, non-costly actions are always selected first, before these costly RD, as intended. Therefore, no additional modification is needed, due to the good direct behaviour of all these methods.

3.2.5 Volume optimisation comparison

These three methods may induce a volume minimisation, since the proportionality reports are modified after the modification of the costs, as for penalty costs. A comparison of the method is therefore developed to detect the most promising solutions against market re-optimisation, avoiding as much as possible volume minimisation inducing larger prices.

The redispatch costs for each generator unit are presented, with the parameter modifications applied for each method (Table 3.11). When an unit is not allowed for an up-regulation (or down-regulation), its up-regulation cost (respectively, its down-regulation cost) is set to 99999 €/MW. Even when these methods are applied to such costs, the values remain so large that they do not introduce any new issues. Therefore, these costs are no longer shown in the table. To compare the new redispatch costs, the RD cost between two units is calculated as the sum of the up- and down-regulation costs, both for the initial parameter configuration and after the modifications introduced by each method (Table 3.12).

Table 3.11: Summary table of the cost transformations with the four methods (method 1: rescaling of the negative costs; method 2: proportional decrease of the negative costs, and; method 3: change of the too high costs of down-regulation.)

Generator name	**Initial cost in €/MW**	**Updated cost penalty cost in €/MW**	**Updated cost Method 1 in €/MW**	**Updated cost Method 2 in €/MW**	**Updated cost Method 3 in €/MW**
G1	-50	-34	69	-34.5	-50
G2	-65	-49	48.3	-44.85	-65
G3	-75	-59	34.5	-51.75	-69
G4	-100	-84	0.01	-69	-69
G5	70	86	70	70	70
G6	100	116	100	100	100

Table 3.12: RD costs between two units after cost modifications by the proposed solutions.

redispatch	**Initial cost in €/MW**	**Updated with penalty cost in €/MW**	**Updated cost Method 1 in €/MW**	**Updated cost Method 2 in €/MW**	**Updated cost Method 3 in €/MW**
RD G1 - G5	20	52	139	35.5	20
RD G2 - G5	5	37	118.3	25.15	5
RD G3 - G5	-5	27	104.5	18.25	1
RD G4 - G5	-30	2	70.01	1	1
RD G1 - G6	50	82	169	65.5	50
RD G2 - G6	35	67	148.3	55.15	35
RD G3 - G6	25	57	134.5	48.25	31
RD G4 - G6	0	32	100.01	31	31

It can be observed that after applying the four methods, negative redispatch costs no longer occur. As a result, the RAO can no longer select profit-driven redispatch actions, since no profit is possible. This effectively resolves the market re-optimisation problem. However, as noted in the analysis of the penalty cost drawbacks (Section 3.1.2), modifying the costs can lead to volume optimisation, which may result in higher overall costs compared to the true optimal solution.

For example, from Table 3.12 we can compare the costs of redispatching between G1 and G5 versus G2 and G5. Initially, the redispatch between G1 and G5 is four times more expensive than between G2 and G5. If both redispatches are equally effective in managing the critical outage (same sensitivity), the option involving G2 and G5 is preferred. This behaviour remains unchanged regardless of which cost modification method is applied. However, if the redispatch between G1 and G5 is four times more effective than between G2 and G5, it becomes the more attractive option with the original costs. When cost modification methods are applied, however, the threshold for this preference changes: the effectiveness threshold becomes 1.4, 1.2, 1.4, and 4 for the penalty cost method, method 1, method 2, and method 3, respectively. This means that volume optimisation occurs with the first three methods for this configuration.

In general, method 1 results in a greater change to proportionality compared to the other methods. For the remaining methods, it is difficult to establish a clear preference among them. An analysis will be carried out in the next chapter on real large-scale scenarios, where all the solutions will be implemented, to observe whether any method delivers better results.

3.3 Prohibition of negative costs

From the previous cases, it has been highlighted that market re-optimisation results from the negative prices applied to decrease the production of a power plant. Therefore, an easy intuition is to completely forbid negative prices to prevent the issue of negative RD costs. In this proposal, whenever the cost of RD is negative, it is automatically set to zero. This proposed method is robust to absolutely avoid negative cost in all situations.

To ensure that only positive RD costs are imposed on the problem, the maximum function is used. The function forces the optimiser to keep the cost of RD if it is greater than zero, otherwise, it uses a zero or positive value. Two different arguments for the maximum function are analysed.

1. Each costs of down-regulation units are set to zero:

   Market re-optimisation can be a problem when some RD allows participants to gain money. A way to prevent this problem is to avoid down-regulation with a negative cost. For this, the first idea is to use the maximum function, to check every redispatch costs and force any negative value to zero. The function is:

   $$c_{down,i,update} = max(c_{down,i}; 0), \ \forall i, \tag{3.18}$$

   with $c_{down,i}$ is the cost of the down-regulation of the units i.

   This method works correctly in several configurations, for example the optimiser applies a too large amount of MW redispatch to increase the profit, even when the line is no longer overloaded. In this case, prohibiting negative costs for down-regulation forces the optimiser to only consider the positive costs, and only the necessary amount of MW of RD is chosen by the RAO (Figure 3.8 and 3.9).

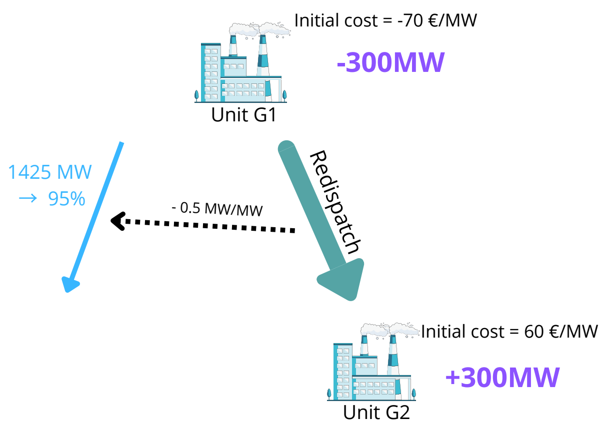


Figure 3.8: Schematic of an extra RD due to market-re-optimisation (objective function = real cost = -3 k€), with a line initially loaded at 105%.

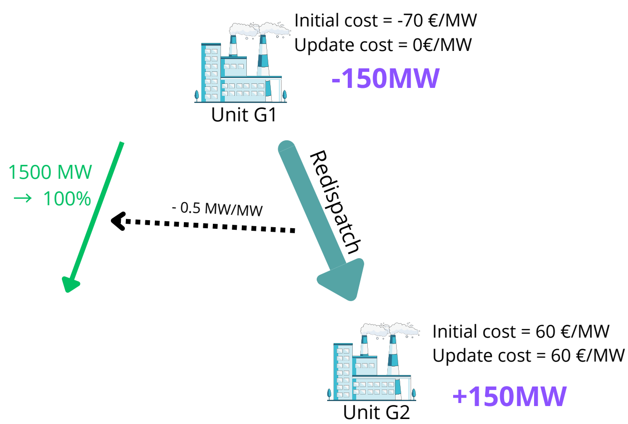


Figure 3.9: Schematic of a limitation of the RD thanks to a prohibition of the negative costs (objective function of 10.5 k€, real cost of -1.5 k€), with a line initially loaded at 105%.

   The drawback of this method is quickly noticed. If several redispatch units are available, with negative RD down costs, these cost are set to the same zero prices. Then the RAO automatically chooses the units with the largest sensitivity on the congestion, blindly on the real units cost for down-regulation. Indeed, the larger the sensitivity, the lower the necessary volume to remove the congestion, and therefore the lower the positive cost for the increase in production (up-regulation). This solution is not robust.

An example is presented here, with one line overloaded of 75 MW and three available RD units. The redispatches between units G1 and G2, and between G1 and G3, have the same sensitivity on the critical line. For this situation, 150 MW are required to relieve the overload. In Figure 3.10, the redispatch between G1 and G3 is used, with a cost of 10 €/MW, resulting in a real cost of 1500 €. In the second configuration (Figure 3.11), unit G2 is used for down-regulation instead of G3, at a cost of 90 €/MW. This RD results in a cost of 13.5 k€, which is nine times higher than the first configuration. With the application of the method presented here, the down-regulation costs of G2 and G3 are forced to zero, so the optimiser only have a visibility on the cost of G1 and assigns both configurations the same cost of 150 k€, allowing the RAO to choose randomly between the two units. This drawback can lead to much higher overall costs.

