Long-Term Benefits for Renewables Integration of Network Boosters for Corrective Grid Security

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Abstract—Using corrective actions to overcome network loading when single lines fail has the potential to free up network capacity that is otherwise underused in preventive N−1 security strategies. We investigate the impact on renewable integration of a corrective network security strategy, whereby storage or other flexibility assets are used to correct overloading that results from line outages. In a 50-bus model of the German power system utilizing these flexibility assets, so-called network boosters (NB), we find significant cost savings for the integration of renewable energy of up to 0.85 billion euros per year. While previous literature has focused on the potential savings in the short-term operation, we focus on the long-term benefits in systems with high shares of renewable energy sources, where the capacities and dispatch of generation and NB are optimised. We demonstrate the benefits of NB for various shares of renewable energy, NB and flexibility costs, as well as different allowed levels of temporary overloading the lines in both (i) a sequential model, where long-run generation investments are optimised separately from the NB capacities, and (ii) a simultaneous model, where generation is co-optimised with NB investment so that mixed preventive-corrective approaches are possible.

Index Terms—Contingency, flexibility, network booster, power transmission system, reliability, security-constrained optimal power flow.

NOMENCLATURE

A. Indices

\(i\) Index for buses.
\(\ell, k\) Index for lines.
\(t\) Index for time.
\(s\) Index for generators.

B. Variables

\(P_+^i\) Upward NB capacity at bus \(i\).
\(P_-^i\) Downward NB capacity at bus \(i\).
\(P_{+i,t,\ell}\) Operation of the upward NB resources at bus \(i\) in time \(t\) for the outage of line \(\ell\).
\(P_{-i,t,\ell}\) Operation of the downward NB resources at bus \(i\) in time \(t\) for the outage of line \(\ell\).
\(e_s\) Specific emission of the fuel for generator \(s\).
\(f_{t,\ell}\) Power flow in line \(\ell\) at time \(t\).
\(g_{s,t}\) Dispatched power of generator \(s\) at time \(t\).

C. Parameters

\(c^+\) Investment cost for upward NB capacity.
\(c^-\) Investment cost for downward NB capacity.
\(c_s\) Investment cost for generator \(s\).
\(d_{i,t}\) Demand for bus \(i\) at time \(t\).
\(o^+\) Operation cost for the upward NB resources.
\(o^-\) Operation cost for the downward NB resources.
\(o_s\) Operation cost for generator \(s\).
\(F_\ell\) Capacity of line \(\ell\).
\(f_{\text{TATL}}\) Temporarily admissible transmission loading (TATL) factor.
\(F_\ell\) TATL for line \(\ell\).
\(PTDF_{i,\ell}\) Power transfer distribution factor.
\(LODF_{i,\ell}\) Line outage distribution factor.
\(\Gamma_{s,t}\) Time-dependent potential of power generation for generator \(s\) at time \(t\).
\(\bar{\Gamma}_{s}\) Maximum of installed potential for generator \(s\).
\(K_{i,\ell}\) Incidence matrix of transmission networks.
\(\eta_s\) Efficiency of generator \(s\).
\(\Gamma_{CO_2}\) Allowed level of CO\textsubscript{2} emissions.

I. INTRODUCTION

A. Background

TRADITIONAL preventive approaches to the N−1-secure operation of transmission networks keep power flows in transmission lines below line capacities so that if a line fails, no other line in the network becomes overloaded. This leads to the under-utilization of network assets and hinders the economic integration of generation sources, particularly those like wind and solar that are transported over long distances. An alternative corrective approach is to react to the line failure only after it happens, by activating flexibility resources such as storage or demand-side management to counteract any overloading that results in the rest of the network [1]. This allows a higher utilization of the transmission network, and could benefit the integration of renewable energy sources (RESs), particularly in regions where transmission expansion is slow because of public acceptance problems.

