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Cross-sector assessment of CO_2 abatement measures and their impact on the transmission grid

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Abstract

The assessment of decarbonization measures is a central discipline of energy system analysis. In order to determine the most cost-efficient emission reduction path, energy system models with varying scope, time horizon, level of technological detail and methodological approaches are applied. Choosing a modeling approach appropriate to the respective object of investigation is a major challenge. Although the static and isolated evaluation of measures can provide seemingly straightforward answers, more complex dependencies often arise when the final energy sectors, coupled energy carriers such as gas or district heating, and the transmission infrastructure are included in the assessment. Electric mobility is a good example to illustrate this: A simplified approach would mean that the emissions and costs of a combustion engine is compared to those of an electrical drive that is "fueled" by the electricity of the generation mix. Emissions are accounted for using the mean yearly emission factor. A scenario-based and cross-sectoral assessment implies that the repercussions of a decarbonization strategy characterized by electrification of final energy consumption are taken into account. In such an evaluation, the additional renewable energy sources (RES) required are included in the analysis, as well as the resulting demand for grid expansion.

Firstly, this work develops, combines, and applies methods to evaluate abatement measures holistically using the tools of energy system modeling. Secondly, scenario analyses are carried out to examine particularly relevant measures in more detail and to collect findings regarding their system repercussions. From a methodological point of view, it is of particular interest how transmission grid loading can be taken into account in the model while utilizing potentially grid-relieving emission reducing technologies. Thirdly, modeling the coupling of different energy carriers in the sense of a multi-energy system (MES) to evaluate flexibilization and substitution measures is an integral part of this work.

The scenario analyses show that the expansion of renewable energies is the decisive measure among all abatement measures in the energy sector for achieving an overall reduction in emissions. In the short and medium-term, the expansion of the transmission grid is the most cost-efficient approach for integrating renewables compared to other grid-optimizing measures. In the long term, the interplay between Power-to-X technologies, storage facilities, and the transmission grid will result in optimization potential that can be enlarged by regulatory intervention. The analysis of a cross-sectoral decarbonization path shows that the exact composition of measures to reduce the last residual emissions should only be made with caution due to the high level of uncertainty regarding techno-economic parameters. Instead, the results show particular robustness concerning the measures required in the near future. In addition to renewables, these include the electrification of final energy consumption, flexibilization through sector coupling, European electricity market coupling, and the market ramp-up of electrolyzers and stationary battery storage systems.

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Kurzfassung

Die Bewertung von Dekarbonisierungsmaßnahmen stellt eine zentrale Disziplin der Energiesystemanalyse dar. Um einen möglichst kosteneffiziententen Emissionsminderungspfad zu bestimmen, werden Energiesystemmodelle mit unterschiedlich weit gefassten Modellgrenzen, zeitlichem Horizont, technologischem Detailierungsgrad und methodischen Ansätzen angewandt. Die Wahl eines dem jeweiligen Untersuchungsgegenstand angemessenen Modellierungsansatz ist von besonderer Relevanz. Auch wenn eine isolierte Einzelbetrachtung von Maßnahmen vermeintlich einfache Antworten zu geben vermag, zeigen sich unter Einbeziehung der Endenergiesektoren, den gekoppelten Energieträgern und den Stromnetzen komplexere und zur Gesamtkostenbeurteilung relevante Zusammenhänge. Am Beispiel der Elektromobilität kann dies gut veranschaulicht werden: Eine vereinfachte Bewertung dieser Dekarbonisierungsmaßnahme würde bedeuten, dass die Emissionen und Kosten eines Verbrennungsmotors jenen eines elektrischen Antriebs, welcher die Emissionen des Strommixes „tankt", gegenübergestellt werden. Eine sektorenübergreifende Bewertung beinhaltet, dass neben den direkten Emissionen und Kosten der Maßnahme auch die Rückwirkungen einer durch Elektrifizierung von Endenergieverbräuchen geprägten Dekarbonisierungsstrategie auf die Energieversorgungsinfrastruktur berücksichtigt werden. Die dafür notwendigen zusätzlichen Erneuerbaren Energien werden in einer solchen Bewertung genauso adressiert, wie die resultierende Netzbelastung.

In dieser Arbeit werden Methoden der Energiesystemanalyse weiterentwickelt und angewandt, um Dekarbonisierungsmaßnahmen ganzheitlich bewerten zu können. In Form von Szenarioanalysen werden relevante Maßnahmen näher betrachtet und Erkenntnisse bezüglich deren Systemrückwirkungen gesammelt. Aus methodischer Sicht ist es dabei von besonderem Interesse, wie die Übertragungsnetzauslastung durch den Ausbau und Betrieb von netzoptimierenden Maßnahmen Modell-endogen berücksichtigt werden kann. Zudem stellt die Abbildung der Kopplung verschiedener Energieträger im Sinne eines Multi-Energy-Systems (MES) zur Untersuchung von Flexibilisierungs- und Substitutionsmaßnahmen einen wichtigen Bestandteil dar.

Aus den Ergebnissen der Szenariorechnungen kann geschlossen werden, dass der Ausbau der Erneuerbaren Energien die entscheidende Maßnahme im energiewirtschaftlichen Sektor zur Erreichung einer umfassenden Emissionsminderung ist. Kurz- und mittelfristig ermöglicht der Übertragungnetzausbau im Vergleich zu den anderen netzoptimierenden Maßnahmen eine besonders kosteneffiziente Integration Erneuerbarer Energien. Langfristig ergeben sich aus dem Zusammenspiel von Power-to-X Technologien, Speichern und Flexibilisierungsmaßnahmen mit der Übertragungsinfrastruktur Optimierungspotentiale, die durch regulatorische Maßnahmen erschlossen werden können. Die Analyse eines sektorenübergreifenden Dekarbonisierungspfades zeigt darüber hinaus, dass die exakte Zusammensetzung der Maßnahmen im Zieljahr 2050 nur unter Vorbehalt bestimmt werden kann. Dies ist durch die hohen Unsicherheiten von techno-ökonomischen Parametern und der hohen Sensitivität dieser Annahmen auf den resultierenden Minderungspfad zu begründen. Hinsichtlich der in naher Zukunft notwendigen Maßnahmen weisen die Ergebnisse hingegen eine hohe Robustheit auf. Dazu gehört neben den Erneuerbaren Energien die

Elektrifizierung von Endenergieverbräuchen, die Flexibilisierung durch Sektorenkopplung, die europäische Strommarktkopplung und der Markthochlauf von Elektrolyseuren und stationären Batteriespeichersystemen.

Contents

Abbreviations

CACM – Guideline on Capacity Allocation and Congestion Management (European Commission)

CHP – Combined Heat and Power

DC-LOPF – Direct Current Linearized Optimal Power Flow

EEG – *German*: Erneuerbare-Energien-Gesetz (German Renewable Energy Act)

ENTSO-E – European Network Transmission System Operators - Electricity

ENWG – *German*: Energiewirtschaftsgesetz (German Energy Act)

EU-ETS – EU Emission Trading System

FREM – FfE Regions Model (Energy System Geo-Database)

GHG – Greenhouse Gas

GOM – Grid Optimizing Measure

ISAaR – Integrated Simulation Model for Planning the Operation and Expansion of Units with Regionalization

LCOE – Levelized Cost of Energy

LTC – Line Transfer Capacity

MES – Multi-Energy System

MInGa –FfE Market and Infrastructure Model of the Gas Industry

NABEG – *German*: Netzausbaubeschleunigungsgesetz
(Act to Accelerate the Expansion of the Transmission System)

NTC – Net Transfer Capacity

PTDF – Power Transfer Distribution Factors

PV – Photovoltaics

SME – Small and Medium Enterprise (sector)

SMIND – FfE Industry Sector Model

SoPHa – FfE Domestic Sector Model

TraM – FfE Transport Sector Model

TSO – Transmission System Operator

(v)RES – (variable) Renewable Energy Sources

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List of Publications

This cumulative dissertation is based on four publications. A summary of each publication is given below. The main part of the dissertation (Chapters 2 to 6) links these publications and supplements them with methodological content and scenario analyses. The publications are referred by their citation keys (/PUB-01/…/PUB-04/). Full transcripts of the publications can be found in Appendix D.

As the work at the Research Centre for Energy Economics (FfE) is highly cooperative and team-oriented, publications by only one author are the exception. For this reason, all persons involved in the implementation of the model described and the input data used are listed as authors. All publications have in common that the basic concept and the methodical approach for answering the respective research questions as well as the interpretation of the model results are to be assigned to the first author. For a more detailed breakdown, reference is made to the section "Own contribution" below.

***Publication I**:* Hourly CO_2 Emission Factors and Marginal Costs of Energy Carriers in Future Multi-Energy Systems

Summary: Hourly emission factors and marginal costs of energy carriers are determined to enable a simplified assessment of decarbonization measures in energy systems. Since energy carriers and European electricity market zones are increasingly coupled in the context of decarbonization, the complexity of modeling the future energy supply and accounting of emissions grows. The energy system model "ISAaR" is introduced, and the general linear optimization approach is described in detail. ISAaR is a multi-energy-systems (MES) model. It can be deployed to simulate the electricity, district heating, hydrogen, liquid hydrocarbons and methane supply. In order to assess the implications of marginal energy costs and emission factors in a trend trajectory, a reference scenario is introduced first. The capacity values and assumptions regarding fuel and emission allowance costs up to the year 2050 are documented for this purpose. The regional focus is on Germany, but the electricity market zones of the coupled neighboring countries are modeled in a simplified manner.

Methods of calculating emission factors and marginal energy carrier costs in a multi-energy carrier model are presented and applied. In this context, a method of accounting emissions has been proposed, which allows for determining time-resolved emission factors for different energy carriers considering the linkages between energy carriers and regions. Complementary to this, an approach for a model-based determination of marginal emissions is introduced and then applied to electricity and district heating supply.

The results show that the method of accounting emissions has a strong influence on the level and the hourly profile of the emission factors. The marginal approach, in particular, shows significantly higher emissions than the generation mix method and, for some hours, also negative values. The comparison of marginal costs and emission factors provides insights into decarbonization potentials. One of these decarbonization measures is the electrification of district heating since a strong correlation between low marginal costs and times with renewable excess is observed. The results of the different accounting and calculation methods show that hourly profiles can in part represent typical system patterns well. For example, a charging process at a high emission factor using the generation mix method should be avoided if emission reduction is aspired. Nevertheless, it can also be shown that a reduced emission and economic evaluation based solely on emission factors and marginal costs can have only limited validity. On the other hand, some questions can be adequately answered and conclusions drawn by using the method presented. This is shown by the exemplary application for calculating the market values of variable renewable energy sources (vRES).

Own contribution: Conceptualization and methodology of the multi-energy carrier model, software, data curation, visualization, writing – sections on multi-energy system model, energy system scenario, results and discussion

Citation: Böing, F., & Regett, A. (2019). Hourly CO_2 Emission Factors and Marginal Costs of Energy Carriers in Future Multi-Energy Systems. *Energies*, *12*(12), 2260. https://doi.org/10.3390/en12122260

This publication can be found in the Appendix.

Publication II: Assessment of Grid Optimisation Measures for the German Transmission Grid using Open Source Grid Data

Summary: The expansion of capacities in the German transmission grid is a necessity for further integration of renewables into the electricity sector. Nevertheless, network expansion is expensive, resource-intensive, and receives only limited social acceptance at present. In this publication, alternative grid optimizing measures like 'Overhead Line Monitoring', 'Power-to-Heat', and 'Demand Response in the Industry' are evaluated and compared against conventional grid expansion. To assess the efficiency of these measures, the energy system model ISAaR is applied. An "Optimal Power Flow" (OPF) approach is integrated, several grid datasets are combined, and an energy system scenario for the year 2030 is developed. Particular attention is paid to the documentation of the working stages acquisition, preparation, and validation of transmission system network data from different sources. Furthermore, the mathematical principles of the "Power Transfer Distribution Factors" (PTDF) approach in a network consisting of DC and AC lines are explained. From a methodological perspective, it is moreover clarified how an electricity market model can be extended by the transmission grid power flow approach.

In a multi-stage optimization sequence, congestion management volumes are calculated. Scenarios including the different grid optimization measures are set up and the results of the optimization runs are compared to a reference case without any measures taken. This results show that the conventional grid expansion is more efficient and entails more grid relief than the evaluated grid optimizing measures. Overhead line monitoring is proving to be very cost-effective, but with a limited potential to significantly reduce the absolute volume of congestion. Due to higher shiftable powers, Power-to-Heat in district heating networks is a more promising measure than Demand Response in the industry.

Own contribution: Conceptualization and methodology of the energy system model, contribution to the model implementation on a significant scale, methods of grid optimization measure assessment, data curation – grid data, result evaluation, visualization and analysis, writing – original draft preparation

Citation: Böing, F., Murmann, A., Pellinger, C., Bruckmeier, A., Kern, T., & Mongin, T. (2018). Assessment of grid optimisation measures for the German transmission grid using open source grid data. *Journal of Physics: Conference Series*, *977*, 12002. https://doi.org/10.1088/1742-6596/977/1/012002

This publication can be found in the Appendix.

Publication III: Relieving the German Transmission Grid with Regulated Wind Power Development

Summary: In the past and today, the yield potential of a site has been a decisive factor in the regional allocation of wind turbines. Due to higher installed capacities in northern Germany, wind turbines are responsible for a large proportion of the grid congestion in the annual balance. The ensuing demand for grid expansion is significant. This problem raises the legitimate research question of whether the reduced yields of a grid-oriented development of wind turbine siting could be (over) compensated by the expenses saved for otherwise necessary grid expansion. In this publication, an approach to relieve the German transmission grid by regulating the wind power regionalization is evaluated for the year 2030.

In a scenario study, a sequential analysis procedure is applied. The scenario used, which assumes a renewable share of 61 % in 2030, includes an energy yield-optimized expansion of wind turbines which is constrained by the federal state capacity targets of the grid development plan. In order to allow a more precise analysis of the interplay with the transmission grid, a slightly delayed expansion of the grid is anticipated. At first, the nodal curtailment volumes due to grid congestion are determined for this reference scenario. Secondly, wind turbines at nodes with high curtailment volumes are redistributed from windy northern Germany to grid-compatible locations in central and southern Germany. Thirdly, this scenario is assessed by a market and grid calculation.

The results show that a reduction of ~2.2 TWh in congestion management can be achieved by the removal of ~1.2 GW northern on- and offshore capacities in combination with an addition of ~1.8 GW southern wind onshore capacities. A scenario-based comparison of which grid expansion would be necessary to reduce congestion management measures to a similar extent shows that less than 200 km of line upgrades in existing corridors would have to be carried out. These results provide a first orientation regarding the interaction of regional distribution and grid expansion demand. In order to integrate the economic perspective into the assessment, the results of the two scenarios are compared using simplifying assumptions regarding grid expansion costs and levelized costs of energy from wind turbines. This analysis emphasizes that the scenario of grid-oriented expansion of wind energy is at least a quarter more expensive than the comparable yield-driven wind scenario that includes higher grid expansion.

Own contribution: Conceptualization and methodology of the energy system model, composition of scenarios, methodology of grid expansion planning, result evaluation and analysis, writing – original draft preparation

Citation: Böing, F., Bruckmeier, A., Kern, T., Murmann, A., & Pellinger, C. (2017). Relieving the German Transmission Grid with Regulated Wind Power Development. *Proceedings of 15th IAEE European Conference, 2017.*

This publication can be found in the Appendix.

Publication IV: Electrification and Coal Phase-Out in Germany: A Scenario Analysis

Summary: The electrification of fossil-fueled processes and applications is frequently quoted as an essential component for the deep decarbonization of the German energy system. A prerequisite for decarbonization through electrification is low emission electricity. In the German case, this leads to the so-called “electrification dilemma”, as both a reduction of the emission-intensive conventional power plant fleet and the significant increase in electricity consumption are driving the demand for vRES and guaranteed capacities drastically. Since both developments have an impact not only on system adequacy but also on the future loading of the transmission system and thus also on network planning, this assessment criteria is included. In the scenario analysis, several measures to reduce emissions in power generation and energy consumption are compared. First, an electrification scenario is introduced for Germany, which foresees an increase in electricity demand by about 40 % until 2030 compared to today's level. Electrification without a simultaneous expansion of renewable energies has no or very little emission reducing effect in the context of the German nuclear phase-out. Therefore, two more ambitious renewable expansion scenarios are set up. The low vRES scenario consists of a constant vRES share of 61 %, as in the reference path without electrification. The high vRES scenario envisages that each additional TWh of electrified demand is fully covered by expansion of renewable energies. This scenario features a renewable energy share of 75 % in 2030. Both scenarios represent a significant transition of the energy system. However, further measures are needed to achieve climate goals. Therefore, very high CO_2 emission allowance prices are assumed as well as a significant reduction of lignite capacities in the context of a coal phase-out path for further sensitivity analysis.

The results show that a European-wide price floor of €120 per tonne CO_2 leads to the lowest overall emissions. If this price would apply only to Germany, a similar reduction in emissions is achieved compared to that achievable by decommissioning 9 GW of lignite capacities. While electrification leads to a capacity gap of approximately 16 GW in 2030, if the conventional power plant fleet develops according to the grid development plan, this gap would increase to 24-27 GW in a coal phase-out scenario. It must be taken into account that scarcity occurs only for a few hours per year, and that the number of consecutive hours with high shortfalls in capacity coverage is low. The analysis of the transmission grid impact shows that the congestion management volumes of the different sensitivities hardly differ. Since, in such a scenario, grid congestion primarily occurs at times of high wind energy generation and these situations define the dimensioning of the grid, the regional distribution of future peak load generation units is irrelevant from a transmission grid perspective.

Own contribution: Conceptualization and methodology of the energy system model, composition of the scenario assumptions (generation capacities and energy system infrastructure), data curation – emissions and energy balance; result evaluation, visualization, and analysis; writing – original draft preparation

Citation: Böing, F., Murmann, A., & Guminski, A. (2018). Electrification and Coal Phase-Out in Germany: A Scenario Analysis. In *2018 15th International Conference on the European Energy Market (EEM).* IEEE. https://doi.org/10.1109/eem.2018.8469771

This publication can be found in the Appendix.

1 Introduction

By the resolution of the Paris United Nations Climate Change Conference, the majority of the international community is undoubtedly geared towards reducing emissions to mitigate anthropogenic climate change. As a result and supported by the massive popularity of the climate protection movement, the issue of decarbonization is increasingly determining the political agenda as well as the public discourse. While a few years ago, emission abatement was seen almost separately as a challenge for the energy industry, this narrative has changed. Within this process, scientists have also recognized that an isolated view on individual sectors of the energy system to achieve climate targets has left many unanswered questions. Therefore, system boundaries have to be drawn farther. Abatement measures need to be assessed across sectors, energy carriers, and demand technologies. As the term “abatement measure” covers all technical and regulatory actions that result in a reduction of emissions compared to the status quo, a large number of measures with direct or indirect effects are conceivable. However, such a holistic assessment of greenhouse gas (GHG) reducing measures poses major challenges. The diversity of the consumption sectors (domestic, small and medium-sized enterprises, industry, and transport) among themselves, and in comparison with the energy industry, is very high. In order to drastically reduce emissions, considerable changes in consumption technologies, e.g. the replacement of fossil-fired heating systems by heat pumps, are necessary. In addition to the conversion of the energy system solely on the generation side, an adaptation of the whole system infrastructure is needed. This primarily concerns flexibility options and the transmission system. From an energy system modeler's perspective, it is of utmost interest to provide advice in this transition process. Expanding the system boundaries increases the complexity of the models and the need for input data. In a dilemma between the models' level of detail and calculation times, it is essential to develop evaluation concepts and model constellations that enable adequate analysis. At this point, the thesis is intended to create added value: The methodical modeling concept presented enables to evaluation of energy system scenarios and decarbonization measures based on optimization results. It is described how input data are acquired, processed, and aggregated. How these data are translated into optimization constraints and how optimization runs are sequenced, are further aspects. The most substantial part is devoted to the analysis of the model results, which should make a contribution to the research for a cost-efficient energy system transformation in Germany.

In detail, the following questions can be derived from this: First, what interactions does electrification of final energy consumption (FEC) have with the transmission grid in combination with a significant expansion of renewable energy sources? Second, how can flexible Power-to-X technologies be deployed to reduce transmission grid congestion? Third, to what extent is a grid-oriented expansion of renewable energies preferable in contrast to a yield-oriented regionalization? All these questions are analyzed in order to develop and assess a holistic, cross-sectoral climate protection scenario for Germany, which forms the final building block of the thesis.

1.1 Research Questions

The definition of the research questions is divided in two sections. The first section relates to future developments in the energy industry and the assessment of abatement measures:

- How will the infrastructure components of the future energy system interact and what repercussions are to be expected from individual abatement measures?
- What system effects do decarbonization strategies have on the grid expansion demand and the operation of the transmission grid?
- How should a grid-serving utilization and expansion of CO_2 abatement measures be designed and which measures are particularly critical for the grid?

The second is the methodological component, which deals with the questions of the scientific approach and the appropriateness of the modeling concepts:

- How to model the interaction between sector coupling measures and the transmission grid?
- How to determine an optimal way of decarbonization from the total system costs perspective?
- Which level of detail regarding modeling approaches and scenario data is suitable for assessing these questions?

These research questions are intended to form the basis for the analyses of this work. Some of the questions are answered in the publications, others are dealt with in a separate excursus in the supplementary chapters. The extent to which such an addendum is made is described below.

1.2 Structure of the Thesis

The format of the publication-based dissertation poses the challenge of bringing together different contextual components. Figure 1, therefore, illustrates which content can be found in the form of publications in the appendix and which elements are described in the individual chapters. This approach aims to create a better overview and understanding of the relationships between the individual publications and the chapters. The supplementary chapters are intended to add content, which is not included in the publications. Here, further analyses, more detailed explanations, additional scenarios, and in-depth methodological basics are given.

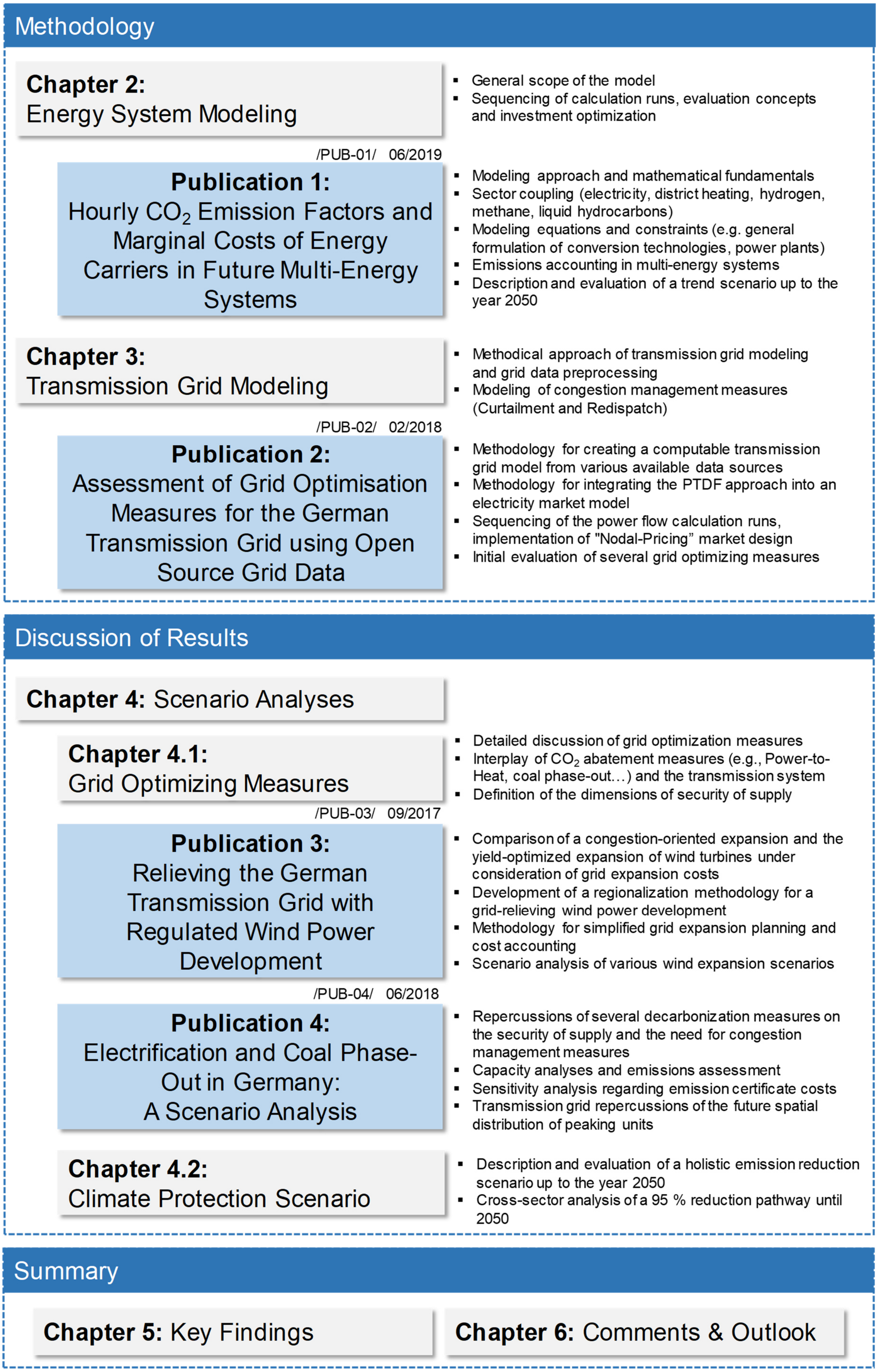


Figure 1: *Context of publications and chapters*

First, the target state of the model is described regarding the considered energy carriers, flexibility options, and sector coupling in Chapter 1.3. Based on /Pub-01/, the spatial and temporal scope is defined. The mathematical basis of optimization is addressed, and the method of investment planning is described. Furthermore, the costs and emissions accounting is specified. The methodology of grid data processing, and the modeling of load flows in the transmission grid are described in Chapter 3 and /Pub-02/. This includes also the adjustments that are necessary to ensure acceptable computing times and stability of optimization at limited hardware resources. Apart from this, the chapter describes the mathematical formulation for the representation of congestion management measures within the framework of current regulation. This is the basis of the analyses made in /Pub-02/ and /Pub-03/. Through the integrated transmission grid representation, a “nodal pricing” or “locational marginal pricing” market design is represented. With the application of both market designs, a framework is being laid to investigate the grid-related impact of flexibility options through comparative calculations. Such an analysis is carried out in the publications /FFE-65 18/ and /Pub-02/, and summed up in Chapter 4.1. The studies carried out in the "Discussion of Results" section can be divided in two parts: The first is the grid-related evaluation, which deals with the interaction of the transmission grid with one or several decarbonization measures. In the context of multiple scenario calculations, this is explored in more detail for various combinations. The second part is a full cross-sectoral decarbonization scenario assessed in Chapter 4.2. This analysis provides information about the far-reaching changes to be expected if an emission reduction of 95 % compared to 1990 is met. And thus, with a view beyond 2030, what major shifts in generation and demand are to be expected. Chapter 5 summarises the results in a final overview and critically assess their validity. Key findings from the publications and supplementary chapters are elaborated. Chapter 6 provides an outlook to which there is a need for further methodological research and which additional scenarios need to be considered in order to gain a better understanding of the decarbonization process of the energy system.

1.3 Literature Review

The research discipline of energy system analysis plays a central role in the scientific guidance of the transformation process towards a secure, cost-efficient and sustainable energy supply. Even though this is a very widely researched area, the size of the system under consideration and the variability of the underlying parameters alone require the application of several models and approaches from a variety of institutions. As will also become apparent in this thesis, the decisions and assumptions regarding the methodological concept, the drawing of the system boundaries, and the selection of the data used are numerous. Against the background, that research projects can only address a part of the scientific questions a choice has to be made at this point as well. The combination of approaches, input data, and researched issues allows a wide range of works in the field of energy system analysis to make a valuable contribution to understanding the overall structure of the future energy system design. In order to put the dissertation at hand in context with existing research, the following chapter provides a classification in distinction to existing literature and highlights the studies on which it is based.

Energy system modeling originates partially in the representation of electricity markets. The initial work on the mathematical principles of electricity markets goes back to Schweppe et al. in 1988 /SCHWEP-01 88/. One of the first complete overviews and differentiation of the different model types can be found in /HOBB-01 95/. In this paper, not only the electricity market but the entire energy supply from the planning and investment phase to the operation stage is addressed. An overview of applications and models that reflect the coupling of energy carriers in the form of multi-energy system (MES) models is given in /HOF-01 76/. This applies above all to supply scheduling and planning. A modeling of energy markets was not considered at that time. The basis of power transmission modeling in terms of optimal power flow is given in /IEEE-01 68/. The simplifications required for applicability to larger models are described in /IEEE-03 09/, /KUL-01 06/ and /KUL-01 14/. While the methodological approaches of investment and dispatch optimization remain fundamentally unchanged, there are variations in the selection of assessment approaches and the sequencing of model runs, as well as extensions through constraints that define specific system characteristics. In /WEB-01 04/ many of these constraints are documented for modeling the operational specifics of devices such as power plants or storage systems.

Based on these fundamentals, numerous scenario studies have been conducted over the years. Focusing on decarbonization paths in Germany, 80 % and 95 % GHG emissions reduction scenarios are published at recurring intervals. The work of /DLR-04 12/, /UBA-04 14/, /ÖKO-03 15/, /ISI-07 17/, /DENA-01 18/, /BART-01 19/, and /BCG-01 18/ are examples for that. These studies place a strong emphasis on a holistic, cross-sectoral, and consistent story of a transformation path. Individual measures are rarely evaluated in detail, and the modeling of transmission infrastructure, such as the electricity or gas networks, is also limited or neglected. The advantage of the diversity and variety of scenarios is that a robust scenario corridor has developed over the years. Almost all studies have in common that the climate targets can only be met in the medium term by growing renewable energy penetration, electrification of final energy consumption, and efficiency technologies such as heat pumps. Depending on the year of publication, there are major differences in the design of the target year 2050. A mix of CCS, imported green fuels, domestic Power-to-X, and efficiency measures, which varies greatly from study to study, is applied for this.

In order to examine the repercussions on the transmission network in such scenarios also, a load flow representation is essential. In /MUEL-01 19/, the final energy sectors are simplified, and primarily electricity is considered, but a load flow calculation is carried out, which shows the resulting congestion management volumes for different stages of grid expansion. Publications like /ELS-01 14/, /IET-01 15/, and /BROW-01 18/ have a stronger focus on the Europe-wide grid-repercussions of scenarios with high renewable penetration. A detailed overview of analyses modeling congestion management in different approaches and with respect to different regions and time horizons can be found in /NOLD-01 13/. First and foremost, the research in these publications does not concentrate on the interplay between the grid and individual measures, but rather on the transmission system expansion demand resulting from entire scenarios. In /NEUM-01 19/ a method for model-driven and endogenous network expansion planning is presented, and its performance is compared to existing approaches. To ensure the computability of the model within these wide system boundaries, different mathematical formulations of the linearized load flow are offered in /HÖRS-01 18/. Aggregation and decomposition methods, as described in /DLR-03 19/, can also be used for this purpose.

From a methodological point of view, the increasing linking of several energy carriers through conversion technologies in low emission energy systems increases the challenge of energy carrier-specific emissions accounting. Nevertheless, hourly emission factors as a result of multi-energy system (MES) model calculations are an important output for simplified emission assessments. In /UOMI-01 16/, /RIP-01 18/, and /PSC-01 16/ MES models are described and methods for calculating time-variable emission factors are presented. This thesis is supposed to add a new combination of energy system scenarios, modeling approaches, and emission accounting methodologies.

The analysis of the state of the literature shows that, despite numerous scenario studies, there is a need for cross-sectoral evaluations of individual measures in relation to the grid. For the design of a suitable modeling approach, numerous methods are available. These methods must be selected and arranged in such a way that they correspond to the specific research question.

1.4 Funding and Related Research

During the five years of research documented in this dissertation, three publicly funded research projects were completed. In the first project, "MOS", the systemic benefit of functional energy storage systems has been evaluated. Functional storage systems include all technologies that are capable of improving system flexibility by deviating from their initial schedule. Secondly, the project "MONA" focused on grid optimization measures for transmission and distribution grids. In addition to the conventional grid expansion, grid-optimizing measures that improve the utilization of the existing grid and thus ensure the integration of variable renewable energy sources (vRES) have been assessed. The third project "Dynamis" has led to an in-depth consideration of emission accounting, sector coupling, and climate protection scenarios.

Within the scope of these projects, all four publications of this work were conducted. The analyses were primarily carried out using the FfE energy system model ISAaR, which is for the “Integrated Simulation Model for Planning the Operation and Expansion of Power Plants with Regionalization”. The ISAaR model is a linear optimization model that uses total cost minimization as optimization target. The evolution of the model started in 2014. It was constantly expanded by the author of this dissertation in order to answer the central research questions of this work and the projects mentioned. The development stages of the model and the focus of the research within the respective studies are shown in Figure 2. In addition, the publications that are relevant in the light of the results presented in this work are referenced in the lower timeline.

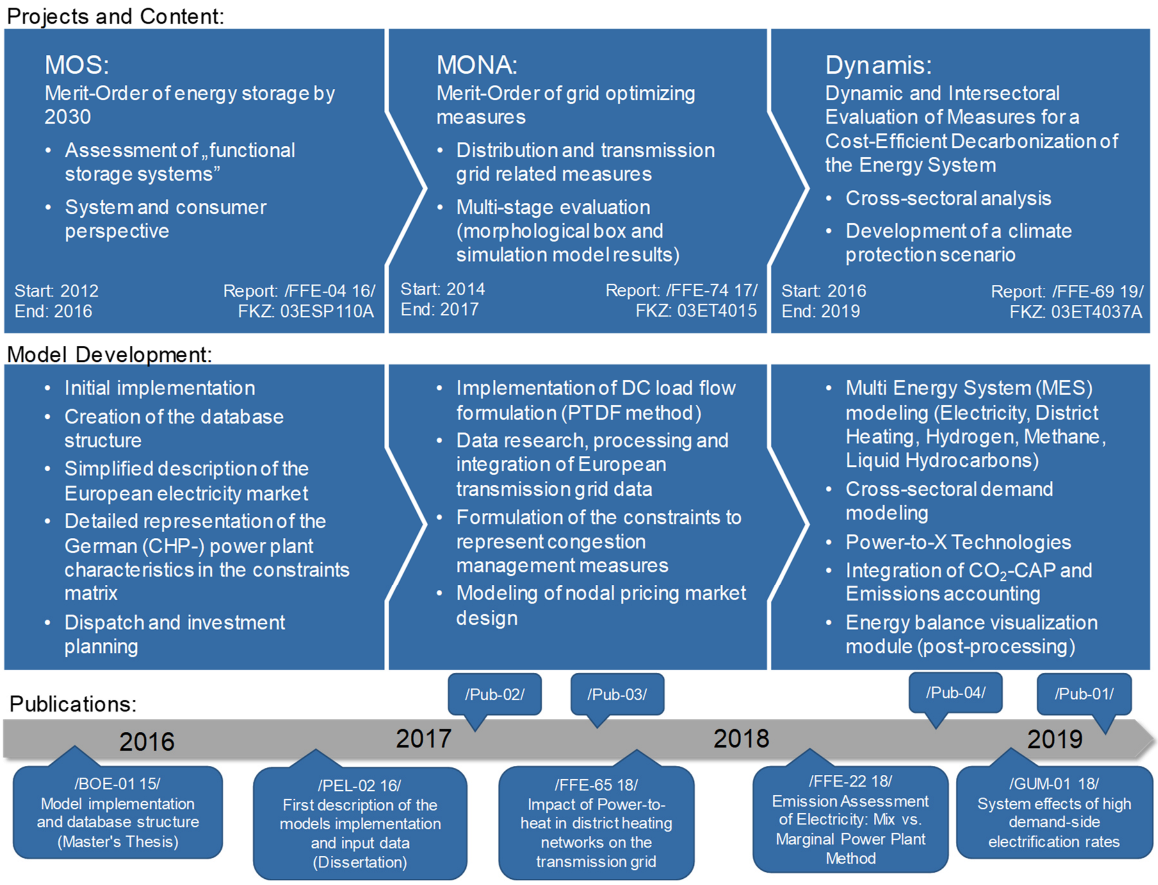


Figure 2: *Accompanying projects and the development stages of the ISAaR model*

Figure 2 shows that the model has been developed continuously over several years. In most cases, such a project-based model development and application contains the aspect of input data processing, i.e. the preparation of the raw data and the scenario building. However, the scientifically interesting dimension of model development includes especially the evolution of the methodological concept. This entails, for example, the formulation of the constraints matrix, or the sequencing of calculation runs. This thesis deals primarily with the methodological aspects of modeling which form the basis of the scenario analyses carried out. A comprehensive documentation of the input data sources used and the data processing specific assumptions can be found in the reports of the respective projects mentioned in Figure 2, in the referenced publications (/PUB-01/…/PUB-04/), and in Appendix A.

2 Energy System Modeling

As described above, starting from an electricity market model with a simplified mapping of the neighboring European countries, the various development stages of the ISAaR model include, among other aspects, the expansion of the regional focus as well as the energy carriers and consumption sectors considered. In the following, the current state of the model is described by summarizing and supplementing the detailed description in chapter "Multi-Energy system model" /Pub-01/.

2.1 Technological Scope

It is to be noted that the name “Integrated Simulation Model for Planning the Operation and Expansion of Units with Regionalization” has not changed over time, and therefore the original acronym and the actual model scope differ. On the one hand, it is an optimization model, which "simulates" a future system state. However, from an energy system modeling perspective, there is a difference between “simulation” and “optimization” approaches. It should be specified that ISAaR is not a rule-based process simulation, but a so-called technologically oriented bottom-up cost optimization model. On the other hand, far more components of the energy system are represented than just power plant units. Thus, considering the state of the model, the term "unit" must be extended to all vRES, storage systems, and Power-to-X applications. Figure 3 shows all other components that have since been integrated. It illustrates why the model is classified as a multi-energy system model (MES). The segment "with regionalization" is also essential in that the georeferencing of generation and consumption is of relevance for grid analyses.

The illustration of the ISAaR model shown in Figure 3 can be divided into three areas: First, the model exogenous sector models on the upper left side. Second, the bottom area for the supply of model exogenous fuels. And third, in the large, middle part, the actual ISAaR model. These boundaries define the technological scope of the model. The modeling of the demand for energy carriers from the consumption sectors on the other hand is done in the stock-and-flow models of the final energy consumption (FEC) sectors represented in the upper left corner. Measures such as the shift from conventional to electric vehicles are being evaluated in terms of replacement rates, direct emissions, costs, and resulting hourly demand profiles in the transport sector model “TraM”. This sector model is documented in /FFE-20 18/. The domestic sector model “SoPHa” is described in /FFE-26 18/ and /FFE-19 19/. A focus on the industrial sector is placed in the "SmInd" model /FFE-79 19/. A comprehensive description of the modeling methodology of all sector models is given in /FFE-69 19/. An application-oriented balancing of final energy consumption is a key component of all sector models. The bottom-up modeling of consumption technologies allows to synthesize load profiles. This facilitates to model the effects of a technology change on the hourly energy demand. The resulting load profiles are then handed over to the model of the supply sector "ISAaR". Figure 3 shows for each energy carrier by means of a line diagram, which temporal resolution is applied. This resolution varies depending on the energy carrier. While electricity is modeled in an hourly resolution, methane, in contrast, is considered on a daily basis. A more detailed discussion and a description containing the mathematical formulation can be found in /Pub-01/.

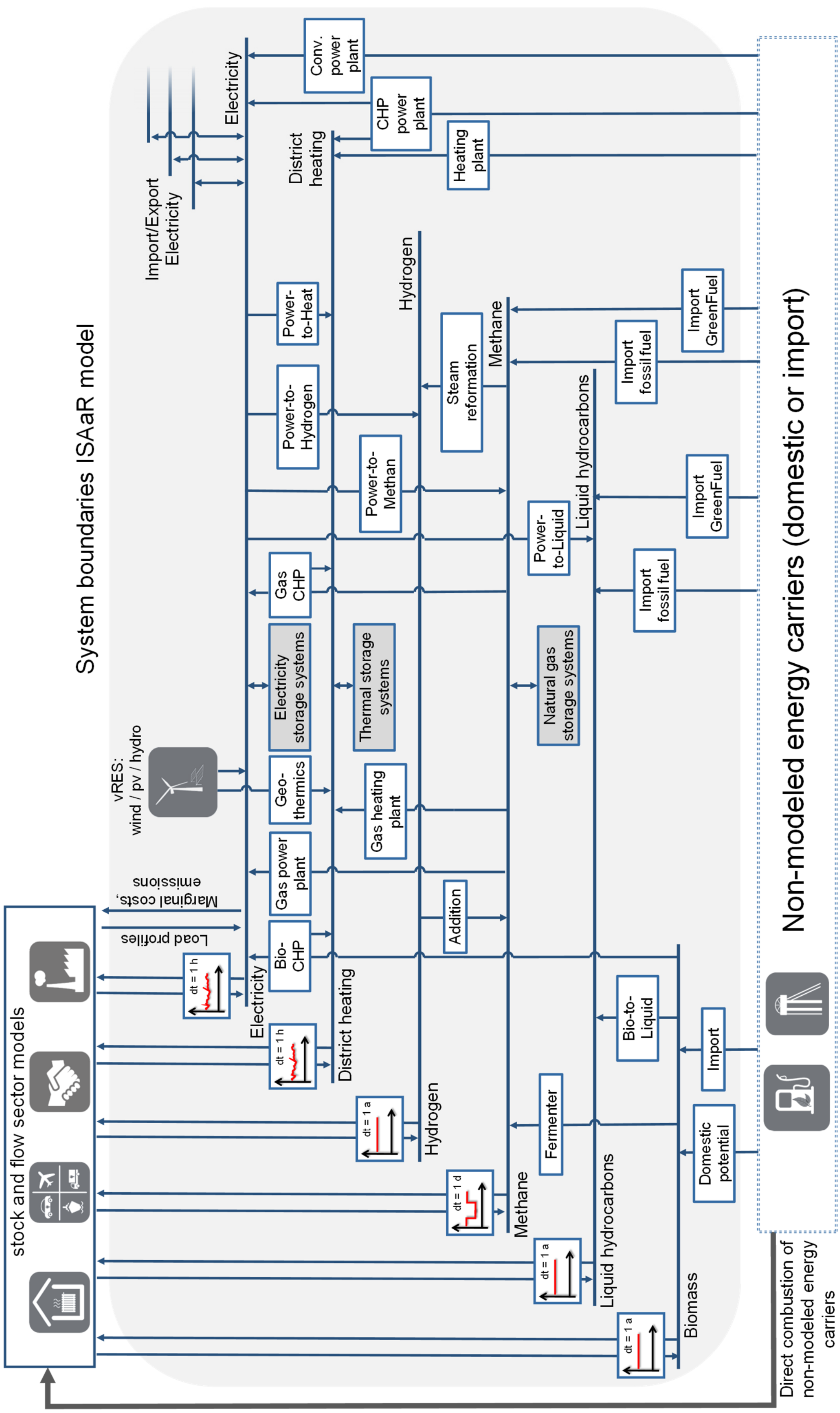


Figure 3: *ISAaR model: Structure of modeled energy carriers, system boundaries, sector coupling, storage systems, and conversion technologies (see /Pub-01/)*

Once ISAaR has optimized the expansion and dispatch of generation units, conversion technologies and storage systems, hourly energy prices and emissions are handed back to the sector models. This enables iterations to take place optimizing the penetration rates of demand-side abatement measures and the deployment of demand-side flexibility. Apart from electricity, district heating, hydrogen, methane, liquid hydrocarbons, and biomass, all other energy carriers are balanced model-exogenously, which is indicated by the box on the bottom of Figure 3. This box includes the use of energy sources such as hard coal or lignite. The extraction, import, and transport of energy carriers are part of this category, too. An upper limit for the usage of biomass is set to state that there is only a limited potential for biomass crops in Germany. A significant import of biomass in solid or unprocessed form is not considered.

The ISAaR model is linked to the gas market model MInGa. MInGa is deployed to re-analyse the gas demand and supply modeled by ISAaR in more detail. This model coupling enables the repercussions of a scenario on the gas price and the utilization of the gas infrastructure to be analyzed and iteratively fed back into the ISAaR model framework. The MInGa model itself, the underlying methodology, and the model coupling are described in /FFE-134 17/, /FFE-44 17/, and /FFE-18 18/, but will not be subject to further investigations outlined here.

2.2 Regional Scope

As shown in Figure 3, the electricity balance is not only linked to the other energy sources but to the "import/export" component. This visualization is simplified, since for electricity each neighboring European country within the scope of the model is considered in detail. The differences in model boundaries between Germany and the neighboring countries are shown in Figure 4.

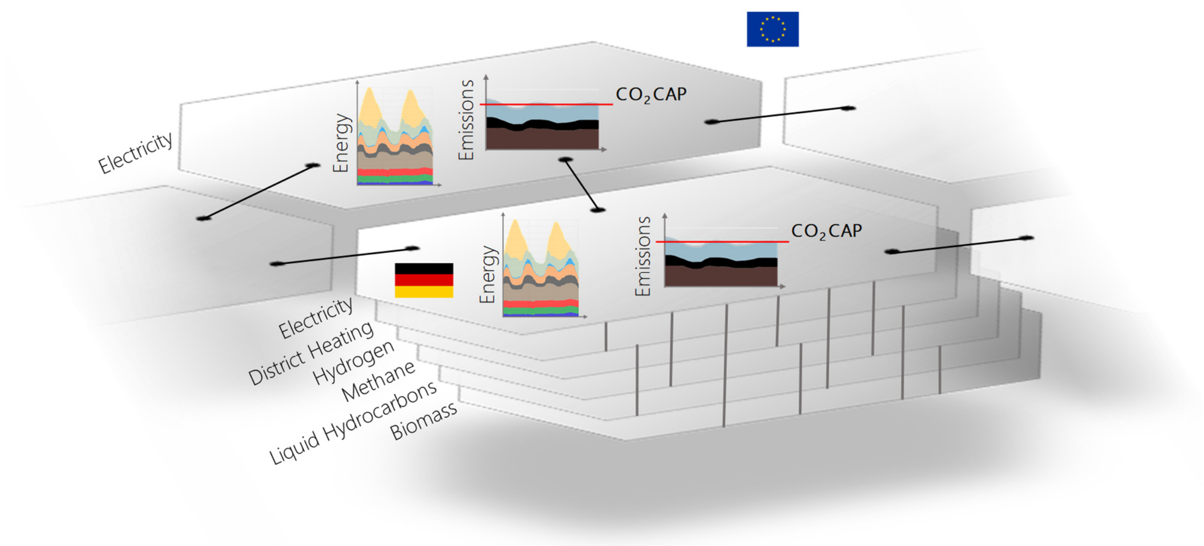


Figure 4: *Schematic representation of the level of detail of the modeling for the neighboring countries*

The exchange with neighboring European countries at hourly resolution is as decisive for no other energy carrier as it is for electrical energy. For this reason, the mapping of the European electricity market coupling is given particular weight.

The option of limiting emissions in Germany through a cross-sectoral emission cap is relevant for calculating a climate protection scenario. When calculating the demand for energy carriers with the sectoral models to evaluate the final energy consumption, direct emissions are determined, too. These emissions are summed up and compared to the annual available emissions budget which results from the reduction target. The remaining emissions for the year under analysis are then allocated to the ISAaR model and thus represent the upper emission limit for the energy sector. In the unit commitment and investment-planning model, model-endogenous measures are to be taken to meet emission limit on hand. The results of an optimization run for one year show which combination of unit deployment and investment is necessary to comply with the cap at minimum costs.

In addition to the emission constraint explained above, an “electricity-only” CO_2 cap is used in the neighboring European countries. This cap is not suitable for mapping target scenarios because no holistic, bottom-up sector modeling approach of energy consumption is deployed. These country specific caps are used to limit the maximum emissions per year to the emissions value of a reference run. The reference run is modeled as a business-as-usual scenario (“Start-Scenario”), described in /Pub-01/. From this reference run, the emissions of each neighboring country are extracted, and used as upper emissions limits for each neighboring country. With this approach, the flexibility through the coupling of electricity markets is maintained, but carbon leakage is prevented. This allows a comparative assessment of the scenarios for Germany. The model region covered in this process is shown in Figure 5.

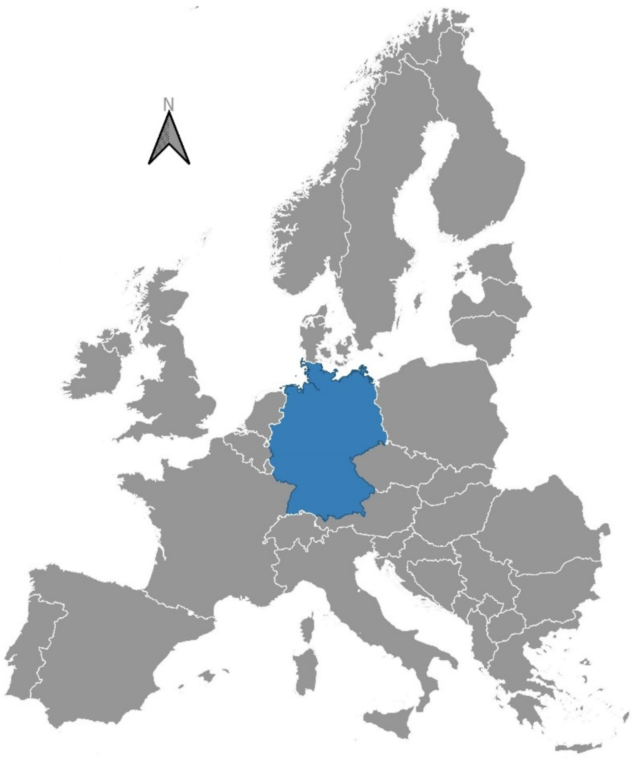


Figure 5: *Regional scope of the model for electricity*

2.3 Investment Optimization and Sequencing of Optimization Runs

Regarding the ISAaR components shown in Figure 3, it should be noted, that all elements of the MES in Germany can be either given exogenously for a scenario computation ("Blackfield"), or they are partly given and partially added model-endogenously ("Brownfield"). The third option is that units are extended cost-optimized on the so-called "Greenfield", which means that no existing supply infrastructure is assumed. In general, all of these methods, described in more detail in /GERBA-01 17/, are valid in model-based energy system assessment. The "Blackfield" and "Brownfield" variants are mostly applied for this thesis. "Blackfield" is suitable for questions from the field of scenario analysis, in which different energy systems of a specific year are compared with each other. In this case, the transformation path is not the primary focus. It is particularly suitable for analyses in which existing scenarios with exogenously defined developments of system components are compared. Due to the absence of time-coupling investment constraints, such calculations are not very CPU-intensive and thus allow the addition of a load flow simulation for the transmission grid. Whereas the brownfield method is suitable for assessing emission reduction paths with specific investment costs that increase or decrease over the years. The applied methods of dispatch and investment planning shown within this thesis are only an extract of the different MES evaluation concepts. A more comprehensive and detailed summary is given in /UOMA-02 14/.

Using the brownfield method, the various energy system components are classified in three categories: First, the stock of assets reflecting today's existing infrastructure. Second, as a model exogenous scenario assumption, new constructions, which are added to the system without optimized investment decision. Third, the model-endogenous expansion of units based on CAPEX and fixed operational costs.

The sequencing of the calculations is a central feature of the brownfield analyses performed here. The endogenous investment decisions are handed over from run to run, as shown in Figure 6. Assets at the end of their useful life are decommissioned. If a unit is added to the system in a previous year and the exogenously given capacity raises, the handed-over endogenous capacity is reduced. This case can be observed in Figure 6 for the hand-over from 2030 to 2035.