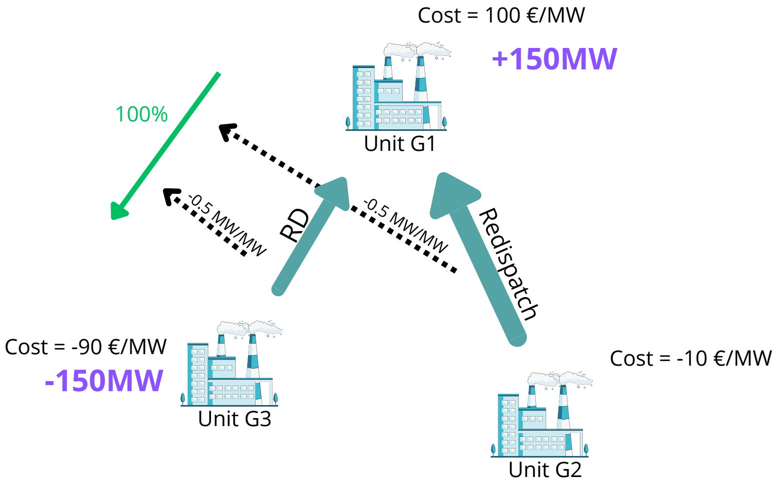


Figure 3.10: Example of a RD (real cost = 1.5 k€, objective function = 150 k€).

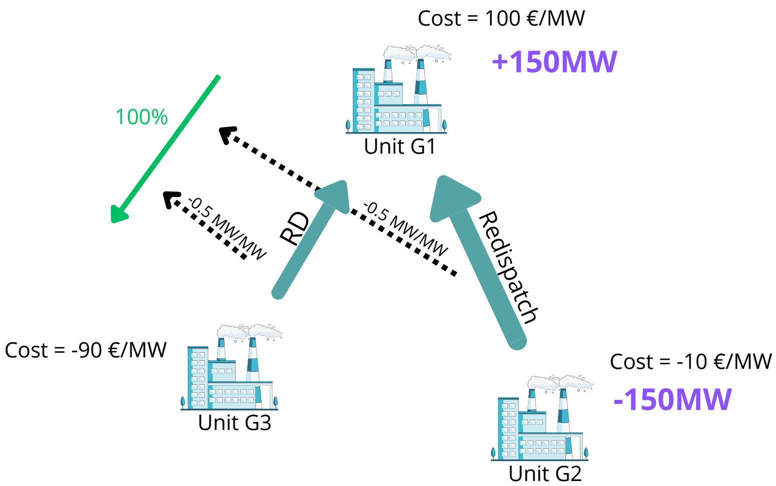


Figure 3.11: Example of a RD (real cost = 13.5 k€, objective function = 150 k€).

2. Costs of the RD are set to zero if they are negatives:

Due to the major drawbacks of the first idea, a second approach is developed. The goal is to force the cost of all RD (both up- and down-regulation) to become zero if the value of the total action is negative, in order to prevent the optimiser from being profit-driven. The function is the following one:

$$max(c_{RD,j}; 0), \ \forall j \tag{3.19}$$

with $c_{RD,j}$ is the cost of the total action of the redispatch (up and down) action j.

There, if a certain amount of RD is required from two units with a total negative RD cost, the optimiser does not take the volume of MW transferred into account. Indeed, the objective function is set to zero regardless of the RD volume. As a result, an excessively large RD transfer may occur between the two units.

Two cases are shown: in the first (Figures 3.12), an RD of 150 MW is carried out with a real cost of -1.5 k€; in the second (Figure 3.13), 1000 MW are transferred with a real cost of -10 k€. In both situations, the cost per MW of RD yields -10 €, resulting in a negative total cost. The maximisation function then sets the value to zero in both cases, making the optimiser blind to the actual amount of RD performed. Consequently, both redispatch situations are treated identically by the RAO, regardless of whether market re-optimisation is considered.

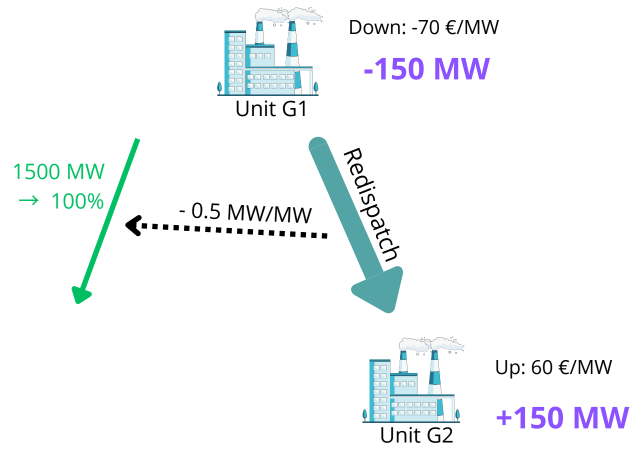


Figure 3.12: Example of a RD with a negative cost (real cost = -1.5 k€, objective function = 0 €).

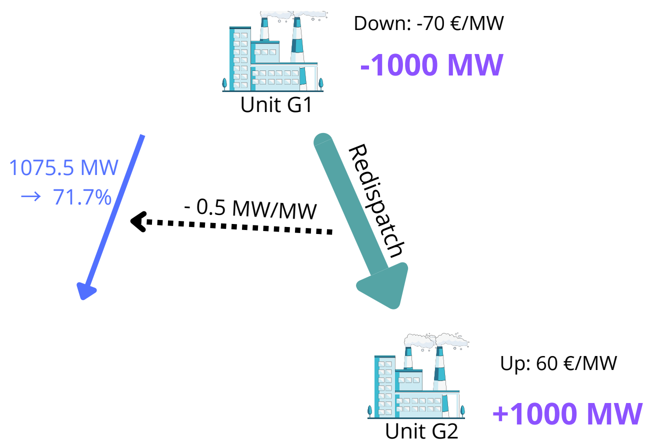


Figure 3.13: Example of a RD with a negative cost (real cost = -10 k€, objective function = 0 €).

In conclusion, both of these methods present significant and potentially serious drawbacks, which rule them out as solutions worth exploring further. On one hand, the first method prevents market re-optimisation but brings a high risk of incurring very large RD costs. This is the opposite of the objective of the optimiser looking for the minimum cost. On the other hand, the second method does not prevent the problem of market re-optimisation, which is the main objective of this research. Therefore, these methods are not be developed further.

3.4 Additional constraint to limit extra reduction of the load

Another type of solution is then developed. Without changing the input parameters, the idea is now to directly modify the optimisation algorithm by adding a new constraint.

A basic and intuitive solution is to set a stopping criterion for the optimiser, preventing it from going further than its maximum loading when searching for a set of RD to resolve a congestion. The aim is to stop the optimiser from selecting economic redispatches that are not required to solve the congestion. Mathematically, an additional set of constraints is imposed:

$$load_i < load_{i,threshold}, \quad \forall i \in CNEC \tag{3.20}$$

where CNEC is the set of all critical network elements and contingencies. This means that, if an element is congested, the optimiser must bring it exactly to its maximum loading threshold.

3.4.1 Test experimentation

To analyse this proposed solution, the same simplified grid containing three RD units is used once again as the base case (Figure 3.14) with initial parameters summarised in Table 3.13.

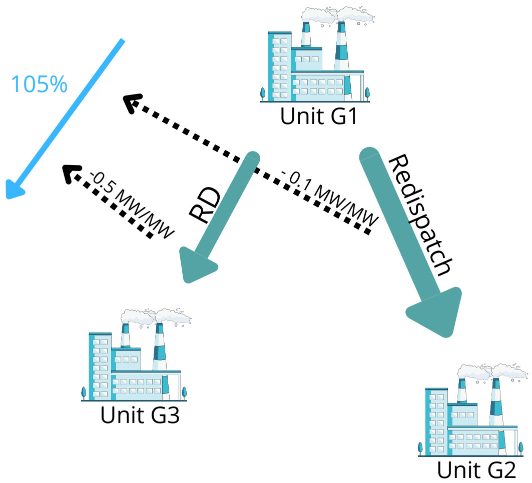


Figure 3.14: Base case schematic for the theoretical analysis of the minimum loading additional constraints, with line loaded at 105% (1575 MW).

Table 3.13: Initial parameters for the theoretical analysis of the minimum loading additional constraints.

Production units	Sensitivity	Cost of production units [€/MW]	MW available for RD
Unit G1	-0.1 MW/MW	-70	[-1200;0]
Unit G2	-0.2 MW/MW	60	[0;600]
Unit G3	-0.6 MW/MW	65	[0;600]

Initially, the optimiser proposes a solution involving market re-optimisation, as the price for up-regulation of unit G3 is higher than the price for down-regulation of units G2 and G3. Therefore, the addition of the constraints well prevents the optimiser from applying certain redispatches once the limit threshold of the critical lines is reached (Figure 3.15, Figure 3.16 and Table 3.14).