B. Literature review

Several studies have investigated the role of contingency constraints as well as flexibility resources in power transmission systems. For instance, operational flexibility and \(N−1\) constraints for transmission lines were considered in a combined generation and transmission planning approach in...
Authors in [3] applied a non-linear security constrained optimal power flow (SCOPF) model with mixed preventive-corrective contingency measures, finding a role for both preventive and corrective actions. Authors in [4] discussed a framework to employ operational flexibility among transmission system operators (TSOs) in multi-area power systems subject to $\mathcal{N}−1$ security criteria. Authors in [5] proposed a corrective approach to solve a $\mathcal{N}−1$ security-constrained unit commitment problem to minimize congestion of transmission lines and curtailment of RESs. Authors in [6] presented a corrective approach to avoid line overloading. In [7], re-dispatching of flexible resources is used in the context of SCOPF as a corrective strategy in response to line outages. A preventive approach has been utilized by authors in [8], where $\mathcal{N}−1$ security conditions have been approximated based on the network’s topology by analysing the polytope of feasible nodal net power injections under contingency constraints to reduce the problems computational burden. Similarly, authors in [9] introduced a geometric algorithm based on the feasible space of net power injections for reducing the number of preventive contingency constraints.

While the mathematical formulation of preventive and corrective security-constrained optimal power flow is well understood [10], [11], most investigations of the benefits of corrective security have focused on short-term cost reductions in the operation of the power system where the investments in generation and flexibility assets is fixed. For example, it was shown in [12] that corrective actions can significantly reduce the costs of maintaining operational security in a case study with the 24-bus IEEE reliability test system. Benefits of a corrective approach were also found in a European case study that showed that investment in corrective controls was complementary to transmission expansion [13], but generation capacities were once again exogenous. In the German context, several recent studies have shown that corrective measures could lead to a significant reduction in congestion management measures such as redispatch [14], [15]. Transmission-connected battery systems that perform these corrective actions have been called network boosters (NB) by the German transmission system operators [16]. In [17] it was shown that there are significant distributed flexibility potentials on the demand side too, including up to 16 GW of upward flexibility potentials from power-to-heat units in district heating networks.

C. Contributions

In this contribution, we explore the longer-term impact of a corrective approach to $\mathcal{N}−1$ security on the distribution of generation capacities within Germany. By freeing up grid capacity, network boosters allow wind and solar generation to be placed at sites with better capacity factors, thus reducing the overall costs of the power system. This impact is expected to be particularly high in countries like Germany, where network expansion is known to experience long delays [18], putting pressure on grid operators to maximise the use of existing assets. We explore the benefit as a function of different levels of renewable energy, as a function of the network booster cost and as a function of the allowed temporary overloading of the lines before the network booster can be activated.

Our main contributions are:

- to present a model that co-optimizes network booster placement with generation investment;
- to explore the difference between an approach where generation and network booster capacities are optimized sequentially versus a simultaneous co-optimization that allows for mixed preventive-corrective security;
- to explore the dependency of network booster benefit on CO$_2$ reduction targets, which are a proxy for renewable penetration in the German context;
- to analyse the effect of the cost of network boosters (particularly relevant given the uncertainty of battery costs and the possible substitution of batteries with demand-side management);
- to investigate the sensitivity to the temporarily-allowed loading capacity (TATL) of transmission lines.

Section III introduces the modelling of NB. In Section IV, TATL strategies for the NB are presented. Then, the performance of our proposed models are studied in Section V. We draw attention to the limitations of the modelling in Section VI. Finally, our findings are concluded in Section VII.

II. NETWORK BOOSTER MODELLING

First, we introduce our generalized network booster (NB) model to investigate possible benefits of a corrective $\mathcal{N}−1$ strategy compared to preventative $\mathcal{N}−1$ security. The network boosters work by injecting or withdrawing power from the grid after a line fails, so that no other line becomes overloaded. Lines may be temporarily overloaded for the few minutes it takes the network booster to come into operation.

The objective of the mathematical problem is to minimize the total required NB capacity at all buses so that we can retain the security of the network considering all single line failures as illustrated in Fig. 1. The proposed NB problem optimizes the capacity to adjust power or demand. $P^+_i$ represents the upward NB capacity to increase power or reduce demand at bus $i$, $P^-_i$ the downward NB capacity to decrease power or increase demand at bus $i$. Thus, both upward and downward NB capacities are positive:

$$P^+_i \geq 0, \quad \forall i,$$  

Fig. 1. Illustration of the concept of preventive strategies to maintain network security under $\mathcal{N}−1$ conditions compared to network boosters as a corrective $\mathcal{N}−1$ security strategy.

