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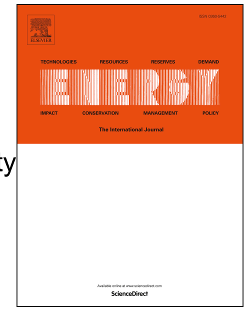

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Risk Assessment of Power Transmission Network Failures in a Uniform Pricing Electricity Market Environment

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Abstract

This paper proposes a novel risk assessment method for power network failures considering a uniform-pricing market environment, different from previous risk assessment studies, which mainly emphasize technical consequences of the failures. In this type of market, dispatch infeasibilities caused by line failures are solved using a counter-trading mechanism where costs arise as a result of correcting the power dispatch. The risk index proposed takes into account these correction costs as well as the cost of the energy not served due to the failure, while considering an oligopolistic behavior of the generation companies. A 3-stage model is proposed to simulate the bidding behavior in the market, under different line failures scenarios. The risk index proposed and the method for its calculation are applied on an adapted IEEE 6-bus

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reliability test system. A sensitivity analysis is performed to investigate the sensitivity of the results with respect to the level of competitiveness of the generation companies, measured by the conjectured-price response parameter which is assumed to be exogenous in our study.

Keywords:
Risk assessment, Transmission network, Electricity market, Line failure, Conjectural-variation equilibrium, Direct-current optimal power flow.

List of symbols

Indices:

a	network bus index
i	generation companies (GenCos) index
j	generation unit index
k	generation unit index (alias for j)
l	transmission line index

Sets:

N	set of indices of network buses
I	set of indices of generation companies (GenCos)
J	set of indices of generation units
J_a	set of indices of generation units located on bus a
J_i	set of indices of generation units belonging to GenCo i
L	set of indices of the transmission lines in the system
Π	set of optimization variables in the DAM problem
Δ	set of optimization variables in the BM problem
Ξ	set of optimization variables in the DC-OPF problem

Constants:

c_j	production cost of unit j (€)
$\overline{q_j}$	maximum production capacity of unit j (MW)
θ_i	conjectured-price response of company i in the day-ahead market [(€/MWh)/MW)
β_i	conjectured-price response of company i in the upwards balancing market [(€/MWh)/MW)
ϕ_i	conjectured-price response of company i in the downwards balancing market [(€/MWh)/MW)
D	total active power demand in the system (MW)
D_a	total active power demand per network bus a (MW)
MC_j	marginal cost of unit j (€/ MWh)
$cens_a$	cost of energy not served at network bus a (€/ MWh)
$ms_{(a,a')}$	mechanical state of transmission line connecting bus a and a'
$B_{(a,a')}$	transmission line susceptance (p.u.)
OR_l	transmission line outage rate per year
T_l	transmission line average outage duration (hr)
Hrs	transmission line total number of operating hours per year (hr)

Variables:

λ_i	day-ahead market price estimation by GenCo i (€/ MWh)
γ_i	upwards balancing market price estimation by GenCo i (€/ MWh)
ψ_i	downwards balancing market price estimation by GenCo i (€/ MWh)
λ^*	day-ahead market equilibrium price (€/ MWh)
γ^*	upwards balancing market equilibrium price (€/ MWh)
ψ^*	downwards balancing market equilibrium price (€/ MWh)
q_j^{DAM}	non-equilibrium solution for the active power quantity bid of unit j (MW) in the day-ahead market
q_j^{*DAM}	equilibrium solution for the active power quantity bid of unit j in the day-ahead market (MW)
x_j^{BM}	non-equilibrium solution for the upwards power quantity bid of unit j in the balancing market (MW)
x_j^{*BM}	equilibrium solution for the upwards power quantity bid of unit j in the balancing market(MW)
z_j^{BM}	non-equilibrium solution for the downwards power quantity bid of unit j in the balancing market (MW)
z_j^{*BM}	equilibrium solution for the downwards power quantity bid of unit j in the balancing market (MW)

$\overline{\mu_j}$	dual variable
$\overline{\nu_j}$	dual variable
$\overline{\xi_j}$	dual variable
$\overline{\delta_j}$	dual variable
u_j^{OPF}	binary variable equals to 1 if unit j is required to participate in the upwards balancing market and 0 otherwise
u_a^{OPF}	binary variable equals to 1 if any unit on bus a is required to participate in the upwards balancing market and 0 otherwise
w_j^{OPF}	binary variable equals to 1 if unit j is required to participate in the downwards balancing market and 0 otherwise
w_a^{OPF}	binary variable equals to 1 if any unit on bus a is required to participate in the downwards balancing market and 0 otherwise
x_a^{vg}	amount of energy not served at network bus a (MWh)
q_j^{OPF}	feasible active production for unit j as found in the optimal power flow problem (MW)
$F_{(a,a')}$	power flow in the network line connecting bus a and a'
δ_a	voltage angle at network bus a

Acronyms:

BM	Balancing Market
DAM	Day-Ahead Market
DB	Downwards Balancing
DC-OPF	Direct-Current - Optimal Power Flow
ELIC	Expected Load Interruption Cost
ELNS	Expected Load Not Supplied
ENS	Energy Not Served
KKT	Karush-Kuhn-Tucker
MCP	Mixed Complementarity Problem
M.O.	Market Operator
S.O.	System Operator
UB	Upwards Balancing
VG	Virtual Generator

1. Introduction

Safety and reliability have always been critical for power systems [1]. A number of studies have been dedicated to propose different criteria [2], assessment methods [3], metrics, and standards [4]. More recently, the focus has been on studying power systems reliability considering distributed generation [5], the integration of renewable energy sources [6] especially wind [7] and photovoltaic [8], the impact of severe weather conditions [9], and the impact of energy storage [10] and electric vehicles integration [11]. In addition, reliability studies have considered the contribution of demand response program [12], smart-grid developments [13] and cyber-security [14]. Moreover, the deregulation of the power systems and the introduction of different market designs have motivated studies of system reliable operation considering different market interactions, such as the uncertainties of renewable power generation [15], the consideration of micro-grids [16], and especially ensuring markets adequately operating for energy reserves [17].

However, reliability assessments may not tell the full story when considering the actual impact of a failure in the system, as that effect is typically evaluated in terms of probability and severity (consequence), within a risk assessment framework [18]. A power system consists of many components (e.g. generators, transmission and distribution lines, transformers, breakers, switches, communication devices, etc.) which are prone to failures. Since most of these components can be -either directly or indirectly- attributed to the transmission and distribution networks, the available literature has been notably focusing on quantifying the impacts of failures in these networks.

A network contingency can be considered to result in one or both of the following effects on the system: the isolation of a demand/generation bus from the rest of the system leading to an amount of energy not served (ENS), and/or the congestion of one or several other lines in the network due to the updated network topology and the limited capacity for each line, leading to the need of re-dispatching the generated power to ensure the technical stability of the network and to minimize any unsatisfied demand. If a line failure produces neither of these effects, then the line can be considered redundant and its failure has no influence on the operation of the system.

In literature, the severity of network failures has regarded technical impacts such as circuit flow limits and voltage level violation, duration and frequency of interruption, amount of energy not supplied (ENS) and expected load not supplied (ELNS), and economic impacts such as the expected load interruption cost (ELIC), and ENS cost.

Reference [19] presents a probabilistic risk assessment of distributed generation (DG) systems, considering extreme weather conditions. They consider the probability of a distribution line contingency and its consequence as the extent of voltage level violation. Reference [20] also proposes a risk assessment method for power systems in extreme weather conditions with the amount of load curtailed as a severity function. References [21] analyzes a distribution network with DG, considering the risk of protection system miss-coordination, under three severity functions: interruption frequency, interruption duration and amount of ENS. A probabilistic risk assessment of transmission network contingencies is proposed in: [22] as the extent of thermal rating violation, [23] within a risk-based multi-objective optimization that accounts for overload risk, low voltage risk, and cost, [24] in terms of voltage level violation for a near-future condition, and in [25] in terms of line overload for wind-integrated power systems. Reference [26] considers the risk of transmission network deliberate outage within a network expansion planning framework, in terms of the amount of load shed. References [27] propose a method to evaluate the risk of transmission network failure in terms of load not supplied, while considering the operator responding to the failure by re-dispatching the power to avoid a system blackout and minimize the amount of load-shed. Reference [28] evaluates the security of a wind integrated power system using a risk index assessing the outage of a single and/or a double circuit of a line, and its economic consequence in terms of

ELIC. Study [29] proposes a risk assessment for the combined transmission and distribution networks within a hierarchical framework, with four severity functions namely: expected energy not supplied (EENS), probability of load curtailement (PLC), expected frequency of load curtailement (EFLC) and the equivalent duration of one complete system outage during peak conditions. Finally, the work [30] implements a risk analysis within a planning framework for the distribution network which accounts for the consequence of overcurrents and voltage violations in monetary terms. All of these studies, however, have considered a system with centralized power dispatch. A power market context has been considered in the risk evaluation proposed by [31], where the merit order power dispatch is selected based on sampled bidding prices and the network failure severity is measured in terms of ENS cost.

