Article

Risk-based active power redispatch optimization

Karol Wawrzyniak [1], Endika Urresti Padrón [1], Wojciech Jaworski [1], Roman Korab [2]

[1] Interdisciplinary Division for Energy Analyses, National Centre for Nuclear Research, Warsaw, Poland;
[2] Faculty of Electrical Engineering, Silesian University of Technology, Gliwice, Poland
* Correspondence: wojciech.jaworski@idea.edu.pl; Tel.: +48-22-118-44-12 (W.J.)

Abstract: Risk-based redispatch optimization is proposed as a methodology to support the Transmission System Operator (TSO) with preventive remedial actions obtained by extending the security constrained unit commitment/economic dispatch with constraints resulting from the risk assessed for the power system. Although being heuristic, the methodology is based on comprehensive dynamic security assessment as time-domain simulations are used, allowing to express the degree of all types of instabilities, e.g., caused by contingencies, in monetary terms. Therefore, the risk is assessed as the expected value of the cost incurred by the TSO. Such approach forms a new pathway to including risk in planning procedures already used by TSOs. Results obtained for the IEEE39 dynamic power system, with costs assigned to load shedding and generator tripping due to single transmission lines short-circuits, are shown as a reference case.

Keywords: Power system security, Optimization methods, Power system dynamic stability, Risk analysis, Time-domain analysis, Power generation dispatch, Power system faults, Power system simulation, Synchronous generator transient analysis

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1. Introduction

The tendency to reduce the number of fossil fuel-based generation to renewable energy sources results in gradual switching from a deterministic and fully controllable generation profiles to ones heavily affected by weather conditions and hence stochastic and uncertain. What follows is an increase of importance of risk assessment for power systems, along with the necessity to perform it for the purposes of short-term planning or even real-time operations. Currently, the most accepted security procedure is based on the N-1 criterion, which when integrated with the security constrained unit commitment/economic dispatch or optimal power flow methods (SC UC/ED or SC OPF, respectively)[1], allows to assure that the system parameters remain within safety limits after removing one of its elements. However, those methods apply only steady-state equations and therefore they skip the power systems dynamic phenomena related to frequency, voltage and angle stability. The main concept behind the proposed method is that preventive remedial actions are designed in order to reduce the risk associated with chosen types of phenomena caused by generators trips resulting from contingencies. Here, such reduction is performed using the active power redispatch, but might be extended to reactive redispatch as well. Several interesting approaches to extending the SC UC/ED and SC OPF with constraints based on transient stability assessment (TSA) may be found in the literature, however they differ with respect to many criteria. First of all, the way of incorporating rotor dynamics into the linear optimization problem spans from using trapezoidal rule [1,3] or Taylor series expansion [2] (to convert differential equations into algebraic ones), to involving direct (or direct-temporal) TSA methods like single-machine equivalent (SIME) [3–6] or the transient energy function (TEF) [7–10]. These methods are used to rank the synchronous machines by their stability margin (or its sensitivity

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1 SC UC results with list of committed units taking into account all inter-temporal and network constraints, as well as the N-1 security criterion. SC ED provides operating points for units with respect to those constraints. SC OPF, does not take into account inter-temporal constraints while network constraints and the N-1 criterion are still included.

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to generation changes) with respect to a considered set of contingencies, however the critical clearing time (CCT) was used for ranking as well [14]. Secondly, the procedure of finding the amount of power to be shifted from the least stable generators, could be based on the identified energy margins, inertia constants [10], values of the rotor speed at the fault clearing time [8] or the power angle trajectory sensitivity [11–13]. In most cases, the power shifting was performed in small steps within an iterative procedure. Hence, the final dispatch was obtained after several iterations of adjusting the constraints for OPF, solving it and repeating the transient stability assessment process, until the desired value of the stability margin or the CCT was found. However, more sophisticated approaches to solving the constrained OPF problem were also proposed to find the most stable dispatch - they included particle swarm optimization, genetic algorithms and neural networks [14,15]. Lastly, the details of dynamic models used to perform time-domain simulations (TDS) were found to be of importance. In particular, using dynamic instead of static load models [5] or 4th order generator models (along with excitation systems and AVR models instead of constant voltage behind a transient reactance) [6] was shown to improve the stability of the resulting dispatch. The general scheme of the redispatch optimization proposed in this paper is shown in Fig. 1. Its basic concept is similar to those described above [1–14], but there are three major differences. First of all, going beyond TSA towards a more comprehensive dynamic security assessment is considered here, where not only transient rotor angle but also frequency and voltage instabilities may be tackled. Secondly, the procedure is based on interactions between a standard SC UC/ED tool and the proposed risk-based redispatch optimization, which includes two processes, namely the dynamic risk assessment and the remedial actions design. Therefore, it does not replace and does not require any modifications of the SC UC/ED tools already used by TSOs (e.g., for operational planning), but is used only to provide its input. This input is used to adjust the constraints for the dispatch optimization problem in order to assure not only static but also dynamic security. Lastly, the risk-based optimization module uses a stochastic approach to identify remedial actions that are based on the value of the assessed risk (being a function of probability and cost) and aimed to decrease that risk until a specified stopping criterion is reached.