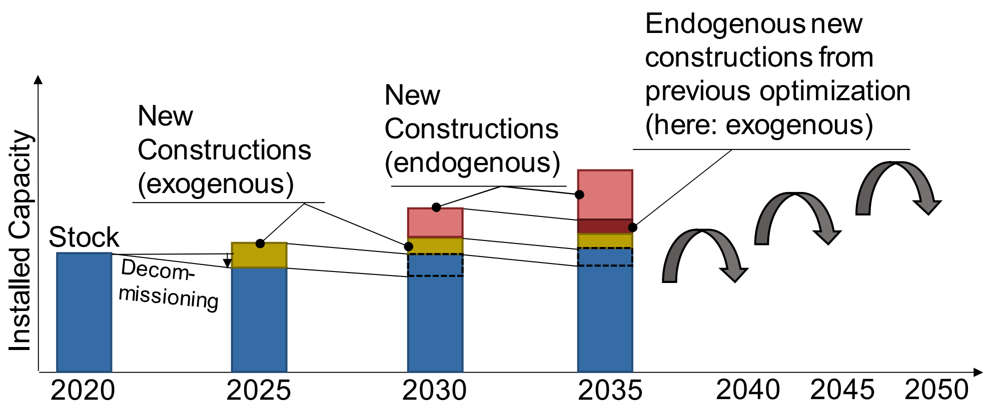


Figure 6: *Sequential hand-over of endogenous and exogenous investment decisions ("Brownfield")*

The analyses in /Pub-01/ and the following Chapter 4.2 are performed using this brownfield method. The computations in the publications /Pub-02/, /Pub-03/ and /Pub-04/, however, correspond to the blackfield approach as grid constraints are included.

Since the model calculations represent an overall cost optimization, the cost elements taken into account are as follows.

- Short-term marginal costs of fossil generation technologies, based on efficiencies, fuel costs, fuel demand of start-up processes and linearized partial load behavior
- For CHP plants: marginal costs, determined by the linearized representation of the CHP operating characteristic field, taking into account the reduction in efficiency of CHP plants in extraction condensation operation (see Appendix in /Pub-01/)
- EU-ETS CO_2 allowance costs for all combustion conversion technologies
- Variable and fixed operating costs, as well as specific investment costs for conversion technologies (i.e., Power-to-X), generation technologies (i.e., power plants) and storage systems (i.e., battery storage systems)

The investment calculation is carried out in an annualized form. All information regarding interest rate, specific costs and fuel costs can be found in Appendix A. Other components such as taxes, levies, and fees are not included. The only regulatory cost component taken into account are the costs of emission allowances. This component is relevant as it has a decisive impact on the dispatch of conventional generation technologies. In addition, EU-ETS allowances are reflected in today's wholesale electricity prices. Apart from this component, the cost balancing approach can be considered as a macroeconomic approach.

2.4 Software

Regarding the technical implementation of the model, reference is made to /Pub-02/. A schematic illustration of the scenario selection process, data fetching, and formulation of the constraints matrix up to the handover to the solver are specified there. A unique feature is that the constraint matrices are not generated by a software for the formulation of optimization problems, such as the "General Algebraic Modeling System" (GAMS®). Instead, the matrices are filled in Matlab®. A PostgreSQL database is used for data handling. Despite the more extensive initial implementation effort, this construct offers some advantages. One is that a direct link to the local FfE database FREM is provided. Beneath the standardized provision of various input data for scenario building, results management and coupling with the sector models are performed via this interface. The general structure of this interface is described in /FFE-69 19/. A detailed description of the database can be found in /SCHM-01 18/. Another advantage is, that Matlab is very performant in processing large amounts of numerical data and matrix calculations.

3 Transmission Grid Modeling

In branched energy transmission networks alternating current (AC) load flows are nonlinear. Linearization approaches are needed in order to combine load flow calculations with linear energy system models. This allows large systems with up to 8760 time steps, which corresponds to one year in an hourly resolution, to be solved within an acceptable computing time. The linearization of branched physical load flows in the transmission grid is implemented in the following by the so-called PTDF approach. PTDF is for "Power Transfer Distribution Factors". As shown in /HÖRS-01 18/, the PTDF approach is one of many methods to implement a "DC Linearized Optimal Power Flow (DC-LOPF)" in energy system models.

Both the general description of a linear optimization model and the specific equations and constraints for the representation of power plants, storage systems, and other elements of the ISAaR model are documented in /Pub-01/. The equations for the implementation of the PTDF approach are described in detail in /FFE-45 17/ and partly in /Pub-02/. These equations are summarized in the following. First, the linearized load flow approach is derived from the nonlinear formulation. Furthermore, the methodology of implementation in the ISAaR model is described. Subsequently, a formulation of the current congestion management cascade is introduced.

3.1 Load Flow Modeling

AC load flow equations, as described in fundamental work such as /ETH-03 11/, show a non-linear behavior and are subject to several parameters: The active P_i and reactive Q_i power feed-in at a node i determine the voltage U_i and voltage angle δ_i at the node i itself, as well as the voltages U_j and voltage angles δ_j of all nodes I connected. Thereby, the series conductance b_{ij} and series susceptance g_{ij} of the linked lines are constant technological parameters.

$$\begin{aligned} P_i &= U_i \cdot \sum_{j \in I} \left(U_j \cdot \left(g_{ij} \cdot \cos(\delta_i - \delta_j) + b_{ij} \cdot \sin(\delta_i - \delta_j) \right) \right) \\ Q_i &= U_i \cdot \sum_{j \in I} \left(U_j \cdot \left(g_{ij} \cdot \sin(\delta_i - \delta_j) - b_{ij} \cdot \cos(\delta_i - \delta_j) \right) \right) \end{aligned} \tag{1}$$

The active and reactive power of a node i is determined by the balance of all linked lines. The power flow components of the line $i \rightarrow j$ is defined by:

$$\begin{aligned} P_{ij} &= U_i^2 \cdot g_{ij} - U_i \cdot U_j \cdot g_{ij} \cdot \cos(\delta_i - \delta_j) - U_i \cdot U_j \cdot b_{ij} \cdot \sin(\delta_i - \delta_j) \\ Q_{ij} &= -U_i^2 \cdot (b_{ij} + b_{ij}^{sh}) + U_i \cdot U_j \cdot b_{ij} \cdot \cos(\delta_i - \delta_j) - U_i \cdot U_j \cdot g_{ij} \cdot \sin(\delta_i - \delta_j) \end{aligned} \tag{2}$$

b_{ij}^{sh} are the shunt susceptances of the lines from i to j. They are taken into account to determine the reactive power flows Q_{ij}.

To implement the load flow equations in a linear optimization model, the formulation needs to be linearized. Therefore, the following simplifying steps and assumptions based on /ELS-01 14/ and /KUL-01 14/ are made:

- Assuming a flat voltage profile: $U = 1\, p.u.$ (no voltage drops)
- Reactive power is neglected: $Q_{ij} = 0$ and $Q_i = 0$
- Active power losses are neglected, so that: $X \gg R \approx 0$
- Assuming small differences in voltage angles between two nodes i and j, so that applies: $\sin(\delta_i - \delta_j) \approx \delta_i - \delta_j$.

Applied to equation (2), the expression for the linearized power flow P_{ij} can be simplified to

$$P_{ij} = b_{ij} \cdot (\delta_i - \delta_j) = \frac{x_{ij}}{x_{ij}^2 + R_{ij}^2} \cdot (\delta_i - \delta_j) \approx \frac{1}{x_{ij}} \cdot (\delta_i - \delta_j) \ . \quad (3)$$

x_{ij} is the simplified impedance (reactance) of the line from node i to j. Based on that, the the injected power at node i is represented by

$$P_i = \sum_{j \in I} \frac{1}{x_{ij}} \cdot (\delta_i - \delta_j) \, . \quad (4)$$

According to the equation (3) and (4), the power injected at node i, and the power flow from i to j depend linearly on the difference in the voltage angles at the nodes. The power flow and line reactances are inversely proportional.

Starting from this formulation, the steps described in /ELS-01 14/ are performed, which lead to the formulation as introduced in /Pub-02/:

$$\underline{P}_{link} = \underline{\underline{PTDF}} \cdot \underline{P}'_{inj} \quad (5)$$

$\underline{P}_{link}$ is the vector of net active power flows and $\underline{P}'_{inj}$ is the vector of the net active power injections at all nodes. According to equation (5), a linear relationship is given between the nodal power balances and the line power flows. The entries of the PTDF matrix are calculated based on the impedances of the lines by matrix multiplication.

The accuracy of linearized load flow is discussed in /IET-01 15/. It is shown that if the line loading is below 70 % of the maximum thermal capacity, the linearized approximation of the nonlinear load flow is sufficiently accurate. The maximum thermal capacity describes the permanent apparent power at which, under standard weather conditions, the current flow does not exceed a maximum compatible conductor temperature and thus guarantees the safe operation of an overhead line /FISC-01 89/. If 70 % of the maximum thermal capacity is exceeded, the non-consideration of the reactive power component leads to considerable deviations in the accuracy.

The approach chosen is therefore sufficiently precise, since the loading of AC-lines is constrained to 70 % of their maximum thermal capacity to approximate a n-1 secure grid operation /TUG-02 12/. This reduced value is named LTC "Line transfer capacity". It describes the utilizable share assumed to ensure a n-1 secure grid operation in the grid planning stage.

Integration of the load flow formulation in the model constraints

As described in /Pub-01/, the optimization objective is to minimize the total system costs C, which result from the specific costs $f_{n,i,t}$ and the utilization of the optimization variables $x_{n,i,t}$. If these costs are broken down according to the optimization variables of each individual node n, instance i and time step t, it follows

$$C = min \sum_{n \in N} \sum_{i \in I_n} \sum_{t \in T} \left(f_{n,i,t} \cdot x_{n,i,t} \right). \quad (6)$$

The result of the optimization is a vector of optimization variables $\underline{x}$, which represent a system utilization and state at minimum total system costs C. This vector contains the dispatch of all instances I at all network nodes N at all timesteps T.

The subsets of the optimization variable x are the group of generation variables G_n of conventional or renewable units and the withdrawal variables W_n of storage systems or Power-to-X units. For each grid node n, the generation minus the withdrawal plus the power transactions $T_{j \leftrightarrow n}$ with all connected nodes J_n have to be equal to the conventional, inflexible demand $D_{n,t}$ of this node.

$$\sum_{i \in I_n} G_{n,i,t} - \sum_{i \in I_n} W_{n,i,t} + \sum_{j \in J_n} T_{j \leftrightarrow n,t} = D_{n,t} \quad \forall\, n \in N \quad \forall\, t \in T \quad (7)$$

This energy balance equation is analogous to the energy balance in /Pub-01/ except for the fact that the transactions $T_{j \leftrightarrow n}$ replace the variable of imported and exported power ($P_{Import/Export}$) in this formulation. As for imports and exports, transactions do not represent physical flows. They represent a model-based exchange of energy between two nodes. So far, the formulations of the market and the power system flow calculation are the same. However, the integration of the PTDF component is enabled due to the transaction formulation and adds further restrictions to the system.

In chapter 3.3 of /Pub-2/ a detailed description of the matrix calculation is made, and all relevant input parameters are documented. The load flow on a single line is defined by the flow variable P_{link}. The entirety of all load flow variables per timestep t is summarized in the vector $\underline{P}_{link,t}$. The impact of the transactions on the power flow of individual lines is defined by

$$\underline{P}_{link,t} = \underline{\underline{PTDF}} \cdot \underline{T}_t \quad \forall\, t \in T. \quad (8)$$

Equation (8) illustrates the basic principle of PTDF matrices: Virtual energy transactions between nodes are translated into physical power flows. The maximum usable capacities of line segments per direction ($\underline{P}_{max,ij,t}/\underline{P}_{max,ji,t}$) is described by

$$-\underline{P}_{max,ji,t} \leq \underline{P}_{link,t} \leq \underline{P}_{max,ij,t} \quad \forall\, t \in T. \quad (9)$$

While transactions have only positive values, the resulting flows can be positive and negative depending on the direction. This formulation is chosen in order to model the directions of power flows between two nodes using a minimal set of variables. The vector of maximum usable capacities $\underline{P}_{max,t}$ consists of the above defined LTC values. Equation (9) ensures that the nodal energy balances are met on the one hand and the LTC limits of the lines are not exceeded on the other.

Since the transactions are not limited, a variety of different combinations of transaction values are possible that result in realistic power flows. The feasible region in the optimal range is vast and flat. Such a constellation leads to very high computing times during the iterative cost minimization of the solver as many solution vectors lead to the same optimal costs. The Linear Optimal Power Flow (LOPF) approach, as described in /HÖRS-01 18/, requires a load flow component that is optimized. This variable is used to add a gradient to the costs of the feasible region. In the approach presented, all transactions are charged with very low costs. The consequence is that a reproducible solution is found at low computation times at almost the same total system cost of the optimum. When comparing the total system costs of different scenario runs, the negligibly low costs for transactions are extracted. Other formulations of the LOPF, for example, include the pricing of the flow variables or integration of an efficiency coefficient for the flow variables, which corresponds to the model-endogenous consideration of losses. In the approach presented here, line losses are taken into account model exogenously by a factor on the exogenous electricity demand.

Modeling Congestion Management

Ensuring a congestion-free power supply is the premise of today's grid planning. If the transmission network does not fulfill the transport task it has to handle at certain times, congestion management measures are taken by the TSOs in the grid operation stage. In these cases, the generation unit dispatch is adapted by the measures “curtailment of vRES” and “redispatch of conventional power plants”. This measures are taken in order to prevent overloading of the transmission system. Due to the high amount of compensation payments for curtailed RES, grid congestion has become an important topic in the German energy transition debate. However, according to the EEG, these payments were taken anyway as feed-in remuneration for the renewable generation, but are balanced to the TSOs in case of grid congestion. In the context of dumped emission-free generation from RES due to curtailment or a costly power plant start-up as redispatch measure, grid congestion is to be avoided from emissions and costs perspective. One of the many measures to prevent grid congestion is the conventional approach of grid expansion. As shown in /Pub-02/ and /Pub-03/ alternative so-called “grid-optimizing measures” (GOM) exist and are assessed in Chapter 4.1. As one parameter to evaluate the impact of these measures, the congestion management volume reduced in comparison to a reference scenario is chosen. In addition to assessing GOM, this parameter is also used to evaluate the interplay with the transmission system of modified scenario assumptions, such as the penetration of vRES.

In order to model the current process of congestion management, the regulatory framework and electricity market design need to be considered. While the capacities between bidding zones are taken into account using the NTC method or the process of flow-based market coupling when clearing the market, congestions within a bidding zone have to be solved by the TSO nowadays. In the German case, the division of the bidding zone between the four transmission system operators also results in a high coordination effort. The extent to which this can lead to inefficiencies is discussed in /DIW-05 13/. In addition to the improvement process of congestion management procedures itself /BMWI-14 18/, the legislation regarding the prioritization and compensation of costs of various congestion management measures is continuously being revised. Until the NABEG 2.0 was passed in May 2019 /BMWI-15 19/, the congestion management measures Redispatch and curtailment of RES were separated according to ENWG §13. If congestion occurred in grid operation, the redispatch of conventional generation units had to be carried out first, and after that vRES were curtailed as "Ultima Ratio". Despite the outcomes of the NABEG-reformation, which allows a "mixed operation", the general prioritization remains unchanged. Now, in cases when low curtailment volumes can avoid high redispatch volumes, this curtailment is permitted. For all these reasons and the semitransparent, internal redispatch processes of the TSOs, modeling of congestion management is and will be an approximation. In the following, the methodology of modeling congestion management in the ISAaR Model is described.

As shown in /Pub-02/ and /Pub-03/, a market optimization run is carried out first. After that, the dispatch of the market result is handed over to the grid optimization run. Here, an entire one-year run including the PTDF approach and thus taking into account all grid restrictions is carried out. In order to determine the redispatch and curtailment volumes, a deviation from the market dispatch of power plants and vRES is penalized. These virtual costs are higher in case of a negative renewable deviation. Because of this, redispatch is deployed first, and after that, renewables are being curtailed to avoid line overloading. In determining the most cost-effective combination of power plants performing a positive and negative redispatch, short-term marginal costs for electricity generation of each power plant unit are the decisive parameter. This interplay is illustrated in Figure 7.

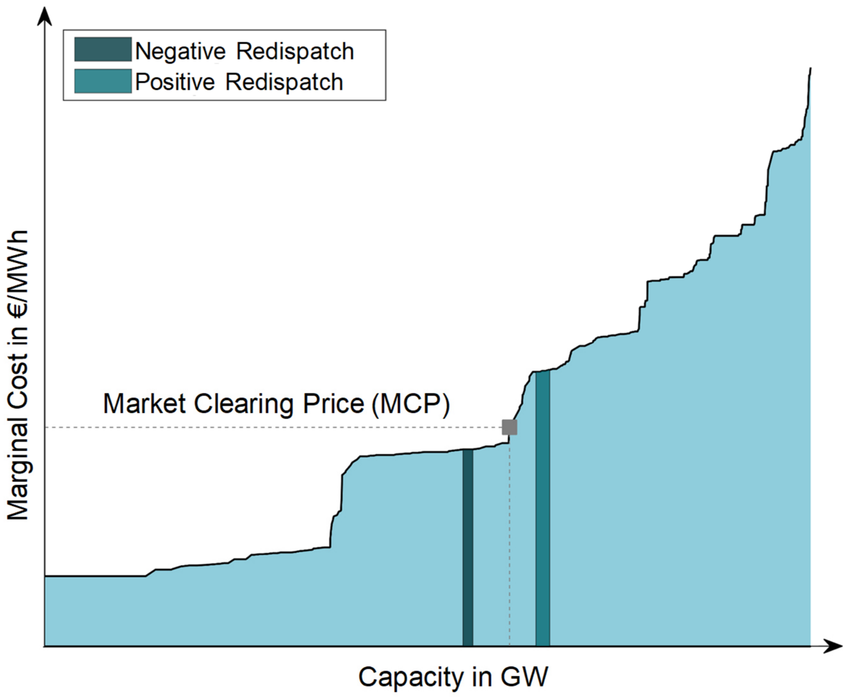


Figure 7: *The merit order principle for the determination of Redispatch power plants*

The mathematical approach for the implementation of such a redispatch behavior is made in ISAaR through the introduction of further variables and constraints as follows: The variable P_{δ}^{+} describes the positive difference between the power output of a power plant $P_{el,out}$ and the market schedule of this unit $P_{el,market}$. Analogously P_{δ}^{-} describes the negative redispatch of a power plant.

The link between $P_{el,market}$, $P_{el,out}$ and the redispatch power P_δ is shown in equation (10). c_{avail} is the available share of the rated power capacity $P_{out,max}$ of a power plant.

$$\begin{gathered} P_{el,market} = P_{el,out} - P_\delta^+ + P_\delta^- , \\ 0 \leq P_\delta^+ \leq \left(c_{avail} \cdot P_{out,max} - P_{el,market}\right) \\ 0 \leq P_\delta^- \leq P_{el,market} \, . \end{gathered} \tag{10}$$

The costs of a positive redispatch are higher, but proportional to the power plant operating costs. In consequence, less costly power plants are ramped up first to provide redispatch. The pricing is set in a way that positive redispatch is very costly, and the utilization of negative redispatch generates low “negative costs”, which equates revenues in optimization. As the power balance within a bidding zone has to be met in the redispatch run as well, each negative redispatch or curtailment needs to be compensated by positive redispatch. This prevents a revenue situation and ensures that deviations from schedules are only done to manage congestion.

To incite the most cost-effective and regulatory-compliant composition of positive and negative redispatch units to solve congestion, the redispatch penalty costs f_δ^+/f_δ^- are based on the short-term marginal costs of power plants, as follows:

$$\begin{gathered} f_\delta^+ = \left(f_{P,el,out} + \frac{f_{fuel} + c_{emmision} \cdot f_{CO2}}{\eta_{el}}\right) \cdot P_\delta^+ + f_{add}, \\ f_\delta^- = -\left(f_{P,el,out} + \frac{f_{fuel} + c_{emission} \cdot f_{CO2}}{\eta_{el}}\right) \cdot P_\delta^- \, . \end{gathered} \tag{11}$$

By considering fuel costs f_{fuel}, efficiencies η_{el}, emission factors $c_{emmision}$, the costs for emission certificates f_{CO2} and the variable operating costs $f_{P\_el\_out}$, short-term marginal costs of electricity generation from conventional units are set up. This guarantees an operation mode in which the power plants with the most expensive marginal costs generate the highest virtual revenues performing negative redispatch and are therefore reduced first. The curtailment of vRES is not subject to penalty costs or revenues, whereby this option is taken as the last option when negative redispatch capacities are not able to resolve congestion. This formulation thus corresponds to the former legislation which was valid at the time of implementation. From a modelling perspective it should be noted that the dispatch of the cheapest positive redispatch unit must be more expensive than the highest revenue from negative redispatch. Otherwise, an unintended revenue situation occures. Therefore, the additional parameter f_{add} for positive redispatch is chosen to achieve a cost shift above the power plants with the highest marginal costs. In the calculations performed this parameter is set to €300 per MWh. As these costs are only virtual, model-based costs that are assumed in order to create a realistic composition of congestion management measures for each timestep, they are not evaluated or used to assess measures.

Electricity storage systems and partial load behavior are not considered in the context of the congestion management run since these create considerable modeling challenges due to their time-coupling constraints.

In order to validate the model, historical congestion management data were compared with the results of an optimization run for 2012. The results of the investigations documented in /FFE-45 17/ show that the model can also identify the seven corridors with the highest historical congestion rates. Nevertheless, the total congestion management volume is 22 % below the historical data.

Many alternative approaches for determining congestion management volumes exist and are to be discussed in the following. One is an hourly comparison of power plant dispatch in the market and grid run. The advantage of this method is that no additional constraints are required. The disadvantage is that due to the lack of penalties for the redispatch and the usage of time-coupling constraints, a change in power plant operation due to grid congestion leads to several changes in the subsequent time steps without congestion. As a result, congestion management volumes can be significantly higher as necessarily needed. As another alternative, the use of virtual generation and consumption units at each grid node can be used to calculate the total congestion volume required. With this approach, however, no information is obtained about the shares of redispatch and curtailment. Further, the regionalization aspect is neglected, which becomes increasingly significant in the context of high vRES penetration and reduced installed conventional capacities. By considering ideally located units, this approach always provides a minimum of redispatch volumes as a result. Thus the results of the chosen approach can be classified in the medium range compared to other modelling approaches.

Apart from this, “virtual generation units” or “slack units” are included in the approach presented for other reason. They are taken into account model-endogenously to ensure security of supply. If, in the context of the market or redispatch run, not enough generation capacities are available to cover consumption or to provide positive redispatch, these capacities are deployed. This modeling feature to provide local security of supply is necessary since decarbonization scenarios are considered in the following. These are partly characterized by a sharp decrease in installed conventional capacities (e.g., nuclear and coal phase-out) and a simultaneous increase in electricity demand due to electrification of final energy consumption. In a grid analysis, it is of high interest at what times and to what extent the regional distribution of backup capacities is important. A positive modeling side-effect is that these units increase the solution space, and therefore computation time is being reduced.

3.2 Grid Data and Regionalization of Demand and Generation

Besides the mathematical formulation of the linearized load flow, two further components regarding the input data are of particular relevance to perform transmission grid calculations. First, grid data need to be processed. Second, electricity demand, RES, and power plants need to be assigned to specific extra high voltage grid nodes. This process is also called “regionalization”.

Grid Data Processing

The derivation of the PTDF approach in Chapter 3.1 shows that reactances and thermal limits are the decisive parameters for determining the resulting power flow of a line. Equation (8) is used to link an energy transaction with a resulting power flow. The power flow of a line is limited by the line parameter LTC, respectively, the maximum thermal capacity. For the grid data used in ISAaR, which are an aggregation of data from different transmission system operators and other platforms /Pub-02/, however, substantial deviations in the line parameters occur. In the data sets, not only different parameters for the same lines exist but also obviously implausible values for certain grid lines. In the grid simulations carried out, these data errors affect the plausibility of power flows and, thus, the quality of the results. The data sets also show that there is no uniformly applicable reactance value for all lines of one voltage level. This impedes the use of very few standard values. In the following, a summary of the grid data preprocessing steps, as documented in /FFE-45 17/, is given.

As outlined in Figure 8, the processing of the grid data is carried out in a multi-stage process, in the context of which the plausibility of technical parameters is checked, and parameters are adjusted if necessary.

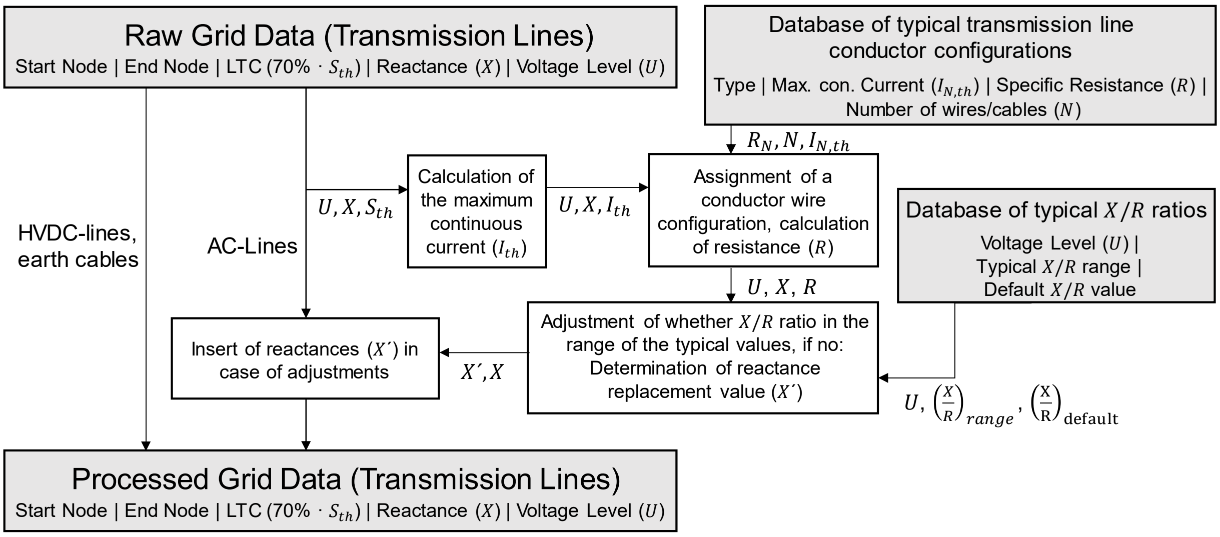


Figure 8: *Grid data processing, according to /FFE-45 17/*

First, the grid data set is divided into AC lines and the group of HVDC lines and earth cables. HVDC lines are not processed because their full capacity is utilizable in the model without considering the reactance value of these lines. The HVDC-utilization corresponds to an optimized transport model approach as applied in the market simulation. Earth cables are of minor importance and are also not processed. For the AC lines, equation (12) is taken to calculate the maximum continuous current I_{th} based on the maximal thermal capacity S_{th} und the voltage U.

$$I_{th} = \frac{\sqrt{3} \cdot U}{S_{th}}. \tag{12}$$

Based on this value, a matching conductor/wire-configuration is selected from the list of approved combinations. This configuration is based on the technical database in DIN EN 50182:2001(D) /SPVG-01 11/. After specific reactance and resistance have been determined, it is possible to identify non-plausible values by comparing them with the ranges of typical X/R ratios. For values outside of this ratio-band, default values are taken. Then, the non-plausible initial ones are replaced by the recalculated reactances. The data from /SPVG-01 11/, /KIES-01 01/ and /KUL-01 06/ are used for this purpose.

The distribution of the specific reactances of AC-lines is shown in Figure 9 in the raw data state. In the following two illustrations of the particular reactances are shown.

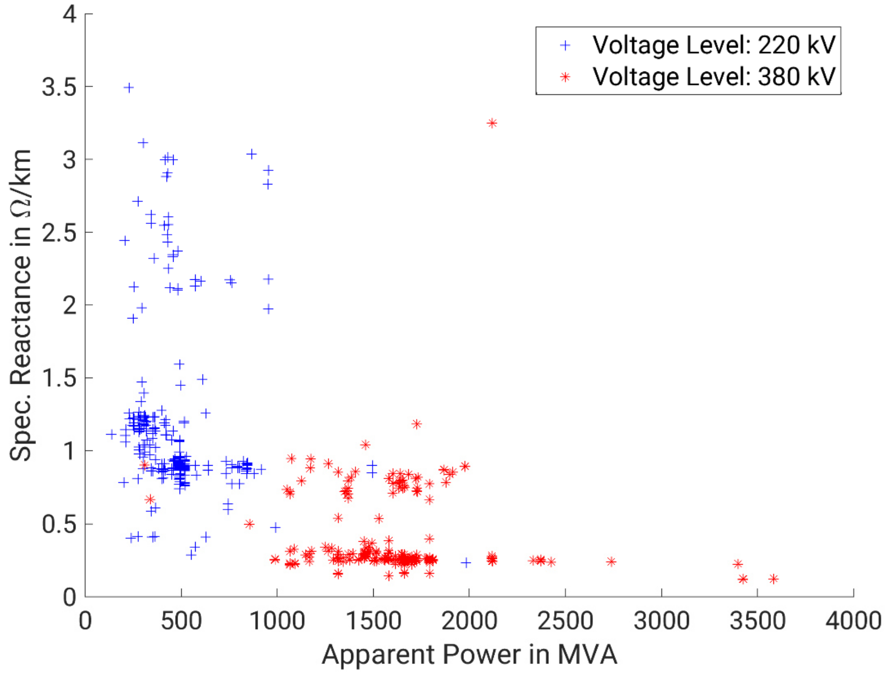


Figure 9: *Correlation of apparent power and reactance of the original, raw line data*

Figure 9 shows that many values lie within the same range, but systematic deviations occur, especially at the 380 kV level. A comparison with the corrected data set (Figure 10) reveals that the range of 380 kV dots at approx. 0.75 Ω/km have been adjusted completely.

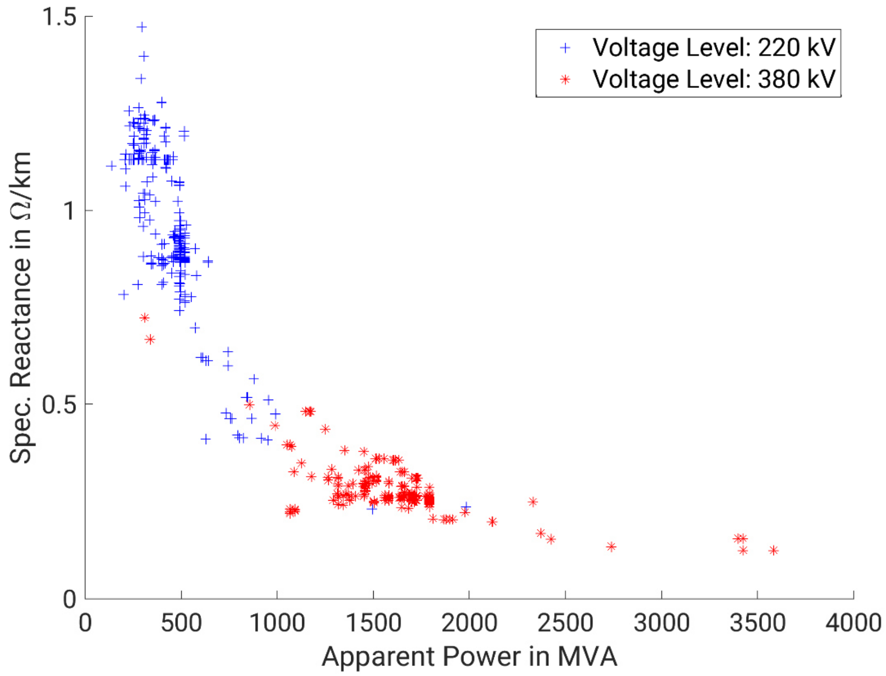


Figure 10: *Correlation of apparent power and reactance of the processed and corrected line data*

Regionalization of Demand and Generation

A large amount of energy system data, such as electricity generation and consumption, is available at municipal and postcode level. In order to obtain this information for energy system modeling at grid node resolution, municipalities and postcode areas are allocated to grid nodes based on a three-stage geographical assignment. A definite allocation of a municipality is made if there is a transmission grid node in this municipality. If there are several grid nodes in a municipality, a partial assignment is carried out. For this purpose, circular areas with a uniform radius are formed around all network nodes and intersected with the area of the municipality.

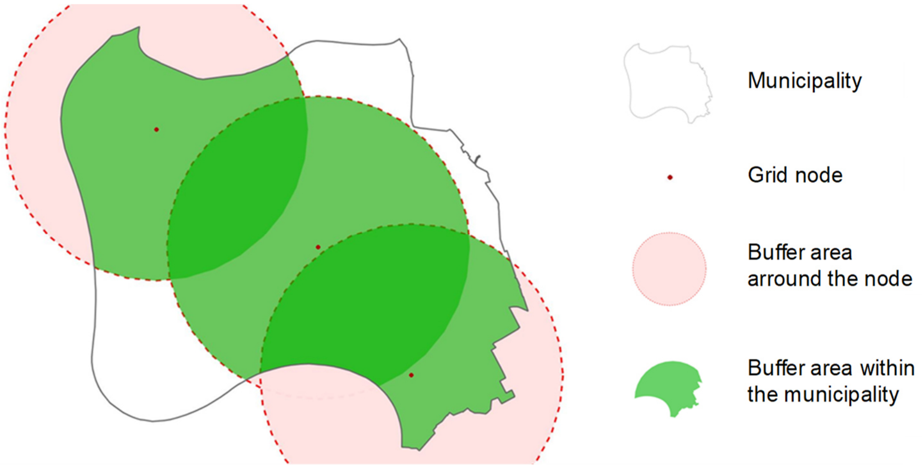


Figure 11: *Assignment procedure for several nodes within one municipality area*

Depending on the size of the circular areas within a municipality, the share of the grid nodes is determined. If there is no grid node in a municipality, the second step is to assign the shortest distance to the next grid node. However, further criteria must be fulfilled for the assignment: To take account of historically grown grid structures, an allocation only takes place if the municipality and the grid node are located in the same high-voltage grid operator control area. For this purpose, a mapping of system operator control areas for the high-voltage level is derived based on the geographical data from /ENET-01 15/ and the information of the EEG register /BNETZA-09 15/. The EEG register contains the information about the DSO and the voltage level of each EEG unit listed. For those municipalities that cannot be assigned to a grid node due to the distance radius, the third step is to assign the shortest distance to the next grid node and its location within the same federal state.

This regionalization approach does not take into account the network topologies of the underlying voltage levels and is, therefore, only a approximation. Nevertheless, it is necessary to weigh up and understand the inaccuracies that are to be accepted. A more detailed allocation of generation and consumption would only be consistent, if a significant improvement of the data situation for regionally resolved generation and demand profiles would be achieved.

4 Scenario Analyses

In the following, individual facets of abatement measures and their grid-loading or relieving effects are assessed using the methodology of scenario analyses. Chapter 4.1 summarizes the findings of the scenario analyses in /Pub-03/ and /Pub-04/. Chapter 4.2 is intended to provide a concluding outlook on the extent to which the scenarios considered will be relevant in a more holistic perspective. A decarbonization scenario is presented here, which represents a pathway until 2050, including a 95 % reduction in GHG-emissions.

4.1 Grid Optimizing Measures

The grid optimizing measures examined in this work can be devided in two types. There are "Grid-related Measures" that have an impact on the transmission system itself and are implemented exclusively to reduce grid congestion. "Abatement Measures", on the other hand, are focusing mainly on sector coupling, flexibilization, and decarbonization, but whose interaction with the transmission grid needs to be assessed at the same time.

In order to research these measures in comparison to a scenario without any measures taken, the following sequence of scenario calculations is performed:

Stage 1: A *market* and a *redispatch* optimization run of the "Standard Scenario" (no Grid-Optimizing measures included) are calculated.

Stage 2: *Market* and *redispatch* optimization runs including "Grid-related Measures" are performed. For each measure, several penetrations are set up and assessed through optimization runs. The regional distribution of measures depends on the results of Stage 1.

Stage 3: *Market, redispatch,* and *nodal-pricing* runs including "Decarbonization Measures" are evaluated. Depending on the measure, penetration stages are set up, too (e.g., total capacity of Power-to-Heat).

In the following, the different measures evaluated and the penetrations chosen are presented and described in detail. At some points reference is made to the stages mentioned above in order to provide orientation in the evaluation process.

Grid-related Measures

The most important, and at the same time trivial measure to relieve the transmission grid is grid expansion. Building new lines, both AC and DC, is always the alternative to more innovative actions, like

- Overhead Line Monitoring (Weather-related utilization of overhead lines)
- Congestion-oriented expansion of onshore wind turbines.

Overhead line monitoring is a promising measure, as it involves very low costs, and the existing assets are deployed more efficiently. In order to assess this measure, the route data of the line corridors of the extra-high voltage lines are taken and intersected with the weather data along these corridors. A thermodynamic model for the conductor cables is used to calculate the weather-dependent hourly transmission capacity, as described in /FFE-45 17/. In order to evaluate the efficiency of the measure, scenarios including different total lengths of monitored transmission lines are set up for the year 2030 in **Stage 2**. Since the monitoring of lines with particularly high capacity utilization promises a very high cost-benefit ratio, the most utilized lines of **Stage 1** are taken up first in the monitoring scenario.

Analogously, two alternative scenario computations are performed to assess the measure "Congestion-oriented expansion of wind turbines", which is researched in detail in /Pub-03/. Here, the calculations are based on **Stage 1**, too. The scenario run of the first stage determines curtailment volumes per grid node. In order to distribute the excess energy to less loaded grid regions, an alternative regionalization for wind turbines is implemented. Capacities are being redistributed primarily from north to south and south-west. The application of the congestion-oriented allocation approach results in more wind turbines that need to be installed to guarantee the same energy generation and thus the same share of vRES in consumption. The induced changes in congestion management volumes and the measures costs are compared with those of the other grid optimizing scenarios (**Stage 2**).

The two measures described above are compared to the grid expansion scenarios. In order to guarantee sufficient comparison stages, the lines with the highest loading are expanded gradually and iteratively based on the initial calculation in **Stage 1**. The amount of congestion management that can be avoided by these grid expansion scenarios is determined. In a post-optimization analysis, the total line length that would have to be built for each stage and the annuity of these costs are calculated. In contrast to works such as /IET-01 15/, no model-endogenous expansion of lines takes place, but a scenario-based iterative grid planning approach. As described in /Pub-02/, /Pub-03/ and in detail in /FFE-74 17/, the selection of lines to be upgraded is made based on the results of **Stage 1**. Therefore, the number of hours a specific line is fully loaded and the amount of energy transferred at full-load state are taken.

In order to provide a reference state of the energy system for the assessment of the measures in all stages, a scenario for the year 2030 is set up, which is described in detail in /Pub-02/ and /Pub-03/. It is assumed that the progress of grid expansion is delayed by five years. This means, that all transmission grid projects of the 2015 grid development plan /UENB-02 16/ until 2025 will be comissioned. All projects later then the comissioning year 2025 are not considered. This assumption reflects the current problems of grid expansion on the one hand, and it ensures that a situation is assessed in which grid congestion occurs on the other. The measures could not be evaluated if there would hardly be any congestion. A summary of the further scenario components is given in Table 1.

Table 1: *Scenario parameters "Standard" scenario in 2030*

Parameter	Value
CO_2 emission allowance price	30 €/t
Fuel prices of Oil Gas Hard Coal Lignite	 52 €/MWh 29 €/MWh 9.5 €/MWh 1.5 €/MWh
Installed fossil electricity capacity without back-up	59 GW
Installed electrical capacity of Wind Offshore Wind Onshore PV	 15 GW 59 GW 77 GW
Electricity demand incl. grid losses	499 TWh/a
Renewable share in demand without curtailment	61 %
Grid Development	German Grid Development Plan 2015, scenario B, 5 years delay /UENB-02 16/
European RES and power plant capacities	TYNDP 2016, Scenario "Vision 2" /ENTSOE-04 15/

Calculating realistic cross-border flows is a major challenge in energy system modeling. For this purpose, a sequential approach is applied. First, a European market optimization based on the NTC method is performed. Subsequently, a strongly simplified load flow calculation for Europe is carried out. The results of this calculation are line-specific cross-border flows, which are applied to the detailed optimization runs of the German and Austrian bidding zones (Stages 1 to 3). The description of the procedure itself and a discussion of the accuracy of the method can be found in /Pub-02/ and /FFE-74 17/.

In order to compare the measures considered for the year 2030, Figure 12 shows the specific annual costs for reducing a TWh of congestion management on the left axis and the absolute amount of reduced congestion management (red dots) on the right axis. The bars are sorted based on the reduced congestion management volume. Each bar/dot-combination represents a scenario run of **Stage 2**. The values ilustrated are differences compared to the reference run (**Stage 1**).

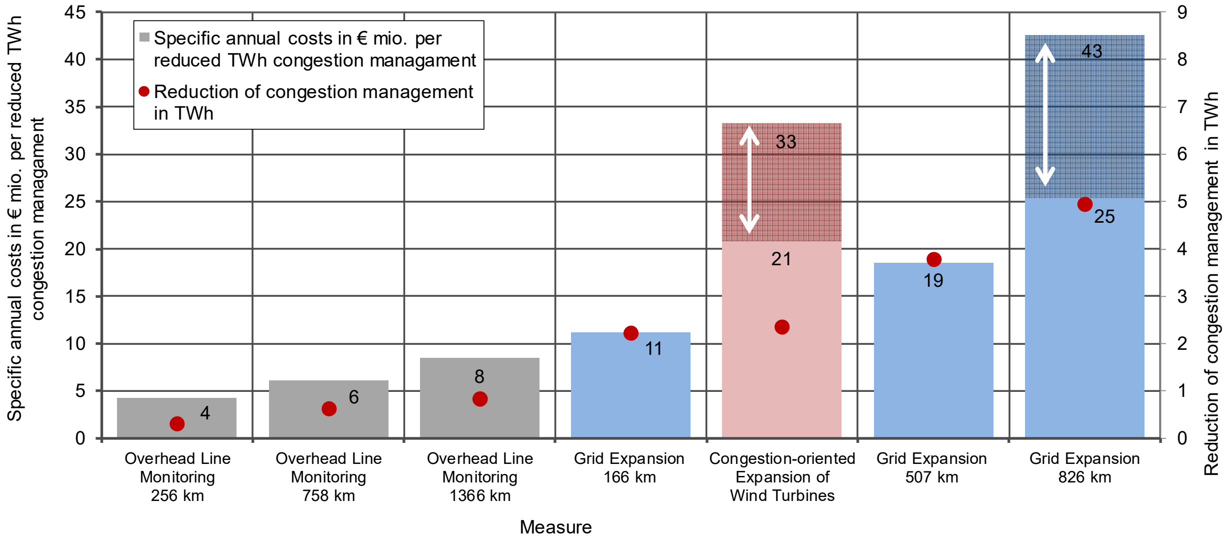


Figure 12: *Ranking of Grid Optimizing Measures in 2030, Scenario “Standard”, 61 % vRES share, annual totals (see /FFE-74 17/)*

Figure 12 indicates that across all measures, the specific costs rise as the overall congestion of the transmission system decreases. Starting on the left, it is noticeable that Overhead Line Monitoring is a very cost-efficient measure, albeit with limited reduction potential. The calculation run for the full monitoring of the German transmission grid is not shown here. If all 23 621 km of line length assessed would be monitored, this would lead to a reduction of approx. 1 TWh in congestion management. The specific costs would be far above the scale shown. In contrast to Overhead Line Monitoring, conventional grid expansion is significantly more expensive, but congestion management can also be avoided on a larger scale. The last stage of grid expansion spans over a range since this stage includes a DC line expansion, and the costs for the converter stations are very uncertain. An interesting comparison is the scenario of congestion-oriented wind expansion with the first stage of grid expansion. Both achieve a similar reduction in congestion management, but the specific costs are higher in the congestion-oriented wind expansion scenario due to lower yields of the redistributed wind turbines. As shown in /Pub-03/, depending on the assumed values for offshore wind, the costs vary between €21 million per TWh and €33 million per TWh. At this point, it should be outlined that, as highlighted in /Pub-03/, the investments for wind turbines or grid expansion are subject to considerable uncertainty. Based on the assumptions made, it can be concluded that the regionalization aspect is relevant and capable of reducing congestion. However, regarding the costs, this measure is not preferable for the scenario under consideration. A more robust finding is that a reduction of ~2.2 TWh in congestion management (red dot in Figure 12) can be achieved by a removal of 737 MW offshore capacity and 511 MW onshore capacity in combination with an addition of 1760 MW southern wind onshore capacity.

The sum of the congestion management volumes in 2030 in **Stage 1** in the scenario under consideration amounts to 9.6 TWh. In the thrid grid expansion scenario (826 km upgraded lines) of **Stage 2**, more than half of this congestion management volume can be reduced. Comparing the specific costs of the stages, it becomes apparent that each additional MWh of avoided congestion management becomes exponentially more expensive. Today's grid planning follows the principle of providing a congestion-free grid. Due to the peak curtailment of RES anticipated in the grid development plan and the smoothening effect of the hourly resolution simulation, this criterion has already been weakened in the current planning process. Nevertheless, there is no cost-benefit analysis as to whether the curtailment of vRES at times of low electricity wholesale prices is also an alternative to a 100 % integration of renewables through grid expansion. This transmission grid planning approach is appropriate in the medium term, given the major long term challenges posed by a climate protection scenario until 2050 (see Chapter 4.2). Since there is a delay in the German grid expansion compared to the development of wind turbines currently and in the foreseeable future, it can be assumed that every planned line will be worthwhile at the time of commissioning. If, in the long term, a target state of renewable penetration or emission reduction is within reach, this debate needs to be held.

In addition, across all grid-related analyses, it is found that the subject of grid expansion and grid congestion in the transmission grid is driven by the expansion of renewable energies, in particular, by wind turbines. This can be substantiated as follows: If curtailment has been carried out to avoid line overloading, this has mostly affected wind energy. In this context, the scenario of the congestion-oriented expansion of wind power can be further developed and thus extended to a redistribution scenario of all vRES technologies. A higher weighting on PV could have several advantages from a transmission grid perspective. Due to the more homogeneous and load-oriented distribution of PV generation capacities, the transmission grid load would be lower.

Chapter 4.2 discusses the extent to which this goes hand in hand with developments in the costs of renewable energies and what role PV and Wind will play in a climate protection scenario. A concluding comparison and assessment of these results in the overall context of the work is made in Chapter 5.

Abatement Measures

CO_2 abatement measures can take effect in a wide range of sectors in the energy system. Directly at the consumer, where, for example, individual mobility is being switched from cars with combustion engines to electric motors, also known as electrification. On the generation side, district heating can be supplied by electrode boilers, for instance. In this thesis, this is referred to as the coupling of energy carriers, as shown in /Pub-01/ and illustrated in Figure 3. All these measures have in common that they have an impact on the transmission grid in a highly coupled energy system. Also, some measures are capable of reducing grid congestion in addition to decarbonization and market-side flexibilization of the energy system. Due to this multi-use concept, a holistic evaluation is of high value. The selection of the measures analyzed on this basis consists of:

- Power-to-Heat in District Heating Networks
- Demand Response (DR) in Industry

In addition, measures are also analyzed which have an impact on the transmission system but do not provide for any mode of operation that would reduce congestion:

- Electrification of Final Energy Consumption
- Coal Phase-Out
- Expansion of vRES

In contrast to the grid-related measures presented in the previous section, these five abatement and flexibilization measures show a strong interplay with other components of the energy system. For example, the deployment of Power-to-Heat influences the dispatch of CHP plants in the same district heating network. From a modeling perspective, this means that the assessment cannot be carried out analogously to the grid-related measures since the intertemporal constraints prevent a redispatch calculation. Any grid-relieving deployment of Power-to-Heat units would lead to a rearrangement of the CHP plants' dispatch and thus to a deviation from the market schedule. This adjustment would be accounted as redispatch according to the modeling approach described in Chapter 3.1.

In order to overcome this issue, a Nodal-Pricing market design run is applied (**Stage 3**). As described in /Pub-02/, the researched flexibility option is dispatched cost-optimized, taking all transmission grid constraints into account. To draw conclusions from the comparison with a market dispatch, a market run without grid restrictions, assuming a so-called "copper plate" within each bidding zone is carried out beforehand.

In the following, the grid-relieving effect of Power-to-Heat and Demand Response are evaluated first. Subsequently, the repercussions of combined decarbonization measures are analyzed.

Power-to-Heat

As a grid-optimizing measure, Power-to-Heat is advantageous in that the specific investments for such systems are relatively low. Power-to-Heat units are considered in the form of electrode-heating boilers or heating rods. This allows vRES-excess to be integrated in the grid without the units having to reach high full load hours. Hence, they are suitable for transmission grid relieving operation when installed at an appropriate location and, therefore, that is why this measure is evaluated in the first instance instead of all other Power-to-X technologies. In the context of decarbonization paths, as discussed in Chapter 4.2, this measure could be applied on a larger scale in the near future. A grid-oriented operation of Power-to-Heat is characterized by the pattern that power is drawn on the oversupplied side of congestion, and the power consumption on the undersupplied side is shifted to alternative hours. In contrast to other Power-to-X technologies, such as Power-to-Liquid, the choice of location depends on existing district heating networks. For this scenario run, it is assumed that the distribution of installed capacities is based on the annual district heating demand in the respective aggregated regions, according to /FFE-65 18/.

Two scenarios of installed Power-to-Heat capacities are applied in order to research the efficiency of Power-to-Heat for grid optimization. The low penetration scenario assumes a capacity of 9.1 GW, while the high penetration scenario consists of 21 GW of Power-to-Heat installed in 2030. All further scenario assumptions are as described in Table 1.

The results show that flexible Power-to-Heat units in southern German district heating networks, which "see" the zonal market electricity price, lead to increasing grid load at times of high renewable feed-in in the north. At these times, the grid-serving operation of the Nodal-Pricing run deviates from the Power-to-Heat dispatch based on uniform zonal pricing. Figure 13 illustrates the yearly energy withdrawn by Power-to-Heat units according to their aggregated location. The scenario shown is the low penetration scenario.

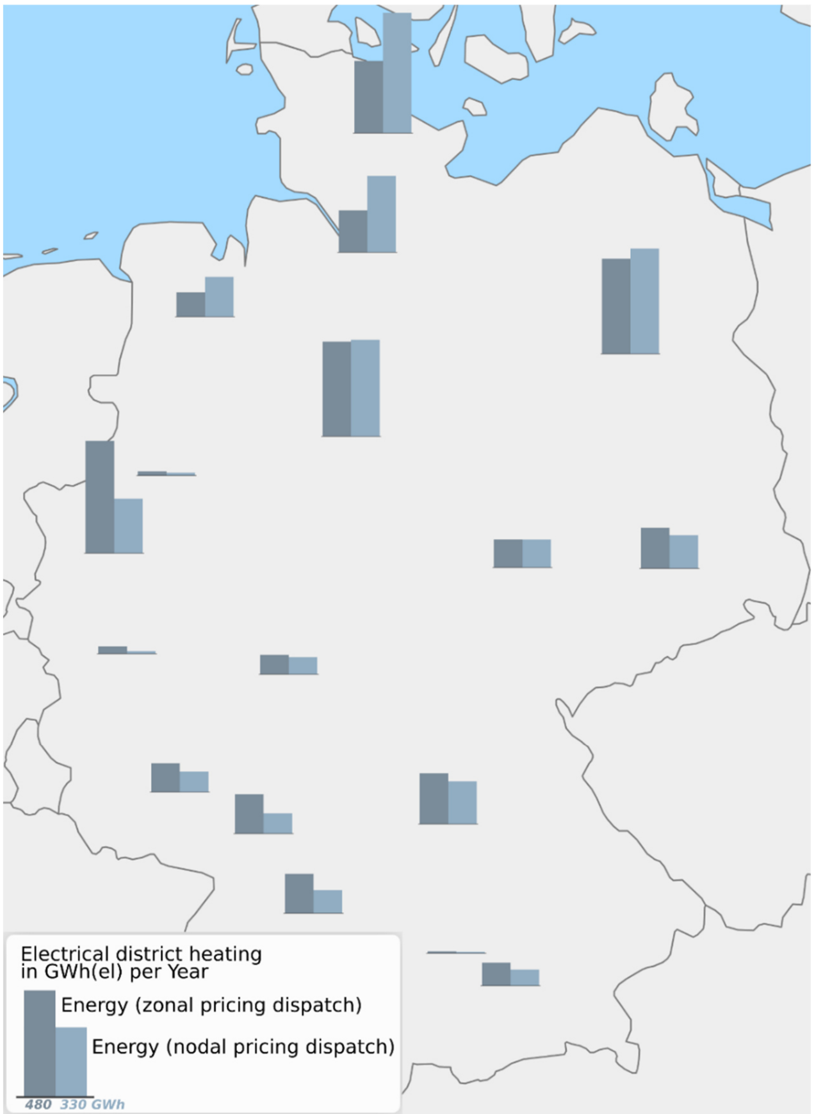


Figure 13: *Comparison of Power-to-Heat dispatch in zonal pricing and nodal pricing market design in 2030, scenario "Standard", based on /FFE-65 18/*

Figure 13 indicates that, depending on the location of the heating units, grid-optimized dispatch would mean higher electricity consumption in north and east, and lower consumption in the west and south. The height of the bars implies that although the grid-oriented dispatch differs from the market dispatch, this is not the case for every hour of the year.