On the contrary to our knowledge, none of the existing works have evaluated the system risk considering the economic cost of correcting the power dispatch due to the network contingency, within a market context. In fact, some studies have argued that the use of economic indexes for risk assessment such as the cost of interruption or the re-dispatching cost is not suitable, as it presupposes the decision itself that the index is ought to facilitate [24], or because it introduces uncertainties beyond those reflected by performance measures, that are difficult to model accurately [22]. The first argument, however, gives exception to cases where load interruptions are inevitable and are, therefore, not the result of an operator decision [24], which is, indeed, the case for many of the network failures scenarios. Moreover, we argue that in a market context where the electricity supplied and demanded are traded and are subject to various price signals, it is important to analyze the global economic severity of the different contingencies.

In this work, we propose a risk assessment method which considers the economic severity of network failures in terms of both the cost of ENS and the cost of correcting the dispatch in the network, in a market context. We consider a uniform pricing market with a counter-trading mechanism for clearing network infeasibilities in case of line failures and oligopolistic generation companies (GenCos) that are able to act strategically and exercise market power. The uniform-pricing market, the zonal market, and the nodal pricing market are the three market schemes dominantly adopted in deregulated systems [32]. However, when it comes to the need of congestion management which could arise due to a network contingency, the nodal pricing schemes internalize the congestion costs in the energy prices at each node [33], and therefore no subsequent mechanism or pricing is needed to manage this congestion. This is not the case for a uniform-pricing market, or within each zone in the zonal market, which are the market schemes implemented in most western European countries. Several works have studied the effects of network congestion on the performance of a uniform-pricing electricity market and especially in terms of strategic bidding and exercise of market power. Most notably, reference [33] compares nodal pricing and counter-trading mechanisms for managing network congestion in electricity markets. In doing so, they study the effect of counter-trading on the generation companies strategic bidding in the day-ahead market (DAM) and on overall social welfare, by evaluating the potential benefits of introducing additional competition. They show that under counter-trading, the new entrant in the export constrained area can collect additional profits, resulting in over-investment in this area, and in a welfare loss for the society. Reference [34] analyzes the congestion influence on GenCos bidding strategies by providing an analytical framework for solving a mixed-strategy Nash equilibrium, representing the GenCos interaction in a uniform-pricing market. They show that congestion in the transmission network may increase the GenCos ability to exercise market power, resulting in higher prices. Both approaches, however, are only aimed at providing insights on the above-mentioned effects and therefore have limited applicability to large size problems. Study [35] address the same issue by proposing a conjectural-variation equilibrium problem to model the GenCos strategic interaction in the uniform-pricing market. The equilibrium problem is cast as an equivalent quadratic minimization that can be readily solved with commercial solvers. The framework proposed includes a Direct-Current Optimal Power Flow (DC-OPF) model to solve the network power dispatch. A similar framework to study the effect of network congestion on GenCos strategic bidding is proposed in [36]; however, the network congestion is considered as the level of voltage level violation, instead of active power flow violation, and an AC-OPF model is implemented, instead of the DC-OPF.

All of the above studies internalize the effect of counter-trading on the GenCos strategic bidding in the DAM. Namely, they consider that since network congestions are a recurring phenomenon, GenCos can anticipate its effect, and internalize it by optimizing their bids both in the DAM and the subsequent counter-trading mechanism, simultaneously. While this is suitable for the purpose of their studies, we defer in that we consider an explicit separation between the GenCos bidding in the DAM and that of the subsequent correction mechanism, which we refer to as the balancing market (BM). This is because we consider congestion situations which arise exclusively due to network contingencies, that occur unexpectedly, and less often during normal power system operation, and therefore it is highly unlikely that GenCos would change their strategies in the DAM to take them into account. GenCos can still, however, react to such contingencies by adapting their offers in the BM, in order to maximize their profits. This explicit separation also helps emphasizing the cost of the dispatch correction arising due to the network contingency, especially for risk assessment and comparison purposes. Moreover, since anticipating and internalizing network congestions in the DAM offering would constitute solving a model represented as an Equilibrium Problem with Equilibrium Constraint (EPEC) [37], that is non-linear and non-convex, iterative solution methods such as that presented in [35] are necessary to solve it, and it is often very difficult to achieve convergence and to validate the solutions obtained.

For the risk assessment, we propose a 3-stage model to simulate the deregulated power system behavior in case of a network failure, consisting of a conjectural-variation equilibrium model simulating the GenCos competition in the day-ahead uniform pricing market (DAM), a direct-current optimal power flow model (DC-OPF) to obtain the feasible dispatch in the network, and a conjectural-variation equilibrium model to simulate the counter-trading mechanism. We finally propose a risk index to quantify the economic impact of the different line failures. The method is tested on a 6-bus system adapted from the IEEE 6-bus Reliability Test System [38], and the results are presented and discussed.

The rest of the paper is organized as follows. Section 2 describes in details the uniform-pricing market scheme under study and illustrates the model assumptions and formulation. Section 3 illustrates the solution method adopted to solve the 3-stage model. Section 4 describes in details the numerical example used in this study. Section 5 presents and explains the risk assessment results. Section 6 provides a sensitivity analysis for the risk index proposed with respect to the level of competitiveness assumed for the different GenCos and Section 7 concludes the work.

2. Model assumption and formulation

In electricity markets, competing GenCos who wish to produce have to participate in the day ahead market (DAM), by offering to the market operator (M.O.) hourly bids that consist of quantities and price pairs for next day production schedule. The M.O. aggregates all the supply bids, and collects and aggregates all the demand bids to construct the supply-demand curve. The M.O. re-arranges all the bids received from the suppliers in an ascending order in terms of prices (each generation unit considered separately) and each bid received from the demand in a descending order, until the total generation equals the total demand. Thus, the market marginal price is set to the bid price of the most expensive unit committed for dispatch. In a uniform pricing market, this price will be the same used for the remuneration of all the units committed. If we do not take into consideration the network representation, it is very probable that the schedule resulting from the market clearing may not be technically feasible (e.g. may exceed the maximum capacities of the lines). Moreover, in the case of a line failure, the system operator (S.O.) will need to re-dispatch the units to ensure an energy dispatch in the network that minimizes the amount of energy not served (in case curtailment is inevitable), and to ensure the system stability so that no other line becomes overloaded, with the risk of leading to a cascading network failure.

In a uniform pricing market, the re-dispatching strategy is typically implemented via a counter-trading mechanism, which can be approximated as follows [33]: the S.O. receives price-quantity bids for the day-ahead market from the GenCos and price-quantity bids for the subsequent balancing market, representing the price at which each GenCo is willing to increase or reduce, in terms of production of each unit with respect to the result of the DAM schedule, in case there is a need for a re-dispatch. The S.O. would solve an OPF problem prior to real-time dispatch, based on the schedule proposed in the DAM, to check the schedule feasibility. Typically, this analysis would have as primary aim the identification and elimination of network congestion.

For those units that will have to increase their production, the transmission adjustments can be paid at the equilibrium price of the production increase bids in the upwards BM. While for the units which are required to decrease their production, they would ideally bid according to their "avoided fuel costs" in the downwards BM, and would be either charged the equilibrium price of this market, or a price in accordance to a pay-as-bid rule [33].

We propose to model this market mechanism through a 3-stage model: the first stage is an equilibrium problem to obtain the DAM price and schedule, the second stage is a DC-OPF power flow problem, which represents the S.O. decisions, and the third stage is an equilibrium problem to find the competition outcome in both the upwards and the downwards BM and, subsequently, calculate the correction costs. Both equilibrium models for the DAM and BM are formulated as a conjectural-variation problem that allows the parametrization of different levels of competition among the GenCos through the conjecture price-response parameters [39], considered to be exogenously obtained in the problem. This formulation is similar to that proposed in [36].

