

First project report

**Definition and monitoring of security of supply on  
the European electricity markets**

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## **Executive summary**

This report is focused on resource adequacy, i. e. the achievement of an equilibrium between generation and consumption in the electricity system by a market clearing in the electricity market.

The analysis available consistently shows a very high level of resource adequacy in Germany. In all scenarios examined here up to 2030 (including a scenario with a reduction in the capacity of coal-fired power plants on the market to achieve the climate protection targets in Germany for 2030), resource adequacy is ensured. Consumers can be supplied with electricity at any time in the present studies, i.e. the calculated loss of load probability for Germany is zero for the entire period under consideration. This corresponds to a load balancing probability of 100 percent.

## Summary

### Mandate

Under the Energy Industry Act, the Federal Ministry of Economics and Energy (BMWi) is obliged to submit a report on the status and development of security of supply in the electricity supply sector at least every two years (Article 63(2) sentence 1 no. 2 EnWG); this report forms the basis for this report in the electricity market sector. In the analyses on which the report is based, pursuant to Article 51 (3) and (4) EnWG the following must be considered in particular:

- developments in production, grids and consumption in Europe,
- adjustment processes on the electricity markets based on price signals,
- cross-border balancing effects with neighbouring electrical countries with respect to renewable energy infeed, loads and power plant outages, and
- the contribution of new flexibility options (such as load management and emergency power systems).

A probability-based (probabilistic, i.e. stochastic) methodological approach shall be chosen and the measurement and assessment of security of supply on the electricity market shall be based on suitably defined indicators and their thresholds.

Against this background, in 2016 the BMWi invited tenders for the project "Definition and monitoring of security of supply on the European electricity markets from 2017 to 2019", the implementation of which was entrusted to a consortium consisting of r2b energy consulting GmbH, Consentec GmbH, Fraunhofer ISI and TEP Energy GmbH.

In the following, we first summarize the results of the security of supply analysis (SoS analysis)<sup>1</sup> for the electricity market. We then describe the most important aspects of the methodology applied, the creation of scenarios and accompanying measures to ensure the SoS level, before concluding with an outlook on the next report under this project.

The model calculations on which the present report is based were carried out in the second half of 2018.

### Analysis of security of supply

The SoS analysis consistently shows a very high level of security of supply on the electricity market in Germany. This predominantly also applies (taking into account the lower model accuracy there) to the modelled neighbouring countries. In all the scenarios examined here up to 2030, including a reduction in the capacity of coal-fired power plants on the market in order to achieve Germany's climate targets for 2030<sup>2</sup>, security of supply on the German electricity market is ensured. Consumers can be reliably supplied at any time in the present investigations, i.e. the determined probability of load excess (the term "Loss of Load Probability", LoLP for short, is used for this) is zero for Germany for the entire period under consideration. This corresponds to a load balancing probability of 100 %. The scenarios differ primarily in the development of the generation system, the development of flexibility options and the necessary imports - the latter always remaining well below the available import capacities. The level of imports required for security of supply can therefore be classified as low compared to (future) existing network capacity.

Several causes are responsible for the very high SoS level determined:

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<sup>1</sup> In the following, "security of supply" is abbreviated as part of compound terms as "SoS".

<sup>2</sup> Without knowing or anticipating the proposal of the "Growth, Structural Change and Employment" Commission to achieve the climate protection targets in 2030, which is currently being drafted, a hypothetical path for reducing the output of coal-fired power plants on the market was designed.

- The balancing groups and imbalance settlement mechanism provide utilities with a strong incentive to comply with supply commitments they have entered into. It is rational for market players to hedge potentially very high balancing energy prices by contracting sufficient generation and / or flexibility capacity, which directly or indirectly triggers corresponding investment incentives.
- The electricity supply system is currently in overcapacity. While market adjustments take place by reducing these overcapacities by shutting down existing plants for reasons of economic efficiency, there are certain inertial factors.
- Capacity markets abroad (including France, Great Britain, Poland and Italy) are creating new overcapacities, which via the electricity market also have a positive impact on the SoS level in Germany.
- New capacities will also be created by the replacement of CHP plants to maintain heat supply and by the subsidised expansion of renewable energy plants.
- In the internal electricity market, there are considerable balancing effects in terms of load and feed-in of renewable energies (RES) as well as unplanned non-availability of power plants.
- Finally, there is considerable potential for increasing the flexibility of consumption (including "new" consumers and a large capacity of economically viable flexibility options in the area of voluntary load reduction from industry), cogeneration and bioenergy, as well as emergency power systems (EPS).

These causes for the consistently high SoS level are partly substitutive: A weakening or even an elimination of a cause does not call the SoS level into question

but would be compensated in the electricity market by adjustment reactions elsewhere. Due to these substitution possibilities, there is more than just one development path of the secure electricity supply system.

## Methodology

In this report, the term security of supply describes the long-term safeguarding of the balance between generation and consumption in the electricity supply system in terms of balancing supply and demand on the electricity market. Security of supply on the electricity market is given if those consumers can always purchase electricity whose willingness to pay (benefit) is greater than or equal to the market price (costs).

In the light of the liberalisation of the EU internal electricity market, security of supply must be considered at a European level, taking into account dynamic market processes, including the price elasticity of demand. In this supra-regional market, there are considerable balancing effects in terms of load, feed-in of intermittent RES and unplanned outages of power plants, which have a positive effect on ensuring security of supply.

Within the framework of this project, a consistent methodology for implementing the legal requirements for monitoring security of supply on the electricity market was developed and implemented for the period up to 2030.

An SoS standard was first defined for this purpose. It was worked out that among the various possible indicators with which the security of supply on the electricity market can be characterised, the load excess probability (or loss of load probability, LoLP) is best suited for the formulation of an SoS standard. Further indicators are helpful as a flanking measure to contribute to the classification of a determined SoS level.

Based on conceptual analyses and literature research, a threshold value for the loss of load probability is defined as the SoS standard for Germany in the amount of  $\widehat{LoLP} = 0.06 \%$ , which corresponds to a load balancing probability of 99.94 %.

The threshold value is an acceptable value in the sense of a manageable yardstick and since it is also within the internationally customary range. Nevertheless, it is subject to unavoidable uncertainty, especially due to the uncertainty of the Value of Lost Load (VoLL) to be applied for its determination.

Our methodical approach is based on the following two core questions of SoS monitoring:

1. How will the European electricity supply system develop in the period under review?
2. Does this European electricity supply system ensure security of supply on the electricity market at an efficient level?

The first question arises since SoS monitoring must look many years into the future in order to have sufficient time for measures to ensure an appropriate SoS level, depending on the results of the statutory audit mandate. To answer this question, one or more scenarios for the development of the power supply system must be generated. Based on this, the second question is to be answered by determining the SoS level for the respective scenario and then classifying and evaluating it by applying it to the defined SoS standard.

In the context of the present study, the methodological approach of a consistent integrated modelling of the development of the electricity supply system in 15 European countries by means of a dynamic electricity market model and a probabilistic SoS analysis based on it was developed and applied against the background of the legal requirements of the EnWG in coordination with the BMWi and with the involvement of the Federal Network Agency and the German transmission system operators. The consistent coupling of the two models in particular accounts for balancing effects and uncertainties.

## Scenarios

The reference scenario (best guess scenario without additional climate protection measures) was generated based on detailed research / preliminary analyses and

comparison with other studies / experts in order to model the legal framework conditions and objectives given in reality. Sensitivity analyses were used to investigate developments within the power supply system that deviated from the reference scenario.

The scenarios comprehensively depict the initial situation, planning and adaptation reactions in the European electricity market. In order to put the reference scenario into perspective, a comparison with scenarios of the German and European TSOs is conducted. It shows that the reference scenario has lower to equal generation capacity in the sum of the countries considered. It represents a realistic and rather conservative development of the power supply system on the basis of the current market design and known developments in Europe.

### Accompanying measures to ensure security of supply

Some measures are necessary or recommendable to ensure or safeguard the determined high SoS level. The implementation of necessary measures was assumed in the analyses because this can be regarded as realistic considering the combination of existing or immediately foreseeable legal obligations and the corresponding lead time.

For example, the level of import capacity required to ensure security of supply can generally be characterised as low in comparison with (future) network capacity. Nevertheless, some preparations need to be made for the increased role of cross-border balancing effects in the future.

There is also a need for coordination and, if necessary, action regarding the international coordination of market and operating rules in the event of shortages. It would appear advisable to also clearly regulate the processes downstream of the day-ahead market on an international level as a precautionary measure.

In addition, measures can be taken into consideration to safeguard against unpredictable extreme events. Owing to their unknown probability of occurrence,

unpredictable extreme events cannot neither be efficiently addressed in the electricity market 2.0 nor in capacity markets. Therefore, they cannot and must not be taken into account when monitoring security of supply on the electricity market and assessing whether an efficient SoS level is achieved. Hedging of unpredictable extreme events falls within the scope of risk preparedness by the state and lies outside the scope of market design. The effects of unpredictable extreme events can be reduced with reserves outside the electricity market, such as the already planned capacity reserve. Therefore, these unpredictable events shall also be considered in the future dimensioning of the capacity reserve.

### Outlook

In accordance with the contract, a further report on monitoring security of supply on the electricity market until 2030 is to be prepared later this year. This serves to support the regular monitoring by the BMWi provided for in Article 51(3) and (4) EnWG. With the regular forecasts on the development of the electricity supply system and the SoS level, it is possible to check with foresight whether compliance with the SoS standard is to be expected and, whether there are still obstacles and disincentives and, if necessary, whether a later "easing" can be expected as a result of market adjustment processes. The forward-looking SoS monitoring thus ensures that there is sufficient time for implementing any measures that may be necessary to ensure an appropriate SoS level.

In addition to updating the database to updated sources and any legal changes at German and European level, we will also examine and potentially implement methodological extensions for the follow-up report.

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## List of abbreviations

AGEB	Working Group Energy Balances
AGEE	Working Group Renewable Energies
ALADINE	Alternative Automotive Diffusion and INfrastructure
BEV	Battery Electric Vehicles
CHP	Combined Heat and Power unit
BMWi	Federal Ministry of Economics and Energy
CCGT	Closed (or Combined) Cycle Gasturbine
CCS	Carbon Capture and Storage
CEP	Clean Energy Package
CoNE	Cost of New Entry
CWE	Central West Europe
DSM	Demand Side Management
DWD	German Weather Service
EDL	Energy Services
EEG	Renewable Energy Sources Act
EENS	Expected Energy Not Supplied
EEWärmeG	Renewable Energies Heat Act
EEX	European Energy Exchange
EnEV	Energy Saving Regulation
ENTSO-E	European Transmission System Operators for Electricity
EOM	Energy-only Market
FB approach	Flow-based Approach

FCEV	Fuel Cell Electric Vehicle
FORECAST	Forecasting Energy Consumption Analysis and Simulation Tool
GIS	Geoinformation System
GTCs	Grid Transfer Capacities
CCGT	Gas and Steam Combined Cycle Power Plant
HEL	Heating Oil Extra Light
HVDC	High Voltage Direct Current Transmission
HO TRUCK	Hybrid Overhead Line (or Trolley) Truck
IEA	International Energy Agency
CHP	Cogeneration of Heat and Power
LNG	Liquefied Natural Gas
LoLE	Loss of Load Expectation
LoLP	Loss of Load probability
LP	Linear Programming Problem
MBF	Maximum Border Flow
EPS	Emergency Power Systems
NGO	Non-Governmental Organization
NTCs	Net Transfer Capacities
NUTS	Nomenclature des unités territoriales statistiques
OCGT	Open Cycle Gas Turbine
PHEV	Plug-in Hybrids
PST	Phase Shifter Transformer
PTDFs	Power Transfer Distribution Factors

PtH	Power to Heat
QT	Cross-sectional Technologies
SAIDI	System Average Interruption Duration Index
UBA	Federal Environment Agency
TSO	Transmission System Operator
VoLL	Value of Lost Load
SoS	Security of Supply
WEO	World Energy Outlook
WTA	Willingness-to-Accept
WTG	Working Day
WTP	Willingness-to-Pay

# 1 Background and Overview

## Background

The transformation process of the European energy and electricity supply system is characterised on the one hand by the liberalisation of the European electricity markets, the establishment of a common European internal market for electricity and the expansion of the European border interconnectors. On the other hand, this is characterised by the progressive expansion of renewable energies (RE) in Germany and Europe, the increasing flexibility of generation and consumption as well as the increased coupling of the electricity, heat and transport sectors (sector coupling). These developments also require further methodological developments in the field of quantitative analyses of electricity supply and in particular analyses of security of supply.

Prior to this transformation process, the electricity industry was characterised by controllable large central generation plants and relatively predictable consumption patterns. Today and in the future however, the energy industry is increasingly characterised by fluctuating feed-in, decentralised plants for electricity generation from renewable energies, and flexible consumers, also against the background of the intended decarbonisation of the energy supply. Since the end of the 1990s, the common, competitively organised EU internal market for electricity has been increasingly liberalised and the cross-border network infrastructure (interconnectors) between the member states of the EU and Switzerland and Norway has been expanded. Against this background, security of supply must be viewed from a European perspective and in the light of dynamic market adjustment processes. In this supra-regional market, there are considerable balancing effects in terms of load, feed-in of intermittent renewable energies and unplanned outages of power plants, which have a positive effect on ensuring security of supply. The purchase of electricity at a high SoS level is of essential importance, especially in the transformation of the energy and electricity supply system described above.

This applies both to the prosperity and international competitiveness of an industrial location such as Germany and to the general quality of life of private consumers. Monitoring and thus a continuous assessment of the security of electricity supply is therefore necessary in order to

- identify SoS challenges at an early stage,
- analyse any remaining barriers or disincentives that could affect a high level of security of supply, and
- if necessary, take timely measures, such as adapting the regulatory framework to maintain a high level of security of supply.

Against the background of present-day reality and the future requirements of the German and European power supply system, the following aspects are of great importance:

- (1) **Security of supply can only be considered across national borders** because the German electricity supply system is connected to the electricity supply systems of neighbouring countries via a comprehensive grid infrastructure and electricity is traded intensively across borders and transported over long distances in the European electricity market.
- (2) **Security of supply can only be considered on the basis of probability (taking stochastics into account).** On the one hand, it is simply not possible to guarantee 100 percent protection against inflexible electricity consumption by generation plants, especially due to the stochastic power plant outages that occur. On the other hand, the question of economic efficiency is also a relevant evaluation criterion. It is therefore not necessary to ensure security of supply at a very high level solely on the generation side because that would be highly inefficient from an economic point of view. Neither is the capacity of renewable energy plants safely available due to the dependence of their generation on weather conditions (e.g. onshore and offshore wind energy plants and PV plants), nor

are conventional power plants safely available to cover consumption in any situation due to unplanned outages (e.g. due to technical defects, material or safety problems) or difficulties in the supply of fuel and cooling water. When monitoring or evaluating security of supply, it is therefore only possible to determine what proportion of inflexible electricity consumption can be covered in the expected value and what proportion of inflexible electricity consumption cannot be covered in the expected value. This applies especially to the envisioned further transformation of the electricity supply system towards intermittent RES and the continued expansion of the European grid infrastructure. In particular, the expansion of the European grid infrastructure and the increased opening of cross-border lines in so-called market coupling are the prerequisites for being able to make full use of existing trans-regional balancing effects of loads, RES feed-in and unplanned power plant outages. Stochastics in general, and in particular cross-national stochastic compensation effects (in the case of intermittent RES feed-in, load structures and unplanned power plant outages) must therefore be accounted for in methodological approaches in order to derive meaningful and robust results.

- (3) **Security of supply can only be considered accounting the dynamics of markets, i.e. the adjustment processes inherent in markets on the supply and demand sides.** In the case of overcapacities on the supply side (currently existing in the European electricity market), power plant operators react for economic reasons with more shutdowns or at least more temporary shutdowns (conservation, so-called cold reserve) of power plants. With (frequent) shortages of generation capacity in the European electricity market and consequently high electricity price expectations, power plants are kept on the market or put back into operation after temporary shutdowns. In addition, investments in new generation facilities and the development of flexibility options, such as load management and emergency power systems, are being encouraged.

(4) **Security of supply must take adequate account of flexibility potentials such as load shifts, load reductions in individual scarcity situations and general current and future developments in the price elasticity of demand.** The most favourable option for a secure balance between supply and demand on the electricity market in very rare situations of scarcity (e.g. low intermittent RES feed-in combined with a high consumption load and extensive unplanned power plant outages) is the active involvement of electricity consumers in the market. For example, flexibility in the form of load shifts and load reductions can be used to balance supply and demand on the electricity market. To this end, considerable potential is available - also taking into account technical restrictions - from consumers with consumption metering, who can contribute to balancing supply and demand on the electricity market if the market sends out corresponding price signals and the regulatory framework is designed appropriately. In addition, this potential can also be used to (financially) secure compliance with delivery commitments entered into by market participants.

### Tasks and Research Objectives

Against this backdrop, methodological approaches for monitoring and evaluating security of supply have been developed in recent years, taking adequate account of stochastics and the integration of national electricity markets into the European internal electricity market, which take particular account of the first two aspects mentioned above. In numerous analyses of supply security, corresponding approaches have already been or are being used.<sup>3</sup>

At the same time, corresponding developments in methodological approaches have led to adaptations of legal frameworks both in the EU and in Germany. The

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<sup>3</sup> See e.g. Consentec /r2b (2015), PLEF (2015), PLEF (2018), ENTSO-E (2016), ENTSO-E (2017a), ENTSO-E (2018b).

Federal Ministry of Economics and Energy (BMWi) is obliged to submit a report on the **status and development of security of supply** in the electricity supply sector at least every two years (Section 63(2) paragraph 1 no. 2 EnWG); the present report forms the basis for this report in the electricity market sector. Concerning the analyses on which the report is based, section 51(3) and (4) of the EnWG particularly requires that

- developments in production, grid and consumption in Europe,
- adjustment processes on the electricity markets on the basis of price signals,
- cross-border balancing effects with neighbouring electrical countries in the case of renewable energy feed-ins, loads and power plant outages, and
- the contribution of new flexibility options (such as load management and emergency power systems)

must be accounted for.

A probability-based (probabilistic, i.e. stochastic) methodological approach shall be chosen and the measurement and assessment of security of supply on the electricity market shall be based on suitably defined indicators and their thresholds.

The adaptation of the legal framework for the assessment of supply security on the electricity market in Germany thus takes account of the current state of science. The EU Commission's state aid rules and the *Winter Package*<sup>4</sup> currently in trialogue (*Clean Energy for All Europeans - CEP*) also provide for a transnational and probabilistic approach to monitoring security of supply.

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<sup>4</sup> European Commission (2016a).

Against this background, the BMWi put the project "[Definition and Monitoring of Supply Security in the European Electricity Markets from 2017 to 2019](#)" out to tender in 2016. The project was implemented by a consortium consisting of r2b energy consulting GmbH, Consentec GmbH, Fraunhofer ISI and TEP Energy GmbH.

### [Overview of the chosen methodological approach](#)

The first step was the further development of the definition of and assessment standard for security of supply on the electricity market and the further development of the methodology for modelling and monitoring security of supply on the European electricity market using existing concepts. Subsequently, the security of supply was empirically analysed based on the monitoring concept developed for the status quo and as a forecast for the following years as well as an outlook for the year 2030.

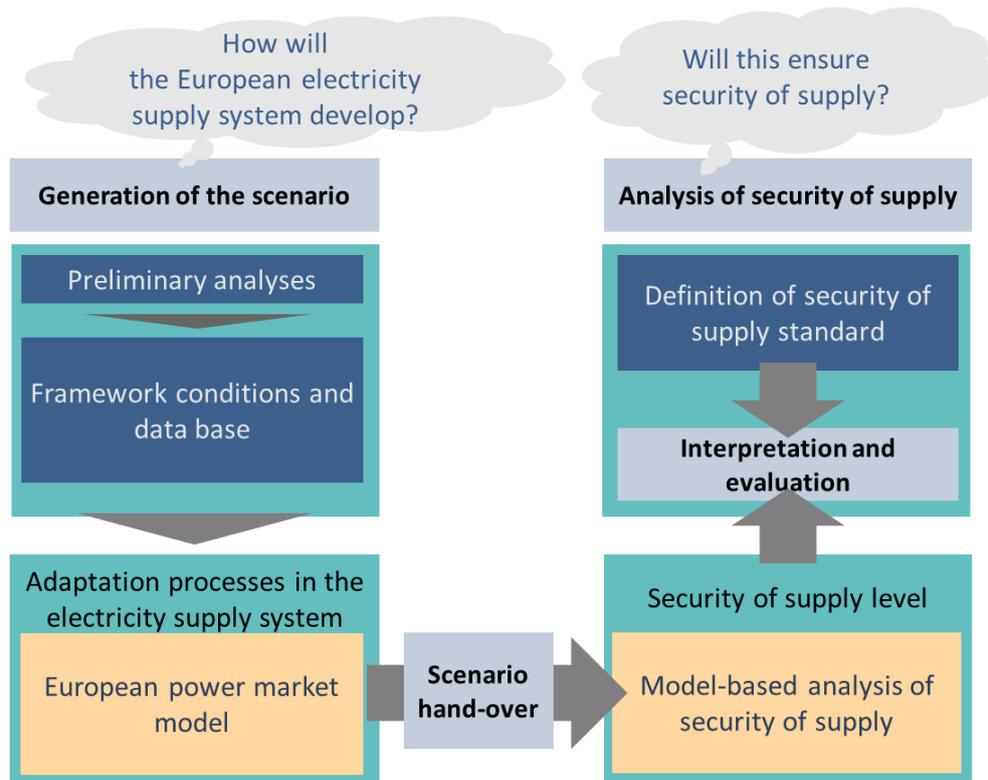
The concrete objectives of the project "[Definition and monitoring of security of supply on the European electricity markets from 2017 to 2019](#)" are defined as follows:

- Definition of one or more suitable indicators and corresponding thresholds for monitoring and assessing the security of supply of the electricity supply system;
- Derivation of scenarios for the development of the electricity supply system based on detailed preliminary analyses and using a dynamic European electricity market model, taking into account stochastics, economic efficiency, market mechanisms and market adjustment reactions;
- Evaluation of the level of security of supply using a probabilistic model that maps the probabilities of occurrence of possible system states.

Within the framework of this project, we have met the new requirements outlined above by monitoring security of supply based on a consistent two-stage approach. To this end, we have methodically and consistently further developed

both models and coordinated them with each other. One focus here is the consistent mapping of stochastics in the two models.

**FIGURE 1-1: CONSISTENT TWO-STEP MODELLING APPROACH**



Source: Own representation.

In the first stage, based on extensive preliminary analyses in which the framework conditions and data basis are determined, we dynamically simulate the development of the electricity supply system on the basis of an integrated investment and dispatch model of the European electricity market (Germany, its electrical neighbours as well as Scandinavia, Great Britain and Italy) taking into account the stochastics of several weather and load years as well as power plant outages. The results of these simulation calculations are the input parameters for the second stage - the analysis of security of supply using the probabilistic SoS model. As a result, we determine the level of security of supply considering the probability of occurrence of various system states, the European internal electricity market and dynamic developments on the European electricity markets in a consistent two-

stage approach. Finally, the level of security of supply will be classified and assessed based on a proposal for a security of supply standard, whose definition is also the subject of this project.

### Structure of the study

This project report describes on the one hand, the central results of the methodological developments of the modelling approaches and the monitoring. On the other hand, results on supply security on the electricity market in Germany are presented considering scenarios for the years 2020, 2023, 2025 and 2030 developed within the framework of the project, which result from the application of methodological further developments.

In [Chapter 2](#) we go into more detail on the definition of security of supply on the electricity market, present parameters for assessing security of supply and examine their significance. Subsequently, the function of a security of supply standard (SoS<sup>5</sup> standard) is discussed and a level for such a standard is derived. The chapter concludes with notes on the interpretation of a determined SoS level.

[Chapter 3](#) presents the further advanced approach to modeling. First, we describe the overarching modelling approach: This is based on the coupling of detailed preliminary analyses and a stochastic European electricity market model to generate a scenario for the future electricity generation system in Germany and Europe with a simulation model for the quantitative SoS analysis. Here we also describe the essential aspects of a consistent coupling of these two model approaches. Second, we then discuss in detail the preliminary analyses carried out and the two models used in this study. This includes the methodological approaches in the preliminary analyses and the stochastic European electricity market model. We use this to derive scenarios for the development of the electricity generation system and for the availability of flexibility options in the electricity

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<sup>5</sup> In the following, "security of supply" is abbreviated as part of compound terms as " SoS ".

supply system, taking dynamic adaptation processes on the European electricity market into account. Subsequently, we present the simulation model for the quantitative SoS-analysis, with the help of which the previously identified parameters for the assessment of supply security can be derived.

In [Chapter 4](#) we present the central framework assumptions of a reference scenario, developed in agreement with the BMWi for this study and which we have extensively checked for plausibility through comparison with other studies and professional exchange with numerous scientific research projects. The aim of the reference scenario is to map a 'best guess' analysis of the relevant framework assumptions from a current perspective, but without an additional climate protection measure related to coal-fired power generation. An exception to the 'best guess' approach could therefore be the further development of installed capacity and the use of coal-fired power plants in Germany.<sup>6</sup> Another exception in the conservative sense are the assumptions on costs of the flexibility options<sup>7</sup>, industrial load reduction and emergency power systems. In this chapter, we also describe the methodological approach and the basis for deriving the framework assumptions of the reference scenario.

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<sup>6</sup> Under the reference scenario, we have not assumed any (additional national) measures to successively reduce greenhouse gas emissions from coal-fired power plants as a contribution to achieving national climate protection targets in the coming years. As a result, the national climate protection targets are not achieved due to the insufficient contribution of the electricity sector and the reference scenario cannot be regarded as a target or 'best guess' development in this respect. This applies even more against the background of the establishment of the "Commission for Growth, Structural Change and Employment" agreed in the coalition agreement, which is to draw up measures both to reduce greenhouse gas emissions from coal-fired power plants in line with targets and to put an end to coal-fired power generation.

<sup>7</sup> In agreement with the BMWi, we have used conservative assumptions in the reference scenario regarding investment and development costs, annual fixed costs and necessary incentives for market participants in the event of load reduction potentials in industry and emergency power plants. This means that we have allocated relatively high costs to these flexibility potentials, which do not correspond to our best-guess. In view of the uncertainties about the exact costs and the heterogeneity of the costs, it seems appropriate to us to make a corresponding setting in the context of this study on security of supply in the sense of a conservative approach.

**Chapter 5** presents the results for the reference scenario. First, we describe in detail the development of the power generation system over time and the availability and development of flexibility options. In addition, in the subchapter "Balancing Effects on the European Electricity Market", we show to what extent the consideration of balancing effects between consumption loads, intermittent RES feed-in and unplanned power plant outages in the European context reduces the requirements for safeguarding supply security on the generation side. Subsequently, we present the results of the simulation calculations to derive the indicators for monitoring and assessing the security of supply.

**Chapter 6** describes the framework assumptions and results of alternative scenarios (sensitivities to the reference scenario) developed and analysed in this study. In each of these scenarios, we have made a core amendment to the framework assumptions of the reference scenario. In the first sensitivity, in contrast to the reference scenario, we have applied our 'best guess' costs for the flexibility potentials, load reduction in industry and emergency power plants. In the sense of a target scenario for national greenhouse gas emissions, in the second sensitivity we assumed an accelerated reduction in the capacity of lignite and hard coal-fired power plants on the market, e.g. based on regulatory requirements at the latest decommissioning date.<sup>8</sup> The accelerated decommissioning is designed to meet the sectoral target for the energy sector in 2030. In the third sensitivity we assumed a delayed grid expansion with corresponding effects on the available import and export capacities between the countries considered. In another grid

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<sup>8</sup> As part of the SoS monitoring on the European electricity markets, there is no commitment to concrete measures to reduce the installed capacity of coal-fired power plants on the electricity market. Whether the installations concerned will be decommissioned or transferred to a reserve, for example, is not the subject of this investigation.

sensitivity we have investigated a limited physical cross-border exchange capacity without the possibility of market adjustment processes.<sup>9</sup>

Finally, in [Chapter 7](#), we summarise the key findings once again, draw conclusions and point out any research and development necessities. In addition, we make recommendations as to which measures may be sensible or necessary to ensure the SoS level.

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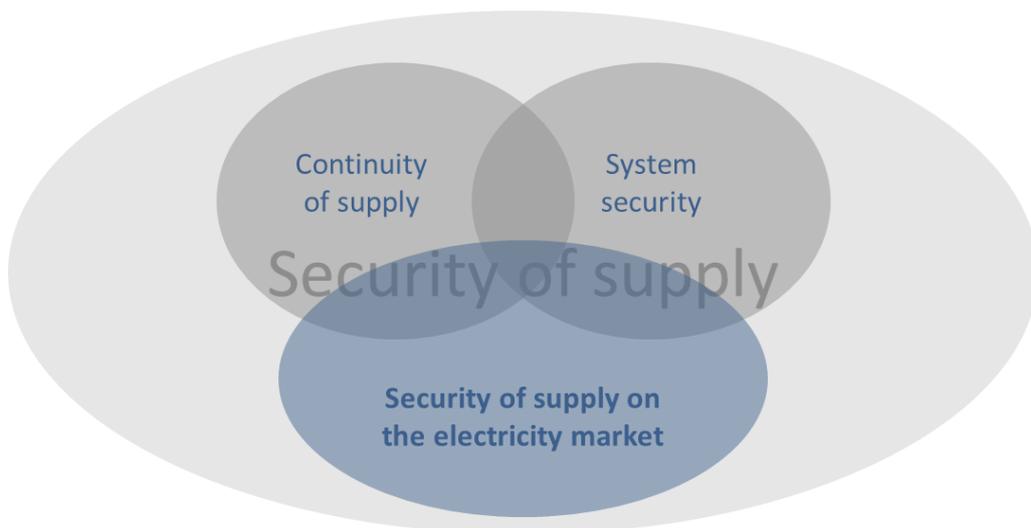
<sup>9</sup> Without the possibility of market adjustment processes, this sensitivity means that only an adjustment is implemented in the quantitative analysis of the SoS level and no market adjustment processes are determined in the context of modelling with the European electricity market model.

## 2 Definition of and evaluation criteria for security of supply on the electricity market

### 2.1 Definition of security of supply on the electricity market and objective of its assessment

Together with economic efficiency and environmental compatibility, security of supply forms an equally important objective of energy policy (energy policy target triangle). The **concept of security of supply** of the electricity supply system is used and interpreted differently depending on the context.

FIGURE 2-1: DEFINITION OF THE OBJECT OF INVESTIGATION



Source: Own representation.

Security of supply in the broader sense has three different dimensions:

- **Continuity of supply**, which essentially deals with the question whether consumers are connected to the electricity grid.
- **System security**, which essentially deals with the question if the power grid is operated in a stable state and remains stable even after failure events.

- **Security of supply on the electricity market**, which deals with the question if electricity production meets demand by balancing supply and demand on the electricity market.

This report looks at **security of supply on the electricity market**. The term security of supply in this report thus describes the long-term safeguarding of the balance between generation and consumption in the electricity supply system in the sense of balancing supply and demand on the electricity market.

In Europe, a domestic market has been established for many years in which electricity is traded as a homogeneous product within so-called bidding zones. The bidding zone layout has so far been predominantly based on national borders. Exceptions are the joint bidding zone of Germany and Luxembourg on the one hand, and Norway, Sweden, Denmark and Italy on the other, which are each divided into several bidding zones. There is considerable transmission capacity between the bidding zones. The common European internal market for electricity is the basis for monitoring security of supply in this report. The development of supply in the European internal electricity market is taking cross-border transmission capacities into account, which is why the examination whether the market ensures security of supply must also be consistent with this concept. Cross-border exchanges contribute to security of supply. This means that although the relevant wholesale price for German consumers is determined on a German marketplace, foreign players naturally also buy and sell electricity on that marketplace. In this respect, domestic electricity supply is never only available to domestic consumers. Therefore, a national view on security of supply (self-sufficiency) is not an applicable concept in the European internal market. The consideration of European cross-border electricity trading also implies that network restrictions within a country do not constitute an evaluation criterion in the context of this study.<sup>10</sup> In

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<sup>10</sup> Congestion within Germany is addressed in other processes (system analyses for the network reserve, network development plan). Suitable measures will be developed and subsequently implemented for the technical challenges that arise in this respect.

English-speaking countries, security of supply on the electricity market is also referred to as *generation adequacy* (in contrast to *transmission adequacy*) in view of the generation capacity required for it.

However, security of supply on the electricity market must also take consumer preferences into account. **Security of supply on the electricity market is given if those consumers can always purchase electricity whose willingness to pay (benefit) is greater than or equal to the market price (costs).**<sup>11</sup> Consumers, e.g. private households, who usually do not and cannot observe the market price, are represented by their suppliers as intermediaries. Due to their supply commitments, the suppliers must secure a corresponding electricity procurement or otherwise bear high balancing energy costs for shortfalls in their balancing groups. Other consumers, such as power-intensive industrial companies, on the other hand, observe the market price directly or via service providers and, depending on their opportunities, can react to the market prices or individual electricity price peaks with short-term reductions or shifts in their consumption.

Supply security therefore does not require that all consumers are able to obtain energy at all times. Rather, reductions or curtailments in consumption are consistent with security of supply, provided that this corresponds to the (price) preference of the consumers concerned. Demand flexibility, in particular the economic potential of load management in the industrial sector, therefore plays an important role for supply security, in addition to the availability of flexible generation plants, and must be appropriately taken into account in the analysis.

Against this background, the objective of monitoring security of supply is to examine whether the electricity markets in Germany and Europe can ensure in the long term that sufficient power plants and other flexibilities in the form of storage

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<sup>11</sup> See e.g. BMWi (2015).

facilities and flexible loads are available to guarantee the above-mentioned condition of balancing supply and demand.

The analysis of security of supply in the electricity market must also consider the fact that transmission system operators (TSOs) have several other measures at their disposal to secure supply even if supply and demand should diverge. This includes the use of balancing power and other existing reserves of the national and foreign TSOs, such as the capacity reserve. Only in the unlikely event that after these measures have been exhausted the price-inelastic consumption still exceeds the total available generation capacity would the grid operators have to carry out involuntary shutdowns of individual consumers or individual distribution grids as a last resort. Only a very small part of the load would thus be affected, while the majority of consumers would continue to be supplied. A secure operation of the European interconnected grid is still possible in such a situation.<sup>12</sup>

In the following, parameters for the assessment of supply security are first presented and examined with regard to their significance (section 2.2). The function of an SoS standard is then discussed and a level for such a standard is derived (section 2.3). The chapter concludes with notes on the interpretation of a calculated SoS level (section 2.4).

## **2.2 Indicators for the assessment of supply security**

### **2.2.1 LoLP, EENS and related indicators**

#### **Description of the indicators**

Security of supply has, in general, a probabilistic character. This is because the ability of the power supply system to meet demand at a given point in time depends on the realisation of a large number of influencing stochastic factors at that

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<sup>12</sup> A widespread power failure or a large-scale collapse of the European interconnected grid is practically only caused by major failures of network resources in the transmission grid (and therefore affects the area of system security).

point in time. In addition to the unavailability of generation plants due to outages, these include above all weather-related influences on demand and on increasingly significant parts of generation (particularly solar and wind energy).

This fact has been addressed for several years by applying probabilistic evaluation methods (see chapter 3). Accordingly, probabilistically defined parameters for assessing the security of supply have been established. They are all based on the assessment of system states in which the remaining power (on the electricity market) is less than zero, i.e. not all consumers can be supplied at any time according to their price preferences (see also section 2.1).

The indicator load excess probability ("Lastüberhangwahrscheinlichkeit" in German) indicates the probability that such conditions will occur. The term "Loss of Load Probability" (LoLP) is widely used for this purpose<sup>13</sup>. LoLP is specified without units or as a percentage<sup>14</sup>. It can also be expressed equivalently by the load balancing probability; this is the probability with which the remaining power (on the electricity market) is greater than or equal to zero.<sup>15</sup>

EENS (abbreviation of "Expected Energy Not Supplied") indicates the expected value of the demand energy that cannot be covered on the electricity market. This corresponds to the expected value of the integral of the negative remaining power and is expressed as the amount of energy (e.g. GWh) per year.

If there are no further reserves outside the electricity market, the LoLP characteristic indicates the probability of involuntary disconnection of consumers. Such a shutdown would affect so-called 'inflexible consumers', who would not be able to express (on a market basis) the price threshold above which they would be willing to forego electricity supply. Therefore, in the event of a lack of production

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<sup>13</sup> The interpretation of an SoS level expressed, for example, by LoLP is discussed below and in more detail in Section 2.4.

<sup>14</sup> Alternatively, it can also be expressed in hours per year - by multiplying it by the number of hours per year (8760) - and is then referred to as Loss of Load Expectation (LoLE).

<sup>15</sup> The following applies for the conversion: Load balancing probability =  $1 - \text{LoLP}$ .

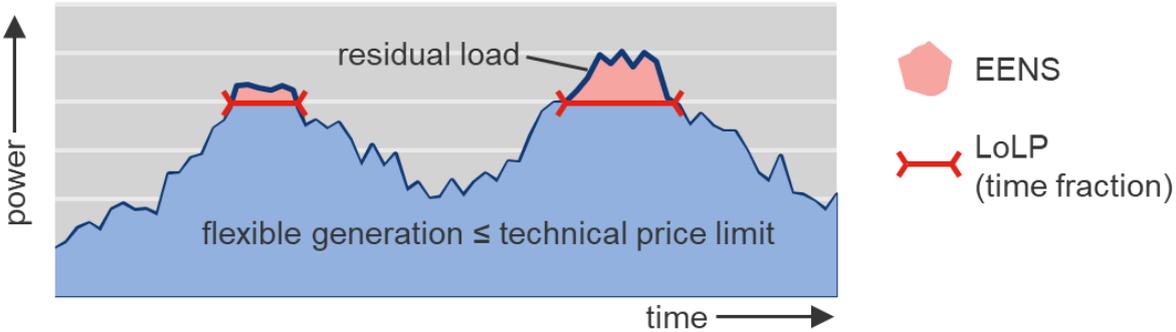
or other flexibility, a (small) proportion of inflexible consumers would have to be involuntarily switched off when reaching the technical price limit in the market in order to maintain system stability, while the remaining (large) proportion of consumers would continue to be supplied.

If, however, as in Germany, there are still reserves outside the electricity market<sup>16</sup>, the LoLP characteristic indicates the probability that these reserves will be activated.<sup>17</sup> In practice, an involuntary disconnection of consumers therefore has a lower probability than the LoLP value expresses.

Both LoLP and EENS give expected values of statistical distributions which result from the stochastic character of the influencing variables for loss of load. Appendix F explains why this is an appropriate approach.

The basic relationship between LoLP and EENS is shown in the following figure by means of a schematic curve of residual load and flexible generation.

**FIGURE 2-2 BASIC RELATIONSHIP BETWEEN L0LP AND EENS**



Source: Own representation.

LoLP and load balancing probability describe probabilities, i.e. time fractions, but do not contain information about the size of the respective loss of load in scarcity

<sup>16</sup> In Germany, this includes in particular the capacity reserve.

<sup>17</sup> Complementary to this, the load balancing probability indicates the probability that these reserves will not be activated.

phases. In contrast, EENS contains information on the extent of the loss of load, but not on the probability of it occurring.

### Classification of the indicators

The assessment of electricity market design in terms of security of supply addresses the question of whether an efficient investment has not been made. This would be the case if the costs of such investment were lower than the amount of benefits in the form of reduced involuntary disconnections that are not yielded without this investment. To this end, an investment in the "next MW" of flexibility is considered, avoiding a deficit of 1 MW for a portion of the time that corresponds exactly to the LoLP value. The monetary assessment of this avoided deficit energy is discussed in more detail in section 2.3.2. However, when selecting an indicator for assessing the security of supply, it should first be noted that only the duration, but not the amount (capacity), of the deficit matters. This clearly favours the LoLP as a relevant indicator.

Strictly speaking, however, the LoLP is not an unambiguous characteristic of a power supply system to be tested. This would only be the case if the system had no temporal flexibility. In fact, however, there are considerable possibilities in the European power supply system to influence the course of the residual load over time. On the one hand, storage facilities are suitable for this purpose, and on the other hand, load flexibility also consists to a considerable extent of potential for shifting demand over time (i.e. voluntary load shifting in addition to voluntary load reduction). If a shortfall in demand coverage cannot be avoided on an integral-time basis, e.g. over the duration of a year under consideration, then the duration of the shortfall can be controlled to a certain extent by using such flexibilities. It is therefore possible to exchange the duration of shortfalls for their amounts (capacity).

As will be explained in chapter 3 simulation methods are used to measure security of supply. Within this framework, a "minimum LoLP" can be determined theoretically by using the flexibilities in such a way that the phase(s) of the shortfall is/are

as short as possible, irrespective of the amount (capacity) of uncovered load then occurring. This "minimum LoLP" can be unambiguously determined in the model. However, it is implicitly assumed that the players on the electricity market coordinate their behaviour in order to minimise the duration of involuntary shut-downs. In reality, imperfect forecasts and a lack of incentives<sup>18</sup> may lead to deviations from this; however, the total demand energy not covered by the electricity market (in calculations: EENS) would remain largely constant. Nevertheless, the "minimum LoLP" is suitable for assessing security of supply, as it represents a lower estimate of capacity utilisation that would be expected on average for an investment in the "next MW" of flexibility. Neglecting other abstractions, potential investors can therefore expect that an additional capacity would on average be operated at least at the capacity utilisation indicated by the "minimum LoLP".

Moreover, the difficulty discussed above with regard to the unambiguity of the indicator would not be solved if EENS was used instead to assess the security of supply. Although EENS can be determined more objectively because it can only be influenced to a limited extent by the use of temporal flexibilities, the challenge would only be shifted to examining the efficiency of investing in additional capacity. Since investment costs are essentially capacity-driven, the costs of an investment to reduce EENS, i.e. to cover the "next MWh", could only be determined if some capacity utilisation were assumed. But this is just the LoLP value again.

In summary, it can be stated that the LoLP indicator (at least in the form of the minimum LoLP using temporal flexibilities) is the suitable parameter for testing the power supply system for the presence of an efficient SoS level. Thus, LoLP is also the suitable parameter for the formulation of an SoS standard against which a given system is to be measured. This is discussed in section 2.3.

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<sup>18</sup> Due to high market prices in times of scarcity, there are considerable incentives to avoid loss of load in general. However, there is no concrete incentive to concentrate the loss of load on short times (with greater size/capacity) instead of longer times (with lower size in each case, i.e. with constant EENS).

The EENS parameter is not suitable for defining an SoS standard, but unlike the LoLP it contains information on the extent of the shortfall. It is therefore useful as an additional indicator to explain the SoS situation, in particular to show that incomplete coverage of inflexible demand is not synonymous with a large-scale (network-related) blackout, but that only a small proportion of consumers would be affected by an involuntary disconnection, while the majority of consumers would continue to be supplied. We will discuss this in more detail in the next section 2.2.2.

## 2.2.2 SAIDI contribution to security of supply on the electricity market

### Motivation

In the practical discourse on security of supply, the above-discussed indicators of security of supply on the electricity market are sometimes perceived as difficult to interpret. This is also due to the fact that they are not directly comparable with the SAIDI (System Average Interruption Duration Index) indicator established to describe continuity of supply from the customer's point of view. On the contrary, the fact that both LoLE (as the equivalent of LoLP) and SAIDI are expressed in terms of duration (hours or minutes) per year may lead to misunderstandings, because while SAIDI refers to the probability of involuntary interruption from the point of view of *each individual* customer, LoLP and LoLE describe the probability that *some* consumer will involuntarily not be supplied.

In the following, we will consider the specification of an indicator that describes the security of supply from the customer's point of view and is comparable to the (disturbance related) SAIDI.<sup>19</sup>

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<sup>19</sup> Depending on the application, SAIDI, which is related to continuity of supply, can include other supply interruptions in addition to interruptions caused by faults. For the sake of simplicity, the term "disturbance-related" will be used in the following (only) to distinguish the SAIDI indicator related to continuity of supply from effects caused by security of supply on the electricity market.

### Determination of SAIDI in relation to continuity of supply

The SAIDI in terms of continuity of supply is the probability that a customer connection will be affected by an involuntary supply interruption due to grid-related reasons. In the vast majority of practical cases, this relates to disturbances in the distribution networks. Therefore, the term "disturbance related SAIDI" will be used in the following. In order to determine the SAIDI, the scope of each failure event is recorded in terms of its duration and, in principle, in terms of the capacity of the affected customers. For practical reasons, the capacity affected is approximated at the low-voltage level by the number of customers affected, and at the medium-voltage level by the installed capacity of the high/medium voltage transformers affected. The extent of the failure (product of duration on the one hand and capacity or number of customers on the other) is aggregated over all the failures of a year and related to the corresponding population (total capacity multiplied by duration of the year for the medium voltage and total number of customers for the low voltage level, respectively).

On closer inspection, SAIDI can therefore be interpreted as a proportion of energy, i.e. the ratio of interrupted energy to total energy supplied. Only for practical reasons certain approximations are made: In the medium voltage level the supplied and the interrupted energy are approximated by the deliverable and non-deliverable energy (product of installed capacity and time), respectively. In the low voltage level, the approximation is made by using the unit "number of customers", i.e. the assumption of identical demand behaviour of all customers.

In Germany the disturbance related SAIDI has in recent years been between 12 and 15 minutes/year per consumer.

One consequence of the abstract nature of SAIDI is that it is by no means comparable with concrete events that actually occur. A SAIDI level of about 15 minutes/year per consumer in Germany does not mean that every single customer has to expect an interruption of his power supply for about 15 minutes each year. Rather, in individual cases supply interruptions of significantly longer

duration can occur, depending on the cause. However, because this only affects a small group of customers and many other customers may not experience a supply interruption for a whole year or longer, the SAIDI as an average value is only in the range of minutes.

### Indicator for the electricity market contribution to SAIDI

It is clear that a parameter comparable with the well-known SAIDI to describe the security of supply on the electricity market from the customer's point of view (in short, electricity market SAIDI) should also be based on the calculation of an energy share.

The already established parameter EENS serves as nominator, i.e. as a counterpart to the interrupted power in the determination of the disturbance related SAIDI (which, as explained above, is approximated in terms of energy in practice). From the customer's point of view, EENS has the same significance as disturbance related downtime; only the causes that lead to the interruption of supply differ.

The specification of the population relevant for the electricity market SAIDI, i.e. the denominator in the calculation, requires further consideration.

Only inflexible customers and customers whose willingness to pay is higher than the price limit at which the shutdown takes place are affected by an involuntary shutdown due to the electricity market. This also applies if, as is usually the case, the shutdown concept of a network operator provides for the temporary shutdown of an entire network district if necessary. This is because some of the flexible customers connected there already voluntarily renounce the utilisation of electricity in the assumed situation due to the increased electricity price, even before the disconnection by the grid operator. The basic population to be used for the

electricity market contribution to the SAIDI can be calculated within the framework of the SoS analysis by subtracting the annual integral of the potential for voluntary load reduction from the annual energy consumption of all customers.<sup>20</sup>

The electricity market contribution to the SAIDI in a bidding zone is thus calculated by dividing the EENS by the annual energy consumption less the annual integral of the voluntary load reduction potential considered in the SoS valuation.

### Interpretation and significance of the electricity market contribution to SAIDI

Due to the basically analogous calculation rule, the electricity market contribution to the SAIDI proposed here is directly comparable with the disturbance related SAIDI. This makes it possible to compare the consequences of electricity market related shutdowns from the customer's point of view with the level of non-availability of the electricity supply, which occurs and is accepted due to grid failures.

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<sup>20</sup> Against the limitation of the population to the customers actually affected, it could be argued that all customers (or the aggregated capacity) are counted when determining the SAIDI in terms of continuity of supply, even though there are customers in the affected network area who are not themselves affected in the event of disconnection caused by a failure. It is these customers who have secured themselves with emergency power generators.

However, this "inaccuracy" does not only affect the nominator, but also the denominator of the SAIDI calculation. Ignoring the customers protected from supply interruptions therefore corresponds to the not implausible assumption that the share of these customers is evenly distributed regionally and therefore has no systematic effect on the SAIDI value.

By contrast, if, when calculating the electricity market contribution to the SAIDI, the flexible customers not affected by a shutdown due to the electricity market were taken into account, then only the denominator, i.e. the population, would be affected. This is because the nominator, i.e. the extent of the SoS related shutdown (EENS), must always correspond to the extent of the load excess. The more flexible customers in a region decide to not abstain from utilizing electricity before the grid operator switches off, the larger (in the grid topological sense) the shutdown area must be in order to achieve the required physical effect of the shutdown. Therefore, the inclusion of all flexible customers in the calculation of the electricity market contribution to SAIDI would lead to a systematic reduction of the calculation result. This effect would also be considerable in terms of its amount, because the share of flexible customers (who are not affected by electricity market related shutdowns) in the total collective is significantly higher than the share of customers with emergency power generators (who are not affected by grid related interruptions), because the flexibility related to security of supply can also be implemented without technical equipment, namely by foregoing consumption.

A numerical example: Assuming an annual electricity consumption in Germany of 525 TWh and a load flexibility potential of 25 TWh (equivalent to approx. 3 GW)<sup>21</sup>, the relevant annual consumption is 500 TWh. Assuming an EENS value of 1 GWh/a, for example, this results in an electricity market-related SAIDI of 1.05 min/a.<sup>22</sup>

As with the disturbance related SAIDI, the electricity market contribution to SAIDI must not be misunderstood as an effect on each customer but must be understood as the probability of an involuntary interruption from the point of view of each individual customer in the sense of an average level of impact, whereby interruptions can be longer or shorter for individual customers.<sup>23</sup>

It should also be emphasized that the electricity market contribution to SAIDI presented here is purely informative in nature and is not suitable for comparison with an SoS standard.<sup>24</sup>

### 2.2.3 Contribution of imports to security of supply

In chapter 1 it has already been stated that, in view of the internal electricity market, an analysis of security of supply on the electricity market must be carried out at an international, i.e. European level. Accordingly, pursuant to article 51(3) EnWG, cross-border balancing effects must be considered when monitoring security of supply.

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<sup>21</sup> Since it can be assumed that in the few periods in which there would be an SoS-related reduction in demand, the potential for load reduction would always be activated, its availability is estimated at 8760 h/a in this rough assessment.

<sup>22</sup> Calculation:  $1 \text{ GWh/a} : 500,000 \text{ GWh/a} * 8760 \text{ h/a} * 60 \text{ min/h} = 1.05 \text{ min/a}$

<sup>23</sup> With usual shutdown concepts, only a small proportion of all customers would experience (rolling) shutdowns at all, which would then take significantly longer than just a few minutes. A refinement of the shutdown concept would have no impact on the electricity market contribution to SAIDI.

<sup>24</sup> Due to the fact that, in order to ensure comparability with the disturbance related SAIDI, it is based on the EENS and thus on an energetic parameter, the electricity market SAIDI, like EENS (see section 2.2.1), is not suitable for comparison with an SoS standard.

Yet, the legislator also requires (in article 63(2) EnWG) that the monitoring report on security of supply should include a description of "*the extent to which imports contribute to ensuring security of supply in Germany*". The contribution of imports to security of supply constitutes the effective use of cross-border balancing effects. It therefore provides important additional information (similar to the EENS or SAIDI contribution) to interpret the SoS level, which is described primarily by the LoLP indicator.

The contribution of imports to security of supply must not be equated with imports that are observed in real terms or expected in the future. The latter result from the economic rationale of the market participants. In simple terms, under ideal market conditions and within the limits of the possibilities offered by cross-border exchange capacities, the most cost-effective generation plants are always dispatched. This regularly leads to imports, although domestic generation facilities or other flexibility options are still available - albeit at higher costs. For the SoS analysis, by contrast, the extent to which an import is necessary in order to prevent a load excess or reduce its extent is decisive. Our two-stage model approach enables us to make this differentiation and explicitly determine the imports required to ensure security of supply. Details can be found in section 3.3.6.

## **2.3 Derivation of a security of supply standard**

### **2.3.1 SoS-Standard as equilibrium condition**

The function of an SoS standard is to provide a threshold against which an electricity supply system can be tested for an adequate level of security of supply. Specifically, article 51(4) of the EnWG stipulates this (unofficial translation):

*"Monitoring [...] shall include the measurement and assessment of security of supply. The monitoring takes place on the basis of*

- 1. indicators suitable for measuring security of supply on the European electricity markets with an impact on the territory of the Federal Republic of Germany as part of the internal electricity market, and*

2. *thresholds above or below which appropriate measures to ensure security of supply are examined and, if necessary, taken. "*

In section 2.2.1 the LoLP indicator (probability of load excess) was identified as a suitable indicator for formulating an SoS standard.

A threshold value for the LoLP indicator can be successfully derived via an economic approach: The efficient level of supply security can be formulated as a state of equilibrium in terms of costs and benefits from an economic point of view (from the consumer perspective). It is not economically efficient if additional capacities are only made available for very rare cases. In other words, it is economically efficient if a small part of the load cannot be covered for a short period of time, i.e. in rare cases, while most consumers continue to be supplied. For it is immediately obvious that with increasing SoS levels, any further investment in capacities on the electricity market will yield an ever smaller additional benefit (in the form of avoided disconnection of consumers).

The SoS standard (threshold value within the meaning of section 51(4)(2) of the EnWG) is defined as a state of equilibrium in terms of costs and benefits from an economic point of view in such a way that the benefits lost through the involuntary disconnection of consumers are the same as the costs that would be incurred to avoid this disconnection.

The costs to be taken into account here are those for the construction of an additional generation plant of the most cost-effective technology (Cost of New Entry, CoNE).<sup>25</sup> Their benefit results from the expected utilisation - i.e. the probability for which their use can be expected in order to prevent consumption shutdowns - weighted with the willingness to pay of the affected consumers (Value of Lost Load, VoLL). If the willingness to pay and the costs are known, one can determine the utilisation ratio for which the balance described above applies:

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<sup>25</sup> More detailed explanations can be found in section 2.3.3.

$$\widehat{LoLP} = \frac{CoNE}{VoLL} \quad (2.1)$$

$\widehat{LoLP}$  (pronounced as "LoLP ceiling") describes the threshold value for the load excess probability as an SoS standard. In a sustainable market design, this threshold should be met by balancing supply and demand on electricity markets. The test to determine whether this is the case is therefore carried out by comparing the threshold value determined - in accordance with the equilibrium state described - for the LoLP indicator with a calculated LoLP value which indicates the probability that the remaining power on the electricity market is less than zero.

If the threshold value of the system under review is exceeded for a future year, this is an indication that an economically efficient investment has not been made. That means, that in the current market environment, the professional players in the electricity supply sector have not recognised the economic viability of such an investment or, in any event, have not exploited it. This would entail the examination of measures provided for in section 51(4)(2) of the EnWG, in particular, the examination of remaining barriers and misguided incentives and the examination of whether a subsequent 'easing' is expected as a result of market adjustment processes.

From an economic point of view, this examination reservation for a later "easing" is also expedient because the equilibrium state described above is of a theoretical nature. Real markets never actually find themselves in a steady equilibrium because they are constantly reacting to new information and changes. Rather, a functioning market is characterised by the fact that it always tends towards such an equilibrium. Exceeding a threshold value determined on the basis of the equilibrium principle described above may result either from market imperfection affecting security of supply (e.g. barriers and misincentives in market and regulatory design) or from dynamic adjustment processes in the market ("easing" of transitory oscillations). Any exceedance of the LoLP threshold value resulting from such market imperfections, which can lead to market failure, may require countermeasures to be taken, such as the removal of barriers and misleading incentives in

market and regulatory design or even the transitional introduction of a capacity mechanism. For this reason, the SoS monitoring looks more than ten years into the future, to provide sufficient time for reaction possibilities. If, by contrast, the assessment shows that the LoLP threshold is exceeded due to dynamic adjustment processes in the market, it can be expected that the reaction of the market will soon bring the electricity supply system back to a state where the LoLP is below the threshold.

### **2.3.2 Value of Lost Load**

In accordance with the mandate of this study, conceptual considerations for the determination of an appropriate value of the Value of Lost Load (VoLL) for the assessment of supply security in Germany are carried out within the framework of this study, and a literature search is carried out with regard to available numerical values. Own original - for example empirical - analyses to determine the VoLL, however, are not the subject of this study.

#### **Conceptual considerations**

The key question for assessing security of supply is: if there were scarcity-related disconnections, would this correspond to the preference of disconnected customers, or would they have been willing to pay more for additional capacity to prevent their disconnection?

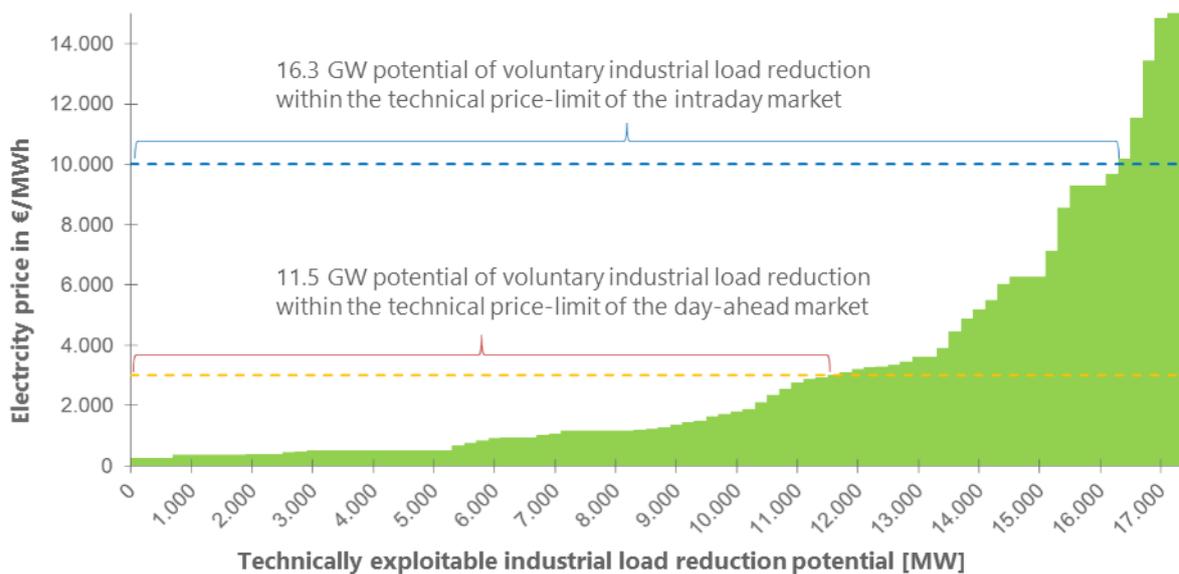
Some of the customers are flexible in the sense that they can express their price preference - i.e. the price threshold above which they would be willing to be switched off - on a market basis. A necessary prerequisite for achieving flexibility in this sense is the possibility of billing the energy supply according to the actual supply profile, which requires a load profile meter or a smart meter.

This is to be distinguished from so-called inflexible customers with delivery according to standard load profiles, i.e. households and some commercial custom-

ers. Since they cannot express their preference on a market basis, it must be determined externally. The indicator to describe this preference or willingness to pay is VoLL and is expressed in the unit €/MWh.

The fact that the VoLL of these inflexible customers is decisive for the definition of the SoS standard can be demonstrated by looking at the order in which the various customer groups are switched off when prices rise. First of all, it is important to recognise that (technically) flexible customers have a wide range of VoLL levels (Figure 2-3). There is both a significant capacity of flexible customers whose VoLL are below the technical price limit of the electricity market and a significant share with a VoLL above that limit.

**FIGURE 2-3: ESTIMATION OF THE DISTRIBUTION OF THE VOLL OF THE TECHNICALLY AVAILABLE LOAD REDUCTION POTENTIALS OF INDUSTRY IN GERMANY (BASE YEAR 2011)**

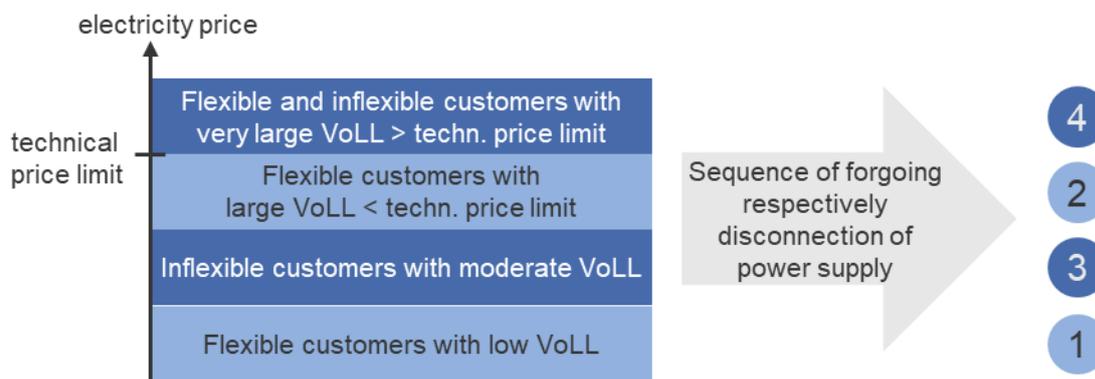


Source: Internal calculations r2b energy consulting (see section 4.4.2)

In a simplified presentation, inflexible customers can be divided into two groups based on their VoLL, one below and one above the technical price limit. Flexible

and inflexible customers are therefore mixed in terms of their VoLL (left-hand side of Figure 2-4).<sup>26</sup>

FIGURE 2-4: SEQUENCE OF FORGOING RESPECTIVELY DISCONNECTION OF POWER SUPPLY



Source: Own Diagram.

When the price gradually increases, the flexible customers with a VoLL below the technical price limit (groups 1 and 2 in Figure 2-4) would first voluntarily renounce their supply. The inflexible customers with moderate VoLL (below the technical price limit) would initially be skipped. If the technical price limit were reached without a complete balancing of supply and demand, involuntary shutdowns would have to take place. In the case of a favourable shutdown strategy (discussed below), this would primarily affect inflexible customers with moderate VoLL (group 3 in Figure 2-4). However, due to the unavoidable roughness of shutdowns processes, group 4<sup>27</sup> customers could also be affected.<sup>28</sup>

<sup>26</sup> In fact, all customer groups are so heterogeneous that there is a greater mix. For the fundamental considerations made here, the simplified assumption of separated groups allows a simpler representation without limiting the general validity.

<sup>27</sup> It should be noted that customers with emergency power systems (EPS) are not included in group 4 because they secure their very high VoLL through their EPS and are therefore not affected by shutdown.

<sup>28</sup> This shows a certain dilemma in setting the technical price limit: an increase in the price limit would allow further group 4 customers to express their willingness to pay on the market, so that inflexible customers would only be switched off later or less frequently. On the other hand, group 3 customers would then be supplied more frequently at high prices above their VoLL. However, it is by no means the case that the price

A single explicit level of the VoLL of inflexible customers is eventually required to fix the SoS standard in accordance with equation (2.1). Due to the heterogeneity of the customer collectives, the shutdown situations and other relevant boundary conditions, however, a differentiated consideration is necessary in order to determine or select the appropriate VoLL for the problem. The following aspects are of particular importance:

- What is the situation from the customer's point of view?
- What's the duration of the shutdown?
- Would the shutdown be announced or not?
- Which customer group (within the group of inflexible customers) would be specifically affected?

Based on the situation that an inflexible consumer is normally free to choose his current electricity consumption at any time and that this is questioned in the context of surveys to determine the VoLL, it is possible to determine their willingness to pay in two "directions". On the one hand, the willingness of the consumer to pay in order to avoid a shutdown can be considered, i.e. the willingness of the consumer to pay for his supply to be maintained. This is called Willingness-to-pay (WTP). On the other hand, one can consider how high the compensation payment to the consumer would have to be in order to (temporarily) forego his electricity consumption. This is known as the Willingness-to-accept (WTA). Rationally, WTA and WTP should be the same or similar. However, psychological aspects also play a role in the practical estimation of VoLL values by means of

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limit should therefore be equal to the VoLL of the inflexible customers - because "the VoLL" does not exist in this sharpness but is always the average of a customer collective with various VoLL levels. If the price limit was set at this average, about half of the inflexible customers would be switched off even though they would be willing to pay more.

surveys, for example because the interviewees consider the reduction of an accustomed service to be graver than ensuring its continuity<sup>29</sup> or because a strategic behaviour of the interviewees cannot be ruled out<sup>30</sup>.

Technically, the involuntary disconnection of consumers would be carried out by the network operators. The shutdown strategy pursued would have an influence on the effective VoLL. In principle, every consumer or consumer group has an individual VoLL. Since a shortfall that would lead to involuntary disconnection would only affect a small part of the demand capacity (see also section 2.4), only a small part of consumers would be disconnected. In conjunction with the heterogeneity of consumers, the concretisation of a shutdown strategy thus has consequences for the effective VoLL. This holds irrespectively of the fact that disconnections induced by load excess are very rare and the majority of consumers would continue to be supplied. From an economic point of view, the lower the average VoLL of switched-off consumers, the more favourable it is.

There are degrees of freedom in the design of shutdown strategies which can be used in the light of the above considerations. Practical manageability is an important boundary condition, since the physical effectiveness of the shutdown is, of course, the most important factor in maintaining system stability in the event of a load excess.

From the customers' point of view (at least from the point of view of the household and commercial customers without metered load profiles, that are in the focus here), the aim should be an as short as possible duration of disconnection. If the shutdown time required from the system point of view were longer, this could be achieved by a rolling shutdown, so that a larger number of customers would be switched off with a shorter individual shutdown time. In this way, high

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<sup>29</sup> London Economics (2013), p. xii

<sup>30</sup> AF Mercados, E-Bridge, REF-E (2016), p. 50

damage such as freezing of the heating system or spoilage of refrigerated food could be prevented.

It would be possible to announce the shutdown or at least a high probability of it because the risk of a shortfall would be known at least a few hours in advance. From the consumer's point of view, the consequence of an announced shutdown would be less serious than that of an unannounced shutdown. However, the announcement may also weaken the effect of the shutdown due to avoidance and anticipatory effects. This would make it more difficult to forecast the impact of the shutdown and could require an extension of the shutdown perimeter.

Finally, the degree of selectivity of the shutdown is also a relevant degree of freedom. The smaller the shutdown areas, the more accurate it would be to select consumer groups with low average VoLL. However, selectivity is associated with effort on the part of the network operators. This obviously applies when a network level limit is exceeded. If, for example, the disconnection would be performed in medium-voltage grid instead of the high-voltage or even extra-high voltage grid, residential areas could be more precisely separated from commercial consumers, for example, who usually have different VoLL levels. However, this would not only require coordination (cascading) of the shutdown process across network operator boundaries but would also require considerably more individual switching operations in order to achieve the same shutdown capacity. This shows that in the concretisation of shutdown strategies, a balance must be struck between the goal of a low effective VoLL and the manageability and certain effectiveness of the shutdown. Other criteria such as fairness can also play a role.

In summary, the above considerations show that the relevant VoLL for the SoS analysis and the derivation of an SoS standard is the VoLL of the inflexible consumers who are involuntarily switched off if necessary. Both the specific consumers and their effective VoLL can be influenced by the shutdown strategy. Thus, the VoLL relevant for the SoS standard does neither correspond to the average of all consumers nor to that of all inflexible consumers.

Taking these findings into account, the next subsection provides an overview of the relevant literature and particularly the numerical values for the VoLL given therein.

### Literature overview

Extensive literature exists on the subject of VoLL. Metastudies deal with double-digit numbers of more detailed studies. It is therefore not possible to create a complete overview. However, this is not necessary either, since the qualitative and quantitative range of the available VoLL estimates can already be represented on the basis of some typical sources that are particularly relevant to the issue at hand.

The study "Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market",<sup>31</sup> commissioned by the EU Commission, deals explicitly and comprehensively with this topic. The authors recommend using the WTP approach (in contrast to WTA, see above) for the estimation of the VoLL. In addition to conceptual considerations, the study also includes an evaluation of VoLL values for a number of countries. It should be noted, however, that some values are derived from historical blackouts (i.e. grid-related power outages that occurred as unselective, unannounced and comparatively long-lasting shutdowns). These were thus much more serious events than the involuntary disconnections of a small proportion of consumers, which are relevant to the security of electricity supply and which would be announced and, if a rolling disconnection concept were adopted, would be of short duration for individual consumers. These values for the VoLL therefore tend to be overestimated with regard to the application relevant here.

The values reported as "current values in Europe" for 10 European countries range from 200 to 68,000 €/MWh. The methodological approaches, as far as shown, differ widely. It can therefore be assumed that the size of the range is more due

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<sup>31</sup> AF Mercados, E-Bridge, REF-E (2016)

to methodological differences than to actual differences in willingness to pay between countries. Where the WTP approach recommended for the SoS analysis is used, the values tend to be low, although some of the cited sources also combine several approaches.

For the introduction of the capacity market in Great Britain, an SoS standard was defined which is also based on a provision of the VoLL.<sup>32</sup> An average of several consumer groups was formed and ultimately a value of almost 17,000 GBP/MWh, i.e. the equivalent of approx. 20,000 €/MWh, was assumed. However, this value is based on the WTA approach, and the underlying report<sup>33</sup> also shows WTP-based values that are significantly lower. Otherwise, a weighted WTP-based VoLL of approx. 5,800 GBP/MWh, i.e. approx. 6,800 €/MWh, would result from the same procedure. In contrast to the authors of the above-mentioned EU study, however, the British experts support the WTA approach with reference to the so-called "ownership effect"<sup>34</sup>.

In a recently published study commissioned by ACER,<sup>35</sup> WTA-based VoLL values are determined for all EU member states. The results for households are presented separately by country group to take account of differences in wealth. But even for the limited group of countries of Western Europe, in which Germany is located, the VoLL values show a considerable range of approx. 7,000 to 23,000 €/MWh (Germany 12,400 €/MWh). The range of results for commercial and industrial consumers - not broken down by country but by sector - is even wider. There are large bandwidths within the industries, but the individual parameters (e.g. medians) also differ greatly between the industries. The entire spectrum of

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<sup>32</sup> Department of Energy & Climate Change (2013)

<sup>33</sup> London Economics (2013)

<sup>34</sup> Cf. London Economics (2013), p. xii: "Psychologically, the loss from giving something up feels greater than the gain from keeping it and avoiding the loss, and thus WTA is often empirically greater than WTP"

<sup>35</sup> CEPA (2018)

commercial and industrial consumers ranges from almost zero to 120,000 €/MWh. The medians of the sectors are predominantly between approx. 200 and 5,000 €/MWh with one exception of almost 20,000 €/MWh.