Through this scenario analysis, a differentiated view on sector coupling in relation to the transmission grid is gained. First, it is evident that an increase in electricity demand also increases the grid load. The transmission system suffers from the systemic disadvantage that a flexible, price-sensitive load, as in Power-to-Heat, consumes more electricity at low prices. At these times, congestion management measures are already more common in these times and this correlation will become even clearer in the future. This can be explained by the increasing centralization of energy generation in the north due to the expansion of wind on- and offshore capacities. Since district heating demand has a strong seasonal profile peaking in winter and wind generation also has the highest yields in the colder half of the year, the profiles show an increased correlation. However, as the regional component of Power-to-Heat electricity consumption is linked to district heating demand, the capacities are distributed among the large district heating networks, which are also located in the west and south of Germany. This indicates that the regulatory framework for grid-compatible operation in today's market design is inadequate if Power-to-Heat penetration rises. In the high penetration scenario, the difference between nodal pricing and zonal market design dispatch increases compared to the low penetration scenario. The following can be derived as advice to the regulator: Regulatory measures are to be taken to ensure the grid and system compatibility of Power-to-Heat expansion and operation if the following points are met:

- Frequent transmission grid congestions due to delayed grid expansion
- High, yield-oriented wind capacity expansion causing grid congestion
- High installed Power-to-Heat capacities increasing the transmission task of the grid

In Chapter 5.2, the available regulatory measures are discussed in more detail and examined in the context of decarbonization pathways.

Demand-Response
The analysis in /Pub-02/ shows that, compared to Power-to-Heat, Demand-Response has only a limited impact on grid congestion. This is due to the “unfavorable spatial arrangement and the restricted shift potential of Demand-Response” /Pub-02/. In 2030 a capacity of 2.2 GW in energy-intensive industrial processes and 1.6 GW in cross-sectional technologies are assumed to be available for flexible, system-serving operation. Nevertheless, this flexibility option leads to a system cost-reducing behavior. The cost reduction compared to a system without demand response flexibility results from improved integration of vRES and load smoothing. However, no considerable grid-relieving effect has been observed.

Combined decarbonization measures
The measures of electrification or the reduction of coal-fired power plant capacities have no or just a minor decarbonizing effect without a simultaneous acceleration of vRES expansion. Therefore, an isolated view on the individual measures is not appropriate. Merely the expansion of renewable energies as a decarbonization measure is effective in itself. Since this measure is already being evaluated extensively within the scope of the grid development plans, the combination with electrification and phasing out coal is under-researched and the focus of this investigation. High grid loading and secured generation capacity shortfalls are intentionally created in order to investigate and understand system effects in temporal and spatial resolution. At this stage, an evaluation of the emissions reduction of these measures is not carried out. For this purpose, reference is made to /FFE-69 19/ and Chapter 4.2.

In two scenario studies, the impacts of combined decarbonization strategies for the year 2030 are analyzed exemplarily. In "System effects of high demand-side electrification rates - A scenario analysis for Germany in 2030" /GUM-01 18/, the final energy consumption sectors are analyzed in detail and electrification potentials as well as sector characteristics are researched. Based on /GUM-01 18/ further investigations concerning additional measures and system effects are carried out in /Pub-04/. Two deep electrification scenarios are set up in comparison to the standard reference scenario described above. The development of the scenarios does not follow a bottom-up approach as described in Chapter 4.2, but rather a constructed "what-if" analysis. The first electrification scenario was formed under the premise that the share of renewables in total electricity consumption remains constant at 61 % while the electricity demand due to electrification increases. The second scenario is based on the assumption that the additional electricity demand from electrification of 230 TWh in 2030 is covered by renewable energy sources by 100 %. This scenario thus results in a 75 % vRES share of consumption in 2030. In terms of installed capacity, this leads to 99 GW Wind Onshore and 146 GW PV in the first scenario for 2030 and 125 GW Wind Onshore and 190 GW PV in the second scenario.

The first subject of the analysis is the trend in annual peak load. From the perspective of conventional grid planning, the hour and magnitude of the highest electricity demand are of high relevance. The electrification of final energy consumption, in particular, due to the strong temperature dependence of many electrification measures, can lead to a significant increase in the annual maximum load. As shown in /FFE-69 19/, with each percent increase in annual electricity demand, the annual peak load increases by approximately two percent due to the high seasonality of the electrified applications.

The analysis of the times of congestion management measures being applied shows that these are no longer the times of the highest electricity demands that causes most congestion in the transmission grid, but a correlation with the generation peaks of wind turbines. As outlined in/Pub-04/, even in a deep electrification scenario, the times of high residual load do not pose a stress situation for the transmission grid. On the contrary, network utilisation is highest at very low residual loads and not necessarily when electricity consumption is highest. Since the national power plant park is fully deployed at these times of high demand, the generation situation is much more homogeneously distributed in regional terms than with very low residual loads.

From today’s perspective, the installed vRES capacities are a crucial factor. The analyses show that the periods of maximum generation from renewable energies will determine the dimensioning of the transmission grid. Both the historical expansion of wind turbines and the expansion to be expected in the future are characterized by an intense regional concentration and thus a centralization of energy generation in northern Germany. The resulting transport demand is growing in comparison to a system with conventional power plants whose density of capacity is more distributed over the whole national territory of Germany. Henceforth, the additional renewable electricity generation in the two electrification scenarios are causing an increase in congestion management measures (sum of congestion caused curtailment and pos./neg. redispatch) of 16.4 TWh (+170 %) in the first and 21.4 TWh (+220 %) in the second scenario compared to the reference scenario (see /Pub-04/). Regarding the high installed RES capacities, these sums are surprisingly low. There are two reasons for this: On the one hand, the electrification of transport and industrial applications reduces the periods of low residual loads, as these applications have a minor dependency on the daily profile. Electrification can, therefore, lead to improved local integration of renewables. On the other hand, due to the high volumes of renewable energy the scenarios show a high proportion of renewable curtailment in the electricity market simulation run. This refers to renewable generation that cannot be integrated cost-effectively despite European electricity exchange and flexible demand technologies. The resulting generation peak shaving behavior shows a positive effect on the transmission grid, too. The extent to which further future flexibility options will enable the integration of these energy quantities has not been part of the analysis. However, it should be noted that an operation and expansion of flexibility measures based on a zonal market design would lead to an increased transmission task.

In the next step, the critical situation of regional, grid-related supply shortfalls and market-side generation shortfalls are to be differentiated and researched for the 61 % vRES electrification scenario. Due to the electrification of demand without expanding the power plant fleet compared to the standard scenario, a capacity gap occurs. If the assumed 59 GW of conventional power plant capacities and the insignificant capacity of pumped hydro plants are not adequate to cover the residual load, so-called virtual generation units are dispatched in the model. These units are unspecified "virtual" plants, which are used in the calculation under high penalty costs as last option for load covering. The hypothesis was, that the regional distribution of the virtual units in the model could influence their effectivity in the redispatch run. In this context, the question is to be investigated as to what extent peak load power plants can achieve an additional grid-relief effect by appropriate localization. By analyzing the resulting operational profile, it can be determined whether future peak load power plants should be localized under consideration of grid restrictions or not. The boundary condition of the analysis is that in the reference scenario no operation of these virtual generation units is required in the market run as well as in the redispatch run. In order to provoke an even more significant deployment of the virtual generation units compared to the reference path, the generation capacities from lignite-fired power plants are reduced by 9 GW in 2030 in order to approximate a coal phase-out path.

First, Figure 14 shows the operation of these virtual generation units in the market calculation run for the two scenario described above at each hour depending on the residual load, including imports and exports. Imports are balanced as generation and exports as consumption. If the generated amount of energy is less than 10 MWh per hour, no dot is displayed.

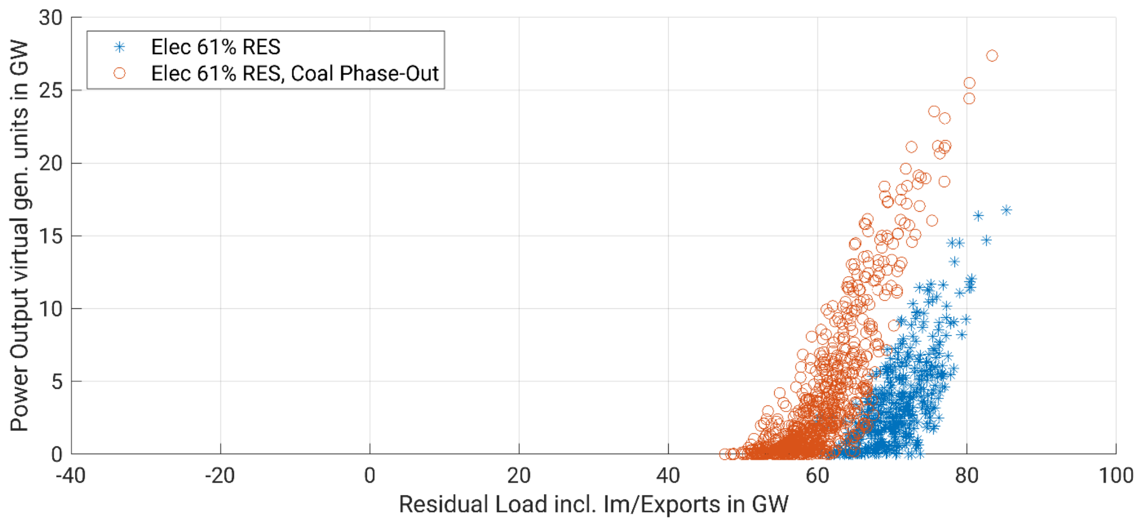


Figure 14: *Virtual Generation Unit Dispatch of the market run; Electrification scenarios 2030*

The findings in Figure 14 are as expected: On the one hand, back-up capacities are used more frequently and at higher peak capacities for the smaller power plant fleet in the coal phase-out scenario. On the other hand, the analysis shows that a higher residual load at low imports leads to an increased capacity gap. Regardless of the intended research of a coal phase-out scenario, it can be seen that even in the 61 % vRES scenario without capacity reduction, security of supply is not given. A capacity gap of 15 GW occurs and contrasts with the monitoring report of the Ministry of Economics (BMWi) /RBE-01 19/. In this report, a power plant fleet of around 60 GW is evaluated to be sufficient in terms of security of supply. However, the additional power demand due to the electrification necessary for decarbonization is not even included in this report. This contradiction reveals that electrification poses a major challenge to the supply infrastructure.

Despite the findings above, Figure 14 serves mainly as a comparison to the results of the redispatch run in Figure 15. This figure shows the deployment of virtual generation units if grid restrictions are taken into account.

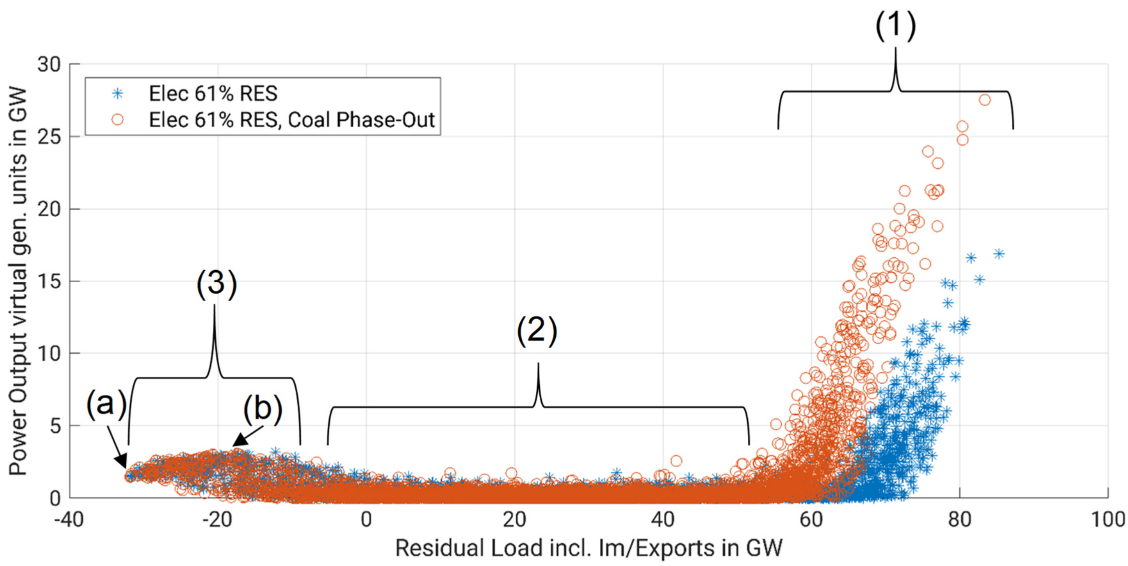


Figure 15: *Virtual Generation Unit Dispatch of the redispatch run*

Considering grid restrictions provides additional insights in comparison to the market simulation. For clarification, the marked sections are analyzed consecutively.

(1) The comparison with the market run shows that the dispatch at peak load times does not change when grid restrictions are taken into account. Even if the deployment calculated in the market run is distributed differently across the ~500 modeled grid nodes in Germany, as shown in /Pub-04/, the dispatch characteristic remains the same. In the following, these situations are referred to as “market-based generation shortfalls”.

(2) This wide range of low power output of virtual generation units is to be explained by poorly allocated electrification demand. Adding 230 TWh of electricity demand to the system and regionalizing it according to the approaches described in /GUM-01 18/ and /Pub-04/ is likely to allocate some of these loads to nodes with inadequately dimensioned transmission line capacities. This illustrates the fact that, regardless of the renewable generation situation and the overall German electricity demand, some grid nodes face a

constant supply shortage. This phenomenon has to be neglected because it is not a major structural problem of the energy system but an inadequacy of modeling.

(3) This section is of particular interest. Here, virtual generation units are required to transfer the market result to a grid-compatible generation situation. These are necessary as the transport task has risen significantly compared to the standard scenario without electrification. Thus, a positive redispatch is carried out south of the congestion. Only limited redispatch capacities are available in the south and west in the form of conventional power plants, which could prevent line overloading to a greater extent in these situations. Since expansion planning of power plants is not permitted in the modeling, the virtual generation units are deployed. In contrast to the situation described in (1), the lack of generation capacity exists only for a part of the bidding zone. There is also a difference to be made between the deployments marked in (a) and (b). In case (a), the lower demand for positive redispatch can be explained by higher imports compared to (b). The higher values of (b) can be substantiated by high exports to the south due to low electricity prices in the German price zone which additionally increases the transport task of the transmission grid and thus the positive redispatch demand. The comparison of the two scenarios shows that the coal exit path investigated does not exacerbate the situation of insufficient generation capacities for the positive redispatch. The assumed phase-out sequence, which initially includes the decommissioning of 9 GW lignite capacity, results in power plants regionally not suitable for a positive redispatch being taken out of the system first. Compared to the market-based capacity gap (1), the maximum power from virtual redispatch units (3) is significantly lower. However, this is only a snapshot that is strongly dependent on the scenario assumptions. The situation could be worsened, for example, by additional price-elastic southern consumers (Power-to-Heat). Further, an increase in cross-border trading capacities, especially at southern market zone borders, would also lead to a tightening of the effect. Table 2 shows a summary of the influencing factors and a qualitative assessment of the future development of these factors on the two dimensions of security of supply.

Table 2: *Classification of the two security of supply dimensions analyzed*

Categories	Market Generation Shortage	Local Supply Shortage
Section in Figure 15	**1**	**3 b**
Demand	**High demand** situation within the whole market zone, typically during winter (heating)	**Low demand** situation
	Future: Increasing quantity and amplitude of demand peaks due to **electrification,** especially of heating applications	*Future:* **Increase of demand** through **industrial electrification** (Especially in **South/West** Germany)
Generation	**Low RES** generation **Low** availability or reservoir level of **flexibility** options Full utilization of the conventional power plant fleet	**High RES** generation Low conventional availabilities and market-based dispatch **High** positive redispatch
	Future: Exacerbation, due to decreasing conventional capacities Expansion of vRES solely has a limited positive effect; Offshore wind is best suited due to high full load hours	*Future:* Exacerbation, due to decreasing conventional capacities in the south vRES expansion weighted on PV or homogenous allocated wind onshore has a relieving effect
Electricity Market	**High** electricity wholesale **prices**	**Low** electricity wholesale **prices**
Residual load and spatial distribution	High residual load, homogenous distribution	Negative in the north, low in the south/west of Germany
Transmission	**No/low congestion** within the bidding-zone Depending on the available conventional capacity abroad, cross border **capacities** are **fully** utilized for imports	**Very high congestion** within the bidding zone **High** traded **export** volumes, due to low prices, especially to the south
	Future: Mitigation by increasing cross-zonal trading capacities	*Future:* Grid expansion is crucial, delays lead to increasing congestion volumes Increasing southern exports, due to growing trading capacities
Potential solutions	Increase of conventional/secured capacities Load Shedding → Incentives set by the energy-only market (no price cap), timely visibility of incentives for new constructions is questionable	Acceleration of grid expansion Increase of southern power plant capacities → Incited by new local (capacity) markets or regulation (e.g. CHP subsidies) Reduction of southern trading capacities or deployment of Power-to-X in the north to relieve the transmission grid Regulatory measures for a more homogeneous distribution of renewables.

4.2 Climate Protection Scenario

The previous analyses considered the specific year 2030, made isolated assumptions about decarbonization measures, and primarily assessed the repercussions on the electricity sector and the electricity grid. Realistic snapshots were created and evaluated. A climate protection scenario is presented in this chapter to gain a better understanding of the entire transformation path and the measures necessary after 2030. It contains a path that aims to achieve a 95 % reduction in energy-related emissions by 2050 compared to 1990, thus complying with the 2°C target of the Paris Climate Change Agreement. A focus is placed on the energy supply sector. A detailed breakdown of the other consumption-oriented sectors and a comprehensive analysis can be found in /FFE-69 19/. All the basic principles of modeling, the balancing of emissions, and the system boundaries are described in Chapter 1.3 and /Pub-01/. Besides that, assumptions regarding costs and technical parameters are documented in Appendix A.

The scenario presented addresses energy-related CO_2 emissions. These are by far the most substantial part of all GHG emissions. As a precondition, it is assumed that these need to be reduced by 95 % in 2050. According to the IPCC analyses, cumulative emissions or in other words, the reduction path, are decisive. It is assumed that, starting in 2030 with a 55 % reduction, GHG emissions of one percent of the 1990 value have to be abated per year until 2050. This cumulative reduction path means that Germany's share of a 2 °C warming target is met. It is also assumed that the development of the non-modeled emissions (e.g., from fuel conversion, agriculture) can be extrapolated from the period from 1990 until 2018 to the following years. Under all these assumptions, the target corridor shown in Figure 16 is given and results in negative energy-related emissions of 23 Mio. Tons of CO_2 in 2050, as the non-modelled emissions with 84 Mio. Tons more than exhausts the available budget of 61 Mio. Tons.

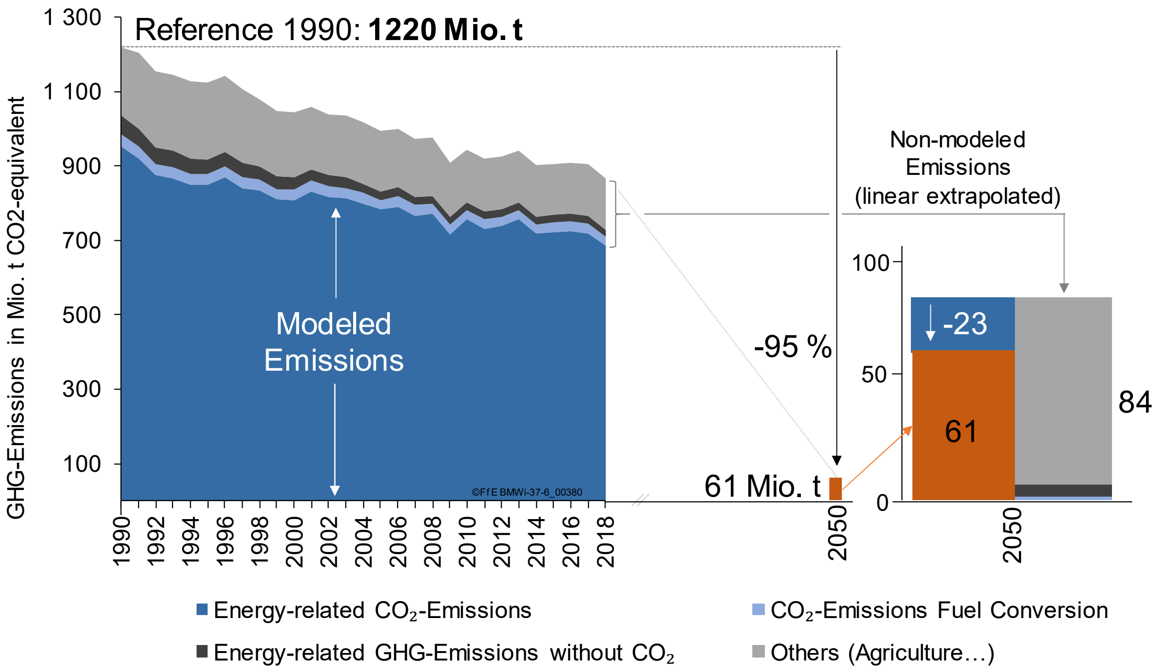


Figure 16: *Historical development of greenhouse gas emissions and the 2050 target of energy-related emissions in the climate protection scenario /FFE-69 19/*

Due to the conservative assumption regarding the non-modeled emissions, a particularly ambitious composition of measures needs to be chosen for the part under study. If significant progress is made in the other, non-modeled sectors, the energy systems presented for the years 2040 or 2045 may approach a target system.

In Chapter 2 it is described that the energy consumption of electricity, district heating, hydrogen, methane, and liquid hydrocarbons (e.g., petrol or kerosene) are quantified as bottom-up models of the final energy consumption (FEC) sectors. This information is relevant for an understanding of the climate protection scenario presented. Due to the two-stage evaluation approach the ISAaR optimization model does not calculate an overall cross-sector optimum, but only the optimal design of the supply sector in response to the given consumption and emissions of the FEC sectors. Nevertheless, the choice of abatement technologies in the consumption sectors is crucial for the design of the whole reduction path. Whether, for example, hydrogen mobility in private transport will make up the majority of traffic volume or the battery-electric alternative has a decisive impact. To counter this, an exploratory approach, as described below, was followed.

As illustrated in Figure 17 and as shown in the pre-analyses /FFE-69 19/, the ideal reduction path takes place in the interplay between electrification and the deployment of green fuels. If the overall level of GHG reduction is still at a lower level, a more cost-efficient reduction can be achieved through electrification measures. The closer one moves towards the reduction target, the more favorable it is to extend the path of decarbonization to Green Fuels. Therefore it can be assumed that extreme scenario designs that rely entirely on electrification or green fuels cannot be cost-effective.

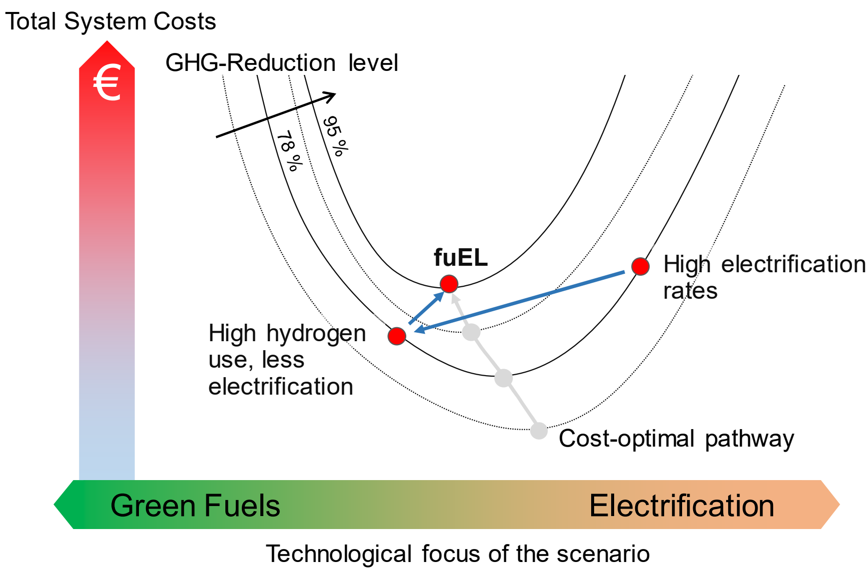


Figure 17: *Schematic visualization of the development process of the fuEL scenario focusing on Green Fuels and Electrification.*

Two scenarios with a reduction level of ~80% of GHG emissions compared to 1990 focusing on green fuels and electrification were calculated in advance (red dots in Figure 17). The 95 % reduction scenario fuEL (Green **fu**els and **EL**ectrification) is based on the resulting information regarding transformation speeds, efficient combinations of abatement measures in interplay with the energy industry, and the overall system costs.

An in-depth breakdown of the transformation path can be found in /FFE-69 19/. The resulting final energy consumption of the sectors is presented in the following in form of energy balances of individual energy carriers (Figure 21 until Figure 27). First, however, a look at the emissions of the trajectory is taken.

As described in Chapter 2, the emissions of a reference run (Start scenario) can be transferred as upper limit ("cap") for subsequent optimization runs. In the context of the climate protection scenario, the emissions of the neighboring European countries are extracted from the reference scenario described in /Pub-01/ and set as an upper limit for each year and each country. Thus, the model allows the neighbouring European countries flexibility for electricity exchange, but prevents a shift of emissions from the German region under consideration.

For Germany, the upper emission limit of the energy industry results from the reduction path minus the components directly emitted in the exogenously modeled final energy sectors shown in Figure 18. The final energy sectors considered are industry, domestic, SME (small and medium-sized enterprises) and transport. The emissions from the supply of electricity and district heating is assigned to the energy industry and is not part of this diagram.

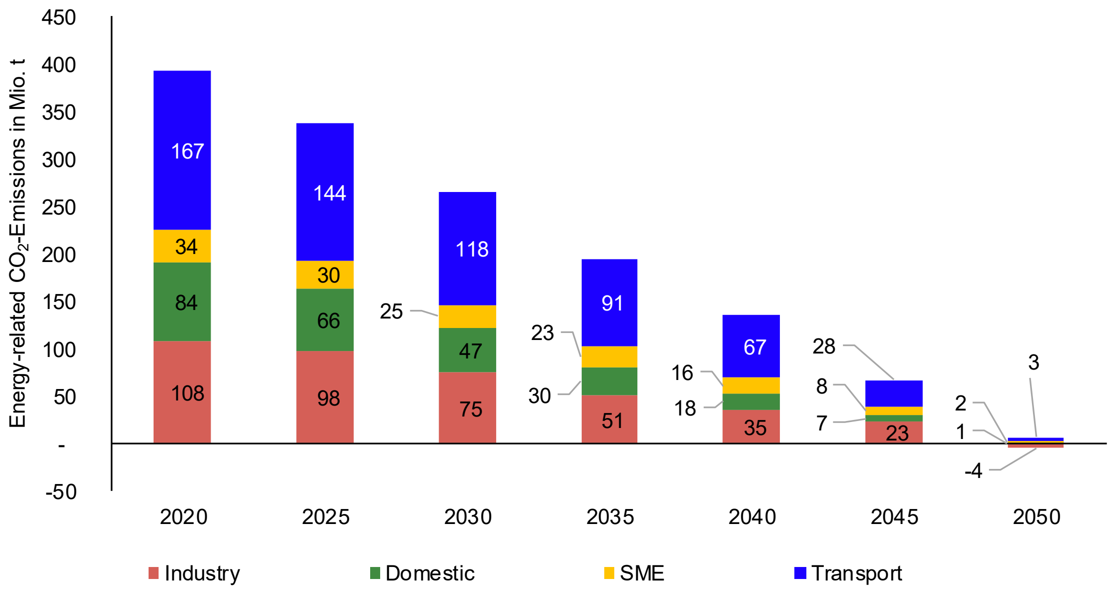
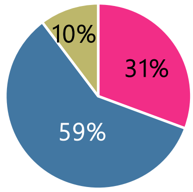
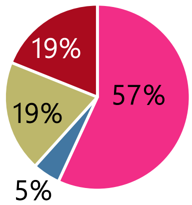
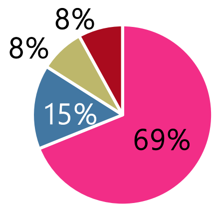
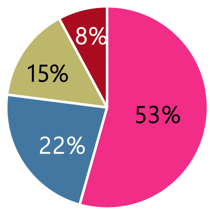


Figure 18: *Energy-related direct emissions of the modeled FEC sectors in the climate protection scenario fuEL*

The remaining emissions of the energy industry can be used to supply the modeled energy carriers of the FEC until the upper limit “cap” is reached. Due to the non-existing political targets regarding emission reduction for Germany until 2030, there is no cap applied for the years from 2020 until 2029. Negative emissions, as shown in the industrial sector in 2050, arise due to less fired biomass compared to the reference scenario. A detailed description of the biomass emissions accounting can be found in /FFE-69 19/.

The emission reduction in the FEC sectors illustrated in Figure 18 occurs as a result of measures being implemented from 2021 on. Conventional heating systems are replaced by heat pumps, and battery electric vehicles are increasingly being manufactured instead of conventional cars. The previous analyses have shown that this early start of the transformation path is inevitable, as some low-emission technologies are already economically viable today. In addition, the transformation needs to be started earlier, as some sectors have particularly long operating useful lifes. If the transition is not started in time, there is a risk that a technolgy needs to be replaced before the end of its useful life in order to achieve the emission targets. An example of this are the heating supply technologies in the domestic sector. Table 3 shows the key measures and characteristics of the FEC sectors in the climate protection scenario.

Table 3: *FEC sector characteristics in 2050, fuEL scenario /FFE-69 19/*

FEC sector	**Key Technologies**	**FEC**	**FEC in 2050 compared to 2020**
Transport	• Cars: 65 % BEV 11 % Fuel Cell • Semitrailer truck units 65 % Overhead contact line trucks 11 % Fuel Cell • Light commercial vehicles 88 % BEV • Aviation no significant changes		**-36%**
Domestic	• Renovation Rate: 1.1 %/a • Heating/Efficiency Technologies, share of all households: 72 % Heat pumps 47 % Heat recovery systems 13 % Building automation systems 15 % Solar thermal heating • Flexibilization of electrical heating systems		**-52%**
SME	• Heating, share of all units: 27 % Heat pumps 12 % district heating 23 % Solar thermal heating • Lighting system: 72 % LED		**-30%**
Industry	• Use of synthetic fuels in high-temperature process heat • Process route change: Conventional steel to H_2 and recycled steel • Almost complete electrification of low-temperature process heat, space heating, and hot water		**-36%**

■ Electricity ■ Fuels ■ Biomass ■ District Heating

The technologies shown in Table 3 describe the development of the consumption. The evolution of the generation to meet this demand is described in the following. Therefore, the energy balances of the modeled energy carriers and the corresponding expansion of generation, storage and conversion technologies are presented.

Electricity

The model-endogenous determined conventional power plant fleet shows a maximum of installed capacity of 82 GW in 2035. In general, the conventional capacities shown in Figure 19 are up to 19 GW above the installed capacities in the reference scenario “Start” analyzed in /Pub-01/ (69 GW in 2030 and 54 GW in 2050).

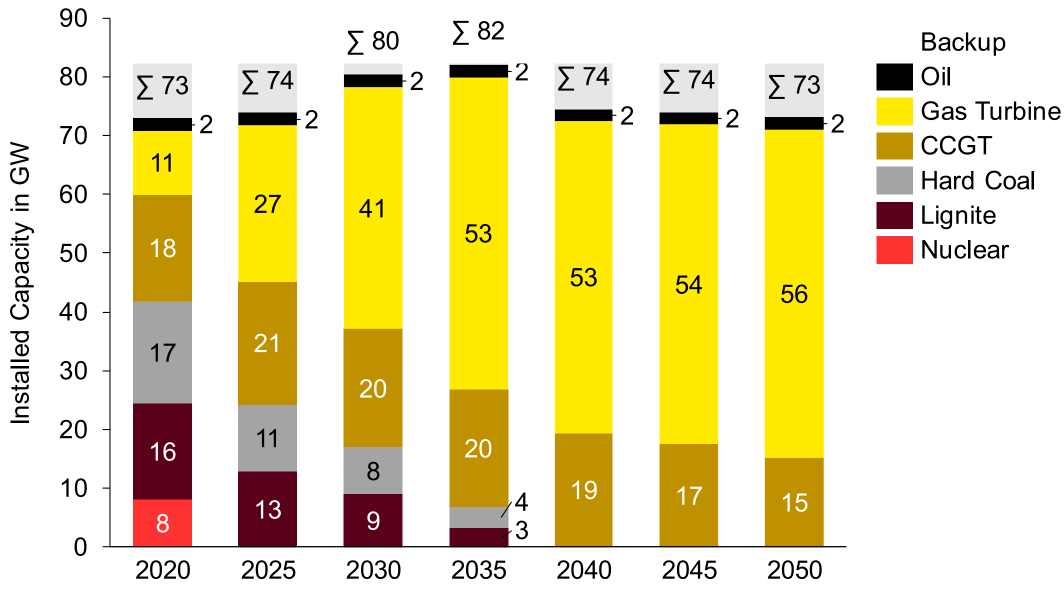


Figure 19: *Installed conventional power plant capacities in the fuEL scenario*

While reports on the security of supply for 2030 suggest a maximum installed capacity of 60 GW in 2030 in a trend scenario /RBE-01 19/, the level determined for this scenario is 20 GW higher. In addition, this analysis does not claim to be a security of supply study, as only one weather year and average power plant availabilities are assumed. In response to this, one has to keep in mind that the power plant fleet is to be extended by an unquantified capacity of reserve power plants (indicated by the gray bar in Figure 19)

Concerning the ambitious level of emissions reduction, however, the question has to be answered what capacity utilization a conventional power plant fleet with an almost constant installed capacity in a decarbonized energy system might have. This can be explained as follows: The full load hours of conventional power plants decrease from year to year. The operating characteristics of fossil generation are changing from high annual power generation volumes to an operation involving many load changes and, in later years, to a pure backup for phases of low renewable generation. At the latest after the decommissioning of the last coal plant in 2038, thermal plants no longer represent a relevant quantity in the overall emissions analysis, as the missing capacities are compensated by the addition of vRES and battery storage systems. A further reduction of the gas-fired power plant fleet in 2050 would occur if the prices for large battery storage systems fell faster and earlier than expected. Reference is made to Appendix A for the techno-economic parameters. The cost path assumed does not take into account any further, overall price decline that would correspond to an extrapolation of the historical development according to /BLOOM-02 19/. Without this, a large share of the gas-fired capacities are added in the optimization in the years 2030 and 2035 and will then be retained in the system until after 2050 following their typical service life. In these years, they primarily replace the declining power plant capacities from coal and are also needed to cover the increasing peak loads due to electrification measures. These plants only provide added value to the system for a short period and, therefore, the risk of stranded investments grows. In /FFE-69 19/ this issue is discussed concerning the modeling approach presented, and in /DIW-04 19/ a further perspective is opened up given limited emission budgets.

The analysis of the full load hours of thermal power plants shows that CHP plants can only serve their typical operational profile of high full load hours for a few years. After a slight increase due to the phase-out of nuclear energy from 2020 to 2025, full load hours keep falling constantly. It should be clearly emphasized that from 2045 onwards when the CO_2 cap allows the system to emit scarcely any emissions, the average full load hours for all types of conventional power plants fall below thousand hours per year.

In 2020, more than half of the electricity generated in Germany is derived from thermal power plants. Due the progress of electrification and the decommissioning of coal and nuclear power plants, demand needs to be covered partially by the construction of new generation units. The investment in these units is made at optimized total system costs. Figure 20 shows that from 2025 on a large share of this generation originates from growing vRES capacities.

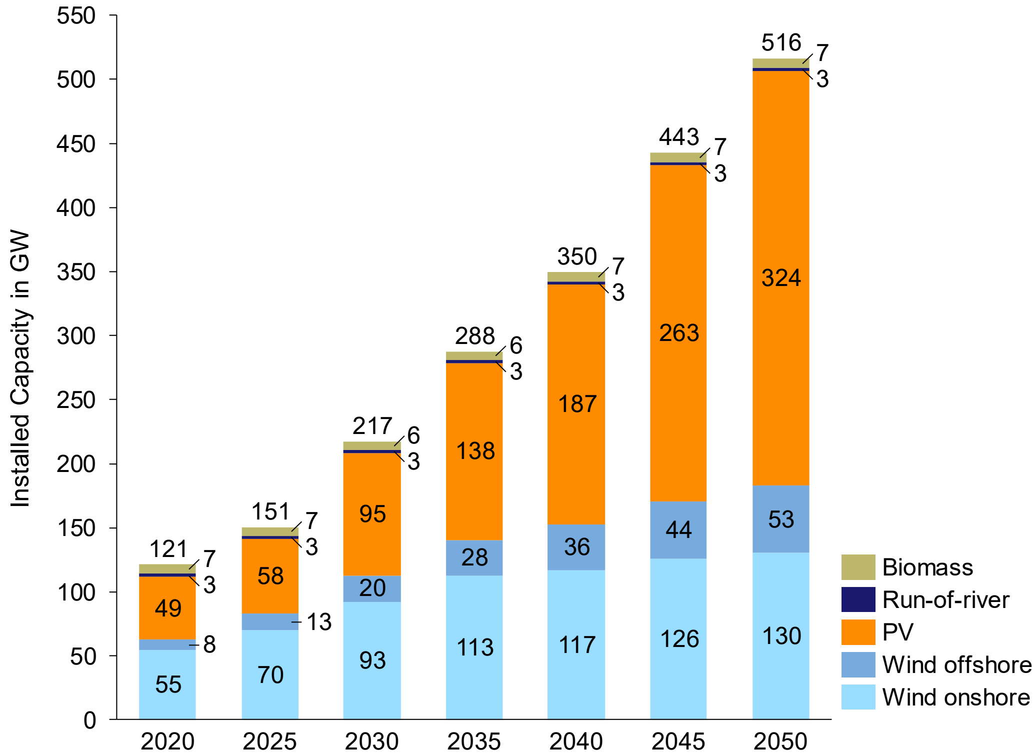


Figure 20: *Installed vRES capacities in the fuEL scenario*

Since wind has the cheapest levelized cost of electricity (LCOE) until 2030 (see Appendix A), the focus lies initially on wind onshore and offshore. From 2035 onwards, the cost decrease of PV continues, and a significant amount of PV is added to the cost-optimized system. However, due to the higher full load hours and the greater generation in the cold half of the year, wind potential is fully deployed in all years. The maximum growth momentum and available potential result from a geo-analysis on available sites and a limitation of the expansion rate based on historical data (see /FFE-69 19/). For ground-mounted photovoltaic systems, the maximum potential shown in /FFE-69 19/ is not reached. Under the influence of the upper emission limit, and the limited potential of wind turbine sites, a considerable increase of 137 GW PV capacities can be observed from 2040 until 2050 (see Figure 20).

For the integration of vRES, flexible technologies such as electricity to electricity storage systems are deployed. Besides the exogenously assumed capacities of pumped storage power plants, model endogenous large battery storage facilities with a capacity of up to 55.5 GWh are added until 2050 (see Table 4). Besides the day and night balancing of PV generation, these large-battery storage units reduce the demand for secured capacity.

Table 4: *Installed capacities of electricity storage systems, fuEL scenario*

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Large-Scale Battery Storage Systems	GW	0.6	0.7	1.9	2.9	6.6	9.9	24.7
	GWh	0.7	1.6	4.3	6.6	14.9	22.2	55.5
Pumped Hydro	GW	8.9	9.6	9.6	11.3	11.3	11.3	11.3

The energy balance for electricity in Figure 21 shows the structure of supply and demand: On the supply side (positive), the development of the electricity mix is illustrated. On the demand side (negative), the composition of electricity demand, consisting of the exogenously determined electricity consumption in the FEC sectors and the optimized dispatch of Power-to-X applications, is shown. The imported and exported electricity is illustrated in light gray color.

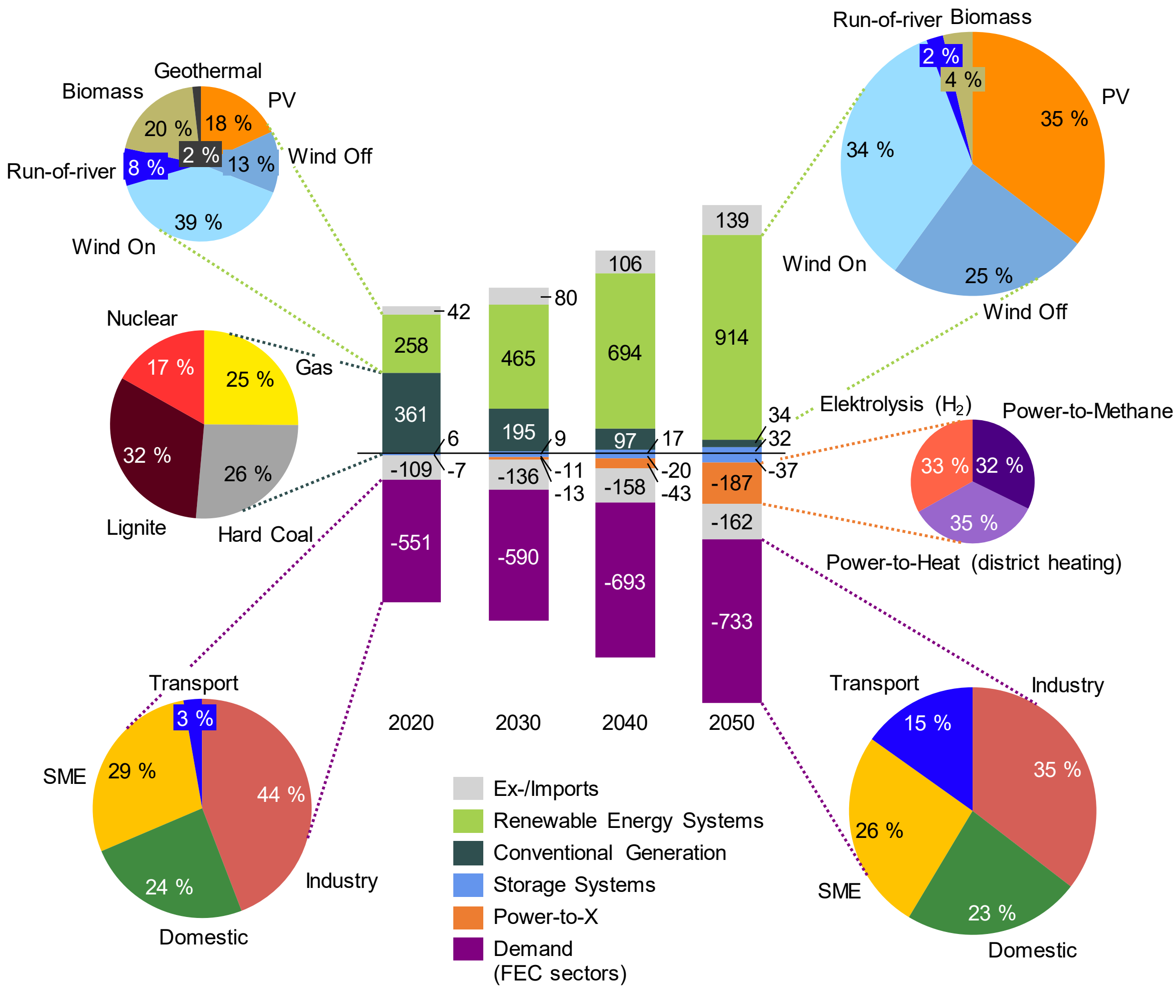


Figure 21: *Energy balance electricity, all values in TWh, fuEL scenario*

According to Figure 21, the development of the electricity system in the fuEL scenario can be divided into two phases: First, the decade of the 2020s is characterized primarily by a shift in the generation structure. Within ten years, the share RES in electricity generation increases from 42 % to 70 %. In 2030, 48 % of the conventional electricity generation and 14 % of the total domestic electricity generation originates from emission-intensive coal-fired power plants. While the trend towards vRES continues, a significant change in the electricity demand structure from 2030 onwards can be observed. On the one hand, electrification measures in the FEC sectors lead to a 33 % growth in the average load in 2050 compared to 2020. On the other hand, due to a 70 % increase in peak load from 91 GW in 2020 to 155 GW in 2050, it is apparent that this results from electrification of temperature-dependent heating applications. Besides that, a further large share of the absolute increase in electricity consumption is attributable to the transport sector.

Another category of demand includes Power-to-X technologies. Their expansion and dispatch is determined model-endogenously. From 2030 onwards, the penetration of these flexibilities grows. This primilary concerns the electrical generation of district heating through heat pumps and electrode boilers. As decarbonization progresses, the importance of electrolysis and, from 2045 onwards, in combination with methanation using a CO_2 source from industry processes grows. In 2050 a total of 187 TWh of annual electricity is converted to the coupled energy carriers district heating, hydrogen, and methane. To gain a better understanding of the Power-to-X operational characteristics, the composition of the electricity demand coverage in temporal resolution is shown in Figure 22. There, the power system flexibility resulting from storage technologies, cross-border flows, and sector-coupling technologies is illustrated in form of a stacked year duration curve. The order of the time steps is being set according to the residual load.

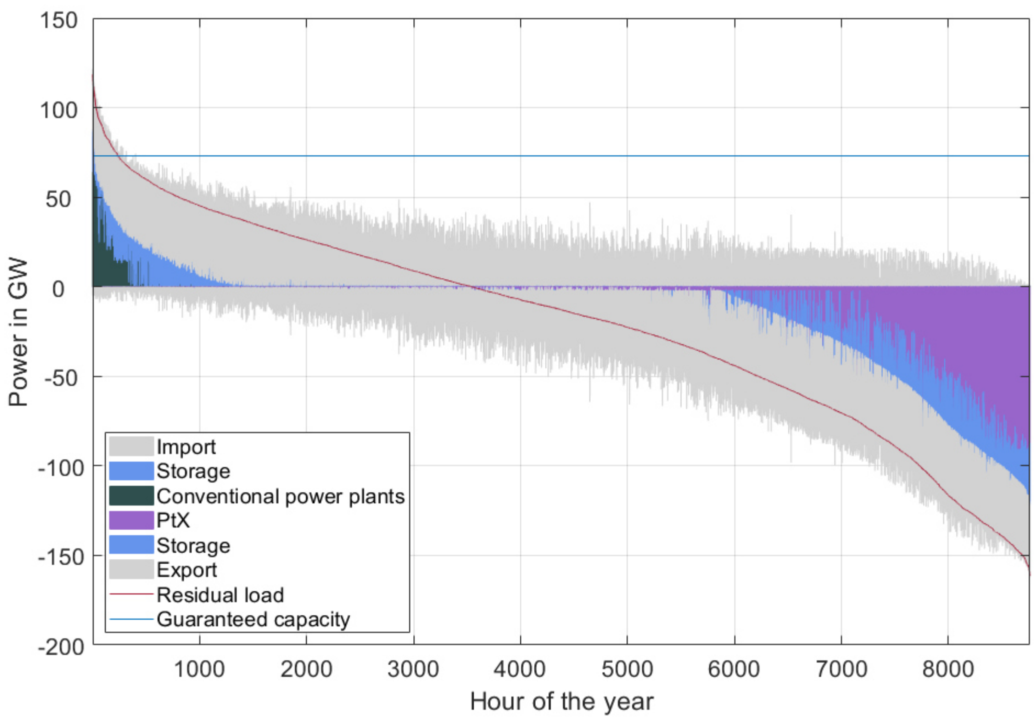


Figure 22: *Duration curve of residual load in the climate protection scenario in 2050*

Figure 22 shows that the residual load is negative in more than 5.300 hours per year in the scenario fuEL in 2050. At these hours, generation from vRES is greater than the hourly electricity demand. The flexible Power-to-X applications deployed to integrate inflexible renewable generation show full load hours of 2160 hours for electrolyzers, 3240 hours for methanation plants, 5950 hours for large-scale heat pumps, and 1230 hours for electrode boilers. Despite the high installed capacities of Power-to-X technologies, approx. 0.6 TWh in 2030, 9.2 TWh in 2040, and 17 TWh in 2050 of vRES power generation are curtailed. In 2050, 5.3 TWh of the market-based curtailment is accounted for by wind onshore, 4.6 TWh by wind offshore, and 7.1 TWh by PV.

The dispatch of Power-to-X technologies is reflected in the short-term hourly marginal costs of electricity generation, which can be equated with real-world electricity wholesale prices in a certain manner. The extent to which this method of price modeling differs from real electricity prices is discussed in /Pub-01/. Contrary to nowadays electricity price structure, these flexibility options are increasingly price-setting. Figure 23 shows the electricity prices for the year 2050 in the fuEL scenario as a duration curve.