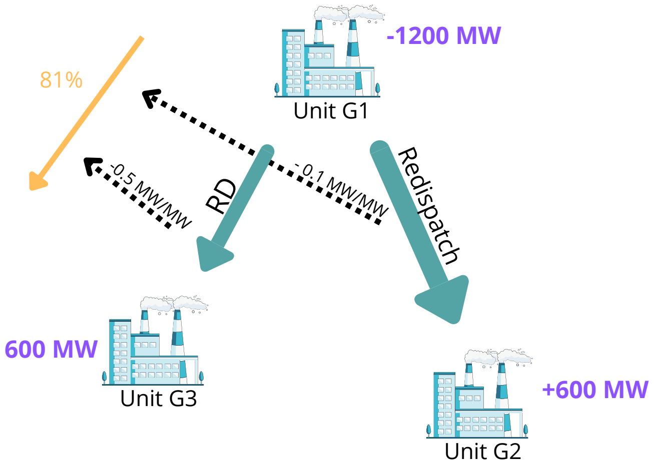


Figure 3.15: Redispatch configuration without additional constraint of minimal loading.

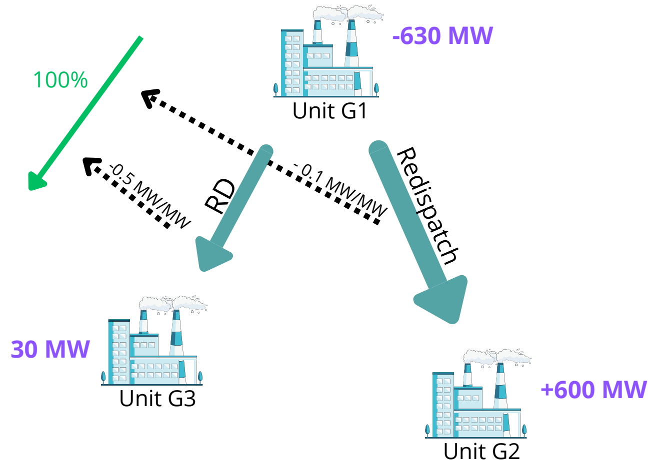


Figure 3.16: Redispatch configuration with additional constraint of minimal loading.

Table 3.14: Results of redispatching with and without additional constraints of minimum loading.

Production units	Without additional constraints		With additional constraints	
	Redispatch [MWh]	Total cost	Redispatch [MWh]	Total cost
Unit G1	-1200	-9000€	-630	-6150€
Unit G2	600		600	
Unit G3	600		30	

In conclusion, the addition of the constraint correctly prevents market re-optimisation in this specific case, and the selected redispatch only allows the necessary generation changes to reduce the congested line loading by 5%.

3.4.2 Drawbacks

This method appears to exhibit the correct behaviour in the classical configuration studied above. However, it also highlights several important drawbacks in other specific configurations. The first drawback occurs when PSTs are used as remedial actions. The second arises when a particular market optimisation configuration induces a negative impact on congestion. Finally, the third issue concerns the development on a larger grid, which will be analysed from a theoretical perspective only, as no real implementation has been carried out.

Issue with discrete values of PSTs

On a simplified network containing only one line overload and one phase shift transformer, the RAO with the additional constraint is applied.

If a simple constraint prevents the critical line from being loaded beyond its operational limit, this may lead to an infeasible solution. Indeed, if the only remedial actions available for the contingency are some PSTs, the RAO can only apply tap changes, which are discrete parameters. The critical line is initially loaded at 105%. In this scenario, one line is overloaded and a PST is available as a remedial action, with a sensitivity of three-percent load decrease per tap change. As a result, the optimiser only has a limited set of possible actions and may be unable to identify a tap position that sufficiently relieves the overload while satisfying the additional constraint. In Figure 3.17, the PST is able to completely relieve the congestion, but it goes slightly further and reaches 99% after a change of two taps. The additional constraints will not be respected. If only one tap is applied (Figure 3.18), a congestion remains present.

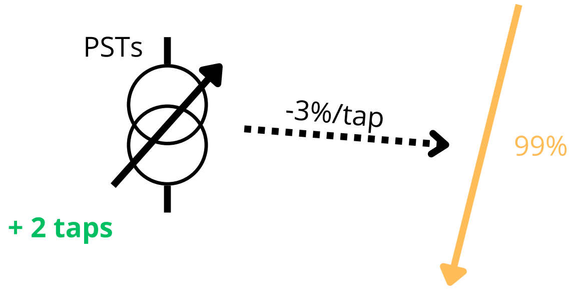


Figure 3.17: Impact of discrete actions (2 taps) on an overload line.

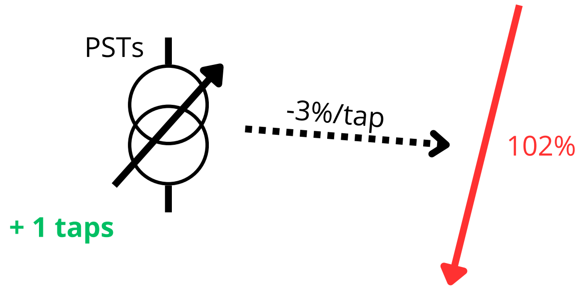


Figure 3.18: Impact of discrete actions (1 tap) on an overload line.

If some redispatch actions are also available, the PST will be limited to a single tap change in this situation, and redispatch will need to be used to reduce the remaining two percent of the overload. As a result, managing this congestion becomes more expensive, as costly remedial actions must be used instead of the non-costly ones that are still available.

Market re-optimisation with RD with negative impact on the congestion

Some market re-optimisation can also happen if undesired redispatching has a negative impact on the congestion. Indeed, this RD may create profit, but increase the load of the line. The extra overload will be compensated by another RAs, which is less expensive than the profit already generated. From on study case configuration (Figure 3.19 and Table 3.15), the problem is highlighted. Starting with the existing algorithm of the RAO, the optimiser will exploit the RD who create a profit, but who has a small negative impact on the overload, and compensate it by using an effective RD with higher sensitivity.

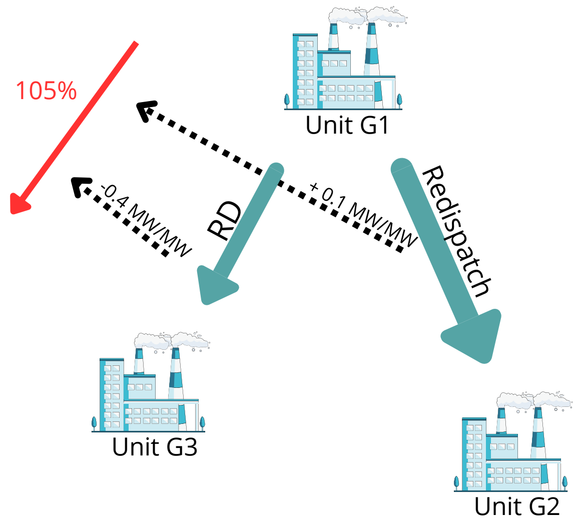


Figure 3.19: Study case schematic of RD with negative impact on the congestion for theoretical analysis, with line loaded at 105% (1575 MW).

Table 3.15: Initial parameters of the RD units for the analysis of RD with negative impact on the congestion.

Production units	Cost of production units [€/MW]	Sensitivity [MW/MW]	Maximum Δ RD
Unit G1	-70	0.2	1000 MW
Unit G2	65	0.1	500 MW
Unit G3	85	0.6	500 MW

To remove this congestion, the most intuitive set of RAs are a RD between G1 and G3 only, since it is the only available RAs capable of decreasing the load on the overloaded line. A redispatch of 187.7 MW with a cost of around 2815 € brings the line to a load of 100%. This solution is the optimal set of RAs that the RAO should propose without market re-optimisation. However, with the profit-driven objective function of the RAO, the set of remedial actions selected by the RAO is not the expected solution. Instead, the RAO chooses redispatch involving all three units, achieving a lower total cost by exploiting some market re-optimisation (Table 3.16).

Table 3.16: Analysis results of RD with negative impact on the congestion.

Redispatch type	Δ RD	Δ overload	Cost of RD
RD between G1 and G2	500 MW	+3.333%	-2500€
RD between G1 and G3	312 MW	-8.333%	+4680€
Total	812 MW	-5%	+2180€

Moreover, the same kind of situation can occur when a profit-driven redispatch does not have any impact on the congestion at all.

In these situations, some market re-optimisation can happen without going further than 100% of the load. In conclusion, the stop criterion of the optimiser after reaching a non-overload line does not totally eliminate the risk of market re-optimisation, but only eliminates it when the re-optimisation has a positive impact on congestion. It highlights the complexity of the problem and the difficulty in determining if there is market re-optimisation in the solution or not, since it is not always a negative total cost that appears for the selection of the RAO.

Implementation on a larger grid

Finally, another drawback of this proposed solution is implementation on a larger grid. The analysis is carried out here on a basic network with one line only. However, a real network is much more complex and larger, and the new constraint is not easy to implement without introducing complications. When several lines are present in the grid, the new constraint cannot be applied to all of them, since there is no desire to force non-congested lines to be loaded at their maximum capacity. Therefore, the constraint should only be applied to congested lines. Unfortunately, in the case of several congested elements in the same area, if redispatch must be applied to resolve these congestions, once the first element reaches its threshold, the new constraint will force the redispatch to stop. If a larger redispatch is necessary for the other critical elements, this process will be prevented by the constraint, and the remaining congestion will persist. For this reason mainly, this additional constraint leads to effects that are too restrictive to be a suitable solution for the market re-optimisation issue.