A recent study by the Energy Institute of the University of Linz<sup>36</sup> deals primarily with the question of a temperature dependence of the VoLL in order to quantify its change due to climate change. WTP-based VoLL values are determined for 19 EU countries. The study differentiates between local shutdowns (i.e. the scenario relevant for the SoS analysis) and nationwide (network-related) blackouts. The documented data allow a conversion of the WTP for local shutdowns into the usual unit €/MWh. The results are between 0(!) and 1,800 €/MWh. Again, the differences between countries appear to be greater than could be expected for obvious reasons (e.g. level of prosperity).

#### Derivation of a VoLL for the SoS standard in Germany

Even the evaluation of only a few (meta-)studies results in a very wide range of the VoLL level. In some cases, the values given for the same countries are very different, and some differences between countries are so great that they appear to be caused rather by the diversity of the approaches used or the sources evaluated than by fundamental reasons.

As was worked out at the beginning of this section, the effective VoLL in terms of security of supply on the electricity market can be influenced by several factors. This includes the distinction between consumers' views, i.e. between WTP and WTA. In the opinion of the experts, the WTP value is more compatible with the concept described above for defining an SoS standard, analogous to the recommendation in AF Mercados, E-Bridge, REF-E (2016). For this concept is based precisely on a hypothetical state of equilibrium based on rational preferences,

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<sup>36</sup> Cohen, Moeltner, Reichl, & Schmidthaler (2017)

whereas the high WTA values are explained precisely by the absence of such rational preferences.

In addition, selective, announced, short shutdowns tend to be more relevant to the issue at hand than long-range, unannounced, long-lasting shutdowns. However, not all sources allow for appropriate differentiation or filtering of the specified VoLL values.

Therefore, even after accounting for the qualitative differences, i.e. the evaluation bases and methods behind the respective sources, insofar as these are documented, a considerable bandwidth in the order of approx. 500-15,000 €/MWh remains.

A certain asymmetry of consideration is justified in the decision on an individual VoLL value as the basis for the SoS standard for Germany, which is necessary for procedural reasons. A VoLL set too low would result in an unjustifiably high threshold according to equation (2.1)  $\widehat{LoLP}$ . This would be accompanied by the risk that a higher loss of benefit would actually occur as a result of involuntary shutdowns, without the necessity of an examination of countermeasures pursuant to section 51(4)(2) EnWG being recognised beforehand. In connection with the fact that the SoS standard constitutes an examination threshold rather than an implementation threshold for measures, the tendency should be to avoid underestimating the VoLL. This applies, however, notwithstanding the above explanations on general possibilities to influence the VoLL in downwards direction.

As a result of the conceptual analysis and literature-based quantitative research, we propose that a VoLL of 10,000 €/MWh be applied. The fact that this is a rounded numerical value also takes account of the vagueness, which is underpinned by the heterogeneity of the sources and would make a value with many valid digits appear pseudo-exact.

### 2.3.3 Cost of New Entry

The SoS standard is to serve as a threshold value above which it must be checked if an economically efficient investment by professional players originally active in the electricity supply sector has not been made (see section 2.3.1). To determine this, the cost of such an investment must be specified in the form of the Cost of New Entry (CoNE).

The SoS standard should be stable over time in order to establish an orientation aid that serves as a fixed framework for assessing security of supply over a significant period of time (at least several years).

When assessing the security of supply for scenarios of future years, the SoS standard must also be consistent with the assumptions on which the scenarios are based.

As mentioned above, the examination and, if necessary, implementation of countermeasures pursuant to article 51(4), sentence 2, EnWG, such as the removal of barriers and misguided incentives in market and regulatory design or even the transitional introduction of a capacity mechanism, is appropriate if in the longer term, new generation facilities are not installed to a sufficient extent by players originally active in electricity supply, even though such facilities would be economically efficient.

This requires a threshold value as a yardstick, which is derived from the CoNE level of the most cost-effective generation technology, which is available indefinitely (and is modelled accordingly in the endogenous electricity market simulation for generating the scenario). An SoS standard determined on this basis is stable over time and, as will be shown in section 2.3.4, supports the common international understanding of SoS evaluation in the sense of article 51(4) sentence 4.

Cost-effective new generation in the sense of the CoNE is characterised by low fixed unit costs, as very short operating times can be assumed. For this purpose,

open-cycle gas turbines (OCGT) and (reciprocating) engine power plants can be considered. The following table compares the fixed annuity costs of these two technologies and the relevant parameters for their determination. The parameters were determined and adjusted in extensive research during the parameterization of the electricity market simulations (see chapter 4).

TABLE 2-1: DETERMINATION OF FIXED COSTS FOR OCGT AND ENGINE POWER PLANTS

Parameter	Unit	OCGT	Engine Power Plant
Invest costs (Overall costs without interest during construction)	€ <sub>2016</sub> / kW <sub>el</sub>	410	390
Construction period	a	2,0	0,5
Interest during construction	€ <sub>2016</sub> / kW <sub>el</sub>	31	7
Invest costs (Overall costs incl. interest during construction)	€ <sub>2016</sub> / kW <sub>el</sub>	441	397
Fixed operating costs	€ <sub>2016</sub> / kW <sub>el</sub> p.a.	9,4	6,0
Technical lifetime	years	20	15
Interest rate (real)	%	7,5	7,5
Annualized Invest costs*	€ / kW <sub>el</sub>	43	45
Annualized Invest costs* and fixed operating costs	€ / kW <sub>el</sub>	53	51

\*Assumption: Continuous payment during construction period.

Source: Own calculations r2b inter alia based on: BEIS (2016, LeighFisher Ltd. (2016), Parsons Brinckerhoff (2013).

The fixed costs for both technologies are at a similar level slightly above 50 €/kW/a. In view of the inherent uncertainties, the rounded value of 50 €/kW/a is used for the following definition of the SoS standard.

### 2.3.4 Quantitative definition of the SoS standard

From the levels of VoLL and CoNE derived in the previous sections, a threshold value for the load excess probability LoLP can be derived as SoS standard for Germany of

$$\widehat{LoLP} = \frac{50,000 \text{ €/MW/a}}{10,000 \text{ €/MWh}} = \frac{50,000 \text{ €/MW/8760h}}{10,000 \text{ €/MWh}} \approx 0.06 \% \quad (2.2)$$

The rounding of  $\widehat{LoLP}$  is appropriate in the sense of a manageable yardstick due to the uncertainties involved.

The threshold  $\widehat{LoLP}$  of 0.06 % corresponds to a load balancing probability of 99.94 %. From a consumer perspective, it corresponds to an electricity market

SAIDI (probability of involuntary interruption from a customer's point of view) of around 5-10 minutes per year (see also section 2.4).

The threshold derived here is similar in size to standards established abroad (e.g. equivalent to<sup>37</sup> 0.03 % in Belgium and France, 0.05 % in the Netherlands, 0.09 % in Ireland). This is an indication of the similarity of the underlying premises and thus supports the common international understanding of the SoS evaluation in the sense of article 51(4) sentence 4 EnWG. In addition, it makes it easier to relate the results of an SoS analysis, i.e. calculated LoLP values, to those of existing studies.

## **2.4 Interpretation of the security of supply level**

In order to be able to put into perspective the numerical value of the SoS standard derived in the previous section or also a certain concretely determined SoS level, it is important to bear in mind the practical significance or the consequences of these rather abstract numerical values.

An involuntary disconnection due to a lack of balance between supply and demand on the electricity market means that only a small proportion of consumers would be left unsupplied for a short period (while the vast majority of consumers would continue to be supplied)<sup>38</sup>. This would mainly affect "inflexible" consumers, who would not be able to voluntarily forego their electricity consumption beforehand, even though the very high electricity price in such situations exceeds their willingness to pay.

This will be illustrated in the following example: If, for example, with a current load of 80 GW in Germany, a deficit of 2 GW per hour were to occur, 2.5 % of demand

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<sup>37</sup> These standards are specified in the LoLE parameter, which is equivalent to LoLP, see footnote 14.

<sup>38</sup> The concrete impact on the individual consumer in the sense of the duration of his individual shutdown can be significantly shorter than the phase during which the shutdowns last, by applying rolling shutdown concepts.

for that one hour could not be met, but the remaining 97.5 % could very well be met.

In order to assess what an SoS standard means from a consumer perspective, the electricity market contribution to the SAIDI according to section 2.2.2 can be used. This makes it possible to convert the standard approximately into an average effect per customer. If no reserves were held outside the electricity market, a LoLP of 0.06 % (corresponding to a load balancing probability of 99.94 %) would mean that an involuntary shutdown would occur per consumer for an average of about 5 to 10 minutes<sup>39</sup> per year - because it would be too expensive from the point of view of the average consumer to prevent this shutdown. By way of comparison, supply interruptions due to network failures in recent years in Germany have been between 12 and 15 minutes/year per consumer (SAIDI).

The actual effect of a LoLP at the level of the SoS standard would be even less than an average involuntary shutdown of about 5 to 10 minutes per year per consumer, because not every unmet demand on the electricity market necessarily leads to involuntary shutdowns by consumers. This is because the SoS standard refers to market processes. In Germany, however, a reserve will be specifically introduced which will be used in the absence of market clearance (capacity reserve of initially 2 GW). In addition, there are further reserves that can be used in the absence of market clearance depending on the situation, such as a contractually secured shutdown of large customers, insofar as this protection is primarily for grid reasons and therefore outside the market. Before switching off consumers, TSOs would also check whether further emergency measures are available, for example in the form of temporary cross-border assistance through activation

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<sup>39</sup> Based on the assumption that the EENS is in the range of 1-2 GWh per hour with loss of load. This corresponds to the range of our simulation results for countries with LoLP > 0 (see sections 5.5.6) and also the results of the SoS analyses of the European TSOs are predominantly within this range. (ENTSO-E, 2017) (Pentalateral Energy Forum Support Group 2, 2018).

of foreign reserves. As a result of these additional measures, the involuntary disconnection of inflexible consumers can in practice be reduced or even prevented altogether.<sup>40</sup>

## 2.5 Interim conclusion

In this chapter it was worked out that among the various possible parameters with which the security of supply on the electricity market can be characterised, the load excess probability (or loss of load probability, LoLP) is best suited for the formulation of an SoS standard. Further indicators are helpful as a flanking measure to contribute to the interpretation of a determined SoS level.

On the basis of conceptual analyses and literature research, a threshold value for the load excess probability is defined as the SoS standard for Germany in the amount of  $\widehat{LoLP} = 0.06 \%$ , which corresponds to a load balancing probability of 99.94 %. From a consumer perspective, it corresponds to an electricity market SAIDI (probability of involuntary interruption from a customer's point of view) of approximately 5-10 minutes per year.

The threshold value is an acceptable value in the sense of a manageable yardstick and also because it is within the internationally customary range. Nevertheless, it is subject to unavoidable uncertainty, especially due to the uncertainty of the Value of Lost Load (VoLL) to be applied for its determination.

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<sup>40</sup> In the above example of a deficit of 2 GW on the electricity market, this would not be noticeable to consumers simply because of the capacity reserve.

### 3 Methodical approach

In addition to monitoring security of supply itself, a central objective of this project is to increase the validity of quantitative analyses of security of supply under the current and future framework conditions and developments in the power supply system by methodological further development of the model instruments used. One challenge was to further develop previous approaches of forecasting the development of the European electricity market system as well as quantitative models for the SoS analysis by relevant aspects and, at the same time, to link them consistently with each other. Besides other modelling aspects, we have implemented stochastic aspects, such as the simultaneous mapping of several weather / water and load years as well as different realisations of the hourly available power plant park (unplanned power plant outages) in the models at a higher level of detail compared to previous analyses. This ensures, among other things, consistent consideration of balancing effects and uncertainties across models.

In the following sections, first the two-stage overarching methodological approach is presented (see section 3.1). Then the methodology for the dynamic electricity market simulations (see section 3.2) and the probabilistic supply security analyses (see section 3.3) are explained in detail.

#### 3.1 Comprehensive methodical approach

Our methodical approach is based on the following two core questions of SoS monitoring:

1. How will the European electricity supply system develop in the period under review?
2. Does this European electricity supply system ensure security of supply on the electricity market at an efficient level?

The first question arises because SoS monitoring has to look many years into the future in order to have sufficient time for measures to ensure an appropriate SoS

level, depending on the results of the statutory audit mandate (see section 2.3.1). To answer this question, one or more scenarios for the development of the power supply system must be derived. Based on this, the second question is to be answered by determining the SoS level for the respective scenario and classifying and evaluating it by comparison with the defined SoS standard.

In the context of the present study, the methodical approach of a consistent integrated modelling of the development of the electricity supply system in 15 European countries by means of a dynamic electricity market model and a probabilistic SoS analysis based on it was developed and applied against the background of the legal requirements of the EnWG in coordination with the BMWi and with the involvement of the Federal Network Agency and the German transmission system operators. The consistent coupling of the two models is based on scientific enhancement to ensure consistency and a consistent combination of state-of-the-art analysis methods.

Quantitative analyses for monitoring security of supply have so far been based on simulation models, which - based on exogenous scenarios, e.g. for the development of

- the installed capacity of controllable electricity generating plants,
- the feed-in curves of electricity generation from intermittent or inflexible power generation plants,
- the grid infrastructure (in its effect on the exchange capacity between bidding zones), and
- the demand for electricity (or hourly load) as well as
- flexibility on the part of consumers (DSM) -

determine the probability of unavoidable rationing of consumers (frequency and / or amount). Usually, an optimization approach is used, taking into account

different weather conditions with influences on RE feed-in and load as well as stochastic unplanned technical unavailabilities of power generation plants.<sup>41</sup>

The scenarios for the above-mentioned parameters have so far generally been given exogenously, e.g. on the basis of expert assessments. Since the results of the subsequent probabilistic SoS analysis depend on the assumptions of the scenarios, a well-founded analysis to derive the scenarios is highly important in order to be able to derive empirically reliable results.

In 'ex post' analyses and in a foresighted analysis with a short time horizon, e.g. an outlook for the next year, statistical data, such as installed power plant capacities taking into account information on plants under construction and announced shutdowns, can be used to a large extent. In the medium and longer term, however, such developments will increasingly depend on legal and economic conditions and the resulting dynamic market adjustment processes on the electricity market. How the development of legal and economic framework assumptions affects the development of the electricity supply system is therefore usually determined in scientific policy advice by means of dynamic simulation models of the electricity market.<sup>42</sup>

Corresponding simulations of the European electricity market are often based on deterministic dynamic market models that assume a competitive market with perfect foresight. A crucial weakness of such an approach is that uncertainties (stochastics) and associated risks as well as regulatory framework conditions of the market design, e.g. capacity mechanisms, balancing groups and imbalance settlement mechanisms, are not or only insufficiently taken into account.

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<sup>41</sup> See eg. other security of supply analyses, such as ENTSO-E (2017a), Consentec / r2b (2015) and PLEF (2018).

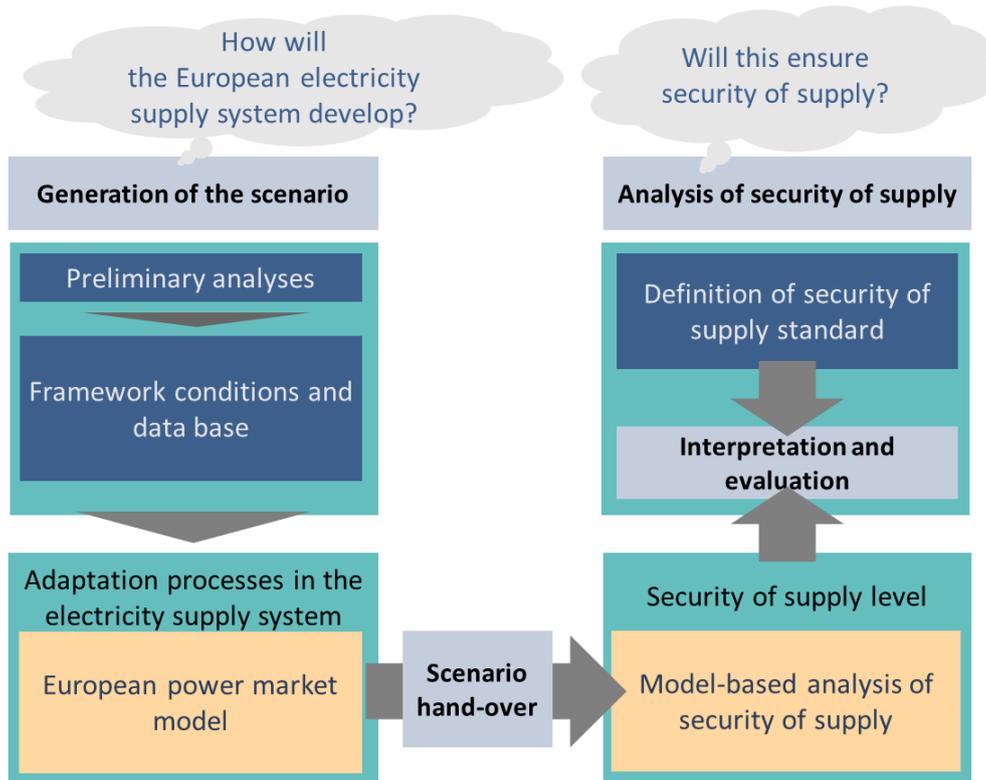
<sup>42</sup> See eg. r2b (2014), Fraunhofer ISI et al. (2017), EWI / gws / Prognos (2010), Öko-Institut / Fraunhofer ISI (2015).

Within the framework of this study, we have therefore, after a detailed examination of fundamental options and their technical feasibility, examined and further developed dynamic models for the European electricity market in order to

- adequately map the decision-making situations of market players and (cost) risks by, among other things, approximating consideration of the balancing groups and imbalance settlement mechanism as well as capacity mechanisms, and
- model the stochastics (weather / water / load years and technical unavailability of power generation plants) consistently to the simulation model for the probabilistic SoS analysis based on it.

With the help of the appropriately adapted dynamic model for the European electricity market, we can thus (for the first time) pursue a consistent, two-stage approach in the determination of relevant key figures for the assessment of the SoS level (see Figure 3-1).

FIGURE 3-1: SCHEMATIC ILLUSTRATION OF THE TWO-STAGE APPROACH



Source: Own representation.

When implementing this approach, we first carried out extensive preliminary analyses and then derived a suitable set of assumptions based on these analyses. This consists of the quantitative assumptions (inputs and model configuration) for the simulation calculations, which are carried out with the European electricity market model of r2b energy consulting GmbH. The electricity market model simultaneously models both the divestment and investment decisions of the market players with rational expectations. The model output in the form of the future development of the power supply system then forms the input data set for the probabilistic security of supply model (SoS model) of Consentec GmbH. The two models are consistently coupled and parameterized. The result of the SoS model essentially consists of key figures for measuring the SoS level in relation to the future reporting years under consideration.

## 3.2 Methodology for Generating the Reference Scenario

The methodology for generating the reference scenario is divided into extensive preliminary analyses on the one hand and quantitative simulation calculations using the European electricity market model on the other. The reference scenario is a *best-guess scenario* without additional climate protection measures, which we have developed on the basis of comprehensive and detailed research within the framework of the preliminary analyses, a comparison with other studies and an exchange with other experts on relevant aspects. In this way, the framework conditions, goals and current developments in Germany and Europe that exist in present conditions are adequately mapped. There is only moderate room for manoeuvre for the shorter deadline to achieve significantly different results in this approach - with the exception of additional energy policy measures, such as an additional climate protection measure in Germany, the effects of which we are examining in a sensitivity study (see Section 6.2). Foreseeable developments and such developments that are largely regulatory in nature have been exogenously specified for simulation calculations based on preliminary analyses. This concerns for example, the areas of installed renewable energy capacity, known construction and decommissioning plans for power plants, the development of CHP to maintain heating supply or the definition of requirements for the capacity markets abroad. Developments such as the further expansion and decommissioning of conventional power plants or the development of flexibility options, which are characterized by mechanisms of the electricity market or economic efficiency in the competitive market, were determined endogenously by simulating dynamic market adjustment reactions with the European electricity market model. To this end, we have modelled the mechanisms of action of the electricity markets (market design) and the penalisation of breaches of supply obligations, cross-border balancing effects and existing uncertainties, e.g. in the form of simultaneous consideration of five weather, water and load years (as stochastics corresponding to

the years 2009 to 2013). Finally, the results were again checked for plausibility and compared with other studies in relevant areas.

### 3.2.1 Preliminary Analyses

As part of the preliminary analyses, we carried out comprehensive and detailed research into the framework assumptions and data basis, such as power plant data (see Section 4.2) or economic and technical parameters, and the framework conditions of the electricity markets. On the other hand, we have identified important developments, such as the development of electricity consumption (see Section 4.5.1 and Appendix C), the hourly load structure (see Section 4.5.2 and Appendix E), heat consumption (see Section 4.2.3 hourly feed-in of intermittent renewable energies (see Sections 4.3.4.3.2, 4.3.3 and Appendix D) and the development of electromobility (see Section 4.5.3 model-based analyses. These analyses precede the electricity market model.

We have also carried out extensive scenario comparisons with a number of third-party studies on the development of the electricity supply system. It has been shown that within the framework of the published scenarios there are sometimes considerable uncertainties regarding the expected future development of the electricity supply system in Germany and Europe. For that part of the electricity supply system whose development is essentially characterised by political framework conditions, e.g. in the form of subsidies, rather than competitive action, we have to some extent drawn on exogenous scenarios. For example (with the exception of hydropower), the assumptions on the future expansion of renewable energies in the foreign countries considered are based on the assumptions of the *Mid-Term Adequacy Forecast 2017* and the *TYNDP 2018 of the ENTSO-E*.<sup>43</sup> We

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<sup>43</sup> ENTSO-E (2018a).

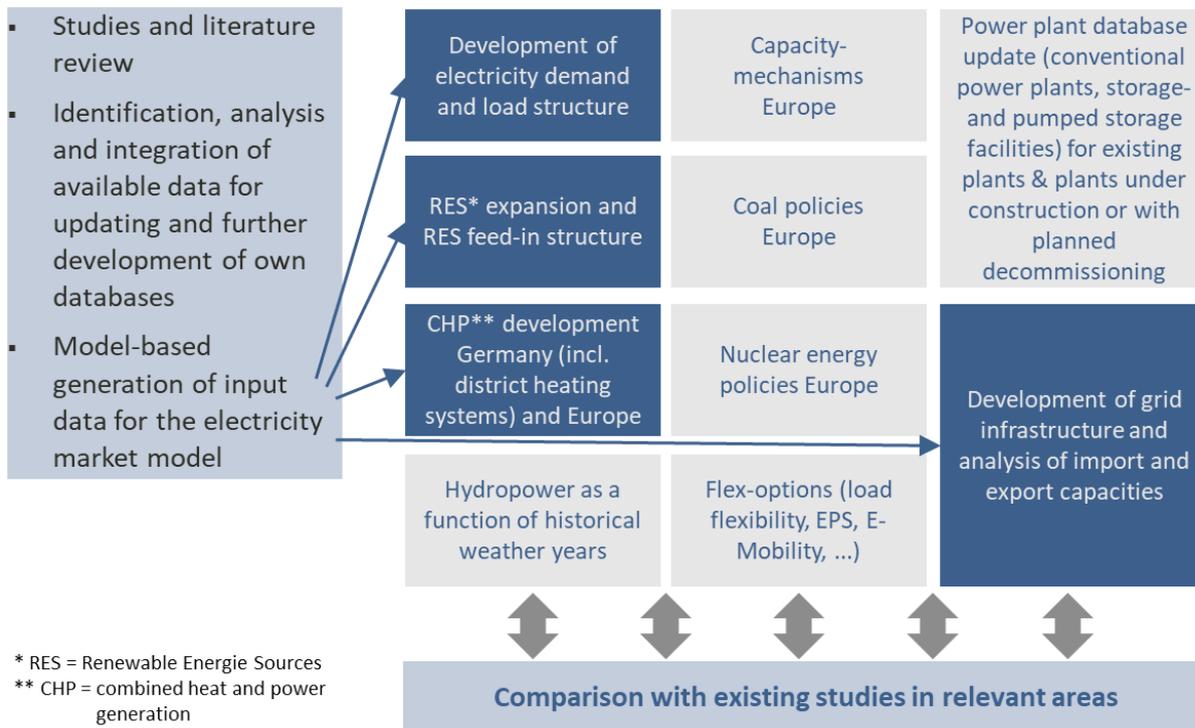
also use model exogenous specifications based on third-party studies for the development of the installed capacity of nuclear energy, which we have checked for up-to-dateness and adjusted in detail if necessary.<sup>44</sup>

Furthermore, in the preliminary analyses we carried out extensive research on power plant data and collected, analysed and integrated into our databases information available today, e.g. on existing power plants, power plants under construction or planned or announced shutdowns (see also Section 4.2 for a more detailed description of the sources used). Finally, model-based analyses were also carried out in this step, with the help of which input data were generated which were later incorporated into the simulation calculations of the electricity market model. This particularly concerns the forecast of future electricity demand and the derivation of the hourly structure of the load, level and structure of the electricity feed-in of renewable energies as well as the analysis of the future developments of district and local heat demand, industrial CHP heat generation and thus the development of the installed capacity of CHP plants. All results of these preliminary analyses were again compared with the results of other studies and checked for plausibility. Figure 3-2 gives an overview of the most important preliminary analyses carried out.

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<sup>44</sup> See sections 4.2 and 4.4.

FIGURE 3-2: OVERVIEW OF THE PRELIMINARY ANALYSES



Source: Own representation; dark blue boxes: Model-based generation of input data for the electricity market model, grey boxes: Research-based determination / derivation of input data for the electricity market model.

Further details on the procedure and the sources as well as the results of the preliminary analyses can be found in chapter 4 on the framework assumptions of the reference scenario.

### 3.2.2 Simulation calculations with the European electricity market model

The fundamental electricity market model for Europe of r2b energy consulting GmbH is a stochastic, linear optimization model depicting currently five weather, water and load years as well as unplanned power plant outages.<sup>45</sup> It reflects the

<sup>45</sup> As part of the integrated modelling of the electricity markets in the 15 countries taken into account, there are particular computational reasons why we do not take into account further weather, water and load years

interaction mechanisms within the European electricity system in balancing supply and demand on the electricity market, taking into account the cross-border network infrastructure. Current and future regulatory framework conditions such as market designs with and without capacity markets and the incentives of the balancing group and imbalance settlement mechanisms are mapped.<sup>46</sup>

This is a dynamic electricity market model which, in addition to deployment decisions and overhauls, also depicts dis/investment decisions of the market players as model endogenous and simultaneous over the entire analysis period against the background of economic aspects. Thus, dynamic market adjustment reactions and thus the non-exogenously predetermined part of the development of the power generation system, including the development of flexibility options such as voluntary load reduction by industry or emergency power plants, are determined endogenously.

The economic impact mechanisms of a competitive market are mapped: Operators of conventional power plants, power-operated CHP plants and storage and pumped storage power plants make their decisions in a competitive market with the aim of maximising revenue. Rational expectations of the actors are assumed

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(base years), as the computation time of the model increases significantly with a higher number of base years. Within the framework of the calculations with the European electricity market model, a consideration was made between extending the base years looked at, mapping further stochastics on unplanned power plant outages and the depth of detail of the endogenous modelling to take account of the market adjustment processes when deriving the scenario. It seems to us, for example, that appropriate market adjustment processes should be integrated and mapped in detail during modelling and that stochastic unplanned power plant outages should be modelled instead of mapping more weather years. In addition, test calculations show that the addition of further base years has comparatively little effect on the model results. In addition, we use weather data in a high-resolution regional clustering and with detailed information, e.g. on hub heights for wind energy (see Appendix D). In the case of weather data lying very far in the past, data quality at this level may not be guaranteed. Nevertheless, we will address a possible extension of the historical base years in chapter 7 where we discuss, among other things, possible research and development needs.

<sup>46</sup> The balancing group and imbalance settlement mechanisms, for example, is mapped approximately by the fact that a potential load loss in Germany in accordance with KapResV for deficient balancing groups causes costs per MWh of deficit in the amount of twice the technical price limit on the intraday market (€20,000/MWh).

by simultaneous consideration of uncertainties and risks resulting from different realisations of load, generation conditions of hydropower and the feed-in of wind energy plants and PV plants under different weather conditions as well as different realisations of unplanned power plant outages.<sup>47</sup> This applies to both investment and operating decisions.<sup>48</sup>

In the development of the available capacity, investment decisions, decisions on premature and temporary shutdowns, recommissioning and overhaul cycles are mapped. In the dis / investment logic of the model, endogenous decommissioning of fossil-fired power plants (hard coal and lignite-fired power plants, combined cycle power plants, gas turbines and motor power plants without CHP) takes place due to insufficient economic efficiency if the maximum technical lifetime has not yet been reached. A provisional decommissioning takes place if the contribution margin 1 (DB 1) of the power plant in the year under consideration is less than 50% of the annual fixed operating costs, but the net present value of the discounted DB 2 is positive over the maximum remaining technical lifetime.<sup>49</sup> Endogenous temporary shutdowns are already permitted in 2020. Final decommissioning takes place if the DB 2 of the power plant is negative in the year under consideration and "losses" in the year under consideration cannot be offset by the net present value of the discounted DB 2 over the maximum remaining technical lifetime. Endogenous final shutdowns will not be permitted until 2023, as we have intensively researched shutdown announcements and it can be assumed that the deadline for the registration of shutdowns will not be sufficient for a

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<sup>47</sup> The modelling assumes rational expectations of the market players on the one hand and perfect competition on the other. Thus the profit maximization of the market players corresponds to a minimization of the system costs under given development of economic, technical and regulatory framework assumptions (input parameters).

<sup>48</sup> An exception to this are heat-operated / subsidised CHP plants, for which we have carried out exogenous capacity development specifications on the basis of preliminary analyses (see Section 4.2.3).

<sup>49</sup> Contribution margin 1 (DB 1) = revenue minus variable costs; contribution margin 2 (DB 2) = revenue minus fixed and variable costs.

shutdown in the first year under consideration, 2020. De facto, however, endogenous shutdowns are permitted from the SoS perspective, as the plants can be transferred to the cold reserve in the reference year 2020 and then finally shut down in the next reference year 2023. Endogenous expansion of fossil-fired power plants (coal-fired and lignite-fired power plants, combined cycle power plants, gas turbines and motor power plants without CHP) and development of flexibility options takes place if the present value of the discounted DB 2 over the technical lifetime is greater than the investment costs or the one-off development costs. In the case of combined cycle power plants, lignite-fired and coal-fired CHP plants, expansions will only be possible after 2020 if they are not already under construction. Lignite and hard coal CHP can only be installed in Poland and the Czech Republic if they are not already under construction (for further information on model specifications for the construction of power plants see Section 4.2). Open cycle gas turbines (OCGT) and engine power plants can first be built in the year of 2020 due to the comparatively short construction periods. Further details and the implementation of the modelling approach are explained in more detail in Appendix A. In addition, the simulation model also maps technical characteristics and regulatory framework conditions: In the medium to long term, for the countries under consideration, these are, for example, age-related shutdowns of generation plants, shutdowns on the basis of the respective national legal framework or restrictions on investments in certain technologies.<sup>50</sup>

When making deployment decisions, various marketing options - marketing on the energy-only market (EOM), marketing on the balancing energy and, if applicable, capacity markets - are taken into account. In addition, technical characteristics of generation plants are considered in detail when the plants are used. In the case of conventional power plants, these are, for example, start-up and shut-

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<sup>50</sup> These include, for example, decommissioning paths for nuclear power plants in countries with corresponding phase-out decisions or decommissioning of coal-fired power plants resulting from national strategies to restrict or terminate coal-fired power generation. See sections 4.2.1 and 4.2.2.

down costs, load gradients and technical minimum capacities. For CHP plants, these are requirements resulting from the coverage of heat demand or process steam demand, taking into account flexibility throughout the CHP system, such as heat storage, natural gas boilers and PtH (Power to Heat). For storage and pumped storage power plants, for example, storage volumes, conversion losses during pumping and turbine operation as well as the extent and temporal structure of natural inflows are accounted for in a suitable approximation. The effects resulting from these restrictions are taken into account simultaneously for marketing on the wholesale market and for marketing on the balancing energy and capacity markets.

The feed-in of the intermittent renewable energies, the heat-operated CHP,<sup>51</sup> the inflexible part of the bioenergy plants as well as other renewable and non-renewable plants is largely determined exogenously for the model.<sup>52</sup>

Stochastics are used to model the supply dependence of wind turbines, PV systems and hydroelectric power plants with natural inflow as well as temperature-related load dependencies. The stochastic modelling takes place simultaneously for five different weather, water and load years. The basis for stochastic modelling linked to weather conditions are the historical years 2009 to 2013. Further stochastics are modelled by taking into account different realisations of the hourly available power plant park (unplanned power plant outages).

In addition, the model also depicts decisions by other market players in the area of flexibility options. For example, the development and use of voluntary load reduction by industry and of emergency power plants are taken into account, as

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<sup>51</sup> The exogenous requirements for electricity generation from heat-operated CHP plants are based on typical feed-in structures for these plants.

<sup>52</sup> The "free output" of heat-operated CHP plants and the flexible part of bioenergy plants can be used endogenously to cover the load in situations of high electricity prices and scarcity (see also sections 4.2.3 and 4.3). In addition, in the case of negative electricity prices, an endogenous determination of the curtailment of electricity from RES takes place.

are decisions by operators of renewable energy plants to use them in direct marketing. Even for so-called new consumers, such as electric heat pumps and electromobility, deployment decisions are determined by means of model endogenous calculations while complying with specified restrictions.

In order to ensure an adequate representation of the investment and deployment decision on the wholesale market (taking into account the revenue potential on the balancing energy and capacity markets), a simultaneous analysis for a long observation period with a simultaneously high temporal resolution is carried out in the model:

- We perform a simultaneous analysis for the period 2020 to 2050. The results will be evaluated for the years 2020, 2023, 2025 and 2030.<sup>53</sup>
- For each reporting year, we use a temporal resolution of 8,760 periods, i.e. periods with a duration of one hour, taking into account their chronological order. In addition, we model the balancing energy market and existing or approved capacity markets abroad using suitable approximations.<sup>54</sup>

In order to adequately map the integration of the German electricity supply system into the European electricity system, we analyze Germany and the neighboring countries as well as the Scandinavian countries, Great Britain and Italy as core regions. Other countries bordering on the core regions are considered as satellite regions. Depending on the direct and indirect importance of the respective countries for the German electricity market, we map imports and exports between core and satellite regions using aggregated import and export functions ("satellite regions") or, as in the case of Spain and Portugal, by simply mapping the markets

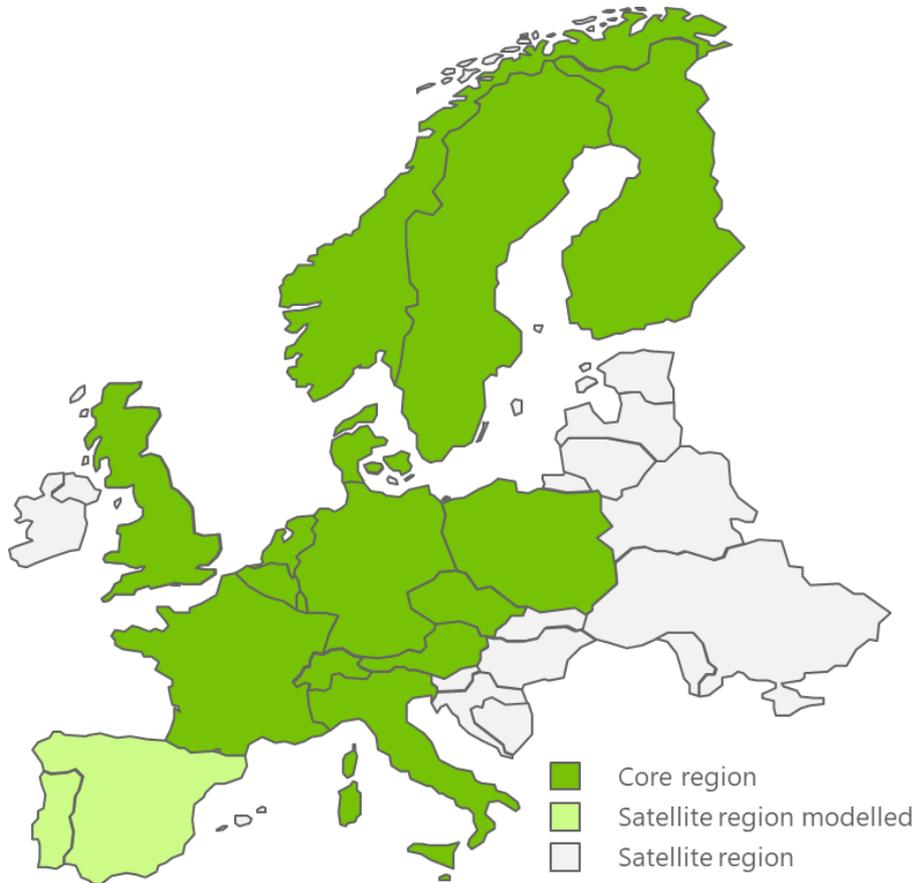
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<sup>53</sup> Modelling up to the year 2050 is carried out because of the so-called final value problem. We do not report the results for the years after 2030 because investments after 2030 do not adequately reflect the entire technical lifetime of the plants.

<sup>54</sup> In the analyses, capacity reserves are in accordance with the requirements of Section 63 EnWG in conjunction with Section 63 EnWG. § Section 51 EnWG not considered, as these are held outside the markets.

within the electricity market model ("satellite region modelled"). Figure 3-3 gives an overview of the regions included in the analysis.

FIGURE 3-3: MODEL REGIONS IN THE MARKET SIMULATIONS



Source: Own representation.

Based on the development of a practical approach for determining flow-based models of cross-border transmission capacity for the period up to 2030 (see Section 3.3.4), the electricity market model was parameterised using publicly available information on future grid expansion for all years under consideration. Thus, in line with the flow-based market coupling applied in practice (in Central West-

ern Europe) and intended for further expansion, an approach has been implemented in the dynamic European electricity market model which reflects this form of congestion management in a suitable approximation.<sup>55</sup>

### **3.3 Methodology for SoS Analyses**

#### **3.3.1 Overview**

The task of the SoS analysis is to determine the SoS level for a previously determined scenario that describes the development of the German and European electricity supply system. This includes the determination of the primary indicator LoLP - which can then be compared against the SoS standard - as well as the calculation of secondary indicators of security of supply, which serve to further interpret the SoS level.

A methodology for SoS analysis requires a proper modelling of key factors influencing the security of supply on the electricity market. Particularly noteworthy are the consideration of stochastic influences on the electricity supply, the consideration of cross-border balancing effects and, consequently, the contribution of electricity imports to meeting demand, as well as the use of flexibilities such as storage facilities. A probabilistic methodology based on a stochastic, cross-border and time-coupling simulation of the electricity supply system is therefore required for an appropriate security of supply analysis.

These basic requirements already apply to the simulation model used in this project in the course of generating the reference scenario (section 3.2.2). Nevertheless, there are several reasons why it is necessary to use a tailor-made methodology for the SoS analysis:

- When choosing model complexity certain trade-offs must be made due to limitations of the available computer hardware and software. In the SoS

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<sup>55</sup> Peripheral regions are represented using the classic NTC approach.

analysis, a given system (without optimization of expansion decisions) is considered and a block-specific simulation of the generation plant employment is renounced in favour of a detailed model of stochastic influences.

- Economic optimisation takes place during scenario generation. However, it is appropriate to use a different specification to determine the result parameters to describe the SoS level. On the one hand, this makes it possible to determine an unambiguous level of the LoLP indicator, whereas economic optimisation would result in a certain indifference with regard to LoLP, since EENS would then essentially be minimised (see discussion in section 2.2.1). On the other hand, the imports necessary to ensure security of supply can be determined, which differ from the market-based imports that would be determined in an economic optimisation (see section 2.2.3).

The SoS analysis model used here is based on the approach first used in *Consentec and r2b (2015)*, which has been further developed in various aspects. The most important model aspects are described in further detail below. Section 3.3.2 sets out framework conditions such as the scope and temporal resolution. Section 3.3.3 deals with the modelling of generation, flexibility and demand, section 3.3.4 with the modelling of cross-border exchange capacities and section 3.3.5 with the modelling of uncertainties. Section 3.3.6 brings these aspects together and describes the model structure and the simulation process.

### **3.3.2 General framework**

For the analysis of security of supply, the general framework conditions to be defined are the geographical and temporal scope. For the latter, the temporal resolution must also be defined.

The geographic scope comprises the countries shown in Figure 3-4. The region considered includes Germany and its spatial and electrical neighbours as well as

Great Britain, Norway, Finland and Italy.<sup>56</sup> This ensures that all repercussions relevant to the SoS level in Germany are considered. The model also calculates key result figures for the other countries in the area of analysis. However, due to their peripheral location in the model, these are subject to a certain blurriness.

FIGURE 3-4: GEOGRAPHICAL SCOPE



Source: Own representation.

In the analyses of security of supply carried out here, a time horizon up to 2030 is examined. This is scanned over the years 2020, 2023, 2025 and 2030. The individual years are modelled at hourly resolution.

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<sup>56</sup> A cross-border exchange with bidding zones outside this geographical area was, as far as taken into account in the European electricity market model (e.g. Iberian Peninsula), is implicitly modelled by adjusting the load of the respective neighbouring bidding zone (e.g. France).

While modelling nominally takes place in the same way for all considered years, it should be noted when interpreting the model results that on the one hand, the uncertainties of the modelling increase with increasing time horizon and on the other hand, there is also more time for adjustment reactions of market participants and for the implementation of political and regulatory measures. The goal of "measuring" the SoS level, which results from the given power supply system and the projected concrete development (particularly of the generation park), will therefore be achieved with greater accuracy for the years 2020 and 2023 in the near future than for the later years under consideration. For the latter, however, by modelling the market mechanisms via dynamic market reactions in electricity market modelling, it is possible to examine whether these market mechanisms are structurally sufficient to ensure security of supply and what behaviour the existing investment incentives can lead to.

### **3.3.3 Modelling of generation, flexibility and demand on the electricity market**

As previously explained in section 2.1, the objective of the SoS analysis is to examine whether the generation and other flexibilities in the form of storage and flexible loads in a scenario under study ensure the balance of supply and demand. In concrete terms, this project refers to the balancing of supply and demand after completion of all market processes. This corresponds to the time after activation of balancing power and before (if necessary) any use of capacity reserves held outside the electricity market (see section 2.2.1).

For the SoS analysis, all plants involved in balancing supply and demand must be modelled analogously to their characteristics within the electricity market simulation (see section 3.2), in principle. In practical implementation, however, certain deviations may be necessary or appropriate while maintaining the consistency of the basic assumptions. For instance, the manageability of probabilistic methods poses a challenge due to their high computational effort, which may require simplifications of modelling. These can in turn be used to model in the SoS analysis

particularly important aspects, such as the uncertainties of the available generation capacity, in a more precise way.

In the following, deviations from the modelling in the electricity market simulation are explained and justified separately for the supply and demand side as well as for the consideration of the provision of balancing power.

### Supply

Generation and flexibility options are not considered in the SoS analysis in a plant-specific manner but are aggregated type-wise for each bidding zone. Accordingly, block-specific startup and shutdown times are also neglected. This is permissible for the purpose of the SoS analysis and, in return, allows the depth of the model to be increased elsewhere, for example in the modelling of uncertainties.

CHP plants are modelled in such a way that they are not subject to any heat-related restrictions in the event of scarcity on the electricity market. They are assumed to be temporarily power-operated on the basis of a bypass, an emergency cooler or the use of a heat storage system (see also section 4.2.3).

### Demand

Non-controllable renewables, controllable generators and other flexibilities contribute to meeting demand on the electricity market. Since generation from non-controllable RES generators does not offer a degree of freedom, the security of supply analysis can be based on the bidding zone specific residual load.

Flexibility on the demand side is reflected in the SoS analyses in the form of pumped storage as well as by the potentials of load reduction of the industry and the Emergency Power Systems developed according to the market simulations. The use of further demand-side flexibility options - electromobility, electric heat pumps and hybrid trolley trucks - is set off against the residual load based on the results of the market simulations to generate the scenarios for the SoS analyses.

Therefore, these options are not available endogenously or flexibly in the SoS model to meet or reduce demand.<sup>57</sup>

### Balancing Power Provision

As mentioned at the beginning of this section, the SoS analysis looks at the situation after all market processes have been completed and thus after the balancing power has been activated. The balancing power available must therefore in principle be taken into account as part of the generation capacity available to cover demand. In order to maintain consistency with the hourly time pattern of the modeling, however, it makes sense to separate low-frequency and high-frequency causes for the activation of balancing power.

The low-frequency components (such as forecast errors and power plant outages, which are expressed in terms of deviations of the forecast from the hourly mean value) are implicitly contained in the hourly residual load - including in the form of EE and load forecast errors - or are explicitly taken into account by modelling unplanned power plant outages (see section 3.3.5). Therefore, the share of the balancing power provided for this purpose must also be taken into account on the supply side in the modelling, i.e. the corresponding generation plants are available to cover the residual load.

High-frequency components (load and RE noise, ramps, discrete schedule steps), which lead to short-term fluctuations around the hourly average, are not taken into account in the hourly residual load. In particular, positive high-frequency components of the balancing power activation, which manifest themselves in a

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<sup>57</sup> The fact that these flexibility potentials cannot be used endogenously in the optimization for the SoS analyses has different backgrounds: On the one hand, in the sense of a conservative approach we did not want to give the SoS model any demand-side flexibility that might be perceived as too optimistic within the framework of SoS monitoring. On the other hand, the modelling of this flexibility is sometimes very complex, requiring a detailed representation of economic aspects and would considerably increase the computing times. In addition, against the background of a highly consistent parameterisation of the two models, the approach pursued appears sufficiently accurate to adequately adopt the use of these flexibility options on the basis of the electricity market simulations for generating the scenarios for the SoS analyses.

load increase, can be critical in scarcity situations. Therefore, the capacity reserved to cover these balancing power shares may not be used to cover the residual load. This is operationalised here by a bidding zone specific supplement to the residual load in the amount of the high-frequency positive share of the balancing power demand.

For this purpose, this share must be determined approximately. The starting point for this is the publicly available 4-second signal of the German automatic frequency restoration reserve (secondary reserve) activation, which we evaluated for 2016. In this signal, high and low frequency causes for the balancing power activation are superimposed. Since for the dimensioning of the balancing power currently applied in Germany only minute values are taken into account and in order to avoid an overestimation of high-frequency shares in the balancing power activation, an equalisation is first carried out by forming minute averages. The high-frequency noise of the signal can then be derived from the difference between the respective quarter-hourly average values<sup>58</sup> of the controller signal and the minute average values.

The positive frequency component relevant for ensuring security of supply is then determined from the distribution of the positive values of the high-frequency noise. The (100-0.0025)% quantile of the noise is evaluated analogously to the deficit level of 0.0025 %<sup>59</sup> accepted in practice for secondary balancing power dimensioning. On the basis of the data used here and the procedure described, a positive high-frequency proportion of the balancing power activation in Germany amounts to approx. 1,350 MW.

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<sup>58</sup> Here, the quarter of an hour was used as the time resolution because this represents the time unit of the German market processes.

<sup>59</sup> Consentec 2010, p. 19.

For the other countries considered here, the positive high-frequency portions of the balancing power activation are derived from the value determined for Germany. Under the assumptions that, firstly, the underlying causes are approximately proportional to the load and, secondly, there is stochastic independence between the country-by-country balancing power activations, this is done by scaling with the root of the ratio of the respective country-wise to the German maximum annual load. The resulting values for the country-specific positive high-frequency portions of the balancing power activation are shown in section 4.7.

### 3.3.4 Cross-border exchange capacities

#### Model structure and parameterization

The modelling of cross-border exchange capacities is of great importance for the assessment of security of supply on the electricity market. The reason for this is that the development of supply in the European internal electricity market takes these exchange capacities into account. Consequently, the examination whether security of supply is ensured must be carried out consistently: Cross-border exchanges of electricity contribute to security of supply. This is also considered in the legal framework<sup>60</sup>, which expressly calls for cross-border balancing effects to be taken into account in SoS monitoring.

The development in the period under review until 2030 is marked by the European goal of increasing exchange capacities. Both the physical expansion of the grid and the optimisation of the utilisation of the existing infrastructure contribute to this. This development should be accounted for in the analysis, while avoiding overestimation of future exchange opportunities.

The classical approach to the description of exchange capacities between bidding zones is based on Net Transfer Capacities (NTCs). An NTC value describes the upper limit of the bilateral commercial exchange of power between two adjacent

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<sup>60</sup> Article 51(4) EnWG

bidding zones. In future, a so-called flow-based model will be used instead in large parts of the European power supply system. In the flow-based approach the commercial power exchanges are only indirectly limited by mapping their effect on the physical network elements (lines and transformers).

In this study, a flow-based model is used for the borders<sup>61</sup> between Germany, Belgium, France, Italy, the Netherlands, Poland, Austria, Switzerland and the Czech Republic for all years under consideration.<sup>62</sup> Compared to operational flow-based models, which are currently being used in Central Western Europe for the day-ahead market coupling, this one has some simplifications. For instance, the physical transmission limits of the network elements are aggregated for each bidding zone border. In order to limit the general complexity of the simulation models, the exchange capacities are basically static for each year under consideration, although hourly optimisation is simulated by the tapping of phase-shifting transformers (PSTs).

The parameterisation of the exchange capacity models and particularly the consideration of the expected network expansion are carried out on the basis of publicly available data, which mostly originate from ENTSO-E. The starting point is the historical transmission capacities in the base year 2016, from which a projection is made until 2030 on the basis of network expansion plans.

A border-wise flow-based model, like the classical NTC values, exhibits certain structural simplifications, because both the distribution of power flows among

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<sup>61</sup> The model simulates the common German-Luxembourg bidding zone as such. Countries with several national bidding zones (Norway, Sweden, Denmark, Italy) are each represented by a national bidding zone.

<sup>62</sup> The remaining limits contained in the model are represented by NTCs. The delineation between flow-based and NTC approaches is based on the network repercussions in the meshed interconnected network that is relevant from the point of view of the focus on Germany. The delineation intentionally abstracts from today's boundaries of so-called capacity calculation regions. This corresponds not only to the fundamental character of the modelling, but also to the practical requirements, since repercussions between capacity calculation regions must also be appropriately taken into account in the capacity calculation methods.

the interconnectors of one bidding zone border and additional bottlenecks within the bidding zone, which can occur with certain extreme combinations of exchanges, are only indirectly contained in the border-wise restrictions modelled. Parameterisation possibilities were therefore provided in the model in order to prevent an overestimation of the exchange capacities due to these simplifications.<sup>63</sup>

### Consideration of the "Clean Energy Package"

Under the title "Clean Energy for all Europeans", an amendment to the energy regulatory framework is currently being prepared at EU level. This so-called "Clean Energy Package" (CEP), often referred to in Germany as the "Winterpaket" (Winter Package), is intended, among other things, to make greater use of existing transmission grids for commercial electricity exchange. In the public debate this has become known under the buzzword "75 percent target" because, to put it simply, 75 percent of the transmission capacity of the interconnectors are to be made available for cross-border electricity trading.<sup>64</sup>

In agreement with the BMWi, it was assumed in the present study that the CEP would be implemented during the period under review.

A frequently discussed question in connection with the CEP is whether the increased commercial exchange capacities will also be physically achieved. This is also important for assessing the security of supply on the electricity market, as commercial capacities form the basis for electricity trading, price formation and thus for investment decisions, whereas the SoS level ultimately results from the possibility of physical coverage of the load.

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<sup>63</sup> Further details can be found in appendix B.2.

<sup>64</sup> Details of the design and precise interpretation of the 75-Percent target were (and still are) open at the time the analyses were carried out. It should be noted, however, that within the framework of the naturally limited accuracy of the model when considering future years, certain differences in detail in the definition could hardly be modelled anyway.

If the physical implementation of the 75 percent target could only be achieved using cross-border redispatch, this would neutralise part of the previous commercial cross-border exchange. In the present study it is assumed, at least in the reference scenario, that the cross-border exchange envisaged in the CEP can also be physically realised.

Achieving this while maintaining network security will require interaction and increased use of various congestion management measures. This may include the use of phase-shifting transformers<sup>65</sup> (PSTs), possibly the installation of additional PSTs, the use of reserves such as the grid reserve and bidding zone internal redispatch (in situations where Germany requires imports, the latter applies particularly to foreign countries). In addition, the network expansion within the bidding zone can also make a significant contribution to the physical achievability of exchange capacities in accordance with CEP.

According to the current status of the Winter Package, Germany will be obliged to achieve the 75 percent target for cross-border electricity exchange. To this end, Germany may have to take some of the above and/or other measures. The analysis of the concrete need for such measures is not the subject of this study, but rather their successful implementation is assumed. A sensitivity analysis (section 6.4) furthermore examines the impact on the SoS level of a 10 % reduction in physical exchange capacity (assumed not to be visible to the electricity market and its players) compared to the CEP target level.

[Detailed documentation in the appendix](#)

In order to ensure in the parameterisation of the exchange capacity model that the effect of the modelled capacities corresponds to the requirements and as-

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<sup>65</sup> Phase-shifting transformers are network equipment that allow a certain control of the power flows even in the meshed three-phase grid, which are otherwise always rigidly distributed according to Kirchhoff's laws.

assumptions made despite the necessarily limited structural and temporal complexity, a comparison was made with hourly and spatially high-resolution models of an exemplary year.

A detailed description of the structure and parameterization of the exchange capacity model can be found in Appendix B.

### 3.3.5 Modelling of Uncertainties

The decisions of the players on the electricity market are always made with uncertainty about future situations and events. This particularly (but not only) concerns investment and divestment decisions. An essential feature of uncertainty is that uncertain events can at least approximately be assigned probabilities of occurrence. Uncertainty thus gives rise to a certain risk, which market players (and the regulator) can (and must) assess and allow for. When analysing a given scenario of the development of the electricity supply system with regard to security of supply, uncertain influencing factors must therefore also be taken into account. This particularly applies to the influence of weather and stochastic power plant outages, which is also accounted for with extreme events in the modelling (see below).

This should be distinguished from rare extreme events for which no probability of occurrence can be determined. These events are therefore described by the term, unpredictability. Such an event can be, for example, the simultaneous non-availability of many power plants due to a common cause, such as a serial failure or as a result of a prolonged heat or drought period. On the one hand, such events are associated with the assumption that they have a strong effect when they occur. On the other hand, it is assumed that they are very unlikely. In particular, they cannot be assigned a probability of occurrence. Thus, it is not possible neither for the regulator nor for the market players to take economically efficient measures to prepare for these unpredictable (as opposed to uncertain) extreme events. Unpredictable events cannot therefore be **efficiently** addressed neither in the electricity market 2.0 nor in capacity markets. For the question of whether an **efficient**

level of security of supply is achieved, these unpredictable events (due to the unknown probability of occurrence) cannot and must not be considered.

The hedging of unpredictable extreme events falls within the scope of state risk preparedness and (due to the unknown probability of occurrence of these events) lies outside market design. An exchange on this topic is currently taking place between the BMWi, the Federal Network Agency and the German TSOs, in which the authors of this study are also involved in an advisory capacity. The effects of unpredictable extreme events can be reduced with reserves outside the electricity market, such as the already planned capacity reserve. Therefore, these unpredictable events shall also be considered in the future dimensioning of the capacity reserve.

In the following, the modelling of the uncertain influences of weather and power plant unavailabilities will be discussed.

#### Influence of the weather

The influence of uncertain weather conditions is accounted for through five different weather, water and load years (see section 3.2.2).

#### Influence of power plant unavailabilities

When modelling power plant unavailabilities, a distinction must be made between planned and unplanned unavailabilities.

Planned unavailabilities are due to, among other things, overhauls that are generally known with sufficient lead time. Within the framework of this project, the time of entry, the duration and the level of the planned non-availability are taken from the scenario generation (see section 3.2.2 in conjunction with appendix A.5.2).

Unplanned power plant outages are not predictable for market players but have a stochastic character. In order to adequately model the influence of such failures,

probabilistic methods are required. Power plant failures are modeled as stochastically independent events whose probability of occurrence can be derived from historical data.

The methodical implementation in SoS analyses so far usually takes place in such a way that for each time slice (here: hour) the failed power plant output is determined individually by a random draw.<sup>66</sup> If this is repeated often enough (so-called Monte Carlo method), a stochastic distribution of the cumulated unplanned power plant unavailability results. If the random drawing per type of power plant is parameterised with its average unavailability, then the expected value of the resulting distribution is precisely this unavailability.

A weakness of this approach is that not only the failure events as such, but also the individual hours are modelled as stochastically independent of each other. It is therefore possible that in the simulation, a power plant is assumed to have failed in hour  $t$ , in the next hour  $t+1$  to be in operation again and in the next but one hour,  $t+2$  again as failed. In reality, however, unplanned power plant outages usually last for many hours, and between outages there are longer periods of trouble-free operation. The modelled temporal curves of the (non-) available power plant capacity are therefore not realistic with such an approach, even if the non-availability is represented correctly overall. This has the following disadvantages:

- First, such power plant outage modelling tends to favour the mitigation of scarcity situations, as the benefits of pumped storage power plants and other flexibilities with time constraints are overestimated. If phases of high and low failure power alternate quickly in the model, the more frequent phases between high failure powers can be used to store energy quantities for the next scarcity situation. In reality, however, longer periods of

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<sup>66</sup> See PLEF (2018), ENTSO-E (2017a), Consentec and r2b (2015)

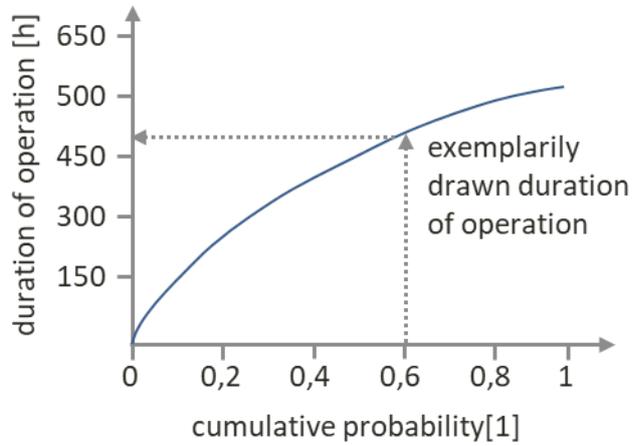
high power failure could mean that the power of these flexibilities cannot be fully utilised due to the limited storage capacity.

- Secondly, it is not permissible to evaluate the duration of shortfall phases as a model result due to the unrealistic temporal progression of the (non) available power plant capacity. However, these can provide important information for the development of efficient and fair shutdown concepts or the dimensioning of reserves outside the electricity market to avoid shortfalls.

In order to overcome these weaknesses, a time-sequential modelling of power plant outages is carried out in the present project, which leads to more realistic time sequences of the cumulated (not) available power plant capacity.

For this purpose, the non-availability per power plant type is broken down into the components, average failure frequency and average failure duration. An exponential distribution is assumed for the frequency distribution of the duration between two failures. This is parameterised for each type of power plant based on the average failure frequency. Figure 3-5 shows such a power plant type specific distribution function. An operating time for each power plant block is now determined by random drawing from the respective distribution (in the example in Figure 3-5 there are approx. 470 hours of uninterrupted operational readiness before a failure occurs) and then the average downtime of the power plant type is assumed.

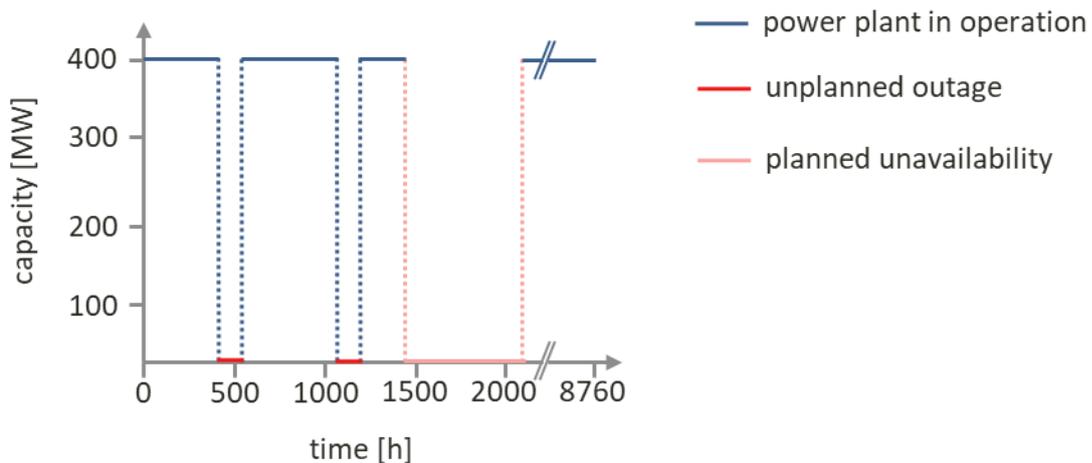
FIGURE 3-5: EXEMPLARY REPRESENTATION OF A POWER PLANT TYPE SPECIFIC DISTRIBUTION FUNCTION



Source: Own representation.

This is carried out successively for the period of a simulation year. This results in a time series of the available capacity of each power plant unit, as shown in Figure 3-6. The sum of all time series of the power plant units per bidding zone derived according to this procedure then corresponds to the annual time series of the available capacity of the respective generation park.

FIGURE 3-6: EXEMPLARY TIME COURSE OF THE AVAILABLE CAPACITY OF A POWER PLANT UNIT



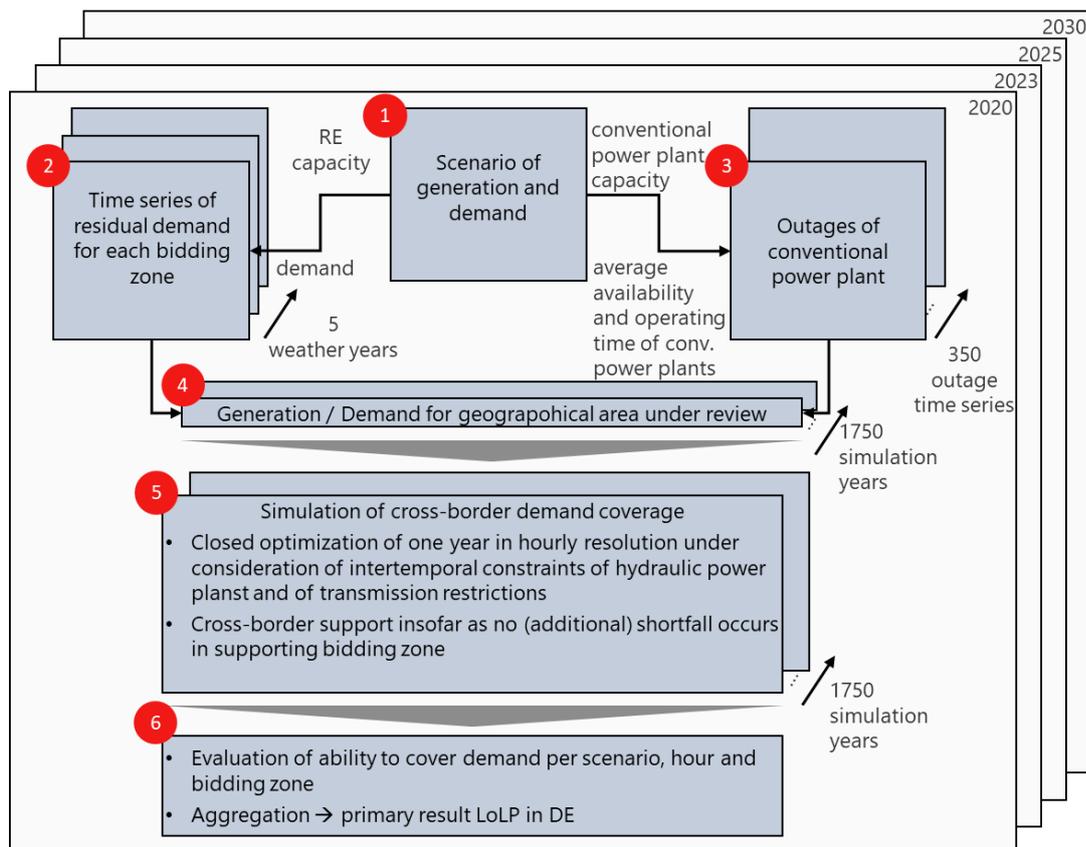
Source: Own representation.

In this procedure as well, the expected value of the distribution of the unavailable power plant capacity corresponds precisely to the average unavailability. However, the time series of the simulated (not) available power plant capacity are now more realistic, so that the weaknesses mentioned above are overcome: Storage volume restrictions become effective in a more realistic way, and the duration of the calculated deficit phases is available for statistical evaluation.

### 3.3.6 Model structure and simulation sequence

Figure 3-7 provides an overview of the SoS analysis method used here. In the following, components and the simulation process are explained in more detail.

FIGURE 3-7: OVERVIEW OF THE METHODOLOGY FOR THE SECURITY OF SUPPLY ANALYSIS



Source: Own representation.

For each of the four years under consideration (2020, 2023, 2025 and 2030), six identical steps are carried out independently of each other to analyse the security of supply for the respective target year.

First, general framework conditions for the area under consideration (see section 3.3.2) and parameters for the generation park and demand (see section 3.3.3) are defined for the scenario to be analysed (❶). Subsequently, on the basis of these assumptions, uncertainties in two respects (see section 3.3.5) are taken into account:

- On the one hand, time series of the residual load are determined on the basis of simultaneous historical load and weather data of the entire region under consideration (❷). These time series thus take into account the spatial and temporal correlation of load and weather-dependent RES feed-in. In order to capture the stochastic properties of these variables sufficiently well, five time series are compiled, each based on different historical weather years (see Appendix A).
- On the other hand, stochastic influences of power plant outages on the balance between supply and demand are taken into account through the generation of 350 annual outage time series in accordance with the procedure described in section 3.3.5 (❸).

The five time series of the residual load (❷) and the 350 outage time series (❸) are combined to 1,750 so-called simulation years with different annual curves of load and available generation (❹)<sup>67</sup>. This corresponds to 15.33 million modelled hours per considered year.

These load/generation curves are the input data for a simulation of cross-border demand coverage (❺). In this simulation, it is determined for each of the 1,750 simulation years in a joint analysis covering the entire region and the entire time

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<sup>67</sup> Preliminary studies on the convergence behaviour of the stochastic simulation have shown that the selected number of 1,750 scenarios is (more than) sufficient for the systems considered here.

range of a year whether the demand can always be met in each of the bidding zones considered, taking into account the available generation and the usable flexibility potentials. The relevant technical framework conditions, in particular the restrictions of the hydraulic power plants and the available transmission capacities, are taken into account.

In principle, the simulation must check whether a system of equations and inequalities can be solved. This system of equations describes the requirement for load coverage for each of the bidding zones considered and for each time interval considered. Further equations describe the time couplings of the storage basins including natural inflows. Inequalities limit the maximum generation capacity of the power plants and the maximum transmission capacities. Variables of the (linear) equation system are the dispatch of conventional power plants and flexibilities, as well as the deployment of storage basin sizes and cross-border transmission capacities. The latter can be optimized by using the phase-shifting transformers, whose tap positions thus represent further variables.

If a solution can be found for a system of equations and inequalities formulated in this way, this means that for the year under consideration a complete coverage of demand is always possible for the entire geographical area and for the given input data.

If the system of equations turns out to be unsolvable, this means that in at least one bidding zone and at least one hour, no complete load balancing is possible. However, this statement alone is insufficient for the determination of indicators for the assessment of supply security (e.g. LoLP), as the frequency, extent and location (bidding zone) of load excess must be determined. For this purpose, the load coverage equations are relaxed by inserting slack variables. Then a linear optimization problem is formulated, the constraints of which are the above equations and inequalities.

The degrees of freedom existing during the parameterization of the optimization problem are set such that the requirements derived in chapter 2 are implemented.

Firstly, this concerns the optimisation target. As explained in section 2.2.1 the minimum LoLP is an unambiguously determinable property of the system to be analyzed, whereas a minimization of the EENS generally does not lead to an unambiguous LoLP value. The objective function of the optimisation is therefore to minimise the duration of load excess for the entire year under consideration and the entire region.<sup>68</sup> This is based on the assumption of rational expectations of the market players, which is usual for such models and is also made in the electricity market simulation in the context of this project.

The second degree of freedom concerns the order in which the available options are used to meet demand. Appropriate weighting of the variables in the objective function ensures that cross-border exchanges take place only when demand cannot be met by bidding-zone internal generation facilities or the use of bidding-zone internal flexibilities. This modelling deliberately differs from the economic simulation of the electricity market (see section 3.2.2), as cross-border exchanges here shall not result from economically motivated decisions on the use of generation facilities, but shall only occur when necessary. Only in this way is it possible to determine the contribution of exchanges to security of supply (see section 2.2.3).<sup>69</sup>

The third degree of freedom is the parametrisation of the trade-off between load excess in different bidding zones. This is required because cross-border assistance

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<sup>68</sup> In order to achieve a linear formulation despite the discrete hourly resolution of the simulation, the technical implementation is such that the load excess is weighted differently in each hour and then the annual sum of the weighted load excess is minimized. By using temporal flexibilities, unavoidable load excess is thus shifted preferably in times with low weighting. Preliminary studies have shown that the exact choice of hourly weighting factors is of secondary importance for the calculations performed here.

<sup>69</sup> An evaluation of the exchanges, e.g. imports, which occur in an economic simulation would, by contrast, only allow an upper estimate of the exchanges or imports actually required since the economically motivated exchanges are more or less significantly higher than the absolutely necessary ones.

can be used within the boundaries of transmission capacities to partially or completely shift load excess between bidding zones. In this project, cross-border assistance is only permitted to the extent that no (additional) load excess occurs in the assisting bidding zone. This specification helps to locate the cause of the load excess.

It should be noted that, in principle, rules deviating from this can also be formulated. If, for example, a stronger international solidarity was assumed, this would tend to lead to a leveling out of the SoS level between the bidding zones. Such a rule is currently implemented in the European Day-ahead Market Coupling.<sup>70</sup> In contrast to this central approach, however, the rules for dealing with a load excess in downstream processes (e.g. intraday markets, imbalance settlement mechanisms) have not yet been harmonised. Thus, firstly it is unclear whether and how a shortage (load excess) would currently be distributed geographically in practice. Secondly, it is open to what extent the regulations would be adapted, e.g. harmonised, after a load excess has occurred. In view of these uncertainties and against the background of the period under consideration here, it appears expedient for the experts to consider focussing on the geographical localizability of the causes of a load excess in the manner described above. This is done not so much in the belief that this is a realistic reflection of the future European regulation, but rather with the aim of determining the level of the SoS as a characteristic of the scenario to be examined, which can also be localised geographically. Nevertheless, international coordination of market and operating rules in the event of a load excess is recommendable.