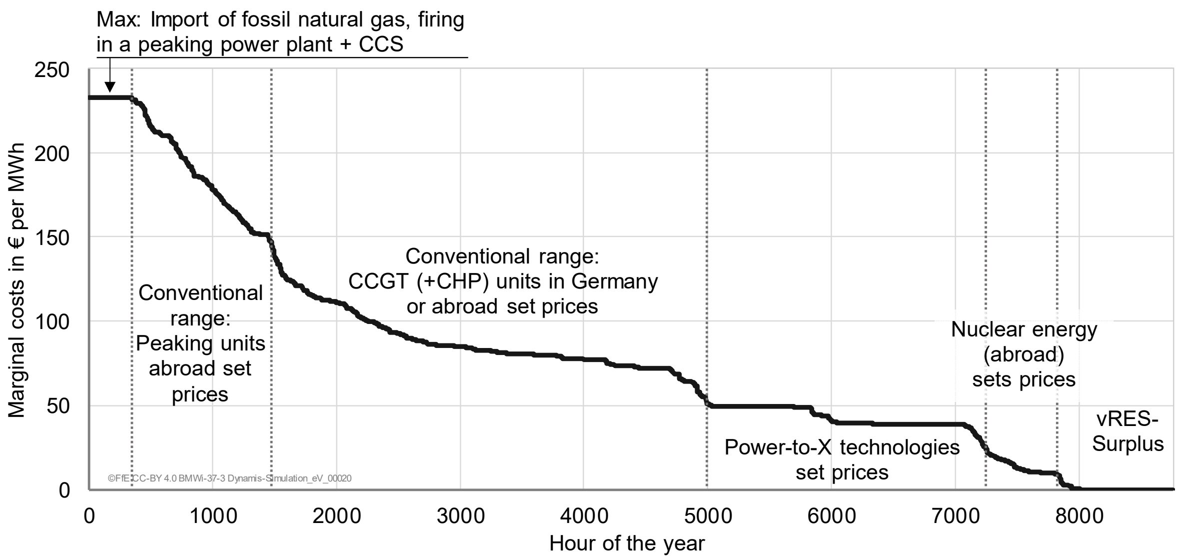


Figure 23: *Duration curve of short-term marginal electricity costs in the climate protection scenario for the year 2050*

The hourly electricity price structure is essential for future investments in power plants, renewable energies, flexibility options, Power-to-X technologies, and storage systems. This price curve defines whether investments are economically viable or prove to be a misinvestment due to a lack of profit margins. In conventional and merit-order based power markets, as described in /SCHWEP-01 88/, the hourly electricity price can be explained in principle by demand as a cut in supply merit-order. For a future power system, the question arises, how pricing works in a system with very high vRES penetration and a very small conventional generation share. While renewables today merely shift the intersection of demand with conventional generators, cf. /EPO-01 08/, they will increasingly interact with flexibility options in the future. The results in Figure 23 indicate that price formation in an almost zero-emission world does not correspond to binary behavior with high prices for conventional system safeguarding and zero prices for negative residual loads. Rather, a surprisingly continuous curve can be observed. In addition to the individually described areas of the curve, two trends should be highlighted: First, conventional generation, even if it accounts for a very small share of total generation in energy terms, is often the last opportunity to the utilized, emission-free technologies. According to the marginal cost approach, they are therefore often price-setting despite negligible production. Due to the progressing coupling of the European electricity markets, this power plant may increasingly be located abroad. Secondly, Power-to-X technologies are visible through marginal prices in the form that the alternative, conventional supply of the product "X" may set the electricity price as shadow price.

District Heating

Remarkably, Power-to-Heat in district heating networks achieves the earliest market penetration of all energy carrier coupling applications, and, from a system perspective, is already economically viable from 2025 on. As outlined in /Pub-01/, the coupling of district heating and electricity is promising, even with smaller proportions of renewables. These advantages are reflected in particularly high electrical district heating penetration rates in the fuEL scenario, as shown in Figure 24.

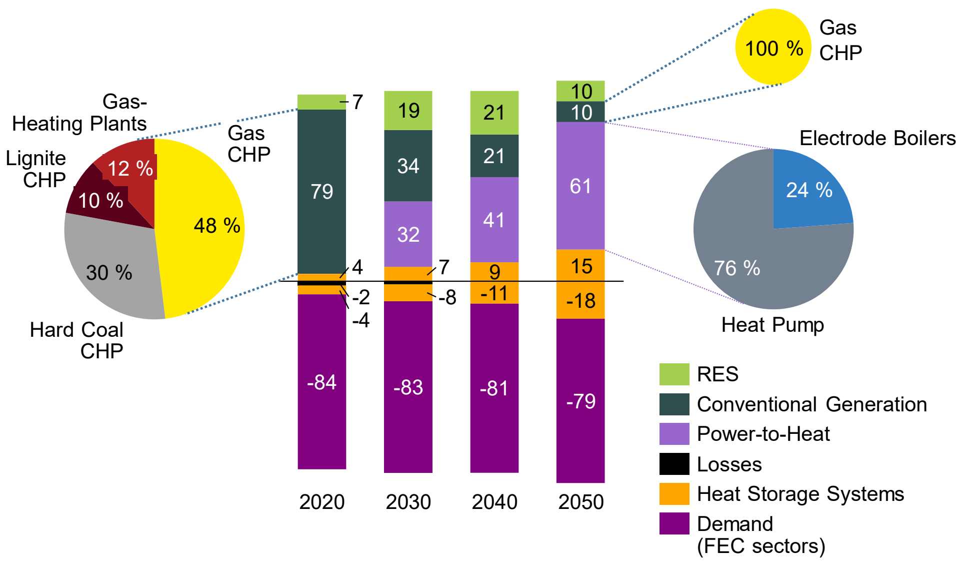


Figure 24: *Energy Balance District Heating, all values in TWh, fuEL scenario*

In interaction with CHP power plants and heat storage facilities, district heating supply is flexibilized, and renewable energies are integrated cost-efficiently using large-scale heat pumps (see Figure 24 and Table 5). In later years, vRES generation peaks can be integrated by electrode boilers at low specific costs. Due to the declining deployment of conventional generation systems, district heating will be generated almost completely electrical in 2050. At dark, windless, and cold times of the year, conventional power generation is ideally provided in the form of gas-fired CHP plants, as there is also a high demand for district heating at these times.

Table 5: *Installed capacities of Power-to-Heat technologies and thermal storage systems, fuEL scenario*

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Electrode Boilers	GW_{el}	1.7	2.4	3.6	4.2	4.7	13.8	14.1
Large-scale Heat Pumps	GW_{el}	0	1.3	1.5	1.7	1.8	2	2.1
Heating Storage Systems	GWh_{th}	39.4	60.2	80.6	93.7	103	231	233

It should be noted that in the years from 2025 to 2040, comprehensive utilization of biomass in the combined generation of electricity and district heating is forecasted. From 2045 onwards, part of this will be replaced completely by electrical heat generation. Due to the high abatement costs associated with the defossilization of the methane sector, this limited resource is used for biomass gasification in later years.

Hydrogen

The energy balance for hydrogen in Figure 25 shows that the marginal costs of electricity for synthetic hydrogen production will not be sufficiently low until 2040. Before that, as it is common practice today, the energy-related demand for hydrogen will be covered by steam reforming plants. The long-running market ramp-up of hydrogen steel and the deployment of hydrogen in long-haul freight transport leads to inefficiencies in earlier years, as the hydrogen demand is reformed from natural gas. However the demand from the FEC sectors in 2050 could be even higher than the 43 TWh determined as 8 TWh of hydrogen are added to the natural gas network.

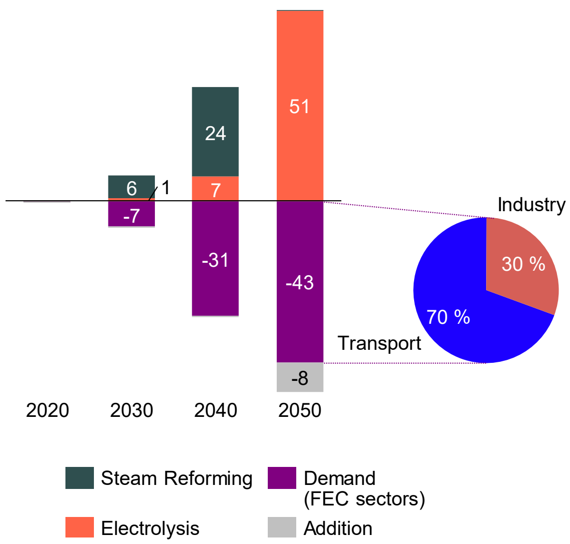


Figure 25: *Energy Balance Hydrogen, all values in TWh, fuEL scenario*

In the researched fuEL scenario, 15 % of the hydrogen is added to the natural gas grid ("Addition" in Figure 25) in 2050. A modeling contraint ensures that for each hour no more than 10 vol-% of hydrogen in relation to the total gas consumption can be added. The formulation of the hydrogen addition condition can be found in /Pub-01/.

To provide this amount of hydrogen, up to 28.8 GW of electrolyzers are added until 2050 (see Table 6). After the electrode boilers and large-scale heat pumps, the electrolyzer is the third most cost-efficient technology for the integration of vRES generation peaks.

Table 6: *Installed Capacities of Electrolyzers, fuEL Scenario*

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
PEM-Electrolyzer	GW_{el}	0.2	0.5	2.2	2.2	2.9	19	28.8

Methane

Due to the high electrification rates in the FEC sectors, methane consumption declines sharply. As shown in Figure 26, the overall gas demand including the energy industry decreases significantly, too. In total, demand falls by 74 % in 2050 compared to 2020. However, gas demand from the energy industry remains almost constant until 2045. Although conventional electricity and district heating generation are falling from year to year from an energetic perspective, gas-fired power plants replace coal-fired and nuclear power plants. Due to the change in the operating characteristics of conventional power plants towards back-up units, their operation is characterized by high peaks in cold and windless times. In the year 2050, their operating hours will decrease noticeably to reach the emission target. Besides that, residual load peaks are increasingly covered by large battery storage systems instead of conventional generation units.

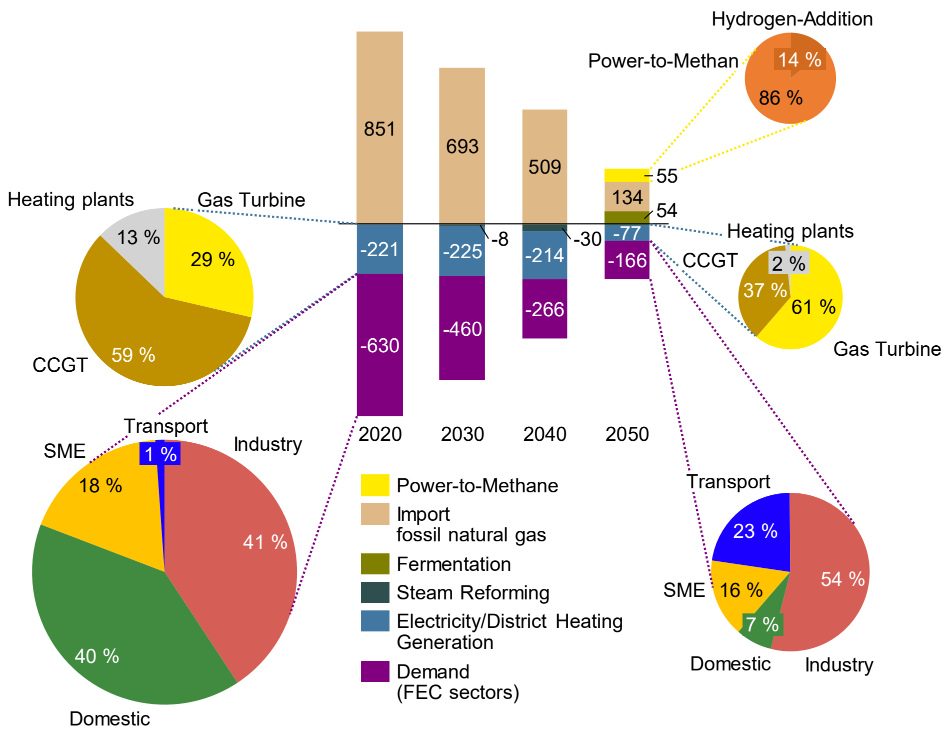


Figure 26: *Energy Balance Methane, all values in TWh, fuEL scenario*

On the supply side, as shown in Figure 26, there will only be a significant shift from nearly 100 % imports to a mix of domestic methanation, biomass gasification, hydrogen addition, and only a share of natural gas imports from 2045 to 2050.

In 2050, PEM-Electrolyzers, in combination with methanation units, which use the CO_2 from the cement industry, consisting of a capacity of 18.6 GW are needed to supply the synthetic methane (see Table 7).

Table 7: *Installed Capacities of Methane Supply, fuEL Scenario*

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
PEM-Electrolyzer with Methanation (Industrial CO_2 source)	GW_{el}	0	0.1	0.4	0.6	0.8	1.0	18.6
Biomass Gasification (Fermenter)	GW_{gas}	0	0	0	0	0	3	6.2

The rapid growth from 2045 to 2050 required to achieve the final percentages of emission reductions is extreme, especially for a technology that was hardly used before. A technology ramp-up would most likely have to take place over at least ten years and would have to be stimulated by subsidies in the preceding years.

Liquid Hydrocarbons

The energy carrier "liquid hydrocarbons" subsumes the fuels petrol, diesel, light heating oil, kerosene, and industrial petroleum products. Even if a large part of the emissions caused by these energy carriers can be reduced by electrification or conversion to gas-based technologies, part of the long-haul freight traffic and air traffic in 2050 remains dependent on liquid hydrocarbons. Figure 27 shows that the demand can be drastically reduced by switching to other energy carriers in the household and transport sectors. On the supply side, the entire demand is covered by imported Green Fuels in 2050. The conversion process to synthetic imports begins in 2045. In this year about half of the 209 TWh demand is met by emission-free imports.

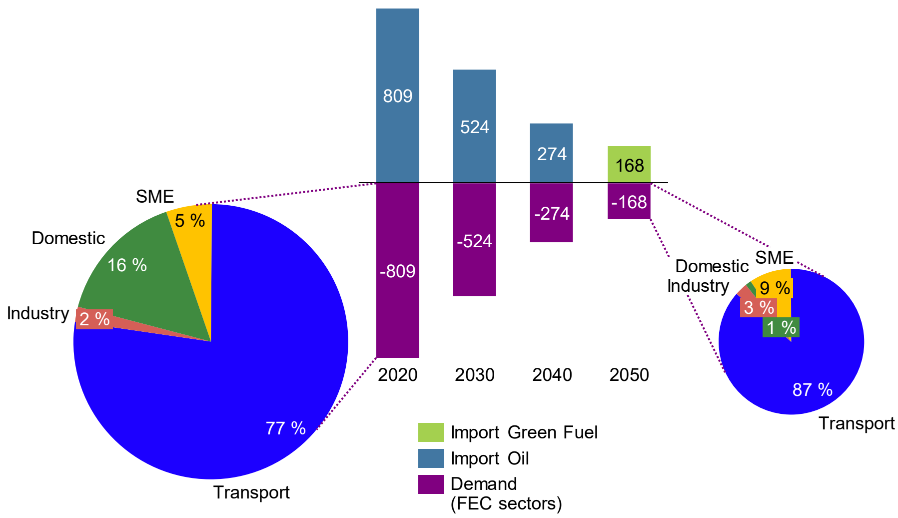


Figure 27: *Energy Balance liquid Hydrocarbons, all values in TWh, fuEL scenario*

Analogous to the technologies used in 2045 and 2050 for the supply of methane, the question must also be asked for liquid hydrocarbons whether a global market for green fuels will emerge within a few years, which will allow the import of up to 168 TWh in 2050.

Green Fuel Imports and CCS

At first glance, the import of 134 TWh of fossil natural gas in 2050 is questionable in a 95 %-reduction scenario. This can be explained by the deployment of CCS. The extraction of 53 million tonnes of CO_2 from the atmosphere per year represents the cost-optimal system configuration in 2050. In addition to the negative emissions of 23 million tonnes of CO_2 based on the relatively high emissions of the non-modeled components shown in Figure 18, there are 28 million tonnes of CO_2 emitted in the supply sector by gas-fired CHP plants and 2 million from the FEC sectors, which are compensated by CCS.

The cost assumptions for CCS and the difference to the abatement costs for an emission-free Green Fuel import compared to the fossil alternative are very sensitive regarding the path design in the years 2045 and 2050, as shown in Figure 28. In this qualitative illustration, the abatement costs per tonne of CO_2 avoided are shown on the ordinate. The overall level of emission reduction is shown on the abscissa. The path of the fuEL scenario is highlighted in gray. The Green Fuel measures, which are shaded in light gray, are to be distinguished from the domestic, alternative measures. These include, for example, the expansion of renewable energies and the reduction of conventional power generation (white background).

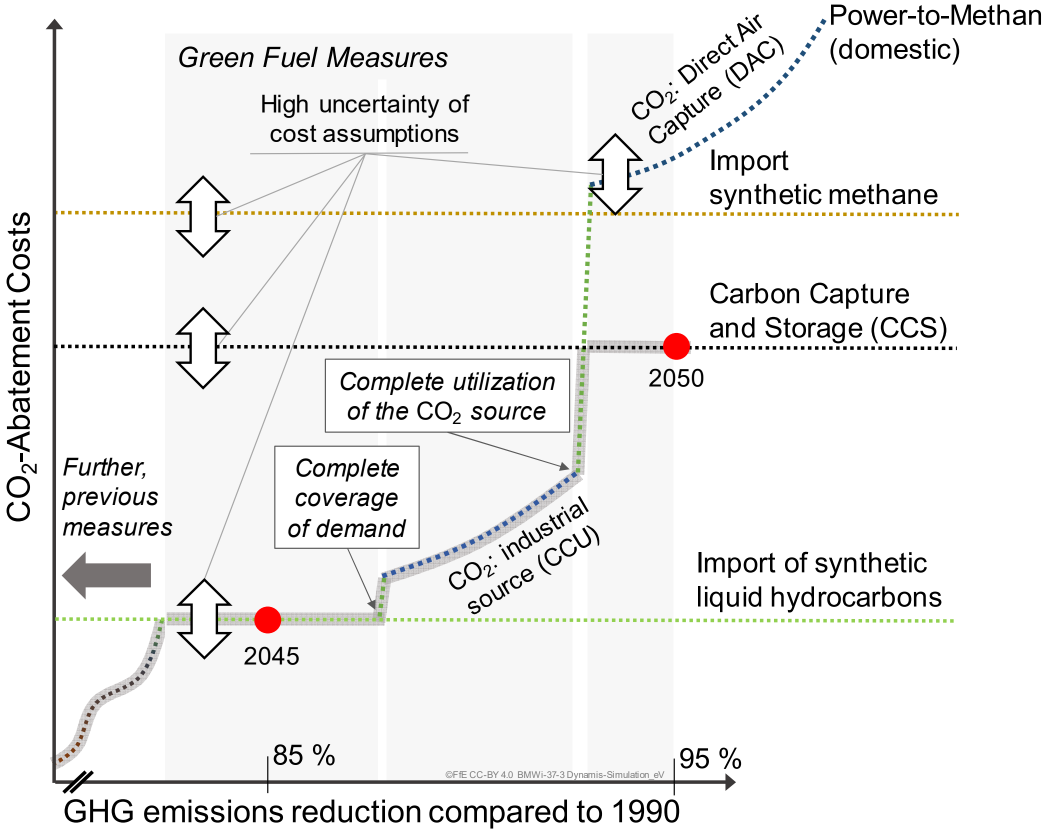


Figure 28: *CO_2-abatement costs of green fuel measures in relation to the GHG reduction level*

Even if the Green Fuel costs are very close, as under the assumptions of the fuEL scenario in 2050 with an average of €98.7 per MWh for liquid hydrocarbons and €101.1 per MWh for synthetic methane, this does not imply that their abatement costs are comparable from a system perspective. The combination of emission coefficient and the opportunity of fossil fuel import needs to be considered. As a consequence, in the case of methane, at a projected gas price of €28.1 per MWh, the additional costs for an emission-free alternative of the energy carrier (synthetic methane) are €73 per MWh. Taking the emission factor into account, the abatement costs for defossilizing the demand for natural gas through Green imports in the year 2050 amount to €368.9 per tonne CO_2. This is also the highest value compared to the other measures at constant abatement costs. For liquid hydrocarbons, this value is only €150 per tonne of CO_2 saved due to the lower difference between the prices of synthetic liquid hydrocarbons and their fossil counterpart, as well as a more favorable emission coefficient. It follows that instead of importing green gases, the CCS technology is applied at €241 per tonne (see Appendix A) in 2050. In the scenario at hand, the change between measures with constant levels is determined by the exogenously predetermined demand or available CO_2 source (methanation). These points are marked by the white boxes.

In /FFE-69 19/ the influence of full load hours, efficiencies, transport costs, and investment costs on the price level of Green Fuel imports are analyzed. It is concluded that there is a high degree of uncertainty regarding the resulting costs. In /CUNY-01 19/ it is shown that there is also a wide range of key parameters for the CCS technology in terms of storability and costs. Therefore, it should be pointed out that the sole consideration of the target year 2050 is not purposeful. A high degree of uncertainty can be observed, particularly in the area of technologies that must be taken into account for the reduction of the “last mile" emissions and that are needed as an emission sink. In the fuEL scenario, this concerns CCS, green fuel imports, and the domestic production of synthetic methane from industrial CO_2 separation. The analyses carried out show that a variety of assumptions on parameters of these technologies can massively influence the design of the resulting path for the final percentages of emission reduction.

5 Key Findings

The key findings of the methodological fundamentals and the scenario analyses are summarized in the following. Based on the scenario outcomes, their implications are discussed and critically assessed in the light of the modeling approach.

5.1 Methodology and Modeling

In this thesis a model framework for assessing the impact of mitigation measures on the energy sector has been developed and implemented. In addition to the modeling approaches for balancing energy carriers and the model-exogenous approach of calculating emission factors described in Chapter 1.3 and /Pub-01/, Chapter 3 and /Pub-02/ cover two further aspects: These are, on the one hand, the processing of transmission grid data and, on the other hand, the linearized representation of the AC load flow. A central finding in this process is that the data quality of the available network data represents a major challenge. The approach chosen for the german grid represents a balance between an unchecked, non-validated extraction of the data from the TSO grid models, and the exclusive use of standard values. The extent to which this approach overestimates or underestimates transmission capacities compared to other methods could be subject of further research. Due to the linearization of power flows, the assignment of loads to grid nodes, the neglection of the high, medium, and low voltage level, and the regionalization method of vRES, many assumptions, as well as inaccuracies, are naturally part of the model. Therefore, determining an appropriate and individual level of detail is a great challenge. Validation runs using historical congestion management data, as performed in /FFE-45 17/, are one way to quantify the degree of accuracy. This analysis shows a high precision in the regional identification of congested corridors. However, the model underestimates the annual volume of congestion management measures by ~20 %.

A central research question is to what extent sector-coupling measures interact with the transmission grid. Since many of these measures show a certain flexibility in their consumption characteristics, it is of high interest to analyze the benefits of using this flexibility to reduce grid congestion. It is shown that modeling a "nodal-pricing" market regime is a suitable approach to assess the grid-relieving effects of these measures. Here, all grid-related constraints are represented in the nodal electricity price. The findings in Chapter 4.1 and /FFE-65 18/ show that this approach can be used to evaluate measures, which, in addition to influencing zonal market price-setting, also determine grid congestion. This is not feasible when using the standard methodology of first modeling a market dispatch and simulating congestion management measures subsequently. This is due to the interdependencies of flexible Power-to-X technologies. The operational characteristics of electrical district heating units would lead to a deviation from the market schedule for other generation units in the time step under investigation and potentially all subsequent time steps. In the end, in a model result where sector-coupling elements can perform congestion management, it is difficult to analyze which deviation was a congestion management measure and which was only a consequence of this action. To overcome this problem, as outlined in Chapter 4.1, the comparison of the results of a nodal and zonal pricing market design allows conclusions regarding the discrepancies between a cost-optimal operation under and without consideration of grid congestion. The higher these discrepancies become, the more urgent regulatory intervention is needed.

By extending the system boundaries to further energy carriers and integrating the FEC sectors through bottom-up models, a cross-sectoral evaluation of CO_2 abatement measures has been enabled. The scenario development is based on an iterative, step-wise evaluation process regarding the penetration and transformation speeds of final energy consumption applications. Based on the calculated FEC demand of the sectors Transport, Industry, SME, and Domestic, the optimization model ISAaR is applied for cost-optimized deployment and expansion of all modeled units and technologies of the energy supply sector. For example, the decision whether synthetic fuels should be produced domestically with a corresponding vRES expansion or imported from other countries is made model-endogenously. This separate approach approximates a global optimum. In contrast, an integrated modeling of consumption and supply sectors would meet higher standards of consistency and holistic nature. In this case, analyses could be performed only at a lower level of detail under the given conditions regarding available data and computing resources. Nevertheless, the model-endogenous representation of measures in the consumption sectors is of particular interest for further research.

One advantage of the wide model scope is the ability to analyze a variety of dependencies between the different energy carriers of the energy system. In practical application, however, such a model framework is too extensive and time-consuming for some research questions. By using hourly emission factors, it is easy and fast to determine how, for example, an emission-saving charging concept for BEVs or a low emission industrial process operation mode could be sceduled. In order to facilitate a simplified ecological and economic evaluation of abatement measures based on energy system scenarios, the calculation methodology has been made available in /Pub-01/. Besides that, the resulting hourly marginal costs and emission factors of different energy carriers for the reference scenario "Start" (see /Pub-01/) and the decarbonization scenario "fuEL" (see Chapter 4.2) are uploaded to the FfE Open Data Platform /OPDA-01 19/. By providing the emission factor time series based on both calculation methods –"mix" and "marginal"– a simplified, but also differentiated assessment can be carried out by other researchers.

Nevertheless, an evaluation of abatement measures based solely on emission time series according to the mix method provides only shortened answers. And also the marginal power plant method discussed in /Pub-01/ and /FFE-22 18/ is only applicable to a limited extent. Besides the challenging and unstandardized calculation method of the marginal approach, /Pub-01/ also discusses that the results of the marginal approach deviate from the mix approach by up to four times. In the hourly analysis, the deviation is even higher. Furthermore, the marginal power plant method as applied in /FFE-22 18/ in contrast to the full marginal approach from /Pub-01/ poses the challenge that this concept can only be used to a limited extent in energy systems with high vRES penetration. As shown in Figure 23, prices increasingly result from the opportunity costs of flexibility options. Thus, if these prices are taken to determine marginal power plants using the conventional merit order, the emission factors are systematically set too high.

One recommendation that could be drawn from the analyses is that due to the limited validity of one individual approach, a mixture of several methods should be used if a complete energy system modeling is not feasible. Besides the emission factors according to the mix and marginal power plant method, suitable parameters could be hourly electricity prices, residual load, or curtailment time series, as discussed in /FFE-22 18/. However, the choice of a suitable parameter has to be made depending on the respective research question.

5.2 Scenario Results

A central finding of the analyses carried out is the great relevance of transmission grid expansion as an enabling factor for decarbonization. As shown in Table 3, Figure 21, and in other studies such as /DENA-01 18/ and /BCG-01 18/, the electrification of final energy applications and the supply of this electricity demand by renewable energies is a very cost-efficient strategy to achieve the climate targets from today's perspective. Assuming that the climate targets are met, it is shown in /FFE-69 19/ that a "wait and see" strategy by maintaining the consumption structure and replacing fossil imports with synthetic fuels over time would cost cumulatively (2020 till 2050) over €1 trillion more. To avoid these extraordinary costs, a significantly accelerated domestic expansion of renewable energies is necessary. With this focus on vRES as primary generation technology, the role of flexibility like Power-to-X and storage systems grows. When implementing these and other measures, it is of the utmost interest to understand their impact on the transmission system and the potential benefits of a grid-serving geographical deployment and gird-oriented operation of these measures, as follows.

One result of the analysis regarding renewable expansion is that wind power entails a high grid expansion demand. However, particularly for wind onshore, there is a potential for reducing grid expansion demand if fewer yield-optimized sites in the north are developed, and weak wind turbines are installed at more southern locations instead. From a cost perspective, such a measure is very difficult to assess, as neither grid expansion costs nor the onshore and offshore costs for wind are transparently available. In /Pub-03/ a simplified attempt is made to compare the costs of both approaches. It concludes that more grid expansion, in combination with yield-oriented wind development, results in slightly lower costs. Given the high degree of uncertainty regarding cost assumptions, it should nevertheless be pointed out that in this scenario a annual reduction of ~2.2 TWh (equals 23 %) of congestion management can be achieved by removal of ~1.2 GW northern off- and onshore capacities in combination with an addition of ~1.8 GW southern wind onshore capacities.

While the results of the grid analyses show in all cases that grid expansion is a reliable solution for the integration of vRES, the task of utilizing existing assets more efficiently grows in the light of increasing grid infrastructure costs. At this point, overhead line monitoring is of high interest. Overhead line monitoring was a mostly unknown measure at the beginning of the studies five years ago. Since among others the MONA project /FFE-74 17/ and the findings from /Pub-02/ have shown that this measure is very favorable, it has meanwhile been implemented by the TSOs /TENN-01 18/. In challenging times of grid operation, it provides an additional security margin. The results have shown that a share of up to 18 % of the total congestion management volume can be avoided at very low costs (€8 Mio. per TWh) in 2030. Nevertheless, it is also shown that the potential for the absolute reduction of grid congestion is small. This measure is, therefore, not applicable as a method to avoid grid expansion significantly in the planning stage.

The flexibilization of additional electricity demand resulting from electrification measures is a central building block of an efficient energy system transformation. In /FFE-04 16/, /GUM-01 18/, /Pub-04/, and /Pub-01/ it has been demonstrated that power-to-heat in district heating networks should be the first of all flexible Power-to-X technologies to be explored. This technology is essential in the long term, as can be seen in Chapter 4.2 and Figure 30. The main advantages are the more cost-effective storability of heat, the simple and cost-efficient integration due to central, existing structures, and the high flexibility in operation, which results from a combination of CHP, Power-to-Heat, and heat storage systems. The two technologies electrode boiler and large heat pumps also form an efficient combination for the integration of vRES. While large-scale heat pumps provide high-efficient district heating source, electrode-heating boilers allow a cost-efficient integration of high generation peaks from vRES. Depending on the scenario, installed capacities of 5 to 10 GW represent the cost-optimized dimensioning of the Power-to-Heat systems in Germany in 2030. The analyses carried out in Chapter 4.1, /Pub-02/ and /FFE-65 18/ suggest that while integrating these flexible consumers, the progress of grid expansion has to be taken into account, too. In high congestion situations, Power-to-Heat dispatch taking into account the transmission network topology deviates from a zonal pricing dispatch. A cost-optimized operation, therefore, involves a higher consumption of electrical energy in northern and eastern district heating networks. In western and southern Germany, on the other hand, less electricity is consumed. The various computed scenarios indicate the following correlations: If grid expansion is delayed, or the development of wind energy is accelerated excessively, or the penetration of Power-to-Heat plants in the south increases massively, then situations arise more frequently in which a positive redispatch in the west and south is necessary. Although market prices are low at that time, and the emission factor of electricity is low, a conventional power plant needs to run in order to supply the additional Power-to-Heat electricity through redispatch. The statements made here can be applied to flexible consumers and Power-to-X technologies in general, even if they have slightly different consumption profiles. For the geographical allocation of Power-to-X, it can be stated that regions with high generation excess and thus specifically in northern Germany should be chosen. Even in the case of regionally undifferentiated electricity prices, this ensures that the additional electricity consumption does not cause immense costs for expanding the grid infrastructure or for the realization of congestion management. However, for Power-to-X technologies in particular, regionalization depends on many other local factors, such as the feed-in infrastructure or the access to a CO_2-source in case of hydrocarbons.

From today's perspective, the integration of vRES is the decisive dimensioning factor for the future transmission grid. In grid planning, the nowadays premise is to provide a congestion-free network for the scenarios under consideration. As shown in Figure 12, grid expansion costs rise disproportionately to the level of dissolved congestion. Given the low market values of renewables at times of very high emission-free generation, a 100 % congestion-free grid at very high renewable penetration rates is not cost-efficient from a system perspective. The grid expansion demand would be enormous in such a scenario. Therefore, as illustrated in Figure 29, the decisive parameters for grid dimensioning need to change in tandem with the progress of energy system transformation.

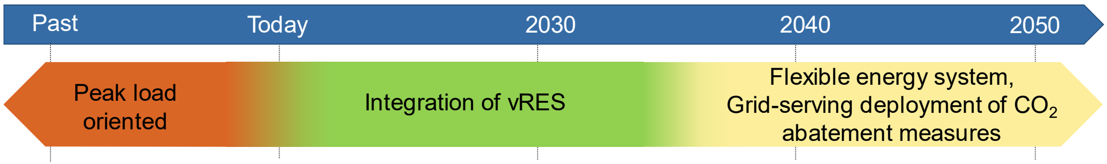


Figure 29: *Grid dimensioning in the context of the energy transition*

The process of flexibilization of the energy system cannot only be to benefit the electricity market. Instead, the electricity grid infrastructure must be kept in view in the context of a cost-efficient and holistic energy system development. The flexible on-site usage of generation excess through Power-to-X Technologies, storage systems, or the curtailment of vRES to relieve the transmission grid need to be taken into account for the planning of cost-efficient future grids. Due to the enormous potential, these flexibilization technologies are of particular significance: As shown in Figure 21, 197 TWh electricity are consumed by Power-to-X technologies in a decarbonization scenario in the year 2050. Around 35 TWh are stored in large-scale storage systems, and a part of future individual electricity consumers may potentially be flexibilized, too. This includes BEVs and domestic heat pumps, for example.

The analyses in Chapter 4.1 show that these abatement measures have a high impact on the transmission grid. In the context of analyzing a cost-efficient decarbonized energy system, the opportunities of a grid-oriented geographical expansion and congestion-reducing operation are to be realized. Regulatory adjustments are needed to achieve such an ideal state in the future. On the one hand, this may take the form of a revision of the market design in terms of nodal-pricing or a more selective design as local flexibility markets. A regulatory differentiation of the flexibility options, i.e., that their operation can be contracted by the TSO, would also be conceivable. Initial efforts have already been made, as can be seen in the Act on Power-to-Heat in the so-called “Grid Expansion Region” (§ 13(6a) EnWG). On the other hand, the design of the market, the future penetration of such flexible consumption technologies, and the regional distribution should be given greater consideration in the grid planning stage.

In principle, the future of market design and pricing needs to be debated. While historically, the electricity market has been characterized by flexible generation and rather inflexible demand, this will be reversed in the future. As can be seen in Figure 23, pricing in a decarbonized energy system is easily possible based on elastic demand technologies from a model point of view. The hypothesis that binary price behavior between renewables (0) and conventionals (1) will emerge, proved unfounded.

Assuming that taxation for electricity demand technologies will be reformed and that these technologies "see" the volatile electricity wholesale price better than under the current regulatory, they provide electricity prices well above zero if there is sufficient competition in the market. This applies even if no thermal power plants are in operation at these times. Such a market design and regulation would provide marketability of vRES without subsidies. Also, if a nodal-price system could potentially be more suitable to stimulate the spatial allocation of investments in a grid-compatible way, practice shows that existing nodal markets struggle just as hard to integrate small-scale renewables and flexibilities as zonal markets /NUD-01 18/. Particularly since investment incentives for flexible consumption or generation units can change sharply as a function of grid expansion in such market regimes. This leads to more considerable uncertainty in the highly regulated (e.g., grid planning) and less regulated (e.g., energy supply) areas. In the discourse on market (re)design, it is also important to note that purely national approaches may not be effective. Although, from today's perspective, the German electricity price zone has the most substantial volume in Europe, Figure 22 shows that cross-border electricity trading is of enormous importance. With the planned increase in trading capacities, the coupling to neighboring zones intensifies. Due to this progress, the overall welfare gains will increase, and renewables will be integrated more cost-efficiently. In addition, the CACM Regulation and its "Bidding Zone Review " are already addressing intensively that bidding zones should be aligned to structural congestions. Alternative measures are therefore necessary in order to guarantee Germany's politically motivated will to maintain an undivided bidding zone. Market-based congestion management in the form of locational flexibility markets is one of many conceivable solutions.

Whether these markets also offer sufficient incentives to expand conventional capacities for redispatch, must be critically questioned. As this local generation shortage is relevant in terms of security of supply, as shown in Table 2, a regulatory solution will probably also be sought here. The analysis in /Pub-04/ and Chapter 4.1 show, that in the case of a coal phase-out in combination with high electrification rates, up to 3 GW power plant capacities are needed in the south in order to transfer the market result into a transmission grid-compatible generation situation through redispatch and curtailment. The regulator recognized this issue, and the Act § 11(3) EnWG took this problem by first measures on so-called "special network resources". Power plant capacities in Southern Germany are tendered, which are exclusively for positive redispatch. Construction and operation will be financed by grid fees.

The scenario-based character of the analyses may explain the fact that the real capacity is to be considerably larger than the 3 GW identified in Chapter 4.1. The study under consideration only deals with two scenarios, which can be used as indicators for the determination of repercussions. A variation of the assumptions, for example, concerning the development of trading capacities, would have a high impact at this point. Besides that, it should be emphasized that the dimensioning of the grid reserve to ensure system reliability for every possible system state (weather conditions, transmission line, and power plant availability) would have to be answered by a Monte Carlo approach. The approach chosen here is only limitedly suitable for reliable quantification of the required reserve. Nevertheless, it has proved to be an appropriate method of illustrating and understanding the problem of local supply shortages in times of high renewable generation.

The analysis of the market-based generation shortage revealed that, despite high RES penetration by 2030 and high electrification rates, conventional capacities are essential, if the recommendations of the “Coal Commission” /KWSB-01 19/ and the nuclear energy phase-out path are followed. In the scenario presented in Chapter 4.2, 80 GW of conventional capacity is deployed in 2030. The studies carried out in /Pub-04/ show that a coal phase-out without expansion of conventional capacities and simultaneous electrification can lead to a shortfall of up to 27 GW in 2030. In total, slightly less than 80 GW of thermal generation capacity is needed for a secure system operation in this analysis as well. From the assessment of different regional distributions of the required back-up capacities, it can be concluded that a large share of these capacities could be located without grid-related restrictions. In times of an energy-only market, it is questionable whether a sufficiently secured capacity will be built until 2030 to 2035 based on market incentives. Especially since the expected full-load hours will be deficient, the expected price level in high-price times is challenging to predict, and battery storage systems with PV will probably replace conventional technologies in the long term. However, the discussion about the costs of conventional security of supply has to be seen in the context of the overall system costs. According to /FFE-69 19/ this component sums up cumulatively over the years from 2020 until 2050 to €48.6 billion and is much lower compared to the cost for the expansion of vRES which amounts to €429 billion in a climate protection scenario.

The climate protection scenario researched, as presented in Chapter 4.2, implies major technological shifts, particularly in the energy industry sector. Figure 30 qualitatively describes the detailed quantitative analyses in the form of a transition pathway.

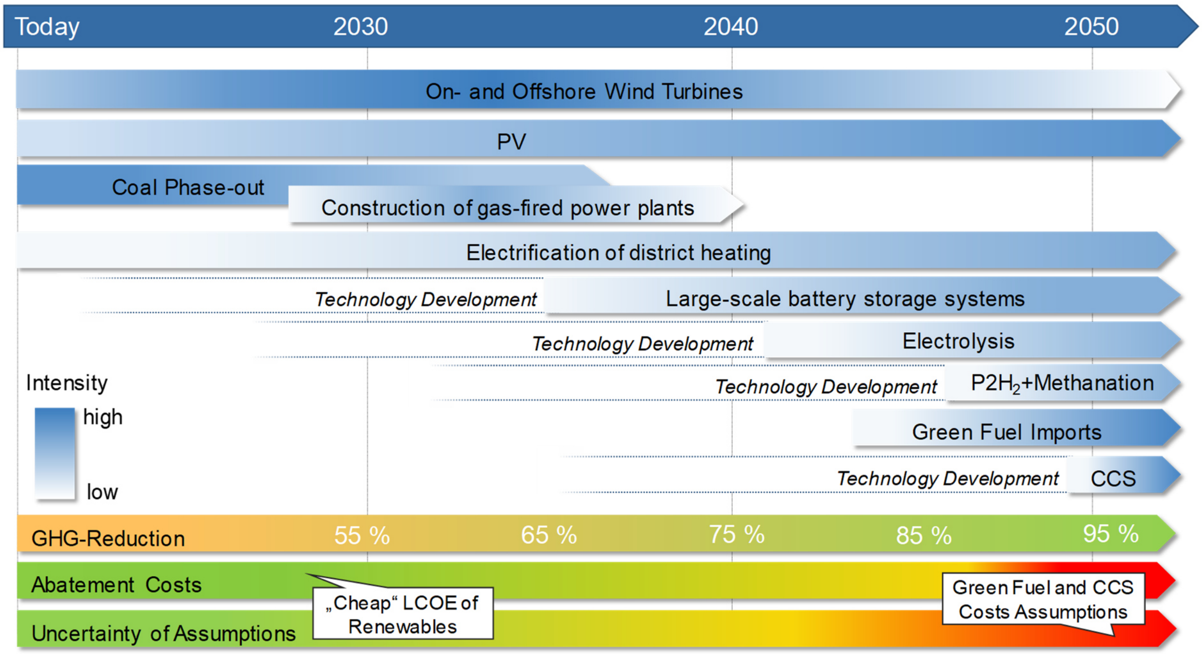


Figure 30: *Key development phases of the supply sector in the fuEL scenario, qualitative representation*

Once coal has been phased out, gas-fired substitute capacities are being built as peaking units. Although very low full load hours are expected for these plants, especially in the later years after 2040, they are the cheapest alternative for this purpose in 2030 and 2035. As mentioned above, this result is to be seen with great caution as it is very sensitive to the price development of battery storage systems. Also, the modeling approach chosen tends to result in stranded investments in general. This is due to the limited foresight approach described in Chapter 1.3. In an integrative analysis, PV and batteries might be added to the system to a greater extent and earlier.

From today's perspective, the technologies used in the calculated path for the last 10 to 15 percent of emission reduction are still far from market maturity. These include CCS, methanation, and foreign-produced green fuels in general. As already indicated in Chapter 4.2 and marked in the above illustration, the cost assumptions for these technologies are associated with a high degree of uncertainty. The same applies to the measures not considered in the study, which involve a similar level of uncertainty. This includes, for example, blue hydrogen or afforestation. In addition, the assumptions made regarding the non-modeled emission components, as shown in Figure 16, have a relatively strong influence in these later years. It follows that negative emissions are required in 2050. This modeling constraint must also be viewed critically. Accordingly, less attention should be paid to the 2050 trajectory, but rather to the obvious measures that are feasible in the next 10 to 20 years. For this near future, as well as for the long-term development of the energy system, the enormous importance of renewable energies needs to be emphasized. According to the scenario presented, an average net addition rate of 3.1 GW for wind onshore and 6.9 GW for PV per year is to be aimed for the next twenty years in order not to fall short of the path to climate target achievement. The studies show also that an almost entirely renewable energy system can be achieved in which less than 4 % of domestic electricity generation comes from controllable, conventional power plants. In 2050, more than 500 GW of installed vRES capacity is integrated to supply an emission-free energy system. To put this capacity in relation to the peak load from the FEC sectors, this corresponds to 3.3 times the hourly annual peak load.

6 Comments and Outlook

Despite liberalization and unbundling, the energy industry in Europe, and especially in Germany, is a highly regulated sector. In the context of the transformations needed for decarbonizing the energy supply, the market design needs to be developed further, technologies are to be improved, and new regulatory guidelines should be defined. Even if the idea of liberalization promises competition and thus gains in welfare, the additional targets of energy policy, sustainability and reliability, can only be achieved through regulatory improvements. In many areas of this work, problems have been identified which result from the interaction of abatement measures and existing energy system infrastructure, as well as the regulatory treatment of these measures.

The duration over which this work was created took almost five years, so that also in the legislation, some things have changed. Many of the challenges addressed here directly or indirectly were taken up and re-evaluated for the first time. These include:

- A legally induced Coal Phase-Out. /KWSB-01 19/
- A discussion, if vRES-investors should contribute to grid expansion costs in areas of high grid congestion. /FAZ-01 19/
- Since 2018 Power-to-Heat units can be used to relieve the transmission grid, according to §13(6a) of the EnWG. For this purpose, TSOs are allowed to contract northern CHP plants equipped with electrical heating technologies.
- For power plant investors, it was made evident in /BKARA-01 19/ that the future price incentives for peak load units will arise solely from the energy-only market. A capacity mechanism is not envisaged. Even though the profit margins of investments in peak load power plants may be difficult to predict, it is nevertheless ensured that there will be no change in the incentive structure. The next few years will show to what extent this provision will require the legislator to ensure security of supply through a strategic reserve or other mechanisms.
- In § 11(3) of the EnWG it was stated that south of the grid bottleneck in Germany, the TSOs are entitled to put out to tender the construction and operation of 1.2 GW of new power plant capacities to guarantee local security of supply. These capacities are, however, not available to the electricity market and will be used to regain a safe state (n-1) in grid operation in case of a grid-related error (e.g., line outages).

These measures show that the process of reforming the legislative framework for energy supply is in full progress. However, the current path of maintaining an existing market design and bidding zone layout in addition to many and increasing individual regulations, must be viewed critically. The central problem remains that the spatial imbalance between generation and consumption, as well as the temporal decoupling of traditional demand and vRES supply, are growing. In the context of temporal balancing, many potentially flexible electricity consumers or storage systems will be involved, but they are still a considerable step away from economic viability in the current levy system. Furthermore, grid expansion projects are prevented or at least delayed by citizens' initiatives, which limits the spatial balancing effect through new transmission grid lines.

The question should be allowed whether a fundamental revision of the market design and the structure of levies could be more purposeful. Alternatives have been much discussed in recent years: Regional electricity and flexibility markets are intended to improve the integration of flexibility and systematically relieve the grid. A split of the German bidding zone has been under debate for a long time. This redesign process would, from an emissions perspective, provide better incentives for a systemic and emission-reducing operation of flexible electricity demand technologies throughout Germany. At the heart of both discussions is a gradual convergence towards a nodal-pricing system, which reflects grid restrictions very clearly in the formation of the electricity prices. But here, too, investment incentives for secured capacity are only provided in tandem with a high degree of uncertainty. To guarantee such incentives, (local) capacity markets would be conceivable.

Concerning the sector-coupling technologies needed to decarbonize the energy system, it is clear that grid fees, EEG tax, and various other levies and charges make the integration of electricity-based renewable energies in other sectors (domestic heating or electromobility) unattractive. In order to balance this asymmetry between the actor's and system's perspective, the charges on electricity prices have to be reduced, and time-variable electricity tariffs have to be passed on to the consumer.

Science can play a guidance role in evaluating different policy options in the context of decarbonization. However, with a view to the upcoming transformation processes, there is still much to be done in the field of energy system modeling. Regarding the methodological approach, it was demonstrated that more reliable and detailed statements could be made through a more extensive system representation. Due to the expansion of the regional scope of the model, future studies will increasingly be able to consider the reciprocal effects with the European neighbors. In particular, the repercussions of a European climate path were not considered in the studies carried out but would be of great interest. The synergies of a European coordinated transformation in comparison to national approaches could be examined. Besides, a cost-optimal allocation of renewables, grid expansion, and flexibilities could be researched. To address the effects of abatement measures on the transmission grid simultaneously, new approaches are needed to accelerate optimization solvers, to integrate high-performance computers or to deploy decomposition methods. However, it should be noted that the extension of system boundaries only serves a purpose if the input data remains at high quality. For this reason, a critical examination of the available data and their validity must take place in the modeling community. To what extent disaggregation methods, which have to be used due to missing regionally resolved data, are applicable can be the subject of further research. The extension of the model boundaries in geographical and technological terms is a future field of study as well.

Equally important is the expansion of the modeling focus to further criteria. While in the work at hand primarily costs and CO_2 emissions are evaluated, the question of further environmental aspects is also highly relevant, especially for renewable technologies and battery storage. Bringing together the disciplines of life cycle assessment and energy system modeling provides the chance to evaluate energy system scenarios more comprehensively and critically.

A Techno-Economic Parameters

Table 8: *Fuel costs from a system perspective (real, based on lower calorific value) and emission allowance costs, /FFE-69 19/*

Year	Energy Carrier Costs in € per MWh								CO_2-Certificate prices (EU-ETS) in € per tonne
	Hard Coal	Lignite	Gas	Mineral Oil	Uranium	Biomass	Gasoline	Diesel, light oil and kerosene	
2020	8.4	4.3	22.7	40.0	3.3	27.6	51.3	46-47	20.1
2025	8.5	5.6	25.2	49.9	3.3	28.2	61.2	56-57	31.0
2030	8.4	5.6	26.4	48.3	3.3	27.7	59.6	54-55	41.8
2035	8.5	5.6	27.9	53.0	3.3	27.3	64.3	59-60	52.7
2040	8.9	5.6	28.0	53.0	3.3	27.0	64.3	59-60	63.5
2045	9.3	5.6	28.0	53.0	3.3	26.7	64.3	59-60	74.4
2050	9.8	5.6	28.1	53.0	3.3	26.3	64.3	59-60	85.2

Table 9: *Direct energy-related CO_2 emission factors of the considered fuels (related to the lower calorific value), /FFE-69 19/*

Hard Coal	Lignite	Methane	Mineral Oil	Gas-oline	Diesel	Oil, light	Kerosene	Waste	Biomass
0.337	0.399	0.198	0.264	0.263	0.266	0.264	0.264	0.165	0.348

The calculatory interest rate is set to 3.5 % /UCL-01 11/.