3.4.3 With soft constraints

The first drawback developed above can be partially tackle. To eliminate the problem of managing discrete parameters such as PSTs, the constraints can be softened and a penalty cost for going too low with the loading can be added.

$$load_i < load_{i,threshold} + c_{penalty}\lambda_{i,overload}, \quad \forall i \in Cnec \tag{3.21}$$

where $\lambda_{overload}$ is the maximum loading violation remaining in the line, and $c_{penalty}$ is the cost associated with this violation.

The value of the cost associated to violations must be adapted, to prevent as much as possible the market re-optimisation, without excluding interesting tap changes to relieve congestion. An analysis is done to find an acceptable tuning of this parameter. The first assumption is the estimation of the sensitivity of an interesting tap change. This value is estimated at 50 MW/tap. To estimate the impact of this type of tap change on the lines, the loading change proportion from it is calculated on the different types of lines in the transmission network (Table 3.17). A tap change with a sensitivity of 50 MW/tap on the 380 kV line will have an impact of around 3% on the line. It means that the penalty cost for underloading must be lower than the cost of a tap change (less than 1 €, since non-costly RA) when the line is underloaded by a maximum of three percent.

Table 3.17: RD results in the analysis of RD with negative impact on the congestion.

Line type	**Range of power of the line**	**Percentage proportion of the PST impact on the line**
380kV line	[1500;2500] MW	2 to 3.3%
220 kV line	[200;1000] MW	5 to 25%
150 kV line	[100;500] MW	10 to 50%

Since most of the PSTs are close to the boundary, they have a large impact on the neighbouring grid. Usually, they are used to manage the 380 kV grid mainly. So the limit forecast considered focuses on the 380 kV line reference only. The margin allows the possibility of a discrete action, but therefore leaves the door open for a slight amount of market re-optimisation as well.

The soft constraint can be linear or non-linear. An example of each type of constraint is presented.

- <u>Linear soft constraint</u>:
  If the additional constraint is completely linear (Figure 3.20), and penalises underloading below the maximum capacity of the line, the slope of the penalty cost must be very low to allow the PST. Indeed, a 3% underload for a very low cost must be chosen by the optimiser, therefore, if a tap change cost 0.033 €, the penalty cost must have a slope under -0.011 €/percent, which is not enough to prevent extra market optimisation.

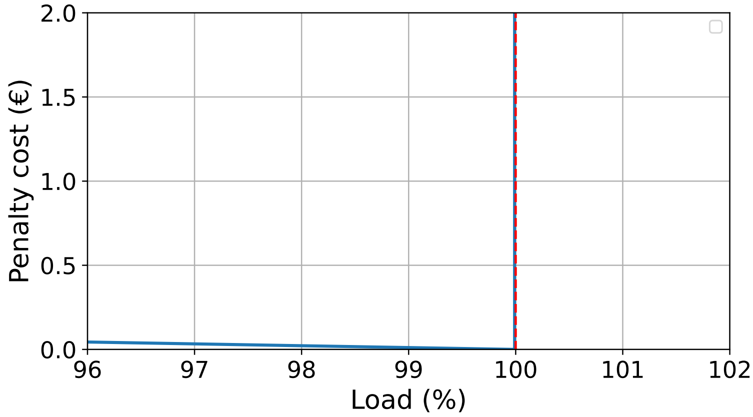


Figure 3.20: Linear soft constraints, with a slope accepting discrete actions.

- Linear soft constraint, with a gap:
  This constraint allows the optimiser to search for solutions leading to a larger decrease in load than expected, while remaining within an acceptable limit of market re-optimisation if it occurs. The size of the margin is arbitrary, but it needs to allow flexibility for the discrete tap positions of the PSTs, as well as to limit significant market re-optimisation when undesired redispatch contributes to congestion management. The constraint can be soft or hard, since a slope that is too small and allows PST actions does not prevent profit-driven RD. In the case of hard constraints, the formulation is as follows, with a Δ_{gap} representing the margin decided to allow discrete actions (Figure 3.21).

$$Load_i < Load_{i,max}, \ \forall i \tag{3.22}$$

$$Load_i > Load_{i,max} - \Delta_{gap}, \ \forall i \tag{3.23}$$

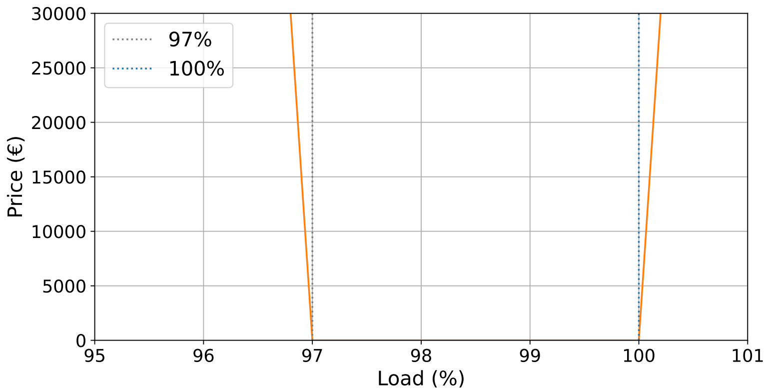


Figure 3.21: Linear soft constraint, with a gap allowing some discrete actions.

- Non-linear soft constraint:
  A linear constraint is better for the solver, and discontinuity is not a problem. For that reason, a linear soft constraint split into several segments is preferred.

Transforming the additional constraints into soft constraints does not resolve the initial issue with this solution. However, introducing a gap margin allows to include more discrete options by allowing small market re-optimisation, a trade-off from a theoretical point of view. Unfortunately, the two drawbacks highlighted in the previous section still remain and prevent the RAO from achieving the fully desired behaviour. Therefore, this method is not an effective solution to prevent the market re-optimisation issue.

3.5 Summary of the theoretical analysis

Table 3.18: Comparison table of all the methods studied theoretically in this chapter to solve the market re-optimisation issue.

<table>
<tr><th rowspan="2">Method applied</th><th colspan="4">Modification of the input parameters</th><th colspan="2">Prohibition of the negative cost</th><th rowspan="2">Additional constraint to limit extra RD (with gap to allow some discrete actions)</th></tr>
<tr><th>Penalty cost</th><th>Rescaling of the negative cost</th><th>Proportional decrease of the negative cost</th><th>Change of the too high cost of down-regulation</th><th>Each down costs are set to zero</th><th>Overall negative RD cost are set to zero</th></tr>
<tr><td>Solved problem of market re-optimisation</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td><td>✗</td><td>1) Not in every case (not when the profit-driven RD has a negative impact on the congestion).
2) Within a limit of the chosen gap (allowing security for discrete action).</td></tr>
<tr><td>Implementation complexity</td><td colspan="4">Easy since only the input parameters are change, no modification of the algorithm.</td><td>Easy, on the input param.</td><td>Hard to define every RD to set to zero.</td><td>Modification of the algorithm by adding a new constraints.</td></tr>
<tr><td rowspan="2">No issue of volume optimisation</td><td>✗</td><td>✗</td><td>✗</td><td>✗</td><td rowspan="2">✗</td><td rowspan="2">✓</td><td rowspan="2">✓</td></tr>
<tr><td colspan="4">Further analyses in next chapter.</td></tr>
<tr><td rowspan="2">Other drawback</td><td colspan="4" rowspan="2">/</td><td colspan="2">Optimiser blind on the down-regulation cost.</td><td rowspan="2">May lead to forced remaining congestions</td></tr>
<tr><td>Lead to non-optimal RD</td><td>/</td></tr>
<tr><td>Prioritisation of the PSTs vs any RD</td><td colspan="4">✓. PSTs will be chosen before a RD with negative real cost. Testing in next chapter.</td><td colspan="2">✓. PSTs will be chosen before a RD with negative real cost.</td><td>✗. RD with negative real cost will be preferred to PSTs.</td></tr>
</table>

In conclusion, prohibiting negative costs or introducing new constraints to limit additional redispatch do not resolve correctly the market re-optimisation, and may lead to significant other drawbacks. Therefore, these approaches are not recommended for further development. In contrast, modifying the input parameters effectively prevents market re-optimisation in all cases, although it introduces a risk of volume optimisation, which may result in sub-optimal redispatching and potentially higher costs. However, these methods correctly prioritise non-costly actions, such as PST tap changes, over the costly redispatch. For these reasons, these parameter modification methods are tested on a large-scale grid in the next chapter to compare the risks of volume optimisation between the different methods, and the appropriate prioritisation of non-costly remedial actions.