Competition in the Day-Ahead Market

Under the simplest assumptions, in the DAM competition each firm i is searching to maximize its profit following:

$$\max_{\Pi} \ \lambda_i \cdot \sum_{j \in J_i} q_j^{DAM} - \sum_{j \in J_i} c_j(q_j^{DAM}) \tag{1}$$

Subject to:

$$\lambda_i = \lambda^* - \theta_i \cdot \left(\sum_{j \in J_i} q_j^{DAM} - \sum_{j \in J_i} q_j^{*DAM} \right) \tag{2}$$

$$\overline{q_j} - q_j^{DAM} \geq 0 : \quad (\overline{\mu_j}) \qquad \forall j \in J \tag{3}$$

$$q_j^{DAM} \geq 0 \qquad \forall j \in J \tag{4}$$

where $\Pi = \{\lambda_i, q_j^{DAM}\}$. The objective function (1) is the profit function to be maximized and it is equal to the revenues obtained from the production in the DAM $\left(\lambda_i \cdot \sum_{j \in J_i} q_j^{DAM} \right)$ minus the costs of production $\left(\sum_{j \in J_i} c_j(q_j^{DAM}) \right)$. The price (λ_i) represents GenCo (i) estimation of the DAM price. Since we assume that the participating GenCos are price makers, their production decisions should endogenously determine the market price. This strategic behavior is represented with constraint (2) by means of the conjecture-price response parameter ($\theta_i = -\ \partial\lambda_i/\partial q_j^{DAM}$). In equilibrium, the single DAM equilibrium price is (λ^*) and the optimal quantity produced is (q_j^{*DAM}). Constraint (2) ensures that both upwards and downwards deviations in the production from the optimal production levels reduce the company profits, thus ensuring that the price estimate (λ_i) is equal to the equilibrium price (λ^*). Constraints (3) and (4) are the boundaries of the production variables.

Competition in the Balancing Market

In case of schedule infeasibilities due to network constraints, generation units will have to be re-dispatched. Some units will have to increase, while others will have to reduce their productions. In a market context, this rescheduling will be achieved by referring to the bids in both the upwards and the downwards BM. It is, therefore, very likely that competing GenCos will choose their bids strategically to maximize their profits as well in this subsequent mechanism. We can approximate the GenCos strategic behavior in the BM by solving an optimization problem where each GenCo seeks to maximize its profit. The BM optimization problem for each firm (i) can be formulated as:

$$\max_{\Delta}\ \gamma_i \cdot \sum_{j\in J_i} x_j^{BM} - (\psi_i + \lambda^*) \cdot \sum_{j\in J_i} z_j^{BM} - \sum_{j\in J_i} c_j(x_j^{BM} - z_j^{BM}) \tag{5}$$

Subject to:

$$\gamma_i = \gamma^* - \beta_i \cdot \left(\sum_{j\in J_i} x_j^{BM} - \sum_{j\in J_i} x_j^{*BM} \right) \tag{6}$$

$$\psi_i = \psi^* - \phi_i \cdot \left(\sum_{j \in J_i} z_j^{BM} - \sum_{j \in J_i} z_j^{*BM} \right) \tag{7}$$

$$\overline{q_j} \cdot u_j^{OPF} - x_j^{BM} \geq 0 : \quad (\overline{\nu_j}) \qquad \forall j \in J \tag{8}$$

$$\overline{q_j} - q_j^{DAM} - x_j^{BM} \geq 0 : \quad (\overline{\xi_j}) \qquad \forall j \in J \tag{9}$$

$$q_j^{DAM} \cdot w_j^{OPF} - z_j^{BM} \geq 0 : \quad (\overline{\delta_j}) \qquad \forall j \in J \tag{10}$$

$$x_j^{BM} \geq 0, \quad z_j^{BM} \geq 0 \qquad \forall j \in J \tag{11}$$

$$\left\{ q_j^{DAM} \right\} \in \arg \Pi \tag{12}$$

$$\left\{ u_j^{OPF}, w_j^{OPF} \right\} \in \arg \Xi \tag{13}$$

where $\Delta = \{\gamma_i, \psi_i, x_j^{BM}, z_j^{BM}\}$. The objective function (5) represents the profit function for each GenCo (i). (x_j^{BM}) and (z_j^{BM}) are the decision variables for the upwards and the downwards production quantities, respectively, while (γ_i) and (ψ_i) are the market prices for the upwards and the downwards BM respectively. It is important to note that the revenues from the downwards balancing market ($\psi_i \cdot \sum_{j \in J_i} z_j^{BM}$) are represented as a negative term in the profit function, this is to portray that competing firms will perceive them as a charge, and calculate their bids in accordance to their avoided fuel cost resulting from the reduced real time production. Moreover, the loss of profit from not producing in the DAM is illustrated by subtracting the term ($\lambda^* \cdot \sum_{j \in J_i} z_j^{BM}$), where at this stage the DAM price (λ) is known. Constraints (6) and (7) ensure that the optimization output is equal to the equilibrium output of the market, and follow the same explanation given for constraint (2). The conjecture price-responses for the upwards BM and the downwards BM are ($\beta_i = -\ \partial\gamma_i / \partial x_j^{BM}$) and ($\phi_i = \partial\psi_i / \partial z_j^{BM}$), respectively.

Constraints (8)-(11) are the boundaries for the decision variables. (u_j^{OPF}) and (w_j^{OPF}) are binary decision variables from the DC-OPF problem, they represent the state of the units which will be able to increase or decrease their productions respectively, in order to correct the real time dispatch. If (u_j^{OPF}) or (w_j^{OPF}) is equal to 1, it means that the respective unit (j) can participate in the upwards or in the downwards BM, respectively; otherwise, it can not. This is to ensure a simplified, yet realistic, representation of the market, where no unit can participate in the BM unless it is physically located on a network bus where the BM is activated in order to solve the congestion. Finally, equations (12) and (13) indicate that the variables $\{q_j^{DAM}\}$ and $\{u_j^{OPF}, w_j^{OPF}\}$ are the output of the decision variables in the DAM market problem and the DC-OPF problem, respectively.

Market Clearing Conditions

Since we seek to find the equilibrium market outcome, we need to define the market clearing equations. These equations are the governing conditions that link the individual GenCos optimization problems together. For a uniform-pricing DAM, the total energy production has to be equal to the total demand, or:

$$\sum_{j \in J} q_j^{DAM} = D \quad \forall j \in J \tag{14}$$

Similarly, for the BM, the sum of the increased or reduced production is equal to the sum of the energy required for the upwards-balancing (UB) or the downwards-balancing (DB), respectively, or:

$$\sum_{j \in J} x_j^{BM} = UB \quad \forall j \in J \tag{15}$$

$$\sum_{j \in J} z_j^{BM} = DB \quad \forall j \in J \tag{16}$$

Equilibrium problem formulation

For the DAM problem, the corresponding MCP is defined by finding the system of equations which corresponds to the Karush-Kuhn-Tucker (KKT) conditions of the problem (1) to (4), after substituting for (λ_i) by the right-hand side of constraint (2) and adding the market clearing condition (14). The DAM-MCP is, thus, defined as:

$$0 \leq q_j^{*DAM} \perp -\lambda^* + \ \theta_i \cdot \sum_{j \in J_i} q_j^{*DAM} + \ MC_j\left(q_j^{*DAM}\right) + \ \overline{\mu_j} \geq 0, \quad \forall j \in J_i, \forall i \in I \tag{17}$$

$$0 \leq \overline{\mu_j} \perp \overline{q_j} - q_j^{*DAM} \geq 0, \qquad \forall j \in J_i, \forall i \in I \tag{18}$$

$$\sum_{j \in J} q_j^{DAM} = D \quad : \quad \lambda \tag{19}$$

where the DAM price (λ) is obtained as the dual-variable of the market clearing constraint (19). All other constraints are solved for all units (j) belonging to GenCo (i), and for all GenCos.

Similarly, we define the BM-MCP as:

$$0 \leq x_j^{*BM} \perp -\gamma^* + \beta_i \cdot \sum_{j \in J_i} x_j^{*BM} + MC_j\left(x_j^{*BM} - z_j^{*BM}\right) + \overline{\nu_j} + \overline{\xi_j} \geq 0, \qquad \forall j \in J_i, \forall i \in I \tag{20}$$

$$0 \leq z_j^{*BM} \perp \psi^* + \lambda^* + \phi_i \cdot \sum_{j \in J_i} z_j^{*BM} - MC_j\left(x_j^{*BM} - z_j^{*BM}\right) + \overline{\delta_j} \geq 0, \qquad \forall j \in J_i, \forall i \in I \tag{21}$$

$$0 \leq \overline{\nu_j} \perp \overline{q_j} \cdot u_j^{OPF} - x_j^{*BM} \geq 0, \qquad \forall j \in J_i, \forall i \in I \tag{22}$$

$$0 \leq \overline{\xi_j} \perp \overline{q_j} - q_j^{*DAM} - x_j^{*BM} \geq 0, \qquad \forall j \in J_i, \forall i \in I \tag{23}$$

$$0 \leq \overline{\delta_j} \perp q_j^{*DAM} \cdot w_j^{OPF} - z_j^{*BM} \geq 0, \qquad \forall j \in J_i, \forall i \in I \tag{24}$$

$$\sum_{j \in J} x_j^{BM} = UB \quad : \quad \gamma \tag{25}$$

$$\sum_{j \in J} z_j^{BM} = DB \quad : \quad \psi \tag{26}$$

where equations (20) to (24) correspond to the KKT conditions of the problem (5)–(13), and equations (25) and (26) are the market clearing conditions as previously described. The market prices (γ) and (ψ) are obtained as the dual-variables of the market clearing conditions of the upwards BM (25), and that of the downwards BM (26), respectively.

