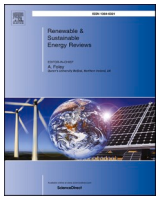
Renewable and Sustainable Energy Reviews 159 (2022) 112163



Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser





Impact of model parametrization and formulation on the explorative power of electricity network congestion management models - Insights from a grid model comparison experiment

Hannes Hobbie [a,*], Jonas Mehlem [b], Christina Wolff [a], Lukas Weber [b], Franziska Flachsbarth [c], Dominik Möst [a], Albert Moser [b]

[a] TU Dresden, Chair of Energy Economics, Münchner Platz 3, 01062, Dresden, Germany
[b] RWTH Aachen, Institute of High Voltage Equipment and Grids, Digitalization and Energy Economics (IAEW), Schinkelstraße 6, 52062, Aachen, Germany
[c] Öko-Institut e.V., Energy & Climate Division, Merzhauser Str. 173, 79111, Freiburg, Germany

ARTICLE INFO

Keywords:
Transmission grid
Renewable energies
Sustainable development
Model comparison
Congestion management
Optimal power flow

ABSTRACT

Integrating increasing shares of weather-dependent renewable energies into energy systems while maintaining high levels of security of supply constitutes a challenge for system operators. The system integration of large shares of variable renewable energy generation requires an effective operation of electricity grids and efficient coordination among grid operators. Hence, the detailed modelling of grid operation has increasingly become important in recent years.

Methods for modelling the operation of (extra) high-voltage grids are undergoing persistent enhancements in academia and industry. Existing approaches vary in data granularity and computational methods. Moreover, assumptions on technical details in grid models vary. The results are thus subject to differences in input data and modelling methods.

The paper at hand aims to identify the most relevant differences that exist amongst grid simulation models and methods for studying congestion management in a European context. Differences are studied based on a comparison of grid simulation models from eight German energy modelling institutions. The effects of model parameterization and formulation on congestion management results are investigated based on three different case studies focusing on outage simulation, line constraint relaxation and the modelling of cross-border measures.

Results indicate that data parametrization can have large impacts on model results with respect to congestion management volumes and the geographic distribution of the respective measures. The analysis also highlights the need to thoroughly calibrate key model parameters. The research findings will assist the grid modelling community and power system planners in simulating congestion management and increase the validity and explorative power of grid simulation models.

1. Introduction

Power system models such as market simulations and grid simulations have become standard tools for decision support in the energy industry and academia over the past years. Market models are typically deployed to investigate techno-economic aspects of energy systems to further the understanding of the interactions between innovative technologies and (adaptive) markets. Electricity grid models cover various aspects of the transportation of electricity and are applied to increase the knowledge on the interplay between market outcomes and the transmission of the dispatched electricity through the physical network.

Ongoing developments toward decarbonizing the electricity supply in European markets are imposing structural changes on the operation and management of electricity grids. Traditionally, energy flows were directed downstream from centralized conventional large-scale generation stations to end-user applications and congestion management measures were activated by transmission system operators at a large scale. The transformation of the electricity system toward a more distributed structure in conjunction with increasing electrification of

* Corresponding author.
E-mail addresses: hannes.hobbie@tu-dresden.de (H. Hobbie), j.mehlem@iaew.rwth-aachen.de (J. Mehlem), christina.wolff@tu-dresden.de (C. Wolff), l.weber@iaew.rwth-aachen.de (L. Weber), f.flachsbarth@oeko.de (F. Flachsbarth), dominik.moest@tu-dresden.de (D. Möst), info@iaew.rwth-aachen.de (A. Moser).

https://doi.org/10.1016/j.rser.2022.112163
Received 31 August 2021; Received in revised form 4 December 2021; Accepted 15 January 2022
Available online 10 February 2022
1364-0321/© 2022 The Authors. Published by Elsevier Ltd. This is an open access article under the CC BY license (http://creativecommons.org/licenses/by/4.0/).

Abbreviations:

AC	alternating current
DC	direct current
DLR	dynamic line rating
FACTS	flexible AC transmission systems
PST	phase-shifting transformers
SCOPF	security-constrained optimal power flow

decentralized sector-coupling technologies is altering traditional practices. New solutions for the future power supply are not only associated with the technical aspects of electricity grids. System planners must also facilitate new forms of competitively organized markets serving grid operators with sufficient flexibility sources to manage grid congestions. These developments have also influenced model-based representations of electricity systems. As a result, the topic of modeling and simulating electricity grids has spurred research amongst the academic community across different disciplines in recent years in order to support regulators and policymakers in designing strategies and developing solutions toward efficiently organizing and managing the future transmission of electricity.

The structure of electricity grid models differs strongly across modeling institutions depending on the specific institution's disciplinary background and field of model application. Differences in grid models, for example, comprise the utilized programming language, optimization technique, granularity of the power system infrastructure, i.e., voltage levels and grid topology, represented as well as methods employed to parameterize the respective input data. Typically, grid models that are employed at technical institutions feature greater detail with respect to the physical representation of the network (e.g. AC vs. DC approximation) than those used at rather economic departments, which abstract from certain technical details to enable a stronger focus on market interactions (e.g. perfect competition vs. strategic behavior).

The variety of different grid models deployed in academia and industry prompts the question as to how model-related simplifications and assumptions concerning key parameters impact model results. Model experiments are a valuable method to compare power system models of different kinds in order to provide insights on the interactions between varying model configurations and model results. While several model experiments with a focus on power market models have been conducted to date [1], a structured comparison of grid simulation tools has yet to be performed.

This paper aims to identify differences in the modelling of congestion management for European power grids existing in academia and increase transparency regarding the specific implementation in grid optimization models. The literature on modeling electricity networks in various application-specific contexts is rich. This research distinguishes itself from existing works by investigating how the parametrization and formulation of crucial model features impact model-endogenous outputs regarding congestion management. The research findings will assist the grid modelling community and power system planners in simulating congestion management and increases the validity and explorative power of grid simulation models.

This paper was prepared as part of the Modex-Net project in which grid simulation models from eight German energy modeling institutions from *TU Dresden (ELMOD), RWTH Aachen University (MarS/ZKNOT), Öko-Institut e.V. (PowerFlex-Grid EU), TU Dortmund University (MILES), Jülich Research Center (Europower), DLR Institute of Networked Energy Systems (eTraGo), Karlsruhe Institute of Technology (PERSEUS), and FfE (ISAaR)* are systematically harmonized and compared against each other based on structured benchmark runs [2,3]. Effects of selected model key parameters and simplifications made in terms of model-based representations of congestion management measures on model results are investigated in this paper with three different modelling case studies and reflected with experiences and insights gained during the development of grid simulation models by the participants of the model comparison. Methods utilized in this work adhere to current practice in Europe and reflect the existing regulation concerning market clearing and congestion management procedures.

The remainder of the paper is organized as follows: section 2 highlights existing market-clearing practices in European electricity markets focusing on congestion management and derives implications for the model-based representation of congestion management. Differences ascertained between the grid simulation models used at the participating institutions within the scope of the experiment are discussed at a descriptive level in section 3. Impacts of different key parameters and system configurations are explored based on the knowledge derived and insights gained by the different participating modelers and quantified by three selected case studies in section 4. Finally, section 5 concludes with a summary of the key insights for the grid modelling community regarding the impact of model features on the validity of simulation results.

2. Simulation of grid operation

2.1. Legal background, market-clearing practices, and modeling implications

The European electricity grid operators are tasked with efficiently managing grid infrastructure reinforcements and reliably operating electricity grids. The management and operation of electricity grids are strongly influenced by the existing regulatory framework and electricity pricing mechanism in the specific market and thus are reflected in the structure and formulation of congestion management models. Market coordination between electricity suppliers and demanders based on nodal pricing, as implemented in restructured electricity markets in the US, e.g., PJM and ERCOT, considers all transmission limitations during the settlement of market-clearing prices at the corresponding electricity grid nodes resulting in an integrated market model formulation incorporating the physical limitations on power line flows.

In Europe, only cross-zonal interconnector capacities are considered in the market clearing process resulting in a uniform price across the entire market zone (typically a country). Electricity grids within a market zone are assumed to have unlimited capacity.[1] Transmission system operators subsequently resolve grid congestions resulting from the market-clearing power plant dispatch via real-time remedial actions in line with the prevailing regulatory framework.[2] This typically entails a two-stage formulation of congestion management in which the market-clearing power plant dispatch is first optimized while in a subsequent step the day-ahead generation schedule is evaluated by means of a power flow and remedial actions are taken to avoid transmission line overloading in the respective bidding zone.

Fig. 1 illustrates the sequence and interplay of (wholesale) electricity markets and the management of grid congestion in European power markets.[3]

Wholesale electricity markets are typically divided into futures and spot markets according to the lead-time between the commercial transaction and delivery of the contracted power products. Similarly,

[1] Most recently, the market organisation in Europe has been adapted in line with the introduction of flow-based market coupling (FBMC), in which most critical network lines are considered during market clearing.

[2] Costs arising from the management of grid congestions are passed on to all end customers within the market zone and paid through a levy on top of the retail price for electricity (network charges).

[3] In Germany, the so-called Energiewirtschaftsgesetz [§13 EnWG] constitutes the underlying legal basis for all congestion management measures that grid operators can utilize.