In the final step (6), the results of the optimisation can be used to determine the following indicators for each bidding zone and year under consideration by evaluating the 1,750 simulation years:

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<sup>70</sup> PCR (2016)

- LoLP (see section 2.2.1)
- EENS (see section 2.2.1)
- Electricity market-SAIDI (see section 2.2.2)
- Contribution of imports to ensuring security of supply (see section 2.2.3)

As already mentioned in section 3.3.2, the result indicators are determined for all countries in the area under consideration. The focus of this project, however, are the results for Germany and the German-Luxembourgian bidding zone. The system under consideration is chosen in such a way that all interactions relevant for the SoS level in Germany are modelled. Results for the remaining countries, however, are subject to corresponding uncertainty due to their peripheral location in the model.

## 4 Reference Scenario Assumptions

The assumptions for the model calculations of the market simulations and the SoS analyses are essential determinants for the quantitative results of the monitoring of security of supply. Some of the assumptions presented in the following sections of this chapter are relevant for both models of the two-stage modelling approach, i.e. for the analyses with the European electricity market model and the downstream quantitative SoS analyses. Other assumptions (e.g. investment costs of power plants as well as fuel prices and CO<sub>2</sub> certificate prices) are only needed for market simulations to predict the development of the electricity supply system. In the following sections, we explain the assumptions for the reference scenario in detail.

The reference scenario is a *best-guess* scenario without additional climate protection measures<sup>71</sup>. We have developed the assumptions on the basis of extensive and detailed research within the framework of the preliminary analyses as well as a comparison with other studies and exchange with other experts. This adequately reflects the most probable framework conditions, objectives and current developments in Germany and Europe. There is little scope, if any, to arrive at significantly different results in this procedure. Further to an additional climate protection measure in Germany (to ensure that the national climate protection target for the year 2030 is achieved), exceptions to the 'best guess' approach are the cost parameterisation of the flexibility options ('voluntary load reduction by industry' and 'emergency power systems'). We examine the effects of these assumptions in sensitivities (see sections 6.1 and 6.2).

In the first sub-section, we describe our assumptions regarding market design in the modelled regions, i.e. whether we have assumed the existence of a capacity mechanism in addition to the electricity only market. Additionally, we give a brief

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<sup>71</sup> See chapter 1.

overview of our modelling assumptions regarding the design of existing capacity mechanisms. Sections 4.2 and 4.3 describe exogenous assumptions on the development of the generation system: In Section 4.2 we present key assumptions on the development of available capacities of conventional power plants as well as our methodology and assumptions for deriving the development of CHP plants in Germany and the other countries considered. Section 4.3 presents our assumptions on the development of renewable energies in the model regions considered. In Section 4.4 we explain the assumptions regarding existing and future flexibility options (emergency power systems and voluntary load reduction in industry). In Section 4.5 we describe the assumed development of electricity demand and the derivation of the hourly load structures, taking into account partially flexible new consumers. Section 4.6 explains the assumptions on technical and economic characteristics of conventional power plants. Section 4.7 presents the modelling of the provision of balancing power before section 4.8 finally describes the assumptions on the development of cross-border import and export capabilities.

## **4.1 Assumptions on market design**

For the model-based analyses on the future development of the electricity market, an illustration of the political and regulatory framework and, among other things, of the market design is quite significant. In this section, we therefore outline our market design assumptions for the countries considered. We distinguish between an *energy-only market* (EOM), an electricity market design with capacity markets and an electricity market design with other capacity mechanisms (e.g. strategic reserves).

In light of increasing shares of renewable energies in national generation systems, the associated decline in demand for capacities from conventional power plants (especially typical base load and medium load power plants) and a simultaneously growing importance of regionally available, controllable generation capacity, a number of European countries have introduced or decided to introduce capacity

mechanisms in recent years. The intention of these mechanisms is to keep especially fossil-fuel power plants on the market and to incentivize investments in new controllable generation capacities. Different designs are used for this: In the case of capacity mechanisms operating within the electricity market, payments are granted to power stations which may simultaneously generate revenues on the electricity market (including balancing energy markets). These mechanisms include centralised capacity markets (e.g. Great Britain), in which a central authority determines a target capacity and procures it through tenders, and decentralised capacity markets (e.g. France), in which market players are obliged to procure a certain capacity to fulfil regulatory requirements<sup>72</sup>. On the other hand, several countries have introduced (strategic) reserves (also known as capacity reserves), in which the power plants remunerated within the framework of the capacity mechanism are not allowed to bid in the electricity market. The latter mechanisms, which work outside of the electricity market, aim to separate investment and dispatch decisions in the electricity market from the capacity mechanism as well as possible. Capacity mechanisms which work within the electricity market, on the other hand, pursue the goal of integrating the trading of electrical energy on the electricity market and the development of installed capacities within the framework of a closed market design. The different variants of market designs with capacity mechanisms in the existing European legal framework and also in its new energy legislative framework – the Clean Energy for All Europeans package – must always be regarded as so-called *second-best* solutions, which are only to serve as temporary solutions until existing barriers or false incentives within the EOM are removed.

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<sup>72</sup> In addition, in the group of capacity mechanisms that operate within the electricity market, there are also price-based instruments under which administrative capacity payments are granted to capacity providers available in scarcity situations on the electricity market.

In **Germany**, a reserve was implemented with the *capacity reserve*<sup>73</sup> and its design was approved by the European Commission on 07.02.2018.<sup>74</sup> The approval of up to 2 GW of reserve capacity will be valid for the period 2019 to 2025. The procurement of reserve capacity shall be organised by the TSOs through tenders.<sup>75</sup>

There are also strategic reserves in **Belgium**, **Sweden**, and **Finland** where an *ex ante* defined target capacity is procured through tenders by the TSO and the capacity providers (power plants or flexible demand) receive payments for maintaining their capacity outside the electricity market for a defined period. A special feature of the strategic reserves in Finland and Sweden is their joint implementation: although the necessary reserve capacity is determined and procured individually by each country, in scarcity situations, power plants in both countries are considered for activation with the aim of minimising overall costs.

In **Great Britain**, the introduction of a central capacity market was already started in 2014.<sup>76</sup> Its design was the first to be approved by the EU Commission under the new "Guidelines on State Aid for Environmental Protection and Energy".<sup>77</sup>

**France** implemented a capacity market in 2017 (first delivery period). In this market, the capacity required is not procured centrally by the TSO, but is organised decentrally by electricity suppliers via a regulatory obligation.<sup>78</sup>

**Poland** currently also has a strategic reserve, which will be abolished by 2021 at the latest with the start of the first delivery period of the central capacity market recently approved by the EU Commission. In addition to the strategic reserve,

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<sup>73</sup> In addition to this market related reserve, capacity is also held in the network reserve, which is used to congestion management inside the German transmission grid (redispatch).

<sup>74</sup> See European Commission (2018a).

<sup>75</sup> See BMWi (2018).

<sup>76</sup> The first delivery period began in October 2018.

<sup>77</sup> See European Commission (2014).

<sup>78</sup> See European Commission (2016b).

capacity payments are currently granted to plant operators whose generation capacities are available in excess of the market-clearing volume on the electricity market. These payments will also be terminated at the start of the capacity market<sup>79</sup>. Similar capacity payments are currently granted in [Italy](#). Together with the Polish capacity market, the EU Commission approved the planned capacity market in Italy in February 2018, the first delivery period of which is expected to start in 2019. The market will then replace the previous capacity payments.<sup>80</sup> Several essential aspects of the design of the central capacity markets in Poland and Italy are based on the design of the capacity market in Great Britain.

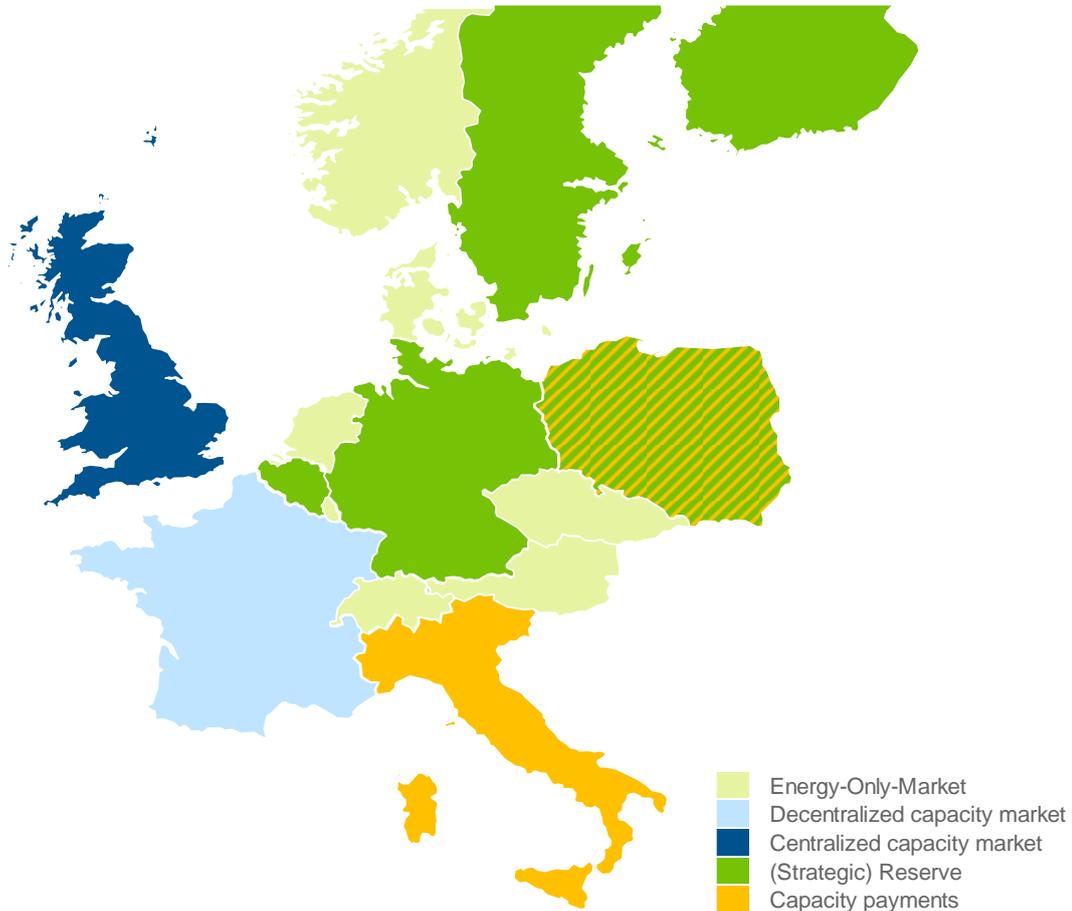
There are currently no capacity mechanisms in [Norway](#), [Denmark](#), the [Netherlands](#), [Luxembourg](#), [Switzerland](#), [Austria](#) and the [Czech Republic](#). An overview of the current market design of the modelled countries can be found in Figure 4-1.

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<sup>79</sup> See European Commission (2018b).

<sup>80</sup> See European Commission (2018c).

FIGURE 4-1: MARKET DESIGNS IN THE COUNTRIES CONSIDERED (AS OF 2018).



Source: Own research.

The (strategic) reserves existing in the countries considered were not (explicitly) taken into account in the SoS analysis on the European electricity markets because these capacities are held outside the electricity market.<sup>81</sup> Only capacities that are available to the electricity market are taken into consideration.

In contrast, the existing or recently approved capacity markets in Great Britain, France, Poland and Italy are explicitly taken into account in the analysis for the duration of their respective approvals by the EU Commission. Specifically, the Brit-

<sup>81</sup> The installed capacities of different technologies described in the following sub-sections are therefore always without strategic reserves.

ish and French capacity markets will already be included in the model in the starting year 2018. However, both the Polish and Italian capacity markets were only approved in February 2018 and are currently still in their introductory phase. In the model, we have therefore assumed that these two capacity markets will only take effect from 2023 onwards. All four capacity markets were initially approved by the EU Commission for a period of ten years. Due to the possibility of subsidizing longer-term contracts in the capacity markets, we also assume that the effect of the central capacity markets in Great Britain, Poland and Italy will largely be maintained for a certain period after the official approval period has expired. For the French decentralized capacity market, on the other hand, our model assumes only an effect until the end of its official approval period.

For each of the countries with a capacity market, a capacity equation must be fulfilled in the electricity market model. We have parameterised these based on the tendered procurement quantities, the *de-rated capacity* of the interconnectors<sup>82</sup> and the residual load. On the basis of the quantities tendered, we have determined the probability of situations in which the residual load cannot be covered by the available capacity, while taking into account the *de-rated capacity* of the interconnectors.<sup>83</sup> For those years for which no tender quantity is known yet, we used this probability (with which the residual load cannot be covered) in order to be able to estimate the tender quantities. For Italy and Poland, we used the probability (with which the residual load cannot be covered) of the central capacity market in Great Britain in order to derive the corresponding capacity equations. In order to account for load management options, additional costs for the provision of services in the central capacity markets were assumed, which among

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<sup>82</sup> The *de-rated capacity* is the import capacity of the interconnectors reduced by a discount, which is expected to be safely available.

<sup>83</sup> We have defined the residual load as the load minus the feed-in from wind energy onshore, wind energy offshore, PV and run-of-river power plants.

other things represent the costs of trial activations that are performed regularly to test the reliability of capacity providers. The capacity equation for the decentralised capacity market in France differs from the equation described above in so far as no additional costs are included for the provision of services and trial activations.<sup>84</sup>

## **4.2 Assumptions on the (exogenous) development of conventional power plants fleet**

The future development of the thermal power plants fleet is basically determined by means of integrated investment and dispatch calculations using the European electricity market model. However, this endogenous calculation takes into account currently known political guidelines and measures, assumptions about technical lifetimes and other information available to the market, which we specify exogenously for the electricity market model.

The starting point for our assumptions regarding the installed capacity in each of the countries considered is the r2b power plant database, which we have built up as part of our many years of consulting activities and technical expertise and which we continuously maintain, update and expand. It contains publicly available information, both commercial and non-commercial. At the European level, we have compared and updated the information whenever necessary on the basis of the *S&P Global PLATTS World Electric Power Plants Database*, *ENTSO-E*, databases of European institutions such as the European Commission or the *European Environment Agency*, private actors (e.g. EEX, consultancies/analysts) and NGOs as well as civil society organisations. We aligned these data on the basis of national information from TSOs, regulatory authorities, government bodies and private actors (e.g. power plant operators, think tanks, consultancies, power exchanges).

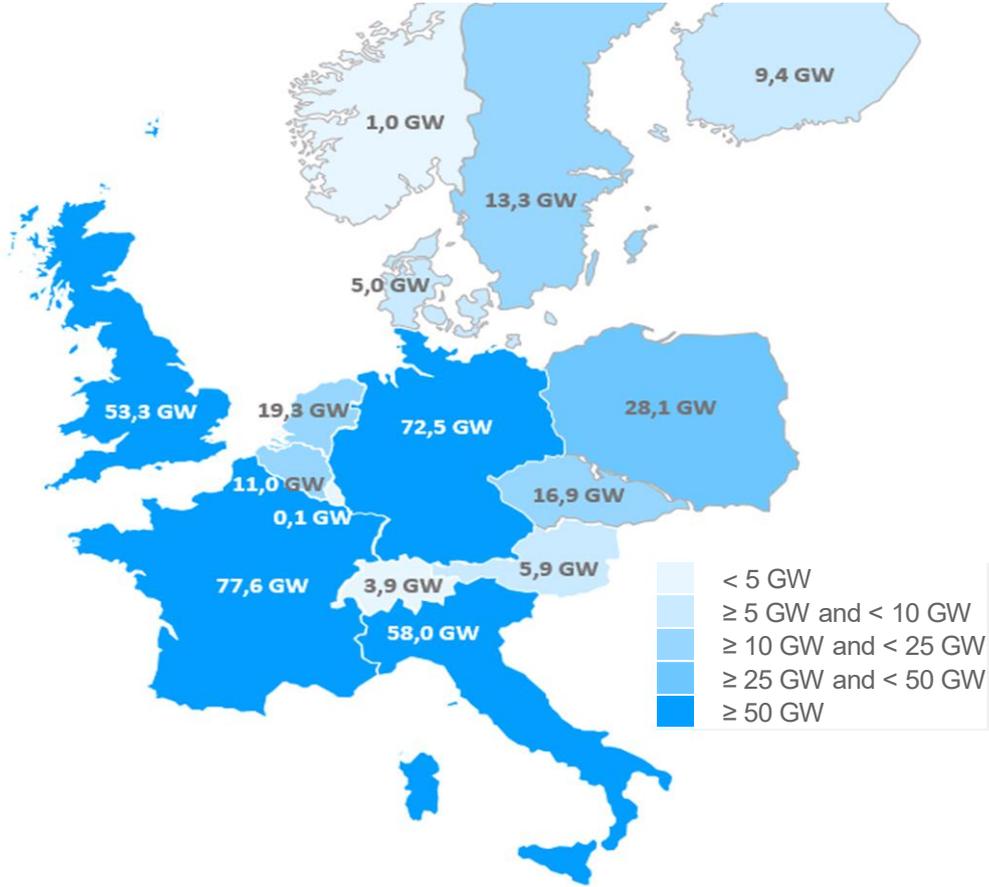
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<sup>84</sup> In the decentralised capacity market in France, utilities can also reduce their demand for certificates by reducing their load by means of flexible loads, which is why we assume that no additional costs will be incurred for the provision of services in the capacity market or for trial activation.

In addition, information received in the course of our consulting activities and which is not publicly accessible feeds our database. In cases of doubt (inconsistencies of the information collected with previous information in the r2b database and between different data sources) we carry out supplementary individual searches. Especially with regard to planned construction and decommissionings of conventional power plants, we have additionally researched information on the basis of national *generation adequacy reports*, energy strategies or concepts and other publications and compared it with the information previously available in our power plant database.

Developments in nuclear energy, coal-fired power plants and, to some extent, CHP plants are of great political importance and strongly regulated in all European countries. In these areas, the expansion of power plants is therefore largely set exogenously. Possible investments in power plants based on natural gas, on the other hand, are completely model endogenous (with the exception of CHP plants to maintain heat supply). Temporary shutdowns (*mothballing* or *cold reserve*) and early final shutdowns (*disinvestment*) can be carried out by the model for all thermal power plant technologies with the exception of combined heat and power (CHP) plants for economic reasons. In the following sub-sections we present the exogenous assumptions on the development of the power plant fleet based on nuclear energy, coal and CHP in detail (see Sections 4.2.1 to 4.2.3). First, however, we give an overview of the exogenous model specifications for the basic development of controllable conventional generation capacity at the European level (starting point of installed capacity) aggregated over the different fuel types in Figure 4-2. The exogenous specifications include already known planned shutdowns and expansions as well as specifications for the technical lifetime of the individual power plant units, which determine the latest possible shutdown date. In the model, this may deviate from the latest possible decommissioning date by early decommissioning and model endogenous capacity expansion.

FIGURE 4-2: EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF THE INSTALLED CAPACITY (NET) OF CONVENTIONAL POWER PLANTS IN 2018 AND TABULAR OUTLOOK UP TO THE YEAR 2030 (GIVEN DEVELOPMENT WITHOUT ENODOGENOUS COMMISSIONINGS / DECOMMISSIONINGS).



[MW]	2020	2023	2025	2030
Germany	78.026	70.713	68.746	60.550
Belgium	10.922	7.839	7.406	3.756
Denmark	5.046	4.890	4.804	4.505
Finland	11.053	10.746	12.020	11.229
France	77.794	69.334	63.557	48.559
Great Britain	49.555	39.255	35.209	25.279
Italy	54.591	52.045	49.364	42.409
Luxembourg	103	101	90	72
Netherlands	18.760	18.614	18.047	16.960
Norway	968	968	968	967
Austria	5.922	5.903	6.041	6.273
Poland	29.512	23.740	23.966	22.728
Sweden	12.322	9.936	9.587	9.408
Switzerland	3.540	3.527	3.159	2.791
Czech Republic	16.220	14.650	14.643	13.195
<b>Sum</b>	<b>426.859</b>	<b>381.217</b>	<b>363.802</b>	<b>308.955</b>

Source: Own representation.

It can be seen across all model regions considered that the exogenous output given in the initial path decreases in total over time across all conventional controllable generation plants. The total exogenous generation capacity of these plants in the model regions under consideration will gradually decline from approx. 440 GW in 2018 to approx. 309 GW in 2030. This decline will be driven in particular by the fact that power plant units reach their technical life expectancy. In addition, we take into account shutdowns announced by power plant operators in the short term as well as political decisions in the short and medium term. The latter relate, for example, to the decommissioning of nuclear power plants in Germany or of coal-fired power plants in countries that have decided to phase out coal from electricity generation (see Sections 4.2.1 and 4.2.2). Conventional power plant units already under construction or at an advanced stage of planning are also taken into account in this presentation of exogenous capacity development, as is an exogenous replacement of CHP plants based on natural gas (for details see Section 4.2.3). However, the additions can by no means compensate for the assumed exogenous shutdowns.

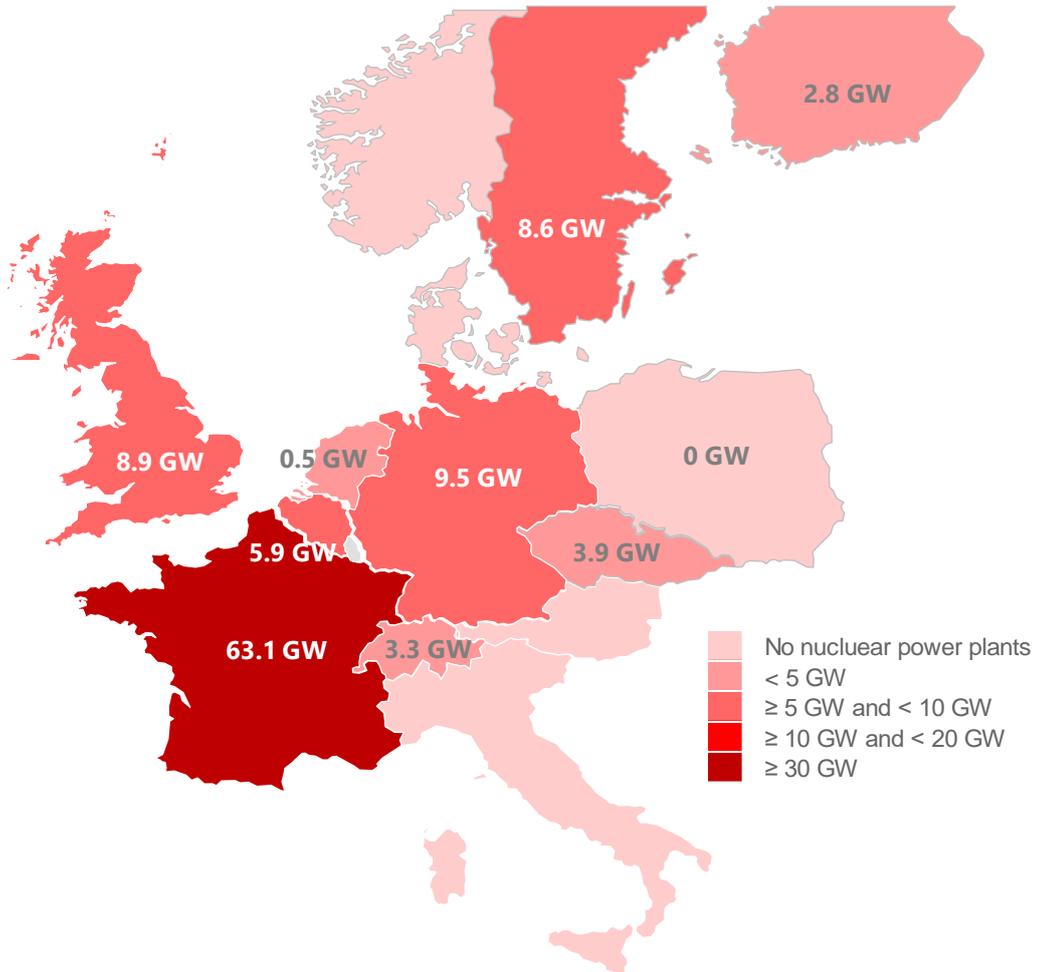
### **4.2.1 Assumptions on the development of nuclear energy**

Future developments in the field of electricity generation from nuclear energy will largely be determined by decisions of the countries in the field of nuclear energy policy. On the one hand, this takes the form of phase-out decisions with fixed residual terms, bans on new constructions or politically adopted targets for the development of electricity generation from nuclear energy, and on the other hand, political decisions on entry into or expansion of nuclear energy. Against this background, the developments of the installed capacities of the nuclear power plants are determined exogenously in the electricity market modelling, i.e. both (latest) decommissioning dates of existing plants as well as planned commissioning dates are determined instead of being calculated by the model. The starting point for the capacity developments is the installed capacity at the beginning of the year 2018 (Figure 4-3). The data basis for this is provided by our European power plant database, which contains all power plants with all relevant technical data as well as up to date information on availability values and currently valid operational permits.<sup>85</sup>

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<sup>85</sup> The database of our European power plant database is regularly updated as part of ongoing research and is constantly kept current.

FIGURE 4-3: EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET) IN NUCLEAR POWER PLANTS IN 2018 AND TABULAR OUTLOOK UP TO THE YEAR 2030 (DEVELOPMENT WITHOUT ENDOGENOUS COMMISSIONINGS / DECOMMISSIONINGS)



[MW]	2020	2023	2025	2030
Germany	8.113	-	-	-
Belgium	5.913	2.866	2.433	-
Finland	4.364	4.364	5.764	5.262
France	62.970	57.970	52.200	37.646
Great Britain	8.883	5.811	6.293	7.798
Netherlands	482	482	482	482
Sweden	7.725	6.842	6.842	6.842
Switzerland	2.960	2.960	2.595	2.230
Czech Republic	3.930	3.930	3.930	3.930
<b>Sum</b>	<b>105.340</b>	<b>85.225</b>	<b>80.539</b>	<b>64.190</b>

Source: Own representation based on ENTSO-E (2017a), ENTSO-E (2018a), BEIS (2017), WNISR (2017) and own research.

In order to obtain a maximum consistent picture of expected implementations of current policy decisions by the countries and their concrete effects on capacity developments, we base our assumptions on future capacity developments in nuclear energy on the corresponding current assumptions of the ENTSO-E. Until 2025 we use the assumptions from the *Best Estimate* scenario of the *Midterm Adequacy Forecast 2017*,<sup>86</sup> for the years 2030 to 2040 the *Sustainable Transition* scenario of the *TYNDP 2018*<sup>87</sup> is used.<sup>88</sup>

As the only exception, for the **United Kingdom** we deviate significantly from the assumptions of the ENTSO-E: Due to the higher timeliness and significantly different forecast values, we use the forecasts of the British government from the reference scenario of the *Updated energy and emissions projections 2017* of the *Department for Business, Energy & Industrial Strategy* for the capacity development of nuclear energy in Great Britain.<sup>89</sup>

We break down the expected capacity developments at the national level into operational live times of individual power plant units. Among other things, we take as a basis, the operator's announcements of decommissioning, legally valid information on operating permits or the age of the power plant. We have carried out additional plausibility checks based on the *THE WORLD NUCLEAR INDUSTRY*

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<sup>86</sup> See ENTSO-E (2017a).

<sup>87</sup> See ENTSO-E (2018a).

<sup>88</sup> Minor deviations from the published figures for ENTSO-E arise in individual years and individual countries on the basis of current, reliable information on the service lives of individual power plants, as well as any deviations in the presentation of installed capacity at the beginning or end of the year. For example, ENTSO-E (2017a) shows 0 for Belgium in 2025. However, since the Doel 2 and Thiange 1 power plant units have valid operating permits until 01.12.2025 and Thiange 3 until 01.09.2025, these units will be made available to our model for electricity generation in 2025 with a total capacity of 2.4 GW.

<sup>89</sup> BEIS (2018a).

*STATUS REPORT 2017*<sup>90</sup> and specific information for individual countries. The resulting installed capacities for the years 2020, 2025 and 2030 are shown in Table 4-1.

In **Germany**, the total installed capacity of nuclear power plants in accordance with Section 7 of the Atomic Energy Act<sup>91</sup> will decline from 9.5 GW in 2018 to 8.1 GW in 2020 due to the decommissioning of unit Philippsburg 2 by December 31st, 2019. The Gundremmingen C, Grohnde and Brokdorf units will be closed at the end of 2021 and the remaining units Neckarwestheim 2, Emsland and Isar 2 at the end of 2023.

The capacity trend is also expected to decline sharply in **France** and in **Belgium**, where the announced phase-out of nuclear power by the end of 2025 is represented. In the United Kingdom, the British government is announcing the decommissioning of major nuclear power plants over the next twelve years, but this will be more than offset by new construction projects.<sup>92</sup> In addition, a capacity expansion of 1.4 GW is assumed in **Finland** by 2025. In **Poland**, on the other hand, the commissioning of the first nuclear power plant is not assumed until after 2030.<sup>93</sup>

## **4.2.2 Assumptions on the development of coal-fired power plants**

The importance of coal-fired power plants for national electricity generation varies significantly between the countries considered. In Germany and Poland, the installed capacity of coal-fired power plants is by far the highest. However, Great Britain, the Czech Republic and Italy currently also have significant installed capacity of coal-fired power plants (see Figure 4-4).

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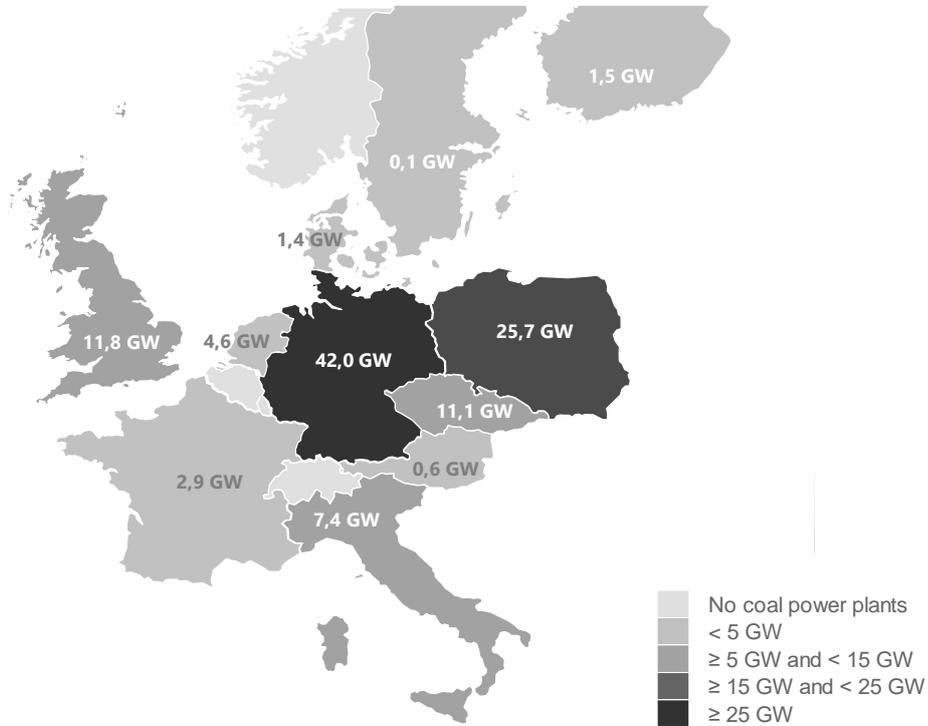
<sup>90</sup> WNISR (2017).

<sup>91</sup> AtG (2017).

<sup>92</sup> See BEIS (2017)

<sup>93</sup> According to our information, a total of 3.3 GW of capacity will be installed in Poland by 2035, and around 5 GW will be connected to the grid by 2040.

FIGURE 4-4: EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED (NET) CAPACITY IN COAL-FIRED POWER PLANTS IN 2018 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS COMMISSIONINGS / DECOMMISSIONINGS).



[MW]	2020	2023	2025	2030
Germany	39.541	37.895	34.966	26.967
Denmark	1.380	1.380	-	-
Finland	1.135	565	565	-
France	2.930	-	-	-
Great Britain	7.812	1.935	-	-
Italy	5.442	5.442	3.604	-
Netherlands	4.617	4.617	4.617	4.617
Austria	560	560	334	-
Poland	26.424	19.870	19.956	18.456
Sweden	120	120	-	-
Czech Republic	10.440	8.811	8.800	7.747
<b>Sum</b>	<b>100.400</b>	<b>81.194</b>	<b>72.842</b>	<b>57.787</b>

Source: Own assumptions.

Since the international agreement on a common climate protection target was reached at the COP21 climate conference in Paris and subsequently, the European Union and individual member states have assured to be willing to meet the

agreed target, an increasing number of political measures are being planned to reduce the share of coal-fired power generation. These include, for example, a number of announcements by European countries to phase out coal-fired power generation in the medium term.<sup>94</sup> This trend towards the increasing decarbonisation of energy supply is reflected in the exogenous assumptions on the development of the installed capacity of coal-fired power plants. In total across the countries considered, it will decrease from approx. 109 GW in 2018 to approx. 58 GW by 2030.

In this analysis, coal-fired power plant units that have already been announced and are currently under construction or that are in an advanced stage of planning have been taken into account as exogenously assumed expansions. This applies to new constructions in Poland and Germany. Other than that, the construction of new coal-fired power plants is considered to be extremely unlikely in all countries (except for Poland and the Czech Republic) due to political statements and regulations or social consensus and will therefore not be approved. For Poland and the Czech Republic, the endogenous expansions for lignite-fired power plants were limited in order to take into account the capacities of open pit lignite mines.

The electricity market model decommissions power plants endogenously either due to a lack of profitability or, as a rule, after an assumed maximum technical

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<sup>94</sup> For example, 64 political and economic partners (including 16 European countries) joined forces in the *Powering Past Coal Alliance* at the COP23 in Bonn and agreed to phase out conventional coal-fired power generation in their countries or spheres of influence (see BEIS, 2017). At the European level, the emission targets for power plants will be tightened with the revised BREF targets approved by the European member states in 2017, which will take effect from 2021. In addition, negotiations are currently underway on a new European Electricity Market framework that links payments from capacity mechanisms to a CO<sub>2</sub> emission standard, among other things. This regulation would *de facto* exclude coal-fired power plants from participating in capacity mechanisms.

lifetime of 45 years has expired.<sup>95</sup> Whenever available, decommissioning announcements by power plant operators, TSOs and regulatory authorities were also taken into account.

In **Germany**, a total of just under 22 GW in hard coal-fired power plants and 20 GW in lignite-fired power plants will be available to the market in 2018. In addition, a further 1,055 MW of Datteln 4 hard coal unit is currently under construction. The simulation calculations for the reference scenario assume that this unit will not be connected to the grid before 2020. Furthermore, in view of the current discussions on the future of coal-fired power generation in Germany, it was assumed that there will be no further new coal-fired power plant units. At the same time, however, no additional exogenous shutdowns of coal-fired power plants in Germany were assumed in the reference scenario, as there are currently no provisions on additional climate protection measures yet.

In 2018, the coal-fired power plant fleet in **Poland** has a total capacity available to the market of 25.7 GW. Of these, 7.8 GW use lignite, 17.2 GW hard coal and just under 650 MW are operated with partial use of biomass. Power generation from coal is extremely important in Poland (77% of electricity generation in 2017 was based on coal) and is expected to remain the main energy source in the medium term<sup>96</sup>. For our model, exogenous additions of coal-fired power plants totalling about 4.4 GW in hard coal units and about 450 MW in one lignite-fired unit (which are already under construction or at an advanced planning stage) were assumed to go online until 2025. In addition, endogenous additions to coal-fired power plants are permitted in Poland in the model.

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<sup>95</sup> In individual cases, technical lifetimes of up to 60 years (e.g. for power plant units in Germany and Poland) were also applied in order to depict very old power plants that are still in operation.

<sup>96</sup> See Agora Energiewende and Sandbag (2018), p. 24 and Forum Energii (2017), p. 6.

In **Great Britain**, coal-fired power plants with a total capacity of 11.8 GW are still available to the market in 2018. Since 2013, the installed capacity in coal-fired power plants has almost halved. This development is attributed, among other things, to the introduction of the British *Carbon Price Floor* in 2013, which is intended to support the transition to a low-emission economy by adding a premium to the certificate price of the European emissions trading system.<sup>97</sup> In the run-up to the 2015 climate conference in Paris, Great Britain announced its intention to phase out coal-fired power generation by 2025. In addition to the existing emissions standard, which de facto excludes the construction of new coal-fired power plants in Great Britain without the use of carbon capture and storage (CCS), the British government is currently planning to introduce a further emissions standard. This standard will apply to existing power plants from the year 2025 and will thus guarantee the phase-out of conventional coal-fired power generation. In accordance with these plans, we assume the successive decommissioning of all coal-fired power plants in Great Britain by the year 2025.<sup>98</sup> A new construction or the retrofitting of existing plants with CCS is not considered as an option.

The **Czech Republic** has 11.1 GW of installed capacity of coal-fired power plants in 2018. At 8.7 GW, lignite-fired power plants account for the lion's share, hard coal-fired power plants for 1.8 GW and coal-fired power plants under 100 MW each for approx. 550 MW. The operators of three-quarters of the power plant units, which are already 30 years old or even older, are currently facing a difficult market environment due to stricter emission regulations, a likely further increase in prices for CO<sub>2</sub> emissions certificates within the EU ETS and low wholesale prices. Based on the assumptions for technical lifetime, we expect that about 4 GW of

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<sup>97</sup> See Hirst (2018).

<sup>98</sup> See BEIS (2018b).

installed capacity of coal-fired power plants will be shut down by 2030. Nevertheless, electricity generation from lignite and hard coal is likely to account for a significant share of Czech electricity generation in the medium term.<sup>99</sup> In the Czech Republic, endogenous commissionings of coal-fired power plants are permitted in the model.

In [Italy](#), a total of 7.4 GW of installed capacity in hard coal-fired power plants are in operation in 2018. In November 2017, the Italian government announced its intention to phase out coal-fired power generation by 2025.<sup>100</sup> However, concrete measures to achieve this objective have not been adopted yet.<sup>101</sup> Four of the existing power plant units with a total installed capacity of just under 2.1 GW were only commissioned between 2005 and 2010. For these units, we assume that they will be converted to bioenergy after 2025. Older units are assumed to be successively shutdown until the end of 2025 due to their technical lifetime.

In addition, the [Netherlands](#), [France](#), [Denmark](#), [Finland](#), [Sweden](#) and [Austria](#) have announced their intention to phase out coal-fired power generation in the short to medium term. The coal-fired power plants currently in operation in these countries will therefore be successively shut down until the politically announced end dates for coal-fired power generation are reached. For the Netherlands, it is assumed that the coal-fired power plants commissioned in 2014 and 2015 will be converted to bioenergy and will continue to operate beyond the end date of coal-fired power generation.

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<sup>99</sup> See CEPS (2017), p. 9f.

<sup>100</sup> See Minambiente (2017).

<sup>101</sup> These measures, as well as the actual date of the coal phase-out, will depend on the new Italian government coalition, the formation of which had not yet been completed at the time of the simulation calculations.

### 4.2.3 Assumptions on the development of combined heat and power generation

The combined generation of electricity and heat in power plants fired by hard coal, lignite, natural gas and petroleum products is of great importance in Germany and many of the other countries included in the analyses. In 2016, the absolute CHP electricity generation of these power plants in Germany was about 80 TWhel, which corresponds to a share of about 25 % of the total electricity generation on the basis of the corresponding primary energy sources.

The economic viability of these CHP plants does not depend exclusively on the revenue opportunities on the electricity markets. Rather, the operators of the plants can achieve additional revenue from the sale of the heat or cost savings in their own consumption (electricity / heat) compared with uncoupled heat generation and in many cases receive additional direct or indirect subsidy payments. In return, they must meet their contractual obligations to supply heat or cover their own heating needs.

Against this background, the development of the **installed capacity of CHP plants** is not exclusively dependent on developments on the electricity markets, but in particular also on developments in the (CHP-capable) heat demand, the development of alternative technologies for providing the heat demand and developments in the promotion of CHP.

In the following subsections we present the assumptions regarding the development of the installed capacity of CHP plants in Germany and the European countries modelled, as well as the methodology for deriving them. A detailed description is firstly given for the relevant developments with significance for the future role of CHP in Germany. For the other countries included in the analyses, we have used a largely identical methodological approach. We will subsequently present the main assumptions and consequent results on the development of CHP plants abroad.

## Development of combined heat and power generation in Germany

The analysis of the development of the installed capacity of CHP plants in Germany is based on forecasts of the development of heat demand. Based on a literature research, including the "long-term scenarios" on behalf of the BMWi<sup>102</sup>, and the short, expert opinion "Flexibility of CHP" on behalf of the German TSO<sup>103</sup>, we first defined a development of the district heating demand, the industrial CHP heat generation as well as the CHP heat generation in other areas - in particular of decentralized object CHP (block heat and power station) and decentralized bioenergy plants. In addition, in line with the German government's climate protection plan,<sup>104</sup> we have assumed the gradual integration of new renewable heat technologies (including solar thermal and large heat pumps) into district heating systems by 2030.

As a result, Figure 4-5 shows a development that is almost constant compared to today's level in the sum of district heating and CHP heat generation in industry and other sectors.

By 2030, heat generation for district heating will have risen moderately compared with the historic year 2016, while CHP heat generation by industry will decline moderately by 2030 and CHP heat generation in other areas will decline.

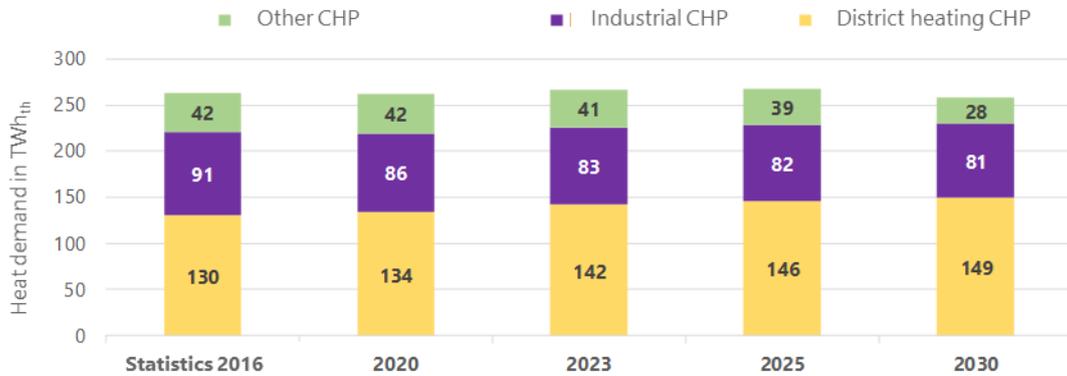
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<sup>102</sup> See Fraunhofer ISI et al. (2017).

<sup>103</sup> See FFE (2017).

<sup>104</sup> See Ökoinstitut (2017).

FIGURE 4-5: DEVELOPMENT OF CHP-CAPABLE HEAT DEMAND

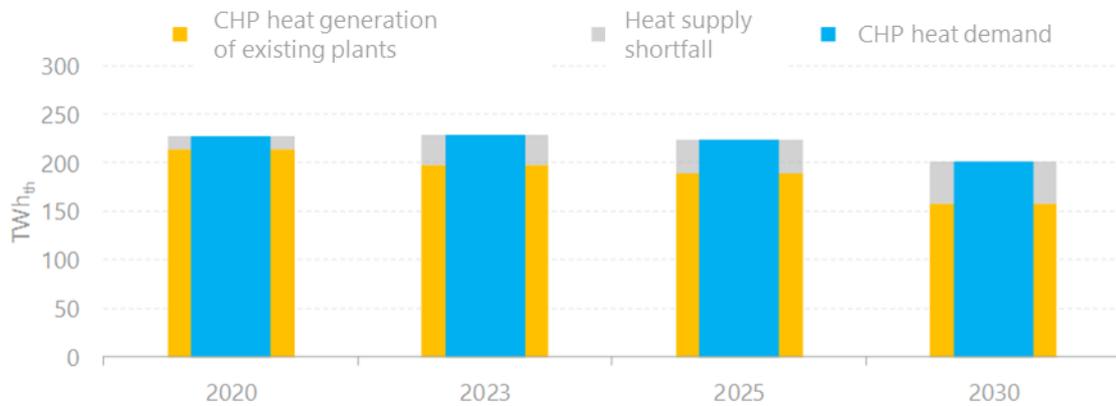


Source: Own presentation based on Fraunhofer ISI et al. (2017), FFE (2017), Öko-Institut (2017).

On this basis, we have derived the residual heat demand, i.e. heat demand minus uncoupled heat generation, taking into account assumptions on the development of heat generation by power to heat (PtH), natural gas boilers, other gases, waste and renewable heat technologies in the district heating systems.

Based on our power plant database and the assumptions made regarding the decommissioning of CHP plants, we determine the CHP heat generation of the existing plants over time. Due to the shutdowns, there is a heat coverage gap, which is covered in the model by newly installed replacement CHP plants based on natural gas (see Figure 4-6).

FIGURE 4-6: ASSUMPTIONS ON THE DEVELOPMENT OF (RESIDUAL) CHP HEAT DEMAND IN GERMANY COMPARED TO 2018

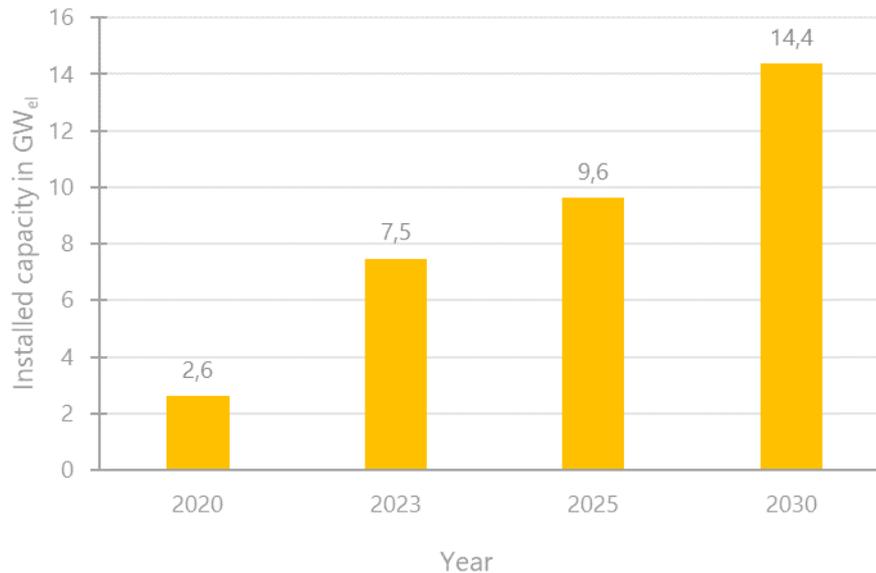


Source: Own calculations.

The heat generation quantities allocated to the individual power plant units are based on individual research on the CHP heat generation of the plants and assumptions on typical operating modes depending on technical parameters and the design of the plants. An exception to this is lignite-fired power plants with CHP heat generation. For the allocation of CHP heat generation quantities for the lignite-fired power plant units,<sup>105</sup> we used the data from the Agora / Ökoinstitut study "Die deutsche Braunkohle-Wirtschaft" (The German lignite-fired industry) after checking the plausibility of the data. Under the assumption of a realistic technology mix, typical capacity-related power to heat ratios and capacity utilisation of the plants in various areas, the additional capacity shown in the Figure 4-7 represents the shortfall in CHP heat generation, which is necessary to guarantee a secure heat supply.

<sup>105</sup> See Ökoinstitut (2017).

FIGURE 4-7: DEVELOPMENT OF INSTALLED CAPACITY OF NEW NATURAL GAS CHP REPLACEMENT PLANTS WITH COMMISSIONING FROM 2018 IN GERMANY (CUMULATED)



Source: Own calculations.

In Germany, we differentiate between the following CHP application fields in the derivation:

- District heating
- Industrial CHP
- Fossil fuel-fired object related CHP units
- Bioenergy for object related or local heating supply

The total amount of CHP heat generation per fuel and application area (district heat / industry) is modelled consistently with the 2016 statistics.

For the new cogeneration replacement plants, we assume a realistic technology mix based on power to heat ratios and annual full load hours for heat generation. Table 4-1 shows the assumed technology mix for cogeneration replacement plants based on natural gas for the different application areas.

TABLE 4-1: ASSUMPTIONS ON NATURAL GAS COGENERATION REPLACEMENT PLANTS IN THE DIFFERENT APPLICATION FIELDS<sup>106</sup>

	capacity-related power to heat ratio	capacity-related CHP power to heat ratio	energy-related power to heat ratio	full load hours CHP heat in h/a
District heating	1,15	1,06	0,92	3.750
Industrial CHP (natural gas)	0,65	0,65	0,65	5.000
Object related CHP units	0,65	0,65	0,65	3.500

Source: Own representation.

As a result, we get an expansion of natural gas cogeneration replacement plants that

- is consistent with the assumptions of residual heat demand,
- is consistent with the assumed decommissioning path / the available decommissioning information on power plants, and
- represents a realistic scenario for replacement CHP technologies.

The use of **CHP plants** is differentiated between the CHP application fields. Depending on the CHP plant technology, the plants are mapped in the model in largely heat-operated modus or in flexible CHP operation. The flexibility in the electricity market model is made possible by a simultaneous mapping of natural gas boilers, an increase in heat storage in the district heating systems and an increase in the output of PtH, which on the one hand are used to cover peak loads

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<sup>106</sup> The capacity-related power to heat ratio describes the ratio between the rated electrical output of the entire system and the maximum heat extraction. The capacity-related CHP power to heat ratio describes the relationship between the electrical power of the CHP-part and the thermal power at maximum heat extraction. The energy-related power to heat ratio describes the relationship between CHP electricity production and CHP heat production. The CHP heat full load hours describe the full load hours in relation to the extracted heat quantity, i.e. with assumed maximum heat output.

on the heat side (exceeding the thermal CHP output), and on the other hand enable an additional flexibilisation of the CHP plants at particularly high and low or negative electricity prices.<sup>107</sup>

### Development of combined heat and power in Europe

For the rest of Europe, we have used a fundamentally identical methodology for determining CHP replacement, although due to the availability of data we have not made any additional differentiation between district heating, CHP in industry and CHP in other areas.

We have derived the residual heat demand based on the figures in the "*PRIMES EU Reference Scenario 2016*" on final energy consumption from CHP and district heating, taking into account the increasing share of renewable heat in district heating networks.<sup>108</sup>

When developing the CHP heat output of CHP plants, we assumed that this would develop in proportion to the development of the residual heat demand. The electrical output of the CHP plants is finally determined on the basis of the technology assumptions on the power to heat ratios of the CHP plants.

As a CHP expansion and replacement technology, we have assumed a representative natural gas CHP technology in all countries except Poland and the Czech Republic. In Poland and the Czech Republic, on the other hand, we have assumed that some coal-fired CHP plants will continue to be added in the future.

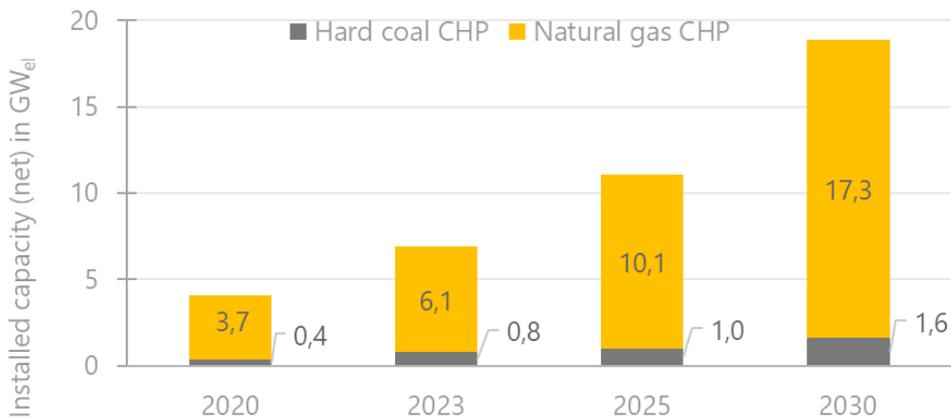
The resulting installed electrical output of new CHP plants, which essentially results from the replacement of old, decommissioned coal and gas CHP plants in the countries included in the analyses (except Germany), is shown differentiated by natural gas and coal in Figure 4-8.

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<sup>107</sup> In the model, for example, there is the possibility of a short-term increase in electricity generation from heat-operated plants in situations of shortage on the electricity side at high electricity prices based on the assumption of a bypass or an emergency cooler or with flexibility to use the heat by means of heat storage.

<sup>108</sup> See European Commission (2016c).

FIGURE 4-8: DEVELOPMENT OF INSTALLED CAPACITY OF NEW CHP REPLACEMENT PLANTS WITH COMMISSIONING FROM 2018 IN THE OTHER COUNTRIES CONSIDERED



Source: Own calculations.

While coal-fired CHP plants are only being built to a small extent (exclusively in Poland and the Czech Republic), there is a considerable gross increase in natural gas-fired CHP plants in other European countries of 17.3 GW by 2030.

We have also assumed a flexibilisation of CHP systems based on natural gas boilers in other European countries but have not explicitly modelled an expansion of PtH and heat storage facilities.

### 4.3 Development of renewable energies and pumped storage power plants

Since the development of renewables is of great political importance in all the countries under consideration and future expansion will therefore be largely controlled by political decisions and guidelines, we fully model the assumptions on the development of renewables exogenously. In the following sections, we therefore present in detail our assumptions regarding the expansion of renewables and

pumped storage power plants in Germany and the European countries included in the modelling.<sup>109</sup>

### 4.3.1 Development of installed RES capacity in Germany

The scenario for the expansion of renewables in Germany was developed jointly with the BMWi. The Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG),<sup>110</sup> which essentially provides for a quantity control instrument in the form of tenders for the major technologies, was assumed to exist further. In addition, the RES expansion target defined in the coalition agreement<sup>111</sup> for the 19th legislative period up to the year 2030 was assumed to be met. Accordingly, the share of renewable energies in gross electricity consumption is to rise from approx. 36 % in 2017 to 65 % by 2030.

The development of the installed capacity of the individual RE technologies including the pumped storage power plants in Germany is shown in Table 4-2. The information on the installed capacity of the respective technologies takes into account both assumptions on the expansion and decommissioning of renewable energy plants. The figures refer to the end of the year.

Accordingly, the installed capacity of **onshore wind energy** will increase by around 50 % between 2017 and 2030. The expansion of onshore wind energy in the next few years will be based on the tendering regime laid down in the EEG. In accordance with the coalition agreement, additional special tenders amounting to 4 GW

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<sup>109</sup> Electricity generated in pumped storage power plants is considered to be renewable energy only if it is generated from natural inflows. In the following 4.3.2 only electricity generated in pumped storage power plants with a natural inflow is taken into account to illustrate electricity generation. In order to map the installed capacity, however, the capacity of all pumped storage power plants is taken into account, including those pumped storage power plants that do not have a natural inflow.

<sup>110</sup> See Act on the Expansion of Renewable Energies (EEG).

<sup>111</sup> See CDU, CSU and SPD (2018).

have been considered, which will take effect in the coming years. Due to the expiration of the subsidies for older existing wind turbines, an increase in decommissioning of wind turbines in Germany is assumed as of 2021. Starting in 2024, an annual gross addition of 4 GW <sup>112</sup> is assumed for onshore wind energy.

TABLE 4-2: DEVELOPMENT OF INSTALLED RENEWABLE ENERGY CAPACITY IN GERMANY (AT THE END OF EACH YEAR)

[GW]	2017	2020	2023	2025	2030
Wind onshore	51,0	57,6	60,9	64,3	75,0
Wind offshore	5,4	7,5	9,2	10,6	17,0
PV	42,9	51,7	62,0	68,6	84,1
Bioenergy*	8,0	8,4	8,5	8,4	7,1
Hydropower**	12,2	12,2	12,2	12,2	12,2
Other RES	0,5	0,5	0,5	0,5	0,6
<b>Sum</b>	<b>120,0</b>	<b>138,0</b>	<b>153,4</b>	<b>164,7</b>	<b>196,0</b>

\* incl. biogenic waste

\*\* incl. all pumped storages

Source: BMWi (2018a).

It is assumed that the installed capacity of offshore wind energy will triple by the year 2030 compared with 2017. The development of installed capacity is basically based on scenario C of the draft scenario framework for the electricity 2030 grid development plan (version 2019) of the TSOs.<sup>113</sup> It is assumed that in addition to the 15 GW expansion of offshore wind energy provided for in the EEG 2017, a further 2 GW will be added by 2030.

<sup>112</sup> The gross expansion is defined as the expansion of all plants regardless of whether a plant is constructed at a new location or replaces an older existing plant. In contrast to this, the net additions also take decommissioning into account. The net increase thus reflects the change in installed capacity.

<sup>113</sup> See ÜNB (2018). Contrary to the installed capacity of 17.3 GW planned for 2030 in the draft scenario framework of the Electricity 2030 network development plan for 2030, an installed capacity of 17.0 GW was assumed in agreement with the BMWi.

In addition to wind energy, significant expansion is also assumed for **photovoltaics** in the course of the period under review. It is assumed that the installed capacity will double by 2030 compared to 2017. As with onshore wind energy, the additional tenders of 4 GW provided for in the coalition agreement will also be assumed for photovoltaics, which will take effect in the coming years. Starting in 2023, an annual gross addition of 3.3 GW is assumed.

For **bioenergy**, including biogenic waste, a further moderate increase in installed capacity to 8.5 GW is assumed by 2023. From 2024 onwards, due to the increased phasing-out of EEG support for old existing plants with an operating time of more than 20 years, there will be an increase in closures, which will be compensated by a further expansion until 2025. After the year 2025, existing plants will increasingly fall out of the EEG subsidy, as a result of which the installed capacity of bioenergy will decrease overall.

At 12.2 GW, the installed capacity of **hydropower**<sup>114</sup> remains largely constant over the entire period under review. Of this, 5.6 GW is attributable to run-of-river power plants and 6.6 GW to storage and pumped storage power plants (including pure pumped storage power plants without natural inflow). It is assumed that due to high licensing hurdles, lack of economic efficiency, acceptance problems and limited potential, no additional plants will be built to a relevant extent. At the same time, we assume that plants in need of modernisation will be overhauled.

Other renewable energies include landfill and sewage gas as well as geothermal plants. While landfill gas plants are expected to decrease due to the increasing outgassing of landfills, sewage gas and geothermal energy are expected to grow moderately. Overall, the total installed capacity of other renewables in Germany will increase only marginally by 2030.

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<sup>114</sup> The values for hydropower given here include run-of-river, storage and pumped storage power plants with and without natural inflow.

### 4.3.2 Development of RES Generation in Germany

We use simulation models to determine the hourly feed-in curves and the resulting annual electricity generation quantities of onshore and offshore wind energy as well as PV, which are intermittent. These models are used to derive feed-in curves for the corresponding renewable energy technologies, taking into account the assumed development of installed capacity in future years.<sup>115</sup> This is done on the basis of temporally and regionally high-resolution data on meteorological conditions (e.g. wind speeds, temperatures, global radiation) of past years and a detailed mapping of the technical parameters and the regional distribution of wind energy and PV plants. In contrast to wind energy and PV, the feed-in curves and electricity generation quantities for run-of-river are based on historical, aggregated feed-in structures.<sup>116</sup> The historical weather years 2009 to 2013 were used as the data basis.

Table 4-3 shows the development of electricity generation based on RE in Germany. According to the study, RE electricity generation will increase by around 69% from around 220 TWh in 2017 to more than 370 TWh in 2030.

In the case of **onshore wind energy**, electricity generation rises more strongly than installed capacity. This is in particular due to the assumption of technological progress. For example, an increasing hub height and thus a higher energy yield per unit of installed capacity is assumed for wind turbines erected in the future. In the case of **offshore wind energy** and **photovoltaics**, capacity utilisation remains largely constant over the years under review.

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<sup>115</sup> In principle, forecasts up to the year 2050 can be carried out within the framework of the simulation model.

<sup>116</sup> For a detailed description of the calculation of feed-in curves of the intermittent RES technologies, see Appendix D.

TABLE 4-3: DEVELOPMENT OF ELECTRICITY GENERATION FROM RENEWABLE ENERGIES IN GERMANY

[TWh]	2017	2020	2023	2025	2030
Wind onshore	88,7	105,7	119,8	128,1	162,8
Wind offshore	19,8	30,9	36,6	42,4	67,9
PV	39,9	46,5	56,3	62,4	77,1
Bioenergy*	49,6	51,7	50,7	49,6	40,1
Hydropower**	19,8	20,5	20,5	20,5	20,5
Other RES	2,0	2,0	2,1	2,1	2,4
<b>Sum</b>	<b>219,7</b>	<b>257,3</b>	<b>285,9</b>	<b>305,2</b>	<b>370,8</b>

\* incl. biogenic waste

\*\* incl. all pumped storages

Source: Values 2017: BMWi (2018b); values forecast: own calculations.

The utilisation of **bioenergy**, on the other hand, is declining due to the assumption that newly built bioenergy plants have a relatively low utilisation compared to existing plants. This is to be expected particularly in view of the current funding under the Renewable Energy Sources Act (EEG), as it encourages greater flexibility in new constructions or plant expansions, which is to be achieved by reducing capacity utilisation. In the case of (small) bioenergy plants, we define the production structure on the basis of historical values. However, these systems can feed in rated power at individual price peaks on the electricity market.

Electricity generation from **hydropower**<sup>117</sup> will remain constant over time, as we do not expect any increase in installed capacity. The reason for the lower electricity generation in the Table 4-3 in 2017 is that this is a historically measured value, while for the forecast years, the average electricity generation over the five considered water years 2009 to 2013 is shown.

Electricity generation from **other renewable energies** increases only moderately during the period under review.

<sup>117</sup> The values for hydropower given here include run-of-river, storage and pumped storage power plants with natural inflow.

### 4.3.3 Development of RES in Europe

The forecast development of renewable energies in the other European countries considered outside Germany (neighbouring countries to Germany as well as the Scandinavian countries, Great Britain and Italy)<sup>118</sup> is based on the *Best Estimate* scenario of the *Midterm Adequacy Forecast 2017* for 2020 and 2025 and for 2030 on the *TYNDP 2018 Scenario Sustainable Transition* for the intermittent RES technologies photovoltaics, onshore wind energy and offshore wind energy.<sup>119</sup>

The starting point for the installed capacity for hydropower is the extensive database on hydropower in Europe of r2b energy consulting GmbH. The information on hydropower includes run-of-river power plants as well as storage and pumped storage power plants with and without natural inflow. The assumptions for the future addition of run-of-river in the European countries under consideration are based on the *EU Reference Scenario 2016* of the European Commission<sup>120</sup>. The expansion of storage and pumped storage power plants is based on the *TYNDP 2016 Project List of ENTSO-E*<sup>121</sup> and our own research.

The development of the installed capacity of bioenergy and other renewable energies is also based on the "*EU Reference Scenario 2016*" of the EU Commission.<sup>122</sup>

Figure 4-9 shows the development of the installed capacity of renewable energies<sup>123</sup> and pumped storage aggregated across the countries considered outside Germany. Accordingly, the installed capacity of renewable energies including pumped storage power plants will increase from around 346 GW in 2020 to

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<sup>118</sup> As the development of renewable energies in Germany has already been explained in the previous sections, this section presents all other countries considered without Germany.

<sup>119</sup> See ENTSO-E (2017a) and ENTSO-E (2018a).

<sup>120</sup> See European Commission (2016d).

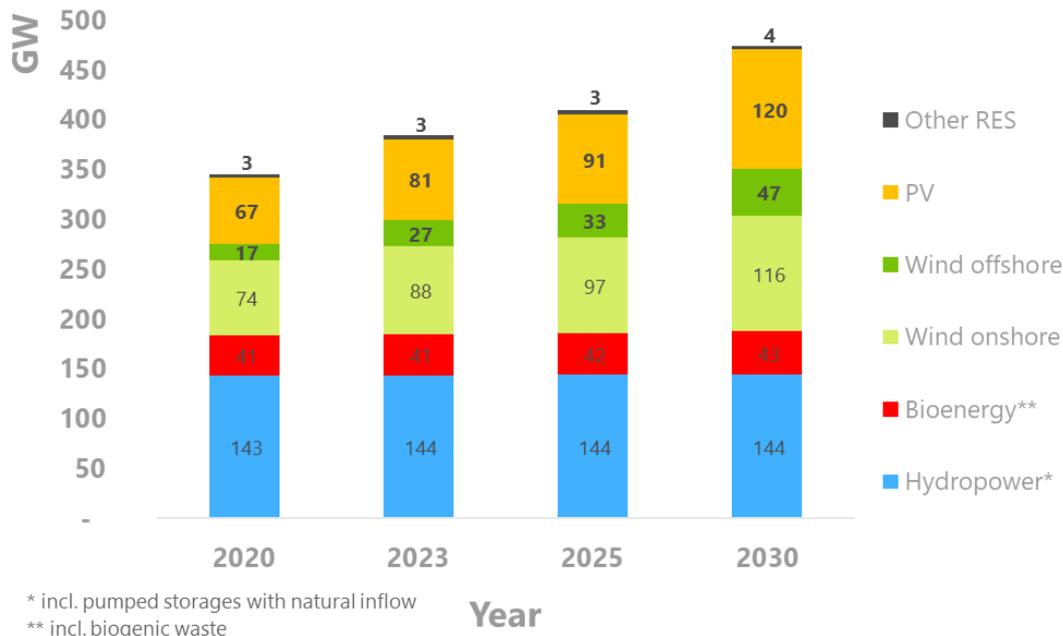
<sup>121</sup> See ENTSO-E (2015).

<sup>122</sup> See European Commission (2016d).

<sup>123</sup> In addition to renewable energies, Figure 4-9 also includes the installed capacity for pumped storage power plants without natural inflow.

475 GW in 2030. While the installed capacity of hydropower, bioenergy and other renewable energies is increasing only insignificantly, the capacities of photovoltaics, onshore wind energy and offshore wind energy are increasing significantly.

FIGURE 4-9: DEVELOPMENT OF AGGREGATED INSTALLED RENEWABLE ENERGY CAPACITY IN THE COUNTRIES UNDER REVIEW, EXCLUDING GERMANY



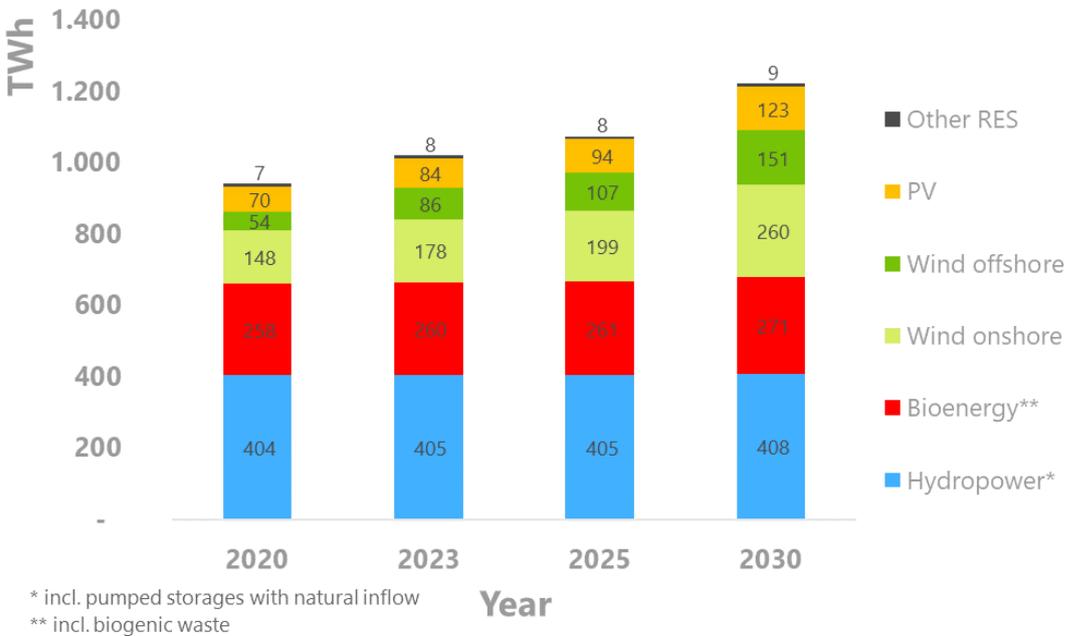
Source: Own presentation based on ENTSO-E (2015), ENTSO-E (2017a), ENTSO-E (2018a), European Commission (2016) and own calculations.

Figure 4-10 shows the development of electricity generation volumes based on installed capacity (RE) aggregated across the countries considered, excluding Germany. The electricity generation volumes for bioenergy and other renewables are based on the "EU Reference Scenario 2016" of the European Commission.<sup>124</sup> For the technologies onshore wind energy, offshore wind energy and photovoltaics, own calculations based on the detailed renewable energy model of r2b energy consulting GmbH and taking into account high-resolution weather data as well

<sup>124</sup> See European Commission (2016d).

as detailed technical parameters and regional distribution were carried out to determine the power generation quantities analogous to the methodology in Germany.<sup>125</sup> In the case of hydropower, the figures include electricity generation from the natural inflow of run-of-river, storage and pumped storage power plants. This is based on the average historical generation volumes of the run-of-river power plants and on the generation of the storage and pumped storage power plants from 2009 to 2013 based on natural inflows.

**FIGURE 4-10: DEVELOPMENT OF AGGREGATED ELECTRICITY GENERATION FROM RENEWABLE ENERGIES IN THE COUNTRIES UNDER REVIEW, EXCLUDING GERMANY**



Source: Bioenergy and other renewables: European Commission (2016); other technologies: Own calculations.

The electricity generation volumes in the countries under consideration, excluding Germany, will thus increase from around 941 TWh in 2020 to 1,222 TWh in 2030. The increase is analogous to the installed capacity and is mainly due to the

<sup>125</sup> For a detailed description of the calculation of production hydrographs of the intermittent RES technologies, see Appendix D.

expansion of onshore wind energy, offshore wind energy and photovoltaics. Even if there are no concrete RES targets for the European Union's electricity supply by 2030, the developments assumed in this study are in principle compatible with the EU target of increasing the share of renewable energy sources in energy consumption to at least 27 %.<sup>126</sup>

## **4.4 Development of flexibility options**

In the electricity market model, various flexibility options are taken into account, in addition to the different generation plants (conventional, CHP, renewable). In addition to the illustration of partly flexible "new consumers" (see Section 4.5.3), these include on the generation side usable potentials of emergency power systems which are held in many consumer facilities to protect consumers who are particularly worthy of protection against local grid failures (see Section 4.4.1). As a flexibility option on the consumption side, we also take into account voluntary load reduction potentials in industry (see Section 4.4.2.).