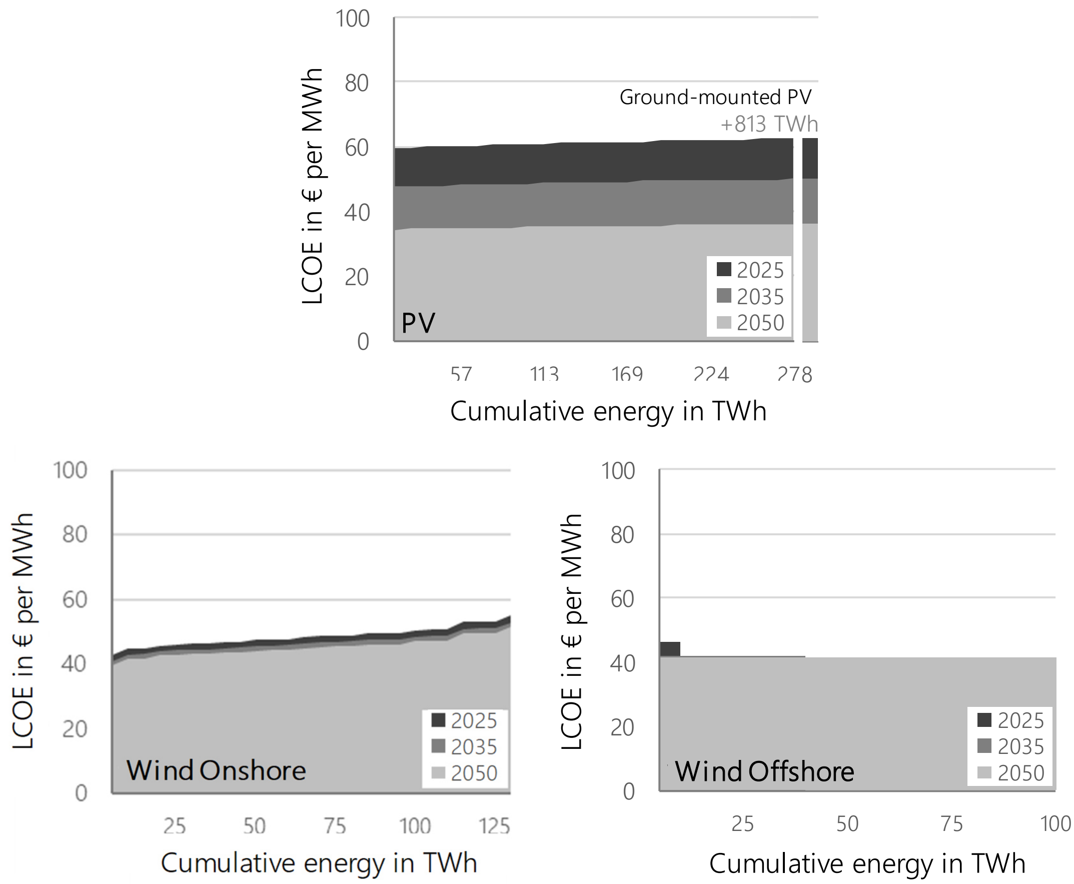


Figure 31: *LCOE of Wind Onshore, Wind Offshore, and Photovoltaics; illustration taken from /FFE-69 19/*

Table 10: *Gas Turbine Power Plant*

	Unit	2020	2030	2040	2050	References
Useful life	a	35	35	35	35	Assumption
Electrical efficiency	%	40 %	40 %	40 %	40 %	/EWI-01 14/ and /DENA-01 18/
CAPEX	€/ MW_{el_out}	408 750	408 750	408 750	408 750	/IAEW-01 12/ and /DENA-01 18/
fixed OPEX	€/ $(MW_{el\_out}$*a)	10 800	10 800	10 800	10 800	/IAEW-01 12/ and /DENA-01 18/

Table 11: *Micro-Cogeneration Plant*

	Unit	2020	2030	2040	2050	References
Useful life	a	20	20	20	20	Assumption
Thermal efficiency	%	40 %	40 %	40 %	40 %	Calculation, based on /ASUE-01 14/, no further improvements assumed
Electrical efficiency	%	45 %	45 %	45 %	45 %	Calculation, based on /ASUE-01 14/, no further improvements assumed
CAPEX	€/ MW_{el_out}	717 936	717 936	717 936	717 936	Calculation, based on /ASUE-01 14/, no further improvements assumed
fixed OPEX	€/ (MW_{el_out}*a)	28 992	28 992	28 992	28 992	Calculation, based on /ASUE-01 14/, no further improvements assumed

Table 12: *Large-scale heat pumps*

	Unit	2020	2030	2040	2050	References
Useful life	a	20	20	20	20	/DLR-04 12/ Page 6
COP		3.52	3.67	3.76	3.81	/DLR-04 12/ (annual COP) Page 6
CAPEX	€/ MW_{th_out}	619 318	560 018	546 593	531 633	/DLR-04 12/ Page 6, /VDE-02 15/ Page 65
fixed OPEX	€/ (MW_{th_out}*a)	21 676	19 601	19 131	18 607	/DLR-04 12/ Page 6

Table 13: *Electrode heating boilers*

	Unit	2020	2030	2040	2050	References
Useful life	a	20	20	20	20	Assumption
Thermal efficiency	%	86 %	86 %	86 %	86 %	/PDM-01 16/
CAPEX	€/ MW_{th_out}	479 665	450 984	424 281	399 556	Mean value from /CAR-02 18/ and /GIER-01 13/
fixed OPEX	€/ (MW_{th_out}*a)	9 593	9 020	8 486	7 991	Assumption: 2 % of CAPEX

Table 14: *Large-scale battery storage systems*

	Unit	2020	2030	2040	2050	References
Useful life	a	20	20	20	20	/ISI-18 15/
Electrical efficiency	%	94 %	96 %	96 %	96 %	/IRENA-01 17/
CAPEX	€/ MWh_{Use}	518 444	240 967	231 856	225 856	/IRENA-01 17/, /ISI-09 17/, /ISEA-01 15/, /TUM-06 16/, /BNETZA-03 18/
fixed OPEX	€/ $(MWh_{Use}$*a)	7 777	3 615	3 478	3 388	/ACA-04 15/

Table 15: *CCS and CCU*

	Unit	2020	2030	2040	2050	References
CCS DAC incl transport and storage	€/t_{CO2}	408	270	266	241	Mean value from /LBST-02 16/, /BERTA-01 18/, /DENA-01 18/ and /TREM-01 18/
CCU from industrial source	€/t_{CO2}	48	48	48	48	Mean value from /THO-01 15/, /DEU-01 08/, /IASS-03 16/

Table 16: *Power-to-Gas PEM-EL*

	Unit	2020	2030	2040	2050	References
Useful life	a	11	13	15	16	/DENA-01 18/ Page 435
Electrical efficiency	%	66 %	73 %	78 %	83 %	/FFE-145 17/ Page 10
CAPEX	€/MW_{el_in}	1 420 000	820 000	741 250	505 000	/FFE-145 17/ Page 10
fixed OPEX	€/(MW_{el_in}*a)	28 400	16 400	14 825	10 100	/FFE-145 17/ Page 10

Table 17: *Power-to-Gas AEL*

	Unit	2020	2030	2040	2050	References
Useful life	a	27	30	30	30	/FFE-145 17/ Page 4 , constant value from 2030 on
Electrical efficiency	%	73 %	75 %	75 %	75 %	Mean value from /FCHJU-01 14/ Page 18 and /DENA-01 18/ Page 434
CAPEX	€/MW_{el_in}	630 000	580 000	580 000	580 000	/FCHJU-01 14/ Page 20, constant value from 2030 on
fixed OPEX	€/(MW_{el_in}*a)	12 600	11 600	11 600	11 600	/FCHJU-01 14/ Page 20, constant value from 2030 on

Table 18: *Steam reformation*

	Unit	2020	2030	2040	2050	References
Useful life	a	15	15	15	15	/ISE-02 15/
Efficiency	%	80 %	80 %	80 %	80 %	/ISE-02 15/
CAPEX	€/MW	955 000	955 000	955 000	955 000	/ISE-02 15/
fixed OPEX	€/(MW*a)	23 875	23 875	23 875	23 875	/ISE-02 15/

Table 19: *Power-to-Gas Methanation (incl. electrolyzer)*

	Unit	2020	2030	2040	2050	References
Useful life	a	11	13	15	16	/DENA-01 18/ Page 435
Efficiency	%	56 %	69 %	74 %	78 %	/FFE-145 17/ Page 6
CAPEX	€/ MW_{el_in}	1 976 667	930 000	857 500	785 000	/FFE-145 17/ Page 6
var. OPEX	€/ (MWh_{el_in}*a)	6.8	8.4	8.9	9.5	CO_2 from industrial source
fixed OPEX	€/ (MW_{el_in}*a)	39 533	18 600	17 150	15 700	/FFE-145 17/ Page 6

Table 20: *Fermenter (incl. gas treatment)*

	Unit	2020	2030	2040	2050	References
Useful life	a	20	20	20	20	Page 63
Efficiency	%	55 %	55 %	55 %	55 %	/VDI-05 14/
CAPEX	€/MW_{in}	1 705 115	1 705 115	1 705 115	1 705 115	/FNR-06 16/
fixed OPEX	€/(MW_{in}*a)	51 153	51 153	51 153	51 153	/ISE-02 15/ Page 74

Table 21: *Power to Liquid*

	Unit	2020	2030	2040	2050	References
Useful life	a	20	20	20	20	/IWES-01 17/, /LUT-102 16/, /LUT-01 17/, /DIET-01 18/
Efficiency	%	44 %	47 %	49 %	51 %	/IWES-01 17/, /LUT-102 16/, /LUT-01 17/, /DIET-01 18/
CAPEX	€/ MW_{el_in}	3 901 670	2 131 894	1 956 065	1 859 824	/IWES-01 17/, /LUT-102 16/, /LUT-01 17/, /DIET-01 18/
var. OPEX	€/ (MWh_{el_in}*a)	1.7	1.0	0.7	0.2	CO_2 from industrial source
fixed OPEX	€/(MW_{el_in}*a)	128 755	70 353	64 550	61 374	/IWES-01 17/, /LUT-102 16/, /LUT-01 17/, /DIET-01 18/

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Hourly CO2 Emission Factors and Marginal Costs of Energy Carriers in Future Multi-Energy Systems

/Pub-01/

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Hourly emission factors and marginal costs of energy carriers are determined to enable a simplified assessment of decarbonization measures in energy systems. Since the sectors and energy carriers are increasingly coupled in the context of the energy transition, the complexity of balancing emissions increases. Methods of calculating emission factors and marginal energy carrier costs in a multi-energy carrier model were presented and applied. The model used and the input data from a trend scenario for Germany up to the year 2050 were described for this purpose. A linear optimization model representing electricity, district heating, hydrogen, and methane was used. All relevant constraints and modeling assumptions were documented. In this context, an emissions accounting method has been proposed, which allows for determining time-resolved emission factors for different energy carriers in multi-energy systems (MES) while considering the linkages between energy carriers. The results showed that the emissions accounting method had a strong influence on the level and the hourly profile of the emission factors. The comparison of marginal costs and emission factors provided insights into decarbonization potentials. This holds true in particular for the electrification of district heating since a strong correlation between low marginal costs and times with renewable excess was observed. The market values of renewables were determined as an illustrative application of the resulting time series of costs. The time series of marginal costs as well as the time series of emission factors are made freely available for further use.

1. Introduction

Future energy systems will be characterized by increased volatility in electricity generation due to variable renewable energy sources (vRES) as well as stronger linkages between energy carriers. These new interdependencies derive from the coupling of previously separate energy carriers in multi-energy systems (MES), as defined in [1] by means of technologies such as power-to-heat (PtH) and power-to-gas (PtG). Therefore, when assessing future energy technologies with regard to CO2 emissions, not only the

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time of energy consumption and generation need to be considered, but also the linkages between energy carriers need to be accounted for.

In recent studies dealing with the decarbonization of the German energy system (e.g., [2–4]), the focus lies on describing changes in absolute emissions. There are some studies available, (e.g., [5,6]) which demonstrate the resulting specific emission factor for the annual electricity mix. However, there are very few analyses on the future German energy system which report the specific emission factor of electricity with a high time resolution, much less for other energy carriers.

An overview of different approaches to quantify emission factors of electricity is provided by [7]. The existing methods differ with regard to the input data and the models used (empirical data and statistical relationship models vs. power system optimization models), the time horizon (historical vs. future), the temporal resolution (from less than one hour to one year), the consideration of imports and exports as well as the regional differentiation. Whereas in several analyses, e.g., [8,9], methods are presented to determine hourly average and marginal emission factors of electricity based on power system optimization models, the work on integrating these methods into the modeling of MES is limited. Considering the increasing integration of various energy carriers in future MES, these methods need to be expanded from electricity and district heating to other energy carriers such as methane and hydrogen. In this context, the allocation of emissions to multiple strongly interconnected energy carriers is the main challenge to be solved. To understand the interdependencies and operational incentives of the modeled future energy system, it is helpful to supplement the time-resolved emission factors with an examination of hourly marginal energy carrier costs.

This study provides a methodology and a data set for specific emission factors and marginal costs of different energy carriers for a future German MES scenario with high time resolution. This data is required when determining the CO_2 emissions of future energy technologies while also considering the dependency of emissions on the load profile and on linked energy carriers. Since load management strategies will play an increasing role in balancing supply and demand in future energy systems, the time series of emission factors provided can also serve as an input for the development of load management strategies aimed at CO_2 emission reduction. An estimation of the economic feasibility of these measures can be carried out by combining the resulting emission factors with the hourly marginal generation costs.

2. Methods

The methodological approach consists of four building blocks. First, the modeling approach of the MES is described in section "*2.1. Multi-Energy System Model*". This model is then applied to simulate the future energy system for the scenario described in "*2.2. Energy System Scenario*". In this section, the scope of the analysis is defined and the associated input data is outlined. Furthermore, the energy balances resulting from the simulation of the described scenario with the MES model are evaluated and discussed for the modeled energy carriers. In a third step, the methods for balancing emissions by energy carrier and calculating hourly emission factors from the generated scenario results are presented in section "*2.3. Emissions Accounting*". Finally, the procedure to determine hourly marginal costs of energy carriers, which also builds on the results of the simulated future MES scenario, is described in section "*2.4. Marginal Cost Calculation*".

2.1. Multi-Energy System Model

The MES model used and modified for this analysis is called "ISAaR, Integriertes Simulationsmodel zur Anlageneinsatz-und Ausbauplanung mit Regionalisierung", with the German abbreviation standing for the term "Integrated simulation model for plant operation and expansion planning with regionalization". ISAaR is a model based on the mathematical method of linear optimization with the optimization goal of minimizing overall system cost C. A detailed description of the model is given below. In addition, individual input datasets, model components and application examples are presented in publications like [10–15].

The equations of ISAaR are based on linear optimization, a method described in detail in works such as [16,17]. The general equations are noted in the following in order to define notations and terms. The model-specific equations can be found in the subsequent sections.

A linear optimization problem is formed by:

$$\begin{aligned} C &= \min_x f^T x \\ \textit{subject to} \quad & d_{lb} \leq x \leq d_{ub} \\ \textit{and} \quad & b_l \leq \mathrm{A}x \leq b_r \end{aligned} \tag{1}$$

The vector of variables x is to be optimized. The vector f contains the specific costs of the variable vector x. All system dependencies are described within the constraint matrix A, the left and right boundary of the constraints b_l and b_r, and the lower and upper bounds of the variables d_{lb} and d_{ub}.

Using this approach, a MES is described by the ISAaR model. The selection of relevant energy carriers is made with a focus on future decarbonization strategies in the German energy system. Key studies used as benchmarks are [2,4,5]. As a result, the energy carriers of electricity, district heating, hydrogen, methane, and biomass are selected. For the consideration of more ambitious decarbonization paths, carbon-based liquid energy carriers are also implemented in a simplified manner. Figure 1 shows the energy carriers considered, the conversion technologies, and the boundaries of the system.

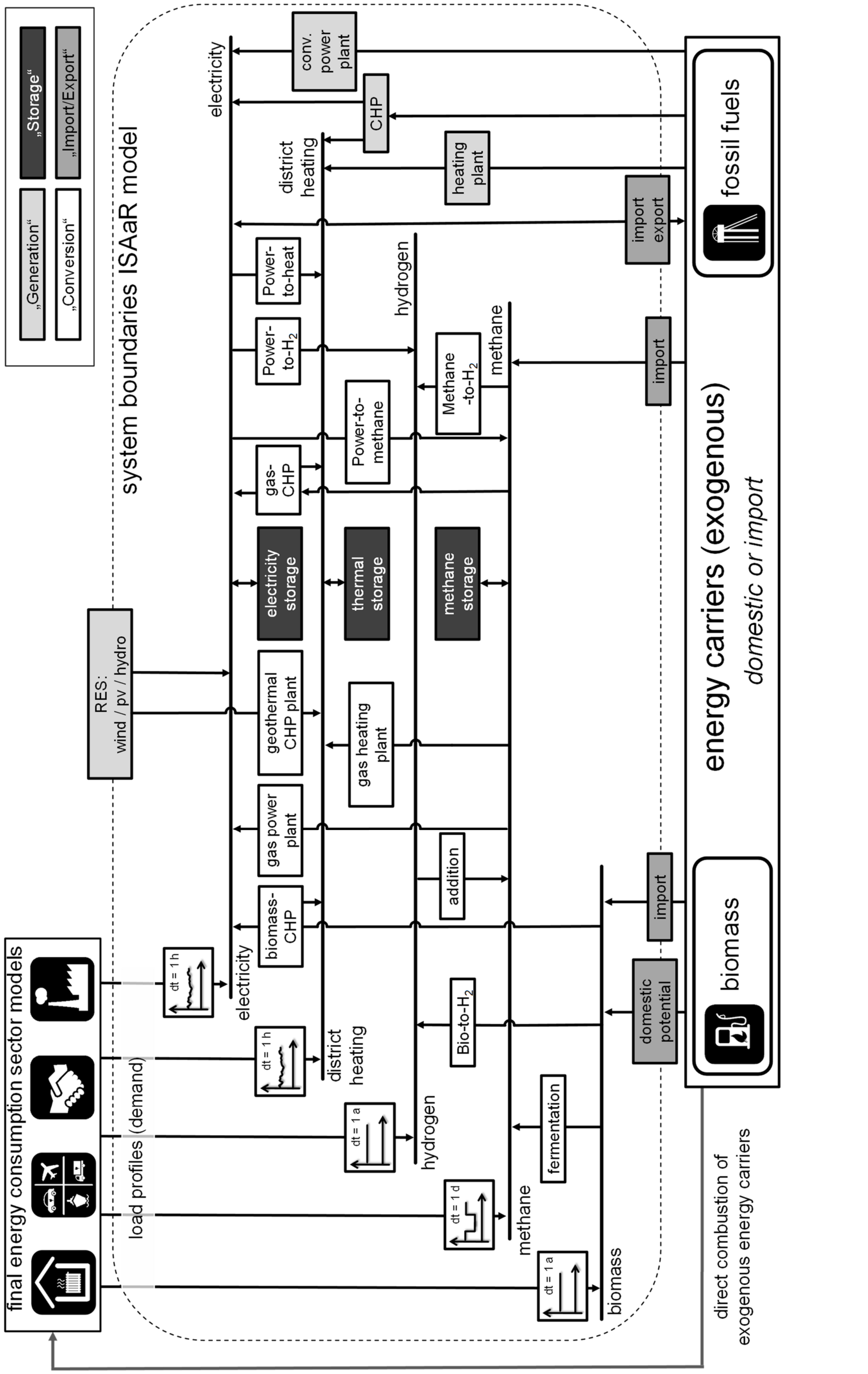

Figure 1. *Multi-energy carrier model “ISAaR”.*

All optimization runs are performed in hourly resolution but not all energy carriers are resolved hourly (see Figure 1). Energy carriers with sufficient storage capability (i.e., hydrogen or methane) are taken into account in annual or daily totals. The weather year used in order to generate load or renewable profiles is 2012. With respect to the German power system, 2012 was an average weather year regarding to temperatures and renewable generation potential [18]. Whereas all energy carriers shown are modeled in detail for the German region, the neighboring countries are considered in a simplified manner. Electricity generation is modeled taking aggregated conventional power plant blocks, hydro storages, and renewables into account. As shown in Figure 1, four different classes of energy system elements are distinguished: generation, conversion, storage and import/export elements. In principle, the elements of “generation” and “import or export” are very similar as energy carrier flows across system boundaries are taken into account in both cases. In contrast, the elements “storage” and “conversion” do not cross the system boundaries. Storage elements provide a temporal offset between charging and discharging without converting the energy carrier. In the case of conversion, a transformation of energy carriers takes place in which emissions can occur during combustion or can be withdrawn from the system. An example for a withdrawal is the absorption of CO_2 from the air to synthesize methane (“Power-to-methane”).

In the following, the mathematical foundations of the model are described in more detail. With regard to the nomenclature for the following explanations, it should be noted that an “element” constitutes a designation for a group of technically similarly operating units whose functionality is modeled by the same set of mathematical equations. The individual plant is referred to as a “unit”.

2.1.1. System Constraints

The system constraints link several generation technologies gen, conversion technologies $conv$ and storage systems sto, thus ensuring load P_{demand} fulfilment of a specific energy carrier ec per final energy consumption (FEC) sector sec for every time step t and in every region reg under consideration. Striked subscripts represent a link to another energy carrier ec' or region reg'. The input in or output out power P of generating, storing or converting devices dev is modeled in addition to imported or exported energy. The breakdown of this hourly power balance is shown in Equation (2).

$$\begin{aligned}
&\sum_{sec} P_{demand}(t, sec, ec, reg) \\
&= \sum_{dev_{gen}} P_{out}\left(t, dev_{gen}, ec, reg\right) \\
&+ \sum_{dev_{conv}} P_{out}(t, dev_{conv}, ec', ec, reg) \\
&+ \sum_{dev_{sto}} P_{out}(t, dev_{sto}, ec, reg) \\
&+ \sum_{reg'} P_{Import}(t, ec, reg', reg) \\
&- \sum_{dev_{gen}} P_{in}\left(t, dev_{gen}, ec, reg\right) \\
&- \sum_{dev_{conv}} P_{in}(t, dev_{conv}, ec, ec', reg) \\
&- \sum_{dev_{sto}} P_{in}(t, dev_{sto}, ec, reg) \\
&- \sum_{reg'} P_{Export}(t, ec, reg, reg')
\end{aligned} \tag{2}$$

The load is assumed to be inflexible. All price-sensitive load components are modeled as flexibility options (e.g., as storage) or in the context of previous profile generation within the FEC sector models (e.g., photovoltaic (PV) home storage for self-supply).

2.1.2. Conversion and Generation Technologies

The equations representing conversion technologies (e.g., electrolyzers) and power plant operation are described as follows. The first step is the reference case of a typical conversion or generation process with one input and one output energy carrier including the conversion or generation efficiency η.

$$P_{out}(t, ec, dev) = P_{in/fuel}(t, ec', dev) \cdot \eta_{conv/gen}(dev) \tag{3}$$

For all instances, their maximum generation capacity is limited by the individual rated power capacity $P_{out\,max}$ and the average operational availability c_{avail} for this technology type.

$$P_{out}(t, ec, dev) \leq P_{out\,max}(dev) \cdot c_{avail}(dev) \tag{4}$$

If no availability is given, $c_{avail}(dev)$ is set to 1, and the upper bound of $P_{out}(t, ec, dev)$ equals $P_{out\,max}$. These bounds of the operational variables apply equally to the power drawn $P_{in}(t, ec, dev)$ and the storage level $W_{sto}(t, dev)$.

Due to the high relevance with regard to the resulting power plant dispatch and, therefore the determination of marginal generation costs and emission factors, a high level of detail is applied for modeling conventional electricity generators. Therefore, the above equations are modified for conventional power plants. The chosen approach is mainly based on the modeling equations shown in [19]. This approach is also used for the linearization of fuel consumption in power plants, which, take partial load behavior and start-up costs into account. In view of the complexity and the large scope of this mathematical description, this section can be found in Appendix A.

An exception requiring an element-specific modeling is the addition of hydrogen to the natural gas network $P_{h_2-to-methane\ out}(t)$. For this purpose the imported methane $P_{methane,import}(t)$, the methane in- and output of natural gas storages $P_{methane,storage,in/out}(t)$ as well as electrolysis and methanation units $P_{methane,P2Gas,out}(t)$ are balanced.

$$\begin{aligned} P_{h_2-to-methane\ out}(t) \\ \leq \frac{c_{h_2\ max}}{(1-c_{h_2\ max})} \Big(P_{methane,P2Gas,out}(t) + P_{methane,Import}(t) \\ + P_{methane,storage,out}(t) - P_{methane,storage,in}(t) \Big) \end{aligned} \tag{5}$$

Although the load condition of the energy carrier methane is to be fulfilled daily, the output variables are determined in hourly resolution. Based on the findings in [20] the maximum volumetric addition factor $c_{h_2\ max}$ is set to 10%.

2.1.2. Storage Processes

A linear optimization approach for modeling e.g., a hydro pumped storage power plant, is described in [21]. A characteristic is the temporal coupling between the optimized variables of the SoC (State of Charge). The self-discharge of a storage system is integrated by the loss coefficient η_{loss}. Based on these definitions, the following condition can be derived for hydro, thermal, methane and battery storage systems:

$$(Dis)charging\ power\ =\ Change\ of\ SoC\ per\ hour$$

$$\begin{aligned} \eta_{in}(dev) \cdot P_{in\ el}(t,ec,dev) - \frac{1}{\eta_{out}(dev)} \cdot P_{out\ el}(t,ec,dev) \\ = W_{sto}(t,ec,dev) - \big(1-\eta_{loss}(dev)\big) \cdot W_{sto}(t-1,ec,dev) \end{aligned} \tag{6}$$

A detailed description of the modeling of seasonal hydro and pumped storage systems with natural inflow is provided in [14].

2.1.3. Software

All input data is stored in a PostgreSQL database. The problem formulation and result processing is carried out in a standardized procedure in MATLAB®. The optimization problem is solved by IBM® CPLEX using the barrier algorithm.

2.2. Energy System Scenario

The research focus of the Dynamis project is the assessment of various CO_2 abatement measures with regard to cost efficiency using energy system modeling. In order to evaluate these measures for decarbonization, it is first necessary to create a reference path as a starting point in order to be able to evaluate deviating and strongly decarbonizing paths. In the following, this reference scenario, which is the object of the examinations documented here, is referred to as the “Dynamis Start Scenario”. The time horizon of the analysis extends in five-year steps from the year 2020 to the year 2050. The regional scope of the analysis is the German grid area. The influence of the 34 surrounding European ENTSO-E (European Network of Transmission System Operators for Electricity) regions, which mostly correspond to countries, are also considered. The list of countries can be found in Appendix B. The input data and assumptions regarding the development of emission certificate prices and fuel prices as well as emission factors related to the combustion processes of the energy carriers considered are included in Appendix C. In order to create a current reference scenario, it is necessary to merge different sources. The studies used for this purpose are listed in Table 1 and classified according to their scope and suitability.

Table 1. *Selection and characterization of scenario sources.*

Source:	TYNDP 2018 [1]	ERP [2]	NEP 2019 [3]
Scenario Attributes ↓ Scenario Names →	"Sustainable Transition"	"Trend-Szenario"	"Szenario B"
Consistent representation of developments in neighboring European countries	yes	no	no
Sufficient level of detail for bottom-up modeling of German final energy consumption	no	yes	no
Scenario until 2050?	until 2040	yes	until 2035
Development of renewable energy capacities in the highest possible regional resolution	Countries/ ENTSO-E-regions	Country (GER)	Federal States (GER)
High differentiation of electricity generation technologies	Yes	No	Yes
Detailed consideration of the German conventional power plant fleet	No	No	Yes

[1] TYNDP2018: Ten-Year Network Development Plan 2018 of ENTSO-E, publication: 2018 [22].
[2] ERP: "Energiereferenzprognose" (energy reference projection) publication: 2014 [23].
[3] NEP 2019: "Netzentwicklungsplan 2019" (German Network Development Plan 2019, Scenario framework draft), publication: 2018 [18].

The scenario considered here is made up of individual components from the sources outlined above. The components are selected on the basis of Table 1 with the aim of using the highest level of detail of available input data for each area. Overall, it may be noted that an essential part of the scenario data for generation in Germany originates from the NEP ("Netzentwicklungsplan 2019", German Network Development Plan 2019). These values are updated by the findings of the German "Coal Commission" [24]. For the NEP and the TYNDP (Ten-Year Network Development Plan 2018 of ENTSO-E), a linear extrapolation up to the year 2050 is conducted to complete the available datasets on the generation side. The discontinuity in consistency with the load data coming from the ERP (energy reference projection) is accepted in favor of actuality. Given the background of an adjusted political environment and the associated strong change in the growth of vRES it appears appropriate to update generation capacities. German demand data, on the other hand, is based on ERP since it is the most recent study providing a detailed breakdown of the FEC sectors. This granular breakdown of consumption sectors is needed because a bottom-up modeling of FEC sectors is being carried out in the context of the Dynamis project. Using this approach, sectoral load profiles can be generated and then specific decarbonization measures, e.g., the transition to electric heating systems in private households, can be assessed. In some areas, there have been developments on the consumption side, which require small deviations from the 2014 ERP scenario data. Large deviations due to efficiency or electrification measures are not considered in this work. Overall, the scenario is of a conservative nature.

In the following sections, for each modeled energy carrier, the processing of input datasets and the resulting scenario data for energy carrier generation and consumption are elaborated on. In addition, the energy carrier balances resulting from the simulation of the scenario are described.

2.2.1. Electricity

Based on the scenario values for installed capacity in the respective years, a decommissioning and expansion planning process is carried out for individual fossil-fired power plant units. This is done until the scenario capacity specifications are met. In neighboring European countries, the PLATTS power plant database [25] is used for conventional power plant unit data. Since the modeling in the surrounding countries is only regarded as a boundary condition for the detailed German consideration, power plant units in these countries are aggregated based on the efficiencies, turbine type and fuel type of the power plants. These power plant data are clustered as follows: First, the individual turbines of a combined-cycle unit are merged. Second, efficiencies are assigned to all units. For this purpose, manually searched turbine model-specific efficiencies are used. Standard efficiencies according to TYNDP are used for the remaining power plant units that are not covered. The TYNDP data are prepared in order to assign the various ranges of values to the age classes of the power plants. Decommissioning is carried out according to the age of the power plants described in [25]. In general, only the same power plant technologies (combined cycle gas turbine, gas turbine, hard-coal steam turbine, lignite steam turbine, nuclear) are grouped within one country. The maximum allowed efficiency deviation from the mean value of a cluster is set to 0.5% and the maximum aggregated unit size is 2 GW. An illustrative analysis of clustering for the year 2030 shows that the number of units in the European surrounding countries can be reduced from ~1200 to ~800 units. The resulting change in the average electricity price in Germany is below 0.1% and the deviation in dispatch of conventional power plants is below 0.2%.

As described above, the development of the generation capacities is extrapolated from the TYNDP. This assumption may lead to capacity shortages in system adequacy in some countries. Therefore, an exception is made for those countries for which these shortages have been identified in an annual calculation. In this case, the 2040 values are kept at a constant level and no further reduction in capacity due to the extrapolation is made. In this particular case, the countries concerned are Bulgaria, Macedonia, Slovakia, Romania, Hungary, Czech Republic, Greece, Northern Ireland, and Hungary.

Another adjustment is the update due to the German coal phase-out. The NEP coal capacities are replaced by the Commission's values for the years 2022 and 2030, as well as 2038. Intermediate data points are interpolated. Decommissioning of individual units takes place as follows.

For Germany power plant units are not being clustered. The unit data is taken from the "BNetzA" (Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway) power plant list [26], which includes the planned construction, retrofitting, and decommissioning of power plants [27]. Another data source is the UBA power plant database [28] for combined heat and power (CHP) plants in particular. In addition, the individual units are provided with manually searched data on nominal output, thermal district heating output, efficiency and CHP technology. Decommissioning is based on the age of the power plant and the district heating output. If, according to scenario data, there is a need to decommission a coal-fired CHP plant in Germany, this unit is replaced by a gas-fired unit. The district heating output capacity is kept constant. In the case of a backpressure steam turbine CHP plant in a district heating network, this plant is replaced by a gas combined-cycle backpressure turbine plant. In principle, the reported planned shutdowns are decommissioned first, followed by the oldest power plants.

Industrial power plants are modeled according to their operating incentive. In addition to the feed-in into the public grid, this includes either the supply of process heat or district heating, the industrial auto-production or the combustion of industrial waste products (e.g., blast furnace gas). A detailed description of data and modeling approach can be found in [15,29]. Small gas-fired cogeneration plants under 10 MW are taken into account for the year 2020 to the extent of 4.3 GW. It is assumed that the installed capacity will double by 2050.

Due to the adjustments of the NEP scenario B capacity data by the coal phase-out, the system faces a capacity shortage. For this reason, an integrated expansion planning of gas-fired units is carried out. According to [30–32], the assumed values for gas turbine power plants are 35 years of service life, an electrical efficiency of 40%, an investment of €408,750 per MW, as well as fixed operating costs of €54,029 per MW and year. The social discount rate for developed countries of 3.5% from [33] is assumed in order to determine the annuities of investments.

In the context of the analysis presented here, there is no further investigation of system adequacy. The energy system described works under the conditions of the weather year 2012. Therefore, it should be noted that times when neither solar nor wind generation are available for a longer period than in the weather year 2012 are not considered. This also applies to the hypothetical simultaneous failure of several power plant capacities. An increased installed capacity of gas turbines or engines would be necessary for ensuring system adequacy in such cases. However, since these units would only be used as a backup, thus producing very few full load hours, their repercussions on emissions and emission factors are negligible. To address this undetermined demand for backup capacities, this demand for backup capacities is included in Figure 2 as an unspecified element. All capacities shown are gross capacities. The availability of the plants is assumed according to the values of the “TYNDP unit data” [22].

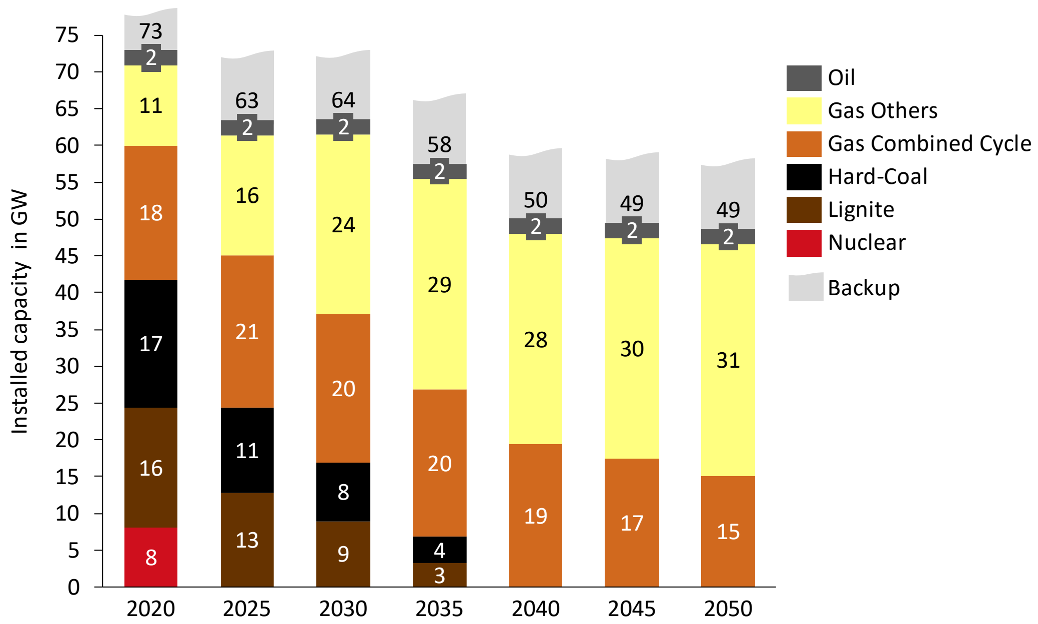

Figure 2. *Installed conventional generation capacities Germany (excluding back-up capacities).*

A two-stage approach is used for the most important renewables, namely hydro, wind and solar. First, the scenario data according to NEP and TYNDP is regionalized. Based on the locations of existing plants, geo-analysis, weather data and local expansion goals, vRES expansion differentiated by location and plant type is carried out. Then the plant characteristic curves are intersected with the weather data of the respective location to generate a generation profile. Whereas the data used for wind and PV systems are described in the following, hydro systems are described in [15]. The generation profiles for photovoltaic systems are based on a model that processes weather data and takes into account technical parameters such as low-light panel performance and inverter efficiency. The model uses radiation data from the Copernicus Atmosphere Monitoring Service (CAMS) [34], containing information on the direct and diffuse components of global radiation. The temporal resolution is from 1 to 15 min. Furthermore the weather parameters of ambient temperature and albedo are taken from the COSMO-EU model [35]. In addition, the COSMO-EU radiation data from the Scandinavian countries are used since, with the exception of Denmark, they are not part of the CAMS dataset. Since the COSMO-EU model does not contain information on the direct and diffuse components of global radiation, this information is derived from the global radiation and the clear sky index. The temporal resolution is one hour. The generation profiles can be calculated for different inclinations and orientations of solar panels.

The generation profiles for wind turbines are based on data from the COSMO-EU weather model DWD [35]. This model includes the wind speeds on a 7.5 km grid at different heights. Regional wind profiles are calculated based on the power curves of different manufacturers and turbine types. A typical plant type must be determined for each NUTS-3 region. Five different types are considered, which differ in their power curves and thus represent the various turbine types for weak to strong winds. The full load hours are calculated for each of the five turbines. Starting from the turbine type for strong winds, it is checked whether a minimum of full load hours can be achieved in this NUTS-3 region. If the strong wind turbine does not meet this minimum requirement, then the turbine types for weaker winds are tested step by step. For the first two turbine types, the minimum requirement of full load hours is 2500 h/a, for the other 1600 h/a.

Due to the growing exploitation of suitable locations, for wind onshore and PV, less suitable locations are being explored over time because the overall penetration is increasing. In the case of wind onshore, this development is overcompensated for by higher hub heights and larger rotor blades. The full load hours of wind onshore will increase on average from 1890 h/a in 2020 to 2280 h/a in 2050. In the same period, the values of PV will fall slightly from 980 h/a to 970 h/a. For offshore wind, this effect will not occur, and full load hours will remain constant at 4570 h/a.

In contrast to conventional generation technologies, renewables (solar, wind and run-of-river) are not being dispatched within the optimization. vRES generation profiles are calculated exogenously and fed into the system as an generation, which is assumed to be generated at a marginal cost of 0 €/MWh. This allows curtailment if doing so is necessary or cost efficient from a systems point of view. Biomass generation in Germany, on the contrary, is dispatched in an optimized way and is dependent on the available biomass potential and the installed plant capacities. Figure 3 summarizes the results for vRES and Biomass.

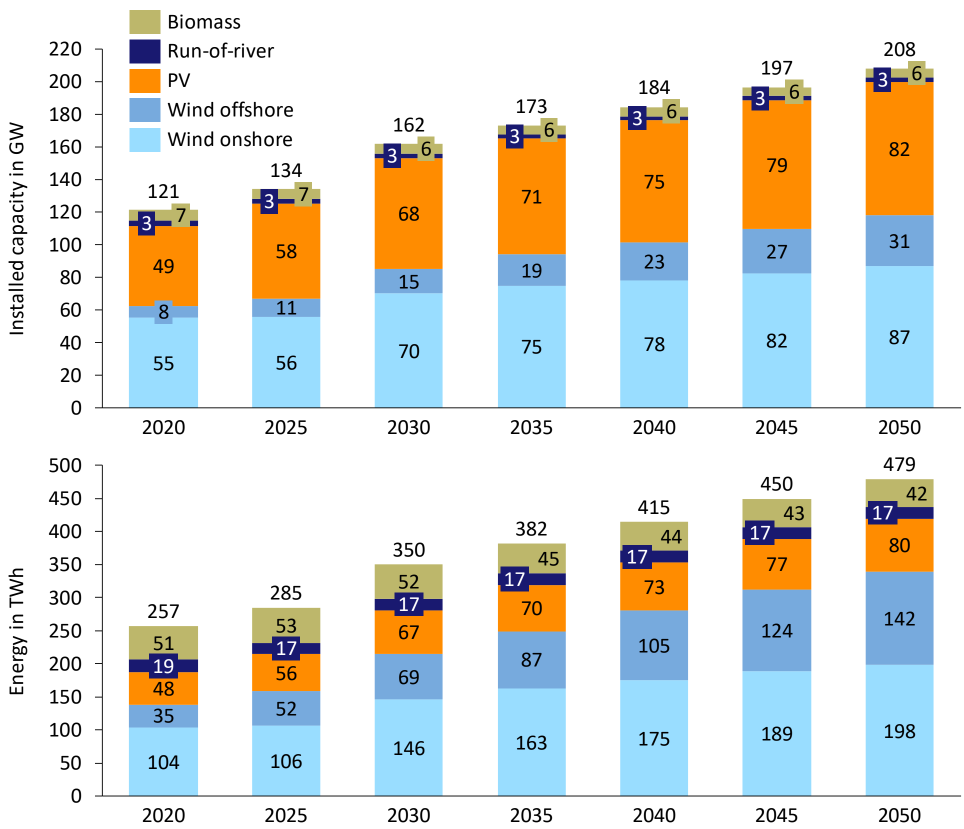

Figure 3. *Installed variable renewable energy sources (vRES) and biomass capacities and yearly energy generation in Germany.*

A current development in the field of self-supply by PV systems is the integration of home storage systems (HSS). This development towards prosumers is an often-neglected fact to be taken into account, especially in the context of falling battery storage prices. For this reason, the probability of an HSS being added to an existing and a new rooftop PV system is determined using the method in [36], which builds on market data from [37]. It is estimated that the number of HSS will increase from 320,000 in 2015 to 1.46 million in 2050.

Dispatch of these storage systems is determined by the incentive of self-supply. For this purpose, the locally applicable PV profile and a standard load profile for households are taken into account. According to [38], PV systems are to be equipped with an HSS at a rated power of 7 kW and a storage capacity of 7 kWh. The PV system is assumed to be dimensioned with an output capacity of 5 kW_p Charging and discharging is optimized to achieve a maximum self-supply rate for each household.

Whereas HSS are already taken into account in the PV profile generation process, standard storage technologies are implemented on a market-oriented basis. Classic storage technologies are primarily pumped storage units and seasonal reservoirs. The expansion rates for these technologies for Germany and the European neighboring countries result from the scenario data according to NEP and TYNDP, respectively. The installed capacity of pumped hydro in Germany increases from 8.9 GW in 2020 to 11.3 GW in 2050. Large battery storage systems according to NEP [38] are also taken into account, leading to an increase in installed power of large battery storage systems from 0.6 GW in 2020 to 2.7 GW in 2050. The ratio of storage capacity (usable) to discharge power is set to 2.2 h. Since the TYNDP does not contain any information about this technology, it is not taken into account for the European neighboring countries. Thus, 37 GW of pumped hydro and 156 GW of hydro reservoir generation capacities are taken into account for the neighboring European countries in 2020. These values rise to 48 GW for pumped hydro and 172 GW for hydro reservoir by 2050. The high capacity of the seasonal reservoirs is mainly due to the installed capacities of the Nordic countries. The energy output generated is based on historical data, which must be met within one day with a maximum deviation of 50% and within one week exactly. This means that the system has sufficient flexible capacity available to participate in the electricity market. However, this potential is limited by natural, seasonal restrictions, such as snow melt. A detailed description of the hydro modeling approach and additional input data can be found in [39].

Since the modeling of the electricity market takes a market view without consideration of intra zonal grid bottlenecks as was done in the scenario analysis already carried out in [10], the NTC values play a decisive role. NTC values represent the “Net Transfer Capacity” between two market zones [40]. These values are also taken from the “Sustainable Transition” scenario from TYNDP. In this case, there is no extrapolation of the data after 2040 and the intermediate values of the reference years are not interpolated. This is due to the fact that cross-border capacities increase depending on specific grid expansion projects, so interpolation would not be realistic from a technical point of view. The scenario data leads to a 58% increase in NTC capacities between Germany and its European neighbors in 2040 compared to 2020. Due to a lack of data on future cross-border grid expansion projects, the 2040 NTC values are kept constant until 2050.

Demand values of the European neighboring countries are taken from TYNDP. The temporally resolved load profiles are based on historical data of the year 2012 from ENTSO-E transparency [41]. The year 2012 is chosen to match the weather year. The profiles are scaled according to the prediction of the annual demand until the year 2050. In contrast, German load profiles are modeled bottom-up using standard load profiles, modeled physical load correlations or metered data for various consumption applications. An illustrative representation of this bottom-up modeling is shown in [42–44]. The demand profiles from the FEC sectors are validated and calibrated to historical load profiles from ENTSO-E transparency platform [41].

According to the modeling systematics explained above, all energy carriers are used in an optimization run for one year in hourly resolution. It should be noted that the values shown in the following illustration (see Figure 4) constitute optimization results and not input data. On the load side, it should be mentioned that 5% transmission grid and 3.3% distribution grid losses according to [18] are taken into account and balanced as “demand”.

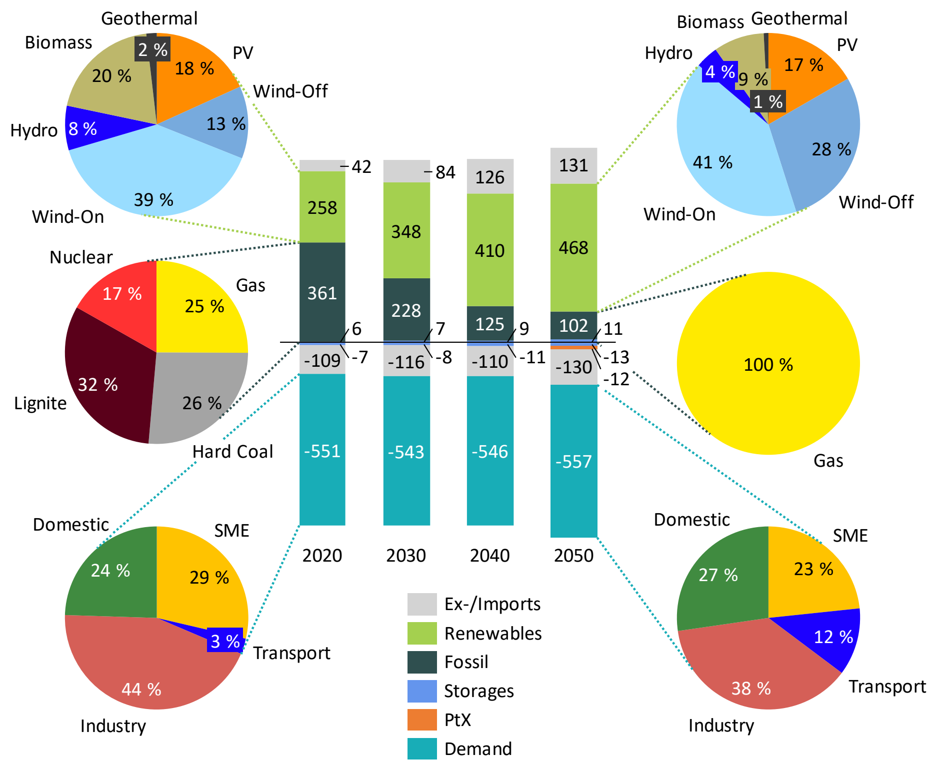

Figure 4. *Resulting German energy balance for electricity in TWh.*

It can be seen from [45] that, in 2018, renewables have reached a share of approximately 40% of electricity generation in Germany. An increase to approximately 42% within 2 years can be expected by 2020 when the expansion of renewable generation being pursued in Germany is taken into account along with the simultaneous decommissioning of nuclear energy and coal capacities [27].

2.2.2. *District Heating*

Compared to the input data of electricity supply, the data for the public district heating supply is more distributed and inconsistent. The AGFW reports on district heating supply are an important source since [46] and the preceding annual reports document the generation and demand structure of individual networks. Information on the technical parameters of existing CHP work was researched in the context of [47]. These include the CHP type, such as extraction-condensation or back-pressure turbines, additional firing capacity, the CHP index (see Appendix A) and the maximum district heating output capacity. This combination of sources allows a consumption scenario to be created for the 34 largest district heating networks up to the year 2050. In addition to the 34 specific networks, two aggregated networks are modeled for the north and south, respectively. This is a so-called "business as usual" scenario characterized by a decreasing demand for heat due to thermal insulation and renovation along with a simultaneous densification of district heating networks. The resulting annual demand will decrease from 65 TWh in 2020 to 58 TWh in 2050. Additional losses, which are particularly high in the case of heat supply and amount to 10% in 2020 and 15% in 2050, are also accounted for. Loss coefficients will increase due to longer network lengths and decreasing demand per junction point; 14% of the district heating demand in 2020 from [23] cannot be allocated to specific networks and generation technologies according to [48]. Therefore, these demands are added to the two aggregated networks divided into north and south. The CHP capacities resulting from the NEP and decommissioning of the power plants are used on the generation side. CHP plants smaller than 10 MW mentioned in [48] are taken into account for the aggregated heating networks. It is assumed that gas-fired heating plants are able to meet demand completely. Geothermal units, electrode heating boilers, thermal storage units, biomass cogeneration units, waste heat recovery units and waste incineration plants are considered according to [47]. The modeling of geothermal and both waste elements is based on a constant heat output over the entire year until the scenario-specified annual energy amount per type according to [47] is reached. The other elements are dispatched optimally in order to reduce the total system costs. For biomass CHP, the electrical efficiency is 31% and the thermal efficiency 39% according to [28]. Based on [2], electrode heating boilers are operated at an efficiency of 99%. Whereas gas heating plants achieve an efficiency of 95% [49], the efficiencies described in Section 2.2.1 are applied to CHP plants. For extraction–condensation turbines, an electricity loss index $c_{chp,v}$ of 0.145 is assumed for combined generation turbines and 0.185 for steam turbines described in [50,51]. In CHP plants, the power loss index describes the loss of electrical power when a higher thermal output is extracted.

The optimized dispatch of the energy system shows that decarbonization is taking place in district heating, but to a much lower extent than for electricity. In terms of emissions, the switch from coal to gas is the key element. A visualization of the district heating energy balance (see Figure A1) for the scenario under consideration can be found in Appendix D.

2.2.3. Hydrogen

In the model there are two technologies available for hydrogen supply, namely PEM electrolyzers and steam reformers. Since the production from natural gas by steam reforming represents the status quo, these plants are assumed to have sufficient installed capacity to completely cover the hydrogen demand. In contrast to electrolysis, this steam reformed hydrogen is associated with direct emissions. According to the investigations in [52], which are included in the NEP, an extension of the electrolyzers from ~0.2 GW for

2020 up to 4.8 GW in 2050 is assumed along with efficiency increases from 66% in 2020 to 83% in 2050. Concerning the load, it should be mentioned that the energy-related demand for hydrogen in the FEC sectors is low and will only increase slightly in the transport sector from 2030 onwards [23]. Another flexible hydrogen demand is the addition of hydrogen to the natural gas network. No networks or storage capacities are available on a computable scale, but they are included on the demand side e.g., in terms of hydrogen fueling stations and tanks in the vehicles. The load condition of the energy carrier hydrogen is optimized on annual basis.

The optimization result shows a 100% generation of hydrogen by electrolyzers, which [18] considers to be existing. Steam reformers are not being used. Hydrogen demand from the transport sector will rise from 1 GWh per year in 2020 to 3.5 TWh in 2050. In addition, 10 GWh will be fed into the natural gas grid in 2020, and 4 TWh in 2050. In real terms, the hydrogen load will be higher at this point, because hydrogen is nowadays mainly used for material use. Within the scope of this investigation, however, the focus lies on energetic use.

2.2.4. Methane

The complexity of modeling the gas market is similar to that of the electricity market. As shown in [53] the repercussions of decarbonization measures in the electricity sector have an impact on the gas market. A complete representation of the gas market in Germany and its coupling to international gas trading, including all pipeline restrictions, is too extensive for the present analysis. To counter this, a model coupling to a dedicated gas market model “MINGA” is carried out [54]. The values transferred from “MINGA” are mainly import and export capacities according to [55] and storage dimensioning in the German gas network according to [56]. Methanization is considered assuming an efficiency of 56% in 2020, increasing to 78% in 2050 [52]. According to [18,52], the installed capacity evolves from 44 MW in 2020 to 1.2 GW in 2050. In addition to the demand from the FEC sectors, power plants and heating plants also consume gas. The result of the optimization is visualized by means of the energy balance in Figure A2 in Appendix D.

2.2.5. Biomass

The modeling of a demand equation for biomass ensures that the biomass potential available in each year is not exceeded and can be used in various conversion technologies. Conversion technologies are, for example, the generation of methane using fermentation or biomass cogeneration units. The available biomass for conversion technologies is determined based on ERP [23].

2.3. Emissions Accounting

In the following, first, the developed approach to determine time-resolved emission factors for energy carriers based on MES modeling results is described in detail. Then, the deployed marginal method is briefly introduced.

2.3.1. Mix Method

As described in [57] in life-cycle assessment (LCA) the emissions inventory g is calculated according to:

$$g = \mathrm{B}s$$
$$\text{with } s = \mathrm{A}^{-1}f \tag{7}$$

The final demand vector f represents the demand for the provided products or services. Considering the technology matrix A, which contains the (economic) exchanges between different processes, the scaling vector s can be determined. The scaling vector s corresponds to the total demand for each process to deliver the final demand f. The resulting total emissions g associated with f are then calculated by multiplying the environmental intervention matrix B, containing the specific emissions per process, and s.

Transferring this approach to MES modeling, the final demand f is an input for the model ISAaR and corresponds to the load from the FEC sectors (including exports) for all modeled energy carriers. The technology matrix A is an output of the model and includes all incoming and outgoing loads per simulated energy carrier. The intervention matrix B can also be derived from ISAaR results by multiplying the fuel inputs per simulated energy carrier with their respective combustion-related emission factors. As in this case, the matrix A resulting from the simulation is exactly valid for f all values in scaling vector s are equal to one.

The ISAaR simulation results, thus, deliver all data required to set up the total emissions balance for the MES energy system. However, in order to derive specific emission factors for the n simulated energy carriers while considering their linkages, an emissions balance for each energy carrier ec is set up in the following.

For each ec it must be fulfilled that the emissions allocated to the outgoing energy carrier E_{out} are equal to the emissions occurring due to the generation of the energy carrier E_{in}. E_{out} can be described by:

$$E_{out}(ec) = emf(ec) \cdot (P_{demand}(ec) + P_{in}(ec, ec')), \tag{8}$$

where emf is the emission factor of the energy carrier, P_{demand} the final demand for the energy carrier and P_{in} the input of the energy carrier for the generation of linked energy carriers ec'. The occurring emissions during energy carrier supply E_{in} are determined from:

$$E_{in}(ec) = emf_{fuel} \cdot P_{fuel}(ec) + emf(ec') \cdot P_{in}(ec', ec). \tag{9}$$

using the fuel input P_{fuel} and the respective conversion-related emission factor emf_{fuel} as well as the input of linked energy carriers ec' to generate ec and the respective emission factor for the supply of ec'.