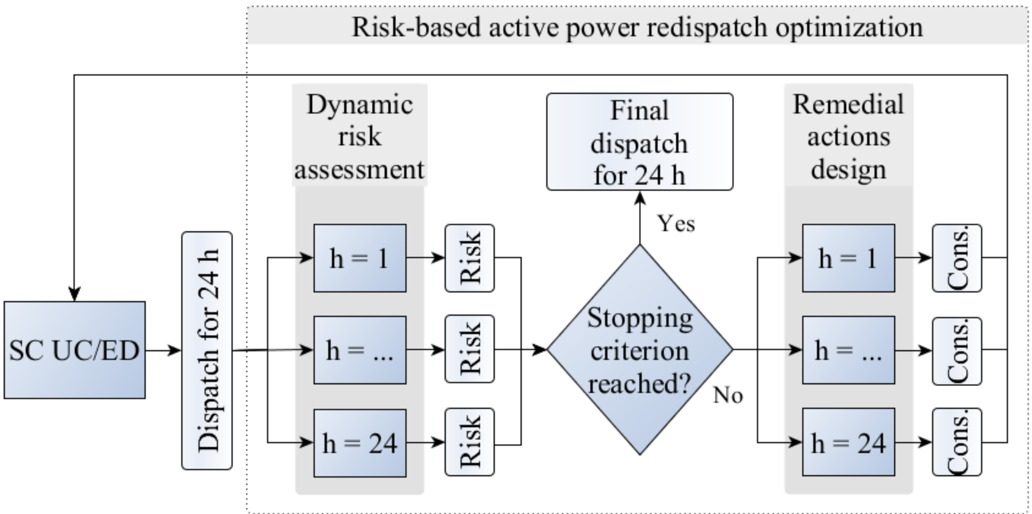

Figure 1. General scheme of the risk-based redispatch optimization method. The method presented in this paper is considered as an extension to the SC UC/ED process aimed to meet the requirement of dynamic stability. This extension includes two main processes shown as grey boxes, namely the dynamic risk assessment (resulting in Risk values assessed for each hourly dispatch) and the remedial actions design (resulting in Cons. - modifications of constraints existing in SC UC/ED hourly dispatches). In general, the process are depicted by dark blue, whereas the output data as light blue boxes (this coloring scheme also applies to Fig. 2 and Fig. 3).

The paper is organized as follows. The methodology of obtaining the risk assessment and remedial actions is described in Sec. 2. The results for the IEEE39 power system are presented and discussed in

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Sec. 3. The paper is concluded by summarizing the results and considering further extensions of the proposed method.

2. Theoretical framework

The SC UC/ED process used within the approach shown in Fig. 1 is considered as a self-contained standard tool used by TSOs to obtain the operating points (e.g., for 24 hours), based on the DC or AC power flow solutions. However, it is assumed to fulfill several criteria including those assuring static security (e.g. withstanding N-k outages) or other tuned to meet particular requirements of the TSO. The purpose of the two main components of the presented generation redispatch optimization method, namely the processes of dynamic risk assessment and remedial actions design, is to be coupled with the SC UC/ED only by adjusting its constraints. The details of that coupling, including the two main components used in the iterative process starting from the output of the SC UC/ED tool, are described in following subsections.

2.1. Dynamic risk assessment

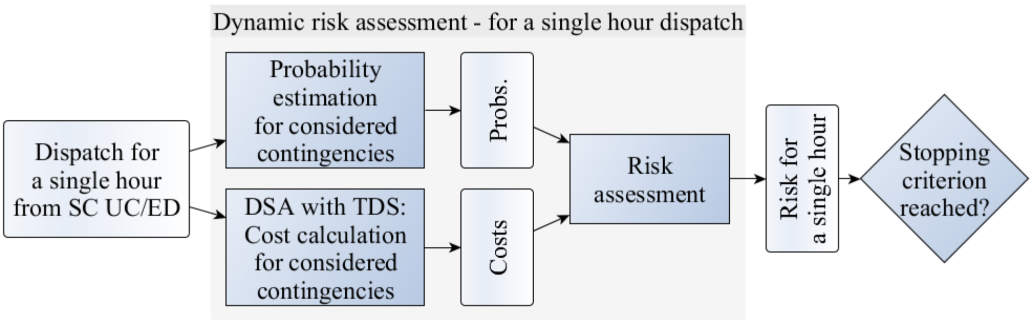

Figure 2. Detailed scheme of the dynamic risk-based optimization method assessment process for a single hour dispatch resulting from the SC UC/ED solution.

Each hourly dispatch resulting from SC UC/ED is used in an independent dynamic risk assessment process as presented in Fig. 2. It comprises three elements i.e. probability estimation, cost calculation and risk assessment. The probabilities may be obtained with the help of historical data or adjusted according to weather forecasts. Within the cost calculation process the Dynamic Security Assessment (DSA) is used – the operating points of synchronous generators are obtained from SC UC/ED and used as initial conditions for time-domain simulations (TDS) [1,11–15]. The cost is obtained basing on the events taking place during TDS after the inception of each fault (e.g. a short-circuit) initiating the considered contingency – an example of the cost calculation procedure is provided in App. A.