### **4.4.1 Emergency power systems**

Emergency power systems (EPS), which are used for emergency power supply during (local) supply interruptions, usually consist of an engine powered by diesel or natural gas and a generator. In the event of a (local) supply disruption (e.g. due to the failure of a network resource), essential infrastructure facilities or processes where a power failure would cause significant material or immaterial damage, are

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<sup>126</sup> The European Commission's "EUCO 27" and "EU Primes REF 2016" studies have developed country-specific development paths for renewable energies in the electricity supply sector that ensure that the EU target of increasing the share of renewable energy sources in energy consumption to at least 27 % is achieved. The expansion of renewables assumed in the present study for the European countries under consideration is within the range of these two studies of the European Commission with regard to the generation volumes of renewable energies in the electricity supply.

safely supplied with the help of such EPS until supply from the power grid is restored.

In addition, EPS can be used at short notice in the context of marketing on balancing power markets and to cover peak loads on the electricity market without interfering with their primary purpose of use. In the event of a local supply interruption, they can maintain the supply of their island grid in emergency power operation until the supply from the power grid is restored.<sup>127</sup>

Already in the "Leitstudie Strommarkt" from 2015 (Lead Study I), we estimated the economically viable installed capacity in EPS in Germany as ranging between 3.8 GW and 5.2 GW.<sup>128</sup> In our opinion, these potentials represent a conservative estimate of the actual potential, since some areas in which NEA are used were not taken into account and only partial surveys were possible for other areas. Against this background, the estimate of a total installed capacity of stationary EPS in the order of 5 to 10 GW in Germany appears plausible on the basis of an extrapolation.

In Germany, we are assuming an economically exploitable potential of 4.5 GW as part of the conservative analyses.

### Assumptions on the economically exploitable potential in other European countries

For the countries included in the analyses, we scale the economically exploitable potential assumed for Germany by the ratio of electricity consumption in the tertiary sector in the respective country to German electricity consumption in the tertiary sector. For example, we are deriving an economically exploitable potential

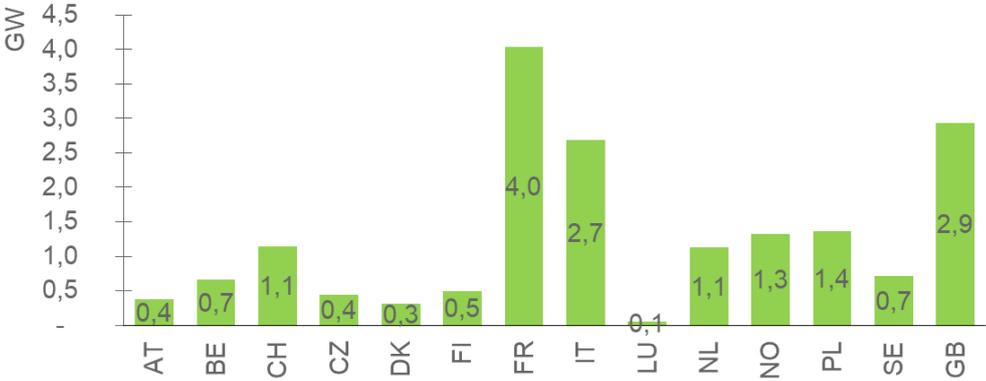
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<sup>127</sup> Any obligations entered into on the electricity or balancing energy markets cannot be met anyway in the event of a supply disruption.

<sup>128</sup> For a more detailed description of the potential analysis see r2b energy consulting (2014) and (2015b).

of just under 3 GW for the UK. A comparison with estimates from relevant literature confirms our estimate: Two studies in which the EPS potential in the UK was estimated show an economically exploitable potential of 1 to 4 GW or 3 GW in 2011 and an increase to 5 GW in 2020.<sup>129,130</sup> The following diagram provides an overview of the assumptions on the economically exploitable potentials in the countries abroad considered. In total, across all countries considered (excluding Germany), the exploitable capacity to EPS amounts to 17.7 GW.

**FIGURE 4-11: ECONOMICALLY EXPLOITABLE EPS POTENTIAL IN 2020 IN FOREIGN COUNTRIES TAKEN INTO ACCOUNT**



Sources: Own research and assumptions.

**Cost parameterization of emergency power systems**

We have assumed the following variable and fixed operating costs as well as development costs for EPS:

- **Variable operating costs:** Starting point is the price of light heating oil with an assumed EPS efficiency of 30 % and a surcharge of 50 % for start-up and shut-down costs.

<sup>129</sup> See Frontier Economics (2015): 1-4 GW and LSE et al. (2011): 3 GW.

<sup>130</sup> In Frontier Economics (2015) the total potential for the UK is estimated at 5 to 20 GW, of which approx. 20 % (1-4 GW) is assumed to be economically viable.

- Fixed annual operating costs: 5,000 € p.a. per MW<sup>131</sup>
- Development costs: 20.000 € per MW<sup>132</sup>

#### 4.4.2 Voluntary load reduction in industry

The strongly increasing shares of electricity generation from intermittent RES not only put the supply side, i.e. the conventional generation system, under pressure to adapt, but also stimulate the flexibilisation of demand. For the efficient integration of renewable energies into the market and from the business perspective of companies, increasing demand flexibility based on market mechanisms is a sensible option for increasing competitiveness and being able to react to potential price peaks or hedge their cost risks.

In previous work for the Federal Environment Agency (UBA)<sup>133</sup> and the Federal Ministry of Economics and Energy (BMWi), particularly in the “Leitstudie Strom”<sup>134</sup>, we have intensively investigated load management potentials in the form of voluntary load reduction in industry for Germany and Europe. We used a combination of a *bottom-up* and a *top-down* approach. Within the framework of the *bottom-up* analyses, we have used available literature and own analyses to examine in detail the potential of individual processes in the most important energy-intensive sectors of the economy to avoid load losses. We have taken into account both technical and economic factors that influence or limit the fundamental technical feasibility and development of load reduction potentials in the industries.

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<sup>131</sup> This assumption does not correspond to our *best guess*, which we have developed on the basis of information from discussions with marketers of EPS. In the reference scenario, we have applied higher and thus more conservative fixed annual operating costs in coordination with the BMWi. In our *best-guess* cost assumptions, whose influence on the results of the endogenous scenario and the SoS analyses we have examined in a sensitivity, the fixed annual operating costs amount to € 3,000 per MW. See also section 6.1.

<sup>132</sup> Derived on the basis of information from discussions with marketers of EPS. These are, for example, costs for the remote controllability and / or for upgrades to ensure permissible network parallel operation.

<sup>133</sup> r2b energy consulting (unpublished), power plant park and climate protection 2030.

<sup>134</sup> r2b energy consulting (2014).

Subsequently, we combined the results in a conservative manner with results of extensive *top-down* analyses based on public statistics for all branches of the manufacturing industry in Germany and Europe. Within the framework of the *top-down* analyses, data on electricity consumption in individual economic sectors and their cost structures in particular were examined in detail.<sup>135</sup>

### Cost-potential curves for load reduction in industry

Our approach of combining the advantages of *bottom-up* and *top-down* analyses enables us to derive well-founded estimates of both the technical and economic potential and the costs of voluntary load reduction in industry.

On the cost side, the short-term costs of retrieving the potential, play a decisive role in voluntary industrial load reduction. They indicate the electricity price on the *day-ahead* wholesale market above which operators of industrial production plants have an economic incentive to reduce their electricity purchases. If they have already hedged against price peaks on the wholesale market on futures markets, they can even generate revenue by reducing their electricity purchases and selling the electricity they have already procured on the day ahead market or intraday markets.

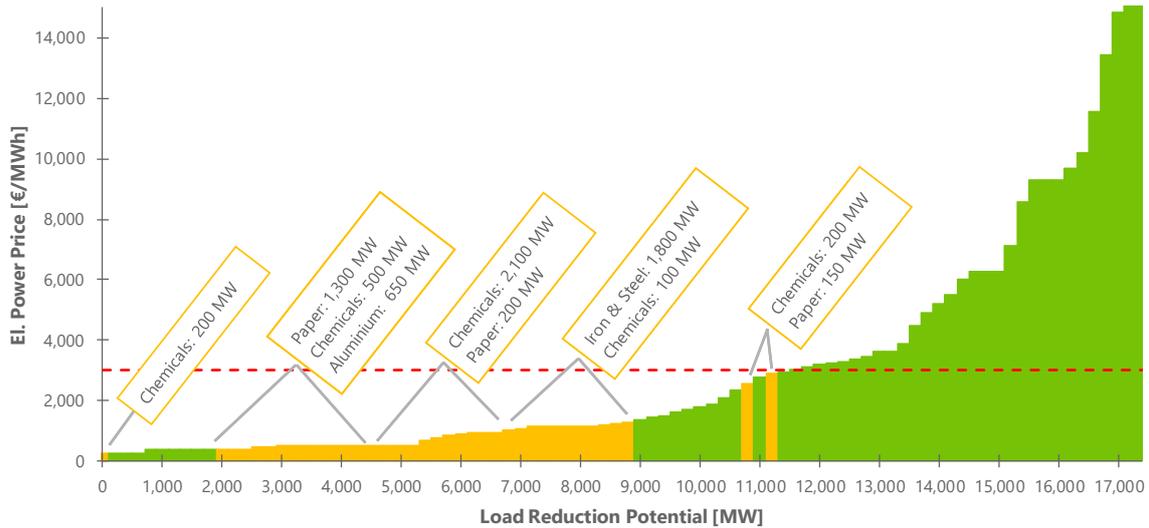
These core results of our analyses can be presented in the form of so-called cost-potential curves for load reduction. Cost-potential curves show which quantitative potentials are assumed to be technically available or economically exploitable at a certain point in time (X-axis) and at which variable activation costs they offer respective load reductions on the electricity market (*day ahead*) (Y-axis). Figure 4-12 shows the cost-potential curve for the technically available load reduction potential in German industry. Highlighted are the potentials of the most important energy-intensive sectors of the economy, for which detailed *bottom-up*

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<sup>135</sup> Economic sectors up to 4-digit level of the WZ-2008 (NACE) classification were examined.

analyses were carried out. The red line represents the upper price limit of the *day-ahead* hourly auction at EPEX Spot.

FIGURE 4-12: COST-POTENTIAL CURVE OF TECHNICALLY AVAILABLE LOAD REDUCTION POTENTIALS IN GERMAN INDUSTRY



Sources: Own presentation based on r2b energy consulting (2014).

The most favourable technically available potentials (e.g. for individual processes in the chemical industry) can therefore be retrieved at costs from approx. 270 € per MWh. Up to an electricity price of 400 € per MWh, the sum of the technically available load reduction potential is approx. 1 GW. Up to €1,000 per MWh, the total potential load reduction is just under 6 GW and at €3,000 per MWh (upper price limit of the *day-ahead* hourly auction) around 11 GW.<sup>136</sup> We take into account the technically available potentials in the model calculations up to an electricity price of € 10,000 per MWh, which corresponds to the technical upper price limit of *the intraday market*. The technically available potentials up to this upper

<sup>136</sup> The values stated refer to statistical evaluations of public statistics for all sectors of the manufacturing industry for the base year 2011, on which the quantitative analyses for deriving the technical load reduction potentials are based.

price limit amount to around 16 GW and vary over time with the development of electricity consumption in the industries considered.

We assume that the technically available potentials can be fully exploited economically by 2030. As a development path of the share of economically exploitable potentials in the technically available potentials by 2030, we take 33 % in 2018, 50 % in 2020, 80 % in 2023 and 90 % from 2025.<sup>137</sup> We assume that favourable potentials will be tapped more quickly than expensive ones due to the economic incentives.

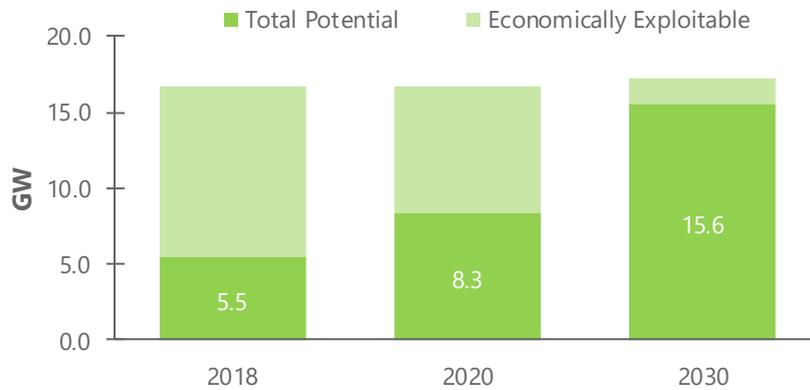
In the context of this project we have adjusted both the technically available and the economically exploitable potentials of the individual economic sectors for the years under review to the respective forecasted annual consumption of the industries<sup>138</sup> over the course of time. This means that the load reduction potential increases or decreases on an annual basis with the total demand of a branch of industry. As a result, we assume that the electricity market model can economically exploit the total potential in the Figure 4-13 framework of the simulation calculations.

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<sup>137</sup> These are the maximum shares of the technically available potentials that can be tapped in the electricity market model within the framework of simulation calculations for economic reasons.

<sup>138</sup> For the derivation of the electricity demands see section 4.5.

FIGURE 4-13: ECONOMICALLY EXPLOITABLE LOAD REDUCTION POTENTIALS OF INDUSTRY IN GERMANY



Sources: Own representation.

In addition to our own analyses of the potential of voluntary load reduction in industry, we also evaluated the *monitoring of the contribution of load management to supply security* carried out by the Federal Network Agency in cooperation with the BMWi as part of this project. As part of this monitoring in accordance with Section 51a EnWG, all companies which in the past calendar years had a total electricity consumption of at least 50 gigawatt hours (GWh) at least once a year were asked about their load management potential and possible barriers.

The results of the evaluation show that extensive potential for voluntary, market-based load reduction by industry has been tapped but is still unused. The developed but unused potential of flexible business locations amounts to approx. 2.5 GW, depending on the survey year considered.<sup>139</sup> In addition, we have estimated those potentials that have not yet been tapped. According to our estimates, the

<sup>139</sup> This potential is still untapped, as the current wholesale prices on the electricity market do not encourage use.

untapped potential of still inflexible company locations<sup>140</sup> amounts to approx. 4.5 GW, depending on the survey year considered. By determining the degree of coverage of the surveyed company locations, we have extrapolated the determined potentials approximately to the entire industry<sup>141</sup>. The extrapolation to all sectors increases the tapped but still unused potential of flexible company locations from around 2.5 GW (reliably tapped potential) to approx. 4.5 GW (probably tapped potential). In addition, the estimate of the untapped potential of still inflexible business locations is increased from about 4.5 GW to 15.5 GW in the extrapolation.

### Hourly varying load reduction potentials

The availability of the developed potentials varies on an hourly basis. The availability of load reduction potentials during the year on an hourly basis depends on the hourly load structures of the respective industry<sup>142</sup> in which the load reduction potentials are located. They therefore vary in our modelling proportionally with the hourly load of the respective industry. The higher the load of an industry branch in an hour, the higher the corresponding load reduction potential usable in the model.

### Development and fixed costs of load reduction potentials

In addition to the variable costs for short-term activations of potentials (voluntary load reduction), our modelling also takes into account one-off costs for tapping potential load reductions (e.g. by installing control technology and establishing market access) as well as annual fixed costs. The latter consist on the one hand of fundamental fixed costs of maintaining availability and on the other hand of an

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<sup>140</sup> Inflexible company locations are those locations for which it has been stated that they are currently not load flexible with respect to the wholesale electricity price.

<sup>141</sup> Here we have assumed structurally identical load management potentials for the company (locations) not included in the data query.

<sup>142</sup> See development hourly demand in section 4.5.2

additional minimum profit expectation of the plant owners as a condition for the provision.

For the investigations in this project, we distinguish between two alternative sets of assumptions. In our *best-guess* assumptions, we assume, as in previous publications, that the development of load reduction potentials is associated largely with no or only very low development and fixed costs. In doing so, we rely on the fact that load management is already widespread in industry (justified by other incentive systems such as the network charging system). Developments in electricity prices on the *day-ahead* market towards more fluctuation and peak pricing in single hours will most probably lead to (existing and new) load management potentials being used on the *day-ahead* market *for* economic reasons and without extensive additional costs. In our basic assumptions, we therefore apply low annual fixed costs of €1,000 per MWa, which consist of fundamental costs for the provision of potential (annual provision costs). Additional profit expectations or development costs are not included in our *best-guess* assumptions. We have considered our *best-guess* assumptions for the development of one scenario in terms of a sensitivity (see Section 6.1).

In agreement with the BMWi, we have developed **more conservative assumptions in the reference scenario** than our basic assumptions in the area of flexibility options (voluntary load reduction by industry and grid replacement plants) where we apply annual fixed costs of € 8,000 per MWa for voluntary load reduction.<sup>143</sup>

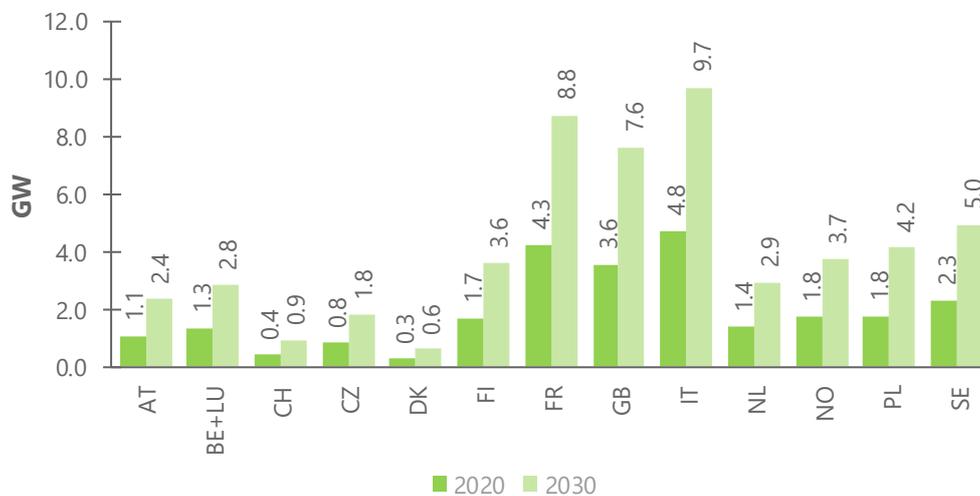
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<sup>143</sup> These consist of annualised one-off development costs of around € 10,000 / MW with a three-year depreciation period and an interest rate of 7.5 % as well as annual fundamental provision costs and additional profit expectations of € 4,000 / MWa in total.

## Potentials in Europe

Our assumptions for the European neighbouring countries are largely based on a transfer of our analyses for the economic sectors in Germany to the neighbouring countries by scaling. To this end, we compared the load reduction potentials of the economic sectors in Germany with their annual electricity consumption and then transferred the proportional potentials to the economic sectors there on the basis of the consumption data of the neighbouring countries.<sup>144</sup> The assumptions used in our quantitative analyses on economically exploitable load reduction potentials in the most important European neighbouring countries for the years 2020 and 2030 can be seen in the Figure 4-14. In total, across all the countries considered (excluding Germany), the capacity available for voluntary load reduction amounts to 25.5 GW in 2020 and 54.1 GW in 2030.

FIGURE 4-14: ECONOMICALLY EXPLOITABLE LOAD REDUCTION POTENTIALS IN 2020 AND 2030 IN THE COUNTRIES CONSIDERED (EXCLUDING GERMANY)



Sources: Own research and assumptions.

<sup>144</sup> A detailed analysis of individual economic sectors of the neighbouring countries on the basis of *bottom-up* analyses was not planned within the framework of the project.

## 4.5 Development of electricity demand

In addition to a realistic representation of the supply options on the generation side, a realistic estimation of the development of electricity demand is important for the analysis. Based on a forecast of the development of the annual electricity consumption differentiated by application areas (see Section 4.5.1), we derive the development of the largely inflexible hourly electricity demand (see Section 4.5.2). In Section 4.5.3 we then outline the assumptions we have made regarding the development of electricity demand by so-called *new consumers*. New consumers within the scope of this study are the mayor sector coupling technologies for the heat and transport sectors, whose demand for electricity is partly flexible under certain constraints. This includes electric heat pumps, electric mobility and trolley trucks.

### 4.5.1 Development of electricity consumption

#### Methodical approach

The FORECAST bottom-up model is used for the analysis of future sectoral electricity demand. FORECAST is a techno-economic simulation model that exploratively describes the annual demand for energy and electricity in Germany and neighbouring European countries with high technological granularity (Fraunhofer ISI, 2018). The model has a modular structure and is structured according to the sectors of households, tertiary, industry and transport in order to map the heterogeneity of the individual sectors accordingly. In the industrial sector for example, processes are the main focus, in the household sector there are individual applications. The main current based sector coupling options of this study are heat pumps, electromobility in passenger transport and trolleytrucks.

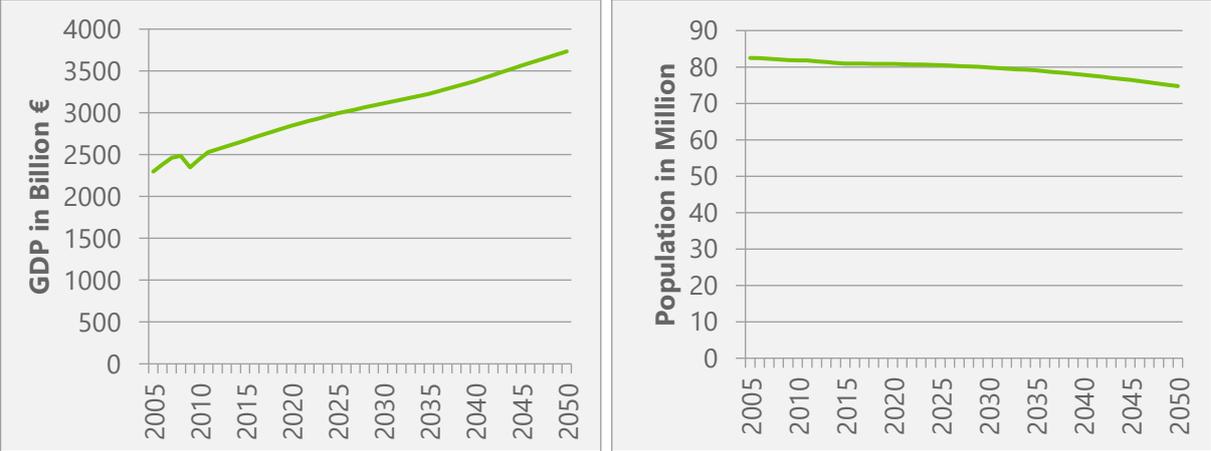
With regard to the methodological design, FORECAST is characterised by extensive consideration of structural and technological change. Structural change is illustrated by exogenous framework parameters (e.g. sectoral gross value added),

while technological change is described by epidemic and discrete choice approaches. Despite a focus on electricity-based applications, non-electricity-based energy sources are also modeled in order to take into account the competition between alternative technological options. This is particularly important for process and space heating. A detailed description of the modelling approach can be found in Appendix C.

**Frame parameters**

The input data for the techno-economic demand model can be divided into cross-sector and sector-specific drivers. Cross-sector input data are population development and economic development (gross domestic product and sectoral gross value added). Figure 4-15 the development of the population and gross domestic product taken from the EU Reference Scenario 2016 (EU 2017). This is based on an average annual economic growth of 1.8 % and a decline in the population to below 75 million in 2050. Further cross-sector input data are energy source prices and CO<sub>2</sub> prices, which are discussed in Section 4.6.2.

**FIGURE 4-15: CROSS-SECTORAL DRIVERS OF ENERGY DEMAND (POPULATION AND GROSS DOMESTIC PRODUCT IN GERMANY) FOR THE PERIOD 2005 TO 2050 (EU 2017).**



Sources: EU (2017)

The cross-sectoral data are subsequently broken down into the four demand sectors (households, tertiary, industry and transport), supplemented by assumptions on technological development.

In the industrial sector, the central framework data is the production quantity in tonnes per product, which is derived from the sectoral value added. In principle, moderate economic growth is assumed, with the energy-intensive industries growing less strongly. Further sector-specific input data for the modelling of the industrial sector are the number of employees per sub-sector. The energy policy assumptions of the industrial sector include the further development of existing instruments for energy efficiency measures, no carbon capture and storage (CCS) and the exploitation of material efficiency potentials.

For the household sector, the development of households, the number of buildings and the heated building areas are the relevant influencing factors. The number of households or buildings is derived from the size of the population and a trend towards fewer people per household. Furthermore, it is assumed that the equipment rates of ICT applications will increase. For household appliances, the minimum efficiency standards will be further tightened and new efficiency classes introduced. The main influence on the heat demand in buildings is due to renovation measures. For this purpose, an increase in the renovation rate to 1.8 % is specified, while the depth of renovation is determined on the basis of the model. A tightening of the guidelines (EnEV and EEWärmeG) and further promotion of renovation measures (MAP and KfW programme) is assumed.

In the tertiary sector, economic development is described by gross value added and the number of persons employed in the individual sub-sectors. According to the empirical development, a stronger economic growth is also assumed for the projection than for the manufacturing industry. The main technological trend in the tertiary sector is increasing mechanisation and the increase in ICT-based power applications (e.g. servers). The heat demand is determined comparable to

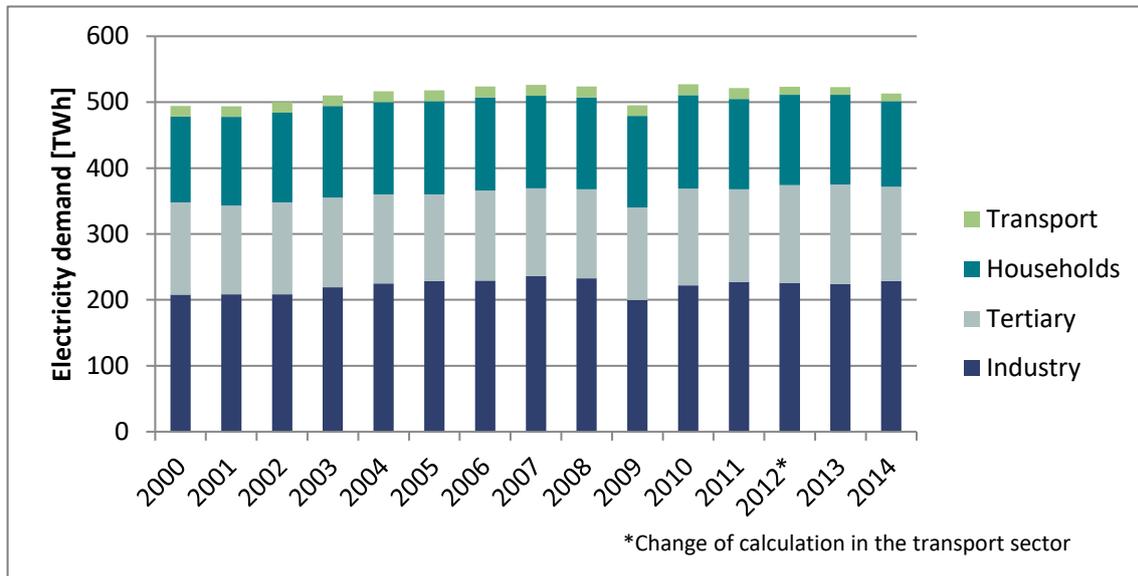
the household sector on the basis of a given renovation frequency and an endogenously determined renovation depth.

The development of electricity demand in the transport sector is mainly driven by the diffusion of electric vehicles in passenger and freight transport. It is assumed that the market shares of battery electric vehicles (BEV) and plug-in hybrids (PHEV) will increase significantly. In freight traffic, overhead contact lines will be built on the busiest stretches of motorways in Europe, which leads to the diffusion of hybrid overhead trolley trucks (HO trucks) in freight traffic. The utilisation of freight and passenger transport by rail is rising moderately, in line with the further electrification of new routes.

## Results

In order to be able to compare the future development with the initial situation, the development of electricity demand since 2000 is shown in Figure 4-16. The development shows a demand for electricity in the transport, household, GHD and industrial sectors that ranges between 494 TWh and 527 TWh in the period under review. The almost constant level is due to the fact that the demand increasing effect of the economic growth and the demand decreasing effect of the efficiency progress nearly balance each other out.

FIGURE 4-16: SECTORAL ELECTRICITY DEMAND IN GERMANY FOR THE PERIOD 2000-2014 (AGEB, 2017).



Sources: AGEB (2017)

For Germany, the statistics of the AG Energiebilanzen (AGEB 2017) and for the neighbouring countries of Eurostat (Eurostat 2017a) are used. The system limit always represents the demand in the sectors households, tertiary, industry and transport. The historical data of the energy balance are an essential part of the model calibration.

In the following, the cross-sector results of national electricity demand up to 2030 will be discussed first, followed by an outlook up to 2050, followed by an analysis of the main developments in the industrial, household, tertiary and transport sectors.

#### Power demand across sectors

The development of the annual electricity demand up to the year 2050 is shown in the Figure 4-17. In 2030, there will be a decline in electricity demand (- 5 % compared to 2015 / 502 TWh), which is essentially due to the efficiency improvements of traditional consumers (e.g. efficiency gains in industrial cross-sectional technologies). From 2030 there will be an increase in demand for electricity, driven by

the penetration of new technologies, particularly in the transport sector, and by heat pumps (+8% compared with 2015 / 571 TWh in 2050). This change in trend from 2030 onwards leads to a characteristic bathtub curve of aggregated electricity demand, which makes it clear that a simplified update for the years 2030 to 2050 is not appropriate.

FIGURE 4-17: SECTORAL ELECTRICITY DEMAND FOR THE PERIOD 2015 TO 2050 (OWN CALCULATION).



Sources: Own calculations.

In Table 4-4, the results are broken down by sector into classical applications and new applications for the reference period up to 2030. Heat pumps will only play a very minor role in industry until 2030, in contrast to residential and non-residential buildings. Demand in the transport sector will rise until 2030 due to the increasing number of electric cars and trolley trucks.

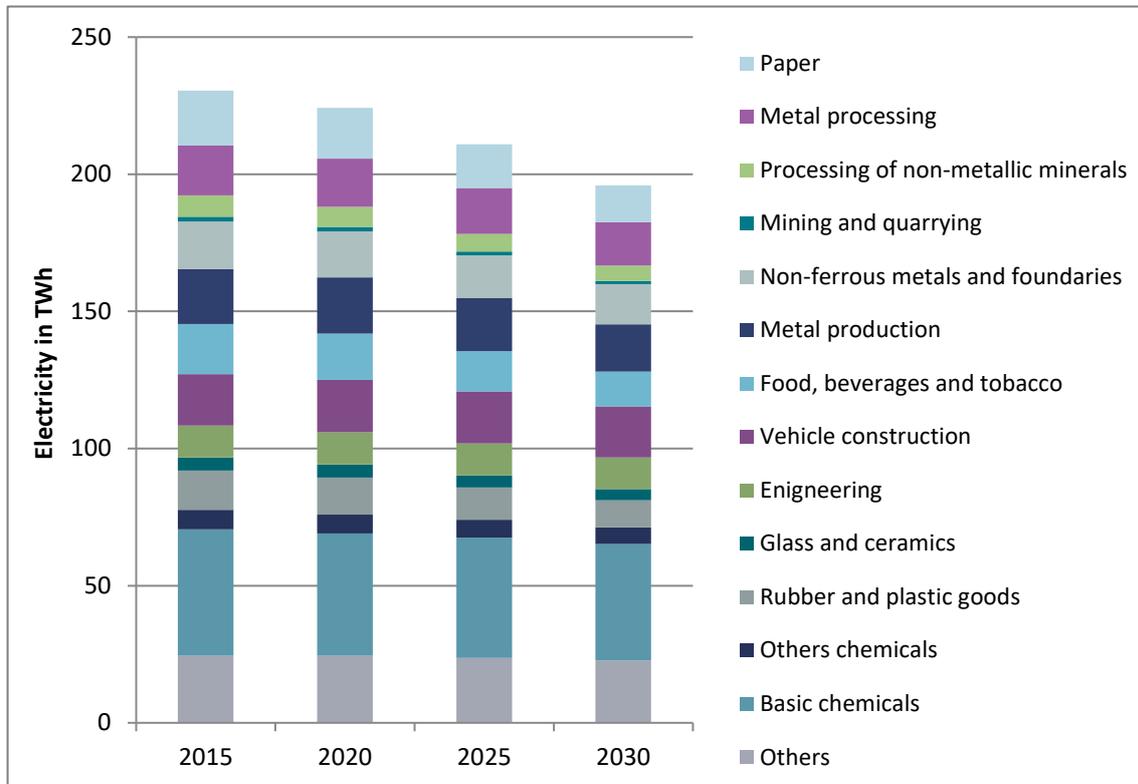
TABLE 4-4: SECTORAL ELECTRICITY DEMAND IN 2020 AND 2030, AS WELL AS BREAKDOWN INTO CLASSIC AND NEW APPLICATIONS (HEAT PUMPS AND ELECTRIC MOBILITY).

TWh	2020			2030		
	Total	Classic applications	New applications	Total	Classic applications	New applications
Households	128,5	116,0	12,5	117,9	101,7	16,2
Tertiary	158,5	154,2	4,3	160,2	153,8	6,4
Industry	224,2	224,2	0,0	195,9	195,9	0,0
Transport	12,1	11,3	0,8	27,7	11,0	16,7
<b>Total</b>	<b>523,3</b>	<b>505,8</b>	<b>17,6</b>	<b>501,6</b>	<b>462,4</b>	<b>39,3</b>

*Power demand: Industry*

Demand for electricity will fall continuously until 2030 (Figure 4-18). The main decline in demand for electricity is attributable to the progress made in the efficiency of motor-based cross-sectional technologies (e.g. pumps, compressed air). Substitution effects in process technologies towards current-based applications (e.g. electrical steel), on the other hand, only lead to a limited increase in demand for electricity. The use of heat pumps plays only a negligible role in the generation of space and process heat in the industrial sector. Overall, it can be seen that the electricity demand of the energy-intensive industries (e.g. steel, cement and paper production) is falling more sharply than the electricity demand of the non-energy-intensive industries (e.g. mechanical engineering and vehicle construction).

FIGURE 4-18: INDUSTRIAL ELECTRICITY DEMAND BY SUB-SECTOR FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION).

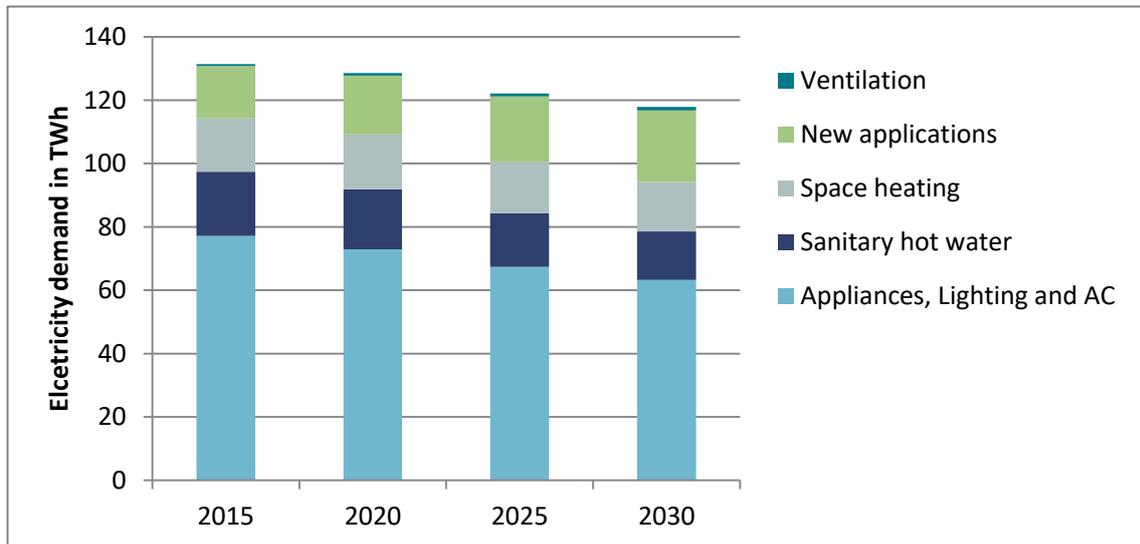


Sources: Own calculations.

#### Electricity demand: Households

The demand for electricity in the household sector will continuously decline until 2030. The largest share of the demand for electricity is due to large appliances and lighting (Figure 4-19). The already implemented and planned guidelines for minimum efficiency standards reduce their specific power consumption. Since appliances, especially white goods, are nearly in the area of market saturation, the absolute demand for electricity is directly reduced as a result. Applications such as electronic equipment and ICT applications lead to an increase in the sectoral demand for electricity due to an increase in equipment rates. The demand for electricity in the electricity-based generation of hot water and space heating will remain almost constant until 2030, as old night storage heaters and inefficient boilers will be phased out and heat pumps will achieve higher market shares.

FIGURE 4-19: ELECTRICITY DEMAND HOUSEHOLDS BY APPLICATION FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION).

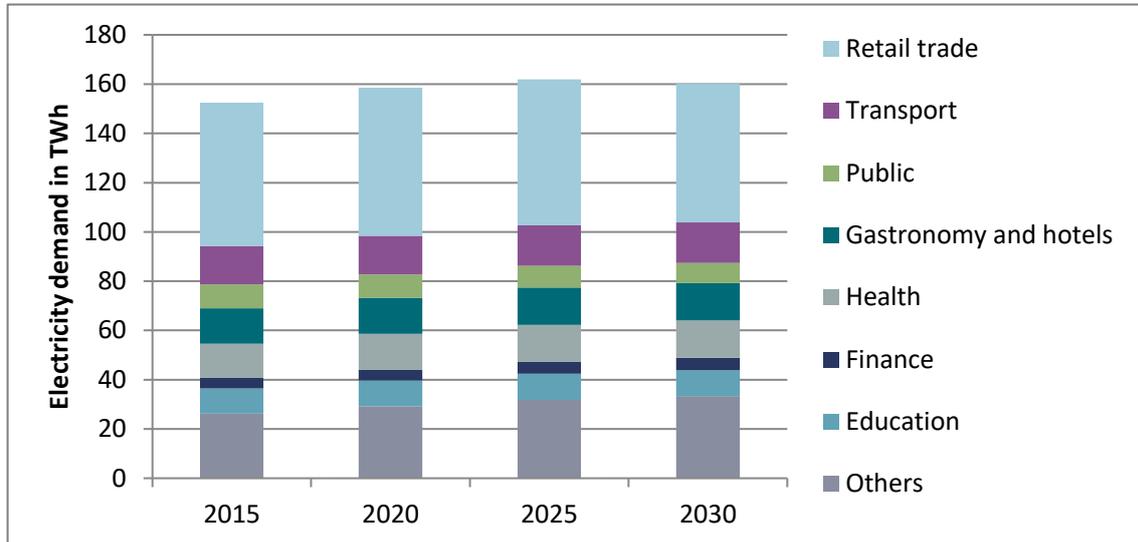


Sources: Own calculations.

*Electricity demand: tertiary sector (trade, commerce and services)*

In the tertiary sector there will be a rising trend in electricity demand until 2025, followed by a slight decline (Figure 4-20). The increase in the demand for electricity is due to an increasing trend towards mechanisation and the increasing equipping of non-residential buildings with ventilation or air-conditioning systems. On the other hand, efficiency gains in lighting in particular are leading to a contrary trend in electricity demand. The share of electricity-based room heating and hot water provision by heat pumps will be 6.4 TWh in 2030.

FIGURE 4-20: ELECTRICITY DEMAND GHD BY SECTOR FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION).

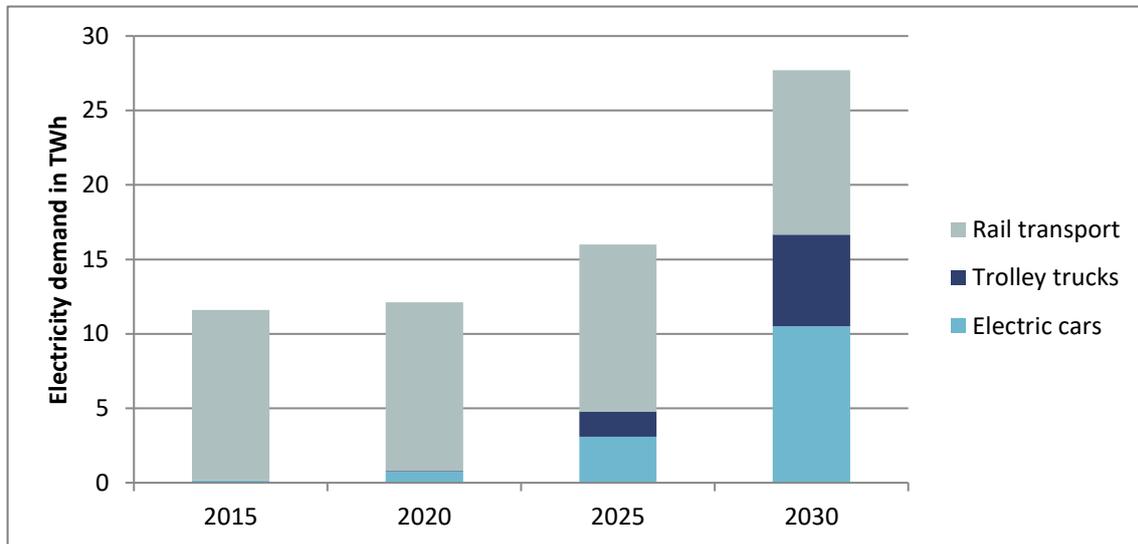


Sources: Own calculations.

#### Electricity demand Transport

The demand for electricity in transport consists of passenger and freight transport by road and rail. In rail transport, the increase in electrified transport capacity is compensated by efficiency gains, so that the demand for electricity is almost constant at 11 TWh. The market ramp-up of electric mobility for vehicles smaller than 3.5 t leads to an additional electricity demand of about 11 TWh in 2030. This corresponds to a stock of 4.4 million electric cars, with almost equal market shares of battery electric (BEV) and plug-in hybrid (PHEV) vehicles (Figure 4-18). In freight transport, trolley trucks lead to an increase in electricity demand of 6 TWh.

FIGURE 4-21: ELECTRICITY DEMAND TRANSPORT FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION).



Sources: Own calculations.

#### *Electricity demand in neighbouring countries*

In addition to the national analysis, an analysis of all EU states that exchange electricity with Germany is also required for the energy system analysis. The analysis of all *neighbouring countries* (as well as Italy, Great Britain, Scandinavia and the Iberian Peninsula) is carried out with the same technological granularity corresponding to the study of Germany (see Appendix C). In analogy to the analysis of Germany, the main European policies were taken into account in the modelling for all the countries considered. The following countries were considered:

- Austria, Belgium, Czech Republic, Denmark, Finland, France, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, United Kingdom.

The main socio-economic drivers of electricity demand are the development of gross domestic product and population growth. As can be seen from Table 4-4 largest increase in population by 2030 is expected for Belgium and Sweden, while Poland is expected to experience a population decline of around 1 million.

In relation to the gross domestic product per capita, an increase between 32% and 51% is assumed, especially for Poland, Spain and Portugal.

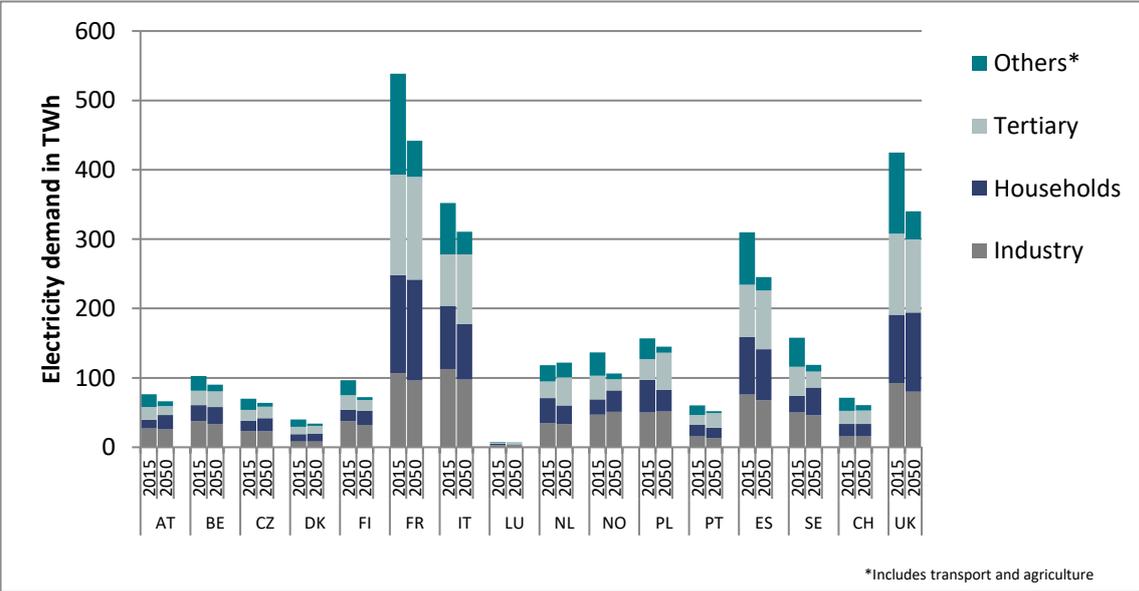
**TABLE 4-5: DEVELOPMENT OF THE DRIVERS POPULATION AND GROSS DOMESTIC PRODUCT IN EUROPEAN COUNTRIES BY 2030**

	POPULATION (IN MILLIONS)			GROSS DOMESTIC PRODUCT/CAPITA IN €2005		
	2015	2030	percentage change	2015	2030	percentage change
<b>BELGIUM</b>	11,2	12,7	14%	30,017	32,847	9%
<b>DENMARK</b>	5,7	6,1	7%	38,173	48,704	28%
<b>FINLAND</b>	5,5	5,9	7%	31,114	34,829	12%
<b>FRANCE</b>	66,5	70,7	6%	29,019	33,860	17%
<b>ITALY</b>	62,3	65,5	5%	22,037	25,224	14%
<b>LUXEMBOURG</b>	0,6	0,8	39%	65,629	71,482	9%
<b>NETHERLANDS</b>	16,9	17,6	4%	33,169	37,972	14%
<b>NORWAY</b>	5,1	5,8	13%	54,335	65,677	21%
<b>AUSTRIA</b>	8,6	9,3	8%	32,778	38,276	17%
<b>POLAND</b>	38,5	37,5	-3%	9,275	13,960	51%
<b>PORTUGAL</b>	10,5	9,9	-6%	14,343	18,981	32%
<b>SPAIN</b>	47,2	45,4	-4%	20,147	27,750	38%
<b>SWEDEN</b>	9,8	11,1	13%	38,423	46,443	21%
<b>SWITZERLAND</b>	8,1	8,8	8%	43,386	50,664	17%
<b>CZECH REPUBLIC</b>	10,6	10,8	2%	11,445	14,654	28%
<b>UNITED KINGDOM</b>	65,1	71,0	9%	33,334	37,523	13%

The results of the analysis are presented in aggregated form in Figure 4-22. In Germany, there will be an increase in electricity demand by 2050, driven mainly by electromobility and other power-based sector coupling technologies.

The sectoral shifts as well as savings through the exploitation of energy efficiency potentials and technology diffusion vary from country to country depending on the technological composition. In Northern European countries, electricity-based heating systems have a high market share, so that an increasing penetration of heat pumps leads to a reduction in electricity consumption for space heating. On average, these countries also have the highest population growth, which also has an increasing effect on demand. In the Eastern European countries, progress in efficiency and lower population growth can largely compensate for the above-average increase in equipment rates and electrification. The Central European countries are characterised by moderate economic growth, increasing efficiency and a moderate increase in the population, resulting in a moderate increase in electricity demand in relation to the other European regions.

**FIGURE 4-22: DEVELOPMENT OF SECTORAL ELECTRICITY DEMAND IN THE NEIGHBOURING COUNTRIES BETWEEN 2015 AND 2050**

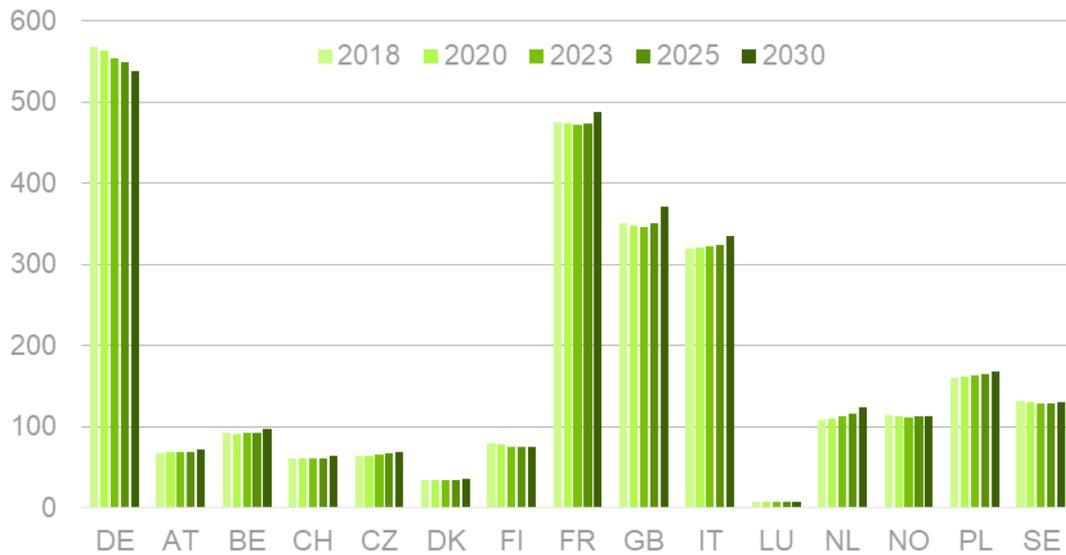


Sources: Own calculations.

For the model calculations for scenario generation (using the European electricity market model of r2b energy consulting GmbH), we have supplemented the electricity demand presented here with grid losses (transmission and distribution grid)

and the consumption of the other transformation area (excluding PtH in district heating). The resulting demand for electricity is shown in Figure 4-23.

FIGURE 4-23: DEVELOPMENT OF ELECTRICITY DEMAND PLUS GRID LOSSES AND PLUS CONSUMPTION IN THE OTHER TRANSFORMATION SECTORS.



Source: Own representation.

#### 4.5.2 Development of hourly demand

In addition to the development of electricity demand on an annual basis, the hourly load curve during the year also plays an important role in the future requirements of the European electricity supply system.<sup>145</sup> Not only the total load of a country is relevant, but also developments in individual sectors and applications. Above all, it is necessary to consider consumption structures that are likely to change significantly in the future, as well as applications that can be made increasingly flexible in the future. In addition to the flexibility options described in Section 4.4.2 whose potentials vary with the hourly load, these primarily include applications with storage options such as electromobility and heat pumps.<sup>146</sup>

<sup>145</sup> A detailed description of our model for generating hourly load structures can be found in Appendix E.

<sup>146</sup> For the modelling of new consumers, see separate presentations in the following section 4.5.3.

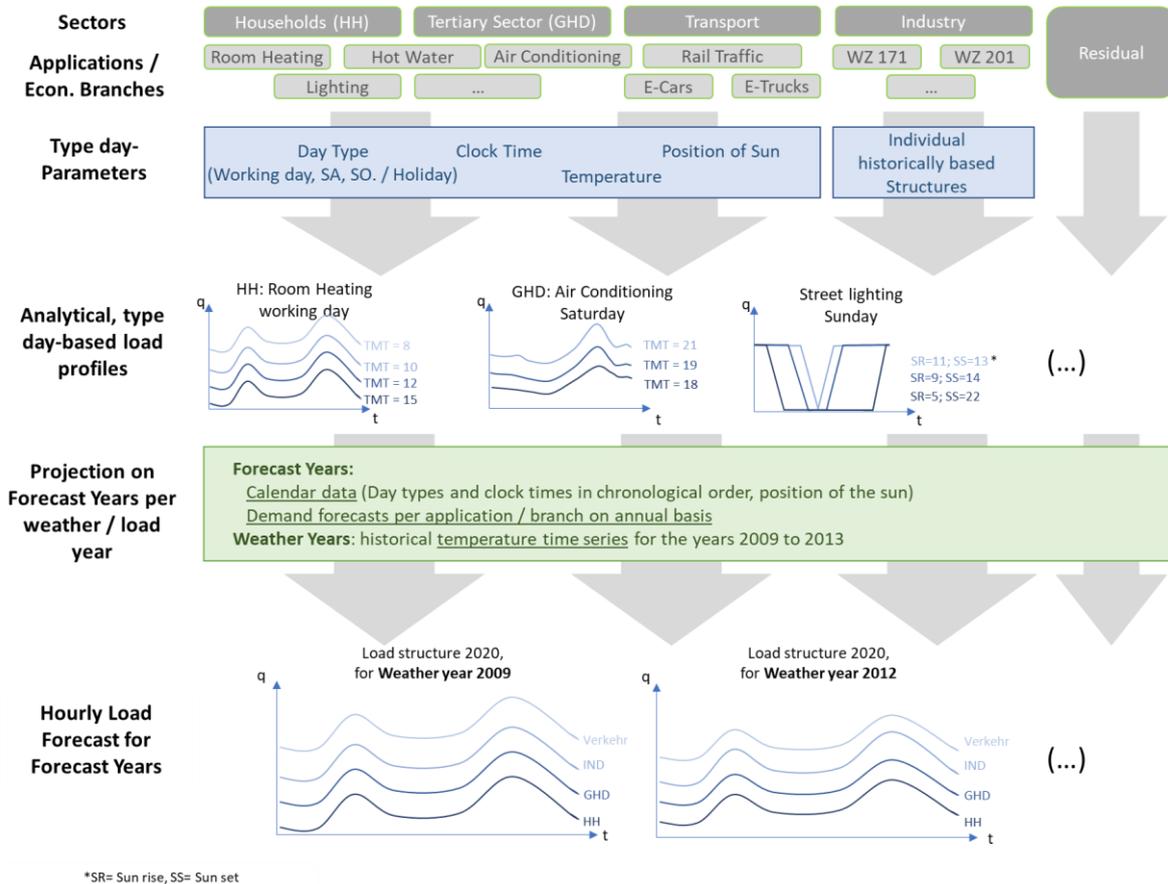
In order to be able to take the current consumption patterns of electrical energy and their future developments into account (as far as possible) in our electricity market modelling, we use a model specially developed for this purpose to generate typical hourly load forecasts (see model description in Appendix E). We follow a *bottom-up* approach with which we generate load structures for individual consumption applications and derive a residual structure for other power consumption in total. In addition to historical consumption data, a number of fundamental influencing factors for power consumption are taken into account in the analytical creation of application-specific load structures. These are, in particular, weather and temperature data as well as clock times and calendar data. In addition, specific assumptions are used for the future development of individual applications, such as the increasing air conditioning of residential and business premises or the rise in electric mobility in various forms.

Within the *bottom-up* approach, hourly load profiles per country, weather year and forecast year are generated for a number of selected applications and economic sectors from the household, tertiary, industry and transport sectors as well as for a residual. The load structures for the individual applications are initially created as type-day-based profiles for each weather year. These are typical consumption patterns depending on the day of the week, the time of day and/or the temperature at which electricity is drawn for an application.<sup>147</sup> The typical day-based load profiles are then rolled out for the forecast years. A schematic representation of the procedure is given in the Figure 4-24.

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<sup>147</sup> Type-day-based load structures are load structures that describe the load as a function of the combination of typ-day parameters (influencing factors). Type-day parameters are, for example, the weekday, the time or the temperature. Ultimately, the type-day parameter combination determines the user behaviour and thus the power consumption of a final energy-consuming application.

FIGURE 4-24: PROCEDURE IN THE MODEL FOR GENERATING HOURLY LOAD FORECASTS BASED ON ANALYTICAL CONSUMPTION PROFILES (SCHEMATIC REPRESENTATION)



Source: Own representation.

The assumptions on the annual final energy consumption of the sectors, applications and economic sectors depicted for the base year 2011 as well as their developments in the forecast period are given in the model and originate in the present project from Fraunhofer ISI analyses (see Section 4.5.1).

For the *new consumers* (i.e. heat pumps and various forms of electric mobility), the demand structures created in the load structure model described are not fixed, but form the basis for optimisation within the framework of electricity market modelling, as explained below.

### 4.5.3 Modelling the load of new consumers

*New consumers* as defined in this study are the central technologies to integrate electricity in the heating and transport sector, i.e. electric heat pumps, electric vehicles in passenger and freight traffic with light commercial vehicles as well as electrified heavy-duty trucks using overhead lines. The electricity demand of these consumers is partly flexible under certain constraints. In the analysis, we have therefore taken certain load shift potentials into account. In this sub-section, we will explain our modelling approach regarding the hourly demand structure of electric heat pumps, electric vehicles and trucks using overhead lines (trolley trucks) in detail.

Our modelling approach for demand structures from passenger and freight transport with light commercial vehicles is based on driving profiles derived from relevant studies, which include several profiles on different weekdays. We consider several types of vehicle users, charging locations (at home, at the workplace, public normal charging, public fast charging) and different capacities at different charging stations.<sup>148</sup>

For passenger cars and light commercial vehicles, we have assumed that vehicles can be charged in three different modes: *immediately*, *reduced* and *smart*. Immediately charging means that vehicles are immediately connected to the grid after parking and charged with the maximum power available at the charging station. With reduced charging, the vehicle is charged with reduced power over the expected parking duration, so that the battery will be completely recharged as soon as the electric vehicle shall be used again. In both immediately and reduced charging mode, the electricity market model is given an hourly, non-modifiable consumption profile. With smart charging, the charging process is optimized during the parking duration according to wholesale prices on the electricity market. As

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<sup>148</sup> See, among others, Gnann et al. (2015), Hacker et al. (2011), Hacker et al. (2014), Morrissey et al. (2016), NPE (2017), Schröder and Traber (2012).

input parameters for the electricity market model, hourly power consumption profiles of the moving electric vehicles as well as the aggregated charging capacity and storage volume of the parked vehicles are specified. According to the development of wholesale prices on the electricity market, charging is then optimised so that the aggregated storage volume is never "depleted" or "overflows" and the amount of electricity charged in one hour is limited to the aggregated charging capacity available to the parked vehicles.

The shares of these three charging strategies in the total volume of charging processes vary over time: while the majority of charging processes are assumed to be immediately in the short term, the share of reduced and smart charging increases in the medium and long term (see Table 4-6). This development is based on the assumption of an increasing share of electric vehicles in the existing stock of vehicles and hence a growing electricity consumption from electric mobility. In light of likely evolving challenges for the distribution networks, it can be assumed that this demand will increasingly be managed by grid operators in accordance with market mechanisms.

TABLE 4-6: ASSUMPTIONS ON THE DEVELOPMENT OF THE SHARES OF THE THREE CHARGING STRATEGIES UP TO 2030.

Type	Charging mode	2018	2020	2030
Passenger cars (private)	immediatly	100%	70%	35%
	reduced	0%	20%	40%
	smart	0%	10%	25%
Passenger cars (commercial) and light commercial vehicles	immediatly	100%	60%	30%
	reduced	0%	40%	70%
	smart	0%	0%	0%

Source: Own assumptions.

It is assumed that trolley trucks will also be used from the year 2023 on. We have assumed that these are hybrid vehicles which, in addition to an electric drive, also use a diesel engine and can therefore run independently of an overhead line for a longer period of time. Based on literature references to traffic volume data, a structured consumption profile was derived. Trolley trucks can either "connect"

to the grid and use electricity to “follow” this profile, or they can switch to diesel operation at high electricity prices<sup>149</sup>. We do not model the possibility of feeding electricity back into the public grid from electric vehicles and trolley trucks.

We have also modelled the electricity demand of electric heat pumps taking into account a load shift potential. First of all, we have derived assumptions on consumption behaviour depending on the outside temperature and the choice of technology (also depending on the outside temperature in the region of use). Building on this, we model the possibility of a consumption shift of up to three hours - analogous to the modelling of smart charging of electric vehicles. This approach maps approximately the thermic inertia the cooling and heating of a building as well as the combined use of heat pumps with a storage system.

## **4.6 Technical and economic characteristics of conventional power plants**

In order to forecast the development of the power supply system as realistically as possible based on models, different parameters have to be defined in the area of conventional power plants. These include economic parameters and technical parameters. The economic parameters consist of investment costs, fixed and other variable operating costs (see Section 4.6.1 and variable operating costs for fuel use and CO<sub>2</sub> emission allowances (see Section 4.6.2)). In addition to the installed capacity, the required technical parameters are electrical efficiencies, duration of start-up and shut-down processes, minimum partial load conditions, load gradients and planned and unplanned unavailability of thermal power plants and pumped storage power plants, as these are not operational throughout the year due to inspections or technical failures. Section 4.6.3 we show the assumptions on the planned and unplanned non-availability of thermal power plants and

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<sup>149</sup> For the replacement costs of the diesel engine, the assumed price development of light heating oil was used, taking into account taxes and other regulated price components incurred as well as their differences in the various countries considered.

pumped storage power plants. In the case of CHP plants, fuel utilisation rates, power to heat ratios and power loss index in particular are also added.

#### 4.6.1 Investment and operating costs

In a dynamic modelling approach in which investment / divestment decisions are made model endogenously, investment costs and fixed and other variable operating costs are central model parameters in addition to the variable costs for fuel input and emission allowances.

As part of the simulation calculations, we carried out the cost parameterization for conventional power plants shown in Table 4-7. On the one hand, we can draw on comprehensive expert knowledge and experience from a large number of projects. On the other hand, we conducted extensive literature researches and exchanged information with other BMWi contractors and other experts.

TABLE 4-7: ASSUMPTIONS ON COSTS OF NEW CONVENTIONAL POWER PLANTS

Parameter	Einheit	CCGT	OCGT	Gas engine Power plant	Lignite	Hard coal
Electrical output (net)	MW <sub>el</sub>	> 400	> 100	> 20	> 800	> 700
Investment costs (Total costs excl. interest during construction)	€ <sub>2016</sub> / kW <sub>el</sub>	750	410	390	1.700	1.450
Fixed operating costs	€ <sub>2016</sub> / kW <sub>el</sub> p.a.	20	9	6	45	42
Other variable operating costs	€ <sub>2016</sub> / MWh <sub>el</sub>	1,5	1,0	0,1	1,7	1,3

Sources: Own assumptions and calculations based on BEIS (2016), LeighFisher (2016), Parsons Brinckerhoff (2013) and others.

Power plants based on lignite have the highest specific investment costs and fixed operating costs, closely followed by hard coal. With specific investment costs of 750 €<sub>2016</sub> per kW<sub>el</sub>, combined cycle power plants are well below coal-fired power plants. Engine power plants and open gas turbines have the lowest specific investment costs.

## 4.6.2 Fuel and CO<sub>2</sub> prices

Fuel costs and the cost of CO<sub>2</sub> emission allowances are the main drivers for the variable costs of generating electricity in conventional power plants. The level of fuel costs is determined not only by the efficiency of the power plants but also by the prices of the used fuels, i.e. the primary energy sources lignite, hard coal, natural gas and mineral oil products.

In Europe, the prices for crude oil, natural gas and hard coal depend on the global energy markets, as these energy sources are predominantly imported. In the case of natural gas in particular, however, it must be kept in mind that despite global trade and considerable interdependencies in price developments, systematic price differences can still be expected in the various regions of the world. High transport costs (LNG) and high costs for the necessary gas grid infrastructure obstruct a uniform world market price (also in the longer term), even more so if production costs differ. For Germany, the cross-border price for natural gas in Europe is to be regarded as the relevant indicator.

In our assumptions on the future development of prices for **crude oil**, **natural gas** and **hard coal** in the medium and long term (from 2025), this study is based on the current *New Policies Scenario of the World Energy Outlook (WEO 2017)* of the *International Energy Agency (IEA<sup>150</sup>)*. For the short term (until 2023) we use current forward market quotations for natural gas, crude oil and hard coal on the relevant trading platforms.<sup>151</sup>

The *New Policies Scenario* represents the reference scenario in the IEA's WEO 2017 and, in relevant areas, reflects the developments that were considered most likely when the study was prepared. In the scenario, the authors take into account all

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<sup>150</sup> See IEA (2017).

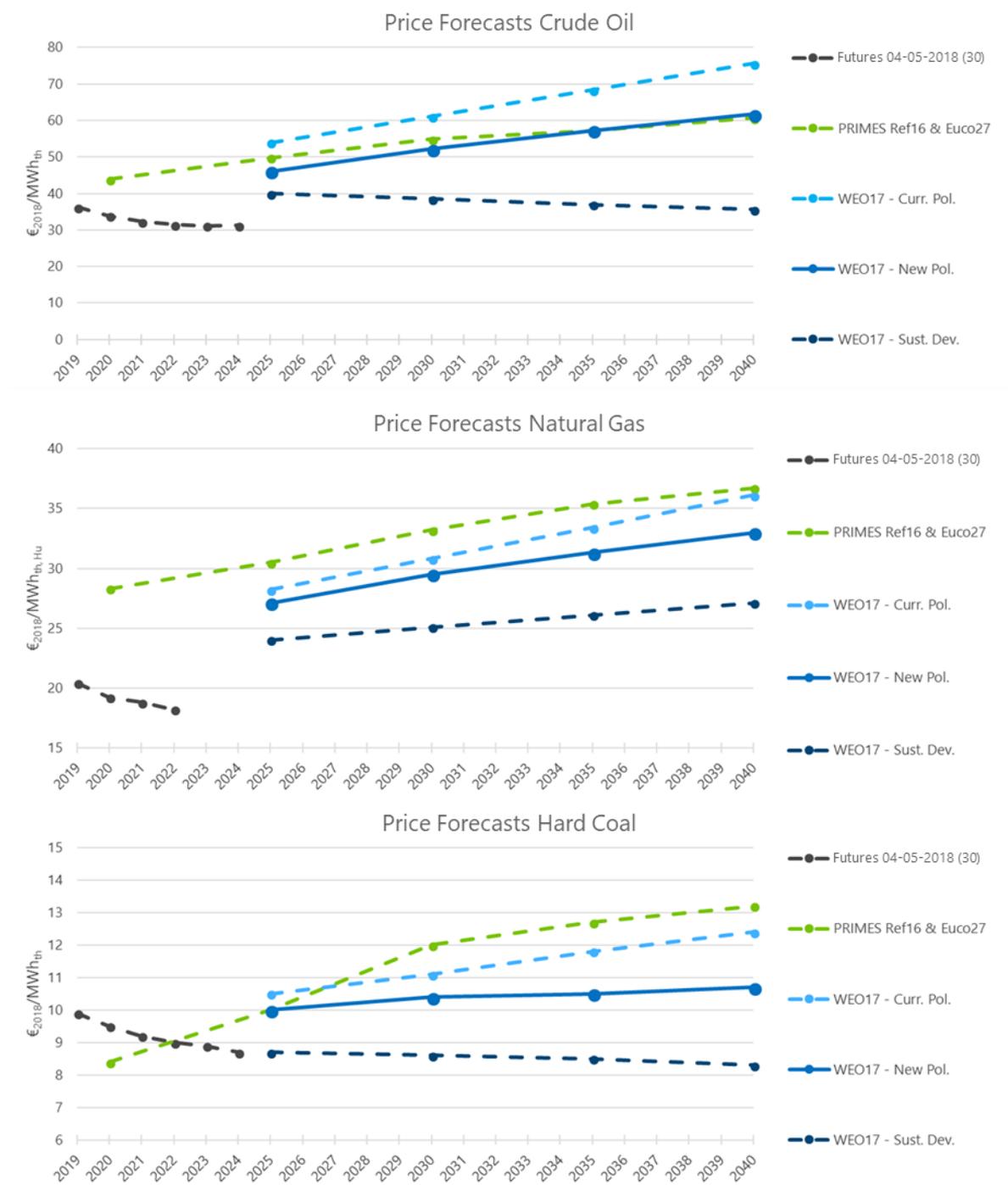
<sup>151</sup> The mean value of the price quotations within the last 30 calendar days before 04.05.2018 is used for the following products and trading places: Crude oil: Brent Crude Oil Month Futures (Last) of ICE; Natural gas: Volume-weighted mean value from NCG and GPL Year Futures (GOBY and G2BY, Settlement) of EEX; Hard coal: API2 CIF ARA Month Futures (FT2M, Settlement) of EEX.

national and international policy measures and regulations already adopted (some of which have not yet entered into force) at the time the study was prepared (by mid-2017), as well as announced measures and decisions whose implementation is considered highly probable.

The price paths used are shown in Figure 4-25 in comparison to alternative price paths of *WEO 2017* and to the latest forecasts of the European Commission (*PRIMES EU Reference Scenario 2016* and *EUCO 27*). In the respective diagram, the selected price path (*WEO 2017 New Policies*) is marked by the (only) solid line in medium blue.

There is no relevant global or European trade in **light and heavy heating oil** on the basis of which corresponding trade prices could be formed. However, the corresponding prices can very well be derived from the development of crude oil prices by means of statistical analyses. Cost premiums result from refinery processing costs as well as transport and distribution costs.

FIGURE 4-25: PRICE FORECASTS FOR CRUDE OIL, NATURAL GAS AND HARD COAL: SELECTED WEO2017 (NEW POLICIES) ASSUMPTIONS COMPARED TO ALTERNATIVE PRICE PATHS



Source: Own presentation based on EEX (2018a), EEX (2018b), EEX (2018c), ICE (2018), IEA (2017), European Commission (2016b); conversion of original values into €/2018 per MWh<sub>th</sub>; European wholesale prices without surcharges for transport, structuring or similar.

There is also no world market price for lignite. Due to high transport costs it is (almost) exclusively produced in the vicinity of the pits. Rather, the costs of open pit mining must be regarded as the relevant reference figure.