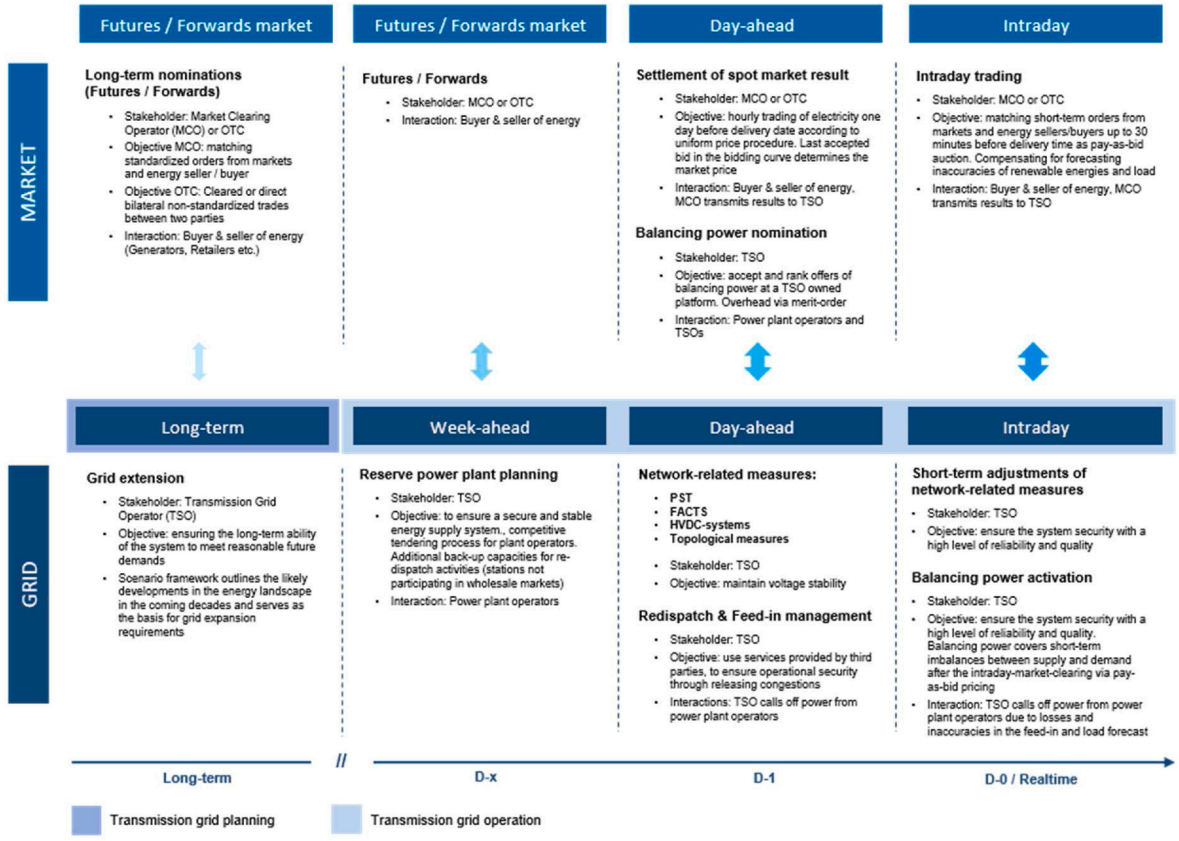


Fig. 1. Grid management and market clearing processes.

different congestion management measures are available to transmission system operators depending on the time of market intervention. Long-term measures comprise grid expansion planning and reserve power plant nominations, short-term measures relate to all ex-post interventions after the wholesale markets have been cleared. These encompass the redispatch of (conventional) generation plants, feed-in management (of renewables) and network-related measures. The focus of the paper centers on the representation of grid simulation models employed to resolve grid bottlenecks after zonal market clearing.

2.2. Congestion management procedure and classification of relevant remedial measures

Modeling congestion management can be performed in various ways and involves several steps. According to existing practices in European markets, wholesale market clearing is initially simulated based on a zonal market configuration with relaxed intra-zonal grid constraints. Typically, power market models do not distinguish between futures and spot markets. All wholesale markets are cleared simultaneously assuming arbitrage-free markets.

The modeled market equilibrium is then fixed and the grid model initialized with the market equilibrium utilized as a starting solution for the grid simulation. In addition to all power balances and generation constraints that are part of the market optimization, the grid simulation includes intra-zonal grid constraints, imposing limitations on the resulting power flows. The simulation of the transmission grid model resolves (all) congestions via out-of-market remedial corrections to the market clearing generation schedule to ensure electricity demands are satisfied at all corresponding electricity grid nodes considering transmission constraints.

European transmission system operators are provided with several different options to resolve grid bottlenecks according to the specific national electricity transmission regulation. Outweighing economic and environmental aspects of energy supply, regulatory frameworks typically prioritize network-related congestion management measures over cost-intensive market-related measures. Fig. 2 summarizes different congestion management measures and their compulsory merit order that are commonly included in grid simulation tools.

Network-related measures include all assets owned by the TSO that can be used to minimize congestions by means of redistributing power flows. Domestic redispatch refers to the simultaneous increase and decrease of conventional power generation at two different locations to resolve grid congestions. Transmission system operators are considered regulated entities. The regulatory framework obliges them to pursue redispatch in a cost-minimizing manner based on the specific plant's marginal cost. Foreign redispatch includes power generation units in neighboring market zones as redispatch options based on international agreements. Feed-in management involves the curtailment of generation from renewable-based generation units and demand-side management comprises all measures relating to the increase, decrease and intertemporal shift of flexible demands. If all respective measures mentioned are insufficient to resolve a grid congestion, conventional electricity generation in conjunction with inflexible demands can be reduced as a last (no-regret) option. The order of the respective congestion management measures is typically specified in the market regulatory framework. Modelers are challenged to ensure that grid simulations reflect this order to be able to capture the interactions that exist in real-world congestion management protocols.

2.3. Optimization problem of congestion management

Market dynamics that determine equilibria and outcomes for resulting electricity transmission requirements are complex and lend themselves to analysis through the deployment of optimization models.

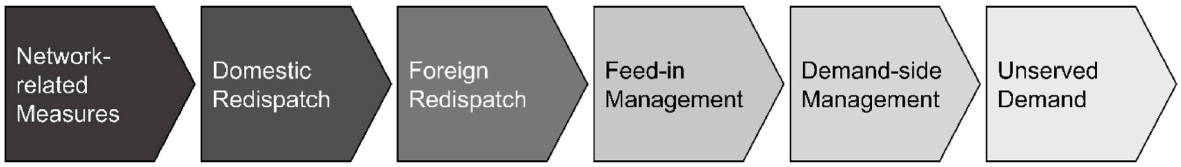


Fig. 2. Merit order of congestion management measures.

The simulation of congestion management typically entails the application of an optimization problem in the form of the so-called security-constrained optimal power flow (SCOPF). Modelers use SCOPFs to simulate congestion management either for operational planning tasks or investigating future market projections during long-term planning studies assuming a steady state. For operational planning, the steady-state refers to a day-ahead forecast or a selected scenario for long-term projections [4–7].

The general mathematical form of the SCOPF is expressed as follows [4–7]:

$$Min\, f(x_0)$$

$$s.t.\ g(x_0) = 0$$

$$h_0(x_0) \leq 0$$

$$h_k(x_0) \leq 0$$

The vector x_0 describes the fault-free system state including all adjustable remedial actions. The minimizing target function $f(x_0)$ includes all costs related to the utilization of remedial actions that can feature linear, quadratic, or nonlinear components depending on the granularity of model details. Quadratic equations for example account for the representation of losses from physical power flows. The target function is constrained with power flow equations g in every optimized system state x_0 and constraints $h_0(x_0)$ describing the fault-free system state. To prevent congestions in every faulty system state x_k relevant for (n-1)-security, safety margins are included in the constraints $h_k(x_0)$ and guaranteed by adjusting the fault-free system state x_0 accordingly [4–7].

4. Model-based representations of congestion management

The model comparison exercise revealed various differences in the model-based representation of congestion management measures and model formulations. The following summarizes differences exhibited by the models of the participating institutions and highlights advantages and disadvantages in their context of application (cf. section 4).

4.1. Power flow calculation

Power flow calculations evaluate system states before, during and after optimizing the SCOPF for a given set of operational points. Formulating power flow equations typically involves modelling a nonlinear system of equations. The Newton-Raphson method is a very common approach for solving such systems [8].

A faster but less accurate method for solving of active power flow equations can be achieved through the utilization of linearized representations of existing nonlinearities in power flow equations. So-called DC power flow equations neglect reactive power flows, use small-angle approximations and assume constant voltage magnitudes [8].

Half of the institutions participating in the Modex-Net project uses a DC power flow calculation and the other half an AC power flow calculation, as shown in Fig. 3. One reason for this may be the technical or economic affiliation of the institution. The slightly higher share of institutions using an AC load flow calculation compared to institutions using a SCOPF based on an AC formulation results from the fact that some institutions additionally perform an AC load flow calculation after solving a SCOPF with DC formulation based on the obtained operating point, for example, to be able to determine power flow losses.

4.2. Congestions on cross-border lines

If not adequately addressed, congestions on cross-border lines can have a significant impact on national congestion volumes reproduced by grid simulation models. In reality, TSOs carry out national congestion management without considering congestions on cross-border lines. After all national congestions are resolved, congestions on cross-border lines are treated through bilateral agreements between the TSOs at both sides of the interconnector. Modelling cross-border measures can be done in several ways.