Direct-Current (DC) Optimal Power Flow Model

The network's operating decisions by the S.O. taking into account the technical representation of the electricity network is modeled through a DC-OPF problem. This problem is formulated as a mixed-integer linear programming problem as follows:

$$\min_{\Xi} \sum_{a \in N} cens_a \cdot x_a^{vg} \tag{27}$$

subject to:

$$\sum_{j \in J_a} q_j^{OPF} + \sum_{a' \in N} F_{(a,a')} = D_a - x_a^{vg}, \quad \forall a \in N, \quad \forall (a,a') \in L \tag{28}$$

$$F_{(a,a')} = ms_{(a,a')} B_{(a,a')} \left(\delta_a - \delta_{a'}\right), \quad \forall (a,a') \in L \tag{29}$$

$$\sum_{j \in J_a} q_j^{OPF} = \sum_{j \in J_a} q_j^{DAM} + \sum_{j \in J_a} x_j^{OPF} - \sum_{j \in J_a} z_j^{OPF}, \quad \forall j \in J_a, \quad \forall a \in N \tag{30}$$

$$0 \leq \sum_{j \in J_a} q_j^{OPF} \leq \sum_{j \in J_a} \overline{q_j}, \quad \forall j \in J_a, \quad \forall a \in N \tag{31}$$

$$0 \leq \sum_{j \in J_a} x_j^{OPF} \leq \sum_{j \in J_a} \overline{q_j} \cdot u_a^{OPF}, \quad \forall j \in J_a, \quad \forall a \in N \tag{32}$$

$$0 \leq \sum_{j \in J_a} z_j^{OPF} \leq \sum_{j \in J_a} \overline{q_j} \cdot w_a^{OPF} \cdot (1 - u_a^{OPF}), \quad \forall j \in J_a, \quad \forall a \in N \tag{33}$$

$$0 \leq x_a^{vg} \leq D_a, \quad \forall a \in N \tag{34}$$

$$\delta_1 = 0 \tag{35}$$

$$u_a^{OPF}, w_a^{OPF} \in \{0, 1\}, \quad \forall j \in J \tag{36}$$

where $\Xi = \{q_j^{OPF},\ x_j^{OPF},\ z_j^{OPF},\ x_a^{vg},\ F_{(a,a')},\ \delta_a,\ \delta_{a'},\ u_a^{OPF},\ w_a^{OPF}\}$. The objective function (27) of the S.O. is to minimize the energy not served in the network, given the DAM schedule, subject to the network technical constraints. (x_a^{vg}) is the amount of energy not served at each network bus (a), which is obtained as the production value of a virtual-generator (vg) added to this network bus. ($cens_a$) is the cost of energy not served at bus (a) and is represented as the cost of production of the respective (vg). (q_j^{OPF}) is the final production output as found in the DC-OPF and $\left(\sum_{j \in J_a} x_j^{OPF}, \sum_{j \in J_a} z_j^{OPF}\right)$ are the total upwards and downwards amounts of energy required per network bus a. Constraint (28) is the supply-demand balance equation considering the power flows in the network ($F_{(a,a')}$), which are either entering (positive) or leaving (negative) bus (a). Constraint (29) defines the active power flow in the different lines of the network, where ($B_{(a,a')}$) is the line susceptance and (δ_a) is the voltage-angle at each bus. The mechanical state of each line ($ms_{(a,a')}$) is an exogenous parameter: it takes the value of 1 if the line is active and the value of 0 if the line fails, and it is how the line failure status is represented in the dispatch problem. Constraint (30) ensures the consistency between the decisions taken in the final production schedule and the DAM bidding schedule. Constraints (31) to (34) are the boundaries of the decision variables, namely the production quantity (q_j^{OPF}), the upwards and the downwards production required (x_j^{OPF}) and (z_j^{OPF}), respectively. (u_a^{OPF}) is a binary decision variable, which is equal to 1 if the units at bus (a) are required to increase their production to solve a network constraint and is equal to 0 otherwise. Similarly, (w_a^{OPF}) is a binary decision variables, which is equal to 1 if the units at bus (a) are required to reduce their production and 0 otherwise. The term ($1 - u_a^{OPF}$) in constraint (33) ensures that units on the same bus can not be required to increase and reduce their productions at the same time. Finally, constraint (35) sets the bus voltage-angle reference point at bus (1).

Risk Index and Assessment Method

To adopt a quantitative definition of risk, we refer to expected consequence as the product of the probability of occurrence of an undesired event (e.g. transmission line failure) and the resulting consequence [18]. To take into account the negative effect of several undesired events, the definition is extended by summing all relevant consequence contributions. Formally, we can express the risk as:

$$Risk(R) = \sum_n p(E_n) \cdot Sev(E_n) \tag{37}$$

where n is the event index, $p(E_n)$ is the probability of occurrence of the undesired event E_n and $Sev(E_n)$ is the severity of the related consequences.

Probability Model

We adhere to the intrinsic failure characteristics of the transmission lines to calculate the probability of line failure, extrapolating the historical data of the permanent outage rate for each line and its respective outage duration in hours. However, different contributions can be considered, for example that of a line failure due to voltage instability caused by a stochastic renewable production source [28] or the probability of failure resulting from extreme weather conditions [19].

The probability model for the risk assessment is, thus, defined as:

$$p(E_l) = \frac{OR_l \cdot T_l}{Hrs}, \qquad \forall l \tag{38}$$

where l is the transmission line index, OR_l is the outage rate per year per line, T_l is the average outage duration for transmission line l in hours and Hrs is the total number of operating hours per year.

Severity calculation

We consider an *economic* severity function where the risk factor proposed is calculated based on the system costs encountered due to line failures. We consider mainly two costs: the costs of energy not served (estimated as a constant function in terms of €/MW) and the costs arising in a uniform-pricing market context for correcting the dispatch in real-time production. The latter represents the economic inefficiencies arising due to the strategic behavior in multiple-market interactions. Formally, this is formulated as:

$$Sev(E1_l) = cens_{a,l} \cdot x^{vg}_{a,l}, \qquad \forall a \in N, \forall l \in L \tag{39}$$

$$Sev(E2_l) = \left[\gamma^*_l \cdot x^{*BM}_{j,l}\right] - \left[(\psi^*_l + \lambda^*) \cdot z^{*BM}_{j,l}\right], \qquad \forall j \in J, \forall l \in L \tag{40}$$

Severity function (39) represents the effect of the energy not served, where ($cens_{a,l}$) is the cost of the energy not served at network bus (a) due to line (l) failure and ($x^{vg}_{a,l}$) is the amount of energy not served at bus (a) in case of such failure. Severity function (40) represents the effect of the schedule correction, considering the amount paid for upwards corrections ($\gamma^*_l \cdot x^{*BM}_{j,l}$) and the amount charged for downwards corrections ($\psi^*_l \cdot z^{*BM}_{j,l}$) minus the savings made from the generation reduction ($\lambda^* \cdot z^{*BM}_{j,l}$) , for each line failure case. The risk assessment index considered is, thus, defined such as:

$$Risk(E_l) = \frac{OR_l \cdot T_l}{Hrs} \cdot \left[(cens_{a,l} \cdot x^{vg}_{a,l}) + (\gamma^*_l \cdot x^{*BM}_{j,l}) - ((\psi^*_l + \lambda^*) \cdot z^{*BM}_{j,l}) \right], \quad \forall a \in N, \forall j \in J, \forall l \in L \tag{41}$$

$$SRisk = \sum_{l \in L} Risk(E_l) \tag{42}$$

where the aggregated system risk index (42) can be used in the comparison of the risk assessment for different power transmission systems.