According to the Öko-Institut (2017), the full costs of lignite extraction in open pit mines average around 6.5 €<sub>2018</sub> per MWh<sub>Br,th</sub>. These full costs are made up of different, fixed or variable cost components which depend (in different ways) on short, medium and long-term operating plans for lignite-fired power plants:

- A share of 1.5 €<sub>2018</sub> per MWh<sub>Br,th</sub> (of the above-mentioned full costs of 6.5 €<sub>2018</sub> per MWh<sub>Br,th</sub>) is to be regarded as a variable cost component directly dependent on the short-term operation of lignite-fired power plants. This share is allocated directly to lignite-fired power plants as variable fuel procurement costs.
- A second share, also amounting to 1.5 €<sub>2018</sub> per MWh<sub>Br,th</sub>, is to be regarded as a share of the fixed costs of open pit mining that can be reduced in the short term (by reducing the production volume). This share is added to the annual fixed operating costs of coal-fired power plants.<sup>152,153</sup>
- Finally, 2.5 €<sub>2018</sub> per MWh<sub>Br,th</sub> is to be regarded as a share of the fixed costs of coal extraction in open pit mining, which can only be reduced in the medium term by reducing capacity, i.e. reducing the maximum extraction volume. From today's perspective, this possible saving in fixed costs can be achieved by reducing the maximum annual production volume from the year 2025 onwards, with sufficient advance planning. In the modelling,

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<sup>152</sup> For the allocation of the 1.5 €<sub>2018</sub> / MWh<sub>Br,th</sub> to the annual fixed costs of the lignite-fired power plants, which are to be assessed in € per kW<sub>el</sub>, an average utilisation of 7,000 full utilisation hours of these power plants is assumed. The resulting fixed cost surcharge in € per kW<sub>el</sub> ultimately depends on the efficiency of the respective power plant.

<sup>153</sup> The fixed cost surcharge described here is not yet included in the fixed operating costs for lignite-fired power plants shown in section 4.6.1.

these costs are allocated to the variable fuel procurement costs of the lignite-fired power plants from the year 2025 is carried out.

In the case of **fuel costs at plant location**, other price components hard coal and natural gas must be taken into account. Hard coal mainly consists of transport costs from the European seaports to the German border and from the German border to the power plants. In total, 1.25 €<sub>2018</sub> per MWh<sub>th</sub> is assumed for Germany. For natural gas, structuring costs and margins as well as the use of the natural gas grid infrastructure shall be taken into account. For Germany we assume this with 0,5 €<sub>2018</sub> per MWh<sub>th, HU</sub>. For light and heavy fuel oil 0,3 €<sub>2018</sub> per MWh<sub>th</sub> is estimated.

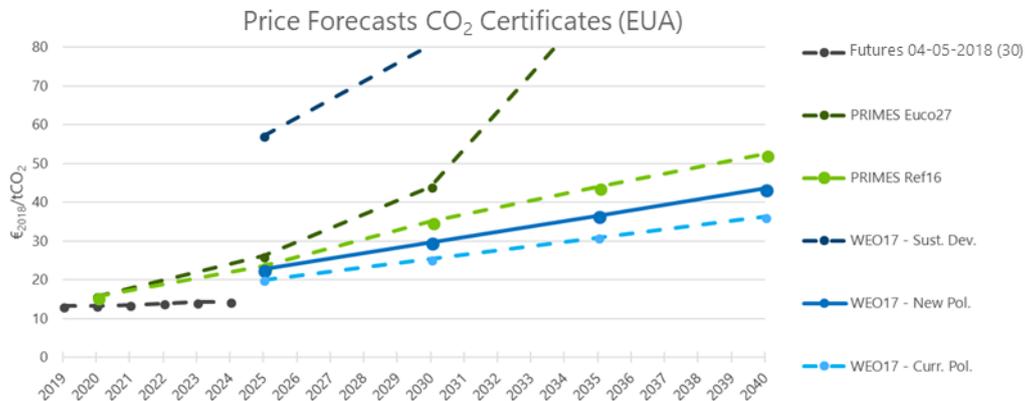
Our prices for **CO<sub>2</sub> certificates** are based on the same assumptions as for fuels. While we use trading quotations for EEX futures for the years up to 2023,<sup>154</sup> we use the forecasts of the *New Policies* scenario of *WEO 2017* for the years from 2025 onwards. Here, the IEA particularly takes into account the reform of the EU ETS (not yet adopted at the time *WEO 2017* was prepared), which among other things also explains the difference between the price time series and the alternative scenario *Current Policies* of *WEO 2017*<sup>155</sup>. The selected price path is shown in the following Figure 4-26 in comparison with the alternative price paths of *WEO 2017* and the forecasts *EU Reference Scenario 2016* and *EUCO 27* of the European Commission. The chosen price path is marked by the (only) solid line in medium blue.

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<sup>154</sup> The mean value of the price quotations within the last 30 calendar days before 04.05.2018 is used for the product FEUA (settlement) of the EEX.

<sup>155</sup> In the *Current Policies* scenario, the continuation of all laws enacted in mid-2017 is frozen. The announced ETS reform is not taken into account in this "conservative" scenario.

FIGURE 4-26: PRICE FORECASTS FOR CO<sub>2</sub> CERTIFICATES (EUA): SELECTED ASSUMPTIONS ACCORDING TO WEO2017 (NEW POLICIES) COMPARED TO ALTERNATIVE PRICE PATHS



Source: Own presentation based on EEX (2018), IEA (2018), European Commission (2016); conversion of original values to €<sub>2018</sub> per tCO<sub>2</sub>

### 4.6.3 Availabilities of conventional power plants

The capacity of controllable power plants, such as thermal power plants or pumped storage plants, is not available throughout the year. Systems are occasionally unavailable as scheduled due to maintenance work as part of inspections. Systems can also fail unplannedly if, for example, a technical defect makes operation (at rated output) impossible.

These non-availabilities of conventional power plants must be taken into account within the framework of the SoS monitoring both in the simulations for forecasting the development of the electricity supply system and in the probabilistic simulation within the framework of analysing the security of supply level.

In the case of fossil thermal power plants, we do not differentiate between different countries, as the planned (scheduled outage) and unplanned (forced outage) power plant outages are either of a comparable magnitude or there is insufficient data available for countries with only a few generation plants. In the case of nuclear energy, on the other hand, we differentiate between the countries considered. On the one hand, the bandwidths of the non-availabilities are sometimes considerable, and, on the other hand, there is a comprehensive database on the

non-availability of nuclear power plants which enables this granularity. The assumptions regarding the planned and unplanned non-availability of thermal power plants and pumped storage power plants are shown in the Table 4-8.

TABLE 4-8: ASSUMPTIONS ON NON-AVAILABILITY OF CONVENTIONAL POWER PLANTS

Non-availabilities 2012 - 2016		Total	planned	unplanned
Hard coal		19,7%	9,4%	10,4%
Lignite		14,2%	6,7%	7,5%
Oil/natural gas steam turbine		17,4%	7,3%	10,2%
OCGT		8,8%	5,1%	3,7%
CCGT		10,4%	6,6%	3,8%
Pumped storage - turbines		15,9%	14,6%	1,3%
Pumped storage - pumps		10,6%	9,8%	0,8%
Nuclear Power (2005 - 2015)				
	BE	21,1%	8,4%	12,7%
	CZ	19,0%	14,4%	4,6%
	FI	6,0%	4,9%	1,1%
	FR	19,7%	12,3%	7,4%
	DE	8,6%	6,7%	2,0%
	NL	10,8%	5,9%	4,8%
	SE	22,4%	11,3%	11,1%
	CH	11,9%	8,9%	3,0%
	GB	27,7%	12,5%	15,2%

Sources: VGB (2017), VGB (2016), IAEA (2016).

We have used outage frequencies given in Haubrich and Consentec (2008) for the breakdown of non-availabilities into the components average outage frequency and average outage duration (see section 3.3.5), which has been applied for the parameterization of the SoS analysis.<sup>156</sup> The outage durations were computed by dividing the unplanned unavailabilities shown in Table 4-8 by these frequencies.

## 4.7 Development of balancing power

As part of the generation of scenarios using the European electricity market model, we depict the restriction that exists in practice that the part of the capacity

<sup>156</sup> Partial outages were added pro rata to the frequency of complete outages.

of plants that is held as balancing power cannot be offered on the electricity market.

Our analyses are based on the assumption that the balancing power requirement will remain constant over time. The amount of the positive balancing power provided is shown in the Table 4-9.

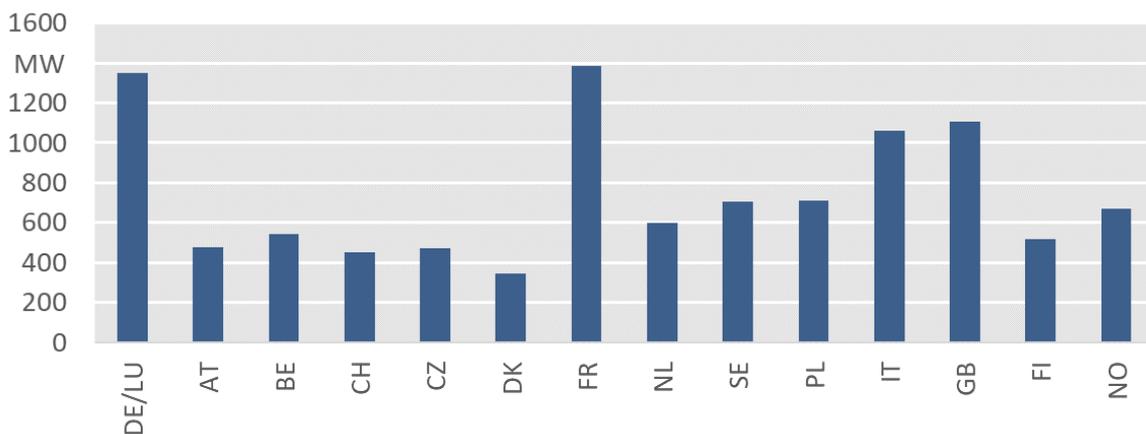
TABLE 4-9: RESERVED POSITIVE BALANCING POWER

Country	MW	Country	MW	Country	MW
DE	3.677	DK	1.070	LU	-
AT	540	FI	1.400	NL	750
BE	543	FR	1.850	NO	714
CH	960	GB	900	PL	930
CZ	1.168	IT	4.000	SE	2.100

Source: Own presentation based on ENTSO-E (2017b); mean values over all given times.

As explained in section 3.3.3, capacity of the generation facilities held to cover high-frequency positive shares of the balancing power demand is not used in the SoS analysis to cover the residual load. The values obtained according to the methodology also described there are shown in the following diagram. Due to the small fluctuations of the determining factors, the values are assumed to be the same for all years under review and for all weather years.

FIGURE 4-27: POSITIVE HIGH-FREQUENCY SHARES OF BALANCING POWER PER COUNTRY



Source: Own representation.

## 4.8 Development of cross-border import and export opportunities

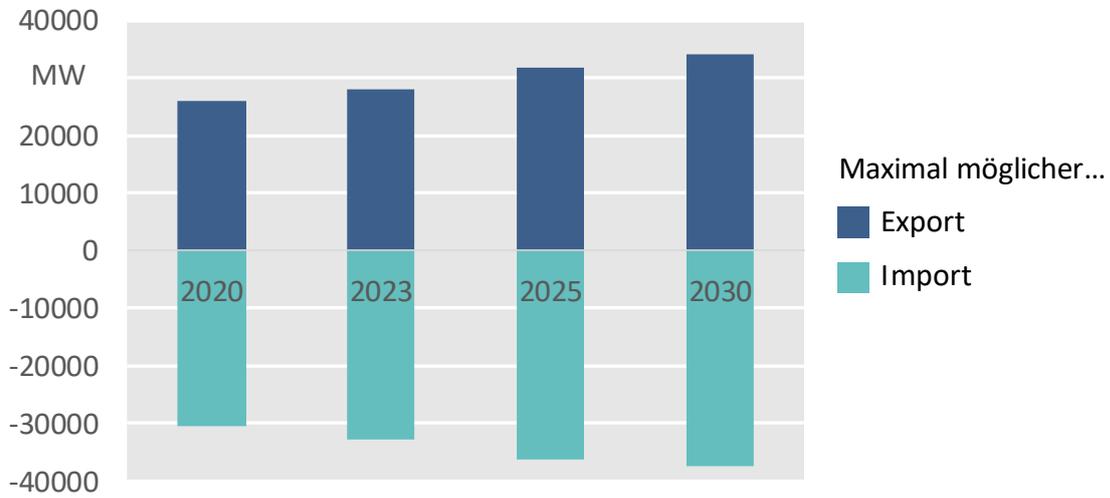
As described in Section 3.3.4, the historical cross-border exchange capacities of the base year 2016 form the starting point of the modelling for the scope of this study. These amount to a total of 12.5 GW in export and 19 GW in import direction for the bidding zone Germany / Luxembourg.<sup>157</sup>

Taking into account the planned expansion of the network, the implementation of the so-called "75 percent rule" of the CEP and the transition to a flow-based model of exchange capacities, the maximum export and import capacities shown in the reference scenario for the years under consideration in this study are shown in Figure 4-28. When interpreting these values, it should be noted that in the flow-based model, in contrast to the classical NTC approach, the export and import capacities of all bidding zones that can be realised at the same time are interdependent. There is therefore no set of clearly defined maximum export and import capacities for all bidding zones that could be realised simultaneously. However, in order to obtain an unambiguous parameter of the network capacity, the maximum possible export and import capacity of an individual bidding zone can be determined objectively (as a theoretical maximum value). These values are calculated separately for each bidding zone and direction and cannot be realized at the same time. Rather, a special constellation of exports and imports of the other bidding zones may be required to achieve the maximum export or import of a bidding zone.

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<sup>157</sup> The separation of Austria from the previously joint bidding zone with Germany and Luxembourg as of 1st October 2018 has been taken into account by an NTC between Germany/Luxembourg and Austria amounting to 4.9 GW per direction.

FIGURE 4-28: MAXIMUM POSSIBLE EXPORT/IMPORT CAPACITIES FOR THE BIDDING ZONE GER-MANY/LUXEMBOURG IN THE REFERENCE SCENARIO



Source: Own representation.

The "maximum possible export or import capacity" is therefore an objective parameter but indicates theoretical extreme values. In the simulation calculations, the mentioned interactions between the attainable exports and imports of the modelled bidding zones are explicitly mapped.

However, the realistically achievable export and import services are also significantly higher in the area under consideration than in the past because, firstly, a considerable expansion of the network is planned, especially in the cross-border area; secondly, the flow-based model enables the hourly balancing of export and import capacities between the bidding zones; and thirdly, the assumed implementation of the CEP will be accompanied by a general increase in cross-border capacities.

## 5 Results in the reference scenario

The model calculations on which the present report is based were carried out in the second half of 2018.

In this chapter we first present the results of the electricity market simulations for the reference scenario regarding the development of the power plant park and the development of flexibility options for Germany and the European countries considered. The dates considered are the years 2020, 2023, 2025 and 2030.

In Section 5.2 we then describe the advantages in the form of trans-regional balancing effects of the load, the feed-in of intermittent renewable energies and unplanned outages of conventional power plants in a common internal market, specifically in the electricity markets of 15 countries which are simultaneously considered in the present study.

Section 5.3 we describe the results of the SoS analyses for the reference scenario. The chapter concludes with a brief interim conclusion in Section 5.4.

### 5.1 Results of electricity market simulations

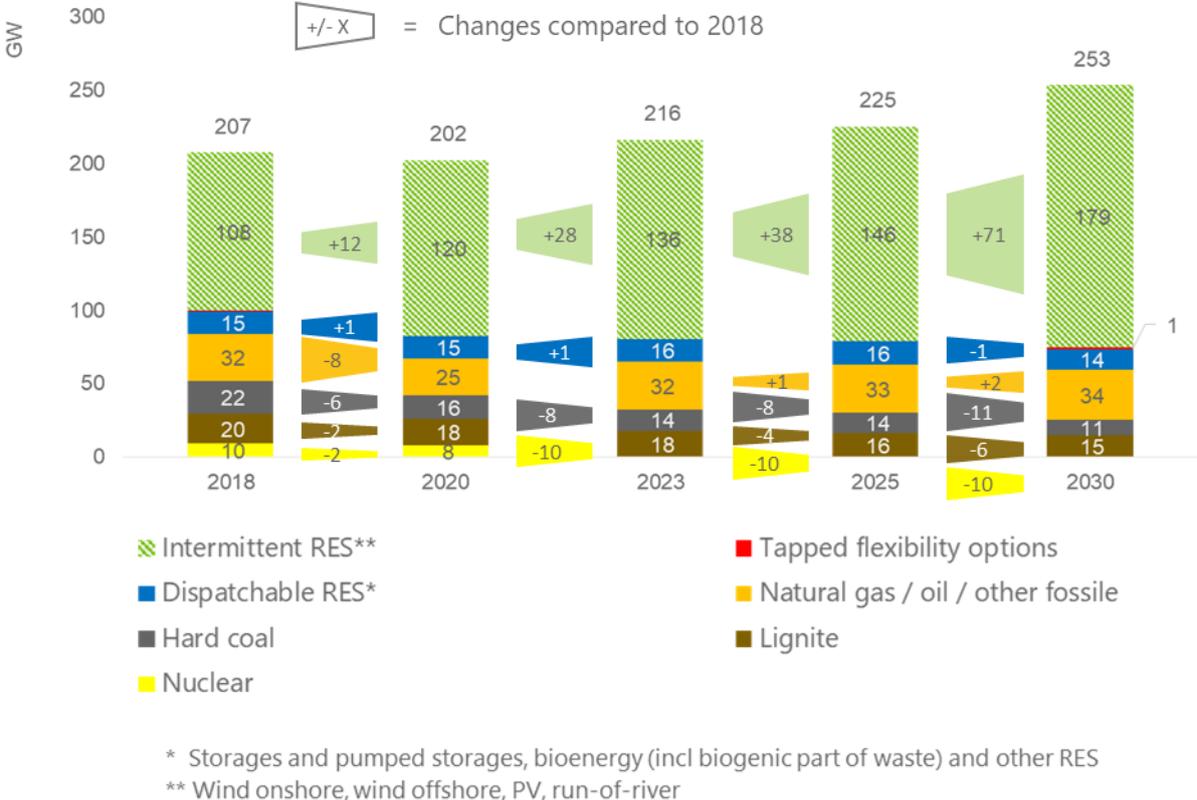
In this section, we first explain in Subsection 5.1.1 how the power plant fleet and the development of flexibility options in Germany are developing over time. We show which developments are based on exogenous specifications and which developments are model endogenous due to market adjustment processes. Subsection 5.1.2 then shows the development of the power plant fleet and the development of flexibility options in the foreign markets considered.

#### 5.1.1 Development of the power plant fleet and development of flexibility options in Germany

The development of the power plant fleet and the development of flexibility options are the central results of the dynamic simulation calculations with the European electricity market model of r2b energy consulting GmbH.

The development of the installed net electrical capacity of the power plant park and the development of flexibility options in Germany are shown in Figure 5-1. Only those services that are actually available for the market are shown.<sup>158</sup> In the chart we have differentiated between controllable capacity and the capacity of volatile renewable energies. In addition, the category-specific changes compared with 2018 are shown in each case.

**FIGURE 5-1: DEVELOPMENT OF THE POWER PLANT PARK AND DEVELOPMENT OF FLEXIBILITY OPTIONS IN GERMANY**



Source: Own calculations.

<sup>158</sup> Both regulatory reserves and long-term conserved power plant capacity (so-called cold reserves) are not considered in the data on capacity development and in the downstream quantitative SoS analyses.

The intermittent feed-in capacity of 108 GW in 2018 from onshore and offshore wind energy, PV and hydroelectric (run-of-river) will rise continuously to just under 180 GW in 2030, in line with the target set in the coalition agreement of a share of renewables in gross electricity consumption. The installed capacity of dispatchable power generation plants, on the other hand, declines in total.<sup>159</sup>

The installed capacity from storage and pumped storage facilities, bioenergy and other renewable energies will remain largely constant until 2025 with 15 to 16 GW. In 2030, it will decline slightly to 14.3 GW. This will be driven by bioenergy, whose capacity will decline from 7.5 GW in 2025 to around 6 GW in 2030. The installed capacity based on natural gas, oil and other non-renewable energy sources will also remain relatively constant at a level between about 32 and 34 GW until 2030. Only in 2020 will there be a decrease to 26 GW, as 7.3 GW are temporarily taken into cold reserve (of which 4.7 GW CCGT and 2.7 GW OCGT) due to lack of economic efficiency and are at least temporarily no longer available to the market. The output of coal-fired power plants, on the other hand, decreases significantly over time, with approx. 5.6 GW being shut down prematurely due to insufficient economic efficiency, i.e. before the technical lifetime life is reached. The installed capacity of hard coal will be halved from 22 GW in 2018 to 11 GW in 2030. The capacity of lignite will gradually decline by about a quarter from 20 GW in 2018 to just under 15 GW in 2030. According to the nuclear phase-out, the installed capacity of nuclear energy will be completely off the grid by 2023. The flexibility options DSM (voluntary load reduction by industry) and EPS (Emergency Power Systems) are only being developed to a very limited extent in Germany. The tapped capacity of these flexibility options amounts to approx. 0.4 GW in the years from 2020 to 2025 and then increases to approx. 0.9 GW in 2030. The capacity of the voluntary reduction of load by industry amounts to only a small

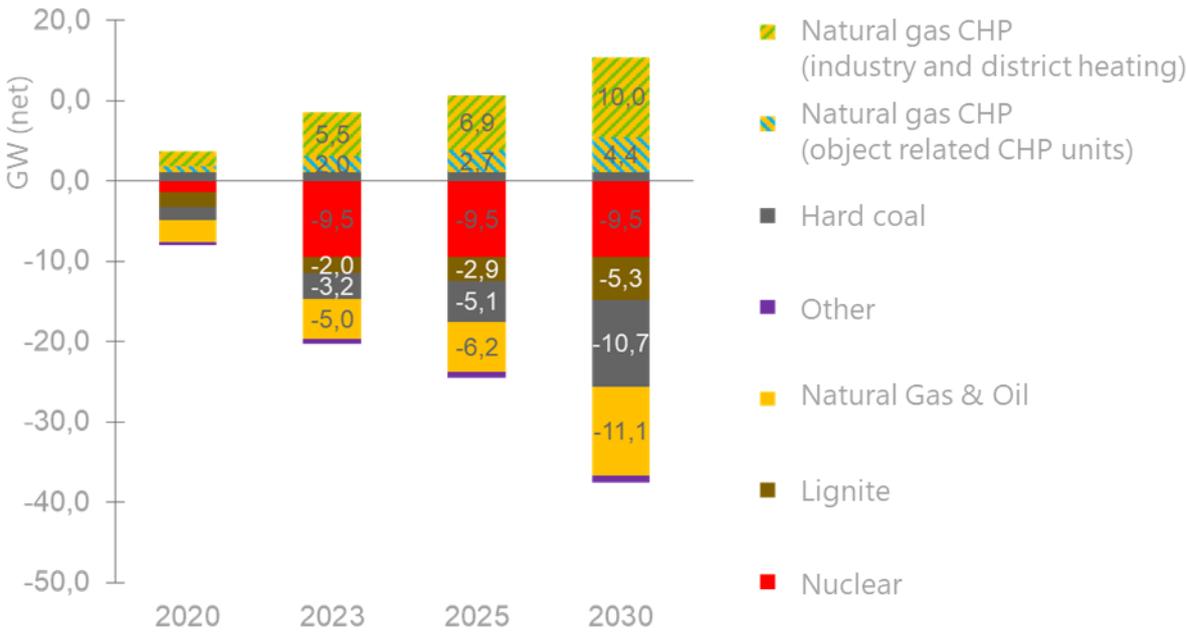
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<sup>159</sup> For detailed assumptions on the expansion of renewable energies in Germany, see sections 4.3.1 and 4.3.2.

part of the potential of about 2.5 GW which has already been safely tapped according to the evaluation of the monitoring of load management of the Federal Network Agency in accordance with article 51a EnWG.<sup>160</sup>

Due to the assumptions on the technical lifetime of the power plants, the replacement of decommissioned CHP plants (see Section 4.2), the commissioning of Datteln IV and the phase-out of nuclear energy, the results take into account the following decommissionings and additions, which are exogenously specified for the model (see Figure 5-2).

**FIGURE 5-2: EXOGENOUS CUMULATIVE ADDITIONS AND REMOVALS SPECIFIED COMPARED TO 2018 IN GERMANY**



Source: Own assumptions.

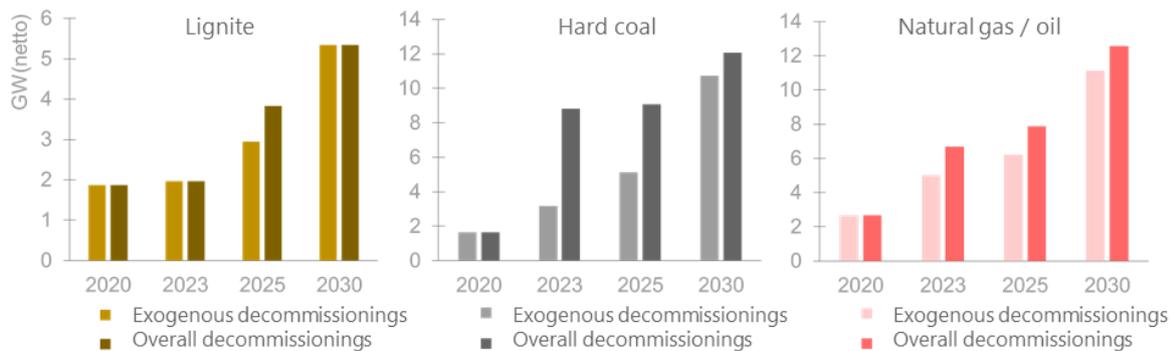
In 2020, we give the model a total of approx. 8 GW for decommissioning and 3.7 GW for commissioning compared with 2018. The shutdowns consist of 1.4 GW of nuclear energy, 1.9 GW of lignite, 1.6 GW of hard coal, 2.6 GW of natural gas, 70 MW of open gas turbines and 400 MW of plants operated with other fossil

<sup>160</sup> See section 4.4.2.

fuels. The expansion includes the commissioning of Datteln IV with 1,055 MW, 800 MW CHP (each less than 10 MW) and 1.8 GW natural gas CHP in industry and district heating supply. Accumulated shutdowns naturally continue to increase gradually over time. They amount to approx. 20 GW in 2023, 24.5 GW in 2025 and just under 38 GW in 2030. The cumulative exogenous commissioning on the basis of natural gas CHP also increases over time. Including the commissioning of Datteln IV, this amounts to approx. 8.5 GW in 2023, just under 11 GW in 2025 and approx. 15.5 GW in 2030. The exogenous net capacity decline compared to 2018 thus amounts to approx. 22 GW in 2030.

In the model analyses, exogenous shutdowns are specified in particular on the basis of assumptions about the maximum technical lifetime. However, this is the latest closure date. The power plant units can be decommissioned at an earlier stage (disinvestment) if the plants are no longer economically viable (see Figure 5-3).<sup>161</sup>

**FIGURE 5-3: EXOGENOUS VS. OVERALL CUMULATIVE DECOMMISSIONING COMPARED TO 2018 IN GERMANY**



Source: Own calculations.

<sup>161</sup> For the model logic of temporary shutdowns (*mothballing*) and final shutdowns, see section 3.2.2.

In the years 2020<sup>162</sup> and 2023, there will still be significant overcapacities, as the model endogenously (prematurely) decommissions approx. 5.6 GW of hard coal capacity more (or earlier) than exogenously specified. Also, in the years 2025 and 2030, the total number of shutdowns carried out at hard coal-fired power plants exceed the exogenously specified shutdowns. In the case of lignite, just under 900 MW of decommissioning beyond the specified decommissioning will take place in the year 2025. This illustrates the competitive advantage of lignite over hard coal. In the case of natural gas, the endogenous shutdowns are only slightly above the level of the specified (exogenous) shutdowns, whereby the endogenous shutdowns are essentially open cycle gas turbines (for economic reasons). There will be no endogenous expansion of power plants in Germany in the period up to 2030. Flexibility options (voluntary reduction of the load by industry and grid replacement systems) are developed only to a limited extent. The reason for the fact that no conventional generation facilities are built in Germany beyond the exogenous requirements is the extensive cross-border balancing effects and, in some cases, overcapacities in the foreign countries with capacity markets considered.

### **5.1.2 Development of the power plant fleet in the foreign electricity markets taken into account**

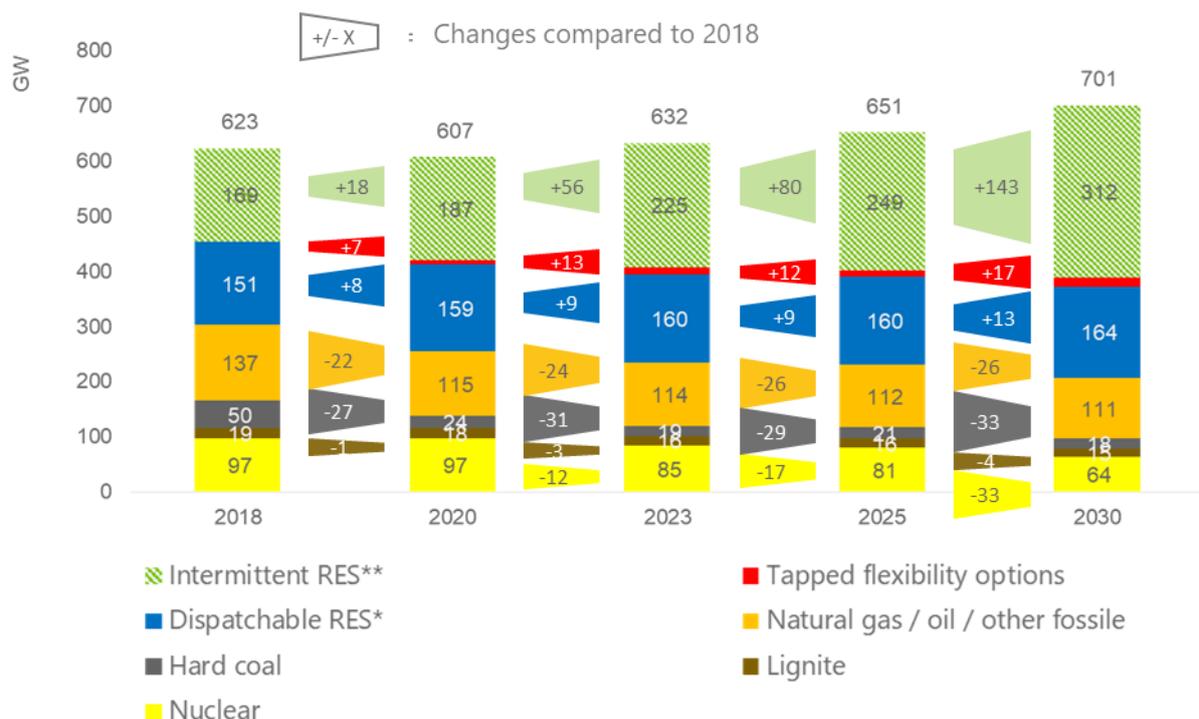
In the European countries considered (AT, CH, FR, GB, IT, LU, BE, DK, NL, PL, CZ, FI, SE, NO), the development of the power plant fleet is characterised by a strong increase in the volatile renewable energies fed in by wind energy (season- and offshore), PV and hydroelectric, with the increase being driven by the expansion

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<sup>162</sup> Strictly speaking, these overcapacities will already exist in 2020, but while we will allow temporary closures in 2020 in agreement with the BMWi, final closures will not be permitted until 2023. For this reason, 5.6 GW of hard coal will be decommissioned temporarily in 2020 and finally in 2023. Irrespective of this, we do not take these investments into account in the downstream quantitative supply security analyses in the sense of a conservative approach.

of wind energy and PV. In total, the installed capacity of volatile renewable energy sources will increase significantly from 169 GW in 2018 to 312 GW in 2030.<sup>163</sup> The 312 GW in 2030 consist of 163 GW wind energy, 120 GW PV and 29 GW hydroelectric power (run-of-river).

FIGURE 5-4: DEVELOPMENT OF THE POWER PLANT PARK AND DEVELOPMENT OF FLEXIBILITY OPTIONS IN THE CONSIDERED FOREIGN COUNTRIES



\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES  
 \*\* Wind onshore, wind offshore, PV, run-of-river

Source: Own calculations.

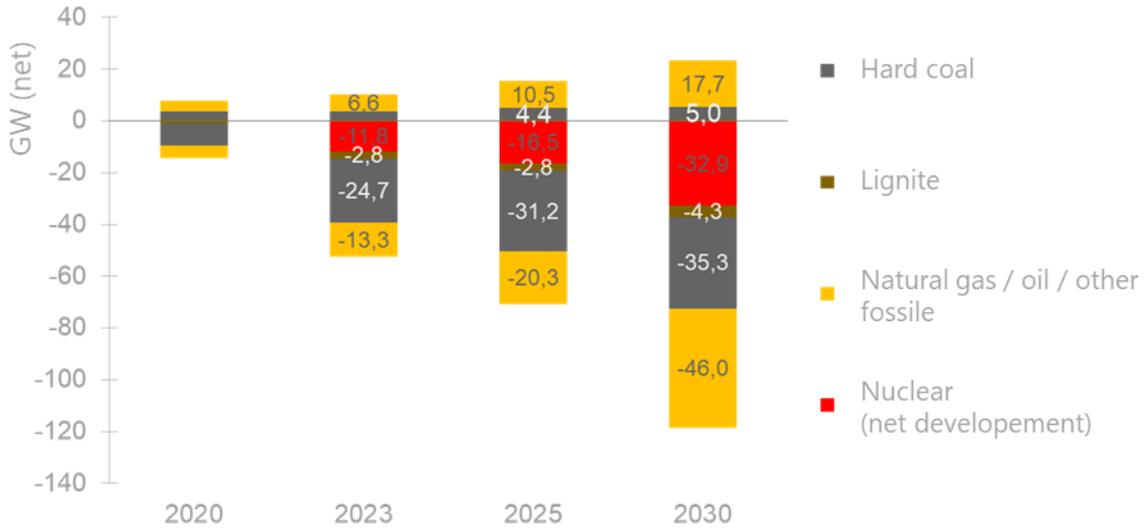
The installed capacity of controllable renewable energies increases slightly between 2020 and 2030 by approx. 13 GW and amounts to 164 GW in 2030. 115 GW of these 164 GW are storage and pumped storage hydro plants, a further 43 GW are bioenergy plants and 6 GW, other renewable energies.

<sup>163</sup> For detailed information on the development of renewable energy in the foreign countries under consideration, see section 4.3.3.

In contrast to renewable energies, the installed capacity of conventional power plants also decreases significantly over time in the other European countries considered. Thus, the installed capacity of power plants based on coal, natural gas, oil and other fossil fuels as well as nuclear power plants still amounts to approx. 303 GW in 2018 and then decreases continuously over time. In the year 2030, the installed capacity of conventional power plants only amounts to approx. 208 GW. The strongest declines are recorded in hard coal-fired power plants and nuclear power plants, each with approx. 33 GW between 2018 and 2030. The installed capacity of natural gas power plants decreases by approx. 26 GW during this period, while the installed capacity of lignite-fired power plants decreases by approx. 4 GW. In addition to the slight increase in controllable capacity of RE, the decline in installed capacity at conventional power plants is partially offset by the moderate development of flexibility options, i.e. Emergency Power Systems (EPS) and voluntary load reduction by industry (DSM). The tapped capacity of these flexibility options amounts to approx. 7 GW in 2020, rising to 13 GW in 2023 and to 17 GW by 2030.

Some of the developments in the conventional power plant fleet of the countries considered are based on exogenous model specifications for the technical lifetime, for maintaining the heat supply by CHP plants, political specifications for the construction or decommissioning of coal-fired and nuclear power plants (see Section 4.2.1). These exogenous requirements are shown in Figure 5-5 as compared to 2018. For nuclear energy, in contrast to other technologies / fuels, the net-development (sum of commissionings and decommissionings) of installed capacity is given.

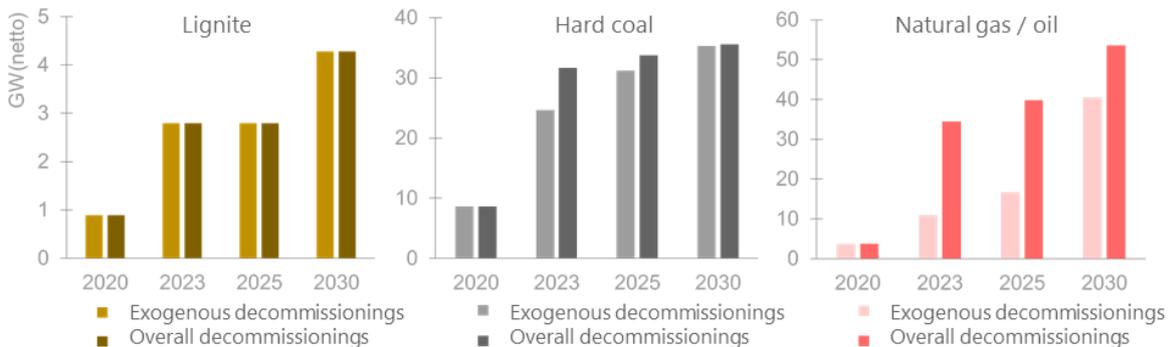
FIGURE 5-5: EXOGENOUS PRESCRIBED INCREASES AND DECREASES IN FOREIGN COUNTRIES TAKEN INTO ACCOUNT AS CHANGE COMPARED TO 2018



Source: Own assumptions.

However, even in foreign countries considered, early decommissioning (i.e. earlier than the exogenous decommissioning) can also be carried out endogenously by the model. The cumulative decommissionings and the decommissionings exogenously specified compared with 2018 are shown in total for all countries taken into account in the Figure 5-6.

FIGURE 5-6: EXOGENOUS VS. ENDOGENOUS CUMULATIVE DECOMMISSIONING COMPARED TO 2018 IN FOREIGN COUNTRIES TAKEN INTO ACCOUNT

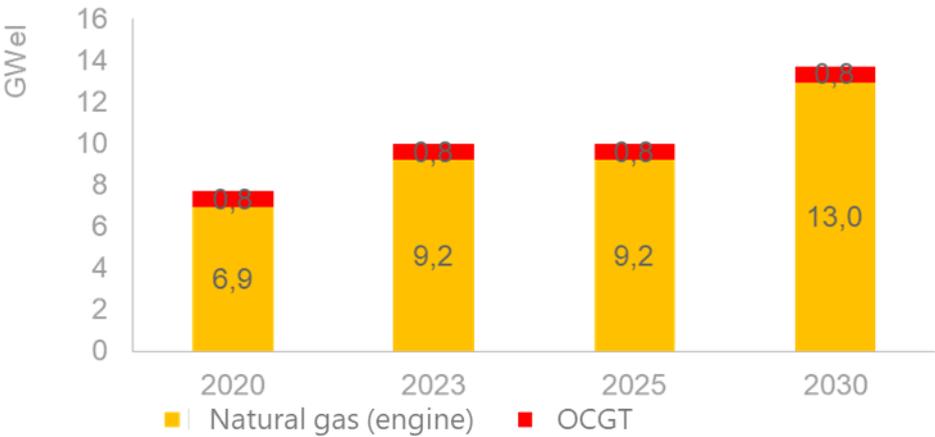


Source: Own calculations.

The lignite-fired power plants in the foreign countries considered (Poland and the Czech Republic) are not decommissioned endogenously. In the case of coal-fired power plants, endogenous shutdowns will take place due to insufficient economic viability of continued operation amounting to approx. 7 GW in 2023 and approx. 2.5 GW in 2025. In the case of power plants based on natural gas and mineral oil, considerable early endogenous shutdowns will take place in 2023 amounting to approx. 23.6 GW, which will remain roughly constant at approx. 23.2 GW until 2025. In the year 2030, the premature endogenous closures will then amount to around 13 GW.

In addition to the development of flexibility options in the form of DSM and EPS (see Figure 5-4), a model endogenous expansion of power plants on the basis of natural gas is carried out abroad (see Figure 5-7).

**FIGURE 5-7: ENDOGENOUS CUMULATIVE COMMISSIONING COMPARED TO 2018 IN THE FOREIGN COUNTRIES CONSIDERED**



Source: Own calculations.

Compared to 2018, approx. 6.9 GW engine power plants and approx. 0.8 GW open cycle gas turbines will be built endogenously by the model in the countries covered. While no further additions will be made to open gas turbines in the further course of time, cumulative additions of engine power plants will increase to approx. 9.2 GW in 2023 and 2025 and to approx. 13 GW by 2030.

## Classification of the Reference Scenario

In model-based scenario generation, the expected market adjustment processes are analysed and simulated (see Section 3.2.2). These are necessarily idealised to a certain extent by enabling the immediate action of rational market players within the framework of the respective requirements. The extent of this idealisation is, however, limited in order to take into account inertia and obstacles that exist in reality:

- In the short term, extensive exogenous assumptions determine the scenarios on the basis of extensive preliminary analyses.
- Endogenous degrees of freedom only gain relevance for later observation years when sufficient lead times are given for adaptation processes.

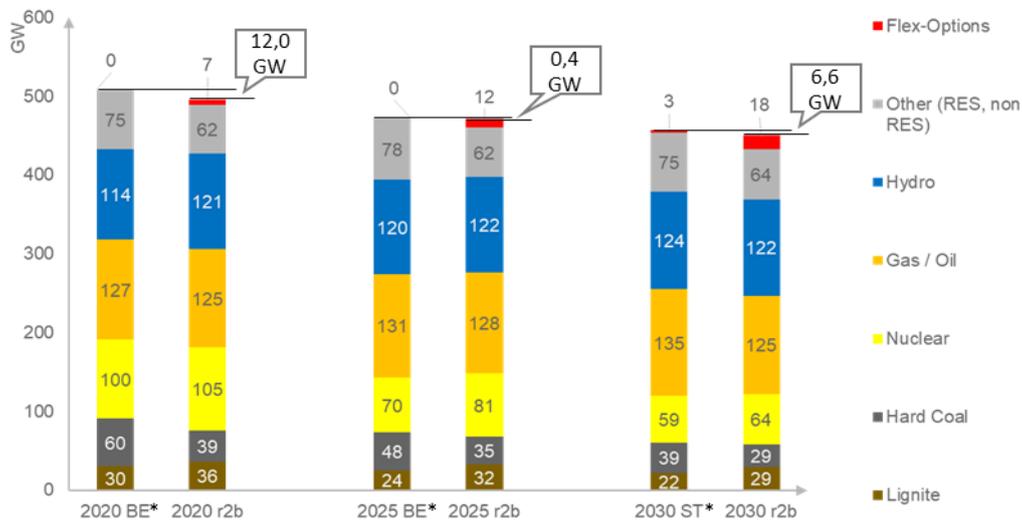
In the following we give a classification of the results in the form of a comparison with scenarios of the German and European TSOs. To this end, we have compared the development of the installed capacity of all controllable generation plants (excluding hydroelectric run-of-river plants) and the flexibility options tapped in the 15 countries of the reference scenario with the *best estimate* (2020 and 2025) and *sustainable transition* scenarios of the ENTSO-E *Mid-Term Adequacy Forecast 2017*<sup>164</sup> and *TYNDP 2018* respectively (see Figure 5-8).<sup>165</sup>

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<sup>164</sup> The 2018 edition was not yet available at the time the analysis was carried out.

<sup>165</sup> The comparison possibilities are limited due to limited data availability and partly different framework assumptions. We have therefore made a different aggregation of the technologies / fuels here than in the corresponding figures in sections 5 and 6.

FIGURE 5-8: DEVELOPMENT OF INSTALLED CAPACITY OF ALL CONTROLLABLE GENERATION PLANTS (EXCLUDING RUN-OF-RIVER PLANTS) AND FLEXIBILITY OPTIONS DEVELOPED IN THE 15 COUNTRIES (INCL. GERMANY)



\* BE = Best Estimate Scenario MAF 2017 / ST = Sustainable Transition Scenario TYNDP

Source: Own presentation based on own calculations and ENTSO-E (2017a) and ENTSO-E (2018a).

The reference scenario developed within the framework of this study shows a lower (to equally high) installed generation capacity (including the flexibility options DSM and EPS) in comparison to the scenarios of ENTSO-E. With 12 GW less in 2020, 400 MW less in 2025 and 6.6 GW less in 2030, the reference scenario represents a realistic to conservative development of the power supply system based on the current market designs and known developments in Europe.

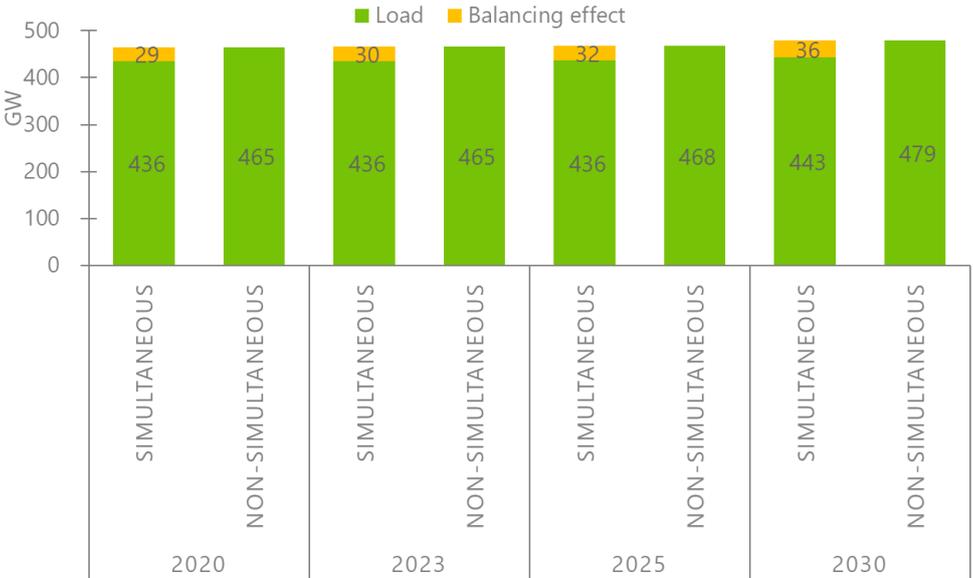
## 5.2 Balancing effects in the common internal electricity market

If, in line with the integration of the European internal electricity market, the electricity supply systems of several countries are considered simultaneously, there are transregional balancing effects for the load and the feed-in of RES, which together represent the balancing effects of the residual load, as well as balancing effects in the event of unplanned non-availability of power plants.

The balancing effects for the load and the residual load shown here reflect the fact that the annual peak load and the residual annual peak load do not occur simultaneously in the countries under consideration.

The balancing effects of the load are shown in Figure 5-9 and are obtained by comparing the simultaneous annual peak load of all countries considered with the non-simultaneous sum of the country-specific annual peak loads. The difference between them is the balancing effect of the load, which is between 29 and 36 GW depending on the reporting year.

**FIGURE 5-9: BALANCING EFFECTS OF THE LOAD: SIMULTANEOUS VS. NON-SIMULTANEOUS ANNUAL PEAK LOAD OF ALL COUNTRIES CONSIDERED**

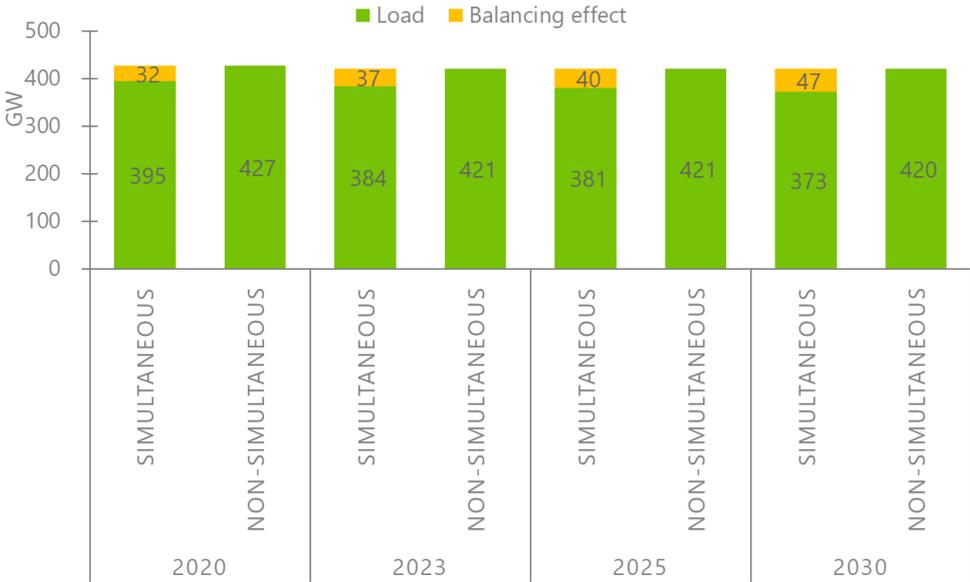


Source: Own calculations; averaged over all 5 weather years.

As the country with the highest electricity consumption, Germany makes a substantial contribution to the simultaneous and non-simultaneous annual peak load. The annual peak load in Germany averages around 90.2 GW over all five base years in 2020 and then shows a slightly decreasing development over time. In 2023 it amounts to approx. 89.6 GW, in 2025 approx. 88.8 GW and in 2030 approx. 88.7 GW.

The intermittent feed-in of RES leads to a further strengthening of these balancing effects, as low feed-in levels neither occur simultaneously in all countries nor at times of the respective peak load. In order to quantify this effect, we compare (Figure 5-10) the simultaneous residual annual peak load of all countries under consideration with the sum of the non-simultaneous country-specific residual annual peak loads. The difference represents the trans-regional balancing effect of the residual load considered here, which amounts to between 32 and 47 GW depending on the reporting year.

**FIGURE 5-10: BALANCING EFFECTS OF THE RESIDUAL LOAD: SIMULTANEOUS VS. NON-SIMULTANEOUS RESIDUAL MAXIMUM ANNUAL LOAD OF ALL COUNTRIES CONSIDERED**



Source: Own calculations; averaged over all 5 weather years.

The absolute residual annual peak load in Germany in 2020 (on average over all five weather years) is approx. 79.2 GW and then shows a slightly decreasing development over time. In 2023 it amounts to approx. 77.2 GW, in 2025 approx. 76.2 GW and in 2030 approx. 72.6 GW.

This transregional or cross-border balancing effects exist not only with regard to the (residual) annual peak load, but also significantly reduce the effective risk of power plant outages. The reason for this is that the simultaneous occurrence of

high non-availabilities in several countries is less likely than from a national perspective.

In order to demonstrate the magnitude of this effect, we have evaluated the 350 simulated time series of hourly plant outage capacity for the year 2023.

If, for example, for each country the cumulative outage capacity is calculated, which is exceeded during 20 % of the time, and these country values are summed up across all countries considered in the model, the result is a value of approx. 53 GW. If one compares this with the distribution of the total outage capacity over all modelled countries (whereby the sum is formed hourly over all countries and thus simultaneity is taken into account), the value of 53 GW is only exceeded during 1.5 % of the time.

The balancing effect is even greater when one considers the outage capacity per country, which is exceeded nationally only during 10 % (instead of 20 %) of the time. Their total of 58 GW is exceeded in the international view only during 0.02 % (instead of 1.5 %) of the time.

The relative advantage of the balancing effect (i.e. the relative reduction of the risk that a certain outage capacity is exceeded), thus increases, the lower the risk level is. In other words, the rarer (but potentially more serious) the cases become, the more the balancing effect reduces the residual risk. This is not a random effect of the concrete outage draw, but a systematic effect that can be theoretically reproduced, e.g. on the basis of normal distributions.<sup>166</sup>

The above shows that the European balancing effects are significant. Their benefit in terms of security of supply is that at times when a country (or bidding zone)

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<sup>166</sup> It should also be mentioned that more extreme cases than the 10 % exceedance probability mentioned above could not be meaningfully evaluated here. If, for example, one determines the outage capacity that is exceeded in at least 5% of the time per country, then we find that the sum of these outage capacities does not occur at all in the overall distribution of all countries (with balancing effect). This means that with more than 3 million simulated hours, there was not a single one that exceeded this value in the sum of the outage capacity across all countries.

needs to import, countries with a current surplus of generation capacity can help out. This reduces the requirements to ensuring security of supply on the electricity markets compared to a purely national view. Full use of the balancing effects is only possible if there is corresponding cross-border transport capacity. In view of the transport capacities already existing today and the considerable further expansion of the network in the future, a large proportion of the balancing effects can be used.

In the SoS model, the amount of cross-border assistance is limited in two respects. First of all, the transport capacities of the transmission system are taken into account (see section 3.3.4) and secondly, assistance is only provided to the extent that no (additional) load excess occurs in the bidding zone providing assistance (see section 3.3.6, including the discussion on possible alternative assumptions).

In practice and on a side note, the provision of such temporary cross-border assistance to the technically possible extent is certainly to be expected, since due to high market prices in the bidding zone with import requirements it is extremely lucrative for the market players to supply it with electricity.

In the results of the SoS analysis presented below, cross-border assistance is described by a dedicated result indicator, namely the import required to avoid load excess (see section 2.2.3).

## 5.3 Results of SoS analyses

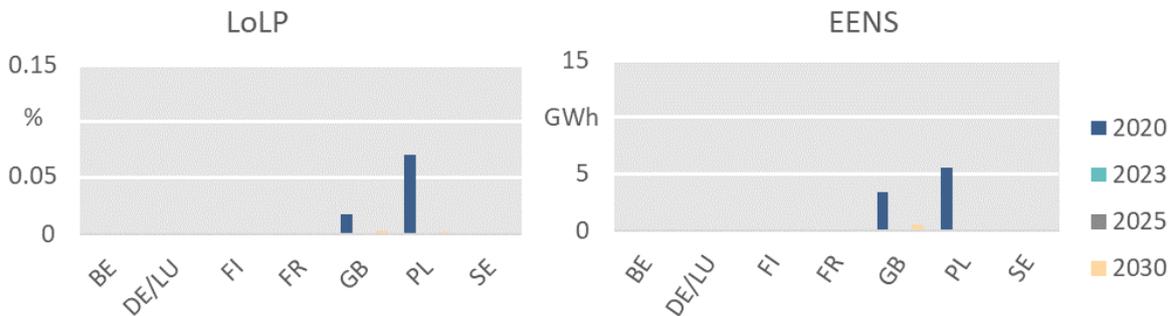
### LoLP and EENS

Figure 5-11 shows the LoLP and EENS indicators for the four years under consideration. For reasons of clarity, the presentation is limited to Germany/Luxembourg and those countries in which a value greater than zero occurs in at least one year under review.<sup>167</sup>

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<sup>167</sup> Some of the values other than zero are so small that they can hardly or not at all be distinguished from zero in the graphical representation.

FIGURE 5-11: SoS INDICATORS IN REFERENCE SCENARIO FOR DE/LU\* AND FOR COUNTRIES WITH INDICATORS GREATER THAN ZERO



Source: Own representation. \* DE / LU form a common bidding zone in the electricity market, therefore DE results also apply to LU

The study shows that German consumers can be supplied securely at any time (LoLP = EENS = 0). This corresponds to a load balancing probability of 100 %.

Notable LoLP and EENS values only occur for Great Britain and Poland and only for 2020.<sup>168</sup> The average extent of the load excess, which can be determined from the ratio of EENS and LoLP<sup>169</sup>, is between 1 and 2 GW. In both countries the values then fall back to (quasi) zero. In the UK, this result corresponds to the completion of several cross-border network expansion projects in the next reporting year 2023 (see Figure 5-11). In Poland it corresponds to the introduction of the capacity market, which will take effect in the next reporting year 2023 (see section 4.1).

### Required imports

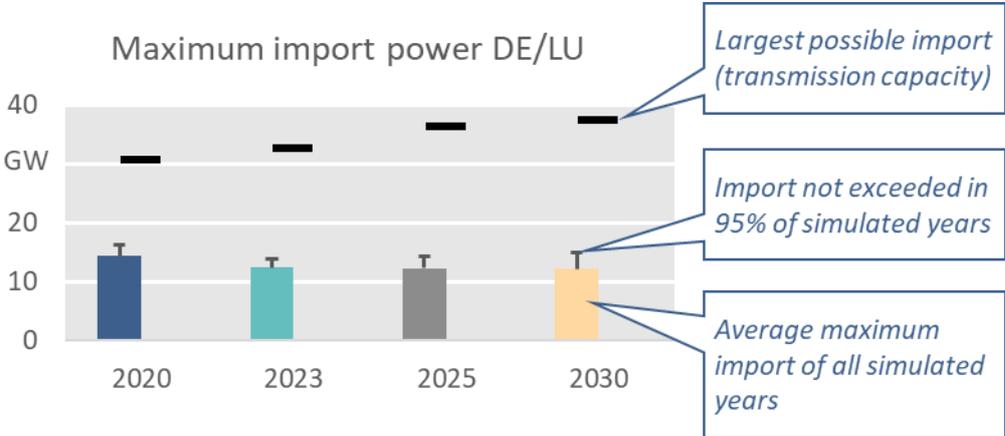
Figure 5-12 shows the level of imports to Germany/Luxembourg required to avoid load excess there. The presentation is based on the maximum values of the required import capacity, which occur in each course of one simulated year. The

<sup>168</sup> However, due to the peripheral location in the model, the key result figures for foreign countries are subject to uncertainties, see section 3.3.2.

<sup>169</sup> Average load excess =  $EENS / (LoLP \cdot 8760 \text{ h/a})$

height of the columns per observation year indicates the average maximum import over all 1,750 simulation years<sup>170</sup>. The "antennas" above the columns mark the import capacity, which is not exceeded in any hour in 95 % of the simulation years. As a benchmark, the maximum possible import capacity is given in the form of black lines for each year under review, i.e. the theoretical largest possible import to Germany/Luxembourg from the grid perspective (see section 4.8).

FIGURE 5-12: REQUIRED\* IMPORTS TO DE/LU IN REFERENCE SCENARIO



Source: Own representation. \* Imports required to avoid loss of load. Market-based imports may deviate from this.

It becomes apparent that (at least in individual hours and depending on the coincidence of the modelled uncertainties) significant power imports are required. These are higher than currently observed import maxima; for example, the maximum power imported to Germany/Luxembourg in the period 1 October 2017 to 30 September 2018 was approx. 7.9 GW.<sup>171</sup> The reasons for this are, on the one hand, the fact that the range of uncertainties modeled in the SoS analysis is greater than that of the situations actually occurring last year and, on the other hand, the decline in dispatchable generation capacity in Germany discussed in the previous section.

<sup>170</sup> For an explanation of the concept of examining an observation year through many simulation years, see Section 3.3.6.

<sup>171</sup> Source: Own evaluation based on data from smard.de

However, the maximum power import required for security of supply is consistently well below the respective maximum import capacity of the grid. The margin even increases over time because import capacity increases as a result of further cross-border grid expansion, while the required import capacity remains virtually unchanged. The average import energy required (that is, the annual integral of the hourly import capacity required) is less than 0.5 % of gross electricity consumption in each year under consideration.<sup>172</sup>

The level of imports required for security of supply can therefore be characterised as low in comparison with (future) existing network capacity. It should be noted, however, that some preparations must nevertheless be made for the increased role of cross-border balancing effects in the future. Firstly, this concerns the examination and, if necessary, implementation of measures in order to realise the exchange capacities (while maintaining operational grid security) which are obligatory according to CEP and which were assumed in this study (see section 3.3.4). Secondly, preparations should be made for cross-border exchange patterns that are already permissible today<sup>173</sup> (within the framework of the allocation of cross-border transmission capacities) but are still unusual in practice. This not only affects temporarily higher import capacity to Germany, but also, for example, increased exports from Italy. In this context, it may be necessary to adapt operational planning processes and/or consider grid measures such as the installation of equipment for voltage/reactive power control.

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<sup>172</sup> The imports within the scope of the SoS analyses are not market-based imports, since the import in the SoS model always represents the last possibility of load coverage, after all domestic possibilities are exhausted. The market-based imports therefore differ from those of the SoS analyses.

<sup>173</sup> The total import capacity to Germany/Luxembourg already amounted to approx. 14 GW in 2016 (excluding the (then still integrated) Austrian border, for which a further 4.9 GW is to be assumed with the introduction of congestion management from 1 October 2018).

## 5.4 Interim conclusion: Results Reference scenario

The reference scenario represents the approach of a best-guess analysis without additional climate protection measures in Germany. Current developments and political framework conditions in Germany and Europe are depicted - with the exception of the failure to achieve the German climate protection targets due to a lack of measures to reduce CO<sub>2</sub> emissions from coal-fired power plants. The output and thus the electricity generation of nuclear power plants and coal-fired power plants are declining and are being replaced in Germany and Europe by the expansion of renewable energies while at the same time making the electricity supply system more flexible. To ensure the supply of CHP heat (district heating and other cogenerated heating), coal-fired CHP plants in Germany and Europe are essentially replaced by natural gas CHP plants. In Germany and Europe, over-capacities of fossil-fired power plants are reduced with temporal inertia within the framework of market adaptation processes. The controllable conventional generation capacity in Germany and Europe will decline over time as the national markets continue to converge and cross-regional balancing effects are utilised.

The SoS analysis for the reference scenario shows that the SoS level on the electricity market in Germany remains very high throughout the period under review until 2030. In the present study, German consumers can be reliably supplied at any time, i.e. the calculated probability of load excess (LoLP) is zero over the entire observation period.

Several causes are responsible for the very high SoS level determined:

- The balancing groups and imbalance settlement mechanism provide utilities with a strong incentive to comply with supply commitments they have entered into. It is rational for market players to hedge potentially very high balancing energy prices by contracting sufficient generation and / or flexibility capacity, which directly or indirectly triggers corresponding investment incentives.

- The electricity supply system is currently in overcapacity. While market adjustments take place by reducing these overcapacities by shutting down existing plants for reasons of economic efficiency, there are certain inertial factors.
- Capacity markets abroad (including France, Great Britain, Poland and Italy) are creating new overcapacities, which via the electricity market also have a positive impact on the SoS level in Germany.
- New capacities will also be created by the replacement of CHP plants to maintain heat supply and by the subsidised expansion of renewable energy plants.
- In the internal electricity market, there are considerable balancing effects in terms of load and feed-in of renewable energies (RES) as well as unplanned non-availability of power plants.
- Finally, there is considerable potential for increasing the flexibility of consumption (including "new" consumers and a large capacity of economically viable flexibility options in the area of voluntary load reduction from industry), cogeneration and bioenergy, as well as emergency power systems (EPS).

These causes for the consistently high SoS level are partly substitutive: A weakening or even an elimination of a cause does not call the SoS level into question but would be compensated in the electricity market by adjustment reactions elsewhere. Due to these substitution possibilities, there is more than just one development path of the secure electricity supply system.

## 6 Sensitivities

Based on the reference scenario, we have calculated various sensitivities in order to quantify the effects of deviating assumptions on the development of the power supply system and the resulting changes in the respective downstream SoS analyses. Here we have carried out three sensitivity calculations, in which changed assumptions are also expected in the European electricity market model, and one sensitivity, in which a changed assumption is only made in the SoS analysis.

We have examined the following sensitivities in consultation with the BMWi:

- 1) Best-guess costs of the flexibility options emergency power systems (EPS) and voluntary load reduction by industry (DSM)
- 2) Achievement of climate protection targets through regulatory measures to reduce the capacity of coal-fired power plants on the market
- 3) Delayed cross-border grid expansion
- 4) Less physical cross-border exchange capacity than perceived by the market

### 6.1 Sensitivity 1: "best-guess cost flexibility options"

In the sensitivity "*best-guess costs flexibility options*" we have applied different annual fixed operating costs and development costs (hereinafter referred to as fixed costs) for EPS and voluntary load reduction by industry (DSM) than in the reference scenario. In the reference scenario, in agreement with the BMWi, we have adopted a conservative approach to monitoring security of supply, deviating from what we believe to be the most realistic assumption regarding the cost structures of these flexibility options and applying higher fixed costs (see also Section 4.4). Our best-guess assumption is considered in this sensitivity. The following table compares the assumptions on fixed costs in the reference scenario and in the sensitivity "*best-guess costs EPS / DSM*".

TABLE 6-1: COMPARISON OF THE ANNUAL FIXED OPERATING COSTS AND DEVELOPMENTCOSTS OF EPS AND DSM

	EPS	DSM
REFERENCE SCENARIO	<p><b>Fixed operating costs:</b> 5.000 € p.a. per MWa</p> <p><b>Development costs:</b> 20.000 € per MW</p>	<p><b>Fixed operating costs:</b> 8,000 € p.a. per MWa</p> <p><b>Development costs:</b> none</p>
SENSITIVITY "BEST-GUESS" -COSTS	<p><b>Fixed operating costs:</b> 3,000 € p.a. per MWa</p> <p><b>Development costs:</b> 20.000 € per MW</p>	<p><b>Fixed operating costs:</b> 1,000 € p.a. per MWa</p> <p><b>Development costs:</b> none</p>

Source: Own assumptions.

In our best-guess assumptions, we assume, as in previous publications<sup>174</sup>, that the development of load reduction potentials is associated largely with no or only very low development and fixed costs. In doing so, we rely on the fact that, among other things, technical requirements for load management are already widespread in industry (justified by other incentive systems, such as the network charging system). Developments in electricity prices on the day-ahead market towards more fluctuation and peak pricing in individual hours will most probably lead to (existing and new) load management potentials being used on the day-ahead market for economic reasons and without extensive additional costs. In our best-guess assumptions, we therefore apply low annual fixed costs of € 1,000 per

<sup>174</sup> See e.g. r2b energy consulting (2015a), r2b energy consulting (2015b).

MW and year, which consist of fundamental costs for maintaining the potential. Additional profit expectations or development costs are not assumed.<sup>175</sup>

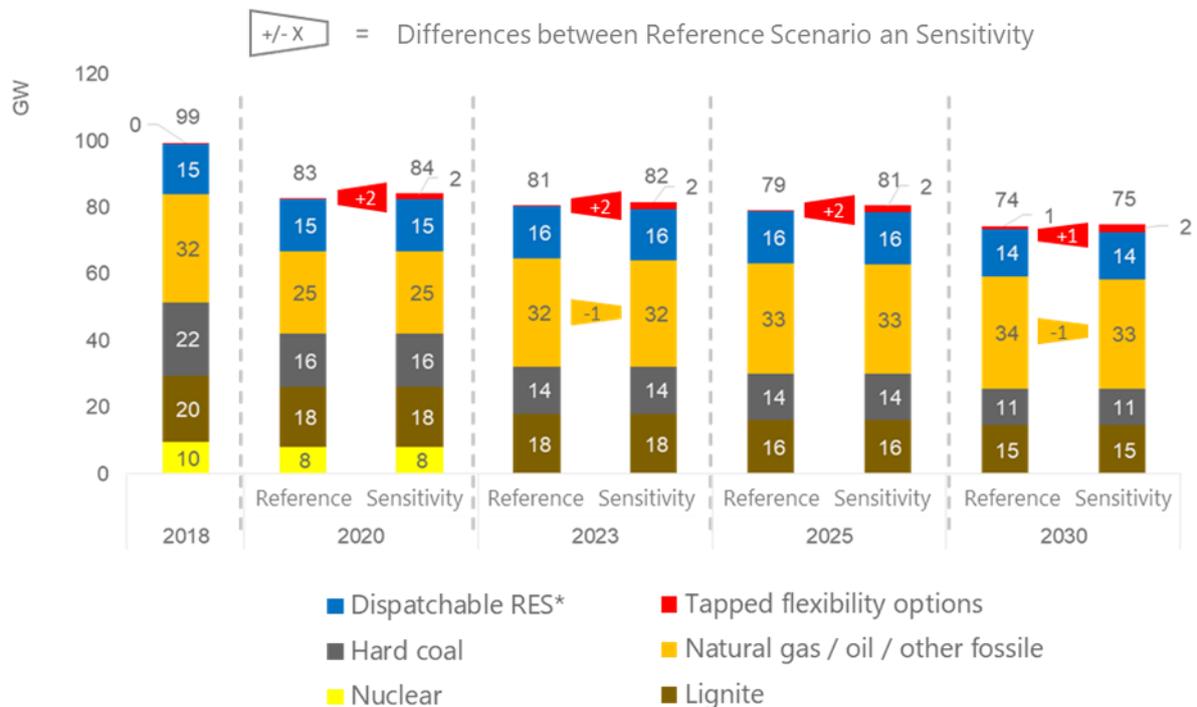
### **6.1.1 Results of electricity market simulations**

In this section, we show how the assumptions on the cost structures of the flexibility options (which differ from the reference scenario), affect the development of the power plant fleet and the development of flexibility options on the electricity market in Germany and on the electricity markets in the other countries considered. First of all, the development of the installed capacity of the German power plant fleet and the development of flexibility options in comparison with the reference scenario is shown in Figure 6-1.

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<sup>175</sup> In the reference scenario, however, in agreement with the BMWi, we have used annual fixed costs of € 8,000 per MW and year to present particularly conservative assumptions in the area of flexibility potentials. These consist of annualised one-off development costs of € 10,000 per MW with a three-year depreciation period and an interest rate of 7.5 %, as well as annual fundamental provision costs and additional profit expectations of € 4,000 per MWa.

FIGURE 6-1: COMPARISON OF THE DEVELOPMENT OF THE POWER PLANT FLEET AND DEVELOPMENT OF FLEXIBILITY OPTIONS BETWEEN THE SENSITIVITY "BEST-GUESS COSTS FLEXIBILITY OPTIONS" AND REFERENCE SCENARIO IN GERMANY



\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES

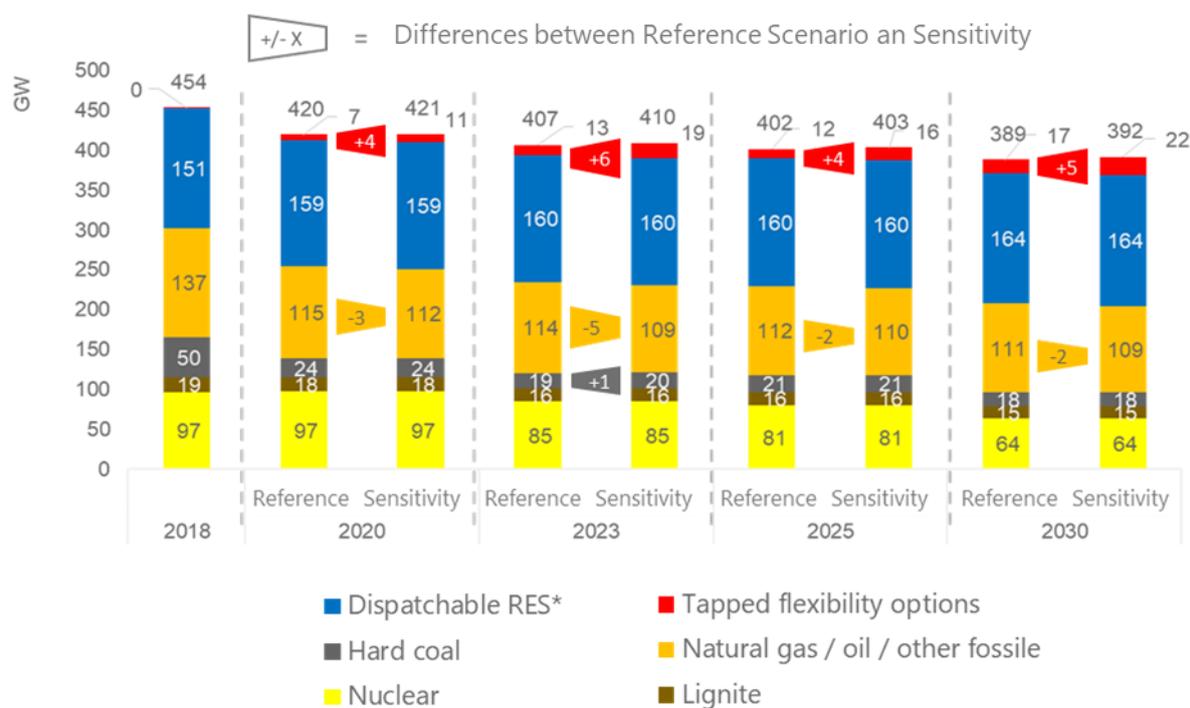
Source: Own calculations.