Chapter 4

From simulation tools to large-scale optimisation: application to the Belgian grid

The remedial action optimiser, developed in Section 2.2, can be used at different scales: local, regional, national or even international; and for different utilities such as congestion management, voltage stability, etc. In this chapter, a national RAO for the Belgian transmission network, the local Elia RAO, is used and studied for congestion management.

To prevent the problem of market re-optimisation (Section 2.3), the different solutions based on modification of the input parameters, developed in the previous chapter, are implemented on a real network. This optimisation is run on PowSyBL software. All solutions are tested and their behaviours observed in the Belgian grid, on artificial configurations highlighting interesting and critical situations.

4.1 Overview of the Belgian grid

The Belgian grid is composed of 4 voltage levels: 36 kV, 70 kV, 150 kV and 380 kV. The simulations in this work focus only with congestion and remedial actions located on the 150 and 380 kV grids (Figure 4.1). The main characteristics of the high-voltage grid are developed as follows [1, 34].

- Strongly meshed network,
- 15 busbars in 380 kV grid (+7 in 150 kV grid),
- around 3800 km of lines and cables (mainly overhead lines for high-voltage),
- AC connection with two neighbouring countries (The Netherlands and France),
- two HVDC links (Nemo and Algro links)
- generation units connected on the 150 kV and 380 kV grids,
- three main corridors from north to south with three phase-shift transformers and six step-down transformers, and
- a large number of generators and loads on each 150 kV bus.

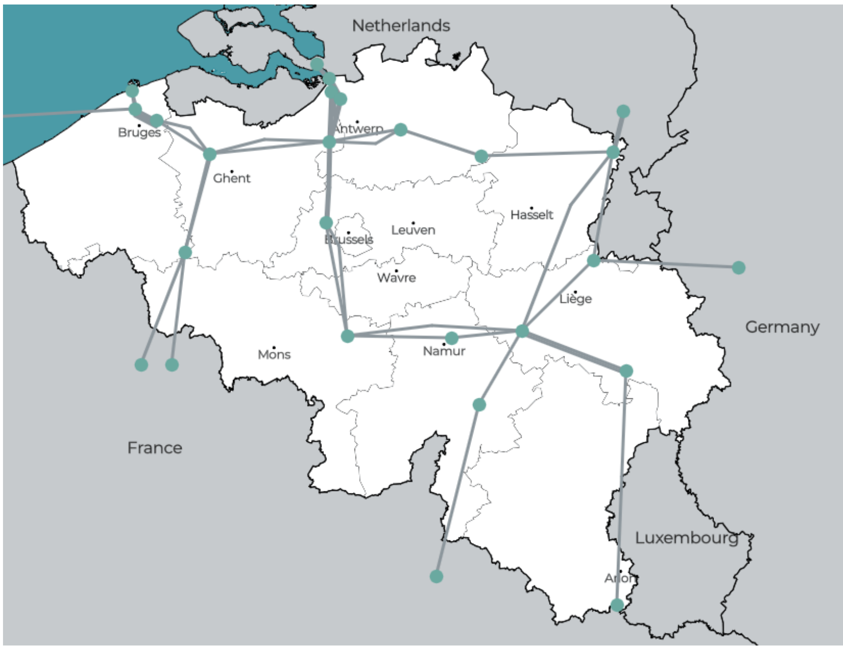


Figure 4.1: 380 kV Belgian network with HVDC links (Source: Elia website [8])

The neighbouring countries are modelled in the Belgian network studies using what is called "the crown". This approach involves creating a simplified representation of the foreign electricity grids surrounding Belgium. By using this crown model, the optimisation tools can efficiently account for cross-border flows and the impact of the neighbouring networks, without having to include the full complexity of each external grid. The crown may be built using different models, such as the Ward reduction [57], or in our case, a simplified PSB reduction developed in Elia. This specific reduction conserves the external grid until the 12th node outside the border, and calculates the sum entering these nodes and coming from the 13th nodes, then transforms it by an equivalent generator and load. The connections between the 12th nodes and the rest of the grid are then deleted. This method ensures realistic analyses of active power in the Belgian system for congestion management.

For the simulations, the critical lines are artificially chosen by decreasing their current limits. They are located to different places of the Belgian grid, on the 380 kV network (Table B.2 for more details on the created congestions), and several generation units connected to the 380 kV or 150 kV are made available for redispatch.

4.2 Software environments

The remedial action optimiser (RAO) for the Belgian grid is implemented using two software tools: PowerFactory and PowSyBl. PowerFactory is currently used by Elia for load flow simulations and dynamic studies of power systems. However, it is not further developed within this work due to its black-box limitations. On the other hand, PowSyBl (Power Systems Blocks) is an open-source software suite in which the adaptation of the RAO to the Belgian grid is currently under development within Elia. The mathematical formulation of the RAO presented earlier in this work is based on the documentation library of this software tool (Section 2.2.2). In both tools, the concept of the crown is implemented to represent the influence of neighbouring systems, and the same contingency list and set of remedial actions are considered.

PowSyBl is an open-source library written in Java and Python that enables complex power system simulations and analyses. It includes functionalities such as load flow computation, security analysis, and the

OpenRAO module [58]. The main advantage of this software is the wide flexibility and data availability resulting from its open-source nature. The RAO in PSB is currently under development for the local Elia grid, in order to adapt it for the Belgian network. At the time of this work, load flow and security analysis results for the transmission network (150–380 kV) are comparable to those obtained with PowerFactory, while the RAO already demonstrates promising performance.

In the OpenRAO, four different objective functions are available [4], but this work focuses on managing congestion by minimising the cost of the RAs. Therefore, the objective function called "Min_cost" is selected. Its mathematical formulation is developed in details in Equation 2.6. This optimisation algorithm operates within an outer loop, which can be implemented in different ways. For example, the French TSO, RTE, uses a DC linearisation approach, applying an outer loop that reruns the optimisation after each previously selected remedial action. This iterative process updates the sensitivity matrix, such as PTDF, to improve its accuracy and reduce errors caused by linear approximations. The method used in Belgium is different. Here, the equations are based on AC calculations, but the overall problem is reduced to a smaller problem focused only on a smaller set of the most critical elements. After each iteration, the solution is checked against the full network to ensure it has not created new critical issues. If a new critical element is identified, it is added to the reduced model and the optimisation is rerun. This process is known as "Fast RAO." Both approaches are designed to improve computation time for remedial action optimisation on large-scale power grids.

Moreover, in contrast to PowerFactory, PSB does not have a visual interface of the complete network, or at least not at the time of this work. Therefore, modification of parameters must be effectuated in some specific files or scripts. Nevertheless, interesting new elements are developed in it, such as topological RAs and smart management of preventive and curative RAs. The OpenRAO includes two specific algorithms: CASTOR and MARMOT algorithm [4].

- OpenRAO - CASTOR algorithm
  The added value of the OpenRAO of PSB is a specific algorithm capable of optimising the topological remedial actions. This algorithm is called CASTOR (previously developed in Section 2.1.3).
- OpenRAO - MARMOT algorithm
  The purpose of the MARMOT algorithm is to handle time-coupling constraints. This option is currently in development, and TSOs do not use it yet in real application. This algorithm goes outside of the scope of this work.

One advantage of this software, compared to PowerFactory, is its criterion of not running the optimisation if the security analysis detects no congestion. This criterion seems logical, but is not present in PowerFactory. This approach avoids unnecessary computations and saves time. Moreover, in situations where market re-optimisation is possible, if no preventive measures are applied to restrict such behaviour, the optimiser still does not select profit-driven redispatch. This functionality has been tested on a real network and has produced good results.

The computation times in PSB for the security analysis (in AC) are about 70 seconds. For the RAO, in total, but without taking into account the logging of the grid (CGMES file) and the initial security analysis, have a median time of about 100 seconds without including topological remedial actions, and about 250 seconds with them with a two depth tree.

Proposed solutions against market re-optimisation are testing with this software tool, by enabling first redispatch actions only, and then adding PSTs and topological modification to the problem. Moreover, the optimiser validates the simplified use cases developed in Section 3.1.

NB: PowerFactory tools has not been used for RAO simulations, but due to its visual interface, has been used for the creation of interesting configurations for the simulations, by using load flow, security analysis and sensitivity analysis functions.

4.3 Implementation of proposed solutions on the Belgian grid

The proposed theoretical solutions based on modification of the input parameters of the RD costs are tested in a large scale grid, using PowSyBl OpenRAO. The network is a configuration of the Belgian grid with artificial congestion applied to obtain interesting use cases (Figure 4.2). Congestions are forced by decreasing the current limit of some specific 380 kV lines situated at different locations on the grid. The thermal limits of 380 kV lines are always set at 95% of their maximum capacity, as these lines are considered critical components of the network. The network with one congestion is called Network 1, and Network 2 is the one with three congestions. Seven generation units are available for redispatch, two for downward regulation and five for upward regulation. The initial RD costs are set so that market re-optimisation issues may occur, i.e. with some upward regulation costs being lower than the absolute value of certain downward regulation costs. The four methods, based on some modifications of the input parameters and introduced in the previous chapter, are applied to these costs. The method involving penalty costs applied to all values is tested using two different settings: one with a very large penalty and one with the optimal value determined previously. The methods are the following ones:

- PC of 500: a constant very high penalty costs adding to all RD costs.
- Optimal PC: an optimal penalty costs adding to all RD costs.
- Method 1: a rescaling of the negative cost
- Method 2: a proportional decrease of the negative cost.
- Method 3: a modification of too large costs of down-regulation.