Afterwards, the value of the risk is obtained in the simplest form as described by (1):

$$R = \sum_C R_C = \sum_C \mathrm{Prob}_C \cdot \mathrm{Cost}_C, \tag{1}$$

where R - total risk of the system, R_C - risk related to contingency C, Prob_C - the probability and Cost_C - the cost assigned to contingency C. Finally, this total risk is verified against a threshold value R^{th} to check whether remedial actions are necessary – for each hour independently. This threshold-based stopping criterion is similar to the ones described in the literature [1–14] as it is aimed at stabilizing the system against credible contingencies. Here, $R^{th} = 0$ was used in order to test the convergence of the proposed method, however an alternative stopping criterion is possible. In particular, the iterative process may be stopped after reaching the minimal value of the sum of the operating cost of generating units $\mathrm{Cost}_{\mathrm{SC\,UC/ED}}$ (resulting from SC UC/ED) and the risk R related to dynamic security of the system,

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$$\min(\mathrm{Cost}_{\mathrm{SC\,UC/ED}} + R). \tag{2}$$

This alternative stopping criterion is also discussed in Sec. 3.

2.2. Remedial actions design

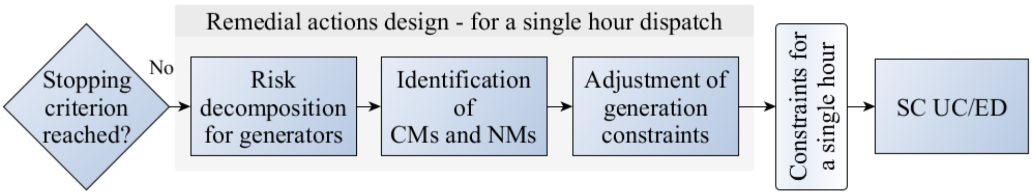

Figure 3. Detailed scheme of the remedial actions design process for a single hour result of the dynamic risk assessment from Fig. 2.

The process from Fig. 2 is continued once the selected stopping criterion is not met, even for one of the considered hourly dispatches. In particular the remedial actions (RA) are prepared basing on the assessed risk – this continuation is depicted in Fig. 3, again, independently for each hour. With the variety of consequences that might be reflected by that risk value in general, e.g., reactions of protection relays due to violations of thermal limits, rotor angle, frequency and voltage instabilities, the remedial actions may be designed to involve redispatching active and reactive power, capacitors, energy storages, etc. For the purposes of our research, preventive remedial actions are considered and based on adjusting the constraints for active power generation levels of synchronous machines in SC UC/ED. The aim of such remedial actions is to prevent the synchronous machines from being tripped by allowing them to withstand dynamic instabilities caused by the simulated faults. This aim is achieved by lowering generation levels of the least stable machines, preventing them from losing synchronism after short-circuits with longer clearing times [18].

The risk assessed with the help of (1) is a global value describing the whole system, however we decompose it to every synchronous generator and identify the critical (the least stable ones) and non-critical machines (CMs and NMs, respectively). Similar identification is used in many approaches listed in Sec. 1, including those utilizing SIME [3–6] or TEF [9,10] methods. It serves the purpose of conducting the redispatch by shifting the active power from CMs to NMs. Nevertheless, only in this approach CMs and NMs are identified basing on the dynamic risk. In order to perform the redispatch, we start with distributing the risk contribution R_C of every contingency C between the generators tripped due to C – those generators form the set TG_C. If there is only one generator in TG_C, the risk value is assigned to it directly. However, in cases with many generators tripped after a contingency, the value of risk R_C is split into all those generators proportionally to P^G – the active power supplied by each generator G. This is done according to the risk R_C^G defined for every tripped generator:

$$\begin{aligned} &\forall_{G \in TG_C} \quad R_C^G = R_C \cdot \frac{P^G}{P_C^{TG}}, \\ &\forall_{G \notin TG_C} \quad R_C^G = 0, \end{aligned} \tag{3}$$

where $P_C^{TG} = \sum_{G \in TG_C} P^G$ is the current active power generated by machines in TG_C.

Afterwards, the risk values resulting from all considered contingencies are assigned to particular generators according to:

$$R^G = \sum_C R_C^G. \tag{4}$$

This in turn allows us to perform the aforementioned identification of CMs and NMs, keeping in mind the following: only a fraction of the power from CMs is shifted to NMs in one iteration of the process from Fig. 1 (alike in [6,10]).