Thus, both upward and downward NB capacities are positive: 

$$P^+_i \geq 0, \quad \forall i,$$  

(1)
The dispatch variables of the NB resources $p_{i,t,\ell}^+ \text{ and } p_{i,t,\ell}^-$ are defined at bus $i$ in time $t$ for the outage of line $\ell$ to be positive and limited to the upward and downward NB capacities respectively:

$$0 \leq p_{i,t,\ell}^- \leq p_{i,t,\ell}^+, \quad \forall i, \forall t, \forall \ell.$$  \hspace{1cm} (3)

$$0 \leq p_{i,t,\ell}^- \leq p_{i,t,\ell}^+, \quad \forall i, \forall t, \forall \ell.$$  \hspace{1cm} (4)

The total power injected into the network by all NB resources is equal to the total power absorbed from the network from NB resources, assuming a lossless transmission network:

$$\sum_i \left( p_{i,t,\ell}^+ - p_{i,t,\ell}^- \right) = 0, \quad \forall t, \forall \ell.$$  \hspace{1cm} (5)

Finally, the minimum and maximum constraints for avoiding overloading in transmission line $\ell$ when line $k$ fails by operating NB resources under $N-1$ security condition is given by:

$$-F_\ell \leq f_{\ell,t} + LODF_{\ell,k} f_{k,t}$$  \hspace{1cm} (6)

$$+ \sum_{\ell} \left( PTDF_{\ell i} + LODF_{\ell k} PTDF_{k i} \right) \left( p_{i,t,\ell}^+ - p_{i,t,k}^- \right) \leq F_\ell$$  \hspace{1cm} (6)

where $f_{\ell,t}$ represents the power flow in line $\ell$ at time $t$ before the outage of line $k$ and $F_\ell$ is the nominal power capacity of transmission line $\ell$, also called the Permanently Admissible Transmission Loading (PATL). The PTDF matrix represents the Power Transfer Distribution Factors which relate nodal power injections to the line flows \[19\]. The LODF matrix introduces the Line Outage Distribution Factors \[20\], \[21\] that measure the sensitivity of line flows to the outage of other lines

$$LODF_{\ell,k} = \frac{[PTDF \cdot K]_{\ell,k}}{1 - [PTDF \cdot K]_{\ell,\ell}}, \quad \forall \ell,$$  \hspace{1cm} (7)

If $\ell = k$, we define $LODF_{\ell,k} = -1$. $K_{i,\ell}$ denotes the incidence matrix of the transmission grid which has non-zero values $+1$ if line $\ell$ starts at bus $i$ and $-1$ if line $\ell$ ends at bus $i$. The orientation of the lines is arbitrary but fixed.

The first two terms in Eq. (6) give the power flow in line $\ell$ immediately after the outage of line $k$, while the sum computes the effect of the network boosters on the power flow to counteract the effects of the outage. It is assumed that it may take several minutes to activate the network boosters. In the meantime, we assume that the transmission lines can be loaded more than their nominal power capacity, up to the so-called Temporarily Admissible Transmission Loading (TATL), before the NB resources activate. The relation between the TATL $\tilde{F}_\ell$ and nominal power capacity (PATL) for line $\ell$ is given by:

$$\tilde{F}_\ell = f^t_{\text{attl}} F_\ell, \quad \forall \ell,$$  \hspace{1cm} (8)

where $f^t_{\text{attl}}$ is the TATL factor, which is larger than one ($f^t_{\text{attl}} > 1$). In this way, if line $\ell$ fails, some lines can become temporarily overloaded, until the NB resources act within a certain time, e.g. 2-5 minutes, to eliminate the overloading. Typical TATL values are 10-30% higher than the PATL. In addition, the NB resources need to be able to operate for a certain time, e.g. 30 minutes, to give time for re-dispatching measures such as reducing wind feed-in or firing up gas power plants. To ensure that no line $\ell$ is loaded above the TATL after the failure of line $k$, additional constraints must be enforced:

$$| f_{\ell,t} + LODF_{\ell,k} F_{k,t} | \leq \tilde{F}_\ell, \quad \forall k, \ell \neq k, t$$  \hspace{1cm} (9)

III. NETWORK BOOSTER PLANNING APPROACHES

In this section, we propose two strategies for optimizing the size and placement of network boosters along with the long-term electricity generation fleet. The first sequential strategy separates the problem into a long-term generation capacity expansion problem where it is assumed that network boosters take care of $N-1$ security correctly, followed by a separate problem to determine the required investment in the network boosters. From a market perspective, this could represent the separation of long-term generation investment from the secure operation of the grid by the network operator. In the simultaneous problem, investment in generation and network boosters is optimized jointly, allowing mixed preventive-correction strategies for $N-1$ security. The related decision-making variables and their corresponding time horizons are illustrated in Fig. 2.