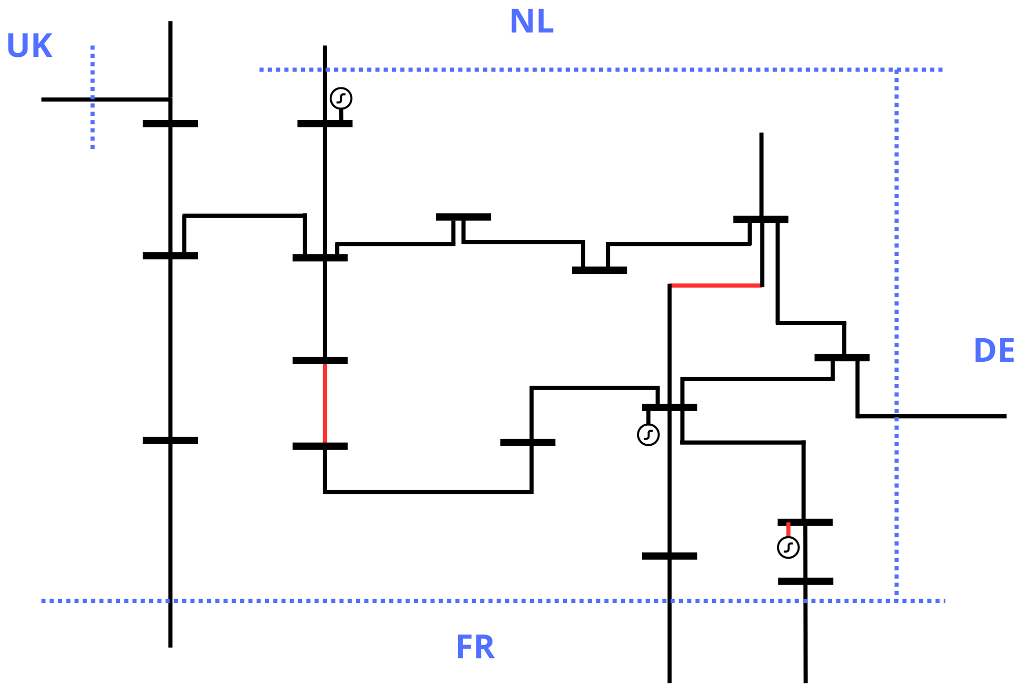


Figure 4.2: Schematic of the 380 kV Belgian grid, with the three artificially congested lines, and three RD units connected to the 380 kV grid, the four RD units available connected to the 150 kV are not represented (Source: inspired from Elia website [8]).

A sensitivity analysis is carried out to observe the efficiency of the available redispatch units for each contingency. For example, for contingency C380-L1, which occurs in Network 1, the most efficient remedial actions involve increasing the production of G2 and reducing the production of G6 and G7. However, while this redispatch combination is the most efficient, it is also the most expensive (Table 4.1). Therefore, it is preferable to select less costly units, such as G3 and G4, and to avoid using G7 as much as possible due to its high cost.

Table 4.1: RD costs of available units for testing in the large scale network, and their sensitivity on the contingency of Network 1.

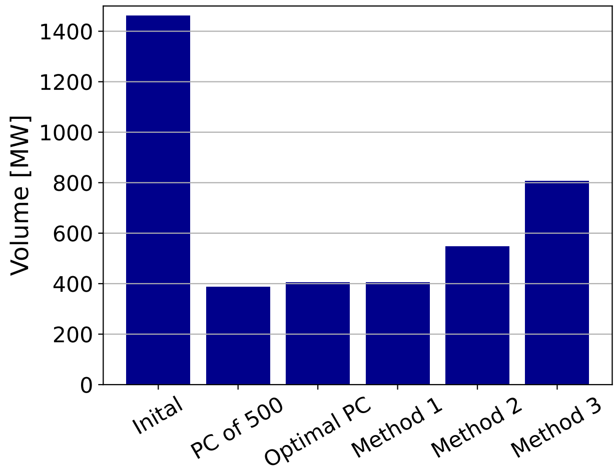
Generator name	**Cost in €/MW**	**Sensitivity [%/MW]**
G1	-110	-0.022
G2	-70	0.021
G3	65	-0.009
G4	65	-0.002
G5	75	0.004
G6	90	-0.028
G7	120	-0.011

First, an analysis is performed with redispatch as only available remedial actions. This analysis aims of assessing their good behaviour in various situations. The goal is to observe the behaviour of the proposed methods in preventing market re-optimisation. Other remedial actions are not considered at that time to determine effective and robust solutions of the redispatch alone. Then, all methods are tested when adding PSTs and topological remedial actions to the optimisation. In this phase, the complete set of RAO use cases is presented, ensuring that the methods behave as intended, correctly preventing profit-driven remedial actions while giving priority to non-costly remedial actions.

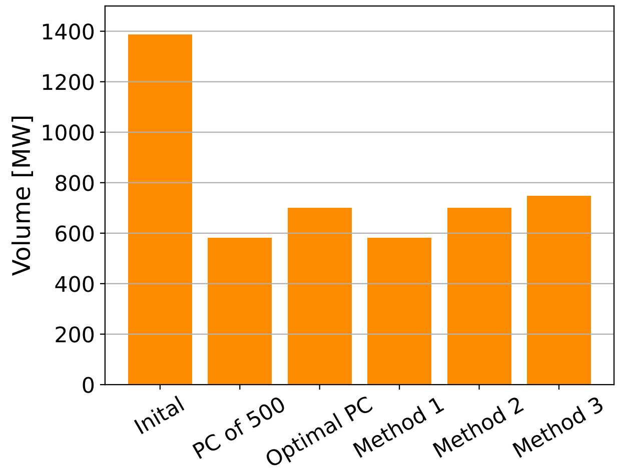
4.3.1 Optimisation with redispatch RAs only

As expected, in both networks studied, when using the configuration with initial redispatch costs, the RAO proposes a large RD volume, above 1.4 GW, associated with very negative prices (around -6000 €). This chosen value is clearly driven by market re-optimisation. The loading of the critical lines does not reach their thermal limits, especially in configurations with multiple congestions. In network 1, which features a single congestion, the line is loaded at 95%, its maximal capacity, suggesting that extra redispatch may have little impact on this line.

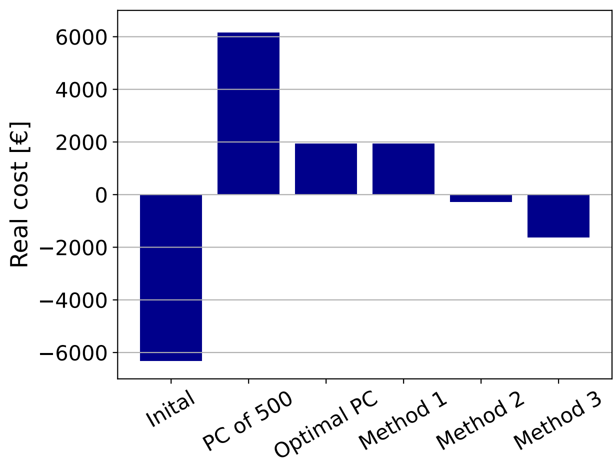
For both networks, the RD prices are updated by applying the different methods. A global overview of the results (Figure 4.3) highlights that in general the lower the volume of redispatch, the higher the real cost of it. Moreover, when the proposed methods are applied, the RD volume decreases, and therefore the real cost increases.



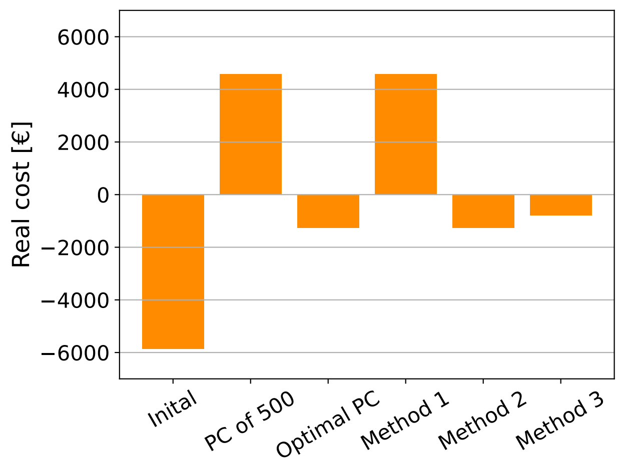
(a) Total volume of redispatching with initial and modified RD costs, in large network with one congestion.