In particular, with Δs we get the ΔP_s value from:

$$\Delta P_s = \Delta s \cdot \sum_{G \in CM} P^G, \tag{5}$$

where the power margin ΔP_m of NMs (depending on the current P^G and maximal P^G_{max} generation power of particular generators):

$$\Delta P_m = \sum_{G \in NM} (P^G_{max} - P^G), \tag{6}$$

should allow the shifting and therefore the inequality (7) should be satisfied:

$$\Delta P_s \leq \Delta P_m. \tag{7}$$

Hence, if the initial set of machines with $R^G = 0$ does not have the proper power margin, we continue to extend this set by successively adding generators with the smallest value of $R^G > 0$, until (7) is satisfied. The power to be shifted from each of the CMs taking into account the step value Δs and the generators risk R^G is expressed as:

$$\forall_{G \in CM} \quad \Delta P^G_s = \frac{R^G}{R} \cdot \Delta P_s, \tag{8}$$

which is used to adjust the constraints of CMs in the following way:

$$\forall_{G \in CM} \quad P^G_{max} := P^G - \Delta P^G_s. \tag{9}$$

The generation limits of NMs are not modified, whereas the constraints for CMs from (9) go back to the SC UC/ED process, where the preventive remedial actions are applied for all synchronous generators, for each hour independently. This procedure joins the resulting constraints with those, e.g., based on generators ramp rates) coupling the generation levels for all 24 hours. Hence, the next iteration is started with a new daily dispatch and the process continues until reaching the desired stopping criterion.

3. Results

This section presents results of adapting the iterative method from Fig. 1 to the IEEE39 power system for the purpose of obtaining dynamically secure operating points, with only one hour chosen for simplicity. However, the results were obtained for two scenarios, namely the SC OPF and OPF (in AC versions). The former is more secure as it satisfies the static N-1 criterion, whereas the latter is profitable from both economical and computational perspective. Moreover, we performed the sensitivity analysis with respect to several values of the iteration step $\Delta s \in \{0.1\%; 0.2\%; 0.5\%; 1.0\%; 2.0\%; 5.0\%\}$ for both dispatch scenarios. First of all, we extended the IEEE39 model with 10 additional lines which allowed us to improve the systems connectivity and hence reliability. Afterwards, we prepared the values of failure probability for each kilometer of the line basing on the mean time to repair and transmission lines failure frequency [17] published by PSE - the Polish TSO[2].

The data describing all 10 generators in IEEE39 are collected in Tab. 1, however the generator from bus 30 is considered as an equivalent of an interconnection with the power supply held constant on the level of 1045 MW. The other 9 generators were modeled as synchronous machines, with

[2] https://www.pse.pl/web/pse-eng

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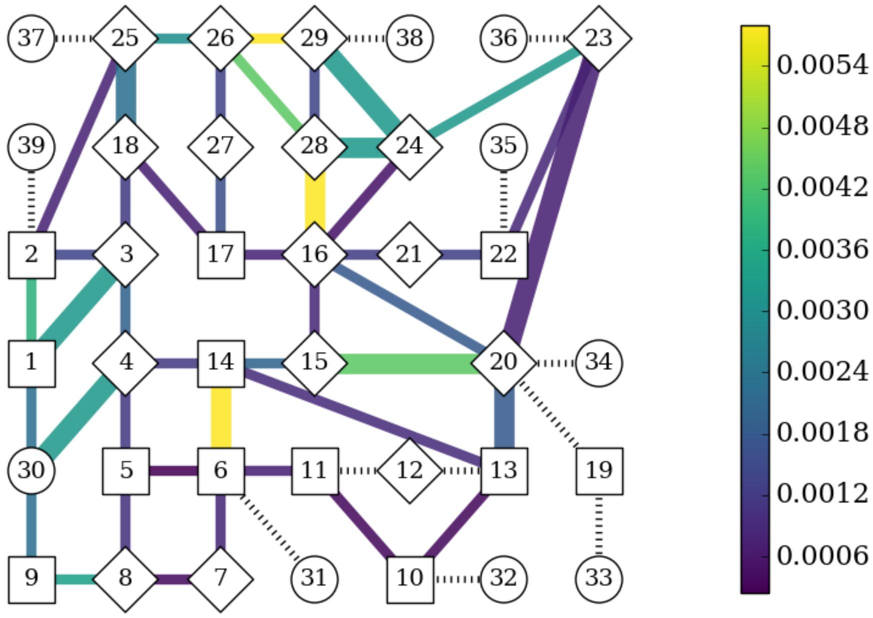

Figure 4. The schematic graph of the IEEE39 network. The dashed lines represent transformers, the solid lines - transmission lines, with 10 thicker ones showing those added by the authors. Buses are depicted by squares (no load), diamonds (non-zero load) and circles (generators, apart bus 30 representing an interconnection with bigger system). The legend shows the values of N-1 fault probabilities obtained by utilizing the historical data published by PSE (Polish TSO).

$P^G_{min} = 40\% \, P^G_{max}$. The variable costs were selected by a simplified matching the types of generators included in the model with the costs expected in Poland.

The initial operating points were supplied to the TDS and the process from Fig. 2 was started with the N-1 contingencies simulated as 3-phase short-circuits. They were applied in 44 transmission lines (shown with solid lines in Fig. 4), all of which were equipped with a distance impedance protection relay, which cleared the fault after 150 ms. As we mentioned in Sec. 2, the risk was calculated by taking into account the events of tripping the generators by out-of-step protection relays included in the dynamic model. Moreover, the load shed by under-frequency protection relays was also included, which gave us the opportunity of enhancing the assessment of transient rotor angle instabilities by additional assessment of the frequency stability. Furthermore, we equipped our IEEE39 dynamic model with models of overcurrent protection relays, the actions of which could also be responsible for disconnecting bus loads resulting in additional costs. In order to include the actions of all aforementioned protection relays, the TDS were performed until achieving the steady-state.