The assumption of the more cost-effective flexibility options compared to the reference scenario has only a very minor effect on the installed power plant capacity in Germany in the simulation calculations. The installed capacity based on natural gas in 2023 is approx. 0.7 GW and in 2030 approx. 0.9 GW below the capacity in the reference scenario. However, the lower fixed costs of the flexibility options mean that in Germany approx. 1.8 GW of flexibility options will be developed in the form of DSM and EPS as early as 2020. The tapped capacity remains more or less constant in the course of time until 2030 and is approx. 1.3 GW above the developed capacity in the reference scenario in 2030. Even in this sensitivity, the development of DSM by the year 2030 is significantly below the potential of

2.5 GW already tapped today according to the evaluation of the Federal Network Agency's DSM monitoring pursuant to Section 51a EnWG.<sup>176</sup>

The effects of the assumption of lower fixed costs for flexibility options on their development and the development of the power plant portfolio in the foreign countries taken into account are shown in Figure 6-2.

FIGURE 6-2: COMPARISON OF THE DEVELOPMENT OF THE POWER PLANT PARK AND DEVELOPMENT OF FLEXIBILITY OPTIONS BETWEEN THE SENSITIVITY OF "BEST-GUESS COSTS FLEXIBILITY OPTIONS" AND REFERENCE SCENARIO IN THE FOREIGN COUNTRIES CONSIDERED



\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES

Source: Own calculations.

Even in the foreign countries considered, more flexibility options are developed than in the reference scenario. In 2020, the developed capacity of approx. 11 GW will be about 4 GW above that of the reference scenario. In 2023, approx. 19 GW and thus 6.6 GW more capacity in flexibility options will be developed. In 2030, a total of about 22 GW in the 14 countries considered (excluding Germany) will be

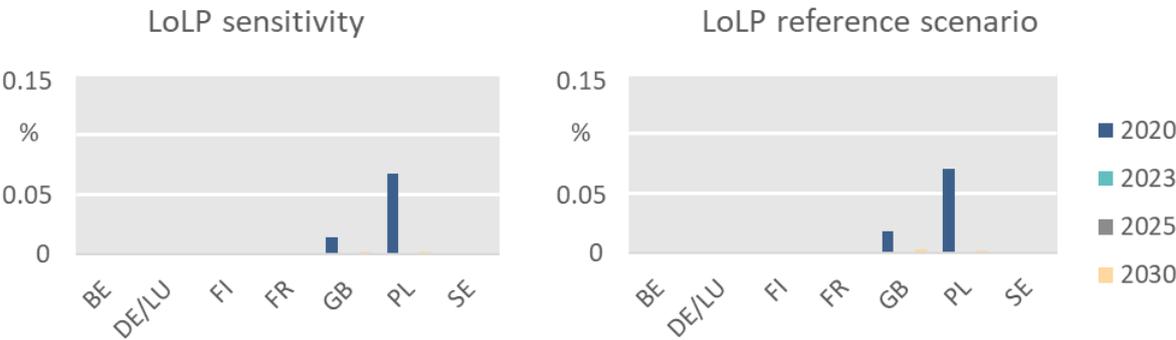
<sup>176</sup> See section 4.4.2.

developed (about 5.4 GW more flexibility options than in the reference scenario). At the same time, the comparatively favourable availability and the associated higher development of flexibility potentials lead to a change in the economic efficiency of conventional power plants. As a result, less power plant capacity based on natural gas is available on the market over the entire observation period. In 2020 there will be approx. 2.9 GW less power plant capacity installed, in 2023 approx. 4.9 GW and in 2025 and 2030 approx. 2.4 GW less power plant capacity is installed. This in turn leads to a slight improvement in the profitability of coal-fired power plants, which in 2023 will temporarily leave approx. 0.7 GW more capacity on the grid, which will already be decommissioned endogenously in the reference scenario.

### 6.1.2 Results of SoS analyses

The LoLP values of the "best-guess cost flexibility options" sensitivity are compared to those of the reference scenario in Figure 6-3. As in the discussion of the reference scenario, for reasons of clarity the presentation is limited to Germany/Luxembourg and those countries in which a value greater than zero occurs in at least one year under review.

FIGURE 6-3: LoLP IN SENSITIVITY "BEST-GUESS COST FLEXIBILITY OPTIONS" FOR DE/LU\* AND FOR COUNTRIES WITH INDICATORS > 0 COMPARED TO REFERENCE SCENARIO

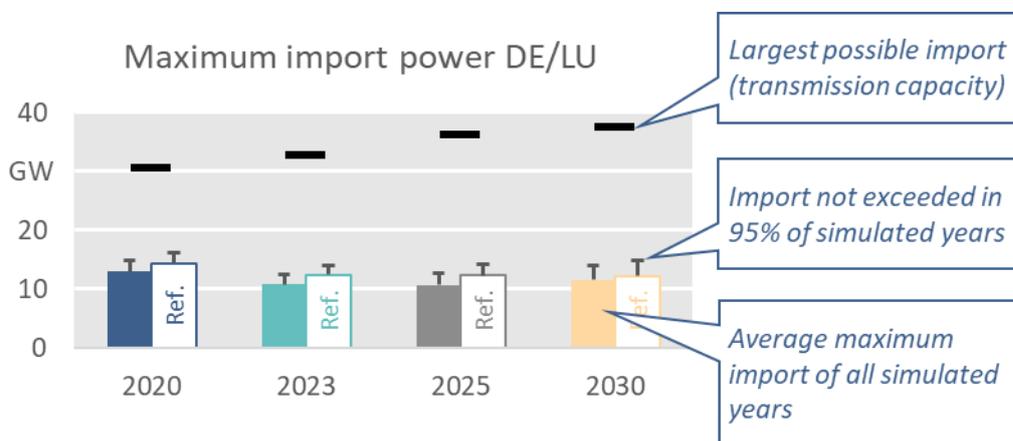


Source: Own representation. \* Germany and Luxembourg form a common bidding zone in the electricity market, therefore DE results also apply to LU

The LoLP values of sensitivity show only marginal differences to those of the reference scenario. In Germany/Luxembourg, LoLP remains zero in the entire time span. This corresponds to a load balancing probability of 100 %.

The maximum import capacity required to avoid load excess is somewhat lower than in the reference scenario (Figure 6-4). The reason for this is that more flexibility options (voluntary load reduction by industry and EPS) are being opened up as a result of the lower cost estimates in Germany and abroad.

FIGURE 6-4: REQUIRED\* IMPORTS TO DE/LU IN SENSITIVITY "BEST-GUESS COST FLEXIBILITY OPTIONS"



Source: Own representation. \* Imports required to avoid loss of load. Market imports may deviate from this.

Overall, the SoS level on the electricity market in Germany remains very high in this sensitivity over the entire observation period up to 2030, and German consumers can be supplied securely at any time.

## 6.2 Sensitivity 2: "Achievement of climate protection targets"

In order to achieve the national climate protection targets of the Federal Government, CO<sub>2</sub> emissions from German power generation must be reduced substantially in the coming years. Against this background, the Federal Cabinet decided in June 2018 to set up the Commission "Growth, Structural Change and Employment". One conceivable option for this is an instrument where the capacity of lignite-fired and hard-coal-fired power plants on the electricity market is in line

with the achievement of the national emission reduction target in 2030 (assumption here: 180 to 188 million t CO<sub>2</sub> for all electricity generation plants, of which 133 to 141 million t CO<sub>2</sub> for electricity generation plants in the energy sector).

This instrument can be implemented, for example, in the form of the regulatory decommissioning of coal-fired power plants, by legally establishing the latest decommissioning dates for all coal-fired power plant units and decommissioning the plants accordingly or transferring them to a category of available reserve.<sup>177</sup>

Since such an instrument can have an impact on security of supply, we have considered it necessary to include this aspect in our calculations. Without knowing or anticipating the proposal of the "Growth, Structural Change and Employment" Commission to achieve the climate protection targets in 2030, which is currently being drafted<sup>178</sup>, we have designed a hypothetical path for reducing the output of coal-fired power plants on the market as follows:

- A decommissioning path is set once, which determines a concrete and final latest exogenous decommissioning date for each of the German coal-fired power plants (endogenous decommissioning for economic reasons can take place earlier). The order of shutdowns is ascending by commissioning date (IBN).
- For the illustration of the instrument in the simulation calculations, a commissioning date was used which, with a few exceptions, corresponds to the data of the power plant list of the Federal Network Agency dated 2nd February 2018.<sup>179</sup> In cases of doubt, e.g. if several IBNs are specified for a

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<sup>177</sup> Irrespective of whether the plants are decommissioned or transferred to a reserve, we speak in the following of decommissioning.

<sup>178</sup> The model calculations on which the present report is based were carried out in the second half of 2018.

<sup>179</sup> When defining a decommissioning path based on the criterion "age", the commissioning date of a power plant must first be defined. It is obvious to use the "first day of commercial electricity generation of the generation unit currently in operation" for this purpose (as defined in the BNetzA power plant list). However, it is also necessary to define how modernizations, retrofits, the exchange of individual power plant parts or a possible fuel change of a plant are to be handled.

power plant unit in the list of the Federal Network Agency, we have determined a clear commissioning date on the basis of individual research in consultation with the BMWi. In the case of a fuel change to the combustion of lignite or hard coal, the date of the fuel change was used as the commissioning date.

In addition, the following measures have been taken into account to accompany (however unaware) the Commission's proposal to achieve the climate protection targets in 2030:

- **Lignite-immediate measure 2020:** Decommissioning of around 5 GW of the oldest large lignite-fired power plant units at the beginning of 2020 (also selected by commissioning date).
- **Early coal cogeneration replacement measure:** Coal cogeneration plants commissioned before 1990 and significant heat generation for which no concrete replacement measures have yet been announced by the operators will be replaced by natural gas cogeneration early / prematurely in 2024 or 2025 as part of an additional coal cogeneration replacement measure.<sup>180</sup> This includes power plant units with an installed capacity of approx. 0.2 GW based on lignite and approx. 2.7 GW based on hard coal.

Figure 6-5 shows the exogenous development of the installed capacity of coal-fired and lignite-fired power plants given to the model with the following differentiation:

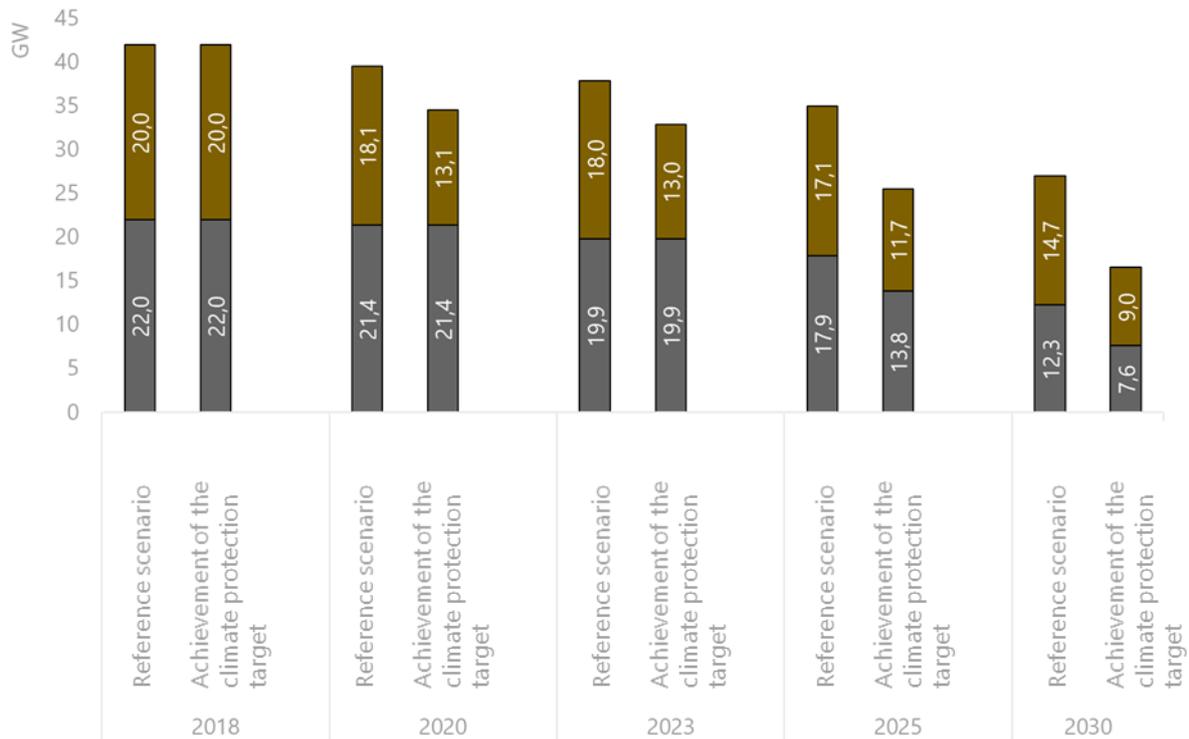
- Without additional measures (corresponds to "*reference scenario*")
- With climate protection measures to reduce the output of coal-fired power plants on the market in order to achieve the 2030 climate target

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<sup>180</sup> The term "early / prematurely" refers to the fact that the blocks would in any case have to be replaced once the technical lifetime had been reached.

before endogenous decommissioning ("achievement of the climate protection target")

FIGURE 6-5: EXOGENOUS ASSUMPTIONS FOR THE DEVELOPMENT OF THE INSTALLED CAPACITY OF COAL-FIRED AND LIGNITE-FIRED POWER PLANTS IN COMPARISON (WITHOUT ENDOGENOUS DECONSTRUCTIONS)



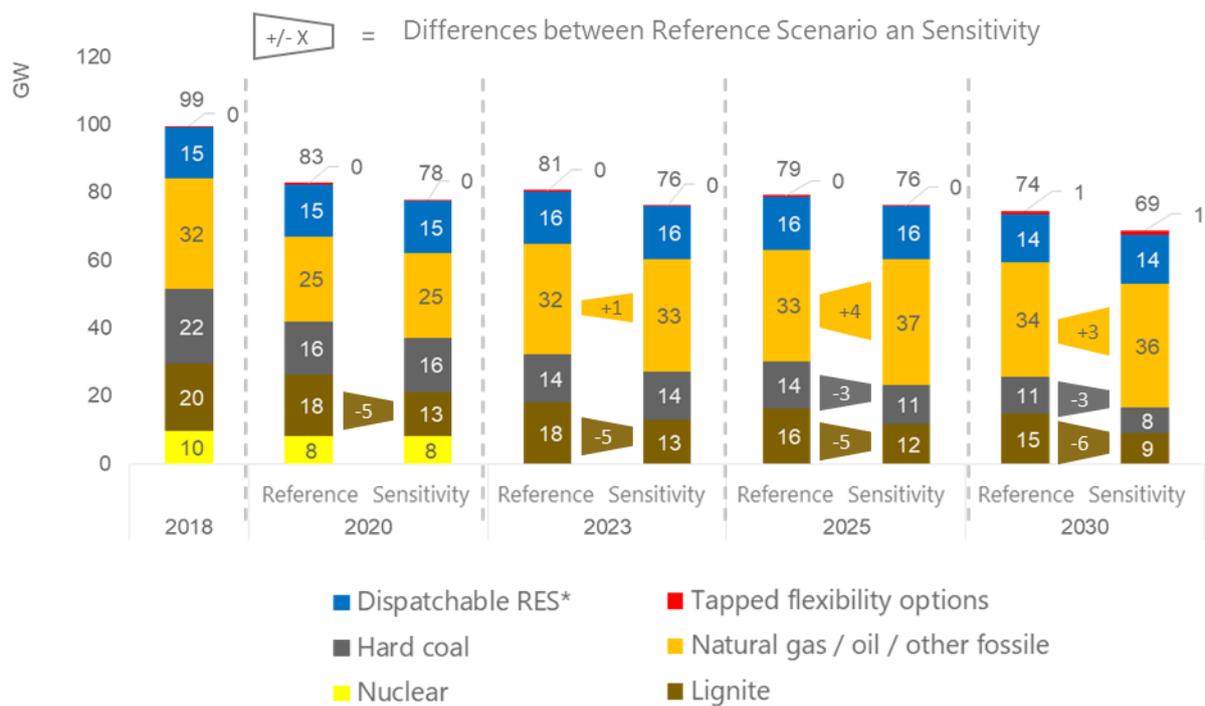
Source: Own assumptions unaware of the "Growth, Structural Change and Employment" Commission's proposal to achieve climate change objectives in 2030.

Based on an output of approx. 22 GW of hard coal-fired power plants and approx. 20 GW of lignite-fired power plants on the market in 2018, the output in the reference scenario will be reduced to 12.3 GW of hard coal and 14.7 GW of lignite by 2030 due to exogenous model specifications. In addition, the installed capacity is further reduced to approx. 7.6 GW hard coal and approx. 9 GW lignite in 2030 due to the assumptions on additional climate protection measures to achieve the climate objective 2030 as well as further exogenously specified developments on technical lifetimes and research information on planned shutdowns or planned replacements. In this scenario, the climate protection sector objective for the energy sector is achieved.

## 6.2.1 Results of electricity market simulations

In this section, we show how the measures in the sensitivity "Achievement of Climate Protection Target " affect the development of the remaining power plant fleet and the development of flexibility options on the electricity market in Germany and on the electricity markets in the other countries considered. First, the development of the installed capacity of the German power plant fleet and the development of flexibility options in comparison with the reference scenario is shown in Figure 6-6.

FIGURE 6-6: COMPARISON OF THE DEVELOPMENT OF THE POWER PLANT FLEET AND DEVELOPMENT OF FLEXIBILITY OPTIONS BETWEEN CLIMATE PROTECTION SENSITIVITY AND REFERENCE SCENARIO IN GERMANY



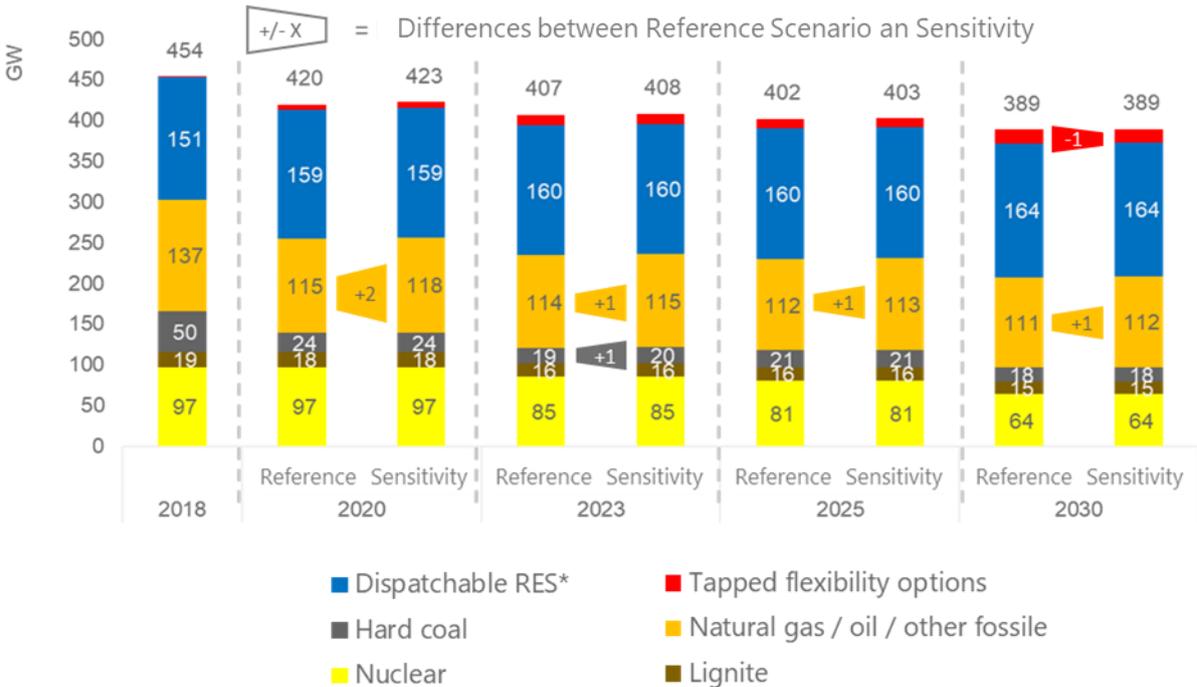
\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES

Source: Own calculations.

The achievement of the national emission reduction target (sector target of the energy industry) is guaranteed with a capacity of hard coal-fired power plants reduced by approx. 3 GW in 2030 compared to the reference scenario and a capacity of lignite-fired power plants on the electricity market reduced by approx.

6 GW. The lower capacity of coal-fired power plants on the electricity market compared to the reference scenario is partly compensated by a 3 GW higher capacity of power plants based on natural gas. These are natural gas CHP plants that replace the omitted CHP heat generation of the coal-fired power plants that have been decommissioned in addition to the reference scenario. The remainder of the lower output of coal-fired power plants is offset by the greater use of balancing effects (imports) and a slightly higher capacity in the other countries taken into account (see Figure 6-7).

**FIGURE 6-7: COMPARISON OF THE DEVELOPMENT OF THE POWER PLANT FLEET AND DEVELOPMENT OF FLEXIBILITY OPTIONS BETWEEN CLIMATE PROTECTION SCENARIO AND REFERENCE SCENARIO IN THE CONSIDERED OTHER COUNTRIES**



\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES

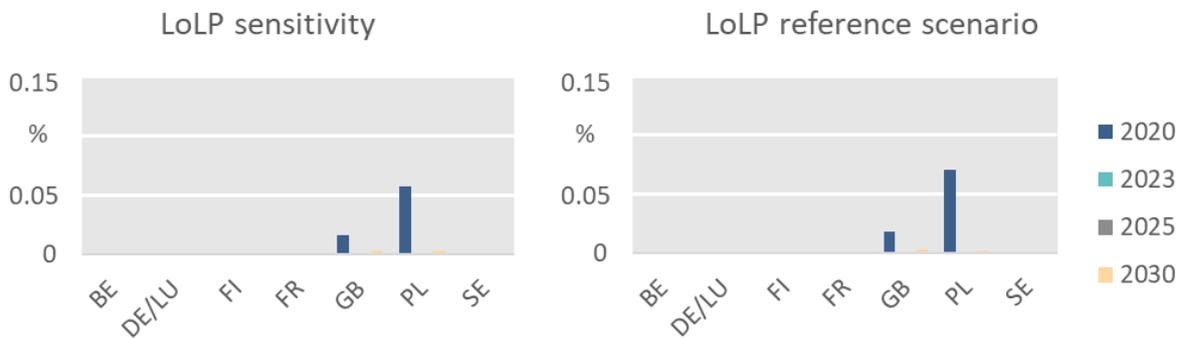
Source: Own calculations.

The lower capacity of coal-fired power plants in Germany on the electricity market leads to a slightly higher capacity of power plants based on natural gas in the foreign countries considered. In the year 2030 this will amount to approx. 1 GW, whereby at the same time about 1 GW less flexibility options (DSM and EPS) will be tapped.

## 6.2.2 Results of SoS analyses

The LoLP values of the sensitivity "Achievement of Climate Protection Target" are compared with those of the reference scenario in Figure 6-8. For reasons of clarity, the presentation is again limited to Germany/Luxembourg and those countries in which a value greater than zero occurs in at least one year under review.

FIGURE 6-8: LoLP IN THE SCENARIO "CLIMATE PROTECTION TARGET ACHIEVEMENT" FOR DE/LU\* AND FOR COUNTRIES WITH INDICATORS > 0 COMPARED TO THE REFERENCE SCENARIO



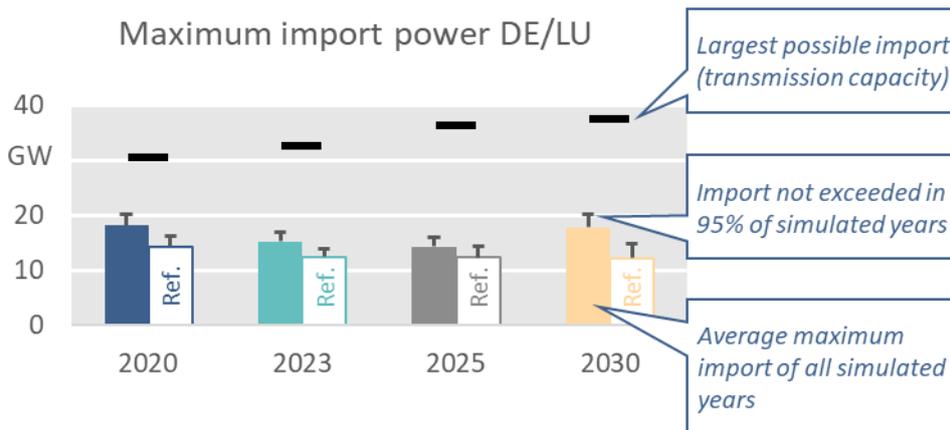
Source: Own representation. \* Germany and Luxembourg form a common bidding zone in the electricity market, therefore DE results also apply to LU

Also with this sensitivity, the LoLP values show only marginal differences to those of the reference scenario. In Germany/Luxembourg, LoLP remains zero in the entire time span. This corresponds to a load balancing probability of 100 %. The reason for this continues to be the aspects mentioned in section 5.4 in connection with the robustness previously mentioned there.

The maximum import capacity required to avoid loss of load, by contrast, increases significantly compared with the reference scenario. The net reduction in the capacity of dispatchable generation plants of gas and coal-fired power plants therefore means that greater use of imports must be made. The average import energy required increases to between 1 % (2020) and 0.6 % (2030) of gross electricity consumption (compared to less than 0.5 % in the reference scenario). The level of imports, however, remains well below the maximum import capacities of

the respective years under review. Hence, also in this sensitivity the level of imports required for security of supply can be characterised as low in comparison with (future) network capacity.

FIGURE 6-9: REQUIRED\* IMPORTS TO DE/LU IN THE SCENARIO "CLIMATE PROTECTION TARGET ACHIEVEMENT".



Source: Own representation. \* Imports required to avoid loss of load. Market imports may deviate from this.

Overall, the SoS level on the electricity market in Germany remains very high in this sensitivity over the entire observation period up to 2030, and German consumers can be supplied securely at any time.

### 6.3 Sensitivity 3: "Delayed grid expansion"

This sensitivity is used to examine the impact of a delay in cross-border grid expansion compared with the reference scenario on security of supply on the electricity market. In agreement with the BMWi, a delay of three years is generally assumed. An exception to this are grid expansion projects that are included in the reference scenario from 2020 onwards and that are already under construction; these are also included in the sensitivity from 2020 onwards. It is also assumed that the delay in grid expansion is foreseeable for market participants.

These assumptions are implemented by postponing the commissioning years of the projects concerned by three years and then reassigning them to the years under review.<sup>181</sup> The network capacity model is then updated.

The updated network capacity model is then considered in both methodological steps of the analysis, i.e. in both scenario generation and SoS analysis. In this way, it is simulated that market adjustment reactions are possible in the event of foreseeable delays in network expansion.

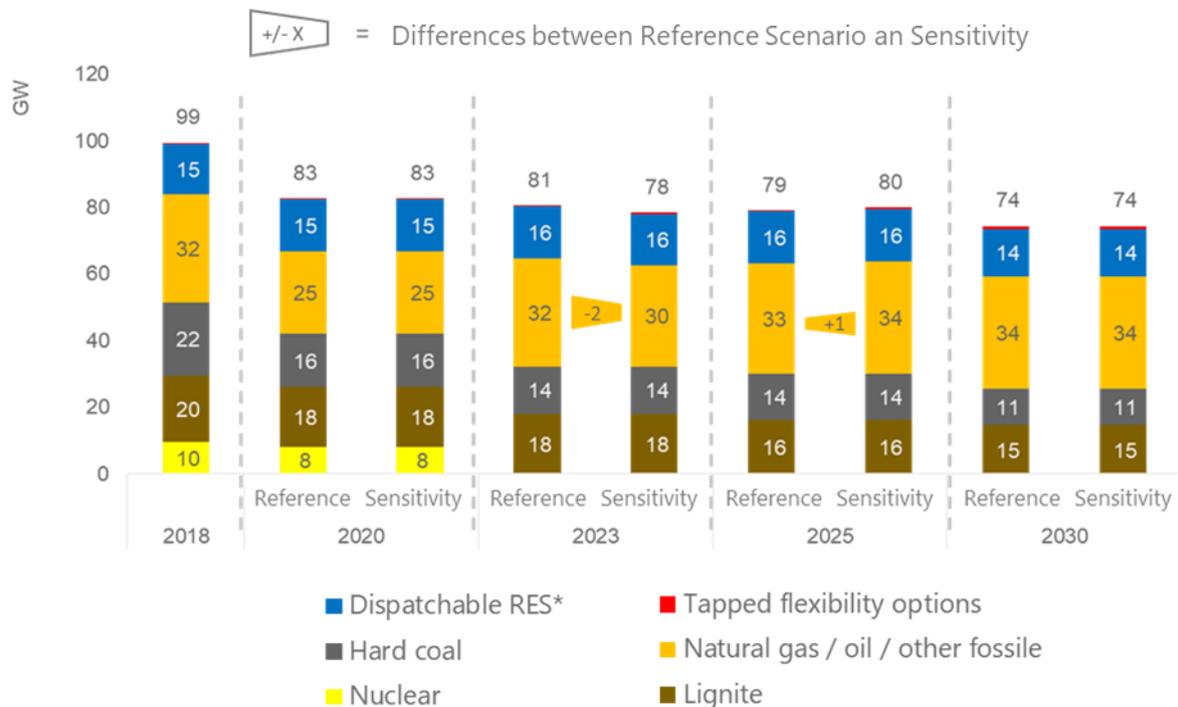
### **6.3.1 Results of electricity market simulations**

Delays in the expansion of the interconnectors between the countries considered in the analyses have a potential impact on the development of the power plant fleet and the development of flexibility options in the context of the endogenous determination of the scenario with the electricity market model. In the following Figure 6-10, we first describe the effects of the delayed grid expansion on the German power plant fleet and the development of flexibility options in Germany.

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<sup>181</sup> A project-specific list of this assignment can be found in Appendix B.1

FIGURE 6-10: COMPARISON OF THE DEVELOPMENT OF THE POWER PLANT FLEET AND FLEXIBILITY OPTIONS BETWEEN THE SENSITIVITY "DELAYED GRID EXPANSION" AND REFERENCE SCENARIO IN GERMANY



\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES

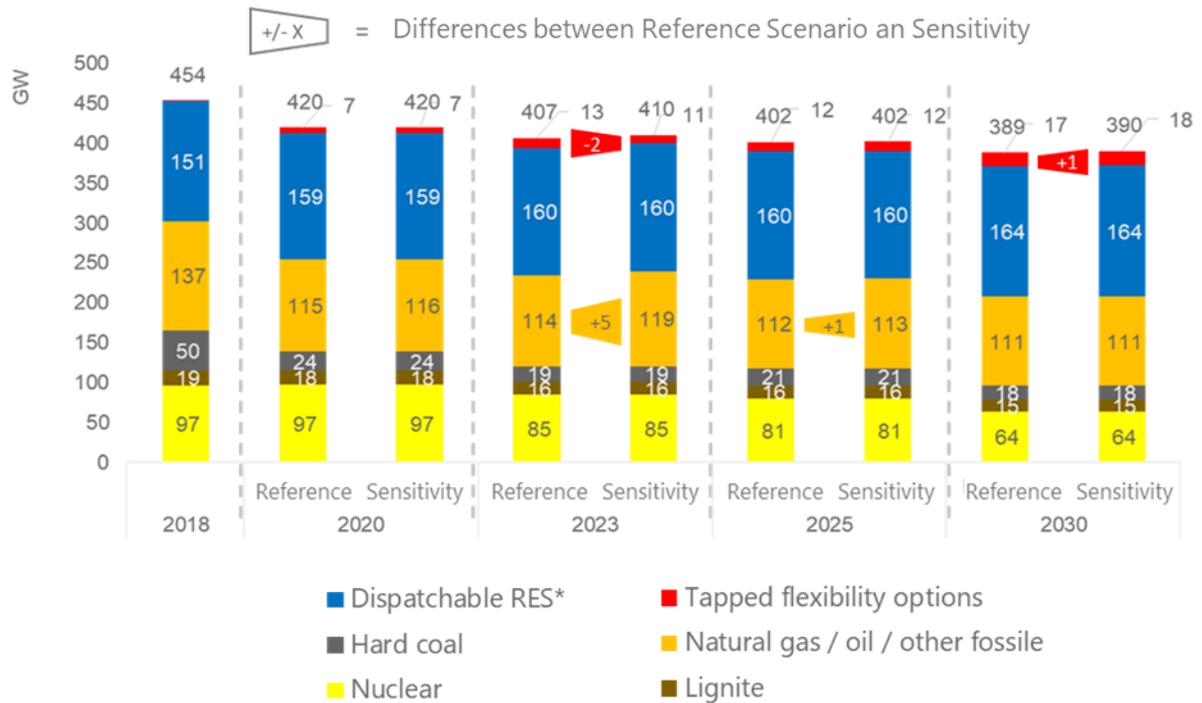
Source: Own calculations.

The repercussions of the delayed expansion of the Interconnectors on the German power plant fleet are very slight and not clear in the direction of action. In 2023, for example, there will be approx. 2.2 GW fewer natural gas-based power plants on the market, and in 2025 approx. 0.8 GW more will be on the market than in the reference scenario. In order to better understand this heterogeneous picture of the repercussions, it is necessary to consider (at the same time) the effects on the other countries considered.

This shows that in 2023, approx. 5.1 GW more natural gas-based power plants will be available on the market than in the reference scenario. This in turn appears to reduce the profitability of natural gas-based power plants in Germany, so that there is less capacity on the market there (as described above). In 2025, there will be only about 0.5 GW more natural gas-based power plants on the market in the

foreign countries considered and about 0.8 GW more in Germany than in the reference scenario.

FIGURE 6-11: COMPARISON OF THE DEVELOPMENT OF THE POWER PLANT FLEET FLEXIBILITY OPTIONS BETWEEN THE SENSITIVITY OF "DELAYED GRID EXPANSION" AND THE REFERENCE SCENARIO IN THE FOREIGN COUNTRIES CONSIDERED.



\* Storages and pumped storages, bioenergy (incl biogenic part of waste) and other RES

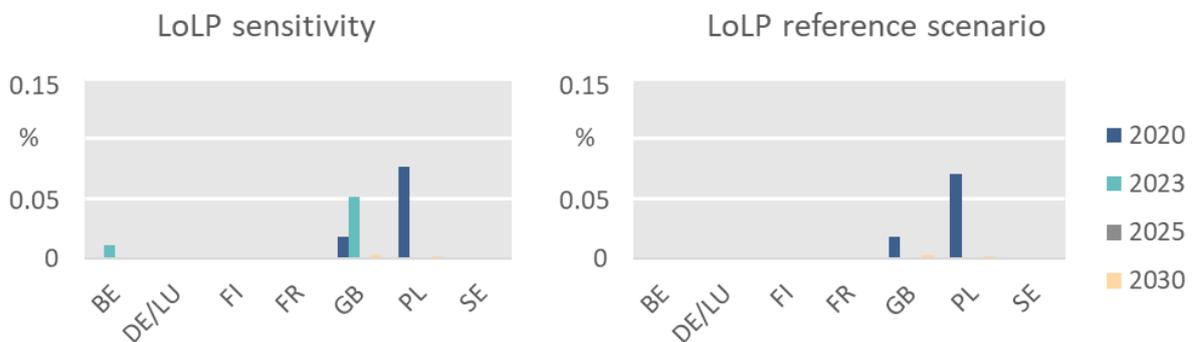
Source: Own calculations.

In 2023, the higher output based on natural gas in the foreign countries considered also means that approx. 2.2 GW fewer flexibility options will be developed in the form of DSM and EPS. In 2025, the delayed expansion of the grid will lead to an approx. 0.5 GW higher capacity of power plants based on natural gas and in 2030 to a slight increase of the flexibility options developed by approx. 1.5 GW compared to the reference scenario.

### 6.3.2 Results of SoS analyses

The LoLP values of the sensitivity "delayed network expansion" are compared with those of the reference scenario in Figure 6-12. For reasons of clarity, the presentation is again limited to Germany/Luxembourg and those countries in which a value greater than zero occurs in at least one year under review.

FIGURE 6-12: LoLP IN THE SCENARIO "DELAYED GRID EXPANSION" FOR DE/LU\* AND FOR COUNTRIES WITH INDICATORS > 0 COMPARED TO THE REFERENCE SCENARIO



Source: Own representation. \* Germany and Luxembourg form a common bidding zone in the electricity market, therefore DE results also apply to LU

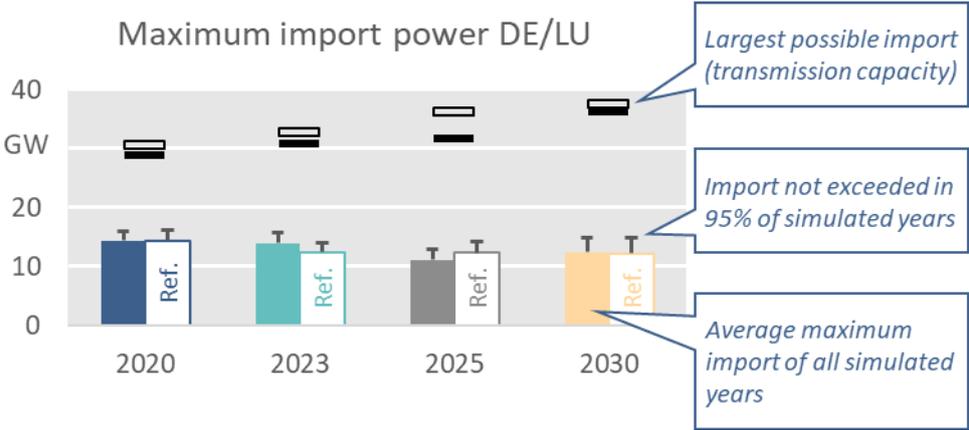
In Germany/Luxembourg, LoLP remains zero in the entire time span. This corresponds to a load balancing probability of 100 %. For Great Britain and to a much lesser extent also for Belgium, the sensitivity shows an increase in the LoLP in the year 2023. These result from the assumed delay of several HVDC connections to Great Britain as well as of an expansion project between France and Belgium (see Table B-1). In addition, we assumed that, due to the required lead time, the tender volumes for the UK capacity market would not be adjusted for the delayed grid expansion. This can also tend to increase the LoLP in the UK. However, this does not affect the later years under consideration.

The effect of the assumed delay of the grid expansion on the maximum possible import capacity to Germany/Luxembourg can be seen from the difference between the "empty" and the "full" black bars in the upper part of the diagram in Figure 6-13. This reduction has very little influence on the imports required to

avoid load excess in Germany/Luxembourg, as adaptation reactions to the delayed grid expansion in terms of generation and flexibility are taking place both in Germany and abroad (see previous section). In the two years under review showing the greatest changes, 2023 and 2025, the sign of this change is consistent with - i.e. opposite to - the sign of the change in (gas) generation capacity in Germany (see Figure 6-10).<sup>182</sup>

Overall, also in this sensitivity the level of imports required for security of supply can be characterised as low compared to the (future) existing network capacity.

FIGURE 6-13: REQUIRED\* IMPORTS TO DE/LU IN THE "DELAYED NETWORK EXPANSION" SCENARIO



Source: Own representation. \* Imports required to avoid loss of load. Market imports may deviate from this.

Overall, also in this sensitivity the SoS level on the electricity market in Germany remains very high over the entire period under review up to 2030, and German consumers can be supplied securely at any time.

<sup>182</sup> In 2023, the installed capacity of the technology class "gas/oil/other fossil" decreases by 2 GW in the sensitivity compared to the reference scenario. Consequently, the necessary imports increase slightly. In 2025, the reverse effect occurs, because then the installed capacity of this technology class is in the sensitivity about 1 GW above the reference scenario, and the necessary imports are consequently reduced slightly.

## 6.4 Exogenous sensitivity: "Limited cross-border transmission capacity"

In the reference scenario it is assumed that the level of cross-border exchange capacity foreseen under the CEP can also be physically realised. Section 3.3.4 noted that this will require increased use of various congestion management measures.

In the context of a sensitivity, the deviating case is investigated that the physical cross-border exchange capacity is lower than the "CEP level" perceived by the electricity market and thus effective there. This can occur, for example, if the above measures are only incompletely implemented.

For the sensitivity, a lump reduction of 10 % is applied to all cross-border capacities in the region modelled using the flow-based approach (see Appendix B.1). With these reduced capacities, a new SoS analysis for the unchanged system of the reference scenario in terms of generation plants and flexibilities is then carried out. This reflects the fact that market participants do not perceive the reduced network capacities and therefore do not take them into account because the "virtual" capacity at CEP level is available in all market processes (as in the generation of the reference scenario).

### 6.4.1 Results of SoS analyses

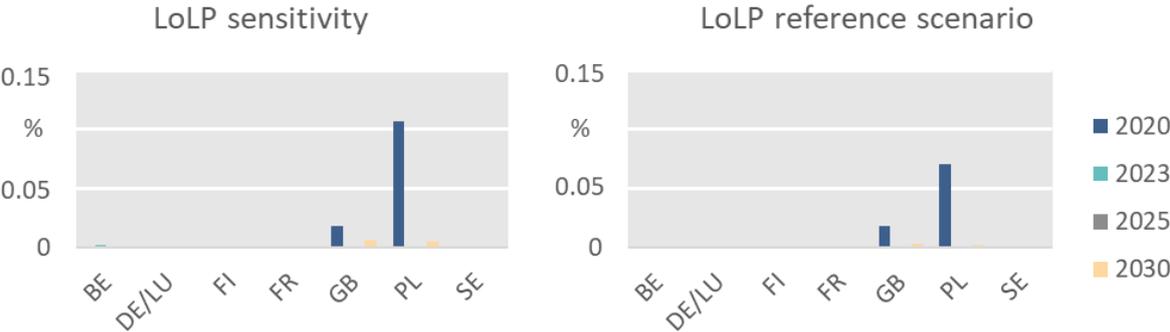
The result of the SoS analysis shows an increase in the LoLP in Poland in 2020, since the limited import capacity is already effective there in the reference scenario (Figure 6-14). In the following years, however, the LoLP there falls practically to zero, as in the reference scenario. Marginal increases in the LoLP compared with the reference scenario have also been recorded in Belgium and the UK.<sup>183</sup>

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<sup>183</sup> However, due to the peripheral location in the model, the indicators for foreign countries are subject to uncertainties, see section 3.3.2.

For the period after 2020, however, the impact on the calculated SoS level is negligible in all countries. For Germany/Luxembourg, LoLP remains zero in the entire time span. This corresponds to a load balancing probability of 100 %.

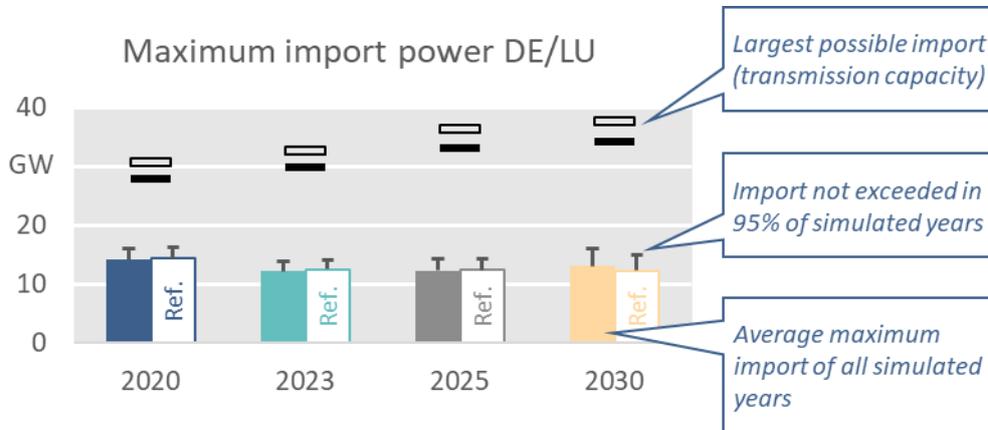
**FIGURE 6-14: LoLP IN THE "LIMITED CROSS-BORDER TRANSMISSION CAPACITY" SENSITIVITY FOR DE/LU\* AND FOR COUNTRIES WITH INDICATORS > 0 COMPARED TO THE REFERENCE SCENARIO**



Source: Own representation. \* Germany and Luxembourg form a common bidding zone in the electricity market, therefore DE results also apply to LU

The level of imports required to avoid loss of load in Germany also remains practically unchanged from the reference scenario (Figure 6-15). This is due to the fact that the cross-border exchange capacity is not binding in the reference scenario, and that the necessary imports show a clear difference to the lower maximum import capacity compared to the reference scenario even in this sensitivity.

FIGURE 6-15: REQUIRED\* IMPORTS TO DE/LU IN THE "LIMITED CROSS-BORDER TRANSMISSION CAPACITY" SCENARIO



Source: Own representation. \* Imports required to avoid loss of load. Market imports may deviate from this.

As a result, also in this sensitivity the SoS level on the electricity market in Germany remains very high over the entire observation period up to 2030, and German consumers can be supplied securely at any time.

## 7 Accompanying measures and outlook

### Accompanying measures to ensure security of supply

Some measures are necessary or recommendable to ensure or safeguard the determined high SoS level. The implementation of necessary measures was assumed in the analyses because this can be regarded as realistic considering the combination of existing or immediately foreseeable legal obligations and the corresponding lead time.

For example, the level of import capacity required to ensure security of supply can generally be characterised as low in comparison with (future) network capacity. Nevertheless, some preparations need to be made for the increased role of cross-border balancing effects in the future.

On the one hand, this concerns the examination and, if necessary, implementation of congestion management measures in order to realise the exchange capacities (while maintaining grid security) which are obligatory according to the CEP and which were assumed in this study. This may include the use of load-flow controlling equipment, e.g. phase shifting transformers (PSTs), possibly also the installation of additional PST, the use of the grid reserve as well as redispatch within the bidding zone. In addition, the grid expansion within the bidding zone can also make a significant contribution to the physical achievability of exchange capacities in accordance with CEP.

On the other hand, preparations should be made for cross-border exchange patterns which are already permissible today (within the framework of the allocation of cross-border transmission capacities) but which are still unusual in practice. This not only relates to temporarily higher import capacity to Germany, but also, for example, increased exports from Italy. In this context, it may be necessary to adapt operational planning processes, but also grid related measures such as the installation of equipment for voltage/reactive power control.

There is also a need for coordination and, potentially, action with regard to the international coordination of market and operating rules in the event of load excess. While a rule currently applies in European day-ahead market coupling for the distribution of a load excess among all countries, the rules for dealing with a load excess in downstream processes (e.g. intraday markets, imbalance settlement mechanisms) have not yet been harmonised. Thus, firstly it is unclear whether and how a load excess would currently be distributed geographically in practice. Secondly, it is open to what extent the regulations would be adapted, e.g. harmonised, after a load excess has occurred. It would therefore appear advisable to also clearly regulate the processes downstream of the day-ahead market on an international level as a preventive measure.

In addition, measures can be taken into consideration to safeguard against unpredictable extreme events. Owing to their unknown probability of occurrence, unpredictable extreme events cannot neither be efficiently addressed in the electricity market 2.0 nor in capacity markets. Therefore, they cannot and must not be taken into account when monitoring security of supply on the electricity market and assessing whether an efficient SoS level is achieved. Hedging of unpredictable extreme events falls within the scope of risk preparedness by the state and lies outside the scope of market design. To this end, an exchange takes place between the BMWi, the Federal Network Agency and the German TSOs, in which the authors of this study are also involved in an advisory role. The effects of unpredictable extreme events can be reduced with reserves outside the electricity market, such as the already planned capacity reserve. Therefore, these unpredictable events shall also be considered in the future dimensioning of the capacity reserve.

## Outlook

In accordance with the contract, a further report on monitoring security of supply on the electricity market until 2030 is to be prepared later this year. This serves to support the regular monitoring by the BMWi provided for in Article 51(3) and (4)

EnWG. With the regular forecasts on the development of the electricity supply system and the SoS level, it is possible to check with foresight whether compliance with the SoS standard is to be expected and, whether there are still obstacles and disincentives and, if necessary, whether a later "easing" can be expected as a result of market adjustment processes. The forward-looking SoS monitoring thus ensures that there is sufficient time for implementing any measures that may be necessary to ensure an appropriate SoS level.

In addition to updating the database to updated sources and any legal changes at German and European level, we will also examine and potentially implement methodological extensions for the follow-up report.

In the area of generating scenarios for the investigation of security of supply, we plan to examine the integration of further weather years against the background of the already considerable computing times with 5 weather years. In addition, we will investigate whether the part of the balancing power that is reserved to compensate for the first hour of unplanned power plant unavailabilities can be used in the electricity market model to cover the load. In addition, we will examine whether it appears expedient to consider battery storage capacities or any future relevant technologies from the Power-to-X field in the electricity market model.

In the area of SoS analysis, it is planned to extend the modelling of cross-border transmission capacities to include HVDC failures. In addition, an extension of the evaluation of results is conceivable, for example, in order to statistically describe and display "free capacity margins" to meet demand as well as phases of cross-border assistance in both the importing and exporting direction.

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## **Appendix A    Model Description Electricity Market Simulations**

The purpose of the European electricity market model is to map the decisions of market participants (companies and consumers) at individual level, taking into account economic and political framework conditions. On this basis, the aggregated market results (e.g. installed capacities and electricity generation from different generation technologies, electricity prices on wholesale markets, CO<sub>2</sub> emissions, fuel consumption) are derived. On the one hand, technical and economic characteristics of existing generation plants and future generation options are mapped in detail. On the other hand, the requirements regarding the coverage of electricity demand, the provision of system services as well as the framework conditions of the markets resulting from the existing and planned grid infrastructure and the expected legal requirements and economic developments are taken into account in the modelling of individual decisions.

In line with the liberalised EU internal market for electricity, investment and decommissioning decisions as well as decisions on the use of generation assets taken on the basis of price signals in competitively organised markets are based on the premise that companies intend to maximise profits. Because of the additional assumption of perfect competition in these markets, this premise is identical to an economic cost minimisation, i.e. an efficient adaptation of the market through individual business decisions. In addition to the wholesale market for electricity, the markets for system services are also taken into account, in particular the markets for the provision of balancing power of various qualities - primary, secondary and minute reserve. In addition, different design options of capacity markets can be taken into account at country level and their repercussions on the other markets mentioned above can be adequately reflected.

In the case of generation plants whose construction, dismantling and use are not (or not exclusively) dependent on price signals on the wholesale market for electricity and on the balancing energy markets, such as generation plants based on renewable energy sources and CHP plants, the legal framework for promotion is shown in the model. Moreover, in the case of variable renewable energy sources (onshore and offshore wind energy, photovoltaics, hydroelectric power), the actual generation is modelled taking into account the individual intermittent energy supply. In the case of generation plants that generate heat and/or steam in addition to electricity, the local marketing possibilities for heat and/or steam are mapped within the framework of the modelling.

Electricity consumption and the demand for system services are integrated as input assumptions in the model. The same applies to specifications for the need for additional capacity in the area of capacity mechanisms. The specifications for the level and temporal structure of the electricity demand (load) and the balancing power requirement are determined on the basis of preliminary analyses and by making corresponding assumptions. There are various options for modelling flexibility on the demand side. Here, too, the decisions of market participants - in this case, electricity consumers - are simulated at the individual level depending on economic aspects and technical restrictions, e.g. in downstream industrial production processes, in the use of heat pumps in the household and commercial sectors or in the charging behaviour of electric vehicles.<sup>184</sup>

The model is designed as an instrument for simulating the European electricity market. Thus, a simultaneous analysis of the national and regional bidding zones in Europe is carried out, whereby imports and exports between the bidding zones

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<sup>184</sup> In all variants, a price elasticity of demand for electrical energy depending on the type of consumer is assumed, which is combined into an aggregated price-elastic demand function taking into account the heterogeneity of consumers.

are determined in the model. The existing and planned grid infrastructure between the modelled regions is taken into account with regard to its restrictive effect on the maximum possible exchange of electricity<sup>185</sup> between the model regions.

In the following, a general overview of the model is given. The procedure for modelling the different economic and technical aspects of decisions on investments and temporary and permanent closures, overhauls and the operation of generating plants is then described in detail. Finally, exemplary application possibilities are shown which, due to the modular structure of the model, can be variably adapted to the respective individual analysis requirements.

The presentations initially refer to a comprehensive version of the European electricity market model, so that the possibilities of application and the respective procedure are fully described. We adjust the degree of detail (e.g. temporal resolution of the model, accuracy of the mapping of technical and economic properties of generation plants as well as accuracy of the mapping of markets for system services) and the countries or regions considered in the model, the analysis period and the (optimised) weather years investigated simultaneously within the framework of weather-dependent uncertainties, depending on the problem and the scope of a certain investigation. These adaptations of the model may be necessary to reduce its complexity to such an extent that, on the one hand, due to restrictions with regard to hardware and software currently available and, on the other hand, the execution of a calculation does not exceed an appropriate runtime. Due to the modular structure of the model, these adaptations can each

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<sup>185</sup> We use a hybrid flow-based / NTC model to model the grid infrastructure by using a flow-based approach for exchanges between the bidding zones France, Belgium, the Netherlands, Germany-Luxembourg, Switzerland, Italy, Austria, the Czech Republic and Poland, which are particularly important from a German perspective. In this model, the hourly transmission capacities between the modelled countries are optimally allocated in the market depending on the respective valid feed-in and withdrawal situation in the countries within the framework of the technical feasibility of the transmission grid. The remaining modelled bidding zones are connected via NTCs. Further details can be found in Appendix B.

be made by automated specifications, without adjustments to the database or programming (i.e. the source code) being necessary.

## **A.1 Model overview**

Our European electricity market model is implemented as a linear programming problem (LP) in the modelling environment GAMS. In its comprehensive version, the model consists of approximately 20 million equations and 30 million variables. The optimal solution of the model is determined using CPLEX 12.6.3, a powerful commercial solver for solving linear programming problems.

The high complexity of the fully integrated European electricity market model requires a powerful computer infrastructure. Depending on the level of detail and the corresponding computing effort of the model, we can either use our in-house computer infrastructure or fall back on so-called cloud computing.

## **A.2 Basic structure of the model**

The basic structure of the model is shown in Figure A-1. The figure distinguishes between input data (inputs), the actual model and outputs.

The input data (inputs) can be divided into five areas. The first area describes the demand side (demand for electrical energy, demand for system services and centrally procured capacity from capacity markets and CHP-capable heat demand). In addition to hourly consumption values (load) and the balancing power procurement, input data on demand-side flexibility can also be taken into account in this area. We are currently considering the following demand-side flexibility options: Flexible industrial consumers, large-scale use of power-to-heat systems in district heating, flexible use of heat pumps in household and tertiary sector applications, and various forms of flexible charging of electric vehicles (including overhead-line trucks). The electricity generation system shall meet the requirements arising from the 'demand side' in the model.

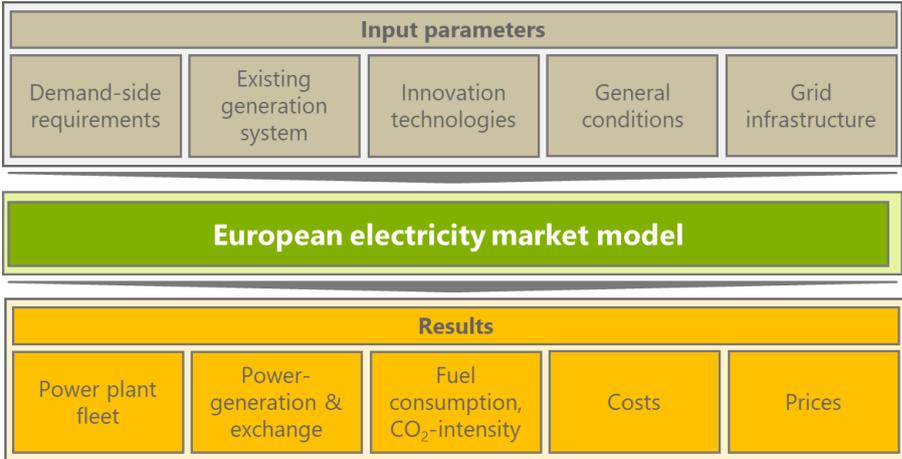
The second area is input data to the existing generation system. In addition to technical and economic parameters of existing conventional power plants as well as storage and pumped storage power plants, the necessary input data for generation plants based on renewable energy sources are also recorded in this area.

In a third area, the potentials, costs and technical properties of future generation options in conventional power plants and generation options based on renewable energy sources are mapped. These can be made available to the electricity generation system through investments, taking into account the respective costs.

The fourth area describes the economic and political framework conditions for the development and operation of the electricity generation system. These include prices for primary energy sources and CO<sub>2</sub> certificates, as well as a mapping of future measures for possible national policies regarding the use of coal in power generation.

In the fifth area, the necessary information on existing and planned grid infrastructure is integrated. Trade flows between model regions and neighbouring regions not explicitly considered in the model are stored as aggregated import and export functions, if applicable.

**FIGURE A-1: STRUCTURE OF THE EUROPEAN ELECTRICITY MARKET MODEL**



Source: Own representation.

The input data is the quantitative starting point of the model calculations. In the model, dependencies and interactions are mapped in the form of a dynamic, interregional and stochastic<sup>186</sup> cost minimization model, which are important in the context of dispatch and investment decisions in the generation system.

After the solution of the model, various model results can be derived and analyzed. Two types of results can be distinguished. On the one hand, there are output values which can be assigned to the values of the variables within the framework of the optimal solution. These include the following result variables:

- Installed capacities as well as expansions and shutdowns of conventional power plants differentiated by generation technologies,
- Power generation and provision of system services (in particular in the area of balancing energy markets) from fossil fuel and renewable energy generation plants,
- Fuel consumption and CO<sub>2</sub> emissions from conventional power plants differentiated by generation technologies,
- Costs of the overall system with a differentiation by cost types (e.g. fuel costs, costs for CO<sub>2</sub> emissions, personnel, maintenance and repair costs as well as investment and capital costs),
- Imports and exports for the model regions.

On the other hand, there are also so-called marginal costs or shadow prices<sup>187</sup> of (in)equations of the model from which, among other things, prices on the wholesale market and prices on the balancing energy markets can be derived. If the model has been calculated, taking into account capacity markets, prices for the reserved capacity can also be derived under these market design options (where

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<sup>186</sup> Within the scope of this study, we exclusively depict a stochastic with regard to uncertain future weather conditions in the form of weather years.

<sup>187</sup> Alternatively, these are also referred to as margins or dual values of the linear programming problem.

the marginal cost of the additional capacity is evaluated on the basis of the [national] reserved capacity on these capacity markets).

The possibilities of regional and temporal resolution of the results arise directly from the specifications of the degree of detail in the modelling. In general, all results are available in up to hourly resolution for all modelled years and all model regions.

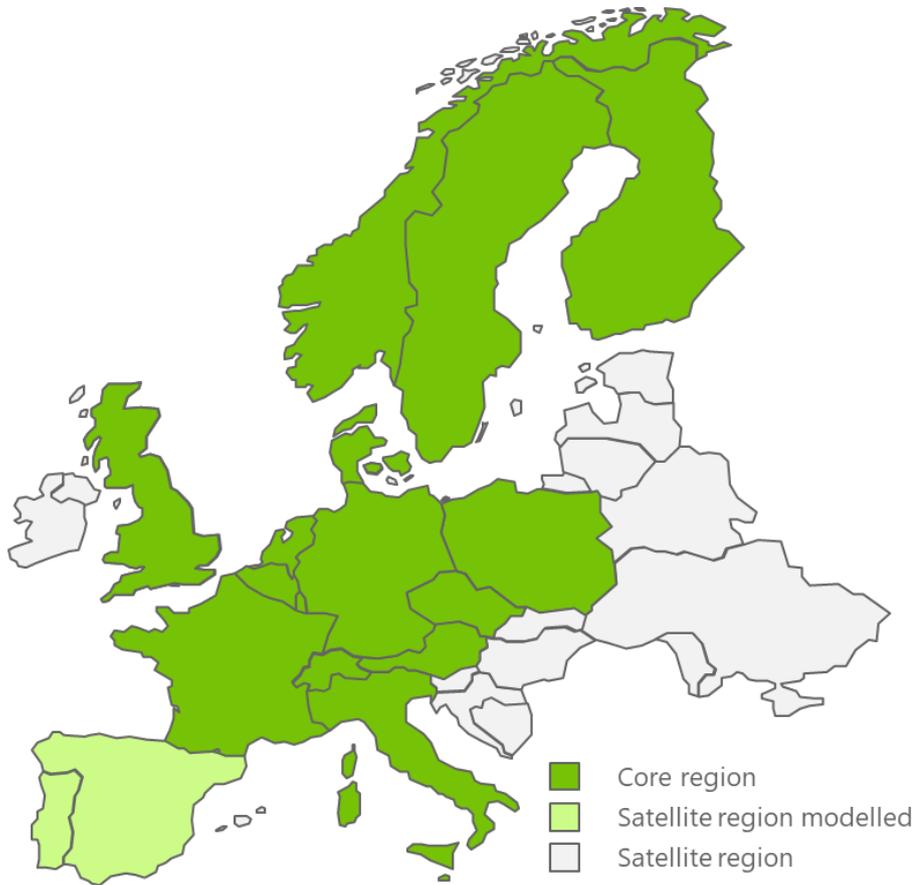
### **A.3 Model and satellite regions**

The model distinguishes between core regions and explicitly modelled and non-modelled satellite regions. In this study, we consider Germany, its neighbouring countries, Italy, Scandinavia and Great Britain as core regions, while the Iberian Peninsula is considered a modelled satellite region. Imports and exports between core regions and between core and modelled satellite regions are represented endogenously in the model. We simulate imports and exports between satellite regions<sup>188</sup> and the respective adjacent core regions using aggregated import and export functions.

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<sup>188</sup> As satellite regions we have modeled in particular the Eastern European countries (east of PL/CZ/AT).

FIGURE A-2: MODEL REGIONS CONSIDERED IN THIS ANALYSES



Source: Own representation.

Both between the core regions and between the core and neighbouring satellite regions, maximum capacity values of power exchange (so-called interconnector capacities) are determined on the basis of the existing and planned grid infrastructures. Taking into account these maximum values of power exchange as well as grid losses during large-scale transport flows, imports and exports of electrical energy between neighbouring regions can take place. Within one model region it is assumed that there are no congestion problems (to an extent relevant for economic considerations) or that these problems are solved by so-called redispatching.

## A.4 Temporal resolution and optimization horizon

A simultaneous analysis of short-term dispatch decisions and of medium and long-term decisions on investments and shutdowns (as well as overhauls) of generation plants requires both a high temporal resolution and a long observation period in the simulation.

The dispatch of generating plants depends both on the level of the respective load at the time under consideration and - due to dynamic effects - on the chronological order of load levels. The load structure can usually be accurately mapped by typical daily cycles, if differences between day types (working days, weekends, public holidays) and the seasons or months of the year are taken into account (see Figure A-3).

FIGURE A-3: MONTHLY DEMAND STRUCTURES (TOP) AND LOAD-DEPENDENT DAILY CYCLES (BOTTOM) IN WINTER FOR THE WEATHER YEAR 2011 IN GERMANY



Source: Own representation.

Due to the share of renewable energies in electricity generation already achieved today and the expected further increase in this share in the future, modelling the residual load on the basis of so-called **typical days** (in the following type-days) and seasonality no longer seems adequate. Rather, the temporal resolution must be suitable to appropriately depict the volatile hourly and seasonal feed-in structures from intermittent renewable energies in addition to the load structure. For this reason, the European electricity market model provides for a temporal resolution of up to 8,760 hours (or 8,784 hours in leap years), again taking into account the chronological order of the hours.

In addition, analyses of the historical intermittent RE electricity generation (wind energy, photovoltaics and hydropower) show that there is a different supply of energy from these energy sources for different so-called 'weather years'. We explicitly address this uncertainty in our model by implementing stochastic weather years. Currently we model this uncertainty by using five weather years, but this is freely selectable depending on available hardware resources. Thus, we currently model  $5 \text{ (weather years)} \times 8,760 \text{ (hours)} = 43,800$  residual data points per observation year (2018, 2020, ..., 2035), each in the correct chronological order.

At the same time, our European electricity market model allows an analysis up to the year 2060 in order to enable the consideration of the entire technical lifetime of power plants from 20 to 50 years when deciding on investments in new power plants or on decommissioning of existing generation plants.<sup>189</sup> The number of years considered (model years) can be set variably. Depending on the level of detail in the modelling of other aspects, (up to) an annual analysis can be done.

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<sup>189</sup> At the same time, the final value problem of dynamic optimization problems is significantly mitigated by an annuity distribution of the investment and financing costs of generation plants over the technical lifetime of the plant (see section 'Modelling of medium and long-term aspects'). This allows a significant reduction between the period to be analyzed and the required optimization period in the analysis.

## A.5 Technology and efficiency classes of the model

The mapping of technical and economic characteristics of existing generation plants is based on a European power plant database and a database on generation plants based on renewable energies in Germany and Europe. These databases contain information on the technology and the primary energy source used as well as parameters on the essential technical properties (e.g. installed net capacity, net efficiencies, load gradients, start-up and shut-down times, technical minimum output and efficiencies when operating at partial load) and economic indicators (e.g. personnel, maintenance and repair costs, variable costs for operating and auxiliary materials) of all generation plants at unit level. In addition, information on the date of commissioning, the technical lifetime (taking into account measures to extend it), the grid connection (voltage level and grid node) and the grid connection operator as well as geoinformation on the location of the plants are stored in the databases.

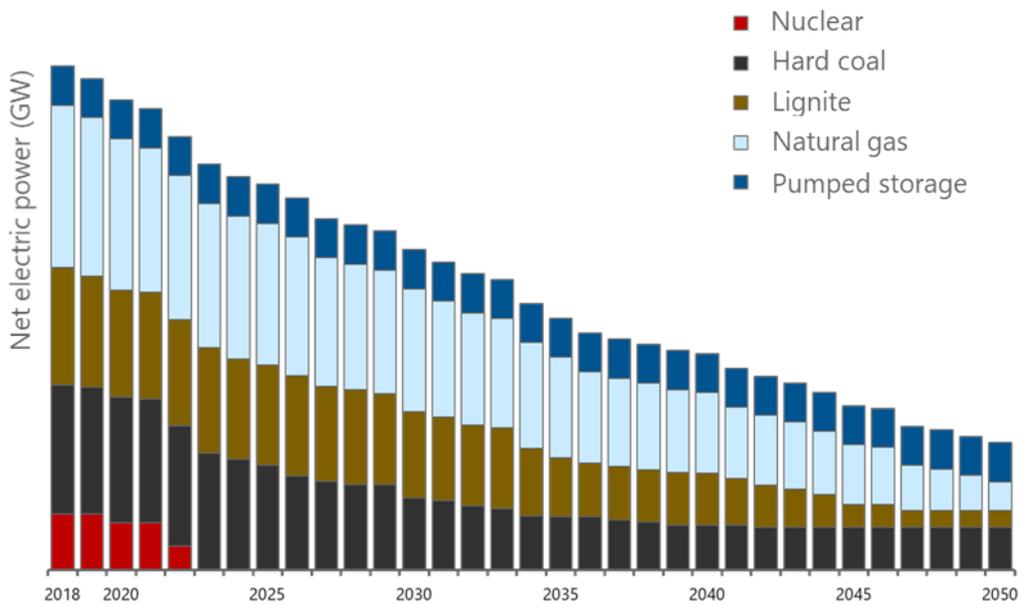
Figure A-4 shows the power plant database for Germany and the corresponding capacity retirement based on fixed technical lifetimes.

In the case of reservoirs and pump storages, additional information is available on natural inflows, storage volumes of the (upper and lower) basins and, in the case of pump storages, the installed capacity of the pumps and their efficiency. Additional information is also available in the case of renewable energy generation plants. On the one hand, the (remaining) duration and the amount of subsidy payments are recorded. On the other hand, specific data, such as hub heights and power curves for wind turbines, are stored.<sup>190</sup>

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<sup>190</sup> The data basis differs with regard to the availability of information in the individual model regions, as the publication requirements are not uniform in the individual countries of the EU, Switzerland and Norway. Missing publicly available information on individual data is supplemented by detailed searches and plausible substitute values.

FIGURE A-4: CAPACITY RETIREMENT OF THE CONVENTIONAL POWER PLANT FLEET IN GERMANY TAKING INTO ACCOUNT POWER PLANTS UNDER CONSTRUCTION



Source: Own representation.