(b) Total volume of redispatching with initial and modified RD costs, in large network with several congestions.



(c) Real cost of total redispatching with initial and modified RD costs, in large network with one congestion.



(d) Real cost of total redispatching with initial and modified RD costs, in large network with several congestions.

Figure 4.3: Comparison of the different proposed methods by analysing the RAO results on one large network with one congestion (a, c) and several congestions (b, d).

For Network 2, in the configuration with the addition of a penalty cost of 500 €/MW and for method 1 (rescaling negative costs), a lower RD volume but higher total costs are observed. This is due to volume minimisation resulting from the changes in proportionality between generation unit costs (as highlighted in Section 3.1.2 and 3.2.5). Here, one nuclear power plant is available as an RD unit, with a very high cost, about twice as expensive as the others. After the input parameters are modified according to these two methods, this power plant sensitivity to congestion remains unchanged, but the cost difference between it and the other units decreases, approaching a 1:1 ratio instead of 2:1. As a result, since this nuclear power plant is more effective in reducing the congestion, it is selected for RD, leading to a higher total cost. The same behaviour appears for Network 2, but the results are not reliable because congestion remains after the RAO decision. An RD solution to remove these congestions is nevertheless available, as shown by the results obtained with other methods. Therefore, due to the significant risk of volume minimisation leading to higher total RD costs, these two methods should be avoided to solve the market re-optimisation issue.

Among the three remaining methods, corresponding to using the optimal penalty cost, applying a proportional decrease to the negative costs (method 2), and modifying the critical negative cost (method 3), the results for the first two methods are similar in Network 2, but differ in Network 1. In contrast, the third method appears to perform better in Network 1, achieving a total negative cost around 1500 € lower than the other methods. However, in Network 2, the opposite occurs: this method produces a less effective solution, with costs about twice as high.

From these simulations, it can be concluded that all methods yield good results in preventing market re-optimisation. However, some approaches are more effective than others in avoiding volume minimisation. Methods involving excessively large penalty costs and a rescaling of negative costs (method 1) produce unfavourable results for this issue, leading to higher total prices, and should therefore be avoided. The remaining three methods deliver satisfactory results in both configurations, but none stands out as the best overall. The optimal penalty cost (Optimal PC) approach yields more expensive results in the first simulation, but with the method 2, a proportional decrease of negative cost, they yield to better solution in the second network. Considering the last method, a modification of too large costs of down-regulation (method 3), it produces a slightly different set of remedial actions, being occasionally cheaper (in Network 1) and at other times more expensive (in Network 2). Consequently, no single method is preferred based on the results of this study. In conclusion, from both simulations, method 2 and method 3 seems the best in general, but these simulations also highlighted that the volume optimisation depends strongly on the configuration and situation study.

N.B.1: Please note that the cost of violation of soft constraints is set to avoid keeping congestions as cheaper prices than redispatch actions, and a Δ_{secure} (Equation 2.2.2) is set to 0.4 A, corresponding to a negligible load of the line study, to avoid very small remaining congestion due to approximation in the RAO.

N.B.2: All initial and updated RD costs, as well as congestions on the network are available in the appendix B.

4.3.2 Optimisation with costly and non-costly RAs

After analysing the behaviour of remedial dispatch as the only corrective action to ensure a prevention of market re-optimisation, the same simulations are performed by incorporating non-costly RAs, such as PSTs and topological actions. These actions should be prioritised as they do not interfere with market outcomes and remain fully under the control of the TSOs. When such non-costly measures are available, the optimisation process should first rely on them and only activate RD when these actions prove insufficient to resolve the constraints.

The simulations show that non-costly actions are effectively prioritised over RD actions, as intended (Table 4.2). For example, in Network 1, which contains a single congestion, the objective function becomes very close to zero after the activation of eight tap changes and one topological modification. These nine non-costly actions are sufficient to bring the line below its thermal limit. The same behaviour appears in Network 2.

Table 4.2: RAO results, with the addition of non-costly RAs to the optimisation on large scale networks in configurations with initial costs and with the modified costs after application of each proposed methods.

	Network 1: 1 congestion		**Network 2: 3 congestions**	
	With initial RD cost	**With modified RD costs by any proposed solutions**	**With initial RD cost**	**With modified RD costs by any proposed solutions**
RD Volume	773.8 MW	0 MW	773.8 MW	0 MW
PST tap changes	10	8	9	9
Topological changes	0	1	1	2
Objective function	-9432.27 €	0.73 €	-9432.17 €	1.03 €
Critical line loading	94.9%	94.8%	94.4% - 56.2% - 91%	94.9% - 91.3% - 91.8%

It is also noteworthy that, in Network 1, under the initial conditions with a large RD volume, more non-costly actions are activated, resulting in an objective function even lower, from around -6000 € without PSTs to about -9500 € when they are included. This suggests that in some cases, the optimiser selects PSTs or topological actions primarily to maximise the profit from RD, rather than purely for congestion management.

Regarding topological actions, it is important to note that not every possible topological modification is tested for each contingency. Instead, a specific set of actions is selected by grid experts, based on their knowledge of the network, in order to limit the search space to potentially useful actions only. In the context of this study, where contingencies are artificially created by modifying the current limits of lines, the predefined set of topological actions may no longer be fully relevant. This could explain why, in these scenarios, only a limited number of topological remedial actions are applied.

In total conclusion of these simulations, all methods propose good prevention of market re-optimisation issue and good prioritisation of non-costly remedial actions. Nevertheless, large constant addition of penalty cost and a rescaling of negative cost must be avoided because these two methods may induce larger risk of volume minimisation.

Chapter 5

Conclusions and perspectives

5.1 Conclusions

This thesis addressed the issue of market re-optimisation within the remedial action optimiser. The aim of this work was to identify potential solutions to prevent this problem and to test the most promising approaches on a large-scale grid for real-word applications. As a reminder, market re-optimisation refers to situations where the optimiser proposes redispatch remedial actions primarily to generate profit rather than to manage congestion as intended. In total, three categories of methods, each with different variants, were analysed.

The first category includes methods that consist of arbitrary modifying input parameters, specifically those related to redispatch costs. In this category, in total four methods were analysed, starting from methods proposed in the state of the art to new proposed methods.

1. An additional penalty cost to all redispatch costs.
2. A rescaling of the redispatch negative costs which forces all the costs to be positive, by keeping the same priority order.
3. A proportional decrease of all the redispatch negative costs, to force them to be less important than positive costs.
4. A modification of critical redispatch negative costs only.

All these methods effectively prevent the market re-optimisation issue, and consistently prioritise non-costly RAs over costly ones. However, they introduce a new problem: volume minimisation. This side-effect can lead to sub-optimal sets of RAs, potentially resulting in a significant increase in total redispatch cost. Although all methods may lead to optimisation solutions including volume minimisation, large-scale simulations have shown that the rescaling method tends to yield less favourable results compared to the others. Additionally, none of the methods can be considered to consistently deliver more optimal results.

The second and third categories, namely the prohibition of negative costs and the addition of extra constraints to limit redispatch, were eliminated as potential solutions after theoretical analysis. Although these methods initially appeared intuitive, they do not address the market re-optimisation issue in all cases. In fact, it was found that they can cause even greater problems, such as non-optimal redispatch or the persistence of network congestions. Due to these significant drawbacks, these methods have not been implemented on large-scale power networks.

In conclusion, no perfect method has yet been found to prevent market re-optimisation by the remedial action optimiser. While some initially intuitive approaches have been eliminated, other solutions that effectively address the issue have been identified; however, these can lead to volume minimisation effects and consequently to sub-optimal redispatch costs. This work highlights the difficulty of finding a perfect solution to address this issue and underlines the potential trade-offs that may need to be accepted in order to manage it effectively.

5.2 Perspectives

To prevent the market re-optimisation issue, this work has proposed adjustments to parameters and small modifications to the optimisation function. Further research could explore larger changes, such as deeper modifications to the algorithm itself or a reconsideration of the primary objective of the optimisation.

For example, it could be interesting to develop alternative types of algorithms for this optimisation problem. One potential approach would be to split the optimisation process into three layers. The first layer would consider only non-costly remedial actions, which should always be prioritised. If these actions are sufficient to resolve congestion, the optimisation process can stop at this stage. The second layer would incorporate both costly and non-costly remedial actions, focusing on identifying a set of potentially useful actions based on their costs. The final layer would then focus on volume optimisation, selecting only from the previously identified set of remedial actions. This approach could effectively prevent market re-optimisation, since the first and last layers, which would be the ones that can finalise the optimisation, are not cost-based. Unnecessary redispatch actions would be removed in the final volume optimisation, ensuring that only the strictly necessary remedial actions for removing congestion are selected. However, as observed in this work, this approach may not completely eliminate volume minimisation effects that could lead to higher costs, and take more computation time. Further development of this method could, therefore, be an potential direction for future research.