Reaching the steady-state required leading the TDS until 10 minutes on average, however such simulations on our HPC server lasted around 1 min. However, the server (128 GB of RAM and 2 Intel Xeon 2.80 GHz processors, 20 cores each) allowed us to perform the TDS in parallel - simultaneously on 22 cores. The results of a single SC OPF run were obtained in additional 0.5 min (per core). The results of the iterative process for $\Delta s = 1\%$, showing that the proposed method allowed obtaining the minimal risk value $R = 0$, are shown in Fig. 5, Fig. 6 and Fig. 7 for both the SC OPF and OPF scenarios. In Fig. 5 (a and b) the evolution of three costs is depicted: the market one describing the cost resulting from the dispatch, the risk-based cost resulting from the dynamic risk assessment (expressing the expected value of the cost incurred by the TSO) and their sum - the total cost. We can see that in the initial iteration the SC OPF dispatch is characterized by lower risk, which means that it provides not only N-1 static security but indirectly increases also dynamic stability. The reason for this behaviour may be found in the fact that SC OPF, with its more restrictive constraints, provides a dispatch with greater values of power margins (see Tab. 1 or the initial iteration in Fig. 6). In the case of OPF, the cheaper generators are loaded more heavily ($P^G = P^G_{max}$ for 4 of them, with only 2 having this property

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Table 1. The data sheet on generators in IEEE39 with the initial operating points for SC OPF and OPF scenarios

Gen. id (bus no.)	Gen. type	P^G_{max} [MW]	Gen. cost [EUR/MWh]	P^G (SC OPF) [MW]	P^G (OPF) [MW]
30	interconnection	1045	35.7	1045	1045
31	nuclear	646	13.1	646	646
32	nuclear	725	14.3	543	725
33	fossil	917	23.8	900	367
34	fossil	508	25.0	203	203
35	nuclear	800	15.5	600	800
36	fossil	816	26.2	326	326
37	nuclear	564	16.7	412	463
38	nuclear	865	17.9	865	573
39	hydro	1040	11.9	651	1040

in the SC OPF case) and as a consequence, they have lower transient stability margin. Furthermore, due to being more stable dynamically, the SC OPF converges quicker to the minimal risk, whereas the OPF favouring cost-optimization – converges quicker to the minimal total cost. The generation levels in each iteration are depicted in Fig. 6, which also illustrates the identification of CMs and NMs (with upward and downward triangles, respectively). In Fig. 7 the total number of generators tripped in each iteration is shown – in the OPF case this number and the risk (Fig. 5b) decrease monotonically. This is not true for SC OPF (Fig. 5a), due to the change of status from NM to CM by one of the units (Gen. 33 in 21st iteration). However, this is fixed in the following iteration and the whole process converges eventually. Such cases confirm the requirement to perform the power shifting in little steps. The importance of adjusting the Δs factor, responsible for the power shifted in each iteration is also discussed in the next subsection (3.1). Most importantly, the total cost after the last iteration with OPF, which is equal to the market cost of the dispatch characterized by no risk ($R = 0$), is lower than the initial market cost in SC OPF. The source of this effect is that the SC OPF provides a conservative solution allowing the system to withstand N-1 contingencies without corrective actions. On the other hand, dynamic simulations include some corrective actions, e.g., by the primary or secondary control and therefore they are able to relax the initial operating points. What is more, due to the fact that dynamic simulations incorporate also all static stability phenomena, we find that the dynamically extended OPF is more computationally and economically efficient than dynamically extended SC OPF.

3.1. *Sensitivity analysis*

The sensitivity analysis of the dynamic risk optimization was applied in order to test the robustness of the proposed method against the amount of power shifted from CMs to NMs in one iteration. For that purpose, we performed the optimization process for SC OPF and OPF scenarios and for the following amounts of the shifted power $\Delta s \in \{0.1\%; 0.2\%; 0.5\%; 1.0\%; 2.0\%; 5.0\%\}$. The results of the sensitivity analysis are shown in Fig. 8 for SC OPF and OPF. The common factor for both scenarios is the inverse proportionality of Δs and the number of iterations as well as the proportionality of Δs and the total costs. Moreover, those figures also show that decreasing Δs below a certain level does not necessarily result in lower total costs (both obtained at the minimum and at the final iteration), as they reach a plateau in the range below $\Delta s = 1\%$. Moreover, although the numbers of iterations taken to reach $R = 0$ are lower in the SC OPF case, the numbers after which the minimum of the total cost (similar to (2)) were found, are lower in the OPF case. To sum up, the sensitivity analysis shows that at some point reducing Δs does not alter the risk results. However, it significantly increases the numbers of iterations, making the computations longer and more expensive. Therefore, it could be found that there is a range of Δs for which it is possible to find a compromise for both, the accuracy and computational costs.