This results in a system of n equations of type:

$$emf(ec) \cdot (P_{demand}(ec) + P_{in}(ec, ec')) = emf_{fuel} \cdot P_{fuel}(ec) + emf(ec') \cdot P_{in}(ec', ec), \tag{10}$$

for which the solution results in n emission factors emf. For the total emissions E_{tot} it then holds true that:

$$E_{tot} = \sum_{ec} P_{fuel}(ec) \cdot emf_{fuel} = \sum_{ec} P_{demand}(ec) \cdot emf(ec). \tag{11}$$

The determined emission factors emf comprise the CO_2 emissions associated with the supply of the simulated energy carriers and can become negative in case more CO_2 is bound than emitted during the generation of the energy carrier. In contrast, the conversion-related emission factors emf_{fuel} are external parameters. They reflect the emissions occurring due to the combustion of both external and simulated energy carriers as well as the CO_2 bound during the conversion process, and can also become positive or negative. Their quantification is based on the stoichiometry of the respective energy carrier input. However, the emissions occurring during the provision of these fuels due to for example mining and transport processes are not in the scope of this analysis.

When applying this approach to the described MES, for each simulated year, the total emissions are assigned to different energy carriers by setting up an emissions balance based on equation 16 for each region reg, time step t and simulated energy carrier ec. While each energy carrier is connected to the linked energy carriers ec´ via devices dev, in the case of electricity each region is also connected to the neighboring regions $reg´$ via trading capacities. The emission factors for the supply of the simulated energy carriers emf are the unknown variables of the linear equation system, which can be specified by:

$$\begin{aligned}
& emf(t,ec,reg)\cdot\left(\sum_{sec} P_{demand}(t,ec,sec,reg)\right.\\
& \left.+\sum_{dev}\sum_{ec'} P_{in}(t,ec,ec',dev,reg)+\sum_{reg'} P_{Export}(t,ec,reg,reg')\right)\\
& =\sum_{dev}\Big(a(t,ec,dev)\cdot\big(emf_{fuel}\cdot P_{fuel}(t,ec,dev,reg)\\
& +emf(t,ec',reg)\cdot P_{in}(t,ec',ec,dev,reg)\big)\Big)\\
& +\sum_{reg'} P_{Import}(ec,t,reg,reg')\cdot emf_{Import}(ec,t,reg')
\end{aligned} \tag{12}$$

All other variables are direct or indirect results from the simulation with the model ISAaR or external input data in case of the conversion-related emission factors emf_{fuel}. It can be seen that the demand is divided by consumption sectors sec and that energy carrier imports P_{Import} and exports P_{Export} are considered. In the case of electricity, a simplified approach is used to determine the emission factors of imports emf_{Import}. These factors are determined for the respective neighboring country by means of the ratio of CO_2 emissions to electricity generation in each hour of the year, which result from the optimization. The charging power of storage units is not explicitly included in Equation (12), meaning that all emissions occurring at a certain time are directly allocated to the final demand in the respective hour. The discharging process is implicitly included in the optimization results, because, in the event of discharging a storage system, the power from generation plants (and therefore emissions) are reduced.

In Equation (12) an allocation factor a is introduced to divide emissions between different energy carriers for multi-output processes. Since a variety of allocation methods exist, which can strongly impact the results, as shown in [58], two methods are compared in the following. For one thing, the method used by the International Energy Agency (IEA) [59], which is also referred to as the “energy method”, was chosen. In this case the allocation factor is determined from the load balance in each time step t. The allocation factor for each generated energy carrier ec and device dev is determined from the time-resolved output P_{out} of the respective energy carrier and the device's total output of energy carriers as described by:

$$a(t, ec, dev) = \frac{P_{out}(t,ec,dev)}{\sum_{ec} P_{out}(t,ec,dev)}; a \in [0; 1]. \tag{13}$$

Secondly, the Carnot method described in [58], which reflects the exergy of the outgoing energy carriers and is in turn also referred to as the "exergy method", was applied. In this case for each type of CHP conversion process pr, the share of emissions allocated to electricity is derived from the electric and thermal fuel efficiencies η_{el} and η_{th} as well as the theoretical Carnot efficiency η_c according to:

$$a_{el}(pr) = \frac{\eta_{el}(pr)}{\eta_{el}(pr)+\eta_c(pr)\cdot\eta_{th}(pr)}; a \in [0; 1]. \tag{14}$$

while the fuel efficiencies are expressed by the ratio of the output of the respective energy carrier to the total fuel input, for η_c it holds true that:

$$\eta_c(pr) = 1 - \frac{T_u(pr)}{T_o(pr)} \tag{15}$$

with T_u and T_o being the upper and lower temperature level of the process. In this case, an average Carnot allocation factor is quantified for each simulated year by weighting the different types of CHP processes by their annual share in total district heating generation in the scenario described above.

Finally, the solution of the system of equations delivers emission factors for the supply of each simulated energy carrier in each time step of the considered year and region, in this case Germany. The quantified coefficients do not only consider the exchanges between different energy carriers in MES, but also the exchange of energy carriers between regions in the context of an increasingly integrated European energy system. This approach is comparable to the method shown in [60], according to which the real-time emission factors of electricity for coupled regions are determined.

2.3.2. Marginal Method

There are different approaches to determine marginal emissions. Building on the mix approach, the so-called displacement mix approach [61] incorporates marginal effects by only including conventional power plants in the mix and, thereby, considering the feed-in priority of vRES. Furthermore, marginal emission factors can be derived based on the time series of electricity prices and the marginal costs of power plants as described in [9]. In the following, marginal emission factors are determined by comparing the results of the baseline scenario with a simulation run with a marginal increase in load.

It is important to note that the aforementioned marginal increase was applied in one single optimization run for the load of each time step. A further optimization run was then carried out for each year and each energy carrier under evaluation. Another approach to calculate marginal emissions would be to increase the load for a single time step and conduct 8760 (for each hour of the year) comparative optimization runs. However, in order to obtain a deviation beyond the calculation accuracy, significantly higher load deviations than the 1% applied here would be necessary. In addition, 8759 additional optimization runs would have been needed to determine a single annual marginal emission factor. The extent to which this approach reveals methodological weaknesses will be explained by examining the results in Section 3.4.

The calculations performed are optimized up to an duality gap of 1×10^{-5}. The choice as to when a load variation will be considered marginal is not intended to be the subject of investigation. Relative increases in electricity demand or district heating of 1% of the respective hourly value are implemented in order to avoid problems with the accuracy tolerance.

2.4. Marginal Cost Calculation

The marginal costs per energy carrier are a result of energy system models using linear programming. In a perfect market world without any trading restrictions and perfect foresight these marginal costs correspond to gross commodity prices. In [62] the extent to which marginal costs of electricity generation represent spot prices is described. In energy system modeling, the so called duality theorem is used to identify the marginal costs of supplying one additional unit of demand of an energy carrier. Therefore, marginal costs for every modeled time step and energy carrier are provided as an optimization result called "dual solution". Due to the fact that marginal costs are widely researched, e.g., in [63,64], no further description of this approach is provided herein. In contrast to the hourly emission factors, no allocation of costs is needed as the theory of duality considers all generation or flexibility opportunities and their temporal restrictions.

Due to the fact that virtual back-up capacities are being used to accelerate optimization, scarcity prices occur in a few hours of some modeled years. These prices reach the level of these virtual generation units in order to guarantee load covering at every hour. Since these units are or will not be existing in real world, these prices are replaced by the highest fundamentally explainable value during the processing of the resulting dataset. The average marginal costs and market values of vRES shown in the following chapter are also determined on the basis of the modified time series.

3. Results

The results are divided into an emissions and a costs section. Due to the different accounting and allocation methods, greater attention is devoted to the emission factors. These are shown in Sections 3.1.–3.4. The marginal costs of electricity and the resulting market values of vRES can be found in the Sections 3.5. and 3.6. In the following the focus lies on Germany and the energy carriers of electricity and district heating. All resulting datasets, yearly average values and hourly data for emissions and costs, have been made freely available (see "*6. Data Availability*"). Therefore, the following analysis represents an aggregated extract of the provided result data.

3.1. Emission Factors: Mix Method, Load Weighted Annual Average

A key indicator for assessing the decarbonization progress of the electricity sector is the annual average emission factor. Figure 5 shows the emission factors of electricity and district heating demand. In this case the mix method is used and the allocation is carried out according to Carnot.

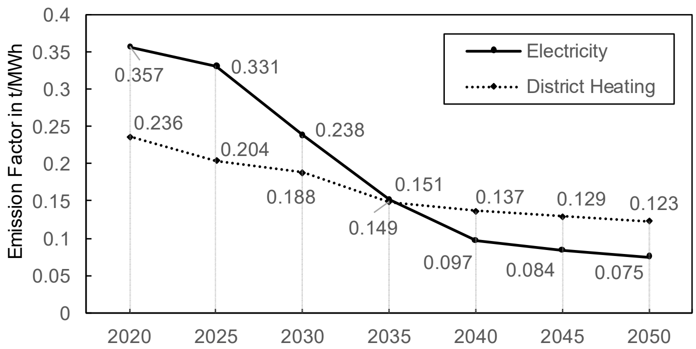

Figure 5. *Emission factor of electricity (mix) in tons of CO2 per MWh; combined heat and power (CHP) allocation method: Carnot.*

It becomes apparent that, on the electricity side, the considerable expansion of vRES results in a decrease in emissions. This is happening despite the phase-out of nuclear energy in 2022. In addition to the constant expansion of renewables, the subsequent decrease is attributable to the simultaneous reduction in capacity of coal-fired power plants. This leads to a 79% reduction of the electrical emission factor from 2020 to 2050. In the scenario considered, district heating is not subject to any major decarbonizing measures. Only a small expansion of renewable heat generators and power-to-heat measures takes place. The largest reduction in emission factor, however, is due to the fuel change in CHP generation from hard-coal to gas. Compared to the emission factor of the German electricity mix in 2017, which amounts to 0.486 kg/MWh [65], the factor for electricity in the year 2020 seems low. However, this is partly due to the method used to calculate cross-border electricity flows and the method for allocating emissions to district heating. The difference becomes even more pronounced when, on average, higher proportions of emissions are attributed to district heating. This occurs if the IEA method is deployed, which assumes that there is no exegetic difference between heat and electricity. In this case, a significantly higher proportion of emissions is attributed to district heating. In 2020 the emission factor of district heating for the IEA method is at 0.352 t/MWh, which is a plus of 50% compared to the values for the Carnot method. Conversely, the emission factors of electricity decrease by only 4% against Carnot. This is to be expected in view of the usually higher thermal than electric efficiencies of CHP power plants. With the decommissioning of emission-intensive CHP plants, this effect will slowly decline until the year 2050. In 2050, the emission factor for district heating according to IEA is 24% above Carnot, and for electricity 11% below.

Regarding the other modeled energy sources, it can be observed that the changes are significantly smaller. Due to the addition of hydrogen, the emission factor of methane is reduced by 0.002 t/MWh from 2020 to 2050. This small reduction is due to the high gas demand from FEC sectors compared to the low hydrogen produced from electrolyzers. The low hydrogen demand in the transport sector is covered by electrolysis. The hydrogen emission factor drops from 0.065 t/MWh in 2020 to 0.004 t/MWh in 2050, which is due to the reduced carbon intensity of electricity and the increase in times of low electricity prices at low emission coefficients. In 2020 the surpluses from renewables are still too small to produce 100% emission-free hydrogen. According to the calculations carried out, these events will occur more frequently in 2050.

3.2. Emission Factors: Marginal Method, Load Weighted Annual Average

While the two mix methods presented differ in the allocation of emissions for conversion units with several energy carrier outputs, the marginal approach uses a fundamentally different approach. As shown in Figure 6, the emission changes of a marginal load addition (marginal emission factor) deviate significantly from the average mix factors in Figure 5.

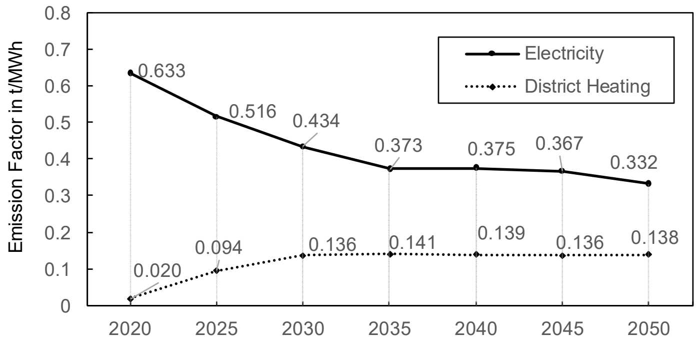

Figure 6. *Emission factor of electricity and district heating (marginal) in tons of CO2 per MWh.*

Whereas the emission factor for the mix method can be explained by the shares of generation technologies, the marginal power plant must be taken into account for the interpretation of marginal emission factors. For electricity it should be noted that the plant in question does not have to be located in Germany. The emission factors in the marginal method are determined primarily by conventional power plants. This can be explained by the design of the electricity market. The conventional power plants are deployed according to the principle of merit order, thus according to ascending marginal costs. Marginal costs of vRES are assumed to be €0 per MWh in order to model feed-in priority. The marginal power plant is the last power plant to be deployed to supply the residual load. Therefore, a marginal change in demand is balanced by adjusting the power output of this specific marginal power plant.

Since the conventional generation units in the residual load range will change constantly over the years from coal-fired power plants to renewable and gas-fired power plants, according to the optimization results the marginal emission factor for electricity will fall steadily from 0.633 t/MWh in 2020 by 48% to 0.332 t/MWh in 2050. The phase-out of nuclear energy does not lead to a temporary increase in the emission factor because this type of power plant rarely represents the marginal power plant.

In the case of district heating, it is noticeable that marginal emissions rise from 0.02 t/MWh in 2020 to 0.138 t/MWh in 2050. This is to be explained by the dimensioning of the cogeneration power plant fleet that will be in operation in 2020: in many district heating networks, the maximum thermal feed-in capacity of the CHP plants is above the annual maximum load of the heating network. The CHP power plants operate mainly in the colder half of the year due to higher residual electricity and heating demand in Germany. Overall, there are many times in the year when CHP power plants are in operation but not fully loaded. A marginal increase in district heating demand leads in many cases to an increase in the electrical and thermal output of a CHP plant and, therefore, to a displacement of another non-CHP plant that only generates electricity. As a result, additional heating demand can be supplied at high overall efficiencies.

The increase in the marginal factor until 2050 is due to the fact that CHP plants will drop out of the market from year to year. Additional heating at times of high renewable generation is primarily generated by gas-fired heating plants and a few electrical heating systems. On winter days with high residual loads and high heating demand, in 2050 the reduced German power plant fleet is fully utilized according to the scenario analyzed. Therefore, additional heating will then be supplied by gas-fired heating plants.

3.3. Emission Factors: Mix Method, Hourly Resolution

In parallel with the load-weighted annual average, the hourly profile of the factors is of high relevance. The annual duration lines for electricity in 2020, 2035 and 2050 are shown in Figure 7.

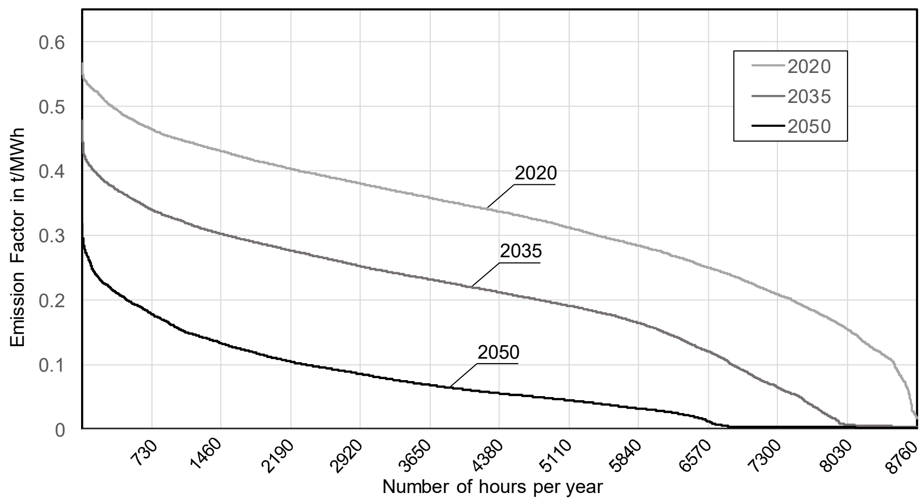

Figure 7. *Year duration line: hourly emission factor of electricity (mix) in tons of CO2 per MWh; CHP allocation method: Carnot.*

A key finding from Figure 7 is that in 2020 no hours with a factor of zero tons per MWh can be found. Although concepts for so-called vRES surpluses are already being applied today, the analysis clearly shows that in a European market analysis there will be no emission-free surpluses in 2020 according to the mix method and the scenario under consideration. However, if network constraints within market areas were taken into account, local surpluses would certainly be observed.

In the later years, on the other hand, times of zero emissions occur. In this trend scenario the total number of hours with an emission factor of approximately zero is ~750 h in 2035 and ~2150 h in 2050. Thus, the CO_2 reduction potential of future electrolyzers or other sector coupling measures depends strongly on their temporal operating concept. Due to high investments these technologies must reach very high operating hours in order to be profitable. However, the analysis of the emission factors shows that such an operating mode would not be 100% CO_2 emission-free in the scenario under consideration. On the other hand, it should be noted that this is a trend scenario that does not meet the climate goals of the Paris aggreement. A decarbonization scenario of this kind would have significantly higher vRES penetration and thus more frequent surpluses.

3.4. Emission Factors: Marginal Method, Hourly Resolution

As already seen in Figure 6, the marginal emissions behave in fundamentally different ways. The hourly values of the marginal method are shown in Figure 8.

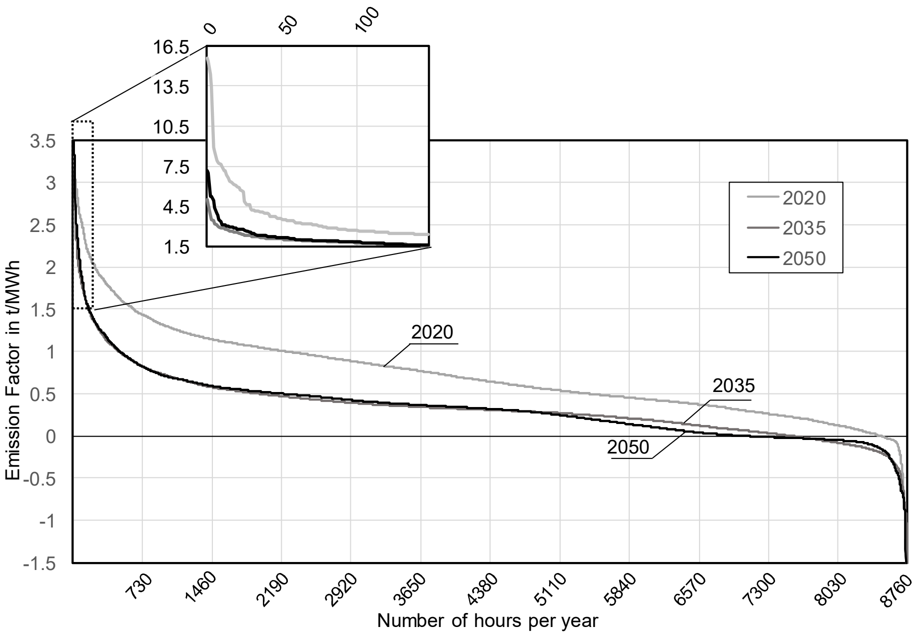

Figure 8. *Year duration line: hourly emission factor of electricity (marginal) in tons of CO2 per MWh in 2020, 2035, 2040.*

It can be seen that the hourly factors in the middle of the curve exhibit a higher level than the values according to the mix method. Furthermore, it is noticeable that the years 2035 and 2050 are much closer to each other in the marginal case. This is because in both cases in both cases gas-fired power plants constitute the marginal power plant, which results from the shift of marginal power plant due to the German coal phase-out. However, the largest difference can be observed in the minima and maxima. Here, the most important limitation of this method of calculating marginal emission factors becomes obvious: Two different energy systems are compared with each other in hourly resolution. But, due to the marginal change in demand, a temporally deviating operational characteristic of the "marginal system" occurs. Divergences in the hourly (dis)charging of storage systems or the operation of conversion processes result in hours during which significantly higher or lower emissions can be observed in the marginal calculation run compared to the reference case. This sometimes leads to large positive or negative marginal emission factors. In low-load situations, for example, even a small deviation in emissions can lead to high emission factors, up to 16 t/MWh, due to a small denominator. A more detailed analysis of the hourly data shows that the slight temporal offset of the hourly emissions results in high volatility over the profile of the marginal emission factors.

3.5. Marginal Costs

In the following, the results of marginal cost are shown and analyzed. This section focuses on electricity and district heating. The marginal costs for booth energy carriers are shown in Figure 9.

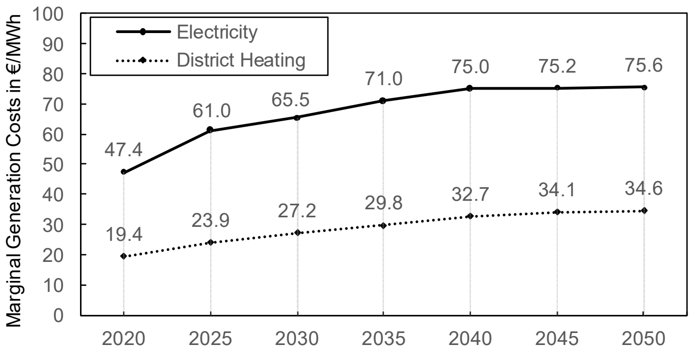

Figure 9. *Load weighted marginal costs of electricity and district heating generation in € per MWh.*

Due to the increase in prices for fuels and CO_2 certificates as well as a capacity reduction of nuclear and coal power plants, the marginal costs of electricity rise by 59% from €47.4 per MWh in 2020 to €75.6 per MWh in 2050. A steep increase is observed in the years 2020 to 2025 in consequence of the phase out of nuclear energy and some coal capacities. From 2035 onwards, the increase in fuel and certificate costs are compensated for by the increasing penetration of renewables. For district heating the absolute increase is lower (+€14.5 per MWh). In relative terms, however, this represents an increase of 78%. Renewables are also increasingly being used for district heating, but with significantly lower shares than for electricity. From this, it can be deduced that due to the low penetration of electric boilers or large heat pumps within district heating networks renewable expansion has hardly any repercussions for the district heating costs. The marginal costs structure in later years will be determined primarily by the gas and CO_2 certificate price development in the scenario under consideration.

The hourly costs of electricity in Figure 10 show that the majority of the hourly costs are within a narrow range of +/−€10 per MWh around the annual average. The high peaks on the left are due to inefficient oil-fired peak load power plants. The hours on the right with marginal costs of about zero are times when renewables constitute the marginal power plant. The number of hours increases from around 80 in 2035 to 760 in 2050. The first step, seen from the right side, can be assigned to the European nuclear power plants. This plateau is a good example for the fact that foreign power plants can also set prices. The second stage, also seen from the right, is noticeably flat. This price stage is set by power-to-heat units which have, in times of high vRES generation, gas heating plants as the sole opportunity for district heating supply. In this case, the marginal power plant is represented by CHP plants, which, in addition to generating electricity, also supply heat for district heating networks or industrial heating. With regard to the amount of electricity generated, their contribution to the emission mix is very small. Therefore, the number of emission-free hours in Figure 7 also includes this stage.

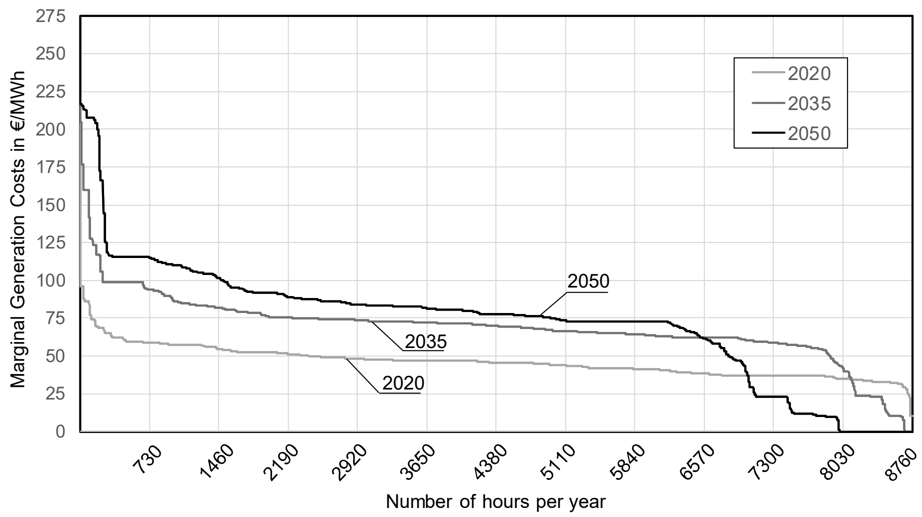

Figure 10. *Year duration line: hourly marginal costs of electricity in € per MWh.*

In principle, it can be seen that in the scenario under consideration a pronounced on/off characteristic of the electricity price occurs from 2035 on. This means that either gas-fired power plants with very similar marginal costs constitute the marginal power plant, or times with very low prices or marginal costs of €0 per MWh occur. However, the range of prices below €25 per MWh should be viewed with great caution. Here it is essential to what extent storage systems or sector-coupling technologies are taken into account in the scenario. In the scenario under consideration, these technologies are deployed only to a very limited extent. In particular, storage systems having high charging capacities can smooth out both low and high prices.

3.6. Marginal Costs: Market Values of Variable Renewable Energy Sources (vRES)

A common application of electricity price time series is the calculation of the "market value" or "market factor" of vRES. This value is determined by multiplying the hourly resolved generation profile of vRES and the marginal costs of the corresponding hour divided by the annual generation of this vRES type. The results for the vRES types "Wind Onshore", "Wind Offshore" and "PV" are shown in Figure 11.

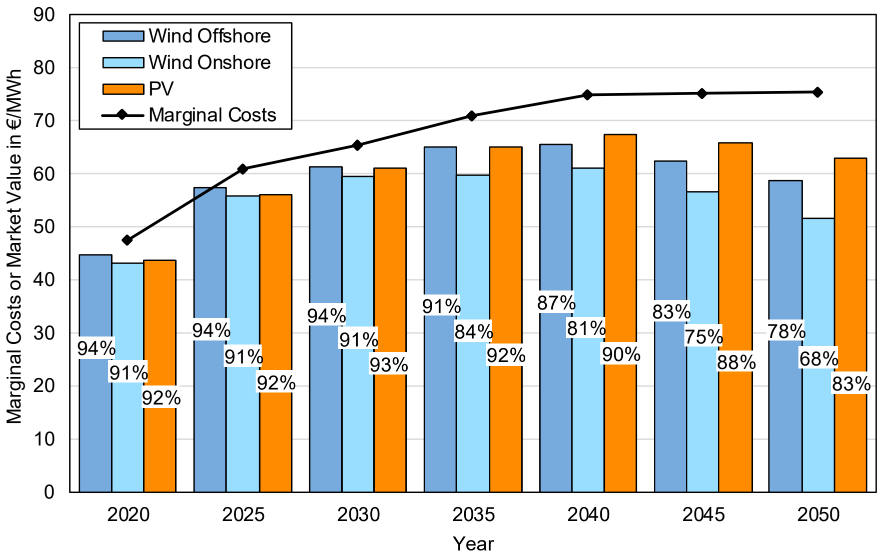

Figure 11. *Marginal costs of electricity and market value of vRES (wind and photovoltaic (PV)) in €/MWh.*

Current market values for wind are approximately at 86% (2016) of the average electricity price [66]. The difference compared to the high values shown in Figure 11 can be explained by the fact that negative electricity prices cannot be represented by fundamental electricity market modeling. Instead renewables are included in the modeling at marginal costs of 0 €/MWh. In reality, however, prices during periods of high vRES generation can become significantly negative. Furthermore, price peaks that are well above the marginal costs of the power plant and result from the bidding behavior of the market participants cannot be modeled from a fundamental point of view. This means that prices in times of low renewable generation are often higher in reality than in the model. However, due to the low vRES generation at such times, this effect is less weighted.

It should also be pointed out that in 2020 all technologies have very similar market values. Only the value for wind offshore is slightly higher due to the high full load hours. Despite the high simultaneity of the generation profile and low full load hours, PV has the lowest reduction in market value over the years, even with high PV installation rates in 2050. This is due to the high residual load correlation of PV, which leads to high generation at times of medium or high electricity marginal costs. The market value of wind onshore, on the other hand, decreases the most due to the largest share of electricity generation in absolute terms and the lower load correlation.

It should be noted, that even with an 82% share of vRES in the generation mix in 2050, the modeled vRES market values are in the range of 68% to 83%. Even considering the slight overestimation of the market value of renewables compared to current market data, the overall level of market values is still high. This is in contrast to a meta-analysis from 2013 [67], which predicts a significantly stronger reduction in market value for high shares of renewables. This behavior can be explained by the wide system boundaries of the model presented here. When modeling a large market area and considering flexibility options close to real-world conditions, such a drastic decrease in market values is not to be expected. A further factor that is of relevance for modeling future vRES market values is the calculation method of the renewable generation profiles. Due to the high-resolution of regionalization of vRES and the weather data used, as well as the consideration of different types of wind turbines, the effect of lower market values due to the high simultaneity of profiles does not occur. If historical vRES generation profiles had been used and had only been scaled, as is the case in many models, a significant decrease in the market value would have been observed.

3.7. Comparison: Emission Factors and Marginal Costs

In addition to the economic operation of consumer devices or storage systems, the ecological component is increasingly becoming the focus of attention. The extent to which economic and emission-friendly operating concepts interact is to be determined by an hourly comparison of marginal costs with specific emission factors. Therefore, the correlation of the hourly marginal costs with the emission factors according to the mix method using Carnot allocation is shown in Figure 12.

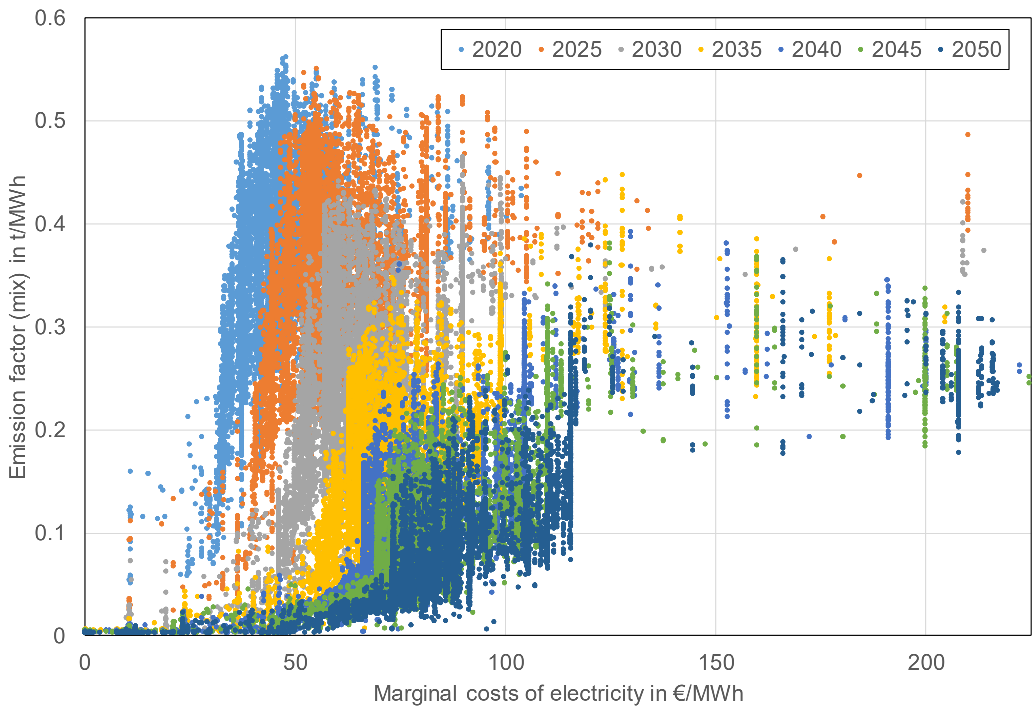

Figure 12. *Hourly emission factors of electricity (mix, Carnot) and marginal costs of electricity.*

It can be seen that there is a slight correlation between the two parameters for lower values. As vRES penetration increases over the years, this becomes evident especially during times of low prices. On the other hand, the point cloud is broadly spread with increasing prices. In 2020, with prices below €25 per MWh, the emission factor is guaranteed to be below 0.2 t/MWh while at prices above €35 per MWh the emission factor ranges from 0.1 to 0.5 t/MWh. As the price range of low emission factors widens over time, it becomes clear that a price-driven operation of flexibilities promises a low-emission operation, if emission factors based on the mix method are used as the basis for the evaluation. This finding is of high relevance for the selection of future control mechanisms for load flexibilization, e.g., the controlled charging of electric vehicles. It simplifies the requirements for designing a cost-efficient and emissions-friendly charging strategy, since low prices are sufficient as a control parameter in future energy systems. Due to the merit-order effect this applies only as long as there are little or no coal capacities with lower marginal costs than gas-fired units.

However, as soon as there is a large amount of flexibilities in the system, this statement cannot be made without the further consideration that the flexibilities in turn can strongly influence the price. The validity of the analyses made here is clearly limited to the scenario under consideration. Larger system adaptations due to additional sector-coupling technologies or storage systems require a holistic and systemic consideration in the form of separate scenario studies. Nevertheless, the analyses in Figure 7 and Figure 12 represent a good first indicator with regard to the expected operating hours in an emission-free operating mode for the scenario under consideration. Nevertheless, it should also be noted here that the mix method is only one assessment approach. For the evaluation of additional loads in particular, a supplementary look at marginal methods is recommended. The extent to which these methods can be applied is discussed below.

4. Discussion

The discussion of the results is divided into the categories of emission factors and marginal costs. Both the methodology behind the calculations and the results themselves are discussed. Conclusively, a critical look is taken at the energy system scenario and an outlook on scenarios to be examined in the future is given.

4.1. Emission Factors

The results for the calculation of the emission factors, which vary greatly depending on the method used, show that the right choice of emission assessment method depends on the application and demands for a critical reflection. While the mix method describes the state of a current or future energy system and is, therefore, suitable for assessing technologies in the respective system, the marginal method can be used to determine effects due to load changes resulting from the introduction of new technologies to the system. As the hourly resolved mix method provides a fundamental explanation of the state of a certain energy system, it is also suitable for analyzing historical or real-time data as done in [60]. The change-oriented marginal method, however, shows that even a small shift of the load can lead to a significant rise in the emission factor.

In [9] it is shown that the marginal and mix method can serve as indicators to identify characteristic hours of an energy system, e.g., hours with a large share of vRES or hours with vRES excess. In [9] also an alternative calculation of marginal emission factors according to the marginal power plant method is described, which obtained values that were more comprehensible than in the approach presented here, especially in the minimum and maximum range. A central shortcoming of the marginal approach described above becomes apparent: It compares two different energy systems which, based on their load, are optimized to meet this varying demand. This optimization results in dissimilar operations between the two systems. Due to the different temporal linking constraints, a single hour of the systems is no longer comparable. An alternative but computational-intensive approach is briefly discussed in Section 2.3.2. The simplified method to prevent these effects should, therefore, be used to calculate marginal hourly emission factors. The method presented is nevertheless suitable for an annual examination in which the hourly differences are not relevant. These different approaches of dealing with marginal effects resulting from the operation of generation processes are useful, especially for load management strategies. If the large-scale introduction of new technologies is to be assessed, in a next step the capacity expansion due to load changes also needs to be considered. For example, in order to assess a specific measure (e.g., electric vehicles) the emissions of two calculation runs, with and without the load of the respective measure, could be compared, as done in the course of the "Dynamis" project.

With regard to the allocation procedures for multi-output processes such as CHP, it should be noted that both methods are justified. However, the exergetic value of the respective output is considered to a greater extent in the Carnot method. The two allocation methods under consideration result in a slight shift of emissions between the energy sources electricity and district heating. The hourly profile and the development over the future reference years are almost identical.

The analysis of the annual marginal emission factor of district heating shows that this approach provides an interesting insight into the heat surpluses and full load hours of CHP plants in the scenario under consideration. In combination with the mix coefficient, a system understanding can be developed. In the scenario presented, decarbonization measures, e.g., electric heat generators or district heating storage systems, appear to be efficient on the basis of emission factors and marginal costs.

Apart from this, it is important to be aware that all the presented values are modeled data and highly dependent on the assumptions made.

4.2. Marginal Costs

The marginal costs in optimization problems are based on a scientifically approved method, which is why there is no methodological discussion herein. What needs to be discussed, however, are real price effects that are not included in the electricity price formation due to the modeling method. These include negative bids due to subsidies or due to avoided start-up or shut-down periods. Price jumps due to incomplete information, sudden power plant outages or forecasting errors for load and renewables are also not represented. In addition, seasonal or political price fluctuations in fuel costs and uncertainties of the EU Emissions Trading System (EU ETS) are not taken into account in pricing. As a result, the absolute level of the modeled electricity price is always lower in the context of validation with real data. For example, futures in the range from €45 to €53 per MWh for 2020 are traded nowadays [68]. Nevertheless, the comparison between the years in combination with the scenario data offers a considerable benefit for understanding system dependencies.

4.3. Energy System Scenario

The scenario examined in this paper shows a reduction in energy-related emissions of 66% compared to 1990. By contrast, the paths in line with the Paris agreement require an emission reduction of 80% to 95%. This illustrates that, in addition to the divergences shown in the methods of calculation, the fundamental scenario assumptions have a decisive influence on the average level of marginal costs and emission factors. In the course of the project “Dynamis” further scenario paths including higher decarbonzation rates for Germany are calculated and published using the method described. As these scenarios are characterized by a significantly higher degree of sector coupling, the relevance of a correct balancing of emissions in MES becomes even more important.

5. Conclusions

Based on the method described and the scenario data presented, emission factors and marginal generation costs have been calculated. In this context, an emissions accounting method has been proposed, which allows for determining time-resolved emission factors for different energy carriers in MES systems while considering the linkages between energy carriers. The applied methods, in particular those for the calculation of emissions, were discussed on the basis of a comparison. By providing the different allocation methods and calculation approaches, users of the published dataset can choose the appropriate method for their respective application. The resulting values can be reconstructed and put into context by a transparent description of the input data and the applied optimization constraints. For further application and for a better understanding of the model presented here, additional scenarios, which include a higher penetration of renewables, energy carrier conversion devices like electrolyzers, and a CO_2 cap, are of relevance.

6. Data Availability

The resulting dataset for emission factors and marginal costs is made available at https://openenergy-platform.org/dataedit/view/scenario/ffe_dynamis_emission_factors_marginal_cost and in JSON format at http://opendata.ffe.de/dynamis-emission-factors.

Author Contributions: Conceptualization and methodology of the multi-energy carrier model, software, data curation, writing—sections on multi-energy system model, energy system scenario, results and discussion, visualization (F.B.); conceptualization and methodology of emissions accounting, writing—sections on introduction, emissions accounting and factors, reviewing and editing, project administration (A.R.)

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Appendix A

Modeling of power plants:

As shown in Equation (A1), $P_{el\ out}$ can be described using the electrical generation capacity online $P_{el\ out,onl}$ and the minimum load factor rlf. $P_{el\ out,onl}$ is the maximum capacity which can be supplied in the next time step without an additional start-up process. The rlf stands for the ratio of minimum to maximum rated capacity of the power plant.

$$\begin{gathered} P_{el\ out}(t, dev) \leq P_{el\ out,onl}(t, dev) \\ rlf \cdot P_{el\ out,onl}(t, dev) \leq P_{el\ out}(t, dev) \end{gathered} \tag{A1}$$

The costs of start-up (stu) processes are considered by pricing positive changes in the capacity online $P_{el\ out,onl}$. This positive delta $\Delta P_{el\ out,onl}$ is calculated by subtracting the values of the variable for two consecutive time steps.

$$\begin{gathered} P_{el\ out,onl}(t, dev) - P_{el\ out,onl}(t-1, dev) \leq \Delta P_{el\ out,onl} \\ C_{stu}(t, dev) = f_{stu} \cdot \Delta P_{el\ out,onl} \end{gathered} \tag{A2}$$

To prevent a constant change in the online output, the partial load behavior of the power plants must be taken into account. The following equation partly corresponds to the formulation from [21]. The last term of Equation (A3) is added to include the losses of combined heat and power (CHP) operation using the CHP loss index $c_{chp,v}$. This index reflects the efficiency losses in operation with heat extraction. The losses depend on the absolute level of heat extraction $P_{th\ out}(t, dev)$.

$$\begin{aligned} P_{fuel}(t, dev) = {} & P_{el\ out,onl}(t, dev) \cdot rlf(dev) \left(\frac{1}{\eta_{min}(dev)} - \frac{1}{\eta_{marg}(dev)} \right) + \frac{P_{el\ out}(t, dev)}{\eta_{marg}(dev)} \\ & + \frac{P_{th\ out}(t, dev)}{\eta_{max}(dev) \cdot c_{chp,v}(dev)} \end{aligned} \tag{A3}$$

The marginal efficiency η_{marg} represents the reciprocal of the marginal heating rate between minimum (min) and full (max) load as described by:

$$\eta_{marg}(dev) = \left(\left(\frac{1}{1 - rlf} \right) \cdot \left(\left(\frac{1}{\eta_{max}(dev)} \right) - \left(\frac{rlf}{\eta_{min}(dev)} \right) \right) \right)^{-1}. \tag{A4}$$

Due to the representation of district heating as energy carrier, a distinction is made between back-pressure and extraction condensation turbines when modeling CHP. The equations used in order to model the plant behavior characteristics are taken from [69,70]. The following applies to extraction condensing turbines under consideration of the CHP coefficient c_{chp}:

$$\begin{gathered} 0 \leq P_{el\ out}(t, dev) - c_{chp}(t, dev) \cdot P_{th\ out}(t, dev) \leq \infty \\ 0 \leq P_{el\ out}(t, dev) + c_{chp_v}(dev) \cdot P_{th\ out}(t, dev) \leq c_{avail}(t, dev) \cdot P_{el\ max}(dev) \end{gathered} \tag{A5}$$

For backpressure turbines, the CHP loss index is set to 0. The operating costs are determined based on the fuel costs f_{fuel} and the CO_2 certificate prices f_{CO_2} in combination with the emission factor emf of the specific device.

$$C_{fuel}(t, dev) = \left(f_{fuel} + f_{CO_2} \cdot emf_{conv/gen}\right) \cdot P_{fuel}(t, dev) \quad \text{(A6)}$$

This equation applies to power plants with external fuel consumption (generation devices, such as coal power plants). If the device is linked to a modeled energy carrier (conversion device e.g., gas power plant), then the $P_{fuel}(t, dev)$ term is replaced by $P_{in}(t, dev, ec')$. The fuel costs f_{fuel} in this case are 0. The costs are accounted for at the system boundaries when the fuel is imported by the import/export element.

It remains to be discussed whether the complexity described above is necessary to model conventional power plants, as well as whether this applies to the 2050 energy system described, which consists of a more homogenous power plant fleet. Nevertheless, the chosen method of modeling shows a high accuracy compared to a static efficiency and is sufficiently detailed compared to a mixed-integer linear program, especially against the background of the uncertainties resulting from the wide system boundaries and the time horizon of the consideration.

Appendix B

Modeled regions:

Albania, Austria, Bosnia and Herzogovina, Belgium, Bulgaria, Switzerland, Czech Republic, Germany, West Denmark, East Denmark, Estonia, Spain, Finland, France, Great Britain, Greece, Croatia, Hungary, Ireland, Italy, Kosovo, Lithuania, Luxembourg, Latvia, Montenegro, Northmacedonia, Northern Ireland, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Sweden, Slovenia and Slovakia.

Appendix C

Table A1 shows the specific fuel costs referring to the net calorific value. The values for 2015 are derived from [71] for hard coal, from [72] for oil and gas and from [73] for lignite. For all energy carriers the costs in 2025, 2030, and 2035 are taken from [38] scenario B. For 2050, a relative increase from 2030 to 2050 according to [23] is assumed for hard coal, gas, and lignite. Between 2035 and 2050, according to [2,23] the cost level of oil is only slightly increasing and decreasing, respectively. Therefore, the cost of oil increased only slightly and decreased, respectively. The price of CO_2 certificates, which is also depicted in Table A1, is taken from market data in [74] for the year 2015. An average value for future price development is derived from various scenario studies [2–6,18,23,75].

Table A1. *Costs (real) of fuels (net calorific value) and prices of CO2 certificates.*

Fuel:		Hard Coal	Lignite	Methane	Oil	Uranium	CO_2 Price
Unit:		€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/t
Costs:	2015	8.3	3.0	20.2	30.1	3.6	5.4
	2020	8.4	4.3	22.7	40.0	3.3	20.1
	2025	8.5	5.6	25.2	49.9	3.3	31.0
	2030	8.4	5.6	26.4	48.3	3.3	41.8
	2035	8.5	5.6	27.9	53.0	3.3	52.7
	2040	8.9	5.6	28.0	53.0	3.3	63.5
	2045	9.3	5.6	28.0	53.0	3.3	74.4
	2050	9.8	5.6	28.1	53.0	3.3	85.2

The direct CO_2 emissions resulting from the combustion of fuels, are determined based on stoichiometry for methane and from the national greenhouse gas inventory report [75] for all other fuels. Table A2 gives an overview of the resulting emission factors of fuels.

Table A2. *Direct CO2 emission factors of fuels (net calorific value).*

Fuel:	Hard Coal	Lignite	Oil	Methane
Unit:	t/MWh	t/MWh	t/MWh	t/MWh
Emission factor:	0.337	0.399	0.264	0.199

Appendix D

District Heating

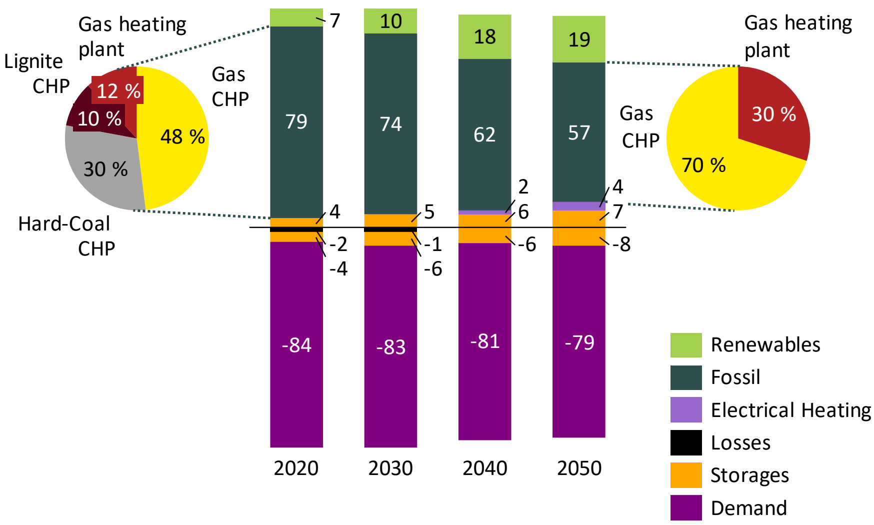

Figure A1. *German energy carrier balance district heating in TWh.*

Methane

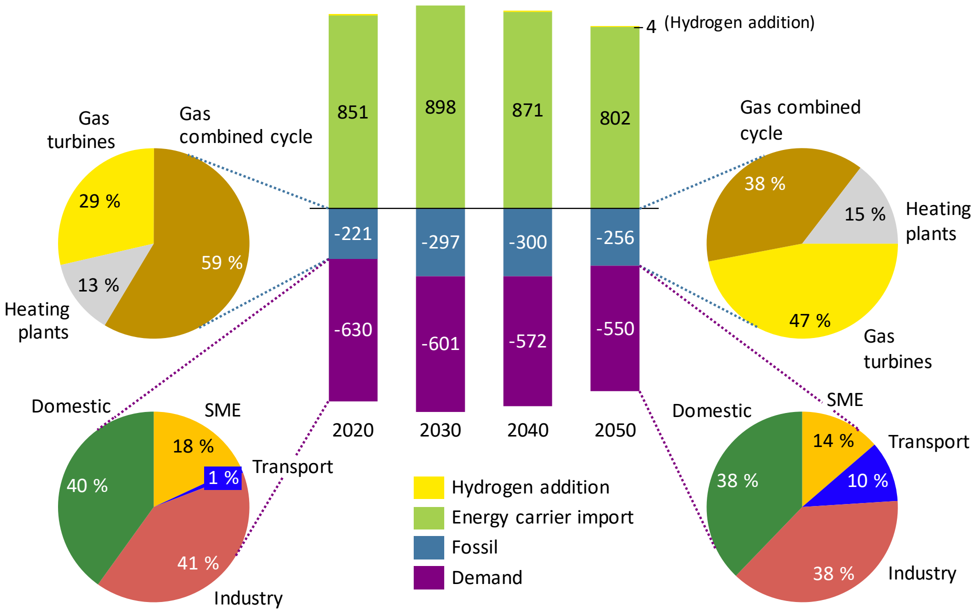

Figure A2. *German energy carrier balance of methane in TWh.*

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Assessment of grid optimisation measures for the German transmission grid using open source grid data

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1. Abstract

The expansion of capacities in the German transmission grid is a necessity for further integration of renewable energy sources into the electricity sector. In this paper, the grid optimisation measures 'Overhead Line Monitoring', 'Power-to-Heat' and 'Demand Response in the Industry' are evaluated and compared against conventional grid expansion for the year 2030. Initially, the methodical approach of the simulation model is presented and detailed descriptions of the grid model and the used grid data, which partly originates from open-source platforms, are provided. Further, this paper explains how 'Curtailment' and 'Redispatch' can be reduced by implementing grid optimisation measures and how the depreciation of economic costs can be determined considering construction costs. The developed simulations show that the conventional grid expansion is more efficient and implies more grid relieving effects than the evaluated grid optimisation measures.

2. Introduction

Due to an increasing share of renewable energy sources (RES) in the German electricity sector, a secure and reliable energy transmission becomes necessary. The conflict between cost and supply reliability, grid operation and planning faces major challenges. Grid expansion is reliable but unpopular with the public [1] and cost-intensive [2], while several 'Grid Optimisation Measures' (GOMs) are also able to reduce or redistribute transmission load in order to avoid curtailment, redispatch and the construction of new lines. The research project *MONA 2030*[5] analyses and compares the GOMs 'Demand Response' (DR), 'Power-to-Heat' (PtH), 'Overhead Line Monitoring' (OLM) and 'Grid Expansion' (GE) [3]. The FfE energy system model ISAaR[6] is applied for assessing the potential, availability,

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[5] MONA 2030 (funding code 03ET4015) is co-funded by German Federal Ministry of Economic Affairs and Energy through the funding initiative "Zukunftsfähige Stromnetze".
[6] ISAaR: Integrated simulation model for planning the operation and expansion of plants with regionalisation.

reliability and cost efficiency of these grid optimisation measures. An evaluation of the measures is carried out for the year 2030 regarding the German transmission grid in consideration of the neighbouring countries. Several approaches are applied to handle OpenStreetMap (OSM) grid data. SciGRID [4], osmTGmod [5] and Gridkit [6] are used as grid data sources beside data without an open source license like the BNetzA "Integral" dataset[7] [7] or the grid data sets of the TSOs TransnetBW [8], Amprion [9], 50Hertz [10], Tennet [11] and APG [12][8].

Focus of this paper is the documentation of the modeling methodology, the used grid data, the GOM scenarios and the discussion of simulation results.