Another point interesting to develop is the following. The current remedial action optimiser is primarily based on minimising costs, in line with regulatory specifications that require remedial actions to be selected for both their efficiency and economic properties. However, in practical operations, other important factors must be considered, such as the limited number of actions an operator can feasibly implement within a given timeframe. For including this aspect, a constraint on the number of actions may be added to the cost minimisation.

More than that, another even more fundamental modification could involve reconsidering the overall objective of the optimisation selecting remedial actions for congestion management. The issue of market re-optimisation arises from the current focus on minimising the cost of remedial actions. However, alternative perspectives could be adopted for this optimisation, potentially shifting the focus to other objective functions, for example:

- An optimisation on the number of actions while adding a limitation on the cost.
- A multi-objective optimisation, with specific weight on the cost, number of actions, or even other objectives.
- An optimiser designed to present several options to the operator, each consisting of different sets of remedial actions, with each set representing a specific optimum or trade-off. This approach would allow greater flexibility for operators in the control room, enabling them to choose the most appropriate solution, thanks to this support tool, but also their expertise and judgement.

All these ideas would require modifications to the optimisation formulation or solution algorithm. However, thanks to the open-source nature of PowSyBl OpenRAO, their implementation should remain relatively straightforward. Beyond the technical developments, the key challenge lies in determining which behaviour is the most valuable from a TSO perspective and, consequently, identifying the most relevant directions for the future evolution of the tool.

Appendices

A PowSyBl OpenRAO validation runs on small network

Three units of RD are made available, situated directly on the 380 kV grid. Two in one side of the congested line, available for up-regulation, and the third one on the opposite side, available for down-regulation (Table A.1). The sign of each units sensitivity on the critical element highlighted the effect and the side where the power plant is situated compare to the overload line. Unit 1, with a negative sensitivity is well the only one on this side on the congestion, while the total sensitivity is about -0.29 MW/MW (-0.203 - 0.088) for a RD between Unit 1 and 2, and -0.31 MW/MW (-0.203 - 0.110) between unit 1 and 3.

Table A.1: Characteristics of the three generation units available for redispatch, in small configuration of the Belgian grid test experimentation.

Production units	**Sensitivity [MW/MW]**	**Range of production [MW]**	**Initial production point**
Unit G1	-0.203	[493; 1036]	1036 MW
Unit G2	0.088	[-210; 230]	0 MW
Unit G3	0.110	[508; 1039.5]	508 MW

Table A.2: RAO results for four different cases, in the small configuration with three RD units test experimentation, on critical lines overloaded at 104.9% (thermal limit of 95%), to validate the reliability of the optimiser on easy use cases.

Test cases	**Production units**	**Cost of production units [€/MW]**		**Redispatch [MWh]**	**Load of the critical line**
		Down cost	**Up cost**		
1) No market re-optimisation and priority on G2	Unit G1	-80	99999	-310	94.9%
	Unit G2	100	100	230	
	Unit G3	99999	200	80	
2) No market re-optimisation and priority on G3	Unit G1	-80	99999	-283	95%
	Unit G2	200	200	0	
	Unit G3	99999	100	283	
3) Market re-optimisation between G1 and G2	Unit G1	-80	99999	-310	94.9%
	Unit G2	60	60	230	
	Unit G3	99999	100	80	
4) Market re-optimisation between G1, G2 and G3	Unit G1	-80	99999	-543	86.8%
	Unit G2	60	60	230	
	Unit G3	99999	70	313	

B Data set for large grid testing

Table B.1: Initial RD costs of available units and updated costs after application of the methods, for testing in the large scale network (PC: penalty cost; method 1: rescaling of the negative costs; method 2: proportional decrease of the negative costs, and; method 3: change of the too high costs of down-regulation).

Generator name	**Initial cost in €/MW**	**Updated cost: penalty cost of 500 €/MW**	**Updated cost: optimal PC of 23.5 €/MW**	**Updated cost: Method 1 in €/MW**	**Updated cost: Method 2 in €/MW**	**Updated cost: Method 3 in €/MW**
G1	-110	390	-86.5	0.01	-64	-64
G2	-70	430	-46.5	64	-40.73	-64
G3	65	565	88.5	65	65	65
G4	65	565	88.5	65	65	65
G5	75	575	98.5	75	75	75
G6	90	590	113.5	90	90	90
G7	120	620	143.5	120	120	120

Table B.2: Artificial congestion characteristics in "N" and "N-1" conditions, in Belgian grid test experimentations.

Network	**Critical line**	**Critical outage**	**Load state N**	**Load state N-1**	**Max loading**
1 congestion network	C380-L1 Central Belgium	BusX	69%	104.9%	95%
3 congestions network	C380-L1 Central Belgium	BusX	69%	104.9%	95%
	C380-L2 South Belgium	LineY	57.3%	102.1%	95%
	C380-L3 East Belgium	LineY	70%	100.9%	95%

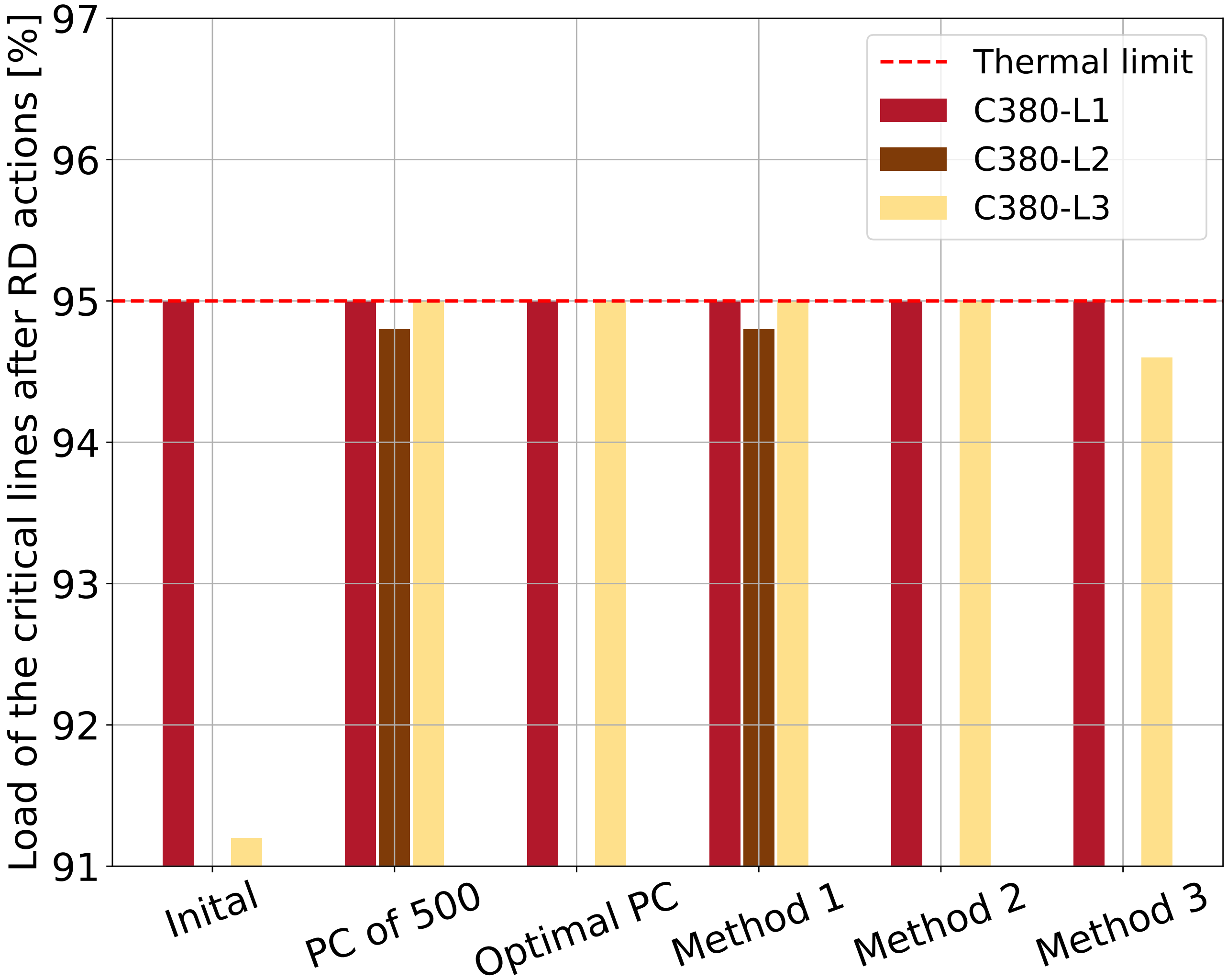


Figure B.1: Load of the critical lines with initial and modified RD costs, in large network with several congestions.

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