A simple but yet useful approach is to neglect restrictions for maximal allowed power flows on cross-border lines. Other methods comprise reducing the number of power plants in neighboring market zones that can contribute to cross-border redispatch and additionally assuming high prices for their use. Both ways can have undesired impacts on model results, e.g., total redispatch volumes [10].

As Fig. 3 depicts, the majority of institutions (88%) explicitly consider cross-border redispatch. This type of modeling is also in line with the latest efforts of European regulators to enable increased coordination for cross-border measures [10].

4.3. Time-coupling

Modelling energy storages and operational restrictions of large-scale power stations (e.g., minimum runtimes, standstill times and power gradients) comprise the utilization of time-coupling constraints. Many grid simulations avoid the modelling of time-coupling constraints to improve solve time [9].

Fig. 3 indicates that a majority (88%) of the institutions participating in the Modex-Net project are able to include time-coupling constraints into the grid simulation, but their use depends strongly on the application case and research framework. Market projections characterized by low penetration levels of electrical storages and larger amounts of flexible generation units may allow for neglecting time-coupling constraints.

4.4. Dynamic line rating

Line loading margins increase during times of cooling weather conditions. Since current limits reported in line characteristics sheets are calculated assuming worst-case weather scenarios, actual line capacities are larger during most days of the year than those reported [10,11].

This additional current carrying capability of overhead lines is exploited increasingly in the operation of transmission grids. So-called dynamic line rating monitors weather conditions along critical lines in the transmission grid and adjusts limits in real-time [10,11].

As indicated in Fig. 3, dynamic line rating can only be modeled by 25% of the participating institutions. Discussions amongst the project participants revealed that dynamic line rating is gaining in importance as a feature in grid simulation models.

4.5. Feasibility feature

Optimizing network simulations are complex programs in terms of

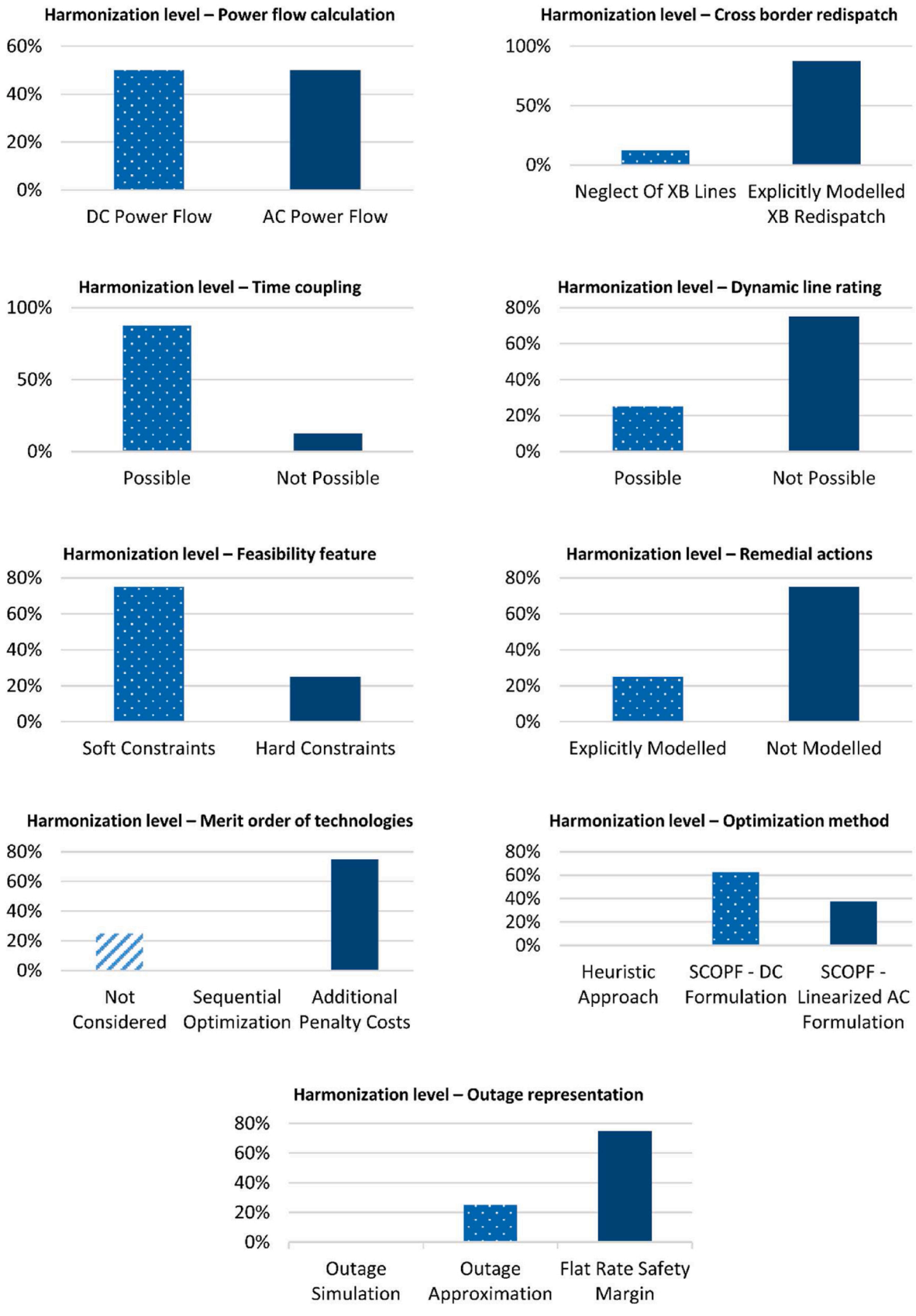


Fig. 3. Harmonization level of congestion management's modeling aspects.

model size (number of equations and variables) and structure of optimization problem (linking variables and equations). Even when formulated as a linear program, solving the respective model instance poses challenges. Moreover, assumptions on input data for future system projections (generation and grid infrastructure) are subject to uncertainty and automated data parametrizations can cause inconsistencies resulting in model infeasibilities [12].

Ways for handling model infeasibilities are incremental adjustments of input data or introducing so-called soft constraints. Soft-constraints impute slack variables to (critical) constraints ensuring solvability. An unrealistic exploitation of slack variables can be controlled by introducing high penalty costs associated with them [13].

As Fig. 3 illustrates, the majority of institutions (75%) uses soft constraints in their network models. It should be noted that soft constraints mainly serve to simplify tasks related to model parameterizations since such tasks require extensive effort by researchers, in particular for the parametrization of long-term projections. Model solutions obtained via soft-constraints are not necessarily equivalent to those generated without such constraints. Moreover, the parametrization of soft-constraints itself can have large impacts on results, as Section 4 showcases.

4.6. Remedial actions

Congestion management measures such as redispatch and changes in operating points of high voltage direct current converters can be approximated with power injections in grid simulation models. The operation of phase-shifting transformers (PST) or flexible AC transmission systems (FACTS) in real-world systems influence power flows and cannot, however, be represented through power injections. Modeling such congestion management measures increases thus the complexity of network simulations.

As Fig. 3 shows, only a few participating institutions (25%) include these devices in their grid modelling. Similar to dynamic line rating, modelling PST and FACTS has become more prominent among power system modelers, even though a limited penetration of the respective technologies in the European transmission grid system has materialized to date.

4.7. Merit order of technologies

European transmission system operators have various measures at their disposal to avert line overloading in the transmission grid (see Fig. 2). Regulatory-related prioritization of congestion management measures can be represented by sequentially solving separate optimization problems or prioritizing individual measures through penalty costs resulting in a merit order of congestion management measures [14].

As Fig. 3 depicts, 75% of the institutions prefer a merit order based approach utilizing penalty costs. This may be due to additional computational efforts involved with sequentially solving the optimization problems for different measures.

4.8. Optimization method

Power flow equations typically feature quadratic and trigonometric components resulting in nonlinear optimization problems with a nonconvex solution space. A variety of different approaches exist to solve such problems. These methods can be divided into analytical and heuristic approaches [15–17].

Heuristic algorithms search the solution space repetitively to find a solution of the SCOPF. Most heuristics learn from feedbacks of previous feasible solutions found during prior iteration steps. Usually, these heuristics include a component of randomness mimicking genetics (evolutionary algorithms), intelligent behaviors of animals (swarm optimization) or physical phenomena (optimization based on physics). Their performance highly depends on the nontrivial parametrization [15–17].

Analytical approaches exploit the mathematical structure of the equation system. Since the SCOPF is nonlinear and nonconvex, they typically relax some of the constraints of the original problem. Most common relaxations make use of linearization techniques in which reactive power is neglected (DC power flow equations), all power flow equations are linearized or AC power flow equations are quadratically approximated. The linearization of power flow equations depends on the operation point in contrast to DC power flow equations. Linearization errors can be reduced through iterative procedures, in which the optimization of the relaxed linearized problem with updates of the linearization based on the previously optimized operation point are repeatedly performed [15–17].

The participating institutions in the Modex-Net project clearly prefer optimization-based methods over heuristics as Fig. 3 shows. Among optimization-based methods, DC formulations of the SCOPF with 63% are more common than AC formulations (37%). Once again, this might be due to the institutional backgrounds.

4.9. Outage representation

The constraints of the SCOPF need to be secured during fault-free and every relevant outage situation. Therefore, analytical optimization methods use safety margins on line constraints to prevent constraint violation in all relevant outage situations. Dimensioning such safety margins involves the estimation of impacts of each outage on the system state [18].