3. Solution Method

The two MCPs formulated can be readily solved with available commercial solvers. For the present study we use the PATH solver [40] in the GAMS environment [41]. For the DC-OPF we use the IBM ILOG-CPLEX solver. The aim is to find the final feasible schedule in case of a line failure, taking into account the GenCos DAM bidding, and subsequently to find both the upwards and the downwards BM prices and quantities bids used for the calculation of the risk index. For this multi-stage problem, we propose a solution method as follows:

1. Solve the DAM-MCP (17)-(19) to obtain the equilibrium DAM price (λ^*) and the generation units quantities bids (q_j^{*DAM}).
2. Solve the DC-OPF problem (27)-(36) given (q_j^{*DAM}) to obtain (q_j^{OPF}, x_j^{OPF}, z_j^{OPF}, x_a^{vg}, $F_{(a,a')}$, δ_a, $\delta_{a'}$, u_a^{OPF}, w_a^{OPF}).
3. Calculate the total energy required for the upwards-balancing (UB) and the downwards-balancing (DB):

$$UB = \sum_{j \in J} x_j^{OPF} \tag{43}$$

$$DB = \sum_{j \in J} z_j^{OPF} \tag{44}$$

4. Since (u_a^{OPF}) and (w_a^{OPF}) are the upwards and downwards binary state for network bus (a), we translate these status to each unit (j) belonging to bus (a):

$$u_j^{OPF} = \begin{cases} 1, & \text{if } u_a^{OPF} = 1 \text{ and } j \in J_a \\ 0, & \text{otherwise} \end{cases} \tag{45}$$

$$w_j^{OPF} = \begin{cases} 1, & \text{if } w_a^{OPF} = 1 \text{ and } j \in J_a \\ 0, & \text{otherwise} \end{cases} \tag{46}$$

5. Solve the BM-MCP (20)-(26) given the values calculated in (43)-(46), and the known DAM price (λ^*), to obtain the BM upwards and downwards equilibrium market prices (γ^*, ψ^*) and quantities bids (x_j^{*BM}, z_j^{*BM}), respectively.
6. Calculate the risk index (41) for each line failure and finally the aggregated index (42).

4. Case study

Numerical Example

The power system under study is a 6-bus system adapted from the IEEE 6-bus Reliability Test System [38]. Figure (1) shows the single line diagram of the adapted RBTS system. As shown, the system has 2 PV buses containing 11 generation units (units 1 to 11), 5 PQ buses , and 7 transmission lines. Units 12 to 17 are the virtual generators used for the calculation of the amount of energy not served in their respective demand bus. The minimum and the maximum ratings of the generating units are 5 MW and 40 MW, respectively. The voltage level of the transmission system is 230 kV. The system has a peak load of 185 MW and the total installed capacity amounts to 240 MW. Table (1) illustrates the breakdown of the total available capacity and peak hour demand per network bus. Since no reactive power is considered in the network, it is assumed that bus voltages magnitudes are constant and equal to 1pu. Finally, Table (2) summarizes the technical characteristics of the transmission lines.

Generation Units Breakdown in the Network

Table (3) summarizes the maximum capacities and the cost data for each of the generation units. Table (4) illustrates the capacity limits and cost data for the virtual units. The ENS cost is calculated on the basis of 120 €/MWh, multiplied by the percentage of the demand present at the respective network bus. The capacity limits for the VGs are set to the maximum amount of load in each bus to ensure that no VG compensates for load shedding located in any network bus other than where it is placed. Finally, Table (5) illustrates the transmission lines maximum capacities, the outage data expressed as the number of complete line outage for each line per year and the duration of this outage in hours. It is important to note that the maximum line capacities are chosen such that they would always be operated close to their limits under normal operating conditions (i.e. under no failure).

GenCos Characterization

Table (6) illustrates the GenCos characteristics. It is assumed that 4 GenCos are competing in both markets, each owning different generation mix and different total production capacities. For the DAM and the BM, GenCos are assumed to have the ability to act strategically, which is represented by the conjectured-price response terms, as previously discussed. The values of the conjectured-price response for the DAM (θ_i) is assumed to be equal to 0.2 for GenCos 1, 2 and 4, and equal to 0.1 for GenCo 3. This is to represent that a GenCo having the smallest capacity and some of the most expensive units (such as GenCo 3) would typically have less chances to exercise market power than the GenCos which have cheaper units more often committed. For the BM, the conjectured-price response (β_i and ϕ_i) are assumed to be equal to 0.1 for all GenCos. Finally, it is assumed that the cost functions for the generation units are linear.

5. Results

We solve the model simulating 8 different cases: the "base case", where we do not consider any network line failures and is, thus, considered as the benchmark or the "business-as-usual" case for an hourly competition in a power system and cases (I to VII), where we consider the separate effects of line 1 to line 7 failure, respectively. All the results reported consider the oligopolistic behavior of the GenCos, as the values of the conjectured-price response parameters in all markets (θ, β and ϕ) are different from zero.

Table (7) illustrates the production quantity bids for all GenCos obtained from the DAM-MCP, for all cases considered. Since the bidding decisions in the DAM do not depend on the line failure case [1], the resulting bids do not change according the different line failures. These results only depend on the assumed level of the conjectured-price response parameters and the intrinsic characteristics of the generation units. It is important to note that units 3 to 11 possess enough capacity to satisfy all the network demand at a lower market price equal to [2] or slightly higher than unit 3 marginal cost [3]. However, since we model an oligopolistic market where ($\theta_i \neq 0$), the equilibrium model correctly portrays the GenCos behavior where units 3 and 4 retract quantities offered to ensure that the more expensive units (1 and 2) are committed and, thus, increase the uniform clearing market-price to the λ level shown in Table (13). These results are consistent with our expectations, and with the studies reviewed, which consider the ability of GenCos to exercise market power. Most notably, for the no-congestion case presented in [35], where market power is equally parametrized by conjecture price-response parameters, the authors reported similar results, showing that GenCos can increase the market price above the marginal level by modifying

[1] We assume that the failure occurs after the DAM gate-closure and close to real-time dispatch.

[2] In case of perfect competition

[3] Both units 1 and 2 have higher marginal costs and typically would not be committed.

the production offers of their units.

Table (8) summarizes the aggregation of the GenCos bids per network bus to clearly illustrate how the S.O. would validate the feasibility of the schedule in the different failure cases.

Table (9) illustrates the solution of the DC-OPF problem which has the objective of obtaining the real feasible schedule. It is shown that compared to the pre-failures schedule, the different failure cases induce the need for some upwards or downwards production adjustments along the buses with active power output. This amount varies from one case to the other, already providing an insight on the impact of the failure in terms of the amount of ENS.

The amounts of the ENS per network bus calculated based on the minimum cost objective are summarized in Table (10). It is shown that in both the no failure case and Case I there is no ENS in the network. Since the network flow limits can initially accomodate the required power dispatch, it is clear that the schedule would remain unchanged if no failure occurs. If line 1 fails, the cheaper generation units 5 to 11 at bus 2 can no longer export all of their production, a schedule correction is required, calling upon the more expensive units 1 to 4 located at bus 1. However, the rest of the network can still accomodate this modified schedule, and hence, no demand is curtailed. The ENS amount varies in all other cases based on the updated topology of the network, and on how much it allows for demand coverage.

Given these results, the BM-MCP is solved, and the equilibrium results of the upwards and the downwards BM obtained are summarized in Tables (11) and (12), respectively. The upwards balancing market is activated only in the case of line 1 failure since it is the only failure case where there are generation units on a network bus (bus 1) that have enough available upwards capacity to compensate for the reductions required on the other bus (bus 2). In all the other cases, there exist no units on the different buses that can compensate for the power losses in the network and, therefore, demand is curtailed, and only the downwards BM is activated.

The resulting upwards (γ) and downwards (ψ) BM prices are summarized in Table (13). For Case I, the upwards BM (γ) is different than zero since the market is activated. However, as shown, this market price is lower than the DAM price (λ). This is due to the strategic behavior of the GenCos in the DAM, where the expensive units (1 and 2) have already been committed to their maximum capacities and, subsequently, only the cheaper units (3 and 4) can participate in the subsequent market. The price, however, is still higher than the marginal cost of both units 3 and 4, similarly representing the effect of the parametrized strategic behavior of the GenCos in this market.