3. Method

A valid assessment of GOMs has to be based on quantifiable parameters. Therefore, an approach is developed to meet the requirements of an adequate power flow simulation and a realistic modeling of the GOMs' dispatch. Two major criteria for the planning of grid development are the parameters redispatch and curtailment. Both values call for a comparison of market simulation results and grid based calculations. In order to analyse the impact of grid-orientated GOMs like 'Overhead Line Monitoring' and 'Grid Expansion', a market simulation with low detailed spatial resolution is performed. Thereupon, a so called PTDF (Power Transfer Distribution Factors) run with fixed load and generation data from the market simulation for each node is conducted (see [13] and [14] for reference). While this method is quite suitable for grid-orientated measures, the assessment of measures like 'Power-to-Heat' and 'Demand Response' is more challenging. Their dispatch is influenced by grid restrictions and factors like district heating demand, electricity cost or operational restrictions (e.g. for DR). Therefore, the FfE energy system model ISAaR is extended to perform an integrated dispatch of power plants, renewable energy, Power-to-Heat elements, heat plants and industrial consumers with DR, considering a PTDF-linearised grid consisting of DC and AC lines. This approach allows for performing a uniform comparison among all GOMs regarding the parameters curtailment, redispatch, and economic costs. The coupling of electricity and heat generation within the model benefits the evaluation of combined system costs and facilitates comparisons of GOMs considering effects on the complete, coupled energy system.

[7] This dataset was made available by BNetzA for exclusive project use.
[8] Each dataset is publicly available via download; no license information is given.

The following description of the methodology is divided into three subsections:

1. Description of the ISAaR model with focus on the modeled elements of the energy system.
2. Implementation of a linearised power flow approach, known as PTDF.
3. Discussion of the setup of the optimisation sequence.

3.1. ISAaR Model

The FfE energy system model ISAaR has been developed within the project "MOS – Merit-Order of Energy Storage" [14]. The linear model optimises the deployment and the expansion of power plants. In order to evaluate the previously mentioned GOMs, the models' structure is modified as shown in **Figure 1.**

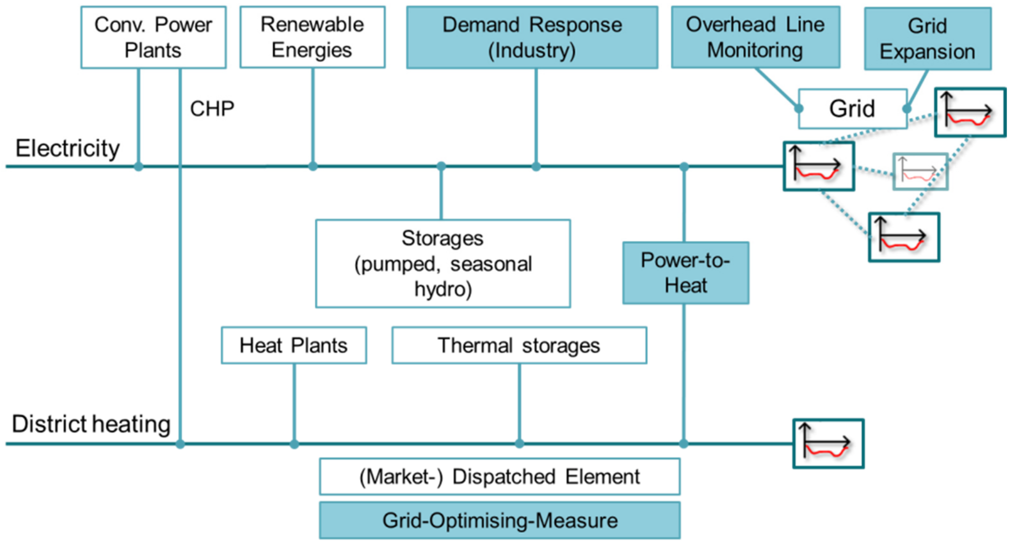

Figure 1: *Schematic Overview of the ISAaR models' structure.*

The spatial resolution for the electricity sector in the German-Austrian market region is grid nodes (#496) and for the heating sector grid regions (#26). The grid regions are described in [16] for Germany and in [17] for Austria. At each node or in each region a load equation is set for the electrical and the thermal sector. Additionally, the thermal sector is divided into two parts: public demand and industrial demand. This adjustment is caused by major differences in the seasonal characteristics of the load curves.

In general, the model follows the basics of linear programming for energy systems as described in [18] and [19]. Differing from the traditional formulation for power plants and storages, the mathematical formulation for non-typical elements like Demand Response, Power-to-Heat or combined heat and power plants (CHP) are described in detail in [15].

3.2. Technical Implementation

Many energy system modelers use predefined software like GAMS [20], whereas our approach is based on a combination of Matlab®, PostgreSQL, and CPLEX®. Especially the usage of PostgreSQL ensures a high degree of flexibility in generating and combining scenarios. The internally developed "process model" ([15] and [21]) is an important element when working with large amounts of data covering grids, renewable energies, loads and power plants. The technical implementation of the ISAaR model is shown in **Figure 2**.

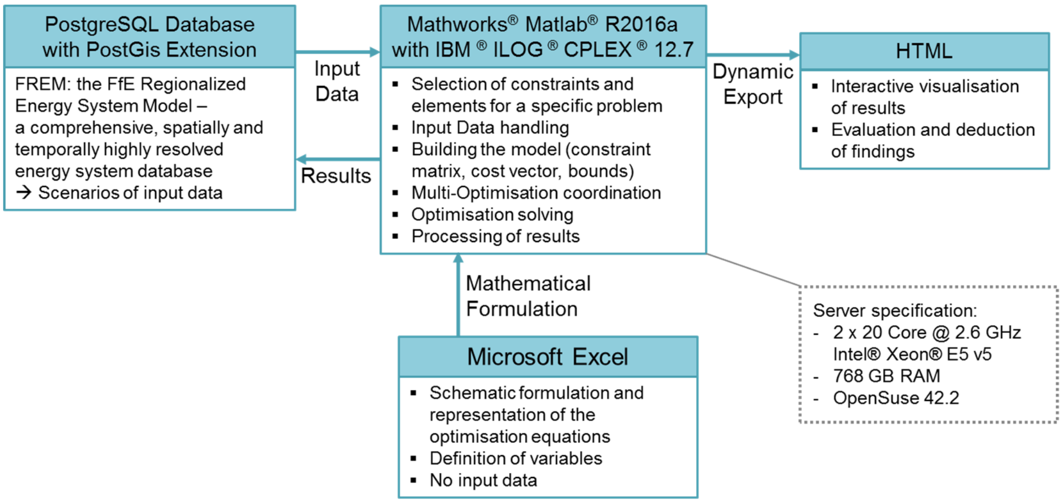

Figure 2: *Technical implementation of the ISAaR model.*

Standard simulation runs use a rolling horizon (168 h) approach for a whole year and take around 20 to 30 h of computation time. Up to six simulations can be solved simultaneously in parallel configuration. The standard model consists of 496 nodes, applied in a PTDF-grid simulation and the elements mentioned in **Figure 1**.

Simulation results are visualised interactively by an html-webpage for the evaluation of outcomes and the derivation of insights. A *Leaflet* JavaScript map [22] displays the load of transmission lines and the amount of curtailment and redispatch. Power plant deployment, the utilisation of renewable energy and further analysis is depicted in charts by *amCharts* [23].

3.3. Grid Modeling: DC power flow

Typical grid representations as given in [24] provide good accuracy but come up with computational expenditure. In order to reduce complexity while providing reasonable accuracy, the ISAaR model uses a DC power flow, a linearization of non-linear power flow equations. A clear derivation of this method is given in [25] and [14]. Load flow equations are simplified, assuming no voltage drops, small voltage angles along a transmission line and the disregard of reactive power and line losses. The calculation of the utilisation of overhead lines $\boldsymbol{P_{link}}$ is simplified by a multiplication of the PTDF matrix (Power Transfer Distribution Factors matrix) and the vector $\boldsymbol{P_{node}}$, representing power injections at the grid nodes:

$$\boldsymbol{P_{link}} = PTDF \cdot \boldsymbol{P_{node}} = (B \cdot A) \cdot (A^T \cdot B \cdot A)^{-1} \cdot \boldsymbol{P_{node}}\,. \quad (1)$$

A [V]:	Incidence matrix, describing the grid topology
B [1/Ω]:	Diagonal matrix of line susceptances $B = diag(1/x)$
$\boldsymbol{P_{node}}$ [W]:	Vector of power injections at the grid nodes
$\boldsymbol{P_{link}}$ [W]:	Vector of power flows of the overhead lines

Due to its singularity, the expression $(A^T \cdot B \cdot A)$ cannot be inverted. Therefore, one random node of the network has to become a reference point and must be removed from **equation 1**. A power injection in $\boldsymbol{P_{node}}$ can then be interpreted as a transaction $\boldsymbol{T}$ of energy from one node of the network to the declared reference point. The values in a column of the PTDF matrix represent the share of the power from a corresponding power transaction in $\boldsymbol{T}$ flowing through the lines of the network. Equation 1 establishes a causal link between the resulting power flow and the power transaction between nodes. Since the European transmission network consists of transmission lines with different voltage levels a transformation of line parameters for normalisation is applied:

$$X^* = a^2 \cdot X \text{ with } a = 1/u \,. \tag{2}$$

X [Ω]: Line reactance
X^* [Ω/V²]: Normalised line reactance
u [V]: Voltage level of the line

This transformation integrates all AC lines into one PTDF matrix. High voltage direct current (HVDC) lines have the ability to control the flow of current and are therefore, contrary to AC lines, independent from power injections at the grid nodes. A HVDC line is included into the PTDF matrix by creating a new transaction $T_{x \to y}$ from line start node x to the line end node y. Its power flow is assigned to $P_{link,DC}$:

$$\begin{bmatrix} \boldsymbol{P_{link,AC}} \\ P_{link,DC} \end{bmatrix} = \begin{bmatrix} PTDF & 0 \\ 0 & 1 \end{bmatrix} \cdot \begin{bmatrix} \boldsymbol{T_{AC}} \\ T_{x \to y} \end{bmatrix} . \tag{3}$$

$\boldsymbol{T_{AC}}$ [W]: Transaction of power towards the reference point
$T_{x \to y}$ [W]: Transaction of power over a HVDC line from start node to end node

3.3.1. Accuracy of DC power flow

The linearisation of the power flow is accompanied with a decreased level of accuracy. In the papers of [26] and [13], the authors show a reasonable precision of the DC power flow if line loads are smaller than 70 % and deviations of voltage levels in the grid are reasonably small.

3.3.2. Correction of line data

With the collected grid data, mentioned in chapter 4.1, the grid model is generated and the outcome is revised. Due to the variety of data sources, some lines possess faulty and dissimilar line parameters (especially line reactances), resulting in distorted power flows in the ISAaR model. To overcome this issue, these inconsistencies are rectified in a systematic correction process which is described in [27]. Only obviously wrong parameters are corrected utilising further available line data and applying standard values where necessary.

3.4. Optimisation Sequence

Figure 3 reveals the structure of the models' optimisation sequence which allows for an analysis of the complete European energy system as computational effort is reduced. The two European simulations generate cross-border-flows for further simulations of the German-Austrian energy market which depend on available net transfer capacities between market regions and the power plant capacities in Europe. Therefore, a European market simulation (EU-Ma[9]) is performed first. The cross-border congestion management of this simulation run is based on the NTC (Net Transfer Capacity) approach. Cross-border line projects are considered with the same ratio of NTC to thermal capacity as existing cross-border links. The spatial resolution of load data and renewable generation corresponds to the NUTS 3 level [28]. Power plants are modeled per unit based on the 'Platts power plant database' [29][10] in combination with the TYNDP[11] scenario "Vision 2" [30]. The values for load and installed capacity of renewable energy per country are also derived from [30]. The regionalisation is based on a geospatial analysis in combination with weather data (7 km grid) from the "COSMO-EU" dataset [31] and statistical data like Eurostat [32]. Further information and citation of used data can be found in [27].

For the following step (EU-Ne[12]), the aggregated European transmission grid (see section 5.1.) is added to the model. Due to the high number of nodes (#1500) and lines (#2800), resulting in exceeding computation capacities, a simple PTDF run is performed with a fixed plant dispatch. The optimised elements are HVDC lines, synthetic generation plants and synthetic consumers to keep every load equation feasible. The dispatch of those synthetic elements may be interpreted as (cross-border) demand of curtailment and redispatch.

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[9] Ma: Market
[10] The 'Platts power plant database' is a commercially available dataset.
[11] Ten-Year Network Development Plan
[12] Ne: "Netz" (Grid)

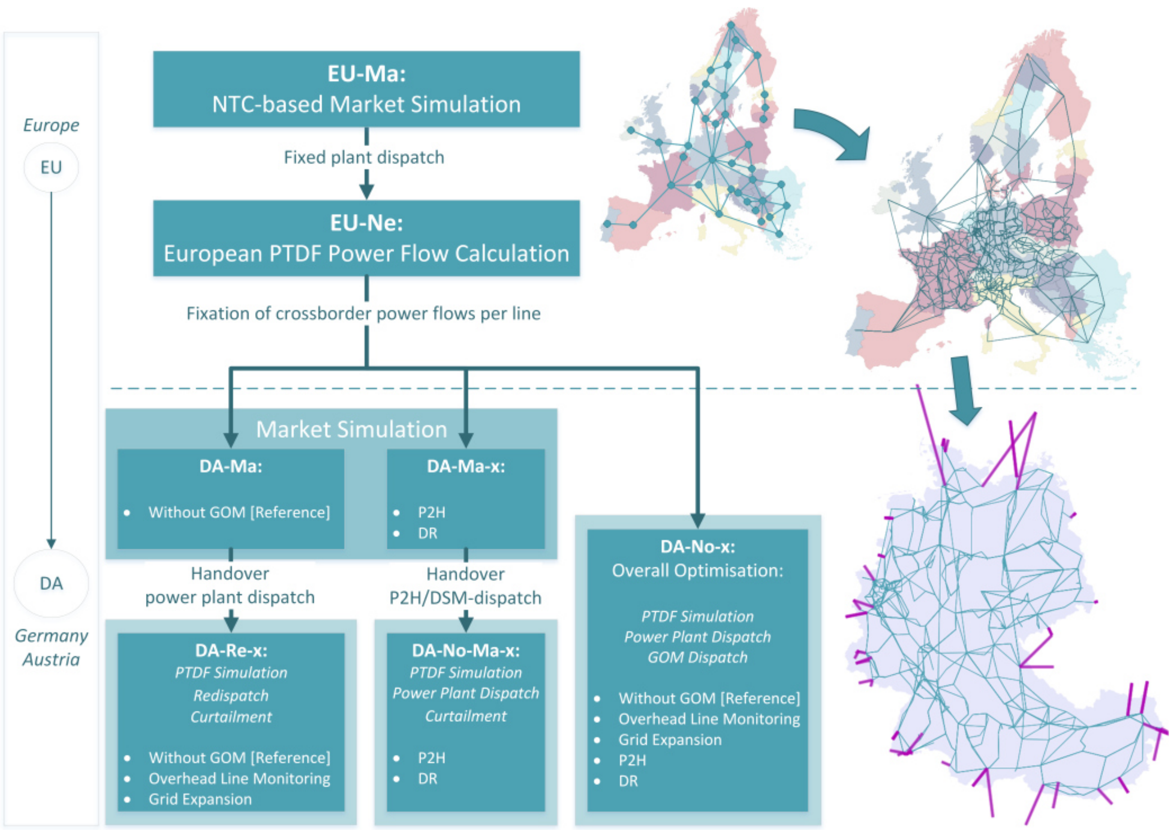

Figure 3: *Schematic representation of the optimisation sequence.*

With fixed, previously calculated European cross border flows, a market simulation for the German-Austrian market region is performed (DA-Ma). To compare market and grid related dispatch of the GOMs Power-to-Heat and Demand Response, a market simulation considering these GOMs (DA-Ma-x[13]) and a PTDF run with fixed market dispatch of GOMs (DA-No[14]-Ma-x) is performed. For grid related GOMs ('Overhead Line Monitoring' and 'Grid Expansion'), a PTDF run with additional costs on deviation from market dispatch is set up in order to quantify curtailment and redispatch volumes (DA-Re-x). It is not possible to determine the redispatch volume if a load-manipulating GOM like 'Demand-Response' or 'Power-to-Heat' is used. Therefore a third PTDF run is carried out. This run contains an optimised power plant dispatch and GOM dispatch. The resulting overall economic costs for power and heat generation from two simulations with and without the GOM are taken to assess the GOMs impact.

4. Grid Optimising Measures (GOMs)

The impact of a GOM is strongly dependent on its level of implementation. For example, the grid expansion of multiple lines may lead to higher specific savings than expanding one single line. In order to consider this effect, several scenarios are formed to represent different implementation levels of the GOMs 'Overhead Line Monitoring' and 'Grid

[13] „x" is a placeholder for different GOMs.
[14] No: "Netzoptimierung" (grid optimisation)

Expansion'. The selection of lines to be upgraded or monitored first, is based on their line loading in the reference case.

4.1. Overhead Line Monitoring (OLM)

'Overhead Line Monitoring' allows to recognize and exploit additional existing weather-related transmission capacities. The temperature of a line is monitored in order to control its slack and thus keep to valid norms (DIN EN 50341) while avoiding early ageing [33]. With equations for the thermal balance in an overhead line discussed in [3], the line temperature can be approximated dependent on weather conditions and the heat input ($I^2 \cdot R(T_C)$) through current flow:

$$q_c + q_r = q_s + I^2 \cdot R(T_C)\,. \tag{4}$$

q_C [W/m]:	Heat removal through convection
q_r [W/m]:	Heat removal through radiation
q_s [W/m]:	Heat input through solar radiation
I [A]:	Current through power line
$R(T_C)$ [Ω/m]:	AC resistance of power line at line temperature T_C

The maximum current in the overhead line can be calculated for the maximum line temperature T_C and the prevailing weather-conditions wind velocity, wind direction, solar radiation, and ambient air temperature. Divided by the maximum norm-line transfer capacity of the overhead line, its additional transmission capacity can then be depicted.

Knowing the route of all German transmission lines and the weather data for the year 2012, the available potential of additional transmission capacities is computed for every single line and for every hour of the year. Furthermore, technical restrictions of OLM are considered: on the one hand, current flow is restricted through limitations in elements like circuit-breakers. On the other hand, current flow has to be limited due to a higher voltage drop and the increased need of reactive power in the lines, leading to a risk of system instabilities. Thus, additional transmission capacities are restricted to 50 % of the norm line transfer capacity, except the current flow is restricted further by technical limits of other elements.

4.2. Power-to-Heat (PtH)

As shown in **Figure 1**, Power-to-Heat (PtH) is a sector coupling element. The dispatch of this element depends on the thermal load situation in its assigned district or industrial heating network. On the one hand, PtH is used as an additional load which may avoid curtailment of renewable energy if placed at a convenient location within the transmission grid. On the other hand, PtH, in combination with CHP plants and thermal storages, leads to an increased system's flexibility.

Provided that future PtH expansions are not driven by grid related reasons, the penetration rate is set to 25 % of the thermal power input of existing district heating networks (state 2015). Assuming that the largest German district heating networks are equipped with PtH-devices by 2030, 9.2 GW of PtH capacity is expected to be installed.

4.3. Demand Response (DR)

Power demand of the industry sector can be flexibilized and thus be utilised for temporarily unloading bottlenecks in the transmission network. In [34], the technical potential of demand response is assessed and its economic considerations are elaborated. In the ISAaR model, 2.2 GW in large electricity-consuming companies and 1.6 GW in cross-sectional processes are available for flexible usage. In general, the two fields of DR-application, modeled in ISAaR, are the shift and the loss of production. Conditions on the frequency of demand response dispatch are set in [15]. The regionalisation of DR is oriented to the allocation of employee-numbers and heavy industry locations.

4.4. Grid Expansion

Besides ‘Overhead Line Monitoring’, ’Grid Expansion’ (GE) is another approach to add transmission capacities to the grid. ‘Grid Expansion’ can be realised in several ways. There are the options of constructing new transmission lines in used or new paths, adding circuits to an existing line or increasing its voltage level. Depending on the individual project, grid planners have to choose the best expansion method for an appropriate grid operation. GE usually comes with high investment costs, but also with high benefits for the transmission grid due to decreased curtailment of renewable energy and reduced redispatch volume.

In the reference scenario, an analysis of all transmission lines is conducted. The most stressed lines are then considered for ‘Grid Expansion’- measures in several scenarios. For 220 kV AC lines, the voltage level is increased to 380 kV. For 380 kV, new AC lines with a norm voltage of 380 kV are built with two circuits on the existing path.

5. Input Data

Due to the enormous quantity of input data, the focus of this chapter addresses grid data. Further information on input data can be obtained in [35] (scenario “standard”).

5.1. Grid Data

Figure 4 gives an overview of the used grid data. In the ISAaR model, the open-source toolkit Gridkit [6] is used to describe the transmission grid of Europe outside Germany and Austria. With an aggregation process, the grid is simplified in countries distant from and not neighbouring Germany and Austria (see [27]). Due to a lack of reasonable line parameters, standard values from literature are used. With results from the SciGRID project [4], grid data in Germany is validated. Applying the data from the model osmTGmod [5], precise geographic information of transmission lines can be obtained and utilised for the computation of additional transmission capacities with OLM. In parts of the grid, where the transmission capacity of the distribution grid becomes relevant (especially the Ruhr area and the region at the German-Austrian border), secondary lines (110 kV) are considered. Line data is directly taken from Open Street Map [36]. Detailed information on the collection of grid data is given in [27].

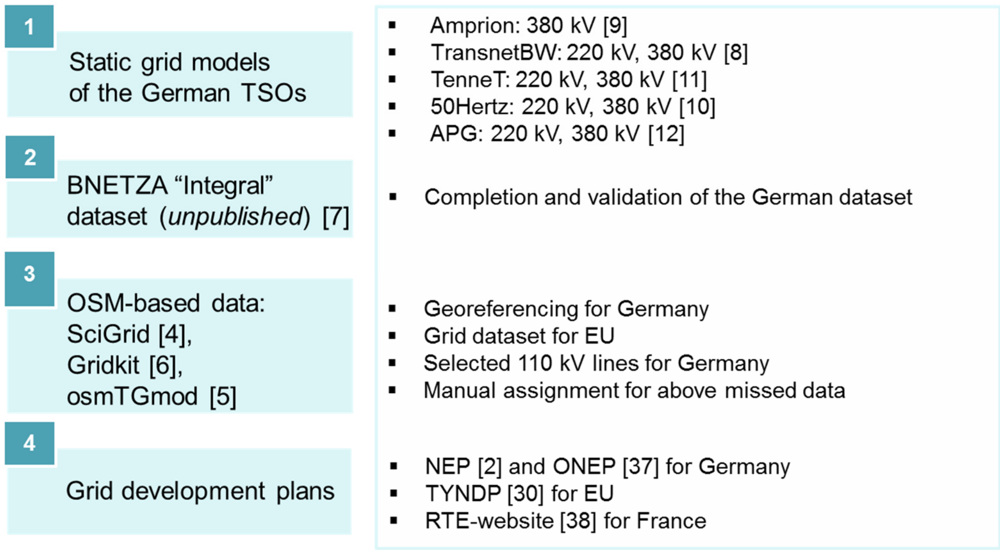

Figure 4: *Origin and usage of different grid data sources*

5.2. Surrounding Scenario

To perform simulations of the unit commitment in 2030, assumptions on the energy system have to be made. Therefore, the "standard" surrounding scenario of 2030 is set in [35]. The installed capacity of power plants in Germany in 2030 is made up of 23.2 GW coal-fired plants and 34.2 GW natural gas-fired generators. The renewable capacities consist of 73.8 GW onshore wind power, 15 GW offshore wind power, and 75 GW photovoltaic power. The regionalisation of RES is carried out as shown in [39]. The annual energy demand is set to 496.2 TWh_{el}, comprising the conventional load, the demand from heat pumps and the energy demand of the electro-mobility sector. Altogether, the share of RES accounts for 61 % of the final electrical energy consumption.

6. Results

Considering the framework conditions, the gathered cross border flows in Chapter 2.4 and the defined surrounding scenario in Chapter 4.2, simulations of the unit commitment in 2030 are conducted for the market area Germany and Austria. First, a simulation without any GOM is computed and taken as the reference scenario for comparisons with further simulations. Thereafter, several GOMs are implemented for following simulations: two different configuration levels of 'Overhead Line Monitoring' (OLM 1 and OLM Max; 256 km and 23,621 km), a scenario of 'Grid Expansion' (GE; 507 km), a scenario with 'Power-to-Heat' elements and a scenario with 'Demand Response'. The main findings of those simulations are given in the following.

The reduction of redispatch and curtailment are two major criteria when assessing the benefits of a GOM. Compared to the reference scenario, the reduction of redispatch is 0.12 TWh and 0.59 TWh for the two different stages of OLM, the decrease of curtailment amounts to 0.18 TWh and 0.31 TWh (see **Figure 5**).

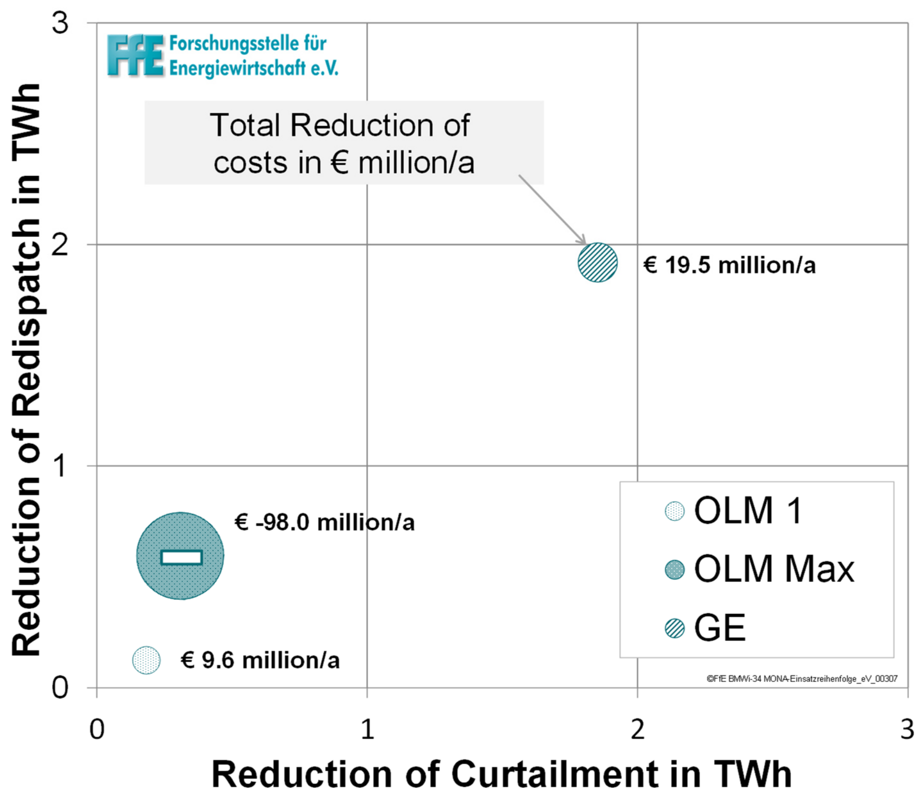

Figure 5: *Reduction of redispatch, of curtailment, and diminution of total costs for different GOMs.*

With a reduction in redispatch by 1.8 TWh and a decrease of curtailment by 1.9 TWh, the ‘Grid Expansion’ scenario achieves a greater benefit than OLM. Even the maximum possible equipment with OLM cannot benefit the transmission grid as much as the ‘Grid Expansion’-scenario. The decrease of redispatch and curtailment consequently leads to reduced power plant commitment costs due to a more reasonable power plant dispatch and higher integration of RES. Considering the annual costs for the construction of the GOMs, in **Figure 5**, the annual benefits of the measures can be examined. OLM 1 and ‘Grid Expansion’ come with a reduction in total cost[15] of € 9.6 million and € 19.5 million, respectively. The measure OLM Max causes an additional total cost of € 98.0 million to the system. An intensive expansion using OLM is neither beneficial for the total cost nor for a significant reduction of redispatch and curtailment.

Figure 6 depicts the reduction of curtailment of the GOMs ‘Power-to-Heat’ with 1.5 TWh and ‘Demand Response’ with 0.1 TWh. DR has a limited potential to integrate surplus energy from RES due to a restricted shift potential of industrial production processes. However, PtH can permanently integrate excess energy to the heat sector.

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[15] Total costs are the costs of one year for the dispatch of power and heat plants minus the annually costs for construction of Grid Optimising Measures.

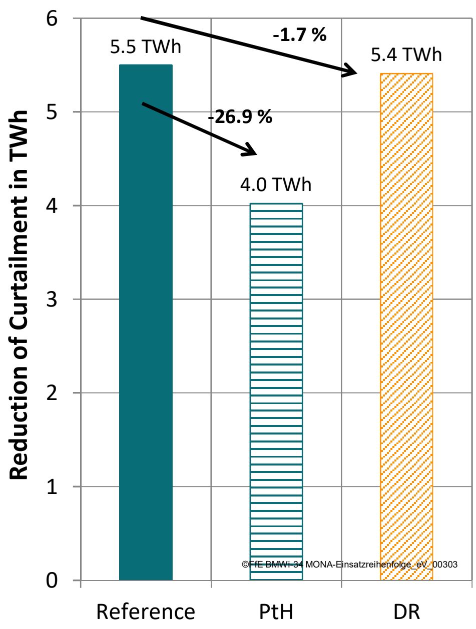

Figure 6: *Reduction of curtailment for the measures PtH and DR in comparison to the reference scenario.*

The reduction in power plant commitment costs due to the GOMs, shown in **Figure 7**, is at € 69 million for PtH and € 49 million for DR. Considering the costs for construction and the total reduction of costs, DR (€ 46 million savings) is more profitable than PtH (€ 11 million). Here, the transfer of load demand to dates with a high share of RES and therefore low prices leads to lower unit commitment costs. Due to the unfavourable spatial arrangement and the restricted shift potential of DR the impact on the network loading is modest.

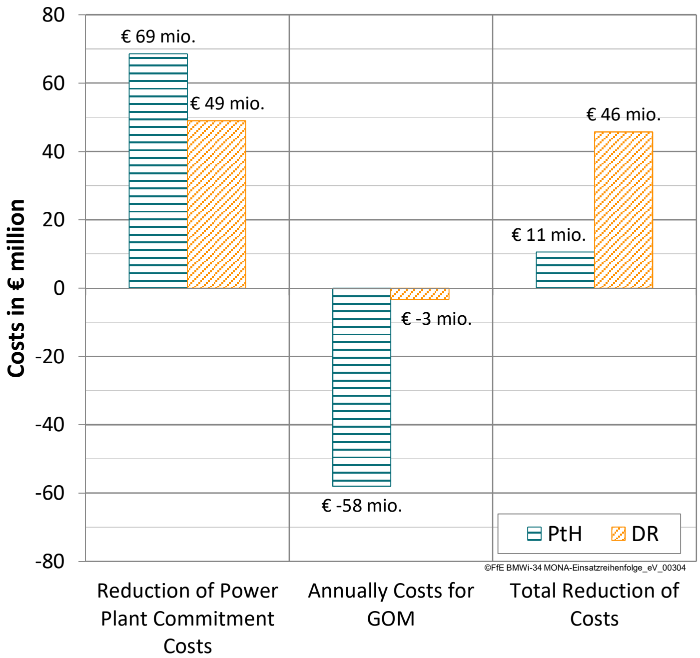

Figure 7: *Reduction of unit commitment costs, annuity costs for construction, and reduction of total costs for the measures PtH and DR in comparison to the reference scenario.*

7. Conclusion

This paper describes the extension of the ISAaR model with a linearised grid model, enabling a holistic assessment of grid optimisation measures and providing comparability among them. Grid data is gathered from sources of grid operators and open-source data, based on Open Street Map. Different OSM-based toolkits help to achieve a reasonable grid representation.

Within the research project *MONA 2030* (Merit Order Grid Expansion 2030), the ISAaR model is applied for evaluating the grid optimisation measures 'Overhead line monitoring', 'Power-to-Heat', 'Demand Response', and conventional 'Grid Expansion'. In Chapter 5, first results and findings are shown, while further outcomes are supposed to follow from the mentioned project.

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Relieving the German Transmission Grid with Regulated Wind Power Development

/Pub-03/

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1. Abstract

A prerequisite for the further integration of renewable energy sources into the German electricity sector is the expansion of transmission network capacities. In this study, an approach to relieve the German transmission grid by regulating the wind power development is evaluated for the year 2030. Compared to a reference scenario, the development of wind power plants with an annual energy yield of 4 TWh is reallocated from the wind-swept north of Germany to grid-convenient sites in central and southern Germany. Benefits of such a measure and resulting expenses are contrasted with the expected status quo in 2030 and two grid expansion scenarios. Results show 24 % - 53 % higher annual cost for the regulated wind power development scenarios compared to conventional grid expansion with a similar grid relieving impact. But taking into account that grid expansion faces public acceptance problems, regulated wind power development can be considered as a reasonable alternative, up to a certain degree. This insight may trigger a debate about the acceptance for either building transmission lines or additional wind power plants.

2. Motivation

The share of renewable energy sources (RES) of gross electricity consumption in Germany is increasing steadily, towards the set target of 50 % by the year 2030 [1]. To allow for the integration of high shares of RES, upgrading German transmission grid capacities has become a necessity. In this context, the research project *MONA 2030*[3] addresses the comprehensive assessment of various grid optimising measures like Overhead Line Monitoring or Power-to-Heat which are contrasted to conventional grid expansion measures and assessed as alternatives for grid expansion. The analysis is performed by using the simulation model *ISAaR*[4].

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[3] "Merit Order Grid Expansion 2030" (funding code 03ET4015) is co-funded by the German Federal Ministry of Economic Affairs and Energy through the funding initiative "ZukunftsfähigeStromnetze". (www.ffe.de/mona).
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Grid simulation results indicate bottlenecks in the transmission grid by the year 2030, when transporting wind energy from northern to southern Germany. As a reaction, conventional grid expansion can be conducted. In this paper, a further approach for relieving the German transmission network is analysed. Bottlenecks in the transmission grid can be avoided by implementing regulatory measures, aimed at controlling the locations for wind power development in Germany. In such a scenario, new wind power plants are constructed in central and southern Germany and consequently closer to the load centres, instead of the wind-swept north. In general, the expenses for the construction of wind power with the same energy yield are higher if wind power plants are built in central or southern Germany compared to the wind-swept north. However, transmission line relief is achieved and reduced curtailment of renewables as well as lower redispatch volumes can be noted.

The following text is outlined as follows: Chapter 3.   describes the optimization model *ISAaR*. In chapter 4. , underlying assumptions, provided in scenarios, are explained, and the scenarios for regulated wind power development as well as grid expansion are introduced in detail. Result are discussed in chapter 5.   and concluded in chapter 6. .

3. Optimisation Model

The FfE energy system model *ISAaR* is a linear optimisation model, which minimises the deployment of power plants to meet the demand for electricity in Europe and for district heating in Germany and Austria. The model allows for the coupling of the electrical and the heating sector, thereby enabling a holistic evaluation of the complete energy system, consisting of power plants, storages, localised demand, renewable energy sources, and heating plants (see **Figure 1**).

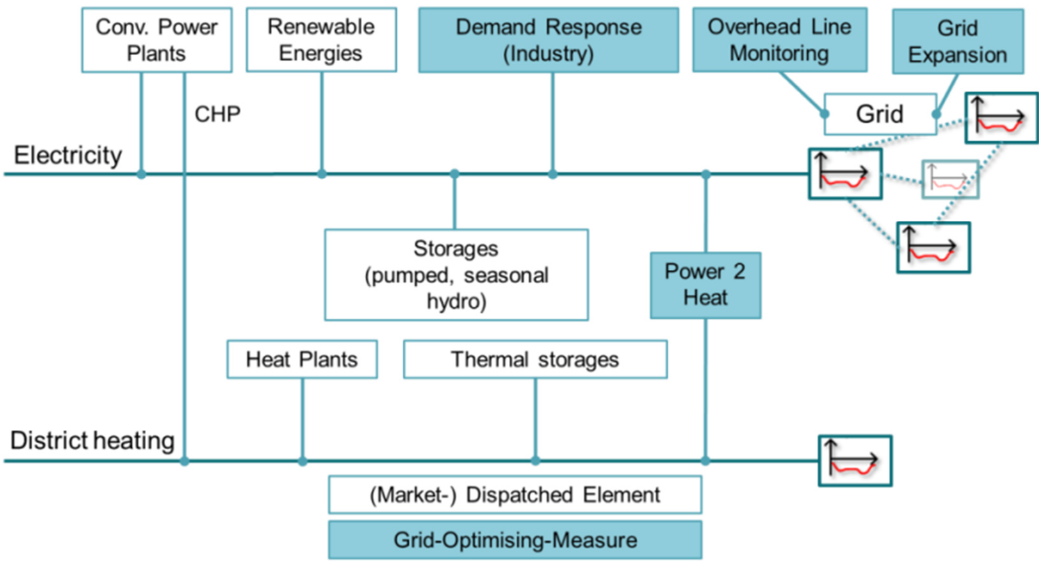

Figure 1: *Overview of the schematic ISAaR-models' structure.*

A detailed conceptual and mathematical description of the optimisation model is provided in [2] and [3]. Information on scenario input data is given in chapter 4. .

3.1. Grid Model

The transmission grid is modeled using the DC power flow approach, described in [4]. This linear representation of the grid is a result of the necessary trade-off between accuracy and computational expenditure. Transmission network losses as well as voltage-drops are neglected. Further, only active power flows are represented in the grid model. Nevertheless, this method is accurate within given bounds (see [5]). Above 70 % utilisation, reactive power becomes relevant, leading to notable deviations between the DC power flow and the non-linear power flow calculation [6]. In the *ISAaR* simulations, AC transmission line utilisation rates are forced to stay below 70 %, thereby guaranteeing the “(n-1)-safety criterion” of the grid (see [7] and [8]).

Grid data for Germany and Austria is taken from available data of transmission grid operators ([9], [10], [11], [12], [13]). The data is validated through comparison with the “ENTSO-E grid map” [14]. Faulty or non-existent data is taken from the unpublished “BNETZA Integral” dataset, instead. Current and planned Grid extension projects (AC-lines as well as DC-lines) are taken from the grid development plans NEP 2015, ONEP 2015, and TYNDP 2016 ([15], [16], [17]). Planned grid extension projects are added to the grid model under the assumption to be completed by the year 2030. Grid data for the rest of Europe is taken from the open-source platform *OpenStreetMap,* using the toolkit *Gridkit* [18]. The toolkits *SciGRID* [19] and *osmTGmod* [20] are used for the georeferencing of nodes and lines in the transmission grid. This is a prerequisite for assigning local loads and renewable energy potentials to grid nodes. In some parts of the German-Austrian grid, the underlying distribution network (110 kV) is a relevant support of the transmission grid and is therefore partly considered in the model.

The collected grid data is revised in order to obtain a consistent grid model. Due to the variety of data sources, some lines possess faulty and dissimilar line parameters (especially line reactances). These inconsistencies are rectified in a systematic correction process which is described in [3]. Line parameters for the rest of Europe are gathered by a method, utilising all available line data (e.g. cables and wires) and applying standard values where necessary (see [3]).

The grid topology in regions in a remote distance from the German-Austrian transmission network possesses only little influence on line utilisation in Germany and Austria. Thus, regions like Spain, Greece, or Norway are simplified to reduce computational expenditure. The method is presented in [3]. The resulting transmission grid builds the basis for grid simulations in ISAaR and is depicted in **Figure 2**.

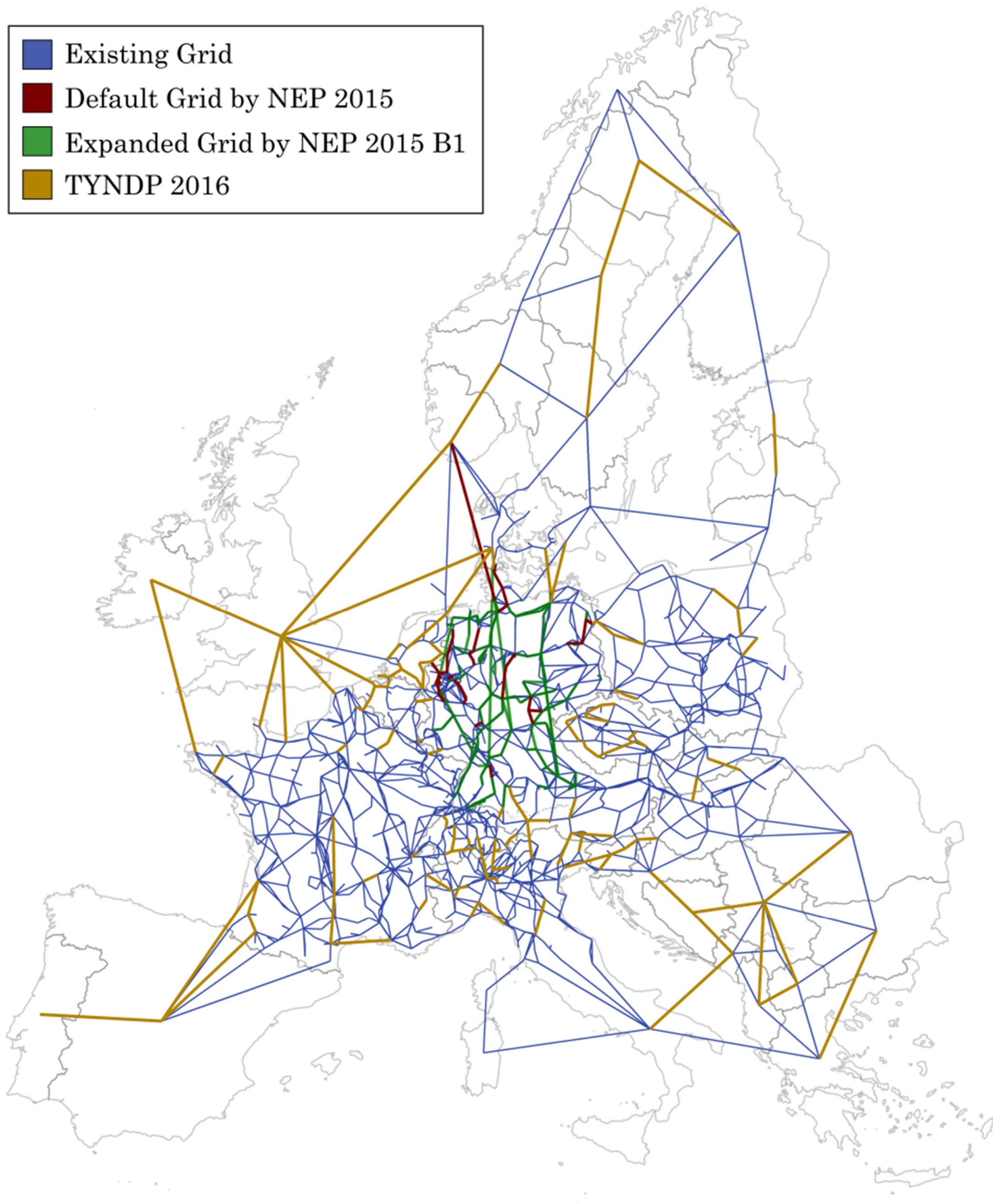

Figure 2: *Applied grid of the year 2030 with simplified grid regions distant from Germany and Austria.*

3.2. Optimisation Sequence

The simulation of a scenario (e.g. conventional grid expansion in the German grid) demands a sequence of different computation runs. This reduces the computational effort, and allows for **Figure 3**: In a first step, the market based dispatch of power and heat plants is calculated for Europe. Existing net transfer capacities between the energy markets are considered. Subsequently, the grid utilisation of the European transmission network is computed. Cross-border capacities are obtained and used as boundary conditions for further simulations of the German-Austrian energy system. Hereby, market-coupling and loop flows are considered in the following isolated simulations of the German-Austrian network.

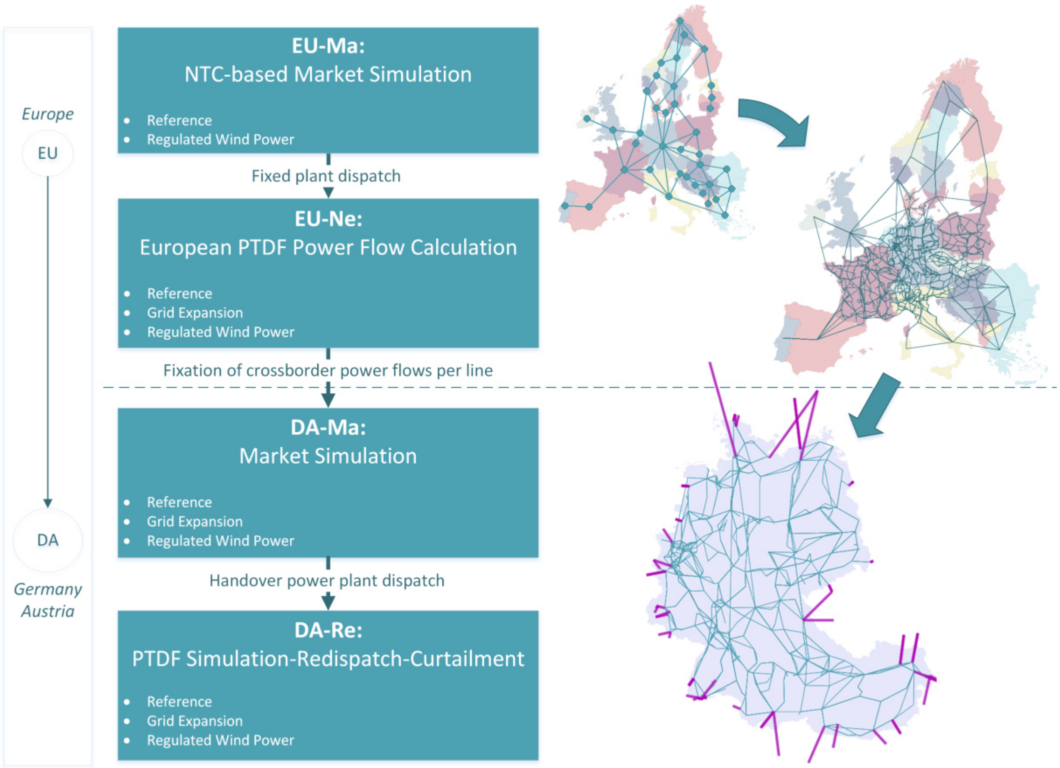

Figure 3: *Schematic overview of the optimisation sequence in ISAaR and the computed runs in each part.*

The first optimisation run of the German-Austrian energy system is a market simulation representing dispatch that results from energy traded on the day-ahead market and energy traded "over the counter". In a second simulation, objective of the power plants commitment is the previously calculated dispatch, but now power flow restrictions in the transmission grid are considered. Arising bottlenecks in the grid lead to deviations from the planned dispatch resulting in redispatch of power plants[5] and curtailment of RES[6].

Using this method, a reference scenario as well as the scenarios "conventional grid expansion" and "regulated wind power development" are computed (cf. Figure 3). Among many other results, the sequences deliver the quantities "redispatch", and "curtailment (of RES)" as output.

4. Scenarios

The year of assessment for the conducted study is 2030, therefore, various surrounding assumptions are provided in a so called coating-scenario (see [21]). **Table 1** shows a selection of relevant assumptions used in the coating-scenario. The share of renewable

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[5] When redispatch is applied, the most expensive power plants causing a bottleneck in the transmission grid are down-regulated. The next-cheapest power plants able to clear the bottleneck are then ramped up to provide the required power. It is to note, this process is an optimal redispatch. There is no condition considering minimum operation hours of redispatched power plants.
[6] Curtailment of renewable energy sources, normally occurring in the distribution grid, is accounted for curtailment in the transmission grid due to the direct linkage of fee-in and loads at high-voltage nodes in the simulation model.

energy production of the total electricity consumption is set to 61 % in all presented scenarios.

Table 1: *Relevant parameters of the coating scenario for the year 2030 [21].*

Parameter	Unit	Status 2015	Coating Scenario 2030 (61 % RES)
CO_2-Price	€ / t	7.6	30.0
Fuel Prices	-	-	moderate increase, see [21]
Installed Capacity of Conventional Power Plants			
Overall Power	GW_{el}	87,0	59,0 (without back-up)
Installed Capacity of Renewable Energy Sources			
Wind (onshore)	GW_{el}	41.2	58.5
Average Full-Load Hours (Onshore) Existing / Addition	h / a	1,700 / -	1,700 / 2,650
Wind (Offshore)	GW_{el}	3.4	15.0
Full-Load Hours (Offshore)	h / a	-	3,950
Photovoltaic	GW_{el}	39.3	76.8

Details on the origin and processing of further input data (available power plants, potential of renewable energy sources, …) are given in [3] and [21]. In general, input data for the *ISAaR*-model is handled in the form of scenarios, which are provided by the "FfE regionalised energy system model" (FREM) [22].

4.1. Conventional Grid Expansion

Conventional grid expansion is conducted in various ways. One can add circuits to an existing line, level up the voltage of a circuit, or construct new lines in a current or new path. Grid planners choose which measures are implemented. Amongst other factors, their decision is based primarily on the evaluation of technical, economic as well as regulatory requirements.

Two scenarios with conventional grid expansion are developed for this study. Therefore highly loaded lines are upgraded as follows: First, 220 kV lines are upgraded to 380 kV if there is an existing 380 kV transformer connectable, otherwise two 220 kV circuits are added. Then, 380 kV lines are upgraded with to two additional circuits. All expansion measures are built on the existing path.

In the first grid expansion scenario *GE 1,* five bottlenecks in the reference scenario are upgraded and thereby 166 kilometres of grid expansions are conducted. In scenario *GE 2*, ten more bottlenecks are upgraded. An additional 341 kilometres are added.

The bottlenecks in the reference scenario are located using an algorithm which searches for the most stressed lines throughout the simulation period. On the one hand, the amount of time of a transmission line in full utilisation is incorporated; on the other hand, the algorithm considers the amount of transported energy during high utilisation periods. The latter is the key factor used in determining the priority of a line extension on big lines. The affected lines for the two grid expansion scenarios are shown in **Figure 4**.

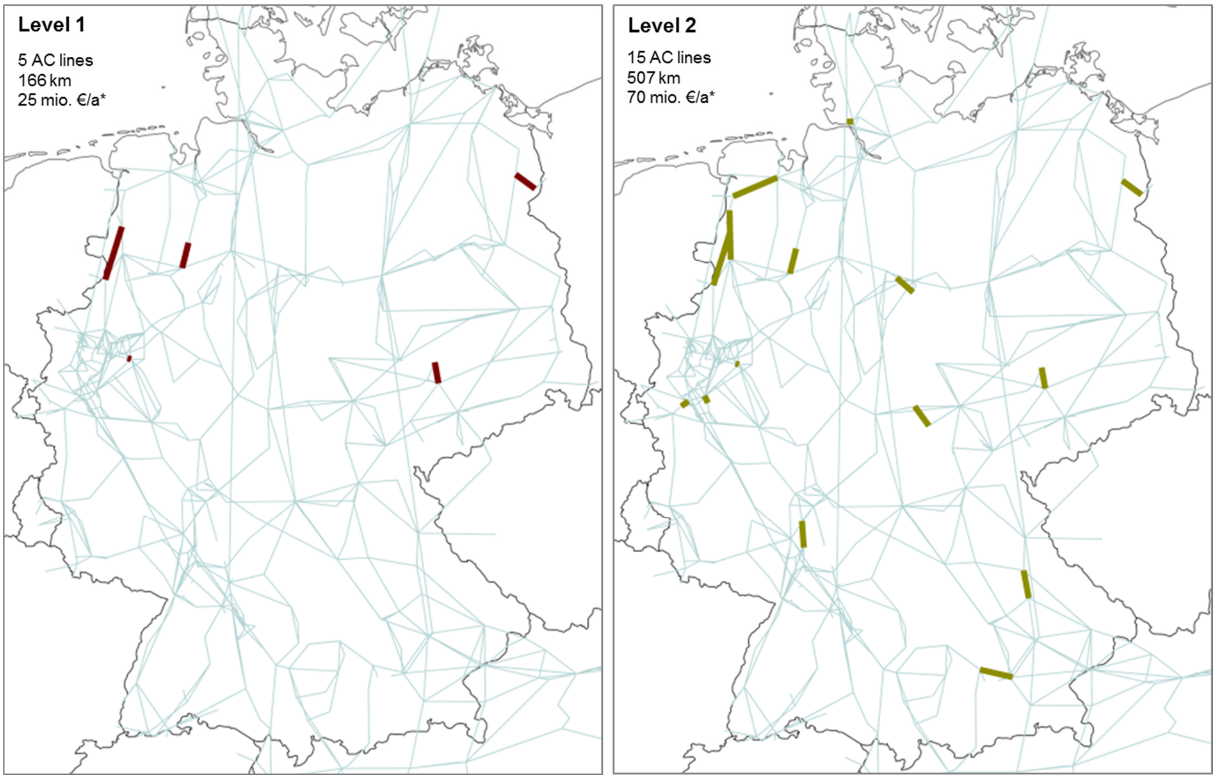

Figure 4: *Upgraded lines in the two different grid expansion scenarios. (*): Cost estimations are based on the NEP 15 [15], the lifetime is set to 40 years, the interest rate to 6 %.*

4.2. Regulated Wind Power Development

In the following scenarios, the expected wind power development, which is set in the reference scenario, is altered. It is assumed that the implementation of regulatory measures, such as laws or incentives, lead to an increased construction of wind power plants at economically less favourable locations in central/southern Germany, when compared to wind sites in the north (see [23]). However, the same amount of energy is to be produced throughout the year, compared to the reference scenario. The consequence is the construction of either additional or more productive wind power plants in central/southern Germany, resulting in higher cost. A relief of the load in the German transmission network is expected, shown within this study.