The most detailed way for simulating outages is the calculation of power flow equations for every relevant outage situation. This approach reproduces system states and safety margins to an exact degree. On the contrary, it involves extensive calculation efforts since power flow equations must be solved for every relevant outage situation [8].

Linearized predictions constitute a faster way for outage simulation through approximation. Likewise, outage approximations consider line-specific impacts of individual outages for dimensioning safety margins.

Flat-rate safety margins, in contrast, consider constant averages for the impact of all relevant outage situations simplifying line-specific impacts. This is less exact compared to the above methods, but has generally positive effects on model solve time.

As Fig. 3 illustrates, the majority (75%) of institutions participating in the Modex-Net project uses flat-rate safety margins. A quarter can additionally depict outages based on approximations. The participants do not use detailed outage simulations as this entails large computational requirements. Effects of outage modelling on grid simulation results are quantified as part of the case study in Section 4.

5. Comparison of model results

5.1. Model extensions and improvements

The following chapter summarizes experiences and insights gained during the development of grid simulation models by the participants of the model comparison. Through the exchange amongst the participants facilitated by the project, individual modelers were able to enhance their models and results in line with the recommendations and experience shared by others in the consortium. The experiences and findings provide a valuable resource for fellow modelers to further develop and improve their own models.

5.1.1. Grid topology

The grid topology between the models varies amongst the participating institutions. Some models included ca. 600 high voltage power lines while others optimize the power flow across ca. 20,000 high voltage power lines (including 110 kV).

Errors in grid topology can occur in the event that power lines are

incorrectly assigned, network connections are incomplete or stub lines are present, but also if the wrong parametrization is applied to the respective power lines. The source of the errors can potentially be ascertained during the evaluation of the initial congestion management results. If individual power lines exhibit large amounts of recurring congestion that cannot be reduced with via the remedial actions available to the model, their technical parametrization may need to be adjusted.

High incidences of line overloading can also occur in models where connections to the neighboring countries are not considered. This can be remedied by incorporating the respective cross-border connections in the model. In border regions and metropolitan areas, 110 kV power lines constitute an essential element of the network topology. If they are neglected in the model, larger amounts of redispatch volumes can arise. Hence, their inclusion should be considered.

5.1.2. Model formulation: soft/hard constraints

As described above, there are two methods to determine requirements for remedial actions on power lines: Either line congestions are allowed but penalized with high costs or it is prohibited by capping the line occupancy variable. In the latter case, the resulting power plant dispatch must be compared to that without binding grid restrictions.

There are advantages and disadvantages to both approaches. The approach with soft restrictions has the advantage that two-stage calculations can be performed, which reduces the respective complexity. In the first step, the market result is calculated, which is then used in the second step for the network simulation and the grid optimization. Introducing a penalty term for line congestion, on the other hand, influences the results and is subject to arbitrariness.

The hard constraints approach ensures optimal deployment of the redispatched power plants, does not need to set a penalty term, and takes into account all the technical constraints of the market model. However, it does not allow for ignoring insignificant line congestions. As a result, it has the effect of overestimating the identified need for remedial actions. If problems occur in the network topology as described above, the optimization problem becomes unsolvable.

In terms of insights, the use of soft constraints at first may provide a valuable method to identify nonresolvable grid congestions and help to pinpoint errors in line parametrizations or in the network topology. Most of the modelers decided to use soft constraints to determine the need for remedial actions.

5.1.3. Interplay between cost of line overloading and parametrization of remedial actions

The amount of remedial actions enacted is not linearly related to that of a line congestion: if a power plant reduces its feed-in, this can reduce congestion on several lines around the node. The avoided costs of line congestion accumulate. On the other hand, if almost all congestions have already been resolved, there may be a case where the reduction in feed-in only causes a marginal reduction in line congestion on one line that is proportionally affected by the feed-in. This illustrates the challenge in “correctly” parameterizing the costs when using soft constraints. One approach to addressing the problem is to vary the penalty costs of line congestion: the optimal value for the penalty costs can be determined at the point where the number of lines exhibiting overloads remain constant and cannot be reduced.

Redispatch costs for individual power plants should be carefully calculated considering the interactions that exist between national and cross-border congestion management. In some models, a large portion of the redispatch volume occurring was located at nodes characterized by large power plants. By increasing their redispatch costs gradually an increase in redispatch volumes at other nodes was expected. Nevertheless, especially in border regions, the price increase may exceed a critical value that leads to a ramp-up of foreign power plants. Therefore, the interaction of grid constraints and power plant prices should be considered in model adjustments of this kind.

5.1.4. Congestions on cross-border lines

If the solution space of the power flow optimization problem is confined to a single bidding zone, i.e, country, by including a net balancing constraint, the identified domestic redispatch volumes rise notably if congestions on cross-border lines are resolved exclusively by nationally available remedial actions. When the cross-border lines were not blacklisted or cured through simplified available cross-border redispatch options, some project partners found congestions that could not be addressed by domestic redispatch - or where redispatch volumes (and costs) increased disproportionately compared to congestion impacts. One project partner, for instance, reported a quadrupling of the overall redispatch volumes. In order to eliminate the impact of this error on the model results, the neighboring countries should be at least included as a single node within the observation horizon of the model, or the cross-border lines mostly affected by congestions should be blacklisted.

Most of the modeling partners apply a penalty margin for the use of cross-border redispatch so that this option is placed at the end of the merit order. One partner conducted a sensitivity analysis on the base value of redispatch costs to determine its impact on the model results. The results of the analysis, which are reported in section 4.2, show a strong influence on the results.

In this context, it is worth mentioning that it makes a difference whether the neighboring countries are modeled as one node or whether a higher level of granularity is implemented. In some of the models compared in this project, different power plant technologies are designated to provide redispatch for the respective countries. This higher level of resolution results in an increase in cross-border redispatch quantities.

In addition to the cost of cross-border redispatch, interconnector capacity plays a significant role in determining the extent of cross-border redispatch. To determine the impact on the results, the dimensioning of the NTCs can be varied.

5.1.5. n-1 criterion/safety margin

To make the results comparable, the modeling partners agreed to model outage situations in a harmonized manner by using a flat rate safety margin approach to prevent constraint violations in relevant outage situations. Hence, the line capacities of each power line are reduced by a constant percentage. Some project partners varied the safety margin to observe its effect on the results. Obviously, the need for redispatch decreases with the assumed safety margin. By lowering the safety margin from 0.3 to 0.25, a decrease in the redispatch volume of 13% could be observed. In section 4, the calculations performed by one modeling partner toward examining the impact of different representations of outages on grid simulation results are described.

5.1.6. Dynamic line rating (DLR) and phase-shifting transformers (PST)

Typical grid-related measures deployed to reduce congestions include dynamic line rating (DLR) (see section 3) and the utilization of phase-shifting transformers (PST). DLR responds to outside temperatures to adjust a line capacity in real-time and PST relieve a congestion on a single line by inducing a corresponding load on adjacent power lines (vice versa). Both measures seem to have extremely positive effects on required redispatch amounts. Since most models cannot explicitly model DLR or PST, the model experiment group agreed to exclude DLR or PST in the harmonized model versions. One partner reported a strong influence of these technologies on congestion management results experienced during the investigation of a projected future grid topology. These calculations were carried out beyond the harmonized scenarios.

In the respective calculations, PST were added to the network topology according to the confirmed network development plan in Germany. Renewable energy projections were based on the historic distribution of the generation fleet. Under these assumptions, redispatch quantities could be strongly reduced.

Implementing DLR may have an even stronger decreasing effect on

congestion management volumes. Contrary to PST, DLR affects not only specific points in the power grid, but can be exploited more widely in the grid. Depending on the deployment rate, reductions of remedial actions may exceed those achieved with PST. Another partner reported that they introduced DLR into their model for a test run toward investigating future grid projections. The model results indicated significant reductions in congestion management volumes, however, the assumed deployment rate of DLR was rather high.

5.2. Discussion of selected case study results

The following illustrates how selected model formulations and their parametrization impact congestion management results. Experiences during the Modex-Net project revealed that the modelling of outage simulations, line-constraint relaxations and cross-border congestion management can heavily influence the solving performance and results of congestion management simulations. In particular, the modelling of line-constraint relaxations has been adjusted from hard constraints to soft constraints by several project members. Therefore, three different case studies are performed to independently investigate the impact of the respective model formulations and parametrizations on model solvability and results of the congestion management simulation in a greater detail.

5.2.1. Impact of formulation of outage simulation

5.2.1.1. Motivation. Actual network operation is subject to specific security requirements. A common rule applied to ensure a reliable electricity supply is the so-called n-1 criterion. The power grid must always be able to cope with a failure of one relevant line element or another grid component at any time without causing widespread supply outages. All remaining lines must not be overloaded during such an event. Grid simulation models must reflect this requirement, though different modeling approaches for outage simulation exist.

5.2.1.2. Case study description. This case study comprises four simulations with different flat-rate line constraints to investigate the model behavior in outage situations with different parameter variations. Flat-rate margins are applied and line capacities incrementally varied between 65% and 80% of the maximum line currents in 5% steps. Results are then compared against a model run with a detailed n-1 outage approximation and a line capacity of 100%.

5.2.1.3. Selected case study results. Fig. 4 shows the cumulative annual congestion volumes per line before congestion management for all congested lines. The congestion volumes constitute the power flows exceeding the respective line loading limits. Results indicate that the distribution of congested lines throughout the year differs between the cases of flat-rate line constraints and a detailed outage approximation. While congestions primarily occur in the center and northwest of Germany across both modelling approaches, slight differences in terms of congestion volumes can be observed in the north, east and west of Germany. In particular, regions allocated in the west of Germany experience grid congestions during the runs with flat-rate margins that are not reproduced by the run with a detailed outage approximation.