The analysis of the strategic bidding in the BM resembles that given for the DAM. GenCos retract quantities offered by the cheaper units in the upwards BM to ensure an increase in the market price. In the downwards BM, this strategy works in the opposite sense: ideally the most expensive unit able to reduce is committed for the downwards balancing, resulting in the highest market price (highest since this market price is represented as a negative term in the GenCos profit function). However, GenCos with expensive units have incentives to bid lower quantities so that cheaper units are committed for downwards balancing, thus ensuring a lower downwards market price and, therefore, a higher profit. For a clear illustration of this concept, it is important to consider that in the downwards BM, GenCos are only interested to participate if they are compensated in accordance to their "avoided fuel cost", or otherwise, the net profit they would have made by being active in the DAM. Expensive units save more cost by being selected to reduce their production and, therefore, to compensate for their profit loss, are willing to bid higher. This is shown in downwards BM price (ψ) in Table (13). First, note that the negative market price indicates that the GenCos would actually be compensated for their participation in this market. For cases I to IV, units with cheaper marginal cost are required to reduce their productions. As discussed, their participation in this market drives the negative prices down and constitute a higher charge to be paid for their participation. For cases V to VII, only expensive units are called upon, resulting in higher negative prices and therefore a lower charge for their participation.

Since none of the reviewed studies considers explicitly the DAM and BM separation, we validate the results obtained by comparing them to what we would obtain out of the perfect competition outcome, which is well known from economics theory [42] and can be calculated analytically. For simple illustration, consider the perfect competition BM solution of Case IV. This can be obtained in the model by setting the conjecture-price response parameters (β and ϕ) to zero for all the GenCos, and solving for the required corrections, to obtain the bidding quantities and the market prices. We focus on the downwards BM, since it is the only correction market active in this case. Active units on bus 2 are required to bid for a reduction of 0.83 MWh; in this setting, and according to the outcome of perfect competition, we would expect that one of the most expensive units on this network bus (one with a marginal cost of 0.8 €/ MWh) would bid its opportunity cost to undergo this reduction. This would be calculated as follows: the total revenue loss from reducing 0.83 MWh is this amount multiplied by the DAM price, or $0.83 * 19.125 = 15.874$ €; the production cost saved is equal to the marginal cost multiplied by the reduced amount, or $0.8 * 0.83 = 0.664$ €. Therefore, this GenCo would be willing to participate in the market if it was at least compensated the marginal loss of $(0.664 - 15.874)/0.83 = -18.325$ €/MWh. This is exactly the outcome obtained by solving the model, resulting in unit 5 offering 0.83 MWh reduction and a clearing market price of -18.325 €/MWh. Notice that a much less competitive output occurs if one of the cheaper units with a marginal cost of 0.5 €/MWh become the marginal unit, resulting in a clearing price of -18.625 €/MWh. This is correctly portrayed in the results reported in Table (13), where we have considered a departure from the perfect competition outcome by setting the parameter $\phi \neq 0$, which leads to a different offering than that of perfect competition and a consistently worse market clearing price equal to -18.367 €/MWh. This is similar for all the other cases presented.

The ENS and the schedule correction costs arising due to network line failure are thus calculated, and are summarized in Table (14). It can be seen that, in this numerical example, the ENS cost is significantly higher than the correction cost, indicating that it remains the most significant cost to consider for the risk assessment. However, it is important to note that a line failure can induce a need for a schedule correction without giving rise to ENS in the network, such as in Case I. Note also that this correction cost can be positive or negative (from the S.O. perspective) depending on the failed line and the resulting dispatch requirements, as well as the level of competition in the BM. The total cost used to calculate the risk index is summarized in Table (14).

Finally, the risk index values for all cases are shown in Table (15). This index is to be used for identifying the effect of the failure taking into consideration the market interactions among the GenCos, and can serve in comparing the impact of the different failures. An important observation, is that within a similar market context, a risk index that only considers the cost of ENS in the severity function such as that presented in [31], would fail to identify Case I presented in the system risk assessment. Moreover, it can underestimate, or overestimate the economic impact of any of the failures, due to the effects arising from the exercise of market power. Such an impact is shown to become increasingly relevant as we depart further from the perfect competition behavior and portray GenCos that are able to manipulate the markets to gain more profits.

In the previous section, we have analyzed in some depth a case study based on the risk assessment method proposed. Next, we examine how much this assessment is sensitive to the assumed level of competitiveness.

6. Sensitivity Analysis

Apart from the specific characteristics of the system under study (e.g. the assumed generation units location, variable costs, units distribution among the GenCos, etc.), the resulting quantity bids, schedules and market prices in the model, and subsequently the risk level are dependent on the assumptions related to the conjectured-price responses (θ_i, β_i, and ϕ_i) in the different markets. As previously mentioned, these parameters are considered as being exogenous in our work but it has been shown that they can be estimated or endogenously calculated in real markets [43]. Therefore, it is of interest to conduct a sensitivity analysis for these parameters to understand their effect on system risk.

We conduct the analysis by solving the 7 cases of line failure while varying the value of the conjecture price-response parameters (θ_i, β_i, and ϕ_i) from 0 to 1 with step size of 0.1, one at a time, resulting in a total of 9,317 cases. We, then, aggregate the different costs arising and the risk indices for all 7 failure cases, to represent each of them as a single value under each level of competition, resulting in a total of 1,331 aggregated schedule correction costs and risk indices. The results are then plotted for a clear representation of the changes in the cost and/or risk index with respect to the changes in the different parameters. Since the plots produced are 4 dimensional, we divide each plot into 3 Figures for clear representation, where we fix the value of one parameter in each and plot the other two along with one of the variables.

Figure (2) illustrates the result of the sensitivity analysis for the schedule correction costs arising due to all 7 line failures, with respect to the competition parameters. In Figures (2a, 2b and 2c) the value of parameters (θ, β and ϕ) are fixed to zero. The ENS costs are not included in these graphs as they are constant for all the cases and do not change with the change in the competition parameters. It can be seen in Figure (2a) that the correction cost clearly increases as we increase the conjectured-price response (i.e. market power) of the GenCos in both the upwards (β) and the downwards

(ϕ) BM. Furthermore, the parameter (ϕ) for the downwards BM affects this correction cost much more than that of the upwards BM (β). As we have shown in the previous section, the different line failures simulated more often resulted in the activation of the downwards BM than the upwards one. The lowest cost resulting from setting the parameters (β) and (ϕ) equal to zero (simulating the perfect competition case) is -263.97 €, indicating that the S.O. would actually receive back some of the costs paid for the generation in the DAM as they would finally not produce. On the other hand, assuming the highest exercise of market power for all GenCos in both BM results in a cost of 5292.75 €, highlighting the big impact that the exercise of market power can have on the system cost.

Figures (2b, 2c) show that the cost increasing trend does not hold with increasing the market power in the DAM through the parameter (θ). This is because the change in (θ) for each GenCo results in a change in their bidding behavior in the DAM; these different starting schedules lead to different correction requirements as the lines fail, possibly leading to less or cheaper corrections compared to the perfect competition schedule. This counter-intuitive result is only due to the fact that we do not take into consideration the energy price in the DAM, which significantly increases as we increase the market power of the GenCos in this market. Figures (3b, 3c) illustrate the cost trend when we include the DAM energy cost. It is clear how important the increase in the DAM price affects the system costs, as we increase the parameter (θ). Finally, although the results are shown for the values of the parameters (θ, β, and ϕ) set to zero, similar patterns are found when they are set to different levels (i.e. 0.1 or 0.9).

Since we are interested in quantifying the economic risk of line failures, we revert to representing the sensitivity of the risk index without taking into account the energy cost in the DAM. Figure (4) illustrates the sensitivity analysis of the aggregated risk index and shows that it follows closely the changes in the correction cost of the system shown in Figure (2). Such representation could be especially useful in comparing the effect of different levels of competition among the GenCos.

7. Conclusion

In the work presented in this paper, a novel risk assessment method for network failures in an electricity market environment has been proposed. The electricity market design considered is a uniform-pricing market with counter-trading mechanism for correcting any network infeasibilities. A 3-stage model has been proposed to model the operation of the electricity system, consisting of:

- A conjectural-variation equilibrium model for simulating the competition in the DAM where the GenCos strategic behavior is modeled through a conjectured-price response parameter.
- A DC-OPF model to simulate the feasible power dispatch in case of a line failure.
- A conjectural-variation equilibrium model for simulating the counter-trading mechanism, where the different GenCos submit bids for both upwards and downwards correction of the dispatch.

Finally, an economic risk index has been proposed, which takes into account the economic effects of a line failure, namely the cost of ENS and the schedule correction cost.

The proposed method has been applied to a case study adapted from the IEEE 6-bus reliability test system and the results have been analyzed both technically and economically. Finally, a sensitivity analysis has been performed to examine the effect of the changes in the competitiveness level of the different market participants, portrayed in our model by the conjectured-price response parameters, assumed to be exogenous to the problem.