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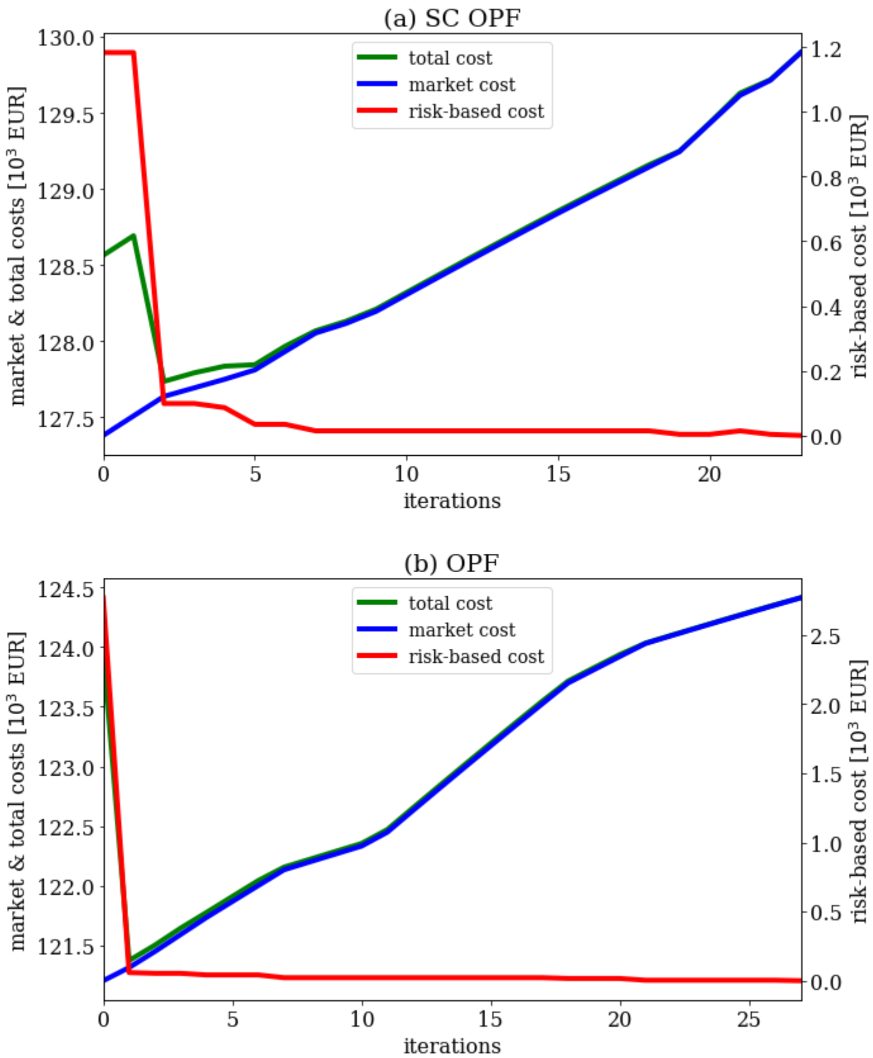

Figure 5. The costs obtained in the risk optimization process for the SC OPF (a) and the OPF (b) scenarios: the market cost (blue solid line), the risk-based cost (red solid line - plotted with respect to the right vertical axis) and the total cost - the sum of two former ones (green solid line).

4. Conclusions

This paper proposed the iterative methodology of obtaining preventive remedial actions by extending the SC UC/ED with constraints based on the risk assessed for the power system. Two criterias are used i.e. risk minimization or total cost minimization. In the case of total cost minimization only 2 or even 1 iteration (if SC conditions are relaxed) are required for modified dynamic IEEE39 system. The method can be successfully used for off-line testing and, if contingency filtering screening techniques are applied, it has also potential for day ahead planning. However, the authors expect that with the growing availability and decreasing costs of distributed computing, going beyond day-ahead to intra-day processes will be possible in the future. In the presented test case we limited the analysis to only one hourly dispatch, which simplified the SC UC/ED (UC/ED) problem to SC OPF (OPF) and made the results easier to interpret and present. However, the same way of reasoning works also for SC UC/ED, where the daily dispatch may be obtained. In such cases the constraints (for generators active power upper limits) are adjusted for each hour independently, still allowing the SC UC/ED tool to deliver a consistent solution for 24 hours. The proposed methodology is general as significant flexibility is allowed with respect to the models of generators and protection relays along with the way to include their actions in calculating the costs. Moreover, it allows adapting the current operating points to variable weather conditions, which may be crucial for the accurate reliability analysis of the power system, especially in the case of increasing the share of RES. Finally, the presented approach could be extended with the following:

- Utilizing contingency screening methods, like SIME used for the transient stability assessment, for the purpose of filtering the most critical contingencies.
- Extending the dynamic model of the power system with under- and overvoltage protection relays to include the costs of load shed due to voltage instabilities.
- Adjusting the value of power shifted from critical to non-critical machines from one iteration to another, e.g., basing on the risk reduction.
- Integrating the reactive power redispatch in the risk optimization.

To conclude, the authors believe that the proposed risk reduction-based dispatch optimization, although being heuristic, provides an interesting alternative planning procedure for TSOs in the future. With the fact of being tunable on one hand and the increase of computational efficiency on another, the method may allow to meet the requirements of future power systems, where the dynamic phenomena will play a significant role.