Performing a comparison of the four sensitivities with flat-rate line constraints, results show that reducing the maximum line capacity results in increased congestion volumes. The regional distribution, however, remains nearly unchanged. Moreover, single lines with low congestion volumes do not show any remaining congestion with a less restrictive flat-rate line constraint. At the same time, lines with high levels of congestion, particularly in the northwest and center of Germany, continue to exhibit high congestion volumes. It can be assumed that those lines strongly influence the magnitude of volumes for remedial actions and their geographic distribution.

Fig. 5 depicts the cumulative annual volumes of remedial actions per model run. The regional distribution of grid congestions differs between the simulations with a detailed outage approximation and the simulations with flat-rate line constraints, which also affects the regional distribution of remedial actions. The outage approximation yields high levels of negative redispatch in the north of Germany. In contrast, the simulation runs with flat-rate margins result in higher volumes of negative redispatch in the west. Differences in local congestions between both approaches translate into a geographic shift of remedial actions. However, large amounts of grid congestions in the center and northwest of Germany in all model runs still require a north-to-south shift of generation from conventional power stations.

Comparing the four flat-rate line simulations, results show that although the total volumes of remedial actions decrease with a reduction of the security margin on the line constraints, the regional distribution remains unchanged.

As depicted in Fig. 6, the impact of the geographic distribution of grid congestions on the distribution of remedial actions is also expressed in the annual sum of remedial actions. Similar to the results displayed in Fig. 5, the overall annual volume of remedial actions decreases with a reduction of the margin on the flat-rate line constraints. Only the run that features an associated flat-rate line constraint of 70% of the maximum line flow capacity results in similar amounts compared to the

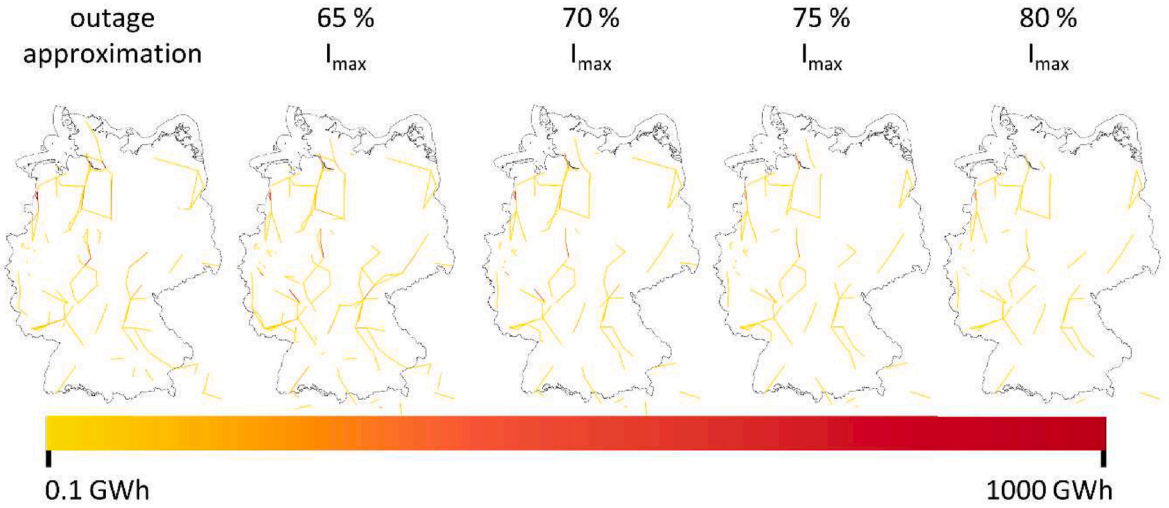


Fig. 4. Outage sensitivity – Cumulative annual congestion volumes per line before congestion management.

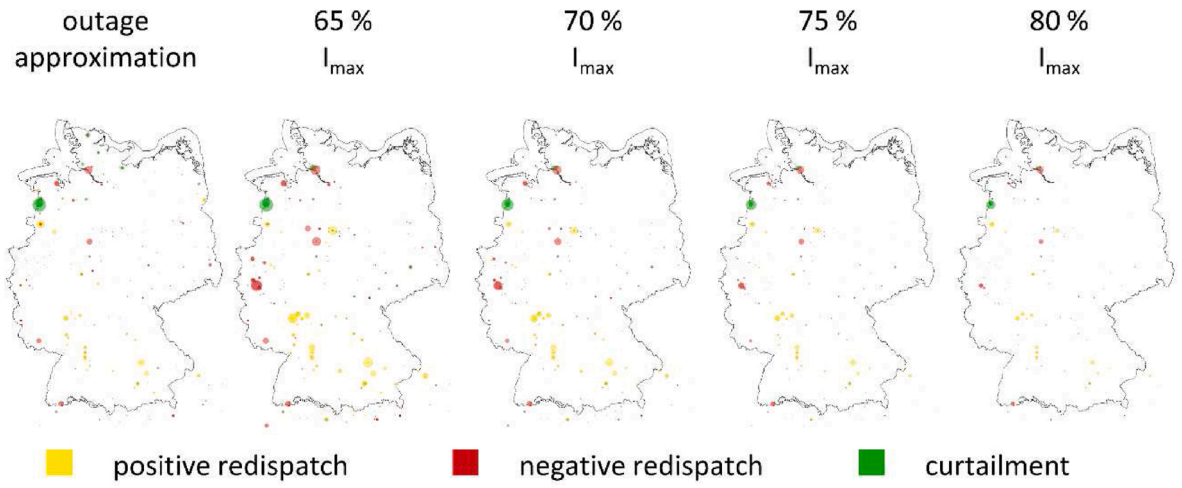


Fig. 5. Outage sensitivity – Cumulative annual remedial actions per node.

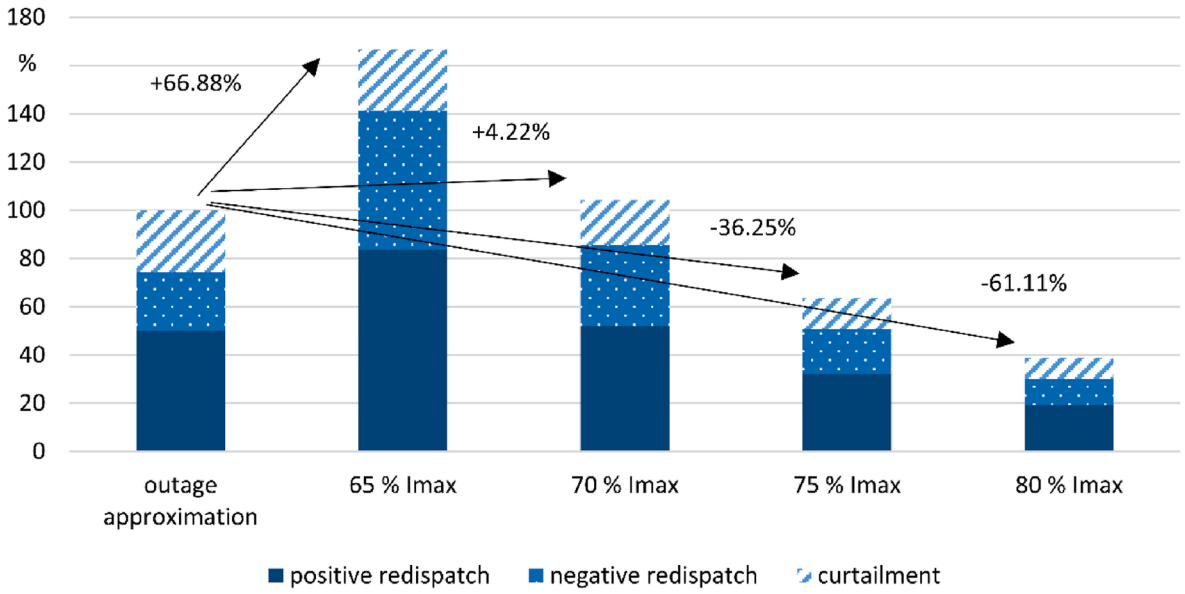


Fig. 6. Outage sensitivity - Annual sum of remedial actions.

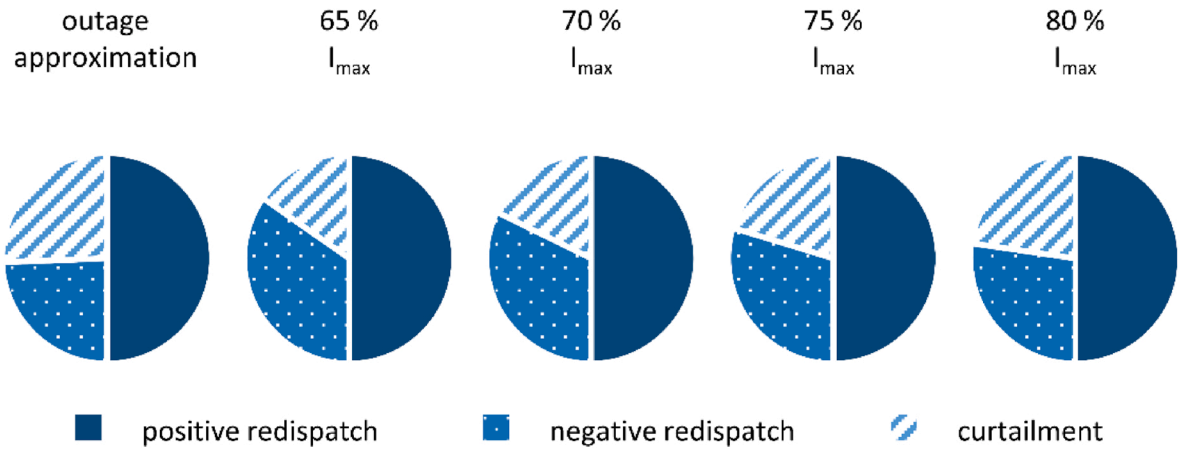


Fig. 7. Outage sensitivity – Distribution of annual sum of remedial actions.

simulation results with an outage approximation.