A. Sequential Model

Our proposed sequential model splits into two stages. The first stage solves the electricity generation investment problem, while the NB placement problem is solved in the second stage. In this way, the power flow ($f_{\ell,t}$) obtained from the investment problem is an input parameter of the NB placement problem.

1) First Stage – Electricity Generation Investment Problem:

The objective function for the electricity generation investment problem is to minimise annual system costs, composed of the capital and operation costs of the generation fleet:

$$\min \sum_s c_s G_s + \sum_{s,t} o_s g_{s,t},$$  \hspace{1cm} (10)

subject to (8), (9), (11) – (15),

where the first and second terms represent the capital and operation costs for generators, respectively. $G_s$ represents the nominal power of generator $s$ that can be built at an annual cost of $c_s$, and $g_{s,t}$ represents the dispatched power of generator $s$ at time $t$, which is multiplied with the marginal cost of operation $o_s$. As illustrated in Fig. 2, $T + 1$ periods for representing demand and weather conditions are used to dimension the investment problem.
Furthermore, the investment problem is subject to some techno-economic and physical constraints which are presented in the following. Eq. (11) presents the balancing constraints, which require generation, demand and network flows to match at any bus $i$ and at any time $t$

$$\sum_s K^g_{i,s} g_{s,t} - d_{i,t} = \sum_{\ell} K_{i,\ell} f_{\ell,t}, \ \forall t, \forall i,$$

where $K^g_{i,s}$ represents the incidence matrix of generators for mapping generator $s$ at bus $i$. Thus, $K^g_{i,s} = 1$ if generator $s$ is located at bus $i$, otherwise $K^g_{i,s} = 0$. $K_{i,\ell}$ denotes the incidence matrix of the transmission grid, as previously noted.

The capacities of generation are constrained by a maximum installable potential $\bar{G}_s$:

$$0 \leq G_s \leq \bar{G}_s, \ \forall s,$$  

Moreover, maximum and minimum limitations of dispatched power of generators are expressed by

$$0 \leq g_{s,t} \leq f_{s,t} G_s, \ \forall s, \forall t,$$

where $f_{s,t}$ represents the time-dependent availability factor for power dispatch given in per unit of the generator’s capacity. This is relevant for modelling variable renewables like wind and solar. Similarly, the absolute power flow in lines is constrained to their permanent transmission line capacities (PATL):

$$-F_{\ell} \leq f_{\ell,t} \leq F_{\ell}, \ \forall \ell, \forall t.$$

Furthermore, the model features a constraint that limits the CO2 emissions to a desired target level, $\Gamma_{CO2}$:

$$\sum_{s,t} e_s g_{s,t} \leq \Gamma_{CO2},$$

where $e_s$ denotes the specific emissions of the fuel, $\eta_s$ is the generator efficiency. This model formulation classifies as linear problem (LP).

2) Second Stage – Network Booster Problem: In the second stage of the sequential model, the NB placement problem is solved globally based on the planned generation fleet and operation considering all single line outages. With the equations from the generalized NB model as described in Section IV, we seek to minimize the total cost of network booster investment and operation:

$$\min \sum_{i} \left( c^+ P_i^+ + c^- P_i^- \right)$$

subject to (1) - (7),

where $c^+ (c^-)$ represents cost for upward (downward) NB capacity. The coefficients $o^+$ and $o^-$ represent the compensation cost paid to the NB resources, i.e. demand side management consumers, or running costs for energy storage system, for dispatching when lines failed in the transmission network. Moreover, it is important to note that $f_{\ell,t}$ is a model input rather than a decision variable in this second stage. Values for $f_{\ell,t}$ are taken from the first stage and used as an exogenous parameter of the second stage in the sequential NB problem. This model formulation is a linear problem (LP) as well.

### B. Simultaneous Model

Our proposed simultaneous model for the NB problem is an alternative to the sequential model. In this simultaneous model, the electricity generation investment problem and the generalized NB problem are co-optimized in a combined linear problem (LP). Thus, the objective function for TATL simultaneous NB problem is represented by:

$$\min \sum_{s,t} c_s G_s + \sum_{s,t} o_s g_{s,t}$$

subject to (1) - (9), (1) - (15),

where the power flow, $f_{\ell,t}$, is a decision-making variable in the simultaneous NB problem. The simultaneous model allows the decision-maker to choose between preventive and corrective measures for each line. If the decision-maker decides against a corrective strategy, it can set $p_{i,t}^- = 0$ and the Eq. (6) reverts to the standard preventive $N - 1$ constraint for an outage of line $k$. This endogenous choice between corrective and preventive strategies cannot be represented by the sequential model. The full problem formulations for sequential and simultaneous network booster strategies are summarized in Fig. 3.