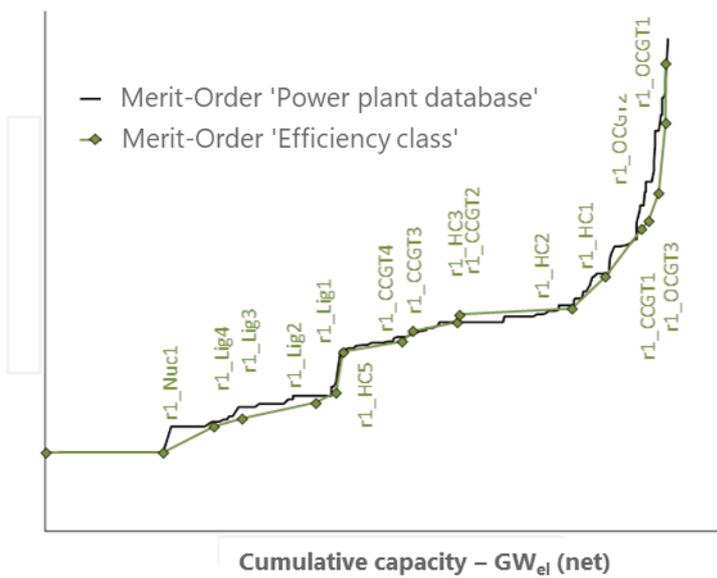
As it is not possible to depict the plants individually in the model, the generation plants are grouped into technology and efficiency classes, taking into account regional differentiation. Different approaches are chosen for conventional power plants based on fossil fuels and nuclear energy, for generation plants based on renewable energies and for storage and pumped storage power plants.

### A.5.1. Conventional power plants and nuclear power plants

In the case of conventional power plants and nuclear power plants, the existing plants are first divided into technology classes according to model regions, generation technologies (steam turbine power plant with and without topping gas turbine, engine power plant, open cycle gas turbine and combined cycle power plant) and primary energy sources (uranium, lignite, hard coal, natural gas and light and heavy fuel oil). Within these technology classes, efficiency classes are

assigned to the individual power plant units. Furthermore, it is possible to subdivide the plant types according to combined heat and power technologies (gas turbine / engine power plant with waste heat utilisation, combined cycle plant and steam turbine with heat extraction on the basis of extraction condensation or back pressure turbines).

FIGURE A-5: MERIT ORDER OF THE CONVENTIONAL POWER PLANT FLEET IN GERMANY (SCHEMATIC)



Source: Own representation.

The main criterion for assigning the individual power plant units to the efficiency classes within the technology classes is the net electrical efficiency. This enables a high degree of accuracy in modelling the operation of power plants, the main criterion of which is variable generation costs. The choice of the number of technology classes can be determined individually according to the requirements of the model and can range up to unit-specific modelling.

Figure A-5 shows an example of the installed power plant capacity sorted according to variable generation costs (so-called 'merit order') with consideration of the individual power plant units and with aggregated consideration according to the allocation of the individual power plant units to technology and efficiency classes

in the basic version of the model for Germany. It becomes clear that the grouping of the existing power plant units into technology and efficiency classes involves only a very small loss of accuracy.

In addition to the technology and efficiency classes for existing plants, further technology and efficiency classes for new plants are specified for the model. As additional technology classes, lignite and hard coal-fired power plants with CO<sub>2</sub> capture and storage (CCS technologies) are specified, which are available as investment options in the model from 2035 onwards.<sup>191</sup> At the same time, several additional efficiency classes are specified for all technologies, which essentially differ among themselves and in comparison to the efficiency classes of existing plants with regard to the electrical net efficiency as well as other technical parameters (e.g. technical minimum load, load gradients, power to heat ratio and power loss index). Regarding these efficiency classes for new power plants, the period during which an expansion is possible is explicitly specified in order to map technical progress in the model. In the current model version, expansions for certain technologies may only be made from 2023 or 2025 onwards, since corresponding construction times are taken into account.

Each technology and efficiency class is assigned technical and economic parameters based on the values of the individual power plant units in the respective technology and efficiency class. In particular, the following is taken into account:

- Installed capacity (net)
- Duration of start-up and shut-down processes
- Minimum partial load
- Electrical efficiency (net) at full load and minimum partial load
- Planned and unplanned unavailability

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<sup>191</sup> These technologies were not considered as a feasible option in this study.

- Positive and negative load gradients
- For combined heat and power plants: electricity to heat ratio and power loss index
- Variable costs
- Costs for start-up and shut-down procedures
- Personnel and maintenance costs
- Investment cost

Generation plants based on other, non-renewable energy sources (e.g. blast furnace gas, mine gas or waste) are not considered endogenously in the model. Rather, the model is given the annual energy quantities as well as a temporal feed-in curve in hourly resolution.

We model CHP plants as subclasses of the generation technologies available in the model and described above. Steam turbines and combined cycle plants can then be expanded as extraction condensation or back pressure steam turbines. Gas turbines and engine power plants are extended by the possibility of waste heat utilisation.

### **A.5.2. Generation plants based on renewable energies**

In the model, generation from renewable energies is divided into the following categories: onshore wind, offshore wind, photovoltaics, solar thermal power plants, geothermal energy, biomass (fixed feed-in and flexible operation), bio-waste, run-of-river, landfill gas, sewage gas and mine gas. The generation capacities in the model are based on a plant-specific RE database. This includes validated EEG plant data of the transmission system operators (master data and transaction data) and of the Federal Network Agency for the past years, supplemented by missing data. The database contains information on energy sources, remuneration, commissioning date, installed capacity, exact location depicted by

postal code (geocoded), avoided grid usage charges and annual electricity generation. Biomass is subdivided into solid, liquid and gaseous bioenergy, remuneration, grid connection level and grid connection operator. The database for Germany also contains detailed potential data to take the expansion of renewable energy plants into consideration. The current priority areas for wind energy, for example, are geocoded, and the area available for new photovoltaic systems on roofs is differentiated on a municipality level. For offshore wind, the database contains all wind farms in operation, under construction and planned with detailed data, including planned commissioning date, output, location and other technical and economic data.

The currently installed capacities of the individual renewable energy technologies are stored for all considered European countries. Detailed country-specific potentials (e.g. roof area potentials for photovoltaics, area potentials for wind on land, designated areas and plant-specific planning for wind at sea) are taken into account for the development of the expansion. This potential was determined on the basis of detailed and comprehensive analyses and is constantly updated (e.g. due to political changes in the respective countries).

For intermittent renewable energy technologies, such as wind energy, photovoltaics, solar thermal power plants and run-of-river power plants, the production quantities depend on the respective meteorological conditions. On the basis of regional hourly wind feed-in curves or on the basis of local hourly values of global radiation, direct radiation and temperatures (data basis: reanalysis data COSMO-EU model (until 2016) ICON-EU (from 2016) of the German Meteorological Service), feed-in profiles for the various technologies can be generated, taking into account the installed plant capacities and the technical parameters at the individual locations.<sup>192</sup> In the case of hydroelectric power plants, the generation capacity

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<sup>192</sup> For a detailed description of how hourly RES feed-in curves are generated, see Appendix D.

depends in particular on the seasonal water conditions of the rivers. For geothermal plants, bioenergy plants and landfill, sewage and mine gas, an hourly feed-in structure is determined based on historical feed-in values and historical full load hours. In general, the development of renewable energies is exogenous to the model based on recognized studies, taking into account the mentioned restrictions and information.

As part of the introduction of renewable energies to the competitive markets in Germany and Europe, e.g. within the framework of mandatory direct marketing, the participation of renewable energies in the wholesale markets for electricity and in the balancing energy markets can be modelled as an option. The necessary division of these renewable energy plants into technology classes with corresponding mapping of the technical and economic properties is carried out using an analogous procedure as in the modelling of conventional power plants. When modelling biogenic energy sources, additional specific aspects are integrated, e.g. bonus payments within the framework of the market premium model and assumptions about the possibility of intermediate storage of biogas. In each case, the modelling is dependent on assumptions about the concrete future design of the subsidy models.

### **A.5.3. Marketing options**

In addition to mapping the European wholesale markets for electricity, the model also offers the option of marketing the available generation capacities on the markets for balancing and reserve energy<sup>193</sup> as well as marketing the generation capacity on regional heat markets.

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<sup>193</sup> In addition, regional or supra-regional capacity markets as well as markets for other system services, e.g. black start capability or regional and local provision of reactive power, can also be taken into account in the modelling.

The wholesale market for electricity is modelled using a competitive market model in which supply (generation side) and demand (consumption side) are balanced at a given market price at the level of the model regions. We model the demand for electricity in terms of its amount and chronological order by using an hourly load curve.

In contrast to the wholesale markets for electricity, heat demand is modelled at the level of the individual power plant. This means that the individual power plant units each serve an individual industrial or district heating hourly heat demand. It is assumed that they do not compete with other CHP plants, but with alternative heat supply options (e.g. heating plants, power-to-heat plants and, in the long term, renewable heat).

When modelling the marketing opportunities on the balancing energy markets, different degrees of detail can be selected. For example, a differentiation can be made between the different balancing power qualities – primary- and secondary balancing power as well as minutes reserve - and types (positive and negative balancing power). Depending on the chosen differentiation, the technical requirements for the generation plants (pre-qualification criteria) as well as regulatory requirements, e.g. bidding periods, are also adapted. In addition, the demand of balancing power is taken into account in the modelling by using a probability function of different demand amounts of the balancing power procured, if necessary, again differentiated by balancing power qualities. In the current version, up to ten different levels of control energy can be considered with corresponding probabilities.

## **A.6 Database and modelling of hydropower**

When modelling hydropower, we differentiate between countries. The differentiation is based on the hydropower technologies available in the respective countries (run-of-river-, pondage-, storage power plants and pumped storage power plants) as well as the available database.

The starting point for all countries is annual production from natural inflows based on EUROSTAT statistics (annual data). This results from the net electricity generation of hydropower plants of autoproducers and of companies mainly active as energy producers minus the net generation of pumped storage power plants of autoproducers and of companies mainly active as energy producers.

The breakdown of annual generation from natural inflow into storage power plants and run-of-river power plants is based on national annual statistics. Depending on the available database, annual production from natural inflow is differentiated based on monthly, weekly and hourly statistics. In addition, a differentiation is made between run-of-river (possibly with further differentiation between run-of-river and pondage) and storage plants. The data sources for weekly or monthly data vary from country to country. In some cases, we have used data from national statistical authorities, transmission system operators, energy supply companies and regulators, and in individual cases from ENTSO-E.

Due to the limited availability of public data on locations, installed capacities, performance curves and water conditions of the rivers, an alternative approach compared to the methodology used for wind energy and PV based on aggregated data is required for the **simulation of feed-in curves for run-of-river power plants** for the projection years. The feed-in curve for Germany for example is based on aggregated data from the Federal Statistical Office on the installed capacity and annual generation volumes of run-of-river power plants in Germany for the water years 2009 to 2013.

In a first step, on the basis of the monthly reports on the electricity supply of the Federal Statistical Office,<sup>194</sup> we derive a feed-in curve of run-of-river

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<sup>194</sup> StaBuA (2009 - 2013), series 066.

power plants for the years 2009 to 2013. We can use monthly data for generation and monthly data for installed capacity.

However, the monthly reports on electricity supply only take into account the installations of the companies belonging to the electricity sector. Thus, not all run-of-river power plants in Germany are included. We therefore use additional information on installed capacity and annual generation volumes provided by the Working Group on Renewable Energies (AGEE)<sup>195</sup> to derive historical feed-in curves of run-of-river power plants in Germany in a second step.<sup>196</sup> For this purpose we scale the generation structures from the first step with a uniform factor, so that the integral of the new generation of all hours of the respective water year corresponds to the total annual generation of the run-of-river power plants in Germany of the corresponding year according to AGEE statistics. In a third step, we scale these hourly generation data with the respective quotients of installed capacity in the respective projection year and installed capacity in the respective historical year.

As a result, there are different realisations of feed-in curves of run-of-river power plants in Germany based on the water years 2007 to 2013, which can be used for the respective forecast years. The respective feed-in curves for European run-of-river power plants are based on the same methodology - depending on the available database, with a different temporal resolution if necessary. The database for other European countries consists of various

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<sup>195</sup> However, these figures also include generation and installed capacity of storage power plants and pumped storage power plants with natural inflow. We therefore adjust the corresponding figures on the basis of the monthly reports on electricity supply of the Federal Statistical Office. We implicitly assume that storage and pumped storage power plants are fully covered in these statistics in contrast to run-of-river power plants.

<sup>196</sup> See AGEE (2014).

publications by national institutions such as TSO's, regulators, energy suppliers or (statistical) authorities, as well as pan-European institutions such as ENTSO-E or EUROSTAT.

Large storage power plants (with extensive natural inflow) with or without the possibility of extensive pumping are mainly found in the Alpine region and in the Pyrenees, while daily and weekly storages dominate the European plains. Large hydrological cascade systems are dominant in Scandinavia. On the basis of the values stored in the power plant database for the individual plants, the aggregated turbine and pump capacity and the average net efficiency are determined for each technology class, or in the case of pumped storage power plants, the overall efficiency, taking into account the losses during storage filling and generation. In addition, assumptions about the energy content and the temporal course of the natural inflows, the aggregated usable storage volume of the plants and other assumptions about the controllability of the pumps are implemented in the input tables of the model. In the case of hydrological cascade systems, particular consideration is given to the fact that the entire system of hydroelectric power plants can be controlled at short notice by means of intelligent control, taking into account the corresponding levels of the basins.

**Storage power plants** are endogenously modelled. The storage volumes of the basins are taken into account. In addition, depending on availability, monthly or weekly inflows to the storage basins are used. If these are directly available (e.g. for Norway, Finland and Sweden), the data on natural inflows are used directly. Otherwise, the data are derived accordingly on the basis of the monthly / weekly generation (of the storage power plants) and the monthly / weekly filling levels of the storage facilities.

The data basis for **pumped storage power plants** is from the publication *F. Geth et al (2015): "An overview of large scale stationary electricity storage*

plants in Europe: Current Status and new developments", as well as supplementary individual data and a comparison with national statistics and power plant databases. This is used to determine the maximum turbine capacity of all pumped storage units, the maximum pumping capacity of all pumped storage units and the storage volume of the pumped storage units. The (average) efficiency of the pumped storage units is determined on the basis of EUROSTAT statistics and is calculated from the net generation of the pumped storage power plants divided by the consumption of the pumped storage power plants (mean value 2012 to 2015). It is assumed that proportional losses of 50 % each occur during pumping and turbine operation.<sup>197</sup>

In the following, the methodology used in the different countries is described in more detail, depending on the hydropower technologies used in the respective country and the available databases.

The comparatively low hydropower generation in **Denmark and the Netherlands** is exclusively run-of-river. Data is available for the period 2006 to 2015. The structure of generation is calculated on the basis of monthly data for 8 760 hours of the year as a percentage of annual production (sum of monthly production) and multiplied by annual natural inflow production on the basis of EUROSTAT statistics. To map the future development, the hourly generation values will be scaled with the installed capacity.

The power generation from storage and pumped storage power plants in **Germany, Luxembourg, the Czech Republic, Poland, Belgium and Great Britain** is mainly based on water previously pumped into the upper basin. Either there is no natural inflow or this inflow is small. If it is possible to determine

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<sup>197</sup> Example: With a calculated efficiency of 75%, it is assumed that an inflow of 0.866 MWh into the upper basin occurs when one MWh of pumped electricity is consumed, and that 0.866 MWh of electricity can be generated from one MWh in the upper basin during turbine operation. Accordingly, the storage volume of an upper basin is the amount of energy that could be generated at a theoretical efficiency of the pumped-storage power plants of 100 % during turbine operation.

or estimate the production from natural inflow, we have assumed that this amount of energy flows proportionately to the upper basin over all hours of the year.

Run-of-river generation is modelled in the same way as in Denmark and the Netherlands. If no separate monthly data are available for run-of-river generation, the monthly generation structure of the run-of-river power plants is calculated from the total monthly hydropower generation less the consumption of the pumped storage facilities (multiplied by the average efficiency of the pumped storage facilities).

Pure pumped storage power plants can be dispatched completely endogenously, taking into account the restrictions with regard to storage volumes. In the case of mixed pump / storage facilities (pumped storage facilities with natural inflow), additional restrictions must be complied with regard to the monthly natural inflow as well as the minimum and maximum monthly storage levels over the years 2006 to 2015. Within these restrictions, the dispatch of such mixed pump / storage facilities is also determined endogenously.

In [Switzerland, Austria and Portugal](#) there are run-of-river power plants as well as storage power plants and pumped storage power plants. The database is of a very good quality and differentiates by run-of-river, storage-river and pumped-storage power plants on an annual basis (installed capacity, etc.) as well as on a monthly basis (storage levels, generation of run-of-river power plants, storage and pumped-storage power plants). Data for natural inflow is not available, but can be derived approximately from the storage levels, the power consumption and the power generation of the pumped-storage power plants.

Run-of-river production is estimated on the basis of the structure of the monthly data on run-of-river production and the annual data on total run-

of-river production. Changes in installed capacity in the past (2006 to 2015) or in the future are considered.

The storage and pump storage facilities are jointly mapped. In the case of mixed pump / storage facilities, restrictions must be observed regarding the monthly natural inflow and the minimum and maximum monthly storage levels over the years 2006 to 2015. Within these restrictions, the dispatch of mixed pump / storage facilities is also determined endogenously.

In **France and Italy**, four categories of hydropower technologies are distinguished: storage power plants, pumped-storage power plants, run-of-river and pondage plants. In principle, we have chosen the same modelling approach for Italy and France as in Austria, Switzerland and Portugal. Based on the definition of pondage plants (France "éclusée"; Italy "Impianti a bacino") with a storage period of 2 to 400 hours, we have modelled the hydropower plants in reference to storage hydropower.

We have modelled hydropower in **Spain** basically analogous to as in Austria, Switzerland and Portugal. Since in Spain the storage levels are differentiated between annual storage and hyperannual storage ("annuales / hyperannuales"), we have also differentiated these storage types in the modelling. The annual reservoirs are modelled with storage water in the same way as the other countries, while the hyperannual reservoirs are subject to stricter restrictions regarding minimum storage levels.

For **Norway, Finland and Sweden**, detailed information is available on total production, inflows to reservoirs, storage level and pumped storage consumption.

For these three Scandinavian countries, we have chosen a different approach as no data on the power production of run-of-river power plants are available. In this case, we have modelled hydropower as a single technology (including pumps from pumped storage). For this purpose, we first determined a monthly minimum generation and maximum generation. This

monthly minimum / maximum generation consists of the third smallest / biggest hourly hydropower generation within the respective month of each weather year. The use of pure storage facilities and mixed pump/storage facilities in excess of the minimum generation is determined by analogy with the procedure in Austria, Switzerland and Portugal, taking into account the monthly natural inflow per weather year and observing the restrictions on monthly minimum and maximum filling levels of the storage facilities per month over the years 2006 to 2015.

## **A.7 Modelling of technical and economic characteristics of power plants**

### **A.7.1. Modelling of short-term aspects**

The dispatch of the available power generation plants (conventional power plants, storage and pumped storage power plants as well as renewable energies) is determined in the model under cost minimization aspects. This means that the existing generation plants with the lowest variable operating costs are dispatched to cover the hourly load, considering dynamic aspects (e.g. start-up and shut-down costs for thermal power plants) and (pumped) storage. The priority feed-in of the EEG plants is also taken into account. In principle, this cost-minimizing dispatch of the generation facilities is carried out simultaneously across all model regions. This ensures that if there is sufficient transmission capacity available between two model regions (interconnector capacity), full market integration takes place, whereas in the case of congestion management there is market partitioning with different wholesale prices. Both the short-term use of power plants and the modelling of imports and exports fully correspond to the ideal of a competitive market, so that the European electricity markets are mapped with sufficient precision.

In addition, the generation plants must provide the necessary system services - within each model region. The provision of positive and negative control power

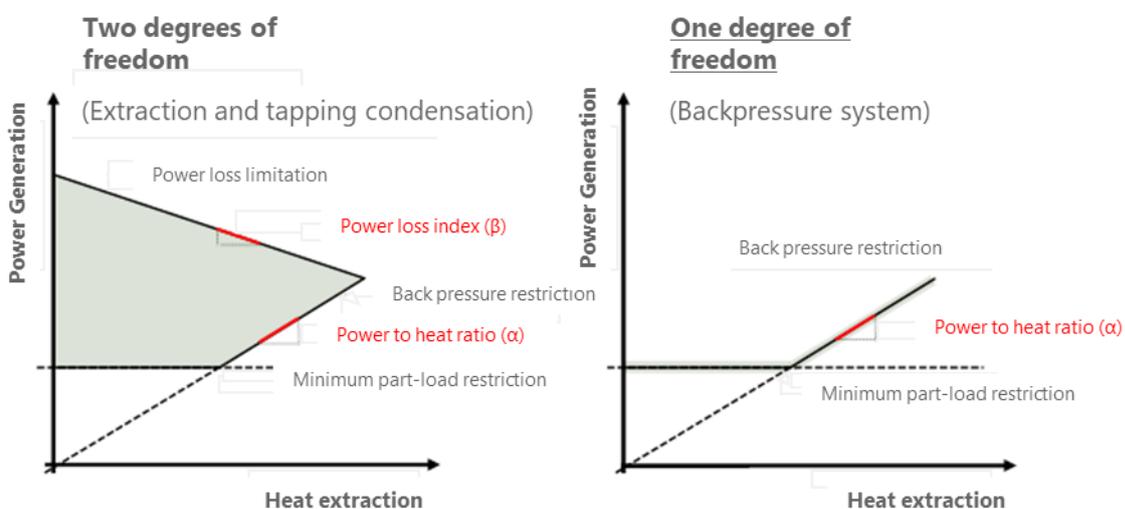
considers the technical restrictions at the generation plants as well as the technical and regulatory requirements (pre-qualification criteria and market and product design). In particular, the interdependencies between the wholesale market and the balancing energy markets are modelled in detail. The additional costs of the provision of balancing power and the resulting calls of balancing power are simultaneously included in the determination of the optimal mode of operation of the generation plants within the framework of cost minimization.

### Modelling of the dispatch of conventional power plants

The operating and dispatch decisions of conventional power plants are depicted in two stages. A generating plant may be in operation or in downtime. After a downtime, a start-up process is required to synchronize it with the grid. The model takes into account the costs as well as the time required for the start-up process. If a plant is switched off, a shutdown procedure is required. In turn, the costs and the time required for the shutdown process are considered.

If a plant is in operation, it must operate between its technical minimum load and its net capacity. Differences in the variable generation costs as a function of the operating point between the technical minimum output and the net capacity are taken into account by approximating the efficiencies in the two operating points.

FIGURE A-6: OPERATING DIAGRAM OF COMBINED HEAT AND POWER PLANTS



*Source: Own representation.*

In the case of combined heat and power plants, in addition to the technical minimum load, the so-called back pressure condition must also be fulfilled. This condition describes the minimum amount of electricity that has to be generated to extract a certain unit of heat. In CHP plants with one degree of freedom (back pressure plants), the generation of electricity and heat is linearly coupled along this straight line. In systems with two degrees of freedom (extraction and extraction condensation), this straight line corresponds to a minimum power generation condition. In addition, the electricity loss condition must be fulfilled for these plants, which means that the maximum electricity generation decreases with increasing heat extraction. Figure A-6 shows the operating diagrams of combined heat and power plants.

In addition to the actual dispatch decision (with regard to electricity and heat), the decision with respect a certain marketing option is also determined by the model. Generation assets can offer both electricity on the wholesale electricity market and the primary and secondary balancing power as well as minute reserve markets.

Thermal power plants must be in operation in order to offer balancing power since, due to the duration of the start-up processes of several hours, provision from a standing start is technically not possible. The feasible amount of provideable balancing power depends on the load gradient of the plant in case of positive as well as negative balancing power. Considering the requirements of the provision time for the respective balancing power quality, different amounts of maximum capacity that can be technically offered result. At the same time, the model takes into account the interdependence between the generation of electricity for marketing on the wholesale market and the provision of balancing power. If positive balancing power has been contracted, the plant may not operate at its maximum net capacity in order to be able to increase electricity generation in the

short term in the event of activation of the contracted balancing power. If negative balancing power has been contracted, the plant may not operate at minimum load in order to be able to reduce electricity generation for a short time in the event of an activation. An exception to the provision of positive minutes reserve are open gas turbines, emergency power systems, gas engines and topping-gas turbines. Due to their high start-up speeds, they can also offer positive minutes reserve from a standing start.

If positive balancing power is activated, additional variable generation costs are incurred, while if negative balancing power is activated, variable generation costs are reduced. The frequency of activation is represented by a probability function. Depending on the activation level, the systems that cause the lowest variable costs (positive balancing power) or enable the highest reductions in variable costs (negative balancing power) are used first when balancing power is activated.

### **Modelling the use of storage and pumped storage power plants**

Storage and pumped storage power plants differ considerably from thermal power plants in terms of the costs to be taken into account and the technical restrictions regarding their dispatch. Storage and pumped storage power plants have no direct variable generation costs. However, storage and pumped storage power plants have only a limited storage capacity (energy content of the reservoirs), which is reduced when electricity is generated. This means that generation at any given point in time reduces generation possibilities in the future. At the same time, it must be taken into account that the energy content is increased by natural inflows and, in the case of pumped storage power plants, by filling the storage basins by pumping.

In the following, the relevant aspects of modelling a seasonal pumped storage facility with natural inflow are presented. The modelling of other storage and pumped storage power plants is analogous, with the difference that the modelling can be simplified by corresponding aspects.

Pumped storage power plants can act as suppliers and consumers on the wholesale market for electricity. As suppliers, they provide electricity for the market. Their maximum generation is limited by the installed turbine capacity. Electricity generation reduces the energy content of the storage basin. As consumers, they increase consumption, which then has to be covered by other generating plants. Maximum consumption is limited to the available pumping capacity. The use of the pumps increases the energy content of the storage basin. Efficiency losses are mapped both during pumping and generation. When optimising the use of the systems, the model also considers that sufficient energy must be available in the storage basin at all times for production and that the maximum storage volume cannot be exceeded when additional energy is absorbed by pumps and natural inflows. Due to the technical flexibility of the plants, start-up and shut-down processes, technical minimum loads and minimum downtimes are not to be taken into account in the modelling.

In addition to the wholesale market, pumped storage power plants can also act as suppliers on the balancing energy markets. There, depending on the operating mode, they can offer both the turbine and the pump capacity to provide positive and negative balancing power of the different qualities. Again, a probability function is used to simulate activation. If positive balancing power is activated, the energy content of the storage basin is reduced, while it increases if negative balancing power is activated. These additional changes in the energy content of the storage basins during the provision of balancing power are integrated into the modelling via expected values to the maximum and minimum storage filling levels restrictions.

### **Modelling of the use of power plants on the basis of renewable energy sources**

The modelling of power generation on the basis of renewable energy sources is carried out with the help of the potential technology-specific feed-in curves al-

ready described. In general, the potential generation of the plants is fully exploited and marketed on the wholesale market for electricity. Should situations arise in which the load in a model region, taking into account the maximum exchange possibilities, the additional pumped storage consumption and the minimum conventional power plant capacity required for system security on the grid, is already covered by the potential production of renewable energies, the actual feed-in is reduced below the level of the potential possibilities. Technical restrictions and variable generation costs of the plants are taken into account.

### **A.7.2. Modelling of medium and long-term aspects**

As with the modelling of the power plant dispatch, the development of the generation plants installed and available at the relevant points in time is also simulated under the aspect of cost minimisation. On the one hand, the development of the installed capacity of the generation plants in the individual technology and efficiency classes is determined on the basis of investment and decommissioning decisions. On the other hand, the times in which the overhauls of conventional power plants take place within a modelled year are determined for the individual technology and efficiency classes.

When modelling investment decisions as well as temporary and final decommissioning decisions for power plants, the model endogenous consideration is limited to conventional power plants as well as storage and pumped storage power plants. The installed capacities of generation plants based on renewable energy sources in the respective years under consideration are determined exogenously.<sup>198</sup> In the case of conventional power plants and storage and pumped storage power plants, those generating facilities which will cause the lowest costs in

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<sup>198</sup> These specifications may be based on studies and policy targets (e.g. national renewable energy action plans of individual Member States). In addition, a coupling with analyses based on a model of renewable energies developed by r2b energy consulting GmbH is possible, in which investments in generation plants based on renewable energies are mapped depending on the potentials, political framework conditions and support mechanisms.

covering the load and providing system services in the future will be added to the system. In addition to the variable generation costs, the investment and capital costs for the construction of the plants as well as for storage and pumped storage power plants are considered. The model is based on rational expectations of the market participants. This means that the investment decision considers the entire technical lifetime of the plants, taking into account the future framework conditions of the energy industry and energy policy.

On the one hand, the decommissioning of generating plants takes place after the plants have reached their technical lifetime. On the other hand, early / premature decommissionings are also possible for economic reasons. If facilities are no longer required to cover the load and provide system services in the system, these facilities can no longer cover their fixed annual operating costs (personnel and maintenance costs) on the European electricity markets. Such a situation then leads to premature decommissioning of the affected plants.

In addition to final closures, temporary closures can also be carried out on an annual basis. Although a part of the annual operating and maintenance costs can be saved, this can only be done under the condition that these plants are no longer available for electricity generation for the corresponding year of temporary decommissioning. In later years, these plants can return to the market. The technical lifetime of the respective plants is not affected by this measure.

Both with regard to decommissionings as well as investments, exogenous specifications can be defined. For example, the current model includes the decommissioning dates of the nuclear power plants in Germany as well as previously announced decommissionings of further conventional plants. In the case of power plants already under construction, the expansions will also be specified exogenously, so that they will be available to the model as generation plants at the time of commissioning as part of the dispatch decision. Within the framework of scenario analyses, the exogenous specification of expansions that are still in the planning stage is also possible.

For plants with heat extraction (CHP plants of the public district heating supply and industry as well as building-close power and heat supply with small CHP plants), the model makes it possible to consider replacement investments. The model replaces the heat generation quantities lost due to plant shutdowns with modern, usually gas-fired CHP plants<sup>199</sup>. Gas turbines and engine power plants with waste heat utilisation as well as large and small flexible combined cycle power plants with heat extraction are available as replacement technologies. Small CHP plants can also be built in the future to meet local heat demand. The choice of plant technology for heat replacement is determined according to the heat demand structure, i.e. as a function of the industrial heat or process steam demand and – in case of public heat supply – as a function of the regional district heating demand.

Due to unplanned outages and overhauls, the available generation capacity is lower than the installed generation capacity in every hour of the year. The installed capacity is reduced by a uniform percentage to take unplanned outages into account. Planned unavailabilities due to necessary overhauls can be flexibly distributed over the individual months of a modelled year. However, in total, the overhaul time required in a modelled year must be achieved. The determination of the months in which the generation plants in the individual technology and efficiency classes go into overhaul is determined endogenously by the model, taking into consideration cost minimisation in the system. Optionally, the overhauls can also be distributed exogenously over the months.

As a result, the installed capacity by technology and efficiency class is initially calculated for each year under consideration by taking into account the final and temporary shutdowns and investments in the system of conventional power

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<sup>199</sup> In this case, the profitability on the wholesale market is not relevant, since it is assumed that there is a corresponding subsidy for these plants, or that revenues from heat generation ensure the profitability of the investment.

plants and in storage and pumped storage facilities. Taking into account the expected unplanned downtimes and overhaul times, the capacity available for electricity generation and for the provision of system services is determined by technology and efficiency classes in each month of a year.

### **A.7.3. Modelling the price elasticity of demand**

In the previous explanations, it was assumed that an exogenous load had to be covered by the power generation system. In reality, large industrial consumers in particular are already reacting to high prices on wholesale markets by reducing or shifting loads. At the same time, these large consumers participate as suppliers in the balancing energy markets and thereby reduce their electricity procurement costs. This trend will intensify in the future. A similar development can be expected in projects in the field of smart metering, e-mobility and heat pumps for households and industry. In the longer term, electrification of heavy goods vehicles is also conceivable. In order to take these developments into account in analyses based on the European electricity market model, the possibility was created to integrate these trends into the modelling via price-elastic demand functions of consumers.

Depending on the respective current marginal system costs, certain consumer groups reduce their load or shift their consumption so that the required generation can be reduced in the corresponding period. Similar to the modelling of the power plant dispatch, the modelling in this area follows a cost minimisation approach. Load flexibilities are used in those areas in which they can reduce costs while taking technical and economic restrictions into account. They shall only be used if the costs of alternatives in the generation system are higher than the necessary costs of the provision of these flexibilities by consumers.

## Appendix B Modelling of cross-border exchange capacities

This section documents in detail the modelling of exchange capacities between bidding zones, the basic features of which are described in section 3.3.4 of the main body.

### B.1 Basic Model: Border-wise hybrid flow-based and NTC model

#### Border-wise flow-based model in the core of the observation area

The task of the exchange capacity model in the present context is to describe the maximum permissible power exchanges between bidding zones, i.e. the maximum permissible power imports and exports of the bidding zones in the future years up to 2030.

The classical approach to the description of exchange capacities between bidding zones is based on Net Transfer Capacities (NTCs). An NTC value describes the upper limit of the bilateral commercial power exchange between two adjacent bidding zones. Two bidding zones are adjacent if there is at least one interconnector between them.

In future, a so-called flow-based model will be used instead in large parts of the European electricity supply system (as is already the case in Central West Europe (CWE)). Unlike the NTC approach, flow-based models are based on a direct representation of the limited physical transmission capacity of network elements (lines and transformers). This indirectly limits commercial exchanges. In principle, this allows a more flexible use of the grid with the same level of grid security. The higher flexibility is expressed by the fact that, for example, the export of a bidding zone to its northern neighbour zone can be increased compared to the NTC value (for example, if the price difference between these bidding zones is high), if at the

same time a reduction of the exchange with its western neighbour zone below the NTC value is accepted.

However, operational flow-based models are very complex because they have a line-wise resolution. This means that every relevant line and every relevant contingency situation (to reflect the network security criterion) are explicitly mapped. In particular, these models are not directly predictable for future years. Furthermore, the simulation models used in this study place demands on the simplicity of the structure of the modelled network restrictions.

The present study therefore synthesizes the flexibility of the flow-based approach (FB approach) and the structural simplicity of the NTC approach. Simplified flow-based models are created for this purpose, which are not line-specific but border-specific. The transmission capability of the network is expressed by the maximum simultaneous power flow over all tie lines per bidding zone border (Maximum Border Flow, MBF). The initial level is determined on the basis of historical NTC values. Thus the MBFs also indirectly express any relevant restrictions of the NTCs due to bottlenecks within the bidding zones.

#### Addition by NTCs

The flow-based model described above is used for exchanges between the bidding zones France, Belgium, the Netherlands, Germany-Luxembourg, Switzerland, Italy, Austria, the Czech Republic and Poland, which are particularly important from a German perspective. The remaining modelled bidding zones are connected via NTCs.

The grid expansion plans of the European transmission system operators also provide for cross-border high-voltage direct current (HVDC) transmission lines within the Continental European three-phase grid in the future. We also model these via NTCs. In this way we model that, in addition to the exchange possibilities within the framework of the restrictions of the three-phase grid (expressed by the flow-based model), a power in the amount of the HVDC capacity can be exchanged between the bidding zones concerned.

## Parameterisation of the flow-based model in base year 2016

The parameterization is based on

- the NTCs of the base year - these are available from public sources as a homogeneous data basis for the entire region modeled with the FB approach. Specifically, we evaluated NTC values - published<sup>200</sup> by ENTSO-E for the year 2016 - and used the 95 % quantile per limit. For some borders, additional sources of information were used, such as national network development plans or data portals of the transmission system operators;
- Power Transfer Distribution Factors (PTDFs) - these describe the influence of an exchange or an export or import on the flow across a border. For example, if the PTDF of the border A→B has a value of 70 % with respect to the exchange A→B, this means that the commercial exchange from A to B physically occupies by 70 % the direct border between A and B. An exchange of 100 MW would therefore cause a flow of 70 MW on the direct border. In this example, the remaining 30 MW flow via adjacent bidding zones, e.g. from A to C and from C further to B.
- We calculate the PTDFs from a load flow model of the European transmission grid that we have built up on the basis of publicly available information.

The parameterization of the MBFs takes place in such a way that the simultaneous use of the NTCs, which would have been historically permissible, is also permissible in the flow-based model. For each bidding zone boundary, the maximum flow on this boundary that can be caused by the simultaneous utilisation of any combination of NTCs is determined. This maximum flow is the MBF of the base year.

The following figure illustrates for a schematic example with three bid zones A, B and C as well as two borders, how the MBFs are determined from the NTCs and

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<sup>200</sup> <https://transparency.entsoe.eu/>

PTDFs. The corresponding NTC and flow-based models are mathematically formulated below the table.

**FIGURE B-1: SCHEMATIC EXAMPLE FOR THE PARAMETERIZATION OF THE FLOW-BASED MODEL**

**Calculation of the max. border flows from NTC and PTDF**

Border	NTC	PTDF		Max. Border Flows	
		Exchanges	A→B		A→C
A→B	2000 MW		60%	20%	$2000 \times 0.6 + 1000 \times 0.2 =$ 1400 MW
A→C	1000 MW		40%	80%	$2000 \times 0.4 + 1000 \times 0.8 =$ 1600 MW

**Admissible exchanges: mathematical representation**

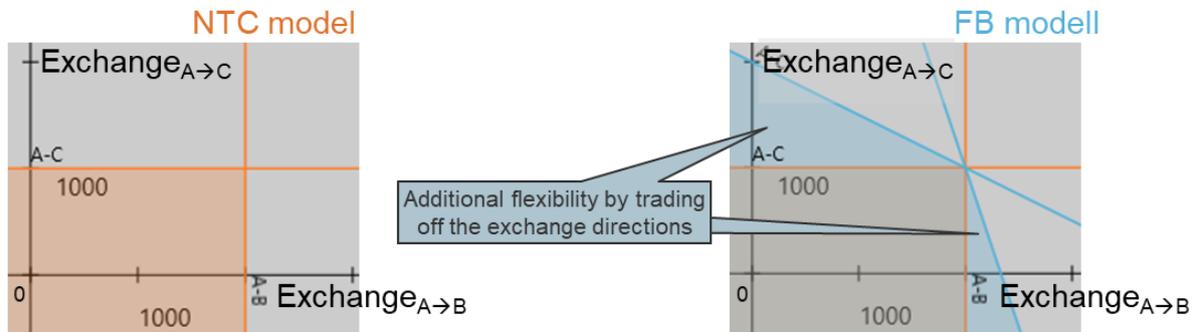
<p><b>NTC model</b></p> $\begin{pmatrix} 1 & 0 \\ 0 & 1 \end{pmatrix} \cdot \begin{pmatrix} Exchange_{A \rightarrow B} \\ Exchange_{A \rightarrow C} \end{pmatrix} \leq \begin{pmatrix} 2000 \\ 1000 \end{pmatrix}$ <p style="text-align: center;">NTCs</p>	<p><b>FB model</b></p> $\begin{pmatrix} 0.6 & 0.2 \\ 0.4 & 0.8 \end{pmatrix} \cdot \begin{pmatrix} Exchange_{A \rightarrow B} \\ Exchange_{A \rightarrow C} \end{pmatrix} \leq \begin{pmatrix} 1400 \\ 1600 \end{pmatrix}$ <p style="text-align: center;">Max. Border Flows</p>
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Remark: Although NTCs and max. border flows both have the unit MW, their values are not directly comparable with each other. This is because NTCs describe commercial exchanges, while max. border flows describe physical power flows.

Source: Own representation.

The higher flexibility of the flow-based model is illustrated in the following figure. In the NTC model (left), each exchange is limited to a fixed (NTC) value, regardless of the amount of the other exchange. Physically, however, both exchanges (to different degrees) have an effect on the power flows across all borders. This is mapped in the flow-based model (right) and enables a trade-off between the exchange directions. For example, significantly more than the NTC of 1000 MW can be exchanged from A to C, if in return the exchange from A to B is reduced compared to its NTC (upper blue triangle in the right diagram).

FIGURE B-2: GRAPHICAL REPRESENTATION OF PERMISSIBLE EXCHANGES IN THE NTC AND FB MODEL



Source: Own representation.

### Parameterisation of the flow-based model for future years

In the Ten-Year Network Development Plan (TYNDP), ENTSO-E publishes so-called Grid Transfer Capacities (GTCs), which describe the effect of the planned cross-border network expansion projects on the permissible power flows per bidding zone border (ENTSO-E, 2016). The changes of the GTCs per boundary can be directly interpreted as changes of the MBFs in the context of our modelling.

At the same time, however, network expansion also changes the electrical properties of the network and thus the PTDFs. We take this into account by integrating the network expansion projects into the above-mentioned load flow model and recalculating the PTDFs.

The following table shows the cross-border network development projects taken into account together with the year from which they are modelled in the analyses. The far right column contains the corresponding figures for the sensitivity analysis for delayed network expansion (see section 6.3).

TABLE B-1: CROSS-BORDER NETWORK EXPANSION PROJECTS AND YEARS FROM WHICH ON THEY ARE CONSIDERED IN THE MODEL

TYNDP Project No.	Identifier	Country 1	Country 2	Considered in the model from	
				Reference scenario	Sensitivity "delayed grid expansion"
36	Kriegers Flak CGS	DE	DKE	2018	
113	Doetinchem - Niederrhein	DE	NL		
172	ElecLink	FR	GB		
21	Italy-France	IT	FR	2020	
25	IFA2	FR	GB		
37	NordLink	DE	NO		
39	DKW-DE, step 3	DE	DKW		
71	COBRA cable	DKW	NL		
74	Thames Estuary Cluster (NEMO)	GB	BE	2020	
92	ALEGrO	DE	BE		
94	GerPol Improvements	DE	PL		
245	201 Upgrade Meeden - Diele	DE	NL	2023	
26	Austria - Italy	IT	AT		
47	Isar-St. Peter	DE	AT		
250	Merchant line "Castasegna (CH) - Mese (IT)	IT	CH		
23	France-Belgium Phase 1	FR	BE	2023	
31	Italy-Switzerland	CH	IT		
40	Luxembourg-Belgium Interco	LU	BE		
110	Norway-Great Britain North Sea Link	NO	GB		
150	Italy-Slovenia	AT	IT		
153	France-Alderney-Britain	FR	GB	2025	
167	Viking DKW-GB	DKW	GB		
174	Greenconnector	CH	IT		
183	DKW-DE, Westcoast	DE	DKW	2025	
190	NorthConnect	GB	NO		
198	Area of Lake Constance	DE	AT		
47	Vöhringen-Westtirol	DE	AT		
16	Biscay Gulf	FR	ES	2028	
26	Austria - Italy	IT	AT		
111	3rd AC Finland-Sweden north	FI	SE		
176	Hansa PowerBridge 1	DE	SE		
187	St. Peter - Pleinting	DE	AT		
198	Area of Lake Constance	AT	CH	2025	
225	2nd interconnector Belgium - Germany	DE	BE		
228	Muhlbach - Eichstetten	DE	FR		
231	Concept Project DE-CH	DE	CH	2030	
270	FR-ES project -Aragon-Atlantic Pyrenees	FR	ES		
276	FR-ES project -Navarra-Landes	FR	ES		
229	GerPol Power Bridge II	DE	PL		
244	Vigy - Uchtelfangen area	DE	FR	-	

Source: Own calculations

## **B.2 Restriction of the basic model to prevent unrealistic exchange patterns**

### Concept

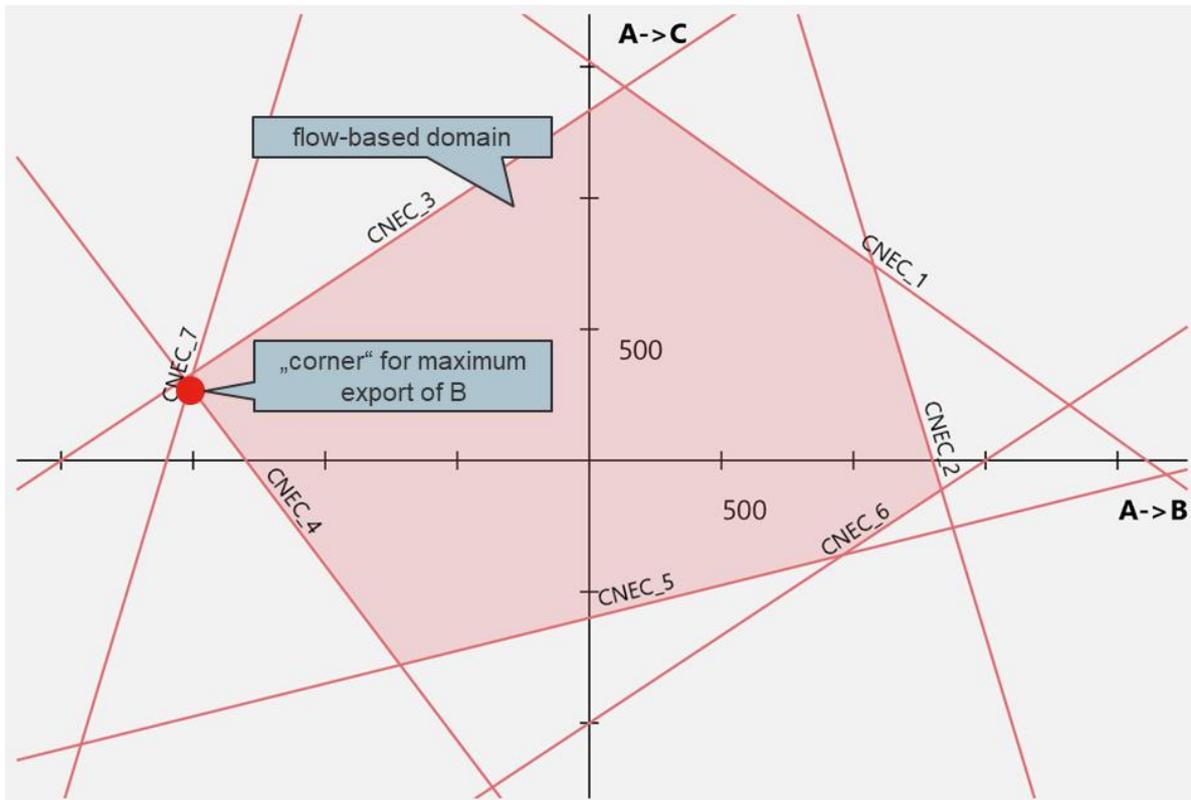
The basic model shows a very high flexibility to increase the exchange at some borders by forgoing exchange at other borders. The reason for this is that due to the deliberately and necessarily simple model structure the flexibility of such trade-off is overestimated if no further steps are taken. Specifically, the border-wise hybrid flow-based and NTC model neglects the following effects:

- By aggregating the interconnectors at each bidding zone border, it is implicitly assumed that the distribution of physical power flows among the interconnectors will not change, even in the case of deviating exchange patterns. However, if there is a strong regional shift in exchanges compared with historical patterns, it is reasonable to expect that the capacity utilisation of the interconnectors will be more uneven. The total flow that can be transported across the border is then less than the MBF.
- One way to approximately take this effect into account is to scale the MBFs. The degree of freedom to be parameterized then is the corresponding scaling factor.
- The NTCs and GTCs on which the MBFs are based take into account bottlenecks within the bidding zone insofar as they occur in usual exchange patterns. However, when exchange patterns strongly deviate, additional internal bottlenecks can become binding. This risk exists in particular if the exchanges are optimized for the "corners" of the flow-based domain. In the basic model, these corners are formally formed only by the limitations of the cross-border flows. In an operational flow-based model, the internal

lines would appear as additional constraints, so that these corners would be outside the flow-based domain.

- The following figure shows such a "corner" using a simple flow-based model for three bid zones A, B, and C. The two axes of the diagram represent exchanges from A to B and from A to C, respectively. Each straight line in the diagram - labeled CNEC\_n here - represents the capacity limitation by a single bidding zone border (i.e. one MBF value and associated PTDF values). The coloured area within the polygon is called the flow-based domain. It is assumed without loss of generality that the exchange between B and C is always zero. Thus the negative range of the x-axis represents an export of B. The maximum possible export of B is reached in the marked corner of the flow-based domain. It can be seen that this export is only permissible if the exchange from A to C takes on a very specific value at the same time. Conversely, the maximum export of C would require a different very specific value of the export of B. The maximum exports of B and C are thus not feasible at the same time.

FIGURE B-3: SCHEMATIC EXAMPLE OF A FLOW-BASED DOMAIN AND EXCHANGE PATTERN ("CORNER") FOR WHICH THE MAXIMUM EXPORT OF BIDDING ZONE B IS REALIZED

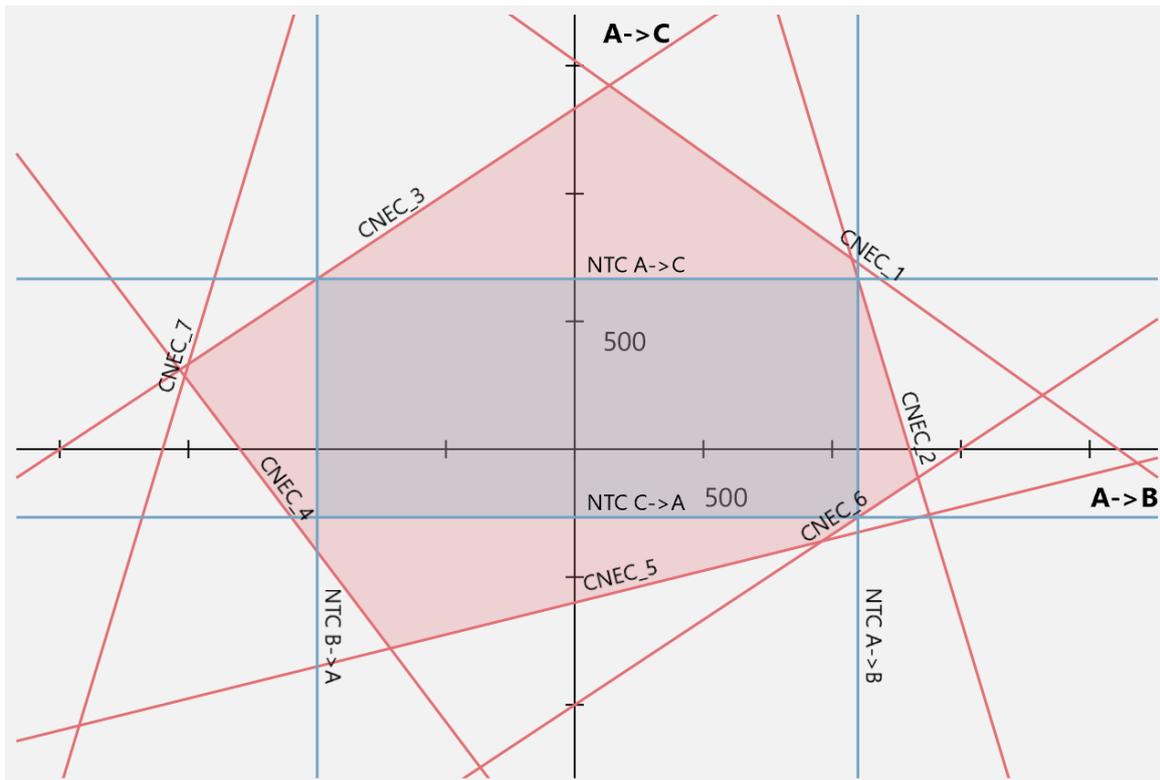


Source: Own representation.

- The flow-based models used in this project contain nine bidding zones, so that the flow-based domain is bounded by an eight-dimensional polytope. In this case, the maximum export of a bidding zone can only be achieved if the eight remaining bidding zones each have a specific export or import at the same time.
- In order to prevent an overestimation of the exchange possibilities without explicitly mapping internal lines, the basic model is additionally limited by an "NTC frame". This is done in three steps as follows:
- In the first step, fitted NTCs are determined for the flow-based model. These are NTCs that can be implemented simultaneously in this model.

For example, in the following figure, the blue NTCs "fit" into the flow-based domain.<sup>201</sup>

FIGURE B-4: NTCs (BLUE RECTANGLE) FITTED INTO THE FLOW-BASED DOMAIN (RED POLYGON)



Source: Own representation.

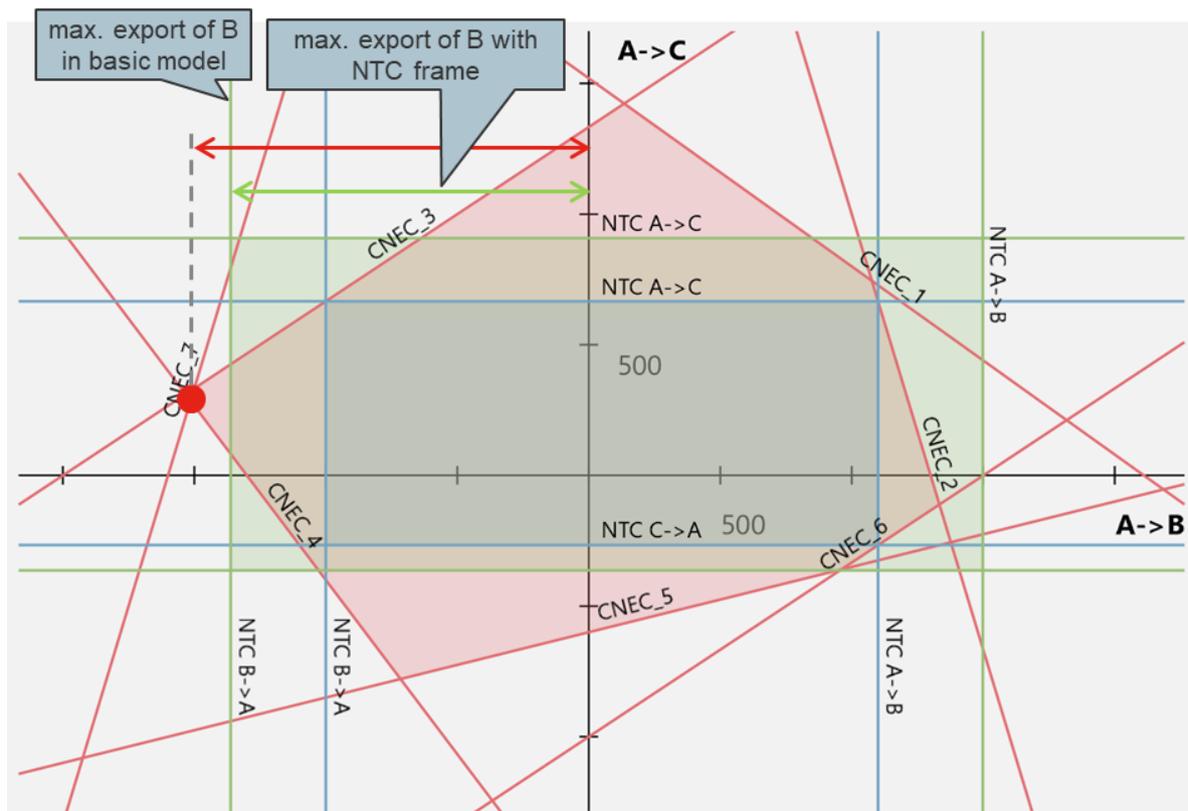
<sup>201</sup> For a given flow-based model, it is always possible to specify NTCs that can be implemented simultaneously in this model. However, there is an infinite number of fitting NTC combinations for each flow-based model. NTCs that are fitted are therefore not unique per se. Rather, additional assumptions are needed to achieve unambiguity.

In the operational flow-based capacity calculation in CWE, an algorithm for calculating fitted NTCs is used, called "ATC Extraction (Documentation of the CWE FB MC Solution, 2014). The bilateral capacities thus determined are reserved, for example, for the 'shadow auctions', which are allocated as a fallback process in the event of a market coupling failure. We use this approach to determine unambiguously fitted NTCs.

A degree of freedom in the above approach is the specification of "starting values", i.e. NTCs per border, from which a gradual increase is determined until the limits of the flow-based model are reached. The initial values take account of the fact that the amounts of the NTCs sometimes differ quite considerably between the various borders. For the calculation of the fitted NTCs, we use 75 % of the NTCs of the base year 2016 in each case. This roughly maintains the fundamental relationship between the NTCs, but at the same time gives the algorithm sufficient leeway to detect not only uniform increases in capacity at all borders, but also regional shifts resulting from heterogeneous network expansion.

- In the second step, the fitted NTCs are proportionally enlarged (scaled). This allows to ensure that the maximum export of a bidding zone, if only limited by these NTCs, is in a certain ratio to the maximum export given by the flow-based domain. This is illustrated in the following figure by the export of bidding zone B: The marked "corner" of the flow-based domain lies beyond the NTC values even after the scaling of the NTCs (green rectangle), and the scaling of the NTCs determines the length ratio of the green to the red arrow at the top of the image. The picture also shows that the green rectangle of the scaled NTCs extends beyond the flow-based domain - these NTCs can no longer be realized simultaneously.

FIGURE B-5: SCALING OF THE FITTED NTCs (GREEN RECTANGLE, "NTC FRAME")

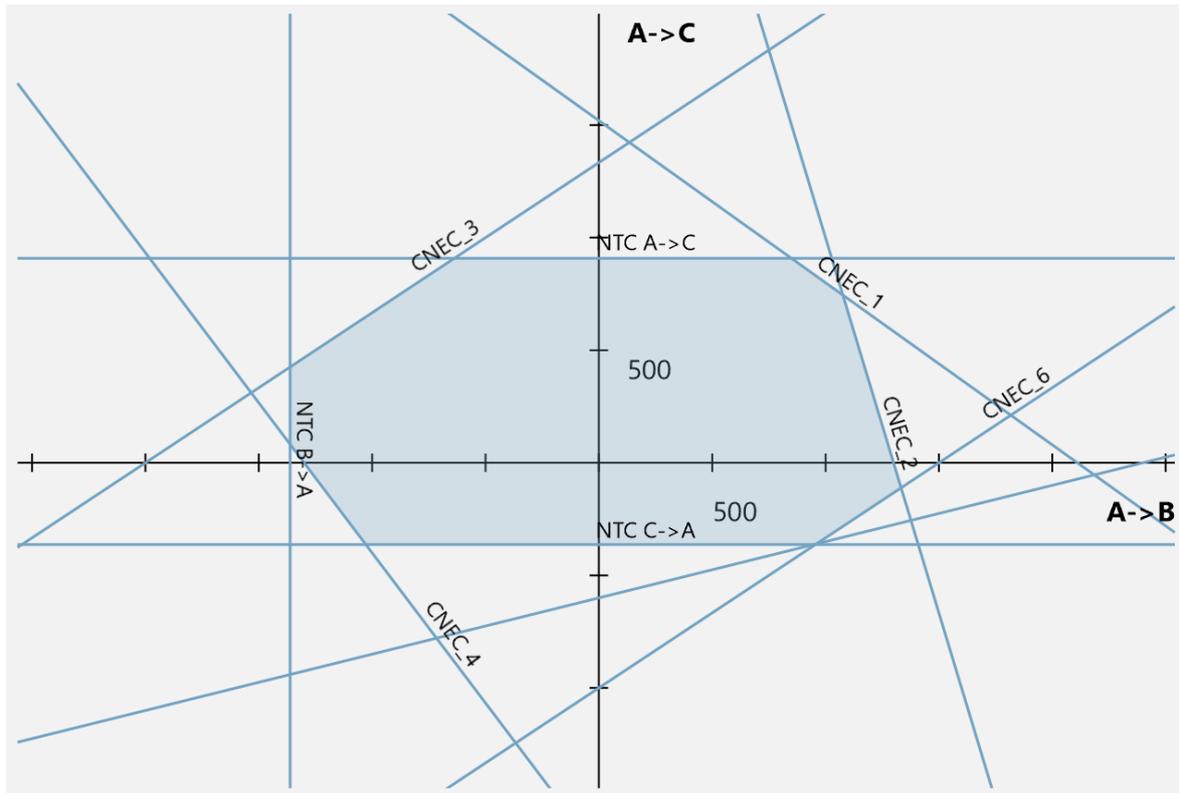


Source: Own representation.

- In the last step, the restrictions of the interconnector flows by the original flow-based domain and the "NTC frame" are merged, i.e. it is required that the restrictions modelled by each of these apply simultaneously. The result

is a final flow-based domain (see following figure), the limits of which come partly from the original flow-based domain and partly from the NTC frame.

FIGURE B-6: MERGING THE ORIGINAL FLOW-BASED DOMAIN AND THE "NTC FRAME"



Source: Own representation.

### Parameterisation

Two degrees of freedom are available per year for parameterizing the restriction of the basic model: The scaling factor of the MBFs and the scaling factor of the fitted NTCs ("NTC frame").

For the year 2025, we have detailed flow-based models in hourly resolution from another project. These are line-specific and contain tie lines and internal lines within the bidding zones. The models represent the so-called 75 percent target according to the Clean Energy Package (CEP). By comparing simplified market simulation calculations with these models on the one hand and with the static

border-wise model on the other, the following scaling factors were derived in such a way that the simulation results for both capacity models were almost identical:

- The scaling factor of the MBFs to map atypical flow distribution among the tie lines is 0.9.
- The fitted NTCs are scaled in such a way that the maximum possible export or import capacity<sup>202</sup> of the bidding zone Germany/Luxembourg determined by them is 90 % of the respective value that would result without the restriction by the fitted NTCs. The scaling is done separately for export and import direction at the borders of the bidding zone Germany/Luxembourg. The fitted NTCs at the remaining bidding zone borders are scaled with the mean value of the scaling factors for German import and export NTCs.

These factors are applied to all considered years in order to parameterise the exchange capacity for the reference scenario.

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<sup>202</sup> In the flow-based model, the simultaneously feasible export and import capacities of all bidding zones are interdependent. However, the maximum possible export and import capacity of a bidding zone can be determined objectively. These values are calculated separately for each bidding zone and direction and cannot be realized at the same time. Rather, a special constellation of exports and imports of the other bidding zones may be required to achieve the maximum export or import of a given bidding zone. The "maximum possible export or import capacity" thus indicates theoretical extreme values. In the graphical representation of the flow-based domain it corresponds to the "corners" mentioned in the text.

## **Appendix C    Model description Development of electricity demand**

The energy demand model FORECAST (FORecasting Energy Consumption Analysis and Simulation Tool) was developed at Fraunhofer ISI in cooperation with TEP Energy GmbH and IREES to model energy demand for the sectors industry, households and GHD (trade, commerce and services) (Fraunhofer ISI, 2018a). The analyses for the household, GHD and industrial sectors are supplemented by results analyses for the transport sector in order to fully reflect demand in accordance with the AGEB balance sheet definition. The modelling of the transport sector is based on the ALADIN model (ALternative Automobiles Diffusion and INfrastructure), which, like FORECAST, has already been frequently used for industrial and political consulting (Fraunhofer ISI, 2017). ALADIN is also based on a simulation approach, so that a combination with FORECAST is also consistent from a methodological point of view. For more information on ALADIN, see the model website. The methodology and result structure of the two models are described below.

### **C.1    Projection of demand by industry, household and tertiary sector (FORECAST)**

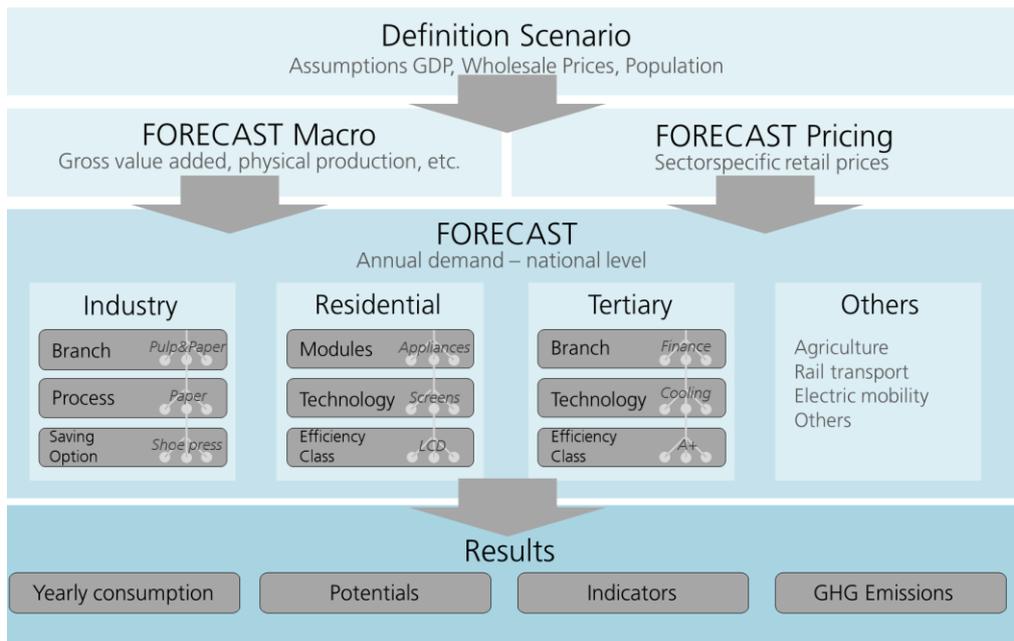
FORECAST is based on a techno-economic bottom-up approach and analyses the annual energy and electricity demand for Germany and other countries of the European Union. Sector-specific features such as the technology structure, the heterogeneity of players and retail prices are taken into account. The modeling logic is based on a simulation - as opposed to an optimization - in order to better map real behavior patterns of decision-makers in the energy-demanding sectors. The main competing technologies competing with each other are taken into account.

In addition to a high level of technological granularity, FORECAST's sectoral demand analysis is based on activity variables and end consumer prices, which are calculated in a macro module or pricing module:

- The macro module calculates all sector-specific activity variables for the energy-demanding sectors (e.g. gross value added by industrial sub-sector or number of households). The main input parameters of the macro module are population development and gross domestic product. In addition, the calculations contain empirical time series of the individual sector-specific activity variables, which are projected into the future on the basis of econometric analyses.
- The pricing module is used to calculate sector-specific retail prices. The data basis for these calculations are the development of the world market prices for crude oil, natural gas and hard coal, as well as the electricity wholesale prices from the market model of the transmission system operators. The retail prices are derived by applying taxes, levies and allocations to the world market or wholesale prices (e.g. EEG allocation).

For the calculation of final energy demand and electricity demand, the activity and price parameters are offset against the techno-economic parameters of the individual technologies. For this purpose, the sectors households, tertiary and industry are each represented by an independent module. Each of the modules is subdivided into three hierarchical levels; the example of the industrial sector illustrates these as the industrial sub-sectors (first level), differentiated according to sector-specific processes (second level) and process- or technology-specific savings options (third level). As a result, FORECAST provides the final energy demand at the national level (focus on the energy source electricity in this study). In addition to the demand for electricity per technology, potentials and indicators can also be identified. The structural design of FORECAST is shown schematically in the Figure C below.

FIGURE C-1: STRUCTURE OF THE FORECAST MODEL



Source: (Fraunhofer ISI, 2018a).

The future technological development paths are derived on the basis of so-called diffusion models. These models convert a combination of parameter assumptions into technological market shares. Parameters that are taken into account are techno-economic parameters (e.g. investments), energy carrier prices as well as energy and climate policy framework conditions. In addition to electricity applications, competition and thus substitutability with and from non-energy-based technologies (such as oil- or gas-based condensing boiler heating systems) are also taken into account.

The overview of selected input data in the Table C-1 illustrates the granularity of the individual modules. Each sector is based on three types of input data: Activity variables, retail prices and techno-economic parameters.

TABLE C-1: INPUT DATA OF THE SECTOR MODELS OF FORECAST

	<b>Residential</b>	<b>Tertiary</b>	<b>Industry</b>	<b>Others</b>
<b>Activity</b>	<ul style="list-style-type: none"> <li>- Number of households</li> <li>- Living area per household</li> <li>- Disposable income</li> </ul>	<b>Per subsector:</b> <ul style="list-style-type: none"> <li>- Number of employees</li> <li>- Floor area per employee</li> <li>- Gross value added</li> </ul>	<b>Per subsector (and process):</b> <ul style="list-style-type: none"> <li>- Physical production</li> <li>- Gross value added</li> </ul>	<ul style="list-style-type: none"> <li>- Passenger and ton-kilometers</li> <li>- Production</li> <li>- Irrigation areas</li> </ul>
	<ul style="list-style-type: none"> <li>- Population</li> <li>- Gross domestic product</li> </ul>			
<b>Retail prices</b>	<ul style="list-style-type: none"> <li>- Energy carrier prices (households)</li> </ul>	<ul style="list-style-type: none"> <li>- Energy carrier prices (tertiary)</li> </ul>	<ul style="list-style-type: none"> <li>- Energy carrier prices (industry)</li> <li>- EUA prices</li> </ul>	
<b>Techno-economic parameters</b>	<b>Appliances and Lighting:</b> <ul style="list-style-type: none"> <li>- Market share</li> <li>- Spec. energy consumption in operation</li> <li>- Lifetime</li> <li>- Standby-power and duration</li> <li>- etc.</li> </ul> <b>Building parameters:</b> <ul style="list-style-type: none"> <li>- Insulation</li> <li>- Efficiency heating system</li> <li>- Market share</li> <li>- etc.</li> </ul>	<b>Energy services:</b> <ul style="list-style-type: none"> <li>- Market share</li> <li>- Installed capacity</li> <li>- Annual full load hours</li> </ul> <b>Savings potentials</b> <ul style="list-style-type: none"> <li>- Efficiency potential</li> <li>- Costs</li> <li>- Lifetime</li> <li>- Diffusion</li> <li>- etc.</li> </ul>	<b>Processes:</b> <ul style="list-style-type: none"> <li>- Spec. energy consumption</li> </ul> <b>Savings potentials</b> <ul style="list-style-type: none"> <li>- Efficiency potential</li> <li>- Costs</li> <li>- Lifetime</li> <li>- Diffusion</li> <li>- etc.</li> </ul>	<b>Processes/energy services:</b> <ul style="list-style-type: none"> <li>- Technology driver</li> <li>- Spec. energy consumption</li> <li>- Efficiency potential</li> <li>- etc.</li> </ul>

Source: (Fraunhofer ISI, 2018a).

Through this technologically granular analysis, bottom-up modelling allows a more detailed breakdown of energy demand compared to the statistics of the Energy Balance Working Group. This is also the case for neighbouring countries, as the FORECAST analysis is carried out in identical granularity for all countries. Further information on the household, tertiary and industry sectors is presented.