Appendix A. Example of cost calculation

For the purposes of this paper transmission lines failure rates published by the Polish TSO were used to obtain the probabilities of single transmission lines faults, simulated as 3-phase short-circuits. Whereas the costs were assigned to the following events:

1. Tripping the synchronous generators by out-of-step protection relays included in the dynamic model,
2. Shedding loads by under-frequency protection relays or disconnecting the load buses from the system.

Events of the first type were associated with a cost of starting up a synchronous generator from a standby mode, which was assumed to be the state of the generator after being tripped by the out-of-step relay. A constant value of $\text{Cost}_{TG} = 15000\,\text{EUR}$ was used for all generators in the IEEE39 system, which is a rough simplification made for the purpose of obtaining quantitative results (see Sec. 3). The cost of load shedding was associated with time and stage of the under-frequency relay action. Here is an example. Let us assume that during a contingency C (initiated by a fault at $t = 0$), a generator was tripped at $t = 1\,\text{s}$ giving rise to the cost by Cost_{TG}. This was followed by frequency drop causing the action of load shedding relays in the first stage, which resulted in disconnecting 20% of the load, equal to $L_1 = 100\,\text{MW}$ at $t_1 = 100\,\text{s}$ in one and $L_2 = 200\,\text{MW}$ at $t_2 = 105\,\text{s}$ in another bus. If the consequences of C was accumulated over time $T = 6\,\text{min}$ (when the steady-state was achieved), the total cost Cost_C is calculated using the value of lost load $\text{VoLL} = 2500\,\text{EUR/MWh}$ in the way shown in (A1):

$$\text{Cost}_C = \text{Cost}_{TG} + \text{VoLL} \cdot \sum_{i=1}^{2} L_i \cdot (T - t_i) \approx 68.5 \cdot 10^3\,\text{EUR}. \tag{A1}$$

Knowing the cost and probability allows us to obtain the contribution of every considered contingency to the risk given by (1).

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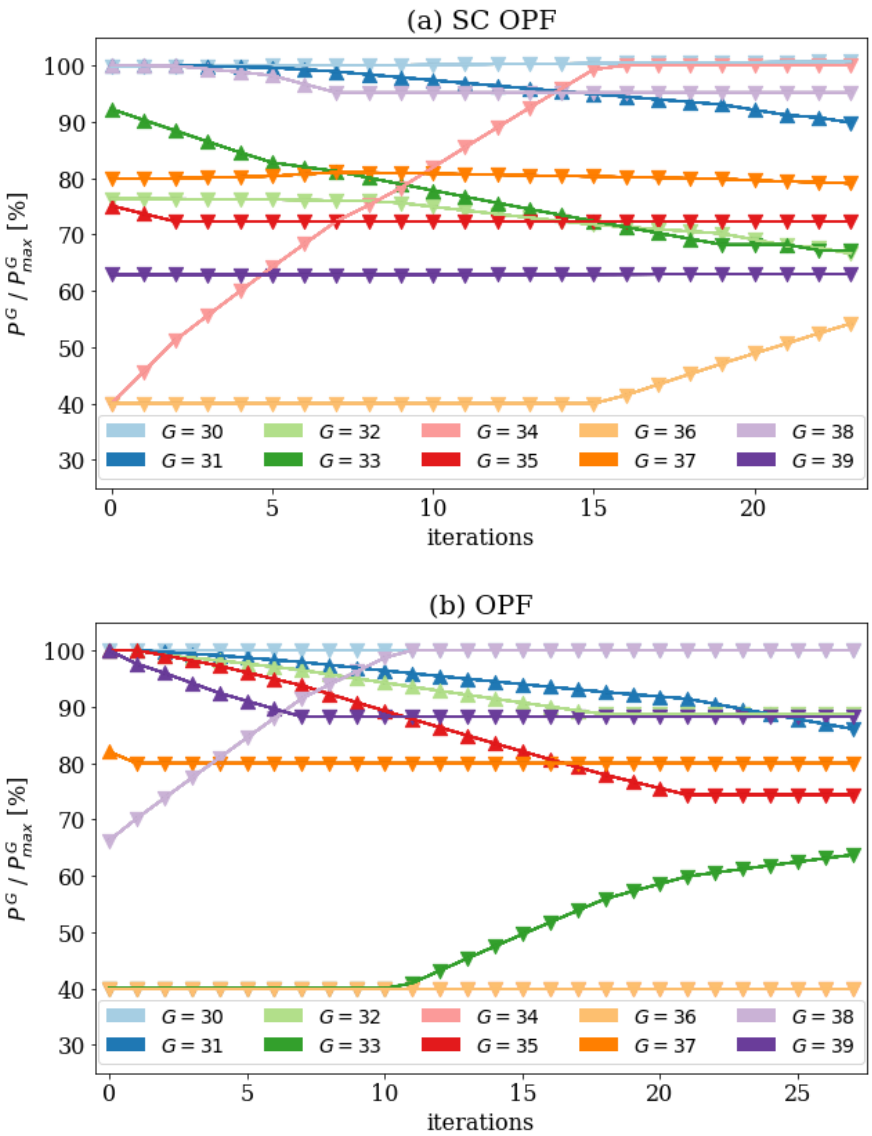

Figure 6. The active power values (P^G/P^G_{max}) obtained in the risk optimization process for SC OPF (a) and OPF (b) scenarios and for every generator in each iteration (apart Gen. 30 with constant generation level). The results include the identification of critical (CMs) and non-critical (NMs) machines, depicted by upward and downward triangles, respectively.