It is shown that within a uniform-pricing market context, a cost arises due to the schedule correction induced by a network contingency. Such a cost is not reflected in the technical risk indices typically calculated, for example, on the basis of voltage level and circuit flow violations, and is often neglected also in the economic risk indices that typically consider only the ENS cost. Our results show that this correction cost is, in fact, non-negligible and that considering it is important because it could alter the relative importance of the network contingencies. The proposed assessment can help the decision maker properly categorizing the impact of the different line failures within a uniform pricing market; this can be useful for deciding on maintenance schedules, for example. Policy implications and market design recommendations could also be derived but this is outside the scope of the present work.

Moreover, recognizing that the output of the model depends on the values of the conjectured-price response parameters assumed for the different markets, the sensitivity analysis performed confirms that there is a linearly increasing risk trend as we set those parameters to portray a less competitive behavior from the GenCos in the BM, which is expected as it is where the correction costs arise. This is not the case when varying the competitiveness level of the GenCos in the DAM, as it is shown that this would result in different initial production schedules and, therefore, different correction requirements. It is, thus, necessary to be careful in estimating and setting the values of these parameters when applying this assessment method.

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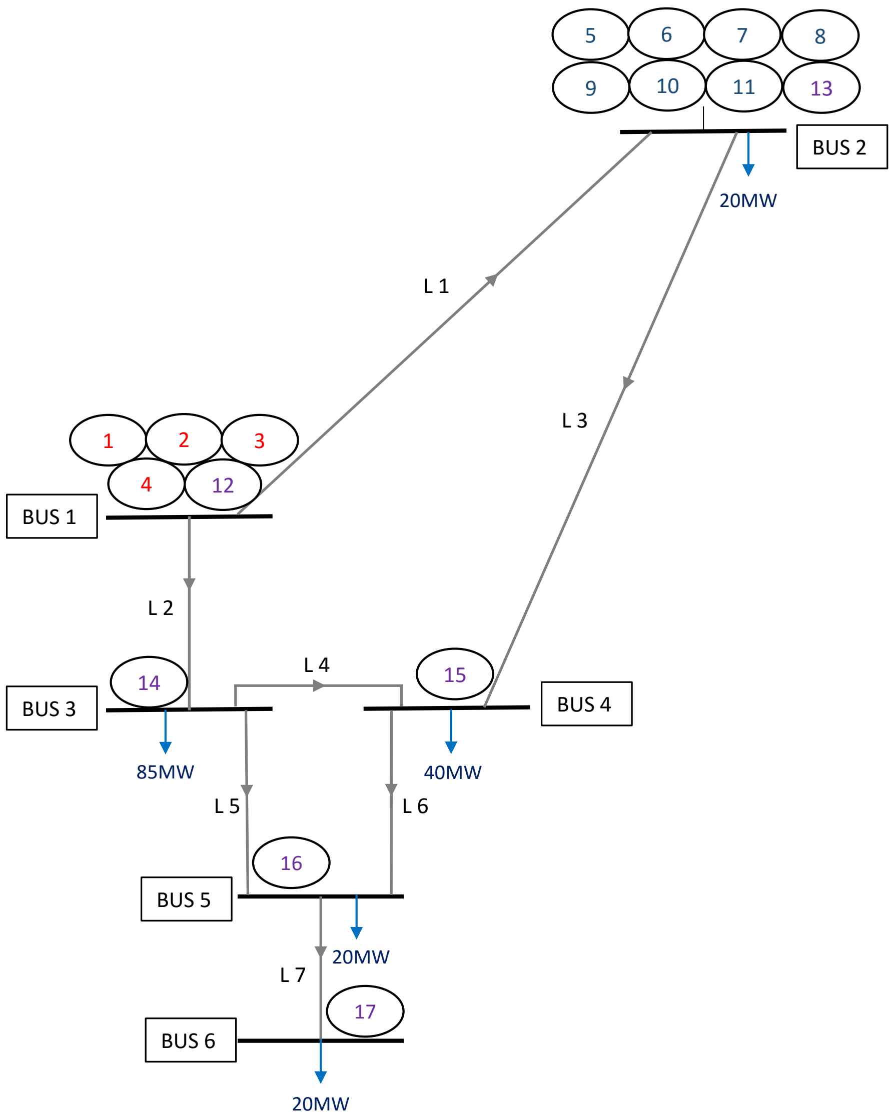
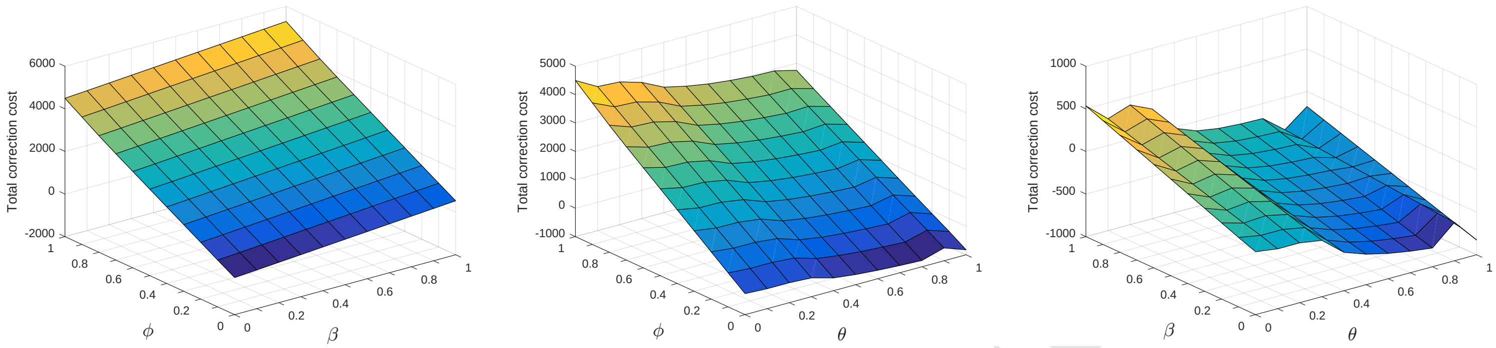
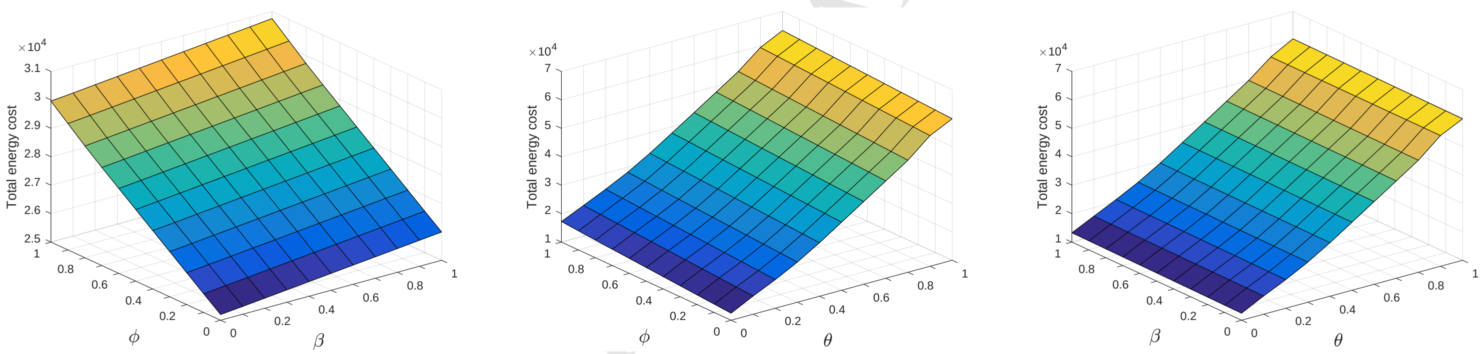


Figure 1: Generation units placement on the RBTS Single line diagram.