In two "regulated wind power development"-scenarios, the reallocation of 4 TWh annual wind power energy production is conducted using the following algorithm: In a first step, specific curtailment[7] is computed for every node in the north of Germany for the reference scenario. Wind power plants are then partially removed from nodes with high specific curtailment. This is performed until the annual energy production is reduced by 4 TWh.

[7] The specific curtailment at a node means the curtailment of renewable energy sources per produced energy at the same node.

This value equals 70 % of the curtailment in the reference case. Then, wind power turbines with the same annual energy production are relocated to central and southern Germany. There, wind turbines are reallocated to grid nodes with low specific curtailment plus high wind yield in the reference simulation.

In scenario *On WPD*, only onshore strong-wind wind power turbines are reallocated. To generate a conservative scenario, the turbine type is not altered when shifting to more southern locations. This results in large additional onshore capacities (See right map in **Figure 5**).

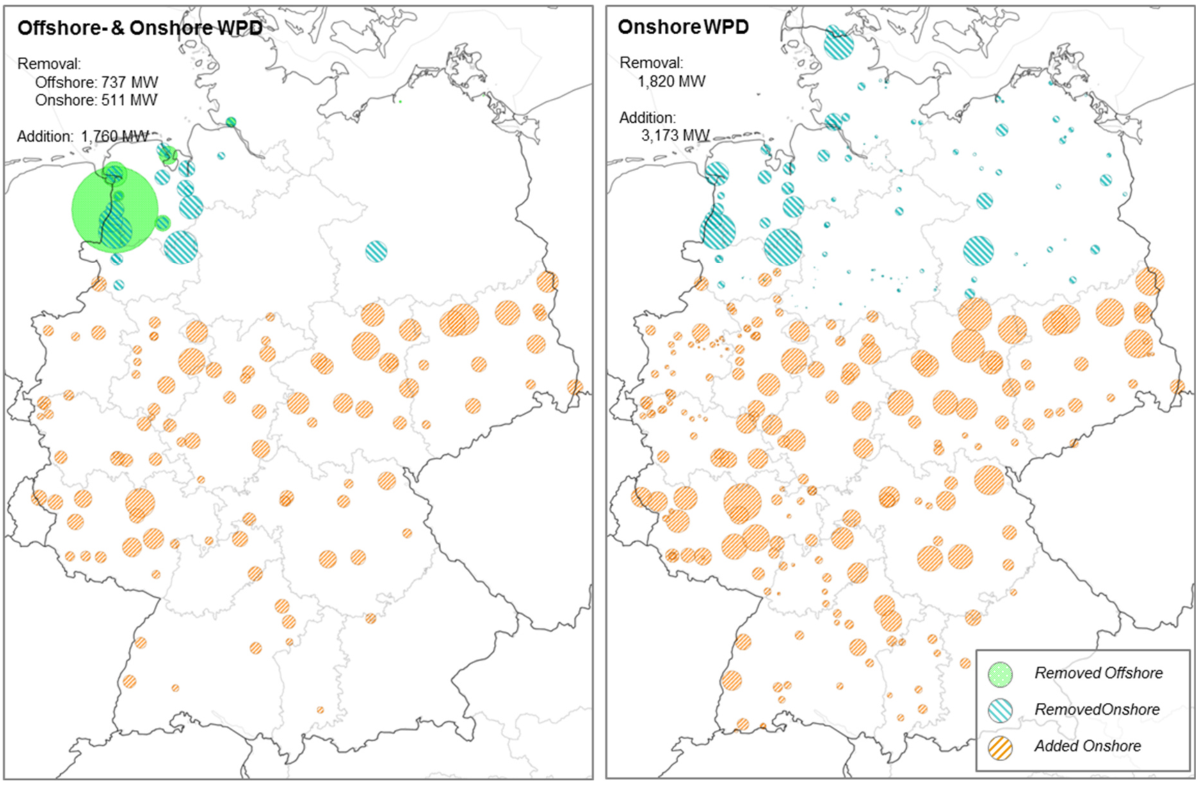

Figure 5: *Deviation in the wind power development scenarios compared to the reference scenario.*

In scenario *Off&On WPD*, wind power plants with an onshore capacity of 0.73 GW and an offshore capacity of 0.51 GW are removed from strong-wind-sites with a high specific curtailment in the north of Germany. For additionally built wind power plants in more southern locations, advantageous turbine types are selected for each wind site. This results in an optimistic scenario, with small additional capacities but large hub heights and wide rotor diameters. The reordering results in this scenario are visualised on the left map in Figure 5.

5. Results

Both, the conventional grid expansion scenario and the regulated wind power development scenario, demand cost for investment. In the following, a cost estimate is performed and put into context to the grid relieving impact of both measures. Due to high uncertainties in determining the cost for grid expansion as well as wind turbine construction, this analysis only serves as approximation cost indication.

Cost for grid expansion

The annual cost for the two grid expansion scenarios are shown in Figure 4. Costs for the chosen measures for line upgrading are based on the NEP 15 [15]. The lifetime is set to 40 years; the interest rate is set to 6 %.

Cost for regulated wind power development

Economic cost for the regulated wind power scenarios are estimated using the "Reference Yield Model" in the "Renewable Energy Sources Act" (EEG) 2017 [24]. It is assumed, the difference in feed-in revenues reflects the economic cost of shifting locations from north to south. First, the average location quality drop of the shifted wind power plants is obtained from the weighted average of the quality factors of the removed and of the added wind turbines. The average quality factors are weighting with the removed/added capacities. The calculation of quality factors is based on the explanations in [24]. In both scenarios, the average location quality of the shifted energy drops from about 100 % to about 72 %. The link between the placement of wind power turbines and their feed-in revenue is then obtained from the correction factor in the "Reference Yield Model" (see **Figure 6**). In both scenarios, shifting onshore wind energy to more central locations in Germany leads to a cost increases of approximately 25 %.

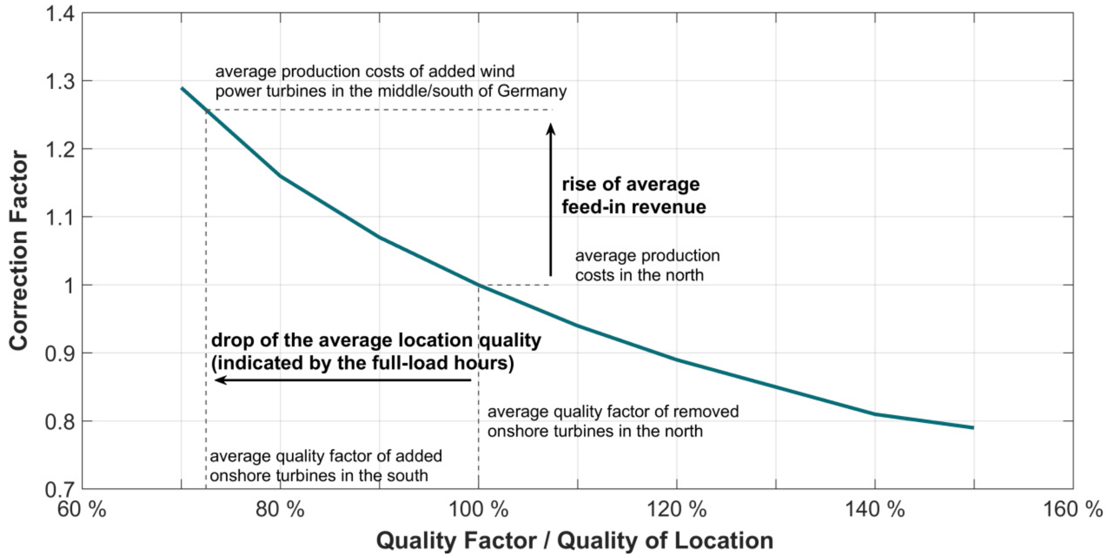

Figure 6: *Correction factors of the "Reference Yield Model" for the revenue of wind energy feed-in dependent on the "Location Quality" from the "Renewable Energy Sources Act" (EEG) 2017. [24].*

The base price for onshore-wind feed-in is 5.71 €/MWh[8], revenues for offshore-wind feed-in are set to a range of 5 to 6 €/MWh[9]. It is furthermore assumed that offshore and onshore bids reflect the investment the bidder has to face in the case of project realisation. Hence, bidder margins or markdowns, which can be realised through cross-financing activities, are not considered. Based on these assumptions, the additional costs of the *WPD* scenarios

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[8] The applied base price is the weighted average price from German tender results 2017 [25].

[9] For the determination of the offshore base price, only non-zero bids in the German offshore tender results are considered, leading to a price of 6 €/MWh. We conduct a sensitivity analysis by setting a range from 5 to 6 €/MWh.

can be compared to the reference case. Following expression shows the derivation of costs resulting from reallocation with the revenue difference of shifted wind turbine revenues:

$$Cost = Rev_{added,onshore} - \left(Rev_{removed,onshore} + Rev_{removed,offshore}\right) \quad \text{with}$$

$$Rev_x = Price_{base,x} \cdot cf_x \cdot E_x$$

$Cost$:	Additional investment cost of a *WPD* scenario compared to the reference case
Rev:	Revenue of the feed-in from added/removed onshore/offshore wind power plants
$Price_{base}$:	Base price of onshore/offshore wind feed-in
cf:	Correction factor gathered from the Reference Yield Model
E:	Produced wind energy of added/removed onshore/offshore wind power plants

In case of scenario *On WPD*, the cost of wind energy production shifted to southern regions account for € 61 million per annum. In scenario *Off&On WPD*, annual costs are in the range of € 49 million to € 78 million, depending on the assumed feed-in price for offshore wind.

Grid relieving effects

In **Figure 7**, these costs are depicted and linked to the corresponding grid relieving impact. The latter is indicated by the reduction of RES curtailment and of redispatch. The highest reduction rates are achieved in scenario *GE 2*. The *Off&On WPD* scenario performs slightly better than *GE 1* and *On WPD*. The greater grid relieving effects of scenario *On&Off WPD* compared to the *On WPD* scenario can be explained by the illustration of the wind turbine removal in Figure 5. In the *On&Off WPD* scenario, capacities from a concentrated wind energy production area in the north-west of Germany are removed, leading to a local reduction of line utilisations and thus a decrease of curtailment. In scenario *On WPD* however, wind power capacities are removed from a wider area, which do not relieve the known bottlenecks in the north-west.

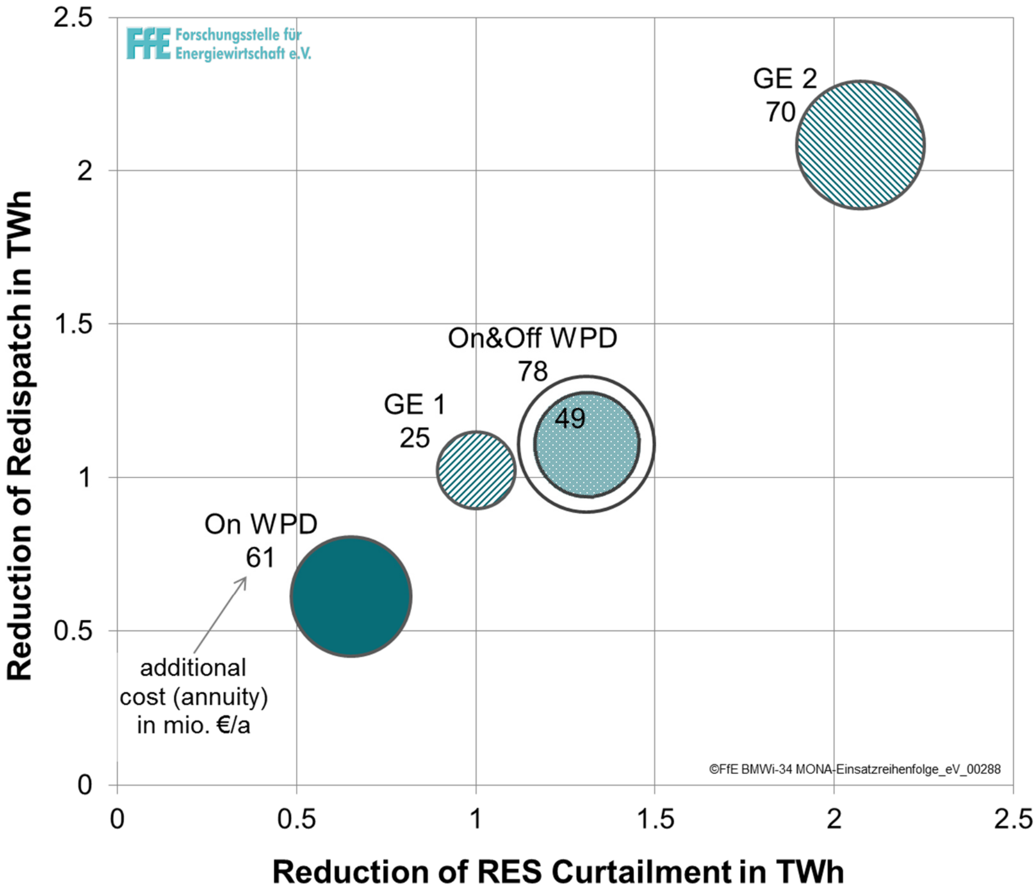

Figure 7: *Reduction of redispatch and of RES curtailment with additional investment for the scenarios grid expansion (GE 1/GE 2) and regulated wind power development (On&Off WPD/On WPD) compared to the reference case.*

Furthermore, the depiction in Figure 7 reveals the fact that in the *On&Off WPD* scenario, bottlenecks are more often solved with redispatch instead of RES curtailment. The use of redispatch causes in general fewer emissions than curtailment and is economically advantageous.

Figure 8 differentiates the commitment of redispatch into its positive and negative amount for all scenarios. Furthermore, the curtailment presented in Figure 7 as well as market-based curtailment of RES is depicted. Hereby, market-based curtailment of RES is a theoretical quantity depicting the overproduction of RES in case of no grid restrictions (dispatch on a "copper plate").

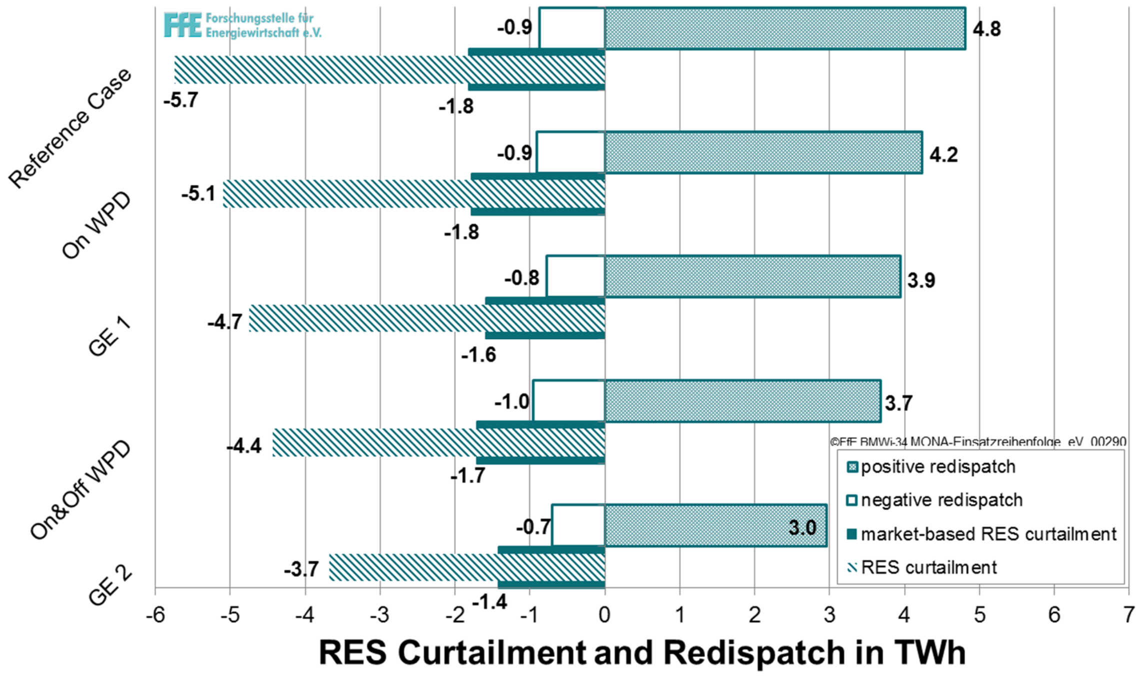

Figure 8: *Redispatch and curtailment of RES in the market region Germany and Austria for all scenarios under analysis.*

Figure 8 shows a reduction in market-based curtailment of RES. This results from increased exports to neighbouring markets. This can be explained through a better utilisation of cross-border lines due to a stronger transmission grid or, in case of *On&Off WPD*, due to a less locally concentrated wind energy production with fewer bottlenecks.

6. Conclusion

In this study, two scenarios of regulated wind power development in the German energy system in the year 2030 are developed and assessed with respect to the bottlenecks in the transmission network. The outcomes are compared and contrasted with the expected status-quo and two scenarios with further conventional grid expansion. In all scenarios, a grid relieving impact can be noted, whereby conventional grid expansion is a more effective and less cost-intensive grid optimising measure compared to regulated wind power development.

Smart regulation of further wind power development bears the potential of reducing system services and therefore relieving bottlenecks in the German transmission grid. But, when considering the large capacities of additionally installed wind power at low-wind speed locations and thus higher cost, grid expansion seems to be a preferable choice under current conditions. This however does not take into account that grid expansion lacks public acceptance and therefore comes at a societal cost [26]. Regulated wind power development can be considered a reasonable alternative to a certain degree. This insight should trigger a debate about the acceptance for building either transmission lines or constructing additional wind power plants.

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Electrification and coal phase-out in Germany: A scenario analysis

/Pub-04/

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1. Abstract

The electrification of fossil fueled processes and applications is frequently quoted as an essential component for the deep decarbonization of the German energy system. A prerequisite for decarbonization through electrification is low emission electricity. In the German case, this leads to the so called “electrification dilemma”, as both a reduction of the emission intensive conventional power plant park and the significant increase in electricity consumption are driving the demand for RES and guaranteed capacities drastically. In a simulation-based scenario analysis, two measures to reduce emissions in power generation in a high electrification regime are compared: CO2-allowance pricing and a lignite phase-out. Using the DC power flow formulation, the effects on the German transmission grid are determined. The results show that both the coal phase-out and an increase in the CO2 prices lead to a significant reduction in the average CO2-coefficient of power generation. Simultaneously the capacity gap increases significantly, but only for a few hours per year.

Index Terms— Electrification, Energy consumption, Power generation planning, Power system planning, Power transmission

2. Introduction

Recently published energy scenarios such as [1]-[3] show that a variety of pathways to deep decarbonization in Germany exist [4]. In all three scenarios the electrification of final energy consumption (FEC) is considered a key enabler for the reduction of greenhouse gas (GHG) emissions by 95 %, compared to the level of 1990.

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Previous work by the authors of this paper [5] analyzes the effects of increased demand-side electrification in combination with high shares of variable renewable energy sources (vRES) on the German energy system in 2030. [5] shows that electrification in combination with a high share of vRES can pose a barrier to the phase-out of emission intensive coal fired power plants, leading to a so-called "electrification dilemma". The latter describes the effect by which the combination of high electrical load and installed vRES capacities result in stronger fluctuations of the residual load. The consequences are an increased need for guaranteed capacity and dispatch of fossil power plants in times of low feed-in from vRES. This in turn, prohibits the phase-out of fossil power plants and a further reduction of the CO_2-coefficient of power generation, thereby restricting the decarbonization effect of increased electrification. To unfold the full decarbonization potential of electrification measures, the implementation of strategies aimed at reducing the dispatch of emission-intensive power plants are required.

This paper builds on the scenarios and findings in [5] and analyzes the effects of a politically forced lignite phase-out and variations of CO_2-prices on the German energy system, in a high electrification and high RES scenario, in 2030. The focus hereby lies on the analysis of the following parameters: capacity gap, curtailment, redispatch, the CO_2-coefficient of power generation, the generation mix and the electricity export balance. Through the analysis, a contribution to answering the following questions is made:

1. What are the energy system effects of a lignite phase-out or an increasing CO_2-price in a high electrification and high RES scenario?
2. What role do Germany's neighboring countries play with respect to the procurement of supply security and emissions?
3. What are the operational characteristics and transmission grid repercussions of future peak-load generation units in a electrification regime?

Furthermore, this work builds the basis for further analyses of the effects resulting from the integration of flexibility measures (e.g. demand-side-management, storage systems) in high electrification and high RES scenarios.

3. Scenario Development

A detailed description of the scenario process is provided in [5]. **Figure 1** shows an overview of the assumptions for the reference scenario (Ref61), the electrification scenarios (Elec61 and Elec75) as well as variations of the electrification scenarios for the year 2030. The latter include the phase out of 9 GW (i.e. 70 % of the capacity in the reference case) of lignite power plants in Germany (Elec61_nl and Elec75_nl) and sensitivities with respect to changes in the CO_2-price. Hereby Elec61_120 and Elec75_120 assume a unanimous European CO_2-price of 120 €/t_{CO2}. In Elec61_120_DE and Elec75_120_DE a CO_2-price of 120 €/t_{CO2} is implemented only in Germany, while the price in the rest of Europe remains constant at 30 €/t_{CO2}.

Reference Scenario [Ref61]
- no electrification
- low grid congestion

Parameter	***Unit***	***Value***	***Value***
Year	-	For comparison: 2015	2030
Electrical FEC (Domestic / Industry / SME / Transport / DistH / Grid losses)	TWh	129 / 225 / 150 / 11 / 1 / 26 Sum: 542	134 / 210 / 110 / 21 / 1 / 23 Sum: 499
Fuel Prices (Oil / Gas / Hard Coal / Lignite)	€/ MWh_{th}	35.9 / 21.8 / 8.8 / 1.5	52 / 29 / 9.5 / 1.5
CO_2-Price	€/t_{CO2}	7.6	30
Conventional Generation Capacities	GW_{el}	87 (of which 32.9 coal-fired)	59 (of which 23 coal-fired)
RES Capacity (Wind-Offshore / Wind-Onshore / PV)	GW_{el}	3.4 / 41.2 / 39.3	15 / 59 / 77
RES-Share	%	**33**	**61**

Constant RES-Share

Higher RES-Share

Electrification Scenario [Elec61]
- high electrification
- Constant RES-share electrification

Parameter	***Unit***	***Value***
Electrical FEC (Domestic / Industry / SME / Transport / DistH / Grid losses)	TWh	180 / 330/ 167 / 28 / 20 / 34 Sum: **759**
RES Capacity (Wind-Offshore / Wind-Onshore / PV)	GW_{el}	15 / 99 / 146
RES-Share	%	**61**

Electrification Scenario [Elec75]
- high electrification
- RES-covered electrification

Parameter	***Unit***	***Value***
Electrical FEC (Domestic / Industry / SME / Transport / DistH / Grid losses)	TWh	180 / 330/ 167 / 28 / 20 / 34 Sum: **759**
RES Capacity (Wind-Offshore / Wind-Onshore / PV)	GW_{el}	15 / 125 / 190
RES-Share	%	**75**

Electrification Scenario [Elec61_nl]
- Constant RES-share electrification
- **Less lignite-fired power plants in GER**

Parameter	***Unit***	***Value***
Conventional Generation Capacities	GW_{el}	**50** (of which **14** coal-fired)
RES-Share	%	**61**

Electrification Scenario [Elec75_nl]
- RES-covered electrification
- **Less lignite-fired power plants in GER**

Parameter	***Unit***	***Value***
Conventional Generation Capacities	GW_{el}	**50** (of which **14** coal-fired)
RES-Share	%	**75**

Electrification Scenario [Elec61_120]
- Constant RES-share electrification
- **European CO_2-price increased**

Parameter	***Unit***	***Value***
CO_2-Price	€/t_{CO2}	**120**
RES-Share	%	**61**

Electrification Scenario [Elec75_120]
- RES-covered electrification
- **European CO_2-price increased**

Parameter	***Unit***	***Value***
CO_2-Price	€/t_{CO2}	**120**
RES-Share	%	**75**

Electrification Scenario [Elec61_120_DE]
- Constant RES-share electrification
- **German CO_2-price increased**

Parameter	***Unit***	***Value***
CO_2-Price (EU/DE)	€/t_{CO2}	**30 / 120**
RES-Share	%	**61**

Electrification Scenario [Elec75_120_DE]
- RES-covered electrification
- **German CO_2-price increased**

Parameter	***Unit***	***Value***
CO_2-Price (EU/DE)	€/t_{CO2}	**30 / 120**
RES-Share	%	**75**

Figure 1: *Summary of the main characteristics of the examined scenario sensitivities*

3.1. Demand-side scenario description

Ref61 is based on Scenario C in Germany's 2025 Grid Development Plan [6] and is characterized by low electrification rates and high energy efficiency improvements on the demand-side. Total electrical final energy consumption (FEC_{elec}) in Ref61 is 476 TWh (excluding grid losses) compared to 516 TWh in 2015 [5]. Compared to 2015, the phase-in of heat pumps and electric vehicles leads to an increase in FEC_{elec} in Ref61 for the domestic (40 %) and transport sector (225 %). In the industry as well as the small and medium enterprise sector (SME) a reduction of FEC_{elec} due to increased energy efficiency of 7 % and 27 % occurs, respectively. There is no change in FEC_{elec} in district heating (distH).

In the electrification scenarios Elec61 and Elec75 demand-side electrification occurs in all energy end-use sectors. The resulting electrical load for 2030 is 725 TWh (excl. grid losses). In the transport sector it is assumed that the national goal of 6 million electric vehicles in 2030 is achieved. Electric vehicles are considered as an inflexible electrical load. This means that direct charging behavior is assumed and vehicles are charged at full capacity once they are connected to the grid. In distH existing cogeneration plants are equipped with a power-to-heat (PtH) module (combination of heat pump and electrode boiler) leading to an additional 20 TWh of flexible electrical load. In the industry, SME and domestic sector, electrical equipment is phased in based on natural technology exchange rates. The latter are used to approximate the share of existing technologies that reach their end-of-life in a respective year. It is consequently assumed that electrical appliances that provide an equivalent service replace retired fossil equipment.

In the SME and domestic sector heat pumps are used to replace existing oil and gas boilers. In the industry sector electrification occurs for processes which operate at a temperature level < 400 °C, as electrification does not afford significant adaptations of the production process. Electrification technologies used in this temperature range are heat pumps and electrode boilers. For temperature levels > 400 °C electrification requires the replacement of process specific equipment such as blast furnaces, rotary kilns or shaft furnaces. Due to the complexity (e.g. costs, acceptance barriers within companies) of the electrification process at these temperature levels, it is assumed that the electrification of high-temperature processes only occurs after 2030.

As described in [5], different load profiles are taken into account depending on the type of FEC_{elec}. The latter are based on [7]. If FEC for space heating is electrified, a strongly seasonal temperature dependency of the load profile is taken into account. This temperature correlation leads to a disproportionate increase in peak load of 68 % from 82.7 (Ref61) to 138.8 GW (Elec61 and Elec75). In comparison, the total electrical demand increases by 52 %.

3.2. Supply-side scenario description

A prerequisite for decarbonizing the demand-side is the supply of emission free electricity. In this analysis, CO_2-neutral electrification is approximated by flanking the increase in FEC_{elec} with an increase of electricity production from renewable energy sources (RES). Hereby two RES scenarios are constructed. Ref61 poses the starting point:

1. Ref61: The share of RES of total electrical load is set to 61 %.

2. Constant RES-share electrification for Elec61: The share of RES of total FEC_{elec} is held constant at 61 %. Compared to Ref61 electricity production from RES increases by 160 TWh.
3. RES-covered electrification for Elec75: each additional TWh of FEC_{elec} is accompanied by an increase in RES generation of +1 TWh from additional RES capacities. This leads to a RES share of total FEC_{elec} of 75 % and an additional 243 TWh of RES production compared to Ref61.

In both electrification scenarios a yield-oriented expansion of RES is performed, as described in [5]. Hereby mainly onshore weak wind turbines and photovoltaic are expanded. Considering Germany's goal of 65 % RES share of total electrical load until 2030 [8], both electrification scenarios can be considered relevant for the current policy framework. The presented scenarios are supplemented by energy system scenario data for the European neighboring countries following "Vision 2" of the TYNDP2016 [9] and power plant data from [10]. Using regionalization algorithms, described in [11] and [12], the installed capacities of RES, load data and power plants are distributed regionally. After intersection with weather data of the year 2012 renewable power generation profiles and load profiles are generated. Grid Data are taken from the TSOs and OpenStreetMap as described in [12]. The state of transmission grid expansion corresponds to the "target grid" of the 2015 German grid development plan for the year 2025 [6]. Furthermore, 507 km of AC grid expansion are added in order to ensure an almost congestion-free transmission grid for Ref61. The methodology of expansion planning is shown in [13].

4. Simulation Methodology

The simulation model used is named "ISAaR: Integrated Simulation Model for Planning the Operation and Expansion of Power Plants with Regionalization", which is described in detail in [7], [11] and [12]. ISAaR is a linear optimization model with an objective function aimed at minimizing the overall system costs. Marginal costs for power plant dispatch include the costs for fuel, operation and emission allowances. In addition, distH networks including heat generators such as heating plants, PtH units and combined heat and power (CHP) plants are taken into account. A cost-optimal dispatch of generation units is calculated in hourly resolution for an entire year. This cost minimization approach is used in both the European and German/Austrian market simulation, which build the basis for determining cross border flows of electricity and load flows in the transmission grid.

The additional PtH units in the electrification scenarios are regionalized according to the heat demand of district heating networks and industrial processes. In total the implementation of 22 GW of heat pumps and electrode boilers in distH networks is assumed. RES are dispatched with marginal costs of 0 €/MWh. To ensure the supply of electrical load, so-called virtual generation units with unlimited capacity are taken into account at each grid node. Their marginal costs are set to 450 €/MWh. It is assumed that these units are gas fired.

Figure 2 shows the simulation sequence which is based on a European market simulation. Cross border flows are taken into account using the "Net Transfer Capacity (NTC)" approach. As described in [12] the methodology tends to overestimate the capability of cross border power flows. Therefore, a second simulation, the "European grid simulation" is performed. In this step, the power plant dispatch determined in the first simulation run is fixed and the resulting grid congestion is calculated. The "Power Transfer Distribution Factors (PTDF)" approach, as described in [14] and [15], is used to determine line loading. Grid overloading is not permitted. The maximum grid loading of AC lines is set to 70 % of its maximum thermal capacity. DC lines can be loaded up to 100 %. The resulting cross border flows are used as input data for the third simulation run, the GER/AUT market simulation. The market simulation generates the dispatch for the fourth simulation step, the GER/AUT congestion management simulation. As mentioned above transmission grid line loading is restricted. Based on the existing congestion management cascade positive and negative redispatch is carried out first. Possible remaining grid congestion situations are solved by curtailing vRES in combination with positive redispatch.

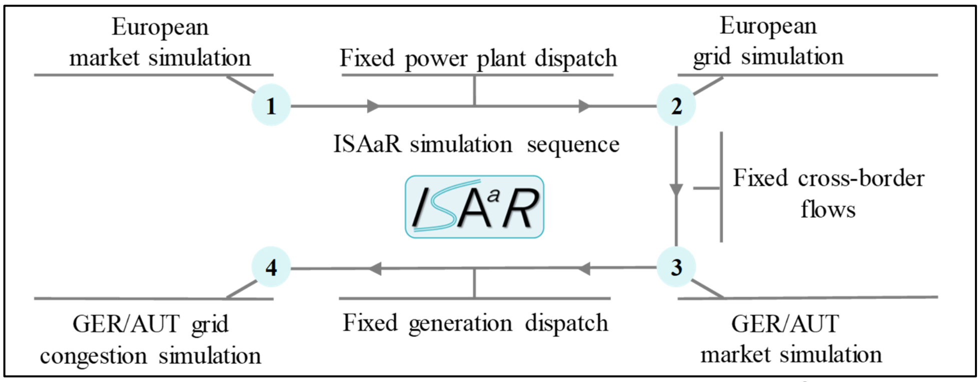

Figure 2: *ISAaR simulation sequence*

A description of the mathematical formulation of the congestion management cascade is given in [11]. The dispatch of PtH units is fixed within the congestion management simulation. Therefore, no grid-relieving effect through PtH units is possible.

5. Results

The effects of a partial lignite phase-out and variations in CO_2-prices on the German energy system in 2030 are analyzed in two steps: A) market-based impact B) transmission grid effects.

5.1. Market-based impact

Based on the results of simulation runs (1) to (3) (cf. Fig. 2), the market based impacts are quantified. Scenarios differ mainly with respect to the dispatch of power plants, cross-border trade flows and the capacity gap. The results are shown in Fig. 3 and Fig. 4. The analyses presented in this chapter relate to the German/Austrian bidding zone.

Figure 3 shows that, compared to the reference case, the import dependency increases in all electrification scenarios. Due to the strong increase in vRES generation and the simultaneous increase in electrical load, the fluctuations in residual load grow. Consequently, a higher number of hours with high residual load is noticed in Elec61 compared to Ref61, resulting in an absolute increase of conventional power plant dispatch. Although the fluctuations in residual load increase further in Elec75, less dispatch of fossil-fueled power plants is observed due to a significant reduction of hours with positive residual load. Simultaneously, less energy is imported due to the high share of vRES in Germany compared to its neighboring countries. This however does not imply that Germany's dependency on trade flows with its neighbors is reduced.

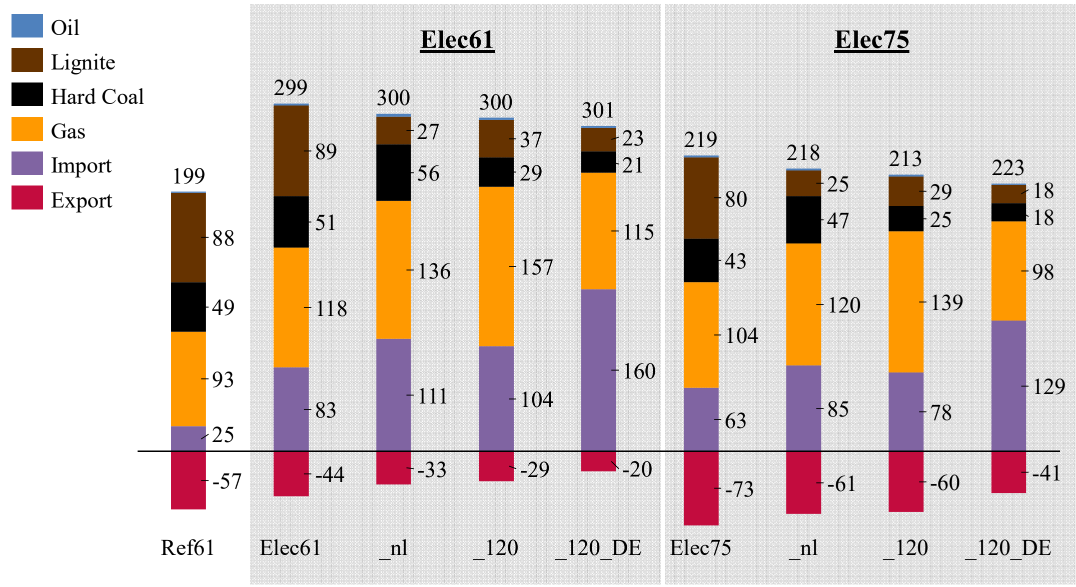

Figure 3: *Energy balance (only fossil energy carriers) of power generation including import and export in TWh*

In all three variations of Elec61 and Elec75 (_nl, _120 and _120_DE), the reduced dispatch of lignite power plants is compensated by an increase in production from gas fired power plants and imports, compared to Ref61. Hereby the compensation through imports is more pronounced in Elec61_120_DE and Elec75_120_DE. This results from the comparably high German CO_2-price, which leads to a 40 % decrease of domestic conventional power plant dispatch. In scenarios with a unanimous CO_2-price across Europe (Elec61_120 and Elec75_120), domestic power plant dispatch is not penalized as strongly, resulting in less imports and more domestic dispatch of fossil capacities. In Elec75, compared to Elec61, exports increase due to an increase in the surplus of energy from vRES, which results in a lower electricity price level. Furthermore, the absolute energy produced by vRES and the installed vRES capacity is lower in countries bordering Germany, resulting in an enhanced capability for absorbing German surplus energy from vRES. In the "narrowed-lignite" scenarios Elec61_nl and Elec75_nl, total lignite start-ups decrease compared to Elec61 and Elec75, as only the "cleanest" lignite power plants remain in the system. The full-load hours of the remaining lignite power plants increase by 3 % and 5 % in Elec61_nl and Elec75_nl compared to Elec61 and Elec75. In a high electrification scenario, the phase-out of lignite consequently results in increased dispatch of the remaining power plants. Furthermore, the lignite phase-out leads to a reduction of the guaranteed capacity of 15 %, while peak load increases by 68 % in the electrification scenarios, compared to Ref61. This results in a capacity gap of 27.4 GW and 23.7 GW in Elec61_nl and Elec75_nl, respectively.

Figure 4 shows the annual load duration curve of the virtual generation units. Comparing Elec61_nl and Elec75_nl shows that increased vRES capacity leads to a reduction of the capacity gap, while the energy generation from virtual generation units is low in both cases. In both scenarios the high capacity gap and low generation from virtual power plants (especially in the range >10 GW) makes a procurement of the required power through conventional power plants (e.g. in a capacity market) very expensive.

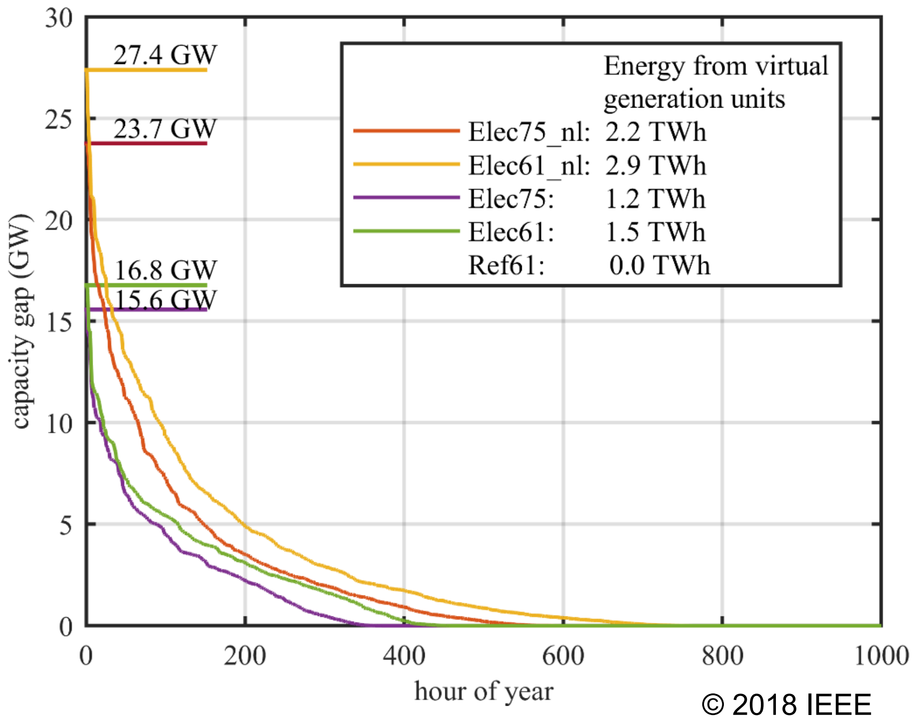

Figure 4: *Annual load duration curve of virtual generation unit dispatch*

In Elec75_nl a maximum of seven consecutive hours with a capacity gap of 10 GW is observed. Further research should aim at analyzing to what extent flexibility options (e.g. demand-side-management or vehicle-to-grid) can close the identified capacity gap.

Figure 5 shows that, compared to Ref61, a reduction of the CO_2-coefficient of power generation (301 g_{CO2}/kWh) is achieved in all variations of the electrification scenarios. Due to the higher RES share the CO_2-coefficient of power generation is lower in all variations of Elec75 compared to the variations in Elec61. In the narrowed-lignite and high CO_2-price electrification scenarios, domestic as well as EU-wide emissions are reduced compared to Ref61. Hereby stronger emission reductions are achieved with a unanimous CO_2-price of 120 € compared to all other scenarios. This results from a Europe-wide decrease of the dispatch of lignite power plants. In comparison, _nl and _120_DE scenarios only cause a reduction of lignite dispatch within Germany.

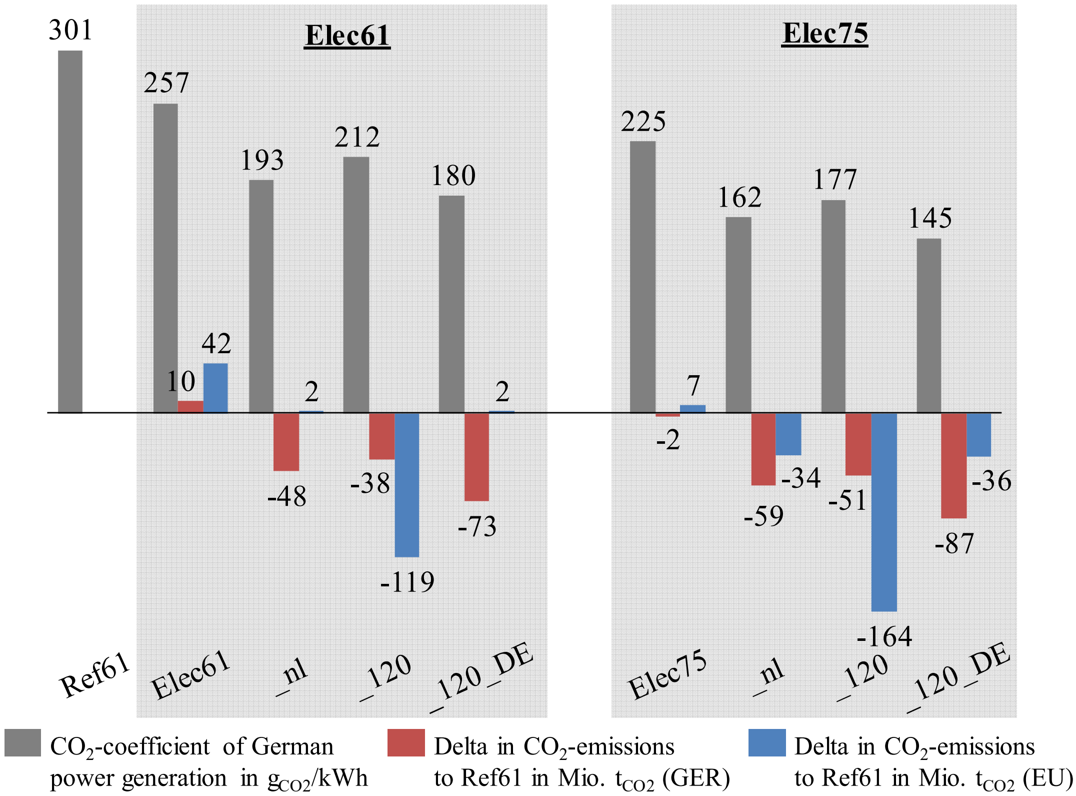

Figure 5: *CO2-coefficient of German power generation and total emission reduction in Germany and Europe compared to Ref61 (excl. grid constraints)*

Figure 5 shows the CO_2-coefficients of power generation excluding grid constraints. The analysis in [5] shows that CO_2-coefficients including grid constraints increase in a high electrification and high RES scenario. Hence, emissions shown in Fig. 5 can be considered a lower boundary.

5.2. Congestion Management

Figure 6 shows curtailment and redispatch results for the analyzed scenarios. Hereby a differentiation between curtailment after the market simulation and before the grid simulation (i.e. “market driven curtailment”) and curtailment after the grid simulation is made (i.e. “grid driven curtailment”). Market driven curtailment shows the ability of the market to accommodate electricity produced by RES. Overall an increase in the amount of curtailed energy is observed, compared to 5.7 TWh in Ref61 and 3.7 TWh in 2016 [16].

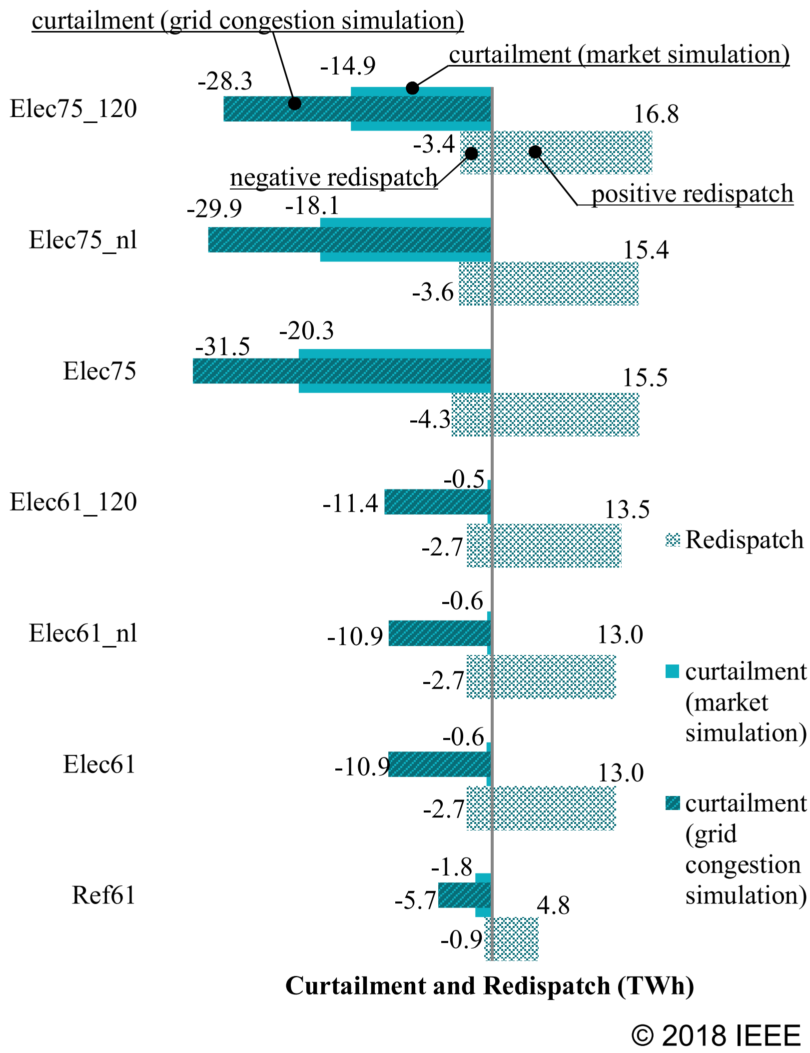

Figure 6: *Congestion management measures and market driven curtailment in TWh*[4]

The figure shows that both market and grid driven curtailment is reduced in Elec75_120 compared to both Elec75_nl and Elec75. In Elec75 situations occur in which the opportunity costs of RES integration are higher (even at zero marginal cost) than the cost of dispatching lignite units. These situations do not occur in Elec75_nl because 9 GW of the most inflexible and cost intensive lignite power plants are retired. Through the phase-out of inflexible power plants, the integration of RES is facilitated. This is supported by the fact that negative redispatch is reduced by 16 % in Elec75_nl compared to Elec75, while positive redispatch remains constant. In Elec75_120 curtailed energy from RES is lower compared to Elec75 as the costs of lignite start-ups exceed the costs of RES integration. Due to increased RES integration, the congestion of the transmission grid results in a higher demand for positive redispatch.

Furthermore, an increase in the energy generated by virtual generation units is noticed in Elec61 (59 %) and Elec75 (111 %) in the congestion management simulation, compared

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[4] A validation based on historical congestion management data of 2012 shows that the overall congestion management volume is underestimated by 22% in the simulation [11].

to the market simulation (share of used capacity remains below 1 %). This shows that the positioning of loads is not optimized with respect to transmission grid capacities. Hence, virtual generation units are not only used to close the capacity gap, but are also dispatched to relieve grid constraints.

This raises the question to what extent the regional distribution of virtual generation units (i.e. peak load production units) impacts congestion management volumes. Several regional distributions have been tested and the analysis shows that the distribution of these capacities only has a small impact on RES curtailment and redispatch. This results from the fact that, in general, peaks in the residual load do not occur at the same time as redispatch situations. The capacity gap is largest in times of low RES feed-in, while congestion management demand is highest in situations where there is a surge in RES feed-in. The positioning of backup capacities consequently only has a marginal impact on congestion management volumes (less than 2.5 % for the tested distributions).

6. Critical appraisal

Performing the analysis based on different weather years could have contributed to the robustness of the results. However, it should be noted that [17] shows that the influence of weather on the peak residual load range is marginal and consequently has no effect on the capacity gap. The latter is also true for RES production: production peaks and the resulting curtailment figures could be similar in magnitude, but differ with respect to the production profile. The effect on power plant dispatch as well as the export balance could be significant and is a topic for further research.

The implementation of a purely German electrification path, without electrification efforts in neighboring European countries, is a very uncertain boundary condition. The high import flows observed in the analyzed scenarios suggest that other European countries contribute significantly to guaranteeing the German security of supply. The extent to which this flexibility will be available to the German electricity market in a European electrification scenario is another topic for further research.

In addition, disregarding the influence of fixed costs on the operation of power plants is viewed critically. High CO_2-allowance prices, as assumed in the _120 and _120DE scenarios, result in low full-load hours and many start-ups for coal-fired power plants. These would therefore not be economically viable.

7. Discussion and conclusions

The analysis shows that the phase-out of 9 GW of lignite power plant capacity in combination with a high RES and high electrification scenario leads to a capacity gap of up to 27 GW in the German energy system in 2030. A demand for solutions aimed at closing the capacity gap exists. Hereby the frequently quoted idea of a capacity market solely for power plants, which should secure the procurement of the required capacity, is questionable because the installed capacities exhibit very low full-load hours. Procuring the missing capacity through power plants can be very costly. Policymaker should therefore consider designing a mechanism aimed at incentivizing the installment of both demand and supply-side capacities. Furthermore, the analyses shows that the system benefits of considering regional restrictions, resulting from transmission grid congestions, when selecting locations for the installation of capacity gap mitigating technologies are negligible. This insight should be considered in the development stage of a capacity market.

The large capacity gap also shows that there is demand for further research in the area of demand-side flexibility and storage systems. Also the degree to which electrification can unfold new demand-side flexibility is a subject for further research.

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