As Fig. 7 indicates, despite the similarity in total annual volumes of remedial actions required, the distribution of redispatch and feed-in management differs. The detailed modelling of outages based on an outage approximation leads to a higher percentage of required curtailment quantities compared to the runs with flat-rate line constraints with high security margins (65%, 70%). Decreasing the respective security margin leads to lower congestion management volumes. Nonetheless, in all model runs with flat-rate line constraints curtailment occurs. The relative share of curtailment on the total volume of remedial actions increases with a higher security margin.

Summarizing, this case study shows that flat-rate margins can be calibrated to similar total volumes of remedial actions compared to a formulation with a detailed outage approximation. Simplifications involved with flat-rate margins, however, affect the geographic distribution of remedial actions. In particular, regions with highly meshed electricity grids (see western Germany in Fig. 5) experience much lower levels of congestion management required to resolve grid bottlenecks due to better compensating capabilities of meshed grids. Flat-rate line constraints only partly reproduce this stress leveraging effect and yield higher congestion amounts.

5.2.2. *Relaxation of line constraints*

5.2.2.1. Motivation. Modelling the operation of the power grid entails not only computational complexities but is likewise very data intensive. Depending on the specific quality of data sources, several assumptions must be made. Furthermore, large amounts of input data can require automated data processing procedures. Hence, the model parametrization required can potentially lead to data inconsistencies that produce model infeasibilities. A common approach to handle such infeasibilities are so-called soft-constraints on line flow equations. Soft-constraints introduce slack variables on line limits, that are penalized with high cost parameters ensuring feasible line-flows in every situation. Moreover, soft-constraints can be used to identify model inconsistencies.

5.2.2.2. Case study description. This case study comprises four sensitivity runs on penalty cost variations to investigate benefits and drawbacks of soft line constraints. A benchmark scenario is created in which a congested coupling line between the two stations “Grafenrheinfeld” and “Bergrheinfeld” cannot be resolved in a model formulation based on hard constraints. Such model errors can occur due to slightly overdimensioned generation capacities at the end of a stub line resulting from automated capacity regionalization procedures. Absent the use of soft constraints, the grid simulation model solution might not converge to the optimal solution or solve only with infeasibilities. In this case study, outage simulation is based on flat-rate margins with reduced line capacities (70% of the maximum line loading). The parametrization of the penalty cost for slack variables is varied between values of 6, 60, 600 and 6,000 times the cost of one equivalent injected unit of conventional power between the different calculated model runs. Since slack costs are applied in each run to resolve a limitation on one single line and remedial actions may affect multiple lines, slack costs and costs for remedial actions cannot directly be compared.

5.2.2.3. Selected case study results. Fig. 8 summarizes the node-specific, cumulative annual volumes of implemented remedial measures. The geographical distribution of remedial actions remains almost unchanged across all simulation runs since the congestions observed are not affected by the parametrization of slack variables. It can, however, be observed that the variation of slack costs impacts the model results with respect to the congestion management volumes in the different regions (e.g. North-Rhine Westphalia).

The cumulative annual residual congestion per line after congestion management is performed is plotted in Fig. 9. The model run with an assumed ratio for slack costs of 6 cannot resolve all grid congestions. Single lines throughout Germany remain congested even though, in theory, these congestions could be resolved as simulations with higher slack-costs indicate. The total remaining congestion volume across all lines sums to 298.45 GWh.

All congestions but for the congestion generated for demonstration purposes (red circle) can be resolved by increasing the slack-cost ratio to 60 and above. Increased slack-cost ratios only slightly lower the congestion on the artificially congested line.

The congestion volumes on all remaining overloaded lines exhibit only slight changes when applying slack-cost ratios of 60 and higher. Changes in the annual volumes of remedial actions are significantly higher as highlighted in Fig. 10. The simulation run with a slack-cost ratio of 6,000 results in a significant increase in the amount of congestion management performed. The model largely utilizes remedial actions to resolve the bottleneck. However, the respective actions have only a minor impact, which translates into very high system costs. In this example, the solution of an equivalent model with hard constraints would converge to a similar solution as long it finds a feasible solution.

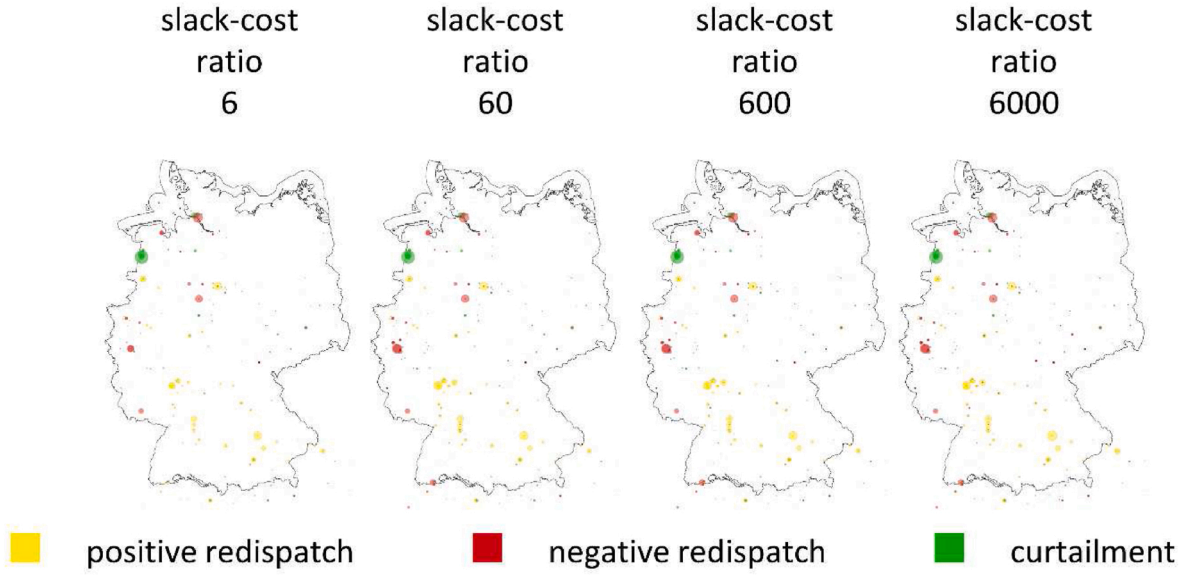


Fig. 8. Slack cost sensitivity – Cumulative annual remedial actions per node.

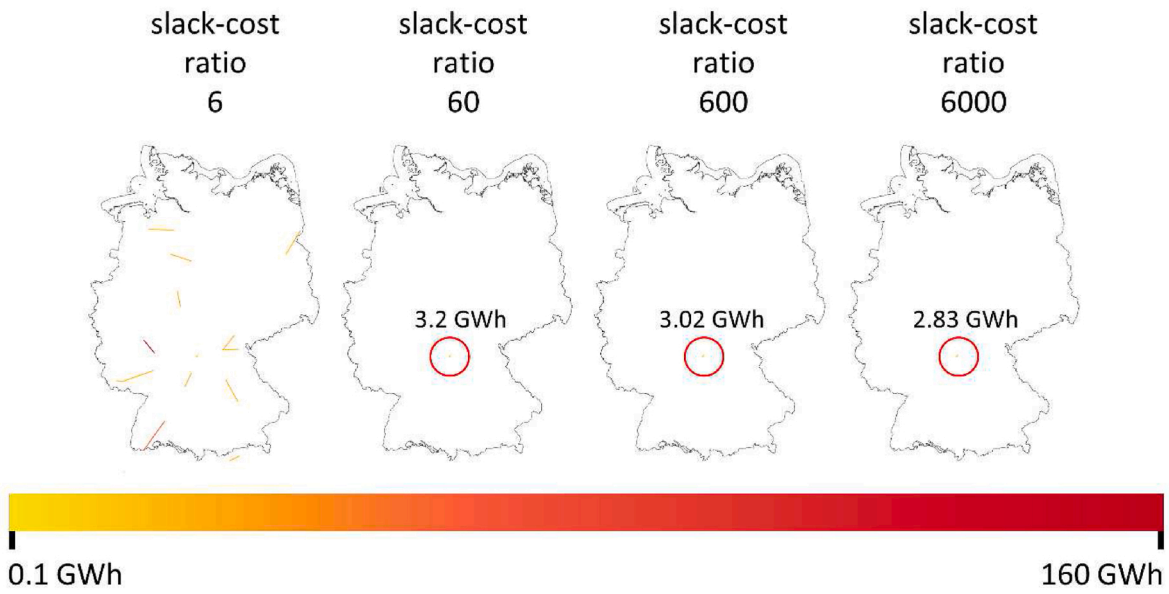


Fig. 9. Slack cost sensitivity – Cumulative annual congestion volumes per line after congestion management.