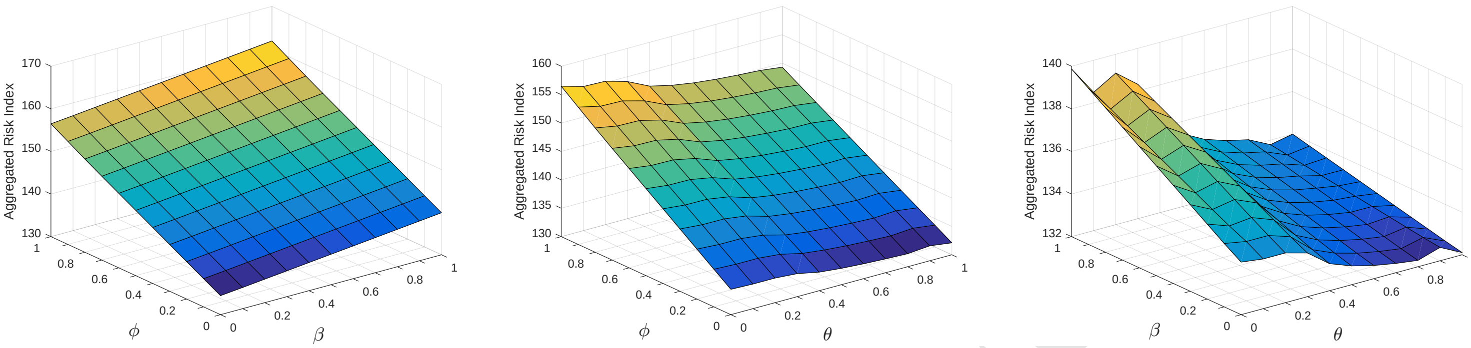
(a) $\theta = 0$ (b) $\beta = 0$ (c) $\phi = 0$

Figure 2: Sensitivity analysis for the correction cost arising due to line failures



(a) $\theta = 0$ (b) $\beta = 0$ (c) $\phi = 0$

Figure 3: Sensitivity analysis for the total system costs (including energy cost in the DAM)



(a) $\theta = 0$ (b) $\beta = 0$ (c) $\phi = 0$

Figure 4: Sensitivity analysis for the aggregated risk index

Table 1: Bus Power Capacity and Bus Demand.

Bus (a)	Total Available Capacity (MW)	Demand (MW)
1	110.00	0.00
2	130.00	20.00
3	0.00	85.00
4	0.00	40.00
5	0.00	20.00
6	0.00	20.00
Total	240.00	185.00

Table 2: Transmission lines Characterization

Line (l)	Buses: From (a)	Buses: To (a')	Line Length (Km)	Resistance R (p.u.)	Reactance X (p.u)	Susceptance B (p.u)
1	1	2	200	0.0912	0.480	2.010
2	1	3	75	0.0342	0.180	5.362
3	2	4	250	0.1140	0.600	1.608
4	3	4	50	0.0228	0.120	8.043
5	3	5	50	0.0228	0.120	8.043
6	4	5	50	0.0228	0.120	8.043
7	5	6	50	0.0228	0.120	8.043

100 MVA base

230 kV base

Table 3: Generation Units Capacities and Cost Data.

Unit (j)	Technology	Capacity (MW)	Variable costs, €/MWh: Fuel Cost	Variable costs, €/MWh: Operation Cost	Variable costs, €/MWh: Total Variable Cost
1	Thermal	10.00	10.00	3.50	13.50
2	Thermal	20.00	9.75	2.75	12.50
3	Thermal	40.00	9.75	2.50	12.25
4	Thermal	40.00	9.50	2.50	12.00
5	Hydro	5.00	0.65	0.15	0.80
6	Hydro	5.00	0.65	0.15	0.80
7	Hydro	20.00	0.45	0.05	0.50
8	Hydro	20.00	0.45	0.05	0.50
9	Hydro	20.00	0.45	0.05	0.50
10	Hydro	20.00	0.45	0.05	0.50
11	Hydro	40.00	0.45	0.05	0.50

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Table 4: Load Shedding (Virtual Generators) cost data.

Bus (a)	Technology	Capacity (MW)	ENS Cost (€/MWh)
2	Virtual Generator	20.00	132.97
3	Virtual Generator	85.00	175.13
4	Virtual Generator	40.00	145.94
5	Virtual Generator	20.00	132.97
6	Virtual Generator	20.00	132.97

Table 5: Transmission lines Capacities and outage data

	Buses				
Line (l)	From (a)	To (a')	Maximum Line Capacity (MW)	Permanent Outage rate (per year)	Outage duration (hours)
1	1	2	45.00	4.00	15.00
2	1	3	100.00	1.50	15.00
3	2	4	70.00	5.00	15.00
4	3	4	20.00	1.00	15.00
5	3	5	20.00	1.00	15.00
6	4	5	25.00	1.00	15.00
7	5	6	20.00	2.00	15.00

Table 6: Characterization of GenCos

Agent	θ_i	β_i	ϕ_i	Unit	Bus	Marginal Cost	$\overline{q_j}$
i	$\left[\frac{€/MWh}{MW}\right]$	$\left[\frac{€/MWh}{MW}\right]$	$\left[\frac{€/MWh}{MW}\right]$	j	a	$[€/MWh]$	$[MW]$
				3	1	12.25	40.00
1	0.2	0.1	0.1	5	2	0.80	5.00
				7	2	0.50	20.00
				8	2	0.50	20.00
2	0.2	0.1	0.1	10	2	0.50	20.00
				11	2	0.50	40.00
				1	1	13.50	10.00
3	0.1	0.1	0.1	2	1	12.50	20.00
				6	2	0.80	5.00
4	0.2	0.1	0.1	4	1	12.00	40.00
				9	2	0.50	20.00

Table 7: GenCos DAM quantity bids

		q_j^{DAM} [MWh]							
Agent i	Unit j	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
1	3	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38
	5	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
	7	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
2	8	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
	10	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
	11	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
3	1	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
	2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
	6	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
4	4	15.62	15.62	15.62	15.62	15.62	15.62	15.62	15.62
	9	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00

Table 8: GenCos quantity bids per network bus (a)

	$\sum_{j \in J_a} q_j^{DAM}$ [MWh]							
Bus (a)	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
1	55.00	55.00	55.00	55.00	55.00	55.00	55.00	55.00
2	130.00	130.00	130.00	130.00	130.00	130.00	130.00	130.00

Table 9: Feasible production schedule per network bus (a)

	$\sum_{j \in J_a} q_j^{OPF}$ [MWh]							
Bus (a)	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
1	55.00	95.00	0.00	55.00	55.00	42.33	41.67	39.88
2	130.00	90.00	90.00	65.00	129.17	127.67	123.33	125.12

Table 10: Amount of ENS per network bus (a)

	x_a^{vg} [MWh]							
Bus (a)	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	55.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	25.00	0.00	0.00	0.00	0.00
5	0.00	0.00	20.00	20.00	0.00	0.00	20.00	0.00
6	0.00	0.00	20.00	20.00	0.83	15.00	0.00	20.00

Table 11: GenCos quantity bids in the Upwards Balancing Market

		x_j^{*BM} [MWh]							
Agent	Unit	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
1	3	0.00	18.75	0.00	0.00	0.00	0.00	0.00	0.00
	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	4	0.00	21.25	0.00	0.00	0.00	0.00	0.00	0.00
	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 12: GenCos quantity bids in the downwards Balancing Market

		z_j^{*BM} [MWh]							
Agent	Unit	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
1	3	0.00	0.00	9.38	0.00	0.00	3.75	6.25	6.25
	5	0.00	5.00	5.00	5.00	0.415	0.00	0.00	0.00
	7	0.00	6.67	7.29	15.00	0.00	0.00	0.00	0.00
2	8	0.00	11.67	20.00	20.00	0.00	0.00	0.00	0.00
	10	0.00	0.00	1.67	0.00	0.00	0.00	0.00	0.00
	11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	1	0.00	0.00	10.00	0.00	0.00	10.00	10.00	10.00
	2	0.00	0.00	20.00	0.00	0.00	0.00	0.00	0.00
	6	0.00	5.00	0.00	5.00	0.415	0.00	0.00	0.00
4	4	0.00	0.00	15.62	0.00	0.00	1.25	3.75	3.75
	9	0.00	11.67	6.04	20.00	0.00	0.00	0.00	0.00

Table 13: DAM and BM prices

	Market Prices [€/ MWh]							
Market	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
λ	19.125	19.125	19.125	19.125	19.125	19.125	19.125	19.125
γ	0	14.125	0.00	0.00	0.00	0.00	0.00	0.00
ψ	0	-19.792	-20.792	-20.625	-18.367	-7.250	-7.50	-7.50

Table 14: Costs arising due to network line failures

	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
Probability		0.68%	0.26%	0.86%	0.17%	0.17%	0.17%	0.34%
ENS Cost [€]	0.00	0.00	14951.50	8967.55	110.80	1994.55	2659.40	2659.40
Correction Cost [€]	0.00	591.67	158.33	97.50	-0.63	-178.13	-232.50	-232.50
Total Cost [€]	0.00	591.67	15109.83	9065.05	110.17	1816.42	2426.90	2426.90

Table 15: Risk Index for the network

	No Failure	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
Risk Index	0.00	4.02	39.29	77.96	0.18	3.09	4.13	8.25

- A risk assessment method for power network failures in a market context is proposed.
- It quantifies the economic impact due to the strategic reactions of the participants.
- The method consists of game theory models and a DC-OPF model solved sequentially.
- Exercise of market power by participants alters the risk level of the network failure.