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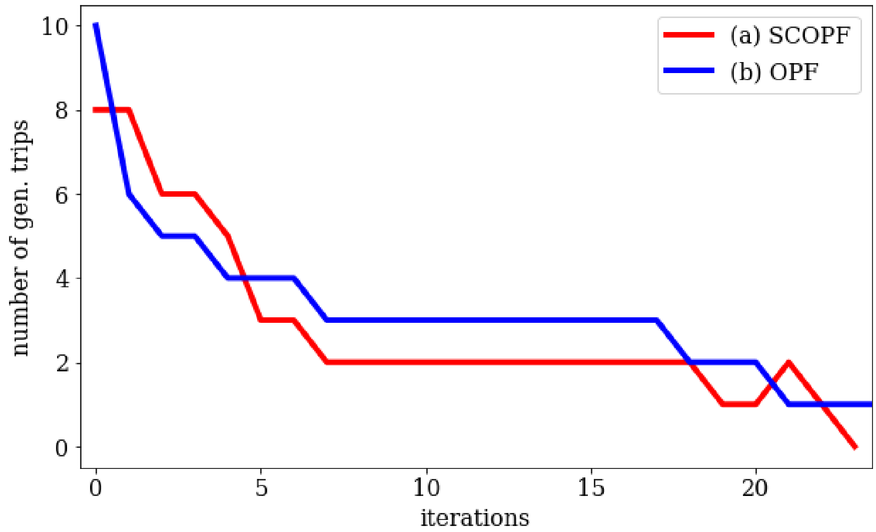

Figure 7. The total number of all generator trips in each iteration obtained in the risk optimization process for SC OPF (red solid line) and OPF (blue solid line) scenarios.

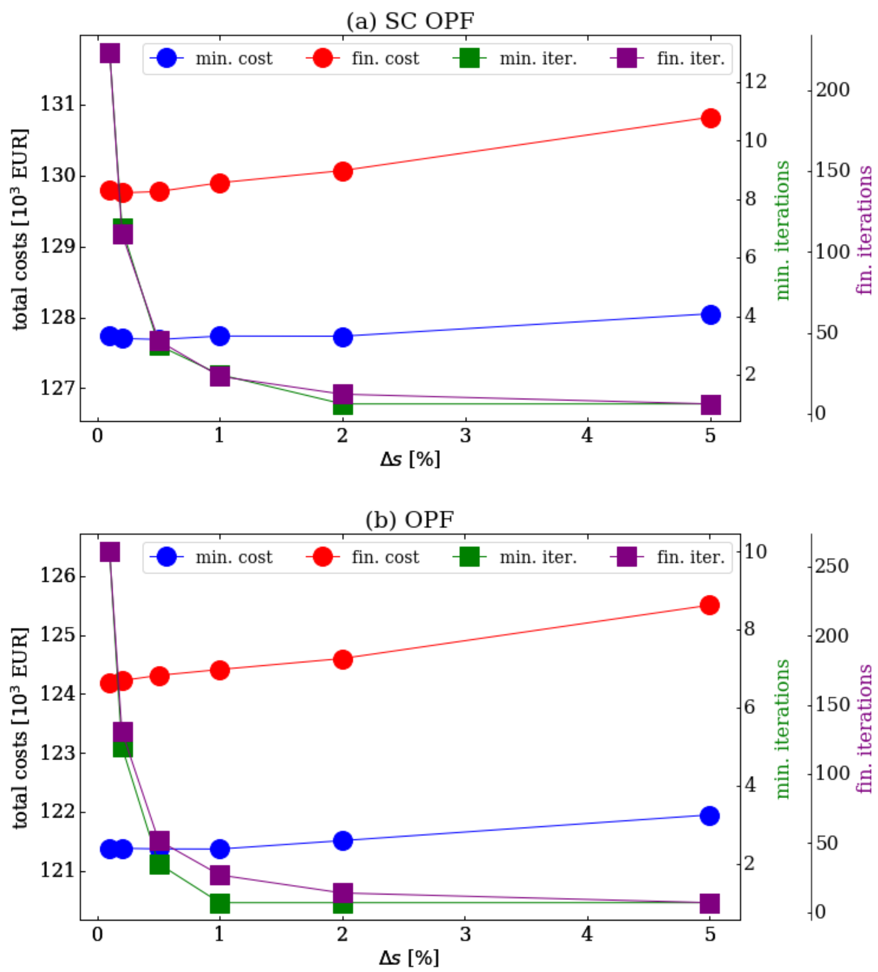

Figure 8. Results of sensitivity analysis for SC OPF (a) and OPF (b) scenarios, and for two stopping criteria: min. – representing the minimal total cost as in (2) and fin. – representing the case with $R^{th} = 0$. The total costs for min. (blue circles) and fin. (red circles) are plotted with respect to the left vertical axis. The number of iterations (iter.) to reach the stopping criterion for min. (green squares) and fin. (purple squares) are plotted with respect to right separate vertical axes.