### IV. Simulation Results

In this section, we study the performance of our proposed NB strategies in finding cost-efficient ways to protect network operation against line outages for a German test case, and observe where flexibility resources are optimally placed. The optimisations are run through the open source modelling framework PyPSA [22]. The results are evaluated in a 50-bus German transmission network using data from the open-source PyPSA-Eur model of the European transmission power system, including time-series for load and renewable resources for each region and existing power plants [23]. Twenty typical hours are chosen to represent typical demand and weather conditions. This represents the upper limit for which we could solve the simultaneous model. It is assumed that a nodal pricing regime is used for the dimensioning of generation assets. The costs of the network boosters are based in the reference case on batteries with an energy capacity cost of 142 €/kWh and a power capacity cost of 160 €/kW, assuming
Fig. 4. Impact of CO\textsubscript{2} emission reduction scenarios on map of allocated NB resources in the sequential model (\(f_{\text{tatl}} = 1.3\)).

Fig. 5. Impact of CO\textsubscript{2} emission reduction scenarios on (a) the NB cost (\(C_{NB}^{(N)}\)) and different between investment cost of full \(N - 1\) and \(N' - 1\) cases (\(C_{I}^{(N-1)(N'-1)}\)) with \(C_{f} = 23\) €/kW/a, (b) energy generation mix in the sequential model.

As an energy capacity equal to 30 minutes at full power. The costs are annualized assuming a cost of capital of 7% to give an annualized cost of \(c^+ = c^- = C_f = 23\) €/kW/a. These costs are then varied in a sensitivity analysis. Very small operating costs of \(o^+ = o^-\) are assumed to avoid random dispatching. The TATLs are uniformly assumed to be 30% higher than the PATLs in the default case, and are then varied in a sensitivity analysis. We study different levels of CO\textsubscript{2} emission reduction levels compared to levels in the year 1990 in the electricity sector.

A. Sequential model

In this section, the performance of the sequential model is assessed. In this way, the impacts of different CO\textsubscript{2} emission reduction scenarios and the TATL factor (\(f_{\text{tatl}}\)) on system costs and allocated flexibility are studied in the power transmission system. Fig. 4 illustrates the map of allocated flexibility resources based on different CO\textsubscript{2} emission reduction scenario in the German transmission network where the positive values represent the discharge capacities (\(P_i^+\)) and negative values represent charge capacities (\(-P_i^-\)) of the network boosters. At no node is both upward \(P_i^+\) and downward \(P_i^-\) capacities installed. For a 90% CO\textsubscript{2} reduction, all the downward capacity is installed in the North of Germany, to absorb power from the newly built wind farms, while the upward capacities are built in the South to supply the power gap that could not be transported. This reflects the dominant pattern of wind power flowing from North to South in the German system. The total capacity of allocated flexibility resources in the 90% CO\textsubscript{2} emission reduction scenario is 11.2 GW, which is 59% higher than total capacity of allocated flexibility resources in the 30% CO\textsubscript{2} emission reduction scenario with \(f_{\text{tatl}} = 1.3\), reflecting the higher wind share for the tighter CO\textsubscript{2} target.

To evaluate this trend systematically, Fig. 5(a) shows the sensitivity of varying the levels CO\textsubscript{2} emission reduction on what is spent on network booster infrastructure (\(C_{NB}^{(N)}\)) and the cost difference (\(C_{I}^{(N-1)} - C_{I}^{(N'-1)}\)) between the generation infrastructure plan of the full preventive case \(N - 1\) (equivalent
Fig. 6. Impact of TATL factor on the NB cost ($C_{NB}$) and different between investment cost of full $(N-1)$ and $(N-1)'$ cases ($C^{I(N-1)} - C^{I(N-1)'}$) in the sequential model in (a) 30% (b) 90% CO$_2$ emission reduction scenarios with $C_f = 23$ €/kW/a.

Fig. 7. Impact of flexibility costs on allocated NB resources in the simultaneous model with $f_{tatl} = 1.3$ in a 90% CO$_2$ emission reduction scenario.

of the benefits of an infinite TATL to be obtained.