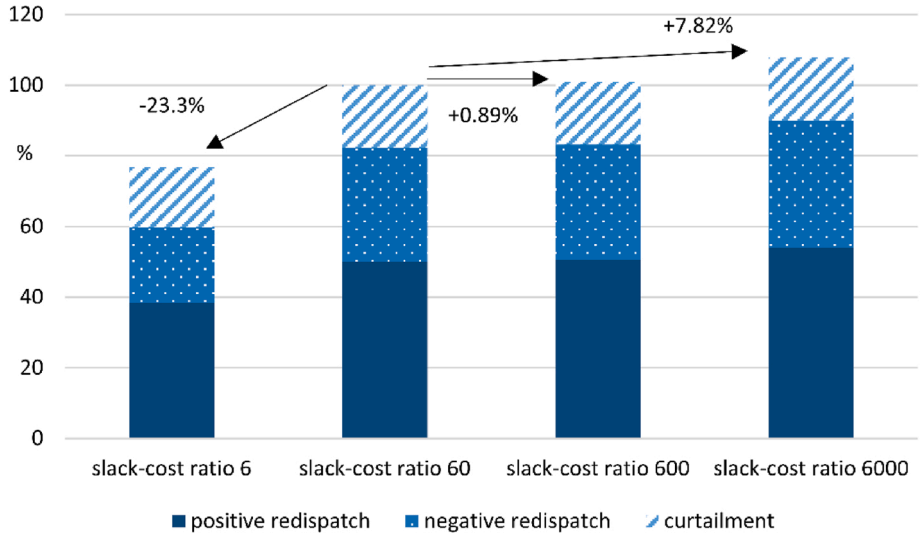


Fig. 10. Slack cost sensitivity - Annual sum of remedial actions.

Fig. 10 also highlights the undesired effects of adopting parametrization values that are too low. In the run with very low slack costs, congestions largely remain, yielding total annual volumes of remedial actions that are significantly lower than actual necessary volumes. Differences in the results of the model runs with ratios between 60 and 600 are rather low. This emphasizes the fact that a wide range of slack-cost parametrization values are acceptable.

The results of this case study highlight that the benefits of employing soft constraints highly depend on the parametrization of the slack costs. If the values imputed are too low, very low total annual volumes of remedial actions are realized. In the case that the values selected are too high, an overestimation of congestion management volumes can result due to the large utilization of inefficient remedial actions. In addition, very high slack costs may have undesired effects in terms of solver performance associated with scaling properties of the model. Parameterizing the slack penalty cost to be too low, however, can reproduce a significantly congested system state even after performing the optimization. Summarizing, soft-constraints provide a valuable means to detect model inconsistencies, but must be calibrated thoroughly.

5.2.3. Parametrization of remedial actions provided from neighboring countries

5.2.3.1. Motivation. In practice, the management of grid congestions is carried out in various ways involving multiple different actors and energy stakeholders. Grid operators typically utilize not only measures provided by national power plant operators or flexibility sources from domestic demand-side applications. Also, power utilities in the neighboring countries may be called on to contribute to resolving national grid congestions and congestions on interconnecting power lines. The model-based representation of this so-called cross-border congestion management and, in particular, cross-border redispatch, may have an impact on model results.

The modeling of cross-border redispatch differs among the grid simulation models participating in the model experiment. The regulatory framework in Germany stipulates a specific order of the existing measures with which grid operators resolve congestions due to interfering energy system development targets. The following illustrates grid simulation results from a selected model which uses a methodology that

builds upon penalty costs to create a merit order of different national and foreign congestion management options. Modeling congestion management purely based on the marginal cost of a particular measure would deviate from this order.

5.2.3.2. Case study description. Four different model runs are performed in total with varying structures of penalty costs for congestion management. We call the penalty cost terms base values since the model adds them to the marginal cost of a particular congestion management measure. The base case assumes penalty costs of 5,000 EUR/MWh that are added to the redispatch cost based on fuel and all other variable cost expenses. The model penalizes redispatch from national generation units with 100 EUR/MWh in addition to the marginal generation cost. All other congestion management measures, i.e., feed-in management, demand-side management and demand curtailment, are penalized with higher penalty costs of increasing magnitude compared to cross-border redispatch. This results in the merit order illustrated in Fig. 2 since the grid simulation model applies a (total) cost-minimizing target function. The comparative runs assume a base value for cross-border redispatch in the range between 150 and 110 EUR/MWh. All other base values are held constant. The electricity grid in Germany is modeled in great detail. Neighboring market zones are modeled as aggregated nodes. Interconnector lines are represented, however, in a detailed fashion with their existing physical characteristics to maintain restrictions in the electricity transmission along the border.

5.2.3.3. Selected case study results. Model results show that the assumed base values for cross-border redispatch impact both national congestion management amounts and the geographic distribution of utilized measures. Fig. 11 displays selected results of the four model runs regarding the magnitude and geographic distribution of congestion management measures among the German grid nodes included in the model. The circle charts are scaled based on the base case run in order to make the sensitivities performed comparable.

The base case run yields significant amounts of negative redispatch in the north of Germany, around the west of Germany and in the Munich area. All corresponding grid nodes are in great proximity to interconnecting lines with the neighboring electricity markets. Comparing the base case run with all three other runs, the base case results clearly show larger negative redispatch amounts around Munich, larger curtailment rates in the northwest of Germany and a more positive redispatch throughout the whole area of Germany. Differences between the comparison runs are not visible at this point. Fig. 12 summarizes the total redispatch and curtailment amounts as relative differences compared to the base case run.

Decreasing the base value for cross-border redispatch has an enormous impact on the resulting total congestion management amounts reproduced by the model. The total reduction amounts almost constantly to about 50% in all comparison runs. There is a clear indication that increasing the penalty costs for cross-border redispatch incentivizes the grid simulation model to utilize national measures more extensively which has a strong impact on the results. This mechanism is also visible when comparing the respective sensitivities amongst themselves. Moreover, the assumption on the magnitude of the neighboring countries' base value has a much stronger influence on resolving grid congestions along the border compared to national bottlenecks as changes in the dispatch from power stations installed farther inland in Germany impact interconnector lines less.

6. Discussion and summary

Energy researchers in academia and industry utilize a multitude of simulation tools for the model-based analysis of power transmission systems. As the individual approaches used are tailored to their specific field of application, the respective model representations strongly impact the results obtained. This paper aims at identifying common differences that exist in selected grid simulation tools used in academia and analyzing how assumptions on key parameters and variations in selected modeling approaches impact the results regarding congestion management.

Equations modelling power flows are nonlinear by nature. Grid modeling, however, involves the deployment of network optimization models. The complexity associated with nonlinear programming problems often necessitates simplifying power flow representations based on linearization techniques such as a DC approximation, an approach adopted by half of the models taking part in the experiment. Other varying model features dealing with the modeling of power flows and generation dispatch include dynamic line rating, the utilization of soft or hard constraints and the treatment of time-coupling equations. Time-coupling equations and soft constraints are the most prominent means of modeling congestion management in the models represented in the project. Only a few institutions include dynamic line rating methods. Moreover, flat-rate margins on power lines are used in favor of a detailed outage approximation by most grid optimization tools due the reduced computational complexity. The models can be further differentiated by the type, number and dispatch order of represented congestion management measures. Most include detailed modeling of cross-border

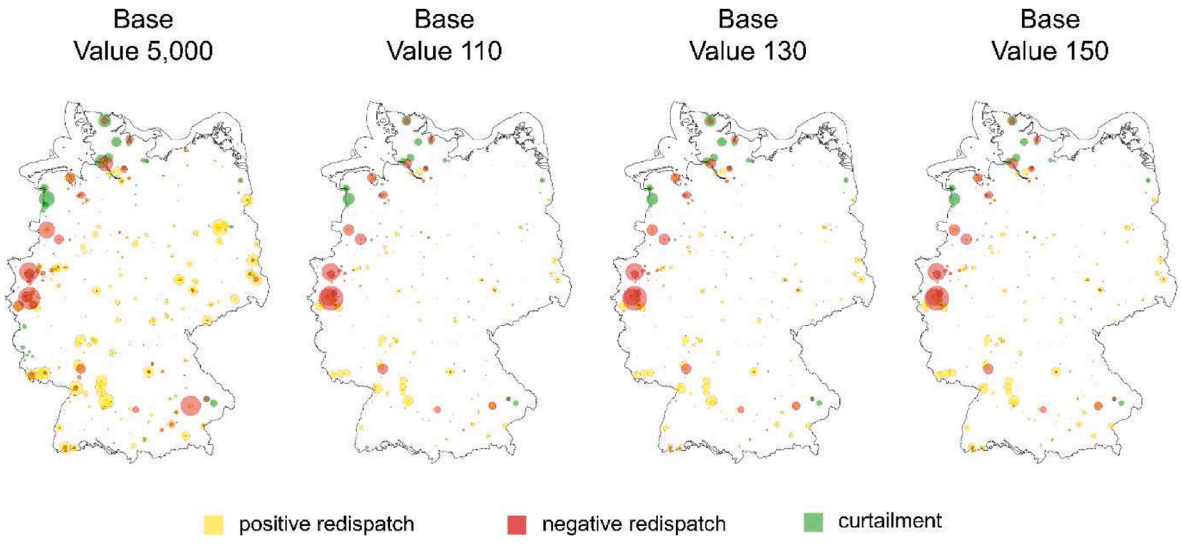


Fig. 11. Base value sensitivity – Cumulative annual congestion management per node.