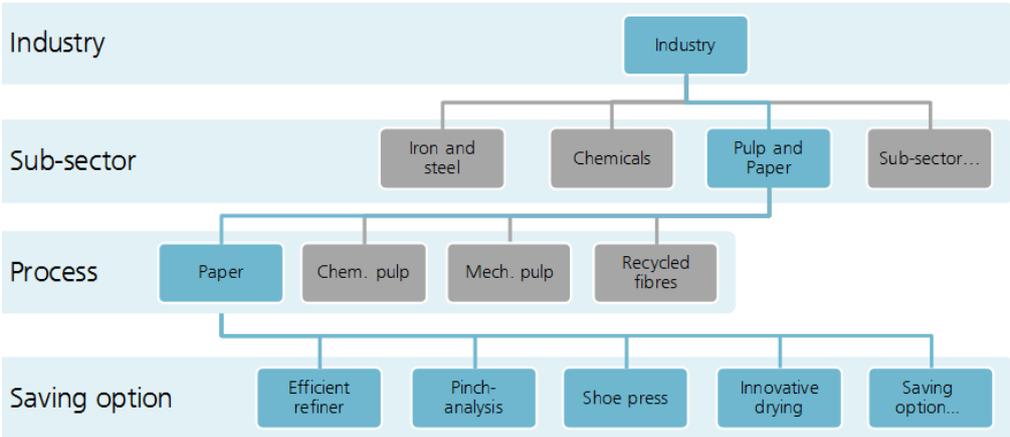
### Module: FORECAST Industry (Industry Sector)

The FORECAST-Industry module has a hierarchical structure and divides the industry into individual sectors based on the energy balances. The industries are assigned processes, which are described by a specific energy consumption and an activity size. The latter is in most cases the production in tons. The definition of a process can vary considerably depending on the application. A process can contain an entire chain of processing steps up to the manufacture of the finished product. Alternatively, a process can also represent a single processing step. The delimitation depends on data availability and energy intensity.

Savings options are assigned to the individual processes of FORECAST-Industry. For each savings option, specific data on the savings potential is stored, which is becoming increasingly widespread in the facility inventory and is therefore used. Through diffusion, the savings options contribute to reducing the specific energy demand of the process and thus also the energy demand of the sector. Savings potentials thus arise at the level of the individual savings options, as well as more aggregated at the level of the processes and industries, by comparing alternative scenarios with regard to the diffusion of the savings options.

In addition to the processes, cross-sectional technologies (QT) are also assigned to each sector. These are used in a similar form across industries and thus allow a relatively broad representation of the technology structure, even in areas with very heterogeneous production processes and a large number of products. For illustration purposes, the structure of FORECAST-Industry is shown in Figure C for the paper industry.

FIGURE C-2: SCHEMATIC REPRESENTATION OF THE MODEL HIERARCHY OF FORECAST-INDUSTRY USING THE PAPER INDUSTRY AS AN EXAMPLE



Source: (Fraunhofer ISI, 2018a).

The industry structure of the industrial model is based on the classification of the energy balances according to Eurostat or, for the calculation of individual countries, on national energy balances such as the AG-Energiebilanzen for Germany. For the Eurostat energy balances, the sector structure includes the eight separate sectors of Section C 'Manufacturing' of the NACE 2 classification (see Table C).

For the energy balances by AG-Energiebilanzen, according to the classification of economic activities (WZ 2003), it includes the two sectors 'manufacturing' (WZ 2003 No 'C') and parts of the sector 'mining and quarrying' (WZ 2003 No 'B') which are not used for energy production (see Table C).

TABLE C-2: INDUSTRY STRUCTURE OF FORECAST-INDUSTRY\_EU

<b>designation</b>	<b>NACE 2 Number</b>
Iron and steel	24.1, 24.2, 24.3, 24.51, 24.52
Non-ferrous metals	24.4, 24.53, 24.54
Paper and printing	17, 18
Non-metallic mineral products	23
Chemical industry	20
Food, drink and tobacco	10, 11, 12
Engineering and other metal	25, 26, 27, 28, 29, 30
Other non-classified	All remaining section C

Source: (EUROSTAT, 2018)

TABLE C-3: INDUSTRY STRUCTURE OF FORECAST-INDUSTRY\_DE

<b>designation</b>	<b>WZ 2003 Number</b>
Mining and quarrying	10.30, 12, 13, 14
Food, drink and tobacco	15, 16
Paper and printing	21
Basic chemicals	24.1
Other chemicals	24 without 24.1
Rubber and plastic goods	25
Glass and ceramics	26.1, 26.2, 26.3
Processing of non-metallic minerals	26 excluding 26.1, 26.2 and 26.3
Metal production	27.1
Non-ferrous metals, foundries	27.4, 27.5
Metal production	27 without 27.1, 27.4 and 27.5 incl. 28
Engineering	29
Vehicle construction	34, 35
Other non-classified	Remaining numbers of C

Source: (AG Energiebilanzen, 2018a).

For the mining, quarrying, engineering, metal processing, vehicle construction and other manufacturing, no tonne-production is taken into account as the structure of these sectors is very heterogeneous with a wide variety of products. Thus,

the projections in these sectors are based exclusively on the forecasts for the development of value added.

At the process level, the absolute energy requirement per process is calculated on the basis of the tonne production per process and its specific energy consumption. Tonnes production is more directly linked to energy consumption than value added, since, for example, an increase in value added need not necessarily reflect an increase in production relevant to energy consumption. In contrast to added value, physical production is directly linked to energy consumption. In the FORECAST-Industry module, approx. 70 of the most energy-intensive products or processes are shown separately on the basis of their tonne production (Table C). These energy-intensive products account for more than half of industry's energy consumption. The remaining energy consumption per sector, which is attributable to a much larger number of processes and plants, is extrapolated on the basis of value added. Sectors in which no individual processes are taken into account due to the very heterogeneous structure are modelled exclusively on the basis of value added and the diffusion of cross-sectional technologies.

TABLE C-4: PROCESS STRUCTURE OF THE FORECAST-INDUSTRY MODULE

<b>Non-metallic minerals</b>	<b>Non-ferrous metals</b>	<b>Basic chemistry</b>
Clinker calcination-Dry	Aluminium, primary	Adipic acid
Clinker calcination-Semidry	Aluminium, secondary	Ammonia
Clinker calcination-Wet	Aluminium extruding	Calcium carbide
Preparation of limestone	Aluminium foundries	Carbon black
Gypsum	Aluminium rolling	Chlorine, diaphragm
Cement grinding	Copper, primary	Chlorine, membrane
Lime milling	Copper, secondary	Chlorine, mercury
Bricks	Copper further treatment	Ethylene
Lime burning	Zinc, primary	Methanol
	Zinc, secondary	Nitric acid
		Oxygen
		Polycarbonate
		Polyethylene
		Polypropylene
		Polysulphones
		Soda ash
		TDI
		Titanium dioxide
<b>Food industry</b>	<b>Metal production</b>	<b>Paper and printing</b>
Sugar	Sinter	Paper
Dairy	Blast furnace	Chemical pulp
Brewing	Electric arc furnace	Mechanical pulp
Meat processing	Rolled steel	Recovered fibres
Bread & bakery	Coke oven	
Starch	Smelting reduction	
	Direct reduction	
<b>Glass</b>	<b>Ceramics</b>	<b>Others</b>
Container glass	Houseware, sanitary ware	Plastics: Extrusion
Flat glass	Technical, other ceramics	Plastics: Injection moulding
Fibre glass	Tiles, plates, refractories	Plastics: Blow mouldings
Other glass		

Source: (Fleiter et al. 2013).

With regard to the technology structure, a distinction can be made between process-specific technologies and cross-sectional technologies. Process-specific technologies can be clearly assigned to individual processes in the industrial sector - for example, the blast furnace process in steel production. Cross-sectional technologies are used in all industries and various processes: electric motors, for example, are used in both paper and steel production.

Cross-cutting technologies are divided into applications that consume electricity and those that provide heat:

- Electricity: Mainly electric motors and working machines such as compressors, fans or pumps, including the associated systems for providing mechanical energy or cooling. Lighting systems as well.
- On the heat side: Industrial incineration plants in the temperature range below 500°C (boilers, pure industrial steam generators). Systems in the higher temperature range are often very process-specific and are therefore taken into account in the individual processes.

#### Module: FORECAST Tertiary (tertiary sector)

The FORECAST-Tertiary module is similar in structure to the industrial module, but adapted to data availability and technology structure in the service sector. This means that in the tertiary module, the energy consumption of individual sectors and energy services is calculated on the basis of a quantity structure depending on framework conditions (e.g. economic development, efficiency policy, energy prices).

The key variables are the number of employees and the floor space per sector of the tertiary sector. The energy consumption of the individual sectors is in turn made up of the sum of individual energy services. The spread of efficiency measures lowers the specific energy consumption of individual energy services and thus reflects a different overcoming of obstacles by political instruments for

the promotion of energy efficiency or varying energy prices. The diffusion of efficiency measures is modeled as a sum of investment decisions of the companies. In the following, the individual levels of activity variables, energy services and technology structure as well as the model logic are dealt with in more detail.

The variables "number of employees" and "usable floor space per sector" form the central variables in the quantity structure for extrapolating energy consumption. Both variables are more directly linked to energy consumption than the value added of the sector. Employees are more relevant for energy services such as IT equipment, while the usable floor space is the central factor for building-related energy services. The sectoral classification of activity sizes is based on the classification of economic sectors in 2003 (WZ 2003) and distinguishes eight sectors (Table C). Accordingly, it allows a "bottom-up" calculation of energy consumption for each of the sectors, which goes well beyond the detailed energy balances according to AGEB, which only shows energy consumption for the tertiary sector as a whole.

**TABLE C-5: CLASSIFICATION OF FORECAST-TERTIARY INDUSTRIES**

<b>designation</b>	<b>WZ 2003</b>
Hotels and restaurants (gastronomy and hotels)	H
Health, veterinary and social work (health care)	N
Education and teaching (education)	M
Wholesale and retail trade (retail trade)	G
Transport, storage and communication (transport)	I
Public administration, defence, social security (public institutions)	L
Banks and insurance companies (finance)	J
Other services (waste, sports, social services) + real estate (other)	O+K

Source: (AG Energiebilanzen, 2018b).

The energy demand per sector is calculated as the sum of the energy demand of up to 13 individual energy services (EDL), which together account for the bulk of electricity consumption in the tertiary sector (Table C). Examples of EDL are lighting, cooling or ICT applications. For most EDL, the absolute demand results from

the global activity size (either area or employees) and the EDL-related activity size (e.g. proportion of illuminated area). Some EDL are not linked to global activity quantities, such as street lighting.

TABLE C-6: ENERGY SERVICES (EDL) CLASSIFIED BY SECTOR

type	Energy services	Description of the	Activity size EDL (D)	Global activity size (G)
El	lighting	room lighting	Percentage of illuminated building area	building area
El/Th	Air conditioning and ventilation	Air conditioning and ventilation of rooms and buildings by means of air conditioning systems	Percentage of air-conditioned and ventilated building area	building area
El	circulating pumps	Distribution of fluids in heating systems	-	building area
El	ICT in the office	PC, monitor, copier/printer, etc.	ICT equipment of an average workplace	Number of employees
El	ICT Server	Server both in data centers and decentralized	Number of servers	-
El	hot water	Hot water and process heat (e.g. cleaning)	-	building area
Th	space heating	Heat pumps and direct electric heaters	Share of building area with electric heating	building area
Th/El	laundrette	Laundry mainly in hotels and health sector	Number of beds/guests	-
Th/El	Cooking	Cooking in restaurants and health sector	Number of dishes, guests, beds	-
El	cooling	cooling of products, mainly refrigerated shelves in supermarkets, but also restaurants and hotels)	-	Number of employees
El	Various building-related EDLs	residual size	building area	building area
El	street lighting	Lighting of streets and public squares	Number of light points	-
El	elevators	For the provision of vertical transport in buildings	Number of lifts	-
El: Electricity-based (hardly substitutable) Th: For heat supply (substitutable by other energy sources)				

Module: FORECAST-Residential (Household sector)

The sector model for the household sector, FORECAST Residential, consists of a module for household appliances (appliance module), modules for space heating

and hot water supply (building module) and a module for calculating electricity demand through electromobility (electromobility module).<sup>203</sup>

The FORECAST Residential Household Appliances module considers the following appliance categories, which are further differentiated according to technologies and/or efficiency classes:

- Large electrical household appliances (including: refrigerators and freezers, dishwashers, washing machines, dryers, stoves)
- Information and communication technology terminal equipment ICT (including: desktop computers, PC screens, laptops, televisions, set-top boxes, modems/routers)
- Small electrical appliances (including: coffee machines, vacuum cleaners)
- Lighting
- Air conditioners
- Other electrical applications: this category represents a residual unit covering all electrical applications in private households not yet included in the other sectors. This category includes both a variety of other small electrical appliances (including cooker hoods, microwave ovens, irons, hair dryers, toasters, shavers, etc.) and the demand for electricity from potentially new appliances that will diffuse into the market by 2050.

With the exception of the stoves, the equipment categories listed contain exclusively current-based applications.

Due to the high availability of data on the number and average specific energy consumption of household appliances, their final energy demand is calculated using an inventory model. Since the calculation of the inventory turnover also requires the collection of historical data, empirical time series for the year-specific

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<sup>203</sup> The electric mobility module is not discussed in more detail in this model description.

number of appliances and the specific consumption of the appliances (differentiated according to operation and standby) are determined or estimated in an upstream step. The projection of the equipment stock is carried out by means of a logistic function, which is calculated from a *least squares* deviation, based on the empirical stock development and an estimated saturation limit. Downstream, a calculation is carried out using a logit function that maps the investment decision and determines the market shares of the substitution alternatives on the basis of costs.

The inventory circulation or market diffusion of new equipment is based on a device-specific useful life with a normally distributed probability of defect, which determines the time of the end of useful life of an old device and the beginning of useful life of a new device. The choice of the technologies or efficiency classes of the old appliances replaced and the increase in the stock that diffuse into the stock as new appliances is based on the design of a scenario. The annual final energy demand of all appliances is therefore calculated on the basis of specific consumption (based either on operating hours, e.g. for televisions, or on the number of cycles per year, e.g. for dishwashers), the average equipment rate (for lighting, this corresponds to the proportion of lighting points per accommodation unit) and the number of private households.

This structure applies in principle to all equipment categories considered, with the exception of the residual unit for other electrical applications. This approach cannot be applied to this category due to its high heterogeneity. Electricity demand in the base year for other electrical applications is therefore calculated as the difference from electricity demand according to the energy balance (excluding consumption for space heating and hot water) and extrapolated for the future on the basis of an estimated equipment rate.

The FORECAST-Residential building module is broken down as follows:

- Buildings: existing buildings and new buildings (differentiated according to building age class, building size classes and building standards)

- Space heating technologies: electricity, oil, coal, gas, biomass, district heating and solar technologies
- Hot water technology: electricity, oil, coal, gas, biomass, district heating and solar technologies

The result of the building projection is shown as useful heat demand. In the case of space heating and hot water technologies, all final energy sources are calculated.

Due to the high availability of data on the German building typology, the useful heat demand is calculated using an inventory model. Since the calculation of the inventory circulation also requires the collection of historical data, the composition of the existing buildings (differentiated according to age class, building size classes and building standards) is determined in an upstream step. The projection of the building stock is based on a logit function in addition to the demolition, renovation and new construction rates.

The calculation of room heating (demand coverage) takes place in a subsequent step to calculate the building stock (demand determination). Data availability here is less detailed than for buildings and equipment. The data basis for space heating is the final energy consumption of the individual energy sources in the base year. The space heating technologies are projected on a logit function in addition to a standard normally distributed service life. The calculation of the final energy consumption by hot water technologies is carried out according to the space heating calculation except for the difference that the demand to be covered here is defined by the number of litres of hot water and the average temperature level of the hot water.

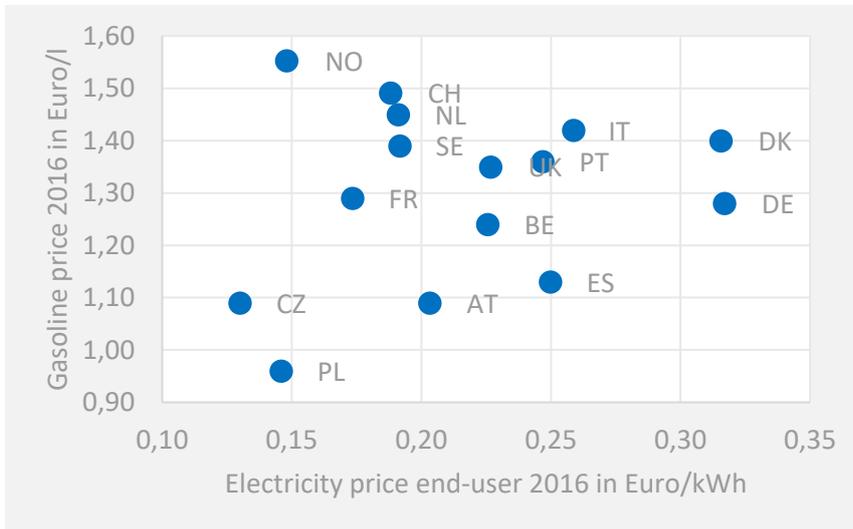
## **C.2 Simulation of Market Diffusion of Alternative Drives in Europe with ALADIN**

The model ALADIN (ALternative Antriebe Diffusion und INfrastruktur) is used for the future market diffusion of alternative drives in road traffic (Fraunhofer ISI,

2018a). The basic principle of the model is that the market share of alternative drive systems is determined by the driving behavior of a large number of individual vehicles [MOP 2010, Fraunhofer ISI 2014, KiD 2010, truckscout 2016]. In the passenger car sector, the focus is on electric vehicles (BEV, PHEV and FCEV) and their charging infrastructure; in road freight transport, various alternative drive types are being investigated, with the current focus on hybrid trolleytrucks [Plötz et al. 2013, Plötz et al. 2014, Gnann et al. 2015, Gnann 2015, Wietschel et al. 2017]. While the observation space was previously limited to Germany until 2030, this project extended the model to Europe and development by 2050.

For the diffusion of electric vehicles in Europe, the results from Germany will be transferred to the other countries and adapted to the special framework conditions in the countries. In detail, the current market share of electric vehicles in the countries is taken as a starting point according to [EAFO 2017]. The market ramp-up for Germany in the years 2020 - 2030 according to the complex ALADIN model for Germany [Plötz et al. 2013, Gnann 2015] is followed by a logistic growth curve (according to minimization of squared differences). This logistic growth curve for Germany contains two parameters: the growth rate of the market and the time at which 50% market share for electric vehicles is reached. As the energy costs for petrol or diesel and electricity vary greatly between the countries considered, the average savings per kilometre are calculated for an electric vehicle compared to a combustion engine vehicle. Throughout Europe, these savings are between three and eight euro cents per km. The growth rate of logistical growth in each country is increased or decreased due to higher or lower fuel cost savings. The linear correlation between growth rates and savings between the Pro and Contra EV scenarios for Germany is used and extrapolated to the growth rates in the other countries. The required petrol and electricity prices are taken from Eurostat 2017c, EC 2017. As an illustration, the figure below shows petrol and electricity prices in the individual European countries. It can be seen that Norway, for example, has a particularly favourable combination for electric vehicles.

FIGURE C-3: ELECTRICITY AND GASOLINE END-USER PRICES IN 2016



The second parameter of the logistic growth, the time with 50% market share of electric vehicles, is determined for each country so that the logistic growth follows the market share of electric vehicles in 2016. Logistical growth curves are thus determined for all countries, taking into account the country specifics, and these will be updated until 2050.

The total energy consumption per year results from the new registrations and consumption of electric vehicles. The demand for energy  $W_t^{PEV}$  follows from the electrical driving components  $s_t^{el,PEV}$  in the year under consideration  $t$  multiplied by the sum of the product of the market shares  $MS_\tau^{PEV}$  the annual mileage  $VKT_\tau^{PEV}$  and electrical consumption  $c_\tau^{el,PEV}$  as follows

$$W_t^{PEV} = \sum_{\tau=t-T}^t MS_\tau^{PEV} \cdot VKT_\tau^{PEV} \cdot c_\tau^{el,PEV} \cdot s_\tau^{el,PEV}$$

The electric driving part is 100% for BEV and is transferred for PHEV from the Germany model of ALADIN.

The second part of the modelling covers the diffusion of hybrid trolleytrucks in Europe. The object of investigation here is trucks with a permissible total weight of over 12 tonnes, which are not used as construction vehicles but primarily in

long-distance traffic. The detailed data basis is provided by the study, Wietschel et al. 2017 in which the feasibility of hybrid trolleytrucks in Europe was investigated. This study uses a cost comparison to calculate the best drive types for 2015 and 2030 (7,000km driven annually) of trucks of different size classes and determines the market potential of a drive on the basis of its share in the size class [KiD 2010, truckscout 2016]. This will be reduced to vehicles driving primarily in Germany and narrowed with limited model availability. The inventory can be determined by polynomial interpolation of the new registrations and subsequent summation. Of great importance is the detailed determination of a vehicle's movements on the overhead contact line, as this is much more economical than driving in diesel mode. For this purpose, driving on motorways with overhead contact lines must be estimated, for which regressions are determined on the basis of use. Since no such detailed data is available for vehicle use in Europe, the market ramp-up from Germany based on Wietschel et al. (2017) is transferred to Europe and assumed to be the same. As the present study is expected to run until 2030 and an update of all individual parameters is considered more error-prone than an update of the market ramp-up, market shares are extrapolated until 2050. This means that the market shares are the same in all countries, but differentiation is based on the different registration numbers and their development. In addition, it is assumed after 2030 that the proportion of electric driving will increase to 100% by 2050 due to the use of larger batteries in the vehicle.

For the future development of freight transport, the reference scenario of PRIMES is used, which assumes an increase in freight transport of about 60% between 2010 and 2050 (EU 2017). The new registrations are calculated from the road freight transport capacity (in tonne-kilometres). Here the stock is calculated by dividing 90% of the tonne-kilometres (share which is provided by semitrailer tractors) by an average annual mileage of 100,000 km (weighted average of vehicles of 12-26 t and semitrailer tractors (from Wietschel et al. 2017) and by a vehicle weight of 14 t (with average payload of 50%). In addition, the new registrations

are determined with the help of a holding period of six years. With the help of these new registrations, the market diffusion by country and the energy demand can be  $W_t^{CHV}$  as an electric driving component  $s_t^{el,CHV}$  in the year under consideration  $t$  multiplied by the sum of the product of the market shares  $MS_\tau^{CHV}$  the annual mileage  $VKT_\tau^{CHV}$  and electrical consumption  $c_\tau^{el,CHV}$  is calculated:

$$W_t^{CHV} = s_t^{el,CHV} \sum_{\tau=t-T}^t MS_\tau^{CHV} \cdot VKT_\tau^{CHV} \cdot c_\tau^{el,CHV}$$

For the energy demand by country, the total quantity of electricity must be distributed according to the domestic principle, since the use is not exclusively by vehicles from the domestic market (domestic principle). However, detailed analyses show a strong correlation between the two variables, so that the reference scenario of PRIMES (EU 2017) is also used for the continuation of freight transport demand according to the domestic principle.

## Appendix D Generation of hourly RES feed-in curves

When it comes to the integration of renewable energies sources (RES), it is essential to take appropriate account of the generation curves of individual RE technologies. Due to the growing European internal market, the consistent and detailed mapping of European foreign markets is of great importance.

In the following, the simulation model of r2b energy consulting GmbH is described for the derivation of high-resolution renewable energy production feed-in curves for the intermittent renewable energy technologies of: onshore wind energy, offshore wind energy, photovoltaics and run-of-river.

### D.1 Basic methodology

Both the level of the annual feed-in and the structure during the year depend strongly on the meteorological conditions of the weather year under consideration for the intermittent renewable energy sources. In order to be able to consider these characteristics (stochastically), the simulation model can be used to flexibly determine the corresponding feed-in curves for different weather years. This study takes into account the weather years 2009 to 2013. The database of r2b energy consulting GmbH contains further historical weather years, which will be successively extended.

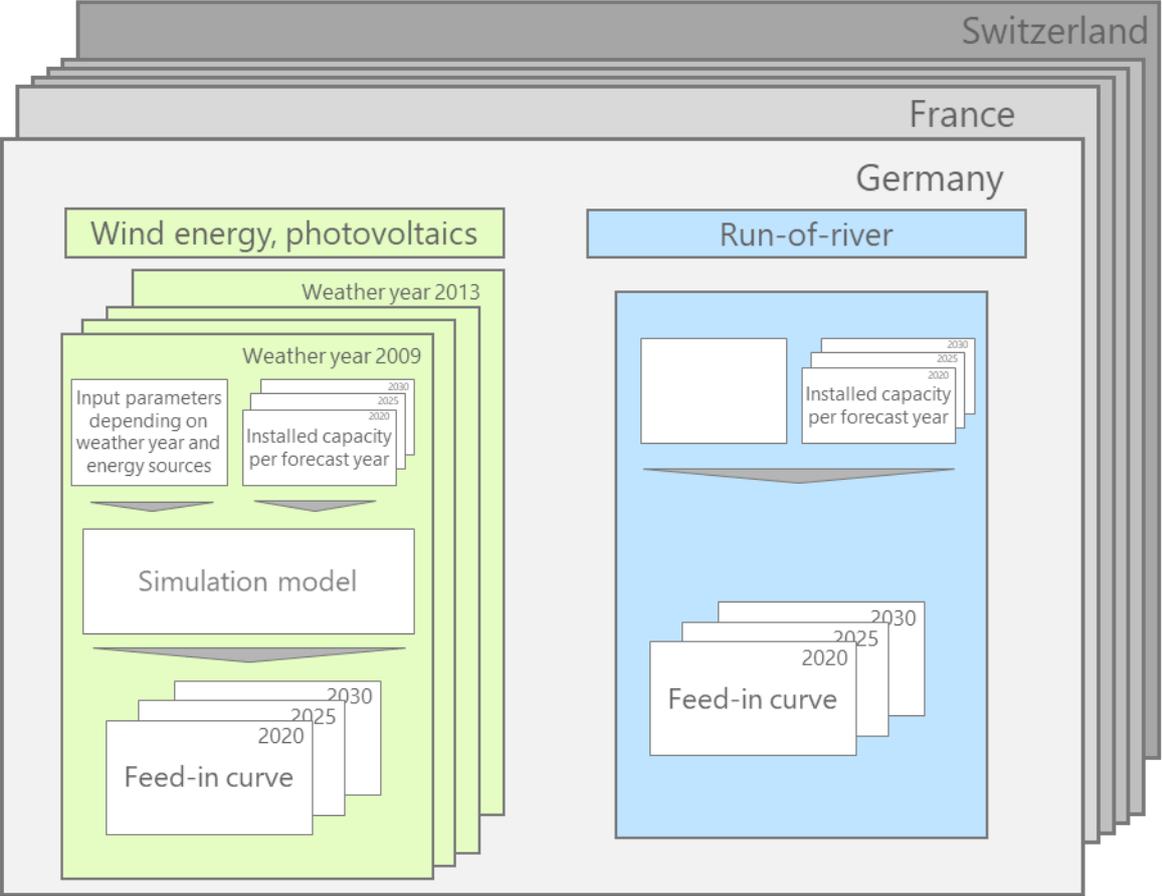
We use simulation models to determine the hourly feed-in curves of the intermittent renewable energy sources onshore and offshore wind energy as well as PV. Using these models, feed-in curves are derived for the corresponding renewable energy technologies by country, taking into account the assumed development of installed capacity in future years.<sup>204</sup> This is done on the basis of temporally and regionally high-resolution data on meteorological conditions (e.g. wind speeds, temperatures, global radiation) of past years (historical weather years)

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<sup>204</sup> In principle, forecasts can be carried out up to the year 2050 within the framework of the simulation model.

and a detailed reproduction of the technical parameters and the regional distribution of wind turbines and PV systems. In contrast to wind energy and PV, the feed-in curves for run-of-river are based on historical, aggregated production time series of individual countries. The procedure is shown schematically in Figure D-1.

**FIGURE D-1: MODELS FOR DETERMINING RES FEED-IN CURVES FOR INTERMITTENT RES TECHNOLOGIES**



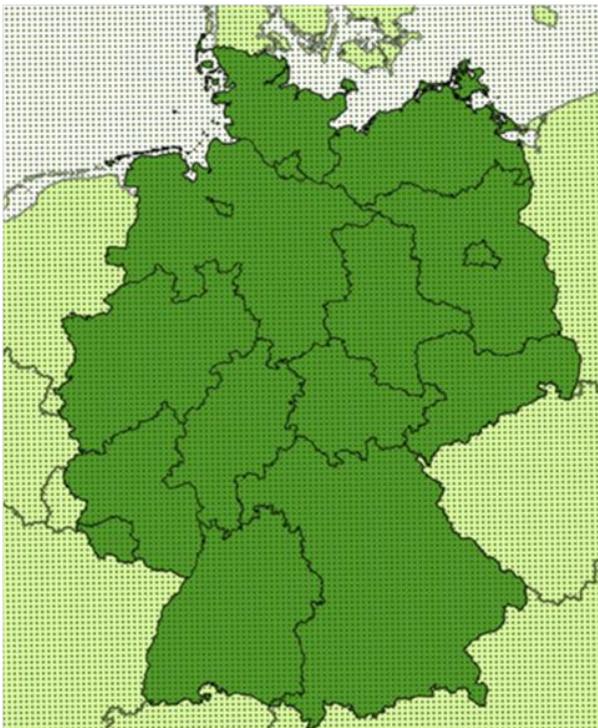
Source: Own representation.

As a basis of data for wind energy and PV, r2b energy consulting GmbH has hourly meteorological data as well as a plant-specific European database at its disposal. For run-of-river, especially statistical data on installed capacity and generation quantities are used.

## D.2 Meteorological database for wind energy and PV

r2b energy consulting GmbH has a database with hourly resolved meteorological data of the German Weather Service (DWD). This study considers the weather years 2009 to 2013 based on the COSMO-EU model. The area of the COSMO-EU model covers almost all of Europe including the entire Baltic Sea, the Mediterranean Sea and the Black Sea as well as North Africa with 665x657 grid points at a mesh size of  $0.0625^\circ$  ( $\sim 7$  km). Among other things, data is available on hourly wind speeds and temperatures at various altitude levels as well as on air pressure, roughness<sup>205</sup> and global radiation. Figure D-2 shows the spatial resolution of the database as an example for Germany.

FIGURE D-2: METEOROLOGICAL DATABASE WITH A SPATIAL RESOLUTION OF THE GRID POINTS OF 7X7KM



Source: Own representation.

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<sup>205</sup> The roughness indicates the degree of unevenness of the surface height.

### D.3 Plant database for wind energy and PV

In addition to the meteorological database described above, a European database of **wind turbines** from r2b energy consulting GmbH is also used.<sup>206</sup> This contains information on existing installations as well as on wind farms under construction and planned. For all installations, data are stored on the geocoded location, installed capacity, hub height, rotor diameter, turbine type, manufacturer and (planned) date of commissioning.<sup>207</sup> In the case of offshore wind turbines, the distance from the coast and the depth of the sea are also known. Each wind farm can be assigned the nearest grid point of the COSMO-EU model via the geoinformation system (GIS), so that typical hourly wind speeds at different heights for different weather years can be accessed locally for each turbine.

For existing **photovoltaic plants**, we have detailed databases for Germany on the geocoded location, installed capacity and commissioning date. For the other European countries, regionalized data on installed capacity and the year of commissioning are available.

### D.4 Simulation model for wind energy and photovoltaics

When determining the hourly feed-in curves for onshore wind energy, offshore wind energy and PV in the individual European countries, specific feed-in curves are derived in a first step in MWh per MW installed capacity for different regions and technology classes, so that regionally different wind conditions, global radiation and temperatures can be taken into account. Subsequently, the percentage

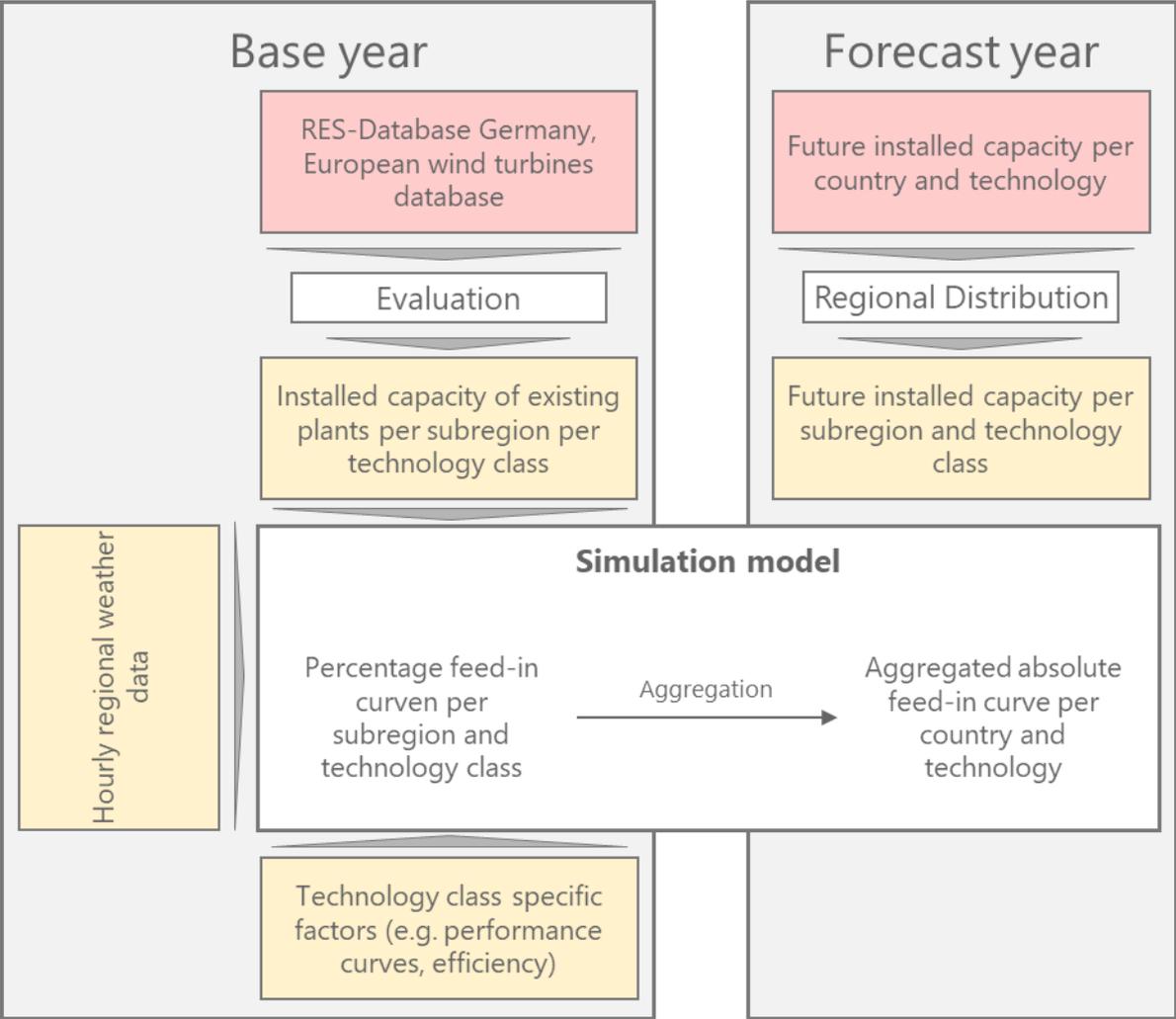
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<sup>206</sup> The database on European wind turbines is based on commercially acquired turbine lists, published turbine lists and independently researched turbine data.

<sup>207</sup> For Germany, the data is fully available for the individual installations. For the other European countries, the availability of specific data such as rotor diameter or hub height is not complete. For these installations, the unavailable data are estimated and supplemented taking into account existing information, e.g. location, year of commissioning and installed capacity.

feed-in curves are aggregated, weighted with the installed capacities to be specified per model region and per technology class of the energy source under consideration. Figure D-3 shows an example of the relationships between country and historical weather year.

**FIGURE D-3: METHODOLOGY FOR DETERMINING THE PRODUCTION FEED-IN CURVES OF WIND ENERGY AND PHOTOVOLTAICS**



Source: Own representation.

**Model regions**

In order to ensure a detailed illustration of regional differences in meteorological conditions and different turbine configurations for wind turbines and PV systems, a high degree of regional differentiation is applied. In the latest model version,

262 regions each for onshore wind energy and PV and 103 regions for offshore wind energy are distinguished within Europe. The classification of the regions is based on the one hand on the respective administrative areas and on the other hand on similar meteorological conditions. The aggregation of the regions can, for example, be carried out flexibly for Germany for federal states or other regions relevant to the electricity market such as control areas. For the other European countries, regions have been divided into different NUTS levels<sup>208</sup> according to data availability. In the case of offshore wind energy, the boundaries of maritime territories were taken into account, as well as information on sea depth and soil conditions. For each region, wind speeds in different altitude levels or ambient temperatures and global radiation values for each historical weather year are stored in hourly temporal resolution and in 7x7 km spatial resolution.

### Technology classes

Furthermore, different turbine designs are taken into account by a total of thirteen technology classes (9 technology classes for onshore wind turbines and 4 technology classes for offshore wind turbines). By means of different technology classes, technological developments with regard to hub height or (power) characteristic curves can be taken into account, for example, for existing installations. For new turbines, this means that in addition to different hub heights, a distinction can also be made between strong and weak wind turbines. The different technology classes of wind turbines are characterized by the nominal power, the rotor swept area, the hub height and a typical power curve. The power characteristic curve is discrete Representation of the functional relationship between the wind speeds at hub height and the resulting feed-in of the turbines at these wind

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<sup>208</sup> NUTS (Nomenclature des unités territoriales statistiques) identifies and classifies the respective administrative levels of the Member States of the European Union.

speeds. In the case of onshore wind turbines, four of the technology classes represent expected future turbine designs: strong and weak wind turbines in two versions depending on time horizon.<sup>209</sup> A future technology is included for offshore wind energy.

The technology classes of PV systems differentiate between small roof systems (installed capacity  $\leq 10$  kWp), large roof systems (installed capacity  $> 10$  kWp) and ground-mounted systems. This differentiation allows differences in module efficiency and performance ratio<sup>210</sup> to be considered, as well as differences in positioning and alignment.

### Hourly feed-in curves per grid point/plant

Since all information is geocoded, each wind turbine in the wind turbine database can be assigned to the nearest grid point of the COSMO-EU model via a geoinformation system (GIS). Thus, for each grid point of a wind region per technology class, the installed capacity of the turbines of this class are calculated in the vicinity of this grid point as well as the hourly wind speeds in this grid point. Each turbine is assigned the closest or most suitable grid point in the vicinity, so that hourly feed-in curves can be simulated for the wind turbines assigned to the grid points and technology classes. In addition, a (partly regionally different) scaling with availability or calibration factors is carried out. In the case of wind turbines, these factors take into account technical unavailabilities and shading effects within wind farms, for example.

For each technology class of PV systems, ambient temperatures and global radiation values as well as the installed power are available at each grid point of a region. On this basis, hourly feed-in curves can be simulated for the PV systems

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<sup>209</sup> Depending on the average wind speed at a location, a weak wind or a strong wind turbine is stored. Wind turbines designed for low wind conditions have a larger ratio of rotor area to rated power of the turbine.

<sup>210</sup> The performance ratio for photovoltaic systems is the ratio between the possible (maximum) yield and the actual yield achieved. It thus reflects the efficiency of the system and takes into account, for example, the module temperature, shading, contamination of the photovoltaic modules and losses.

assigned to the grid points and technology classes. The hourly feed-in is determined taking into account the module efficiency assigned for each technology class under standard test conditions, the hourly global radiation and the ambient temperature (converted to module temperature). Furthermore, a performance ratio takes into account (for example) technical unavailabilities, shading effects and additional module contamination.<sup>211</sup>

### Treatment of future technologies

The allocation of existing plants is based on existing information about the location and the power plant design. In the case of new turbines, for each potential location, the average annual wind speed of the historical weather year under consideration is used to determine whether it makes sense to add strong or weak wind turbines at this point.

### Aggregation by regions

The use of the methodology described so far results in absolute hourly feed-in curves for each technology class of the respective energy source per grid point. An aggregation of the feed-in curves over all grid points of a region and a division by the underlying installed capacity results in percentage feed-in curves in MWh per MW per technology class and per region (these are shown within the simulation model in Figure D-4). Depending on the installed capacities assumed per technology class and per region for future forecast years, weighted aggregation can determine absolute feed-in curves per forecast year and per country for each historical weather year.

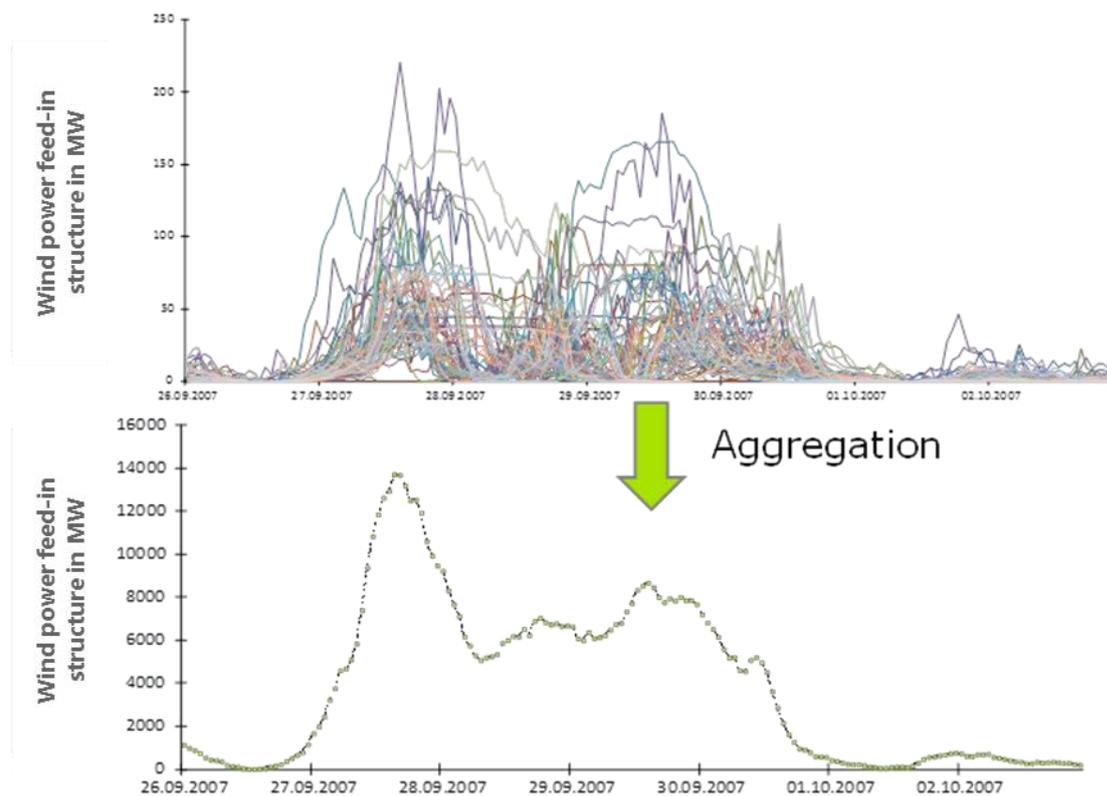
Figure D-4 shows the aggregation of technology class dependent feed-in curves and regional feed-in curves for onshore wind energy to a feed-in curves at country level as an example of an excerpt from the historic weather year 2007. There

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<sup>211</sup> The corresponding factors are determined on the basis of a comparison between historical feed-in volumes and corresponding 'ex post' simulation calculations for different years.

are enormous regional differences in the structure as well as in the level of the wind energy feed-in, so that such a detailed consideration is of great importance.

FIGURE D-4: ILLUSTRATION OF THE AGGREGATION OF GENERATION FEED-IN CURVES FOR ONSHORE WIND ENERGY



Source: Own representation.

### Installed renewables capacity in Europe for forecast years

In order to be able to determine country-specific production feed-in curves and thus annual production quantities for electricity from wind energy and PV systems for the future, assumptions must be made about the development of renewable energy capacities per technology class and per region. Depending on the issue at hand, this can be done in various scenarios.

Published studies are used to define assumptions on regionalised renewable energy capacities. The development paths assumed there are again critically examined based on the company's own databases on potentials, for example. Subsequently, the data on the installed capacity of the respective country is divided into

technology classes and regions (this is shown schematically in the right part of Figure D-3). For this purpose, based on the existing plants whose regional division into technology classes is known due to existing databases, decisions are made about decommissioning paths and the commissioning of replacement and new plants for the forecast years.

## **Appendix E      Simulation model for deriving load structures**

In order to generate hourly load structures, r2b energy consulting GmbH has at its disposal a model which, based on analytical procedures, creates typical consumption structures of individual applications and sectors and, as a result, the total load of a country. With this 'bottom up' approach, hourly consumption structures for all modelled countries and forecast years are created, taking into account country-specific (annual) consumption forecasts for all investigated consumption applications.

In addition to historical consumption structures and load data, the analytical generation of application-specific load structures takes into account a number of fundamental influencing factors for power consumption, in particular weather and temperature data as well as clock times and calendar data. In addition, specific assumptions are used for the future development of individual applications, such as the increase in air conditioning of residential and business premises or the expansion of electric mobility in various forms.

The assumptions on the annual final energy consumption of the sectors, applications and economic sectors depicted for the base year 2011 as well as their developments in the forecast period are given in the model and originate in the present project from analyses by Fraunhofer ISI (see Section 4.5.1).

### **E.1      Procedure in the model**

Hourly load profiles per weather and forecast year are generated for a number of selected applications and economic sectors for the household, tertiary, industry and transport sectors as well as for a residual. A schematic representation of the

procedure is shown in the following Figure <sup>212</sup>. Basically, the creation of load profiles can be divided into three steps.

**Step 1, Load profiles for the base year 2011:** For each of the separately considered applications or industries (for each country) standardized type-day-based load structures based on analytical methods are created (see below). These are then multiplied by the respective final energy consumption per application for the base weather year 2011. As a result, the model generates absolute type-day-based load structures per application for the base year 2011. These type-day-based load structures contain power consumption in MW depending on the combination of type-day parameters (type-day parameter combination). A type-day parameter combination is the combination of the values of relevant parameters that describe a point in time, such as a certain time on a Saturday with a daily average temperature of 20 degrees Celsius. Ultimately, the type-day parameter combination determines the user behaviour and thus the load absorption of an application consuming final energy.

**Step 2, Load profiles for the further weather and load years (2009 - 2013):** The final electrical energy consumption of the separately considered applications for the other weather years is generated by applying or rolling out the absolute type-day-based load structures (derived on the basis of the year 2011, see above) to the type-day parameter combinations of the respective weather year that have changed compared to the base year 2011.

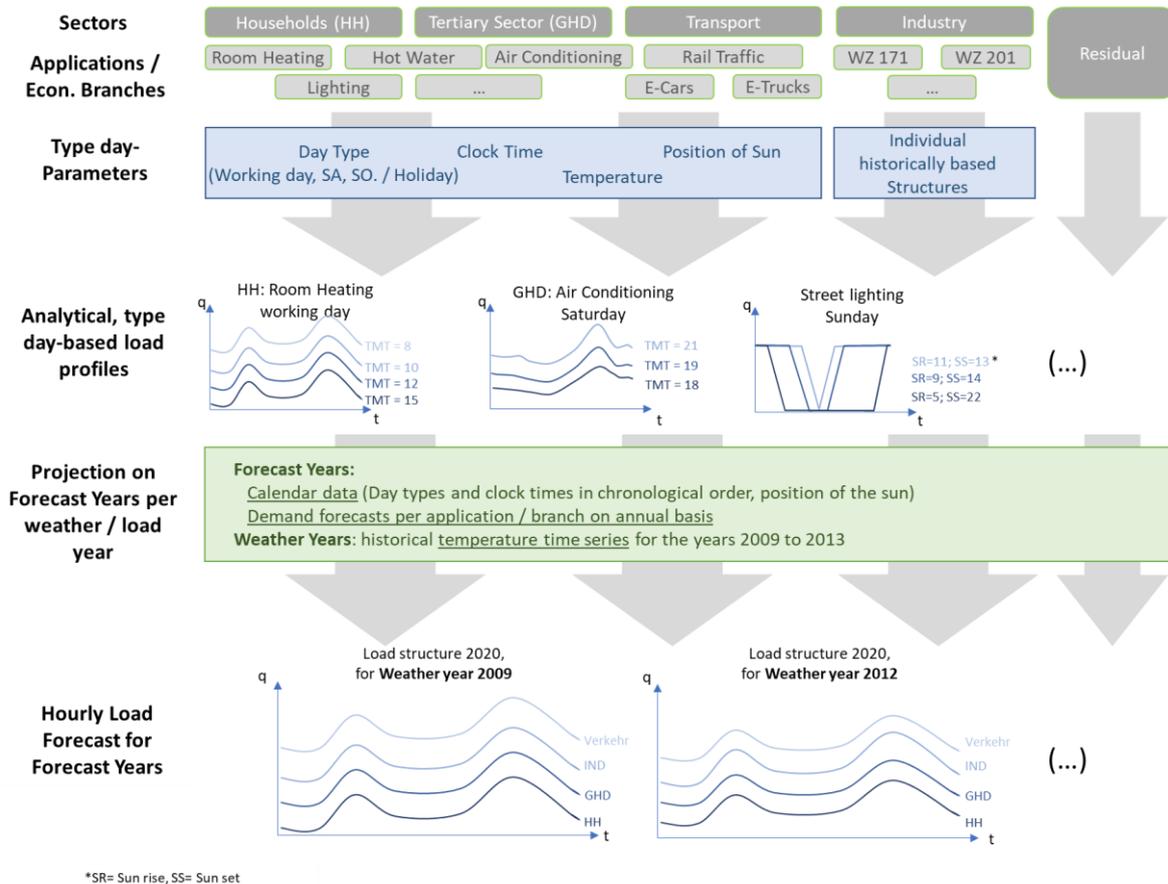
**Step 3, Transfer to the forecast years:** The load structures created in this way (type-day-based) are rolled out to the forecast years by scaling the type-day-based structures of the base weather year 2011 to the (predefined) forecast annual consumption of the application in the respective forecast year. Subsequently, the generated absolute type-day-based load structures for the forecast year (and weather year 2011) are rolled out to the type-day-parameter combinations of the

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<sup>212</sup> The procedure for deriving and forecasting the residual structure is dealt with separately in section E.4

same forecast year in combination with the other weather years. As a result, 5 hourly load structure forecasts (depending on the five weather years) are produced for each separately illustrated application and each forecast year.

**FIGURE E-1: PROCEDURE IN THE MODEL FOR GENERATING HOURLY LOAD FORECASTS BASED ON ANALYTICAL CONSUMPTION PROFILES (SCHEMATIC REPRESENTATION)**



Source: Own representation.

The structure and the annual sum of the residual quantity is finally derived as the difference between the hourly sums of the application-specific load structures and the total load (ENTSO-E basis). The remaining figure is also derived initially for the base year 2011 and then transferred to the following years in a suitable manner (see below).

Currently, the years 2009 to 2013 can be used as "weather years", for which regionally and temporally high-resolution weather data is available for the whole of Europe.

## **E.2 Sectors, industries and applications considered**

The forecast of the hourly load for all modelled countries is based on the sectors private households (HH), commerce, trade services (tertiary sector), industry and transport. For each sector, selected economic branches and applications of particular relevance are examined in more detail, for which hourly load structures are analysed and forecast.

The economic branches and applications considered separately were selected according to the following criteria:

- relevant change in the hourly structure during the year over the forecast period,
- relevant change in the share of electricity consumption of the application or industry within the sector,
- relevant effect on shifts between sectors,
- weather dependency.

Figure E-2 shows the economic branches and applications considered separately with regard to the hourly structure and the annual quantities. Applications and economic branches to which these criteria do not (or only to a negligible extent) apply do not have to be considered separately and are instead represented in a residual by a common annual electricity demand and a common residual structure.<sup>213</sup>

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<sup>213</sup> For France, separate structures for electric heating are defined for space heating in the household sector and for Norway in the tertiary sector.

FIGURE E-2: SEPARATELY CONSIDERED APPLICATIONS PER SECTOR FOR CREATING HOURLY LOAD STRUCTURES

Households		Tertiary		Industry (NACE 2008)	Residual
Hot Water Electric Heating				WZ 17.1: Mfg. of pulp, paper and paperboard	
Hot Water el. Heat Pump				WZ 20.1: Mfg. of basic chemicals, fertilisers and nitrogen compounds, plastics and synthetic rubber in primary forms	
Room Heating Direct (el.) Heating	Street Lighting			WZ 22: Mfg. of pesticides and other agrochemical products	
Room Heating El. Storage Heating	El. Storage Heating		Transport	WZ 23: Mfg. of other non-metallic mineral products	
Room Heating el. Heat Pump	el. Heat Pump	Trolley Trucks		WZ 24.1: Mfg. of basic iron and steel and of ferro-alloys	
Air Conditioning	Air Conditioning	E-Mobility		WZ 28: Mfg. of machinery and equipment n.e.c.	
Lighting	Lighting	Railway Traffic		WZ 29.1: Mfg. of motor vehicles	Residual
				WZ 29.3: Mfg. of parts and accessories for motor vehicles	Residual

Source: Own representation.

### E.3 Creation of application-specific, type-day-based load structures

When creating the load structures, analytical methods based on so-called type-day-specific parameters are used. In particular, day types (working days, Saturdays, Sundays and public holidays), times of day, sunshine levels and temperatures are taken into account as parameters. The combinations of different values of the mentioned parameters define typical days, so-called 'type-days'. A type-day can be for example a working day (in month A) with sunrise at hour X and sunset at hour Y as well as a daily average temperature of Z°C. An overview of the parameters used per application in the sectors is given in Figure .

FIGURE E-3: INFLUENCE PARAMETERS ON THE LOAD STRUCTURES PER APPLICATION

Sector	Application	Influence Parameter				
		Month	Day Type	Clock Time	Temperature	Sun Position
Private Households (HH)	Lighting		x	x		x
	Air Conditioning		x	x	x	
	Room Heating					
	Direct Heating			x	x	
	Night Storage Heating		x	x	x	
	Electric Heating (direct + storage), excl. for France		x	x	x	
	Heat Pump			x	x	
	Hot Water					
	Electric Heating		x	x	x	
	Heat Pump		x	x	x	
Tertiary Sector (GHD)	Lighting	x	x	x		
	Street Lighting		x	x		x
	Air Conditioning		x	x	x	
	Room Heating and Hot Water Heat Pump			x	x	
	Electric Heating		x	x	x	
	Electric Heating (Norway)		x	x	x	
Transport	Railway Traffic	x	x	x		
	Electro Mobility					
	Cars (private, light transport vehicles)		x	x		
	Overhead Line Trucks		x	x		
Industry	Industrial Processes / Branches	x	x	x		

Source: Own representation.

The (type-day) parameters used are determined for all calendar days of the base year 2011 as well as for all other weather years. Based on this, the type-day-specific load curves determined for each application (in MWh/h)<sup>214</sup> are initially transferred to the base year 2011. The type-day-specific load structures are then transferred to the other weather years by scaling on the basis of the total annual power consumption of the applications.

### Household sector

For the household sector, application-specific load structures are created for the following applications:

- Lighting,
- Air conditioning

<sup>214</sup> See following sub-sections

- Room heat-direct heating, room heat-secondary storage heating, room heat-electric heating (direct + storage) and room heat-heat pump
- Hot water heat pump and hot water electric heating

For the **lighting** application, for example, the total electricity consumption in (MWh/h) in the household sector is determined by:

- the day type ((working day (WTG), Saturday (SAM), Sunday or public holiday (SON)),
- the clock time on the day in question and
- the times of sunrise and sunset

Thus, the model is given hourly daily power consumption curves typical for the application of lighting in the household sector, which are applied to all days with identical characteristics of the parameters 'day type', 'sunrise' and 'sunset'. This means, for example, that all working days with sunrise in hour X and sunset in hour Y have an identical hourly load curve for the lighting application.

In the case of **air-conditioning**, the type-days for deriving the load structures (in the household sector) are calculated using the parameters:

- day type,
- temperature (average daily temperature) and
- clock time

Since the times of sunrise and sunset do not play a role in air conditioning, the corresponding parameter is not taken into account here. The most important parameter is the daily mean temperature in conjunction with the clock time. It is assumed that air conditioning systems in private households are typically only switched on from a daily average temperature of approx. 12 °C. At the beginning, i.e. at average daily temperatures slightly above 12 °C but not yet very high, they start working in the afternoon and evening. At higher average daily temperatures, they go towards all-day load bearing capacity.

In the case of electricity demand for the generation of **space heating** in the household sector, the influencing parameters are also:

- clock time and
- temperature (in principle, the temperature measurement TMZ is used here as a parameter, as is the average daily temperature for electric heating systems in France)

These are irrespective of the concrete application used to generate heat (direct heating, storage heating, electric heating or heat pump). In the case of applications (night) storage heating and electric heating (in France), the influence parameter *type-day* is also used.

The load curves for direct heating are positive at all times with temperature measurements (TMZ) in the range from -3 to 26 (this corresponds to average daily temperatures between 26 and 1 degree Celsius). In the morning and evening hours they reach their highest values, in the hours around midnight, the lowest.

Electric heating systems in France exhibit similar load patterns, with high loads during the classic consumption times in private households (morning and evening). From average daily temperatures of approx. 17 degrees Celsius their loads go to zero.

As a rule, storage heaters only accept loads at night. At average daily temperatures below 2 degrees Celsius (TMZ greater than or equal to 25), they additionally absorb load in the midday hours. In the case of storage heaters, the load capacities also differ depending on whether it is a working day, Saturday or Sunday or public holiday (see above).

The heat requirements of **heat pumps** typically take on the same characteristics as in other applications, although the electrical load capacities of the heat pumps may differ over their flexible use. These deviations arise within the framework of electricity market modelling, in which the inertia of the heat supply is used as a storage for economic reasons (see Section 4.5.3).

For heat pumps, in addition to the parameters influencing short-term load curves, assumptions are made about the development of annual coefficients of performance, which will increase in the coming years due to the still existing learning curve effects, and about the market shares of aerothermal and geothermal heat pumps.

In the area of **hot water preparation**, the applications electric heating and heat pump are mapped. The load curves in both cases depends on the parameters

- day type,
- clock time and
- temperature (-measurement, TMZ)

Typically, the loads during hot water preparation (again, heat pumps are only heat requirements<sup>215</sup>) are highly correlated with typical consumption times. The heaviest loads occur in the morning and evening. In the hours around midnight, the load goes towards zero.

RTE (2016) was one of the **data sources** used to derive consumption profiles in the household sector. From this, consumption profiles for applications in the areas of air conditioning, lighting and heating as well as hot water were analysed for France and evaluated according to type-day parameters. For the transfer to other countries, additional country-specific data were used, e.g. statistical data on market shares of different heating technologies (night storage heating, direct heating etc.).<sup>216</sup>

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<sup>215</sup> For the modelling of heat pumps see above and section 4.5.3 in the main text

<sup>216</sup> The sources in these areas are a variety of publicly available data sources, such as national statistics, publications by public authorities or associations. For Germany, data from monitoring reports of the Federal Network Agency, application balances of AGEb, BDEW (2015, Wie heizt Deutschland) and SHELL/BDH (2013, Klimaschutz im Wohnungssektor - Wie Heizen Wir morgen?) have been taken into account.

In addition, in the area of heating profiles (room heating and hot water) and in particular heat pumps, common standard load profiles have been used to generate the key figures for the analytical profiles. For example, procedure-specific parameters of the SLP procedure of Westnetz GmbH<sup>217</sup> were taken into account.

In the area of heat pumps, further literature was used, in particular on the development of market shares and the technology mix to be applied. These include a study by the European Commission (2016c)<sup>218</sup> and the *BWP Industry Study 2015*.<sup>219</sup>

### Trade, commerce, services (tertiary sector, incl. public sector)

For the tertiary sector, the model creates application-specific load structures for the applications:

- Lighting (office buildings etc.)
- Street lighting
- Space heating and hot water (heat pumps)
- Electric heating

The influencing factors in the tertiary sector for the individual applications are basically very similar to those in the household sector. Differences arise in the different typical characteristics of the load curves at times of day and day types, some of which are strongly dependent on typical business or working times. In the case of lighting, instead of the position of the sun in the tertiary sector, the month is used as a simplifying parameter. Street lighting, on the other hand, uses the position of the sun.

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<sup>217</sup> See <https://iam.westnetz.de/>

<sup>218</sup> European Commission (2016c)

<sup>219</sup> Federal association heat pump (BWP) registered association. (2016), BWP Industry Study 2015 - Data on the heat pump market up to 2015 and forecasts up to 2030, available online at: [https://www.waermepumpe.de/fileadmin/user\\_upload/waermepumpe/07\\_Publikationen/2016-04-08\\_Branchenprognose\\_2015\\_web.pdf](https://www.waermepumpe.de/fileadmin/user_upload/waermepumpe/07_Publikationen/2016-04-08_Branchenprognose_2015_web.pdf) last accessed on 20.09.2018

In the tertiary sector, the **data sources** used to derive the specific analytical profiles largely correspond to the data sources for private households (see above).

## Industry

For the economic branches in the industry sector separately analysed, typical load patterns were derived as functions depending on

- the month,
- the day type (working day, Saturday or Sunday/holiday) and
- the clock time.

The basis for this was given by the evaluation of historical, measured load profiles of several companies and locations for each branch of industry. The economic branches considered are energy-intensive industries whose electricity consumption is largely independent of temperature and weather but depends only on the calendar data (incl. day types) and clock times (due to production schedules).

## Transport

In the transport sector, a distinction is made between rail transport and electromobility. In the case of electric mobility, a distinction is again made between passenger cars and light commercial vehicles with electric drive and trolleytrucks.

To derive the consumption profiles for the **rail transport** sector, hourly data from different transport companies were analysed. These were evaluated according to **months and weekdays** and converted into day type-based load structures.

In the field of **electromobility in passenger transport and freight transport with light commercial vehicles**, different driving and usage profiles were initially defined on the basis of available literature on the development of electromobility.<sup>220</sup> These differ with regard to

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<sup>220</sup> See, among others, Gnann et al. (2015), Hacker et al. (2011), Hacker et al. (2014), Morrissey et al. (2016), NPE (2017), Schröder and Traber (2012).

- types of vehicle users,
- behaviour according to days of the week,
- charging locations (at home, at work, public normal charging, public fast charging) and
- according to loading capacity and parking duration of the vehicle.

Within the framework of modelling electric mobility in our electricity market model, three different charging modes are assumed for passenger cars and light commercial vehicles, namely "immediately", "reduced" and "smart". In the case of immediately charging, an electric vehicle is charged with the maximum possible power immediately after parking and in the case of "reduced" charging, the charging process is distributed evenly over the expected parking duration with reduced power. In both cases there is no optimization on the market. With "smart" charging, on the other hand, the costs of the charging process are optimised on the basis of wholesale electricity prices.

The assumptions on the development of user types or user behaviour, charging locations and charging capacities as well as battery capacities are combined with the assumptions on the development of charging modes in order to generate hourly load time series, including flexibility potentials of intelligent charging.

The result distinguishes **type-day-based structures for the following 8 cases:**

- privately immediately, privately reduced and privately smart,
- commercially immediately, commercially reduced and commercially smart,
- public normal loading and public fast loading.

In the case of immediately and reduced loading modes as well as in the case of public (normal and fast) loading, (only) hourly loadings are determined as a function of the type-day parameters weekday and time and entered as input parameters in the electricity market model. These load structures represent load capacities of passenger cars (and light commercial vehicles) located at the charging

stations at different times and charging locations resulting from the assumed developments described above.

For the **smart charging mode**, the following structures are determined. They are separated according to private smart charging and commercial smart charging, instead of 'simple' load-bearing structures, which serve as a framework for optimisation for use in electricity market modelling (in each case aggregated for each country):

- Driving energy consumption
- Charging capacity
- Storage volume (depending on battery levels)

These structures are also type-day-based structures that also depend on the time and day of the week.

Within the framework of electricity market modelling, smart charging is based on the structures shown and optimised in line with the wholesale prices on the electricity market. The (aggregated) storage must never be "empty" or "overflow" and the charging capacity is limited to the aggregated charging capacity of the batteries of the stationary vehicles.

The proportions of these three charging strategies in the total volume of charges will vary over time: While it is assumed that the majority of charging processes will take place immediately in the short term, the proportion of reduced and smart charging will increase in the medium and long term (see Figure E-4). This development is based on the assumption that if the proportion of electric vehicles in existing vehicles increases and electricity consumption increases as a result of electric mobility, it can be assumed that this demand will increasingly have to be controlled intelligently, taking into account the challenges of the distribution network and the mechanisms of the market.

According to the developing shares of the three loading modes, the respective loading structures also develop within one loading mode and location. In addition to the level of loading (on an annual basis), the within day structure is also changing. For example, flat "load peaks" decrease with time due to the decreasing number of electric cars in the uncontrolled case.

FIGURE E-4: ASSUMPTIONS ON THE DEVELOPMENT OF THE PROPORTIONS OF THE THREE LOADING STRATEGIES UP TO 2030.

Type	Charging mode	2018	2020	2030
Passenger cars (private)	immediatly	100%	70%	35%
	reduced	0%	20%	40%
	smart	0%	10%	25%
Passenger cars (commercial) and light commercial vehicles	immediatly	100%	60%	30%
	reduced	0%	40%	70%
	smart	0%	0%	0%

Source: Own assumptions.

It is assumed that **trolley trucks** will be used from the year 2025. We have assumed that these are hybrid vehicles which, in addition to an electric drive, also use a diesel engine and can therefore run independently of an overhead line for a longer period of time. Based on literature references to traffic volume data, a structured consumption profile was first derived. This can either be 'connected' in line mode when the (electrical) power is taken from the grid or - in the case of high electricity prices - switched over to diesel operation.<sup>221</sup> We do not model the possibility of feeding electricity back into the public grid through electric vehicles and trolley trucks.

The resulting type-day-based load structure for the durations that the trolley truck draws power from the grid depends on the **weekday and time** parameters. Typically, the load in Germany at the end of the day on Saturdays goes towards

<sup>221</sup> For the replacement costs of the diesel plant, the price development of light heating oil was assumed, taking into account taxes and other regulated price components incurred and their differences in the various countries considered.

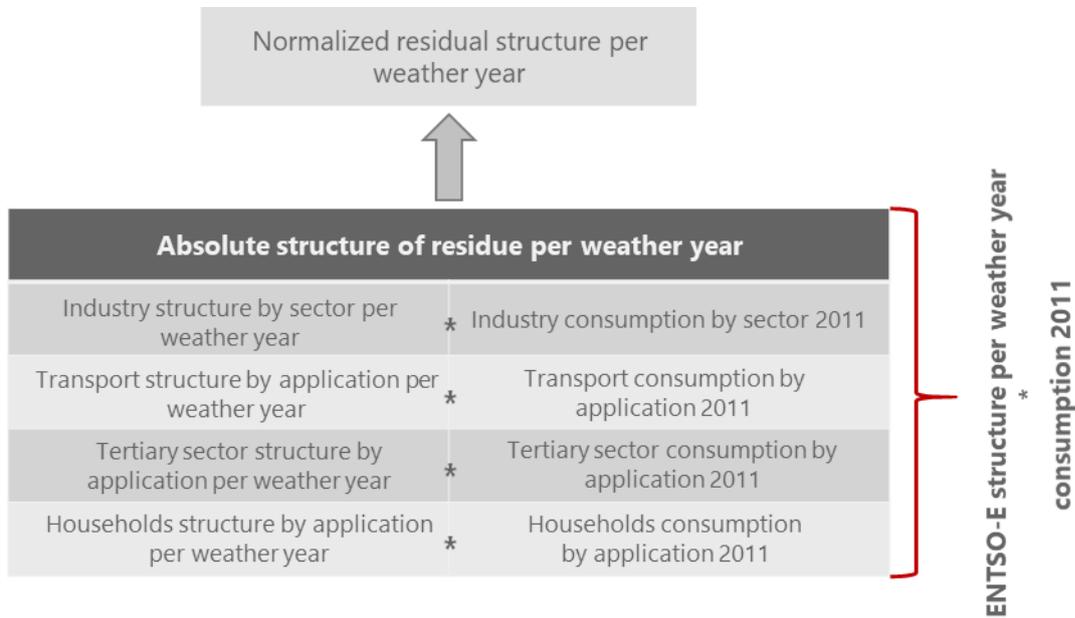
zero and does not rise again until Sunday 22 o'clock. On weekdays, the load rises sharply from the night hours until around 6 am to 7 am and then remains at a high level until around 6 pm. Afterwards, it sinks quite steadily into the night hours.

#### **E.4 Derivation of the residual structure and the total load**

Since the applications considered separately only account for part of the total load of a country, the structure of a residual load is also determined in the load model. This is first derived based on the base weather and load year 2011 and then transferred to the other weather/load years before being rolled out to the forecast years.

In principle, the residual structure is derived as the difference between the load structure of the total electricity consumption of a country and the sum of the loads of the separately considered consumptions of applications and branches of industry. As total load structures of the countries for the weather/load years, corresponding data of the ENTSO-E is used.

FIGURE E-5: DETERMINATION OF RESIDUAL STRUCTURE PER WEATHER YEAR



Source: Own representation.

The determination of the residual structure per weather year (and country) is shown in Figure E-5. The following calculation takes place per weather year:

- First, the standardised structures of the applications (adapted to the respective weather year with regards to weekdays and holidays) are multiplied with the 2011 electricity consumption of the application.
- Subsequently, all absolute structures of the individual applications thus obtained are summed up in order to obtain the sum structure of all applications considered separately.
- This is subtracted from the product of the standardised ENTSO-E structure of the weather year and the total electricity consumption of the country in 2011 (net electricity consumption plus grid losses). This results in the absolute residual structure per weather year.
- Finally, the normalisation of the absolute residual structures per weather year takes place.

## **Appendix F      SoS parameters: Expected value vs. (e.g. 95-%-) Quantiles**

In accordance with the stochastic character of supply security, the parameters discussed in Section 2.2 defined as expected values or probabilities. This takes account of the fact that, due to the stochastic nature of relevant influencing variables, the duration and energy of shortfalls also have a statistical distribution. The expected value of such a result distribution does not only have the practical advantage of intuitive interpretability as "average". Rather, it also shows a certain robustness with respect to the type and extent of the stochastic influences taken into account in the assessment.

The distribution of the result variables become broader the more influence variables are considered as stochastic. This means that more and more extreme (extremely high and extremely low) values of the result variables occur in their calculated distribution, albeit with very low occurrence probabilities. On the other hand, the consideration of a further stochastic influence variable always has a smaller influence on the expected value. Even if an additional stochastic influence quantity does not change the expected value of the result distribution at all, it always changes its form.

Consequently, the margins of the distributions of the result parameters (e.g. shortfall durations and size with the expected values LoLP and EENS) are not robust against the type and extent of the stochastic influencing variables considered. An interpretation of these margins or, statistically expressed, of high or low quantiles of the distributions is therefore not permitted. Questions such as "What is the maximum duration of shortfall?" or "What is the shortfall duration that will not be exceeded with 95 percent certainty?" cannot be answered robustly. Nor is it therefore appropriate to set limits for such "parameters".