B. Simultaneous model

In this section, the performance of the proposed simultaneous model is evaluated, while addressing sensitivities regarding CO$_2$ emission reduction levels, flexibility cost ($C_f$), and the TATL factor. Fig. 7 displays a map of cost-optimally allocated NB infrastructure in a 90% CO$_2$ emission reduction scenario for the highest and lowest considered flexibility costs. The figure shows how considerably more NB infrastructure is built at low flexibility costs, with NB capacity rising from 10.4 GW to 28.7 GW. As previously observed for the sequential model, power consuming network boosters are predominantly found North of the power supplying network boosters in both shown cases. Additionally, Fig. 8 shows how the TATL factor impacts the investment in network booster
Fig. 8. Impact of \( f^{tatl} \) on the NB cost \((C^{NB})\) under various flexibility costs in the simultaneous model for a 90% \(\text{CO}_2\) emission reduction scenario.

Fig. 9. Comparison between total costs of the sequential and simultaneous strategies (with \( f^{tatl} = 1.3 \) and \( C_f = 23 \text{ €/kW/a} \)) and SCOPF \( N-1 \) for three different \(\text{CO}_2\) emission reduction targets of 30% (top), 50% (center) and 90% (bottom).

C. Cost benefits of corrective over preventive measures

In this section, the costs of the system based on sequential and simultaneous models are compared to a system that is secured by standard preventive \( N-1 \) security constraints. Fig. 9 illustrates the total system cost comprising electricity generation investment, operation, and the NB costs for different \(\text{CO}_2\) reduction targets.

The advantage of the simultaneous model is that it can choose for each line failure a mixture of preventive and corrective measures. For a low \(\text{CO}_2\) target of 30% there are low levels of wind and network loading, so the simultaneous model does not build any network boosters and it is cost-optimal to apply a preventative strategy everywhere equivalent to the standard \( N-1 \) case. For a target of 50%, some network boosters are optimal, but only 65% of the NB capacity of the sequential model are built. Instead, a selective preventive-corrective strategy is applied which sits between the standard \( N-1 \) case and the full sequential NB case. This results in costs which are below both extreme cases. Finally, for a 90% \(\text{CO}_2\) reduction the simultaneous model chooses a corrective strategy everywhere, since this enables the existing grid infrastructure to be fully used for integrating renewable energy. The results are therefore more or less identical to the sequential NB model which applies a corrective strategy for all line failures. There is a substantial annual cost saving of 0.85 billion euros from moving from preventive to corrective security. There is an overall cost benefit of just 0.04% of the simultaneous model over the sequential model, which indicates that there is only a small advantage to having a mixed preventive-corrective approach compared to the purely corrective approach in the sequential model. In addition, the sequential model has a clearer separation between generation and network security which may be advantageous from a regulatory perspective.

V. LIMITATIONS AND FUTURE WORK

Our model contains several simplifications that may affect the results. The power flow has been linearized to allow the joint optimization of generation and network booster investment in a reasonable computation time, but this neglects reactive power flows and losses, which should be examined using the full non-linear power flow equations. Similarly we have ignored short-term dynamics that could result from the fast activation of the network boosters, as well as the possible benefits of topology switching to deload the network after a line failure. We have focused on the long-term benefits of the network booster assuming that the current single bidding zone for Germany with subsequent nodal redispatch is replaced by a single market clearing process with nodal power markets. There may be additional benefits for network boosters in today’s system where market dispatch is separated from congestion management. On the other hand, planned network expansion may reduce the benefit from network boosters.
VI. CONCLUSION

In this paper, we have explored the long-term benefits of a corrective strategy towards line failures compared to a traditional preventive security approach. We have examined both a sequential model, where network boosters are assumed to provide $N - 1$ security on all lines, and a simultaneous model which allows mixed preventive-corrective strategies depending on local conditions.

According to our simulation results on a 50-bus German transmission network, we found that using a corrective strategy frees up existing network capacities, allowing cost-saving investments in high quality renewable sites that bring total system cost savings of up to 0.85 billion euro per year for a 90% CO$_2$ reduction target. Even for lower targets, the selective use of network boosters is beneficial. For a high share of renewable energy sources, a widespread use of network boosters is optimal and there is only a small cost-benefit of the mixed preventive-corrective strategy of the simultaneous model. Moreover, it is found that once the temporarily admissible loading (TATL) rises 30% beyond the permanent rating, there is no additional cost saving, so that for lower TATL most of the advantages of the network booster are still gained.

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