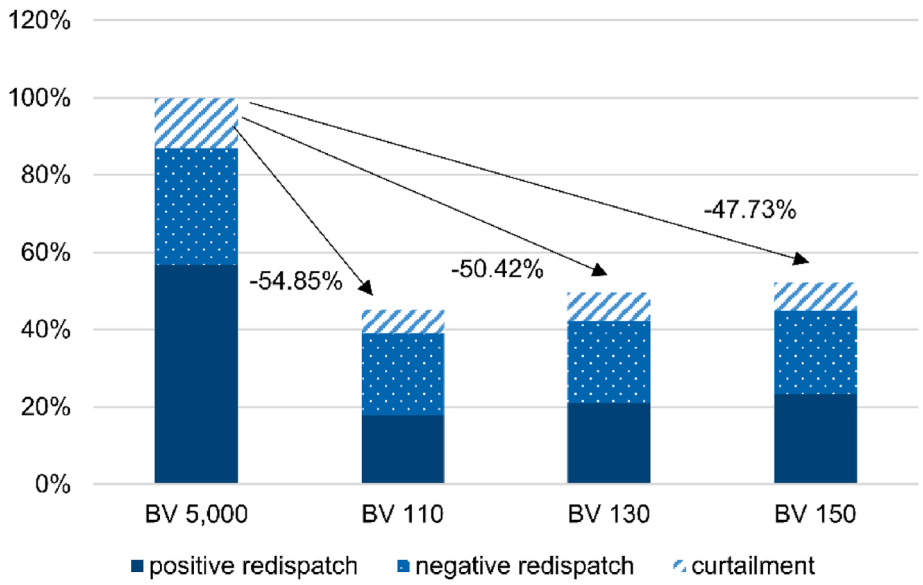


Fig. 12. Base value sensitivity – Cumulative annual congestion management per node.

congestion management. Grid-related measures, in particular FACTS and PST, are only rarely included as an option to resolve grid bottlenecks in the different models. The majority of institutions utilize penalty costs to create a merit order of individual congestion management measures that resemble real-word practices.

A typical modeling task requires thorough consideration and selection of individual model features relevant to the specific requirements of the research question being addressed. The parametrization of individual model features, however, can be a challenging task. The research findings presented in the paper indicate that key model parameters with respect to modelling outage situations, line constraint relaxations and cross-border congestion management must be calibrated thoroughly as inaccuracies can produce undesired effects.

The results of the case studies show that modelers can calibrate flat-rate margins on power lines so that grid simulations yield similar congestion management amounts compared to the modelling of detailed outage approximations. The discrepancies in the results derived by the different approaches are most apparent in highly meshed regions. Modelers should evaluate the meshed nature of the grid topology before deciding upon the respective approach toward modeling grid outages. The results further demonstrate that soft constraints on power lines should be carefully calibrated. Too high slack costs may drive additional congestion management volumes since the model does not use the soft constraint for relieving line overloading. If the slack costs imputed are too low, on the other hand, too much capacity is allocated to the grid to handle network congestions, resulting in implausibly low total congestion management volumes. Moreover, the results indicate that parametrizing cross-border congestion management can have enormous impacts on total congestion management volumes reproduced by grid simulation models. If deviations between the base values for redispatch in the market zone under consideration and the neighboring markets are too large, generation stacks in neighboring countries provide only a minor contribution to cross-border redispatch. If grid congestions frequently occur on interconnecting power lines, this effect largely impacts total congestion management volumes. Special emphasis must be given to stressed grid elements in the border region when deciding on the appropriate type and scope of modeling cross-border congestion management in the specific area of model application.

In summary, modeling congestion management is a valuable means of supporting system operators and energy policymakers in the design of electricity systems. Features of grid simulation models differ in type and granularity and must be adjusted to the relevant question under investigation. The respective model formulation regarding outage situation assessment, line constraint relaxation and cross-border congestion management as well as the parametrization of corresponding model features can have large impacts on model results and must be done carefully. Future research may comprise a detailed comparison of grid simulation results of all participating institutions.

Authors Contributions

Hannes Hobbie: Conceptualization, Methodology, Software, Validation, Investigation, Data curation, Writing – original draft preparation; Jonas Mehlem: Conceptualization, Methodology, Software, Validation, Investigation, Data curation, Writing – original draft preparation; Christina Wolff: Conceptualization, Methodology, Validation, Investigation, Data curation, Writing – original draft preparation, Visualization; Lukas Weber: Methodology, Software, Validation, Investigation, Data curation, Writing – original draft preparation, Visualization; Franziska Flachsbarth: Writing – original draft preparation; Dominik Möst: Supervision; Albert Moser: Supervision. All authors have read and agreed to the published version of the manuscript.

Funding

This research was funded as part of the Modex-Net project by the Federal Ministry for Economic Affairs and Energy in the 6. energy research funding program. Grant number: 03ET4074.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

We would like to thank all partners and project members for their contributions regarding model descriptions and input data harmonization as well as dispatch and redispatch modeling results, especially from Jülich Research Center, Institute of Technoeconomic Systems Analysis: Jochen Linβen and Chloi Syranidou, from DLR, Institute of Networked Energy Systems: Oriol Raventós, Chinonso Unaichi, Julian Bartels, Jan Buschmann and Wided Medjroubi, from Forschungsstelle für

Energiewirtschaft (FfE): Andreas Bruckmeier, Timo Kern, Felix Böing, Tobias Schmid and Christoph Pellinger, from Karlsruhe Institute of Technology (KIT), Institute for Industrial Production (IIP): Thomas Dengiz, Rafael Finck, Armin Ardone, Katrin Seddig and Manuel Ruppert, from Öko-Institut e.V., Energy & Climate Division: Matthias Koch, Sebastian Palacios, Christian Winger and Susanne Krieger, from RWTH Aachen, Institute of High Voltage Equipment and Grids, Digitalization and Energy Economics (IAEW): Annika Klette, Levin Skiba and Alexander Fehler, from TU Dortmund, University - Institute of Energy Systems, Energy Efficiency and Energy Economics (ie3): Björn Matthes and Jan Peper and from TU Dresden, Chair of Energy Economics: Constantin Dierstein, Martin Lieberwirth and David Schönheit.

References

[1] Lechtenböhmer S, Pregger T, Palzer A, Gils HC: RegMex-Modellexperimente und -vergleiche zur Simulation von Wegen zu einer vollständig regenerativen Energieversorgung. Schlussbericht.
[2] Syranidou C, Koch M, Matthes B, Winger C, Linßen J, Stolten D, Rehtanz C. Development of an open framework for a qualitative and quantitative comparison of power system and electricity grid models for Europe: this issue. 2021.
[3] Raventós O, Dengiz T, Medjroubi W, Unaichi C, Buckmeier A, Finck R. Comparison of different methods of spatial disaggregation of electricity generation and consumption time series: this issue. 2021.
[4] Capitanescu F. Critical review of recent advances and further developments needed in AC optimal power flow. In: electric Power Systems Research, vol. 136; 2016. p. 57–68.
[5] Alsac O, Stott B. Optimal load flow with steady-state security. In: IEEE transactions on power apparatus and systems PAS-93, vol. 3; 1974. p. 745–51.
[6] Molzahn DK, Hiskens IA. A survey of relaxations and approximations of the power flow equations. In: foundations and Trends® in electric energy systems, vol. 4; 2019. p. 1–221. 1–2.
[7] Leveringhaus T. My University (Mitarb.): netzoptimierung durch Wirk- und Blindleistungsredispatch auf Basis von konvexifizierten quadratischen Näherungen der Netzgleichungen. 2018.
[8] Balu NJ, Lauby MG, Kundur PS, Hrsg. Power system stability and control. Indian edition. Chennai, New York, St. Louis, san Francisco, Auckland, Bogotá, Caracas, Kuala Lumpur, Lisbon, London, Madrid, Mexico city, Milan, Montreal, san Juan, Santiago, Singapore, Sydney, Tokyo, Toronto: Mc Graw Hill Education (India) Private limited. (The EPRI power system engineering series); 1994.
[9] Sheble GB, Fahd GN. Unit commitment literature synopsis. Feb. 1994.
[10] IEEE Standard for calculating the current-temperature relationship of bare overhead conductors.
[11] Cigre WGB2. 43: technical Brochure 601: guide for thermal rating calculations of overhead lines. 2014.
[12] Santos JM, Ferreira P, Araujo M. A methodology to incorporate risk and uncertainty in electricitypower planning. 25.04.2016.
[13] Kendall JW. Hard and soft constraints in linear programming. Jun 1975.
[14] Bundesnetzagentur. Festlegung der Mindestfaktoren für „Redispatch 2.0“: Beschluss - Az. PGMF-8116-EnWG; 30.11.2020. p. 13.
[15] Garcés FF. Electric power: transmission and generation reliability and adequacy. In: Encyclopedia of energy. Elsevier; 2004. p. 301–8.
[16] Benhamida F, Bandaoued A, Ramdani Y. A literature survey of the optimal power flow methods and its applications. Acta Electrotechnica 2010;51(3):163–70.
[17] Khaled A, Niveen B, Almoataz A. Optimal power flow methods: a Comprehensive Survey. In: international electrical Engineering Journalvol. 7; 2016. p. 2228–39.
[18] Commission Regulation (EU). System operation guideline (in Kraft getr. Am 15. 3. 2021). 2021-03-15.