

Project report

## **Monitoring the adequacy of resources in the European electricity markets**

Project no. 047/16

Commissioned by the

Federal Ministry for Economic Affairs and Energy

---

Cologne, 26 April 2021

**Company Information:**

**r2b energy consulting GmbH**  
Zollstockgürtel 61  
50969 Cologne  
Tel.: +49 (0)221 - 78 95 98 60

**Consentec GmbH**  
Grüner Weg 1  
52070 Aachen  
Tel.: +49 (0)241 - 93 83 60

**Fraunhofer Institute for Systems and Innovation Research ISI**  
Breslauer Straße 48  
76139 Karlsruhe  
Tel.: +49 (0)721 - 68 09 0

**TEP Energy GmbH**  
Rotbuchstr. 68  
CH-8037 Zurich  
Tel. +41 (0)43 500 71 71

## Executive Summary

Resource adequacy, as an aspect of security of supply, is defined in this report as the long-term safeguarding of the balance between generation and consumption in the electricity supply system, in the sense of a continuous balancing of supply and demand in the electricity market.

The characterisation of resource adequacy is primarily based on the load excess probability. This indicates the probability that not all consumers can be supplied via the electricity market in line with their price preferences.

The present analysis consistently shows a very high level of resource adequacy in Germany. In all scenarios examined here (until 2030), resource adequacy is ensured. This also applies in all sensitivities, i.e. in the case of a hypothetical Energy-Only-Market in all examined countries and in the case of a market-driven decommissioning of coal-fired power plants that goes beyond the Act to Reduce and End Coal-fired Power Generation (KVBG) as a result of significantly more ambitious European climate protection in conjunction with increased sector coupling. Resolutions with respect to the so-called "Green Deal" were not yet available when the assumptions for the analysis were finalised.<sup>1</sup> However, key developments in this regard have been included in the sensitivities for increased sector coupling. According to today's assessment, special attention should therefore be paid to the sensitivities for increased sector coupling, which already take into account more ambitious climate targets. The determined probability of load excess (the term "Loss of Load Probability", LoLP for short, is used for this) has an amount of zero in the reference scenario and at most an insignificant 0.003 percent in the alternative scenarios examined as sensitivities. This is a factor of 20 below the threshold value of 0.06 percent derived as a standard of resource adequacy. Converted into the internationally frequently used indicator "Loss of Load Expectation" (LoLE), where the loss of load probability is expressed in hours per year, this results in 0 hours per year in the reference scenario and a maximum of 0.25 hours

---

<sup>1</sup> Cf. European Commission (2019)

per year in the examined sensitivities. That corresponds to a load balancing probability of 100 percent in the reference scenario and at least 99.997 percent in the sensitivities examined. The Expected Energy Not Supplied (EENS) is zero in the reference scenario and at most 0.4 GWh per year in the sensitivities.

## Summary

### Mandate

Until the end of 2020 the Federal Ministry for Economic Affairs and Energy (BMWi) was obliged under the Energy Industry Act (EnWG) to continuously monitor the resource adequacy (RA). The present report and its development form an essential component for this monitoring in the sector of the European electricity markets with impact on the territory of the Federal Republic of Germany as part of the internal electricity market. In addition, this report serves as a basis for the BMWi to fulfill its reporting obligation according to Article 63(2) EnWG.

In the analyses on which this report is based, pursuant to Article 51(3) and (4) EnWG the following must be considered in particular:

- the developments of generation, grids and consumption in Europe,
- adjustment processes on the electricity markets based on price signals,
- cross-border balancing effects with neighbouring countries for feed-ins of renewable energy, 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., considering the stochastics) methodological approach should be adopted, and the measurement and assessment of resource adequacy in the electricity market as an aspect of security of supply should be carried out using suitably defined indicators and their thresholds.

Against this background, in 2016 the BMWi invited tenders for the project "Definition and monitoring of resource adequacy in the European electricity markets", which was commissioned to the consortium of r2b energy consulting GmbH, Consentec GmbH, Fraunhofer ISI and TEP Energy GmbH.

This report is the second and last project report within the framework of this project. Compared to the first report<sup>2</sup>, we have made the following additions:

---

<sup>2</sup> Cf. r2b / Consentec (2019).

- Inclusion of the weather year 2017, so that in total, six weather years are considered in this report including the year 2017, which is often discussed in Germany in connection with so-called Dunkelflauten (periods of low wind and solar radiation), and the cold spell of 2012.
- Consideration of new sector coupling technologies (in the conversion sector) such as electrode boilers and large-scale heat pumps (PtX) as well as hydrogen electrolysers (PtG).
- Presentation of two sensitivities with increased market penetration of all sector coupling technologies in Germany and Europe with a corresponding increase in annual electricity consumption with two different alternative primary energy sources and CO<sub>2</sub> price scenarios (hereinafter, energy price scenarios)
- Extensive consideration of the requirements of the EU Electricity Market Regulation, e.g., in the area of opening up interconnectors for cross-border power exchange
- Presentation of an additional result indicator, the so-called leeway status, in the quantitative analyses of resource adequacy, to provide a better view on the likelihood of different system states.

In the following, we first summarise the results of the analyses of resource adequacy in the electricity market. We then describe the most important aspects of the methodology applied, the creation of the scenarios and accompanying measures to ensure resource adequacy, before concluding with an outlook.

The model calculations on which this report is based were carried out in the second half of 2020. Accordingly, the "acceptance deadline" with regard to the assumptions, input data and parameterisation was the beginning of August 2020. The underlying assumptions as well as methodological aspects were extensively consulted with representatives of the Federal Network Agency (Bundesnetzagentur, BNetzA), the four German transmission system operators (TSOs), the 16 responsible federal state ministries as well as the Federation of German Industries (BDI), the Association of Municipal Enterprises (VKU), the German Chamber of Industry and Commerce (DIHK) and the German Association of Energy and Water Industries (BDEW).

## Analysis of the adequacy of resources

The analyses on which the report is based consistently show a very high level of resource adequacy in the electricity market in Germany. This also applies for the most part (taking into account the lower model accuracy there) to the neighbouring countries modelled. In all scenarios examined up to 2030, the adequacy of resources on the electricity market in Germany is ensured, i.e. even in the case of a hypothetical energy-only market in all countries examined, as well as in the case of a market-driven closure of coal-fired power plants that goes beyond the Act to Reduce and End Coal-fired Power Generation (KVBG) as a result of significantly more ambitious European climate protection in conjunction with increased sector coupling. Resolutions with respect to the so-called "Green Deal" were not yet available when the assumptions for the analysis were finalised.<sup>3</sup> Moreover, it still has to be decided at EU level which instruments are to be used in which sectors to achieve the new climate targets. Nevertheless, sensitivities to increased sector coupling were examined in the context of this report, which represent a possible variant of the implementation of the Green Deal. According to today's assessment, special attention should therefore be paid to these sensitivities.<sup>4</sup> The consumers can also be securely supplied in these scenarios. The determined probability of load excess (the term "Loss of Load Probability", LoLP for short, is used for this) has an amount of zero for Germany in the reference scenario and a low amount of no more than 0.003 % in the alternative scenarios examined as sensitivities. This is below the threshold value derived in the first project report as the standard for resource adequacy by at least a factor of 20 (see section below, "Definition of "the adequacy of resources" and description of the methodology "). Converted into the internationally frequently used indicator "Loss of Load Expectation" (LoLE), where the loss of load probability is expressed in hours per year, this results in 0 hours per year in the reference scenario and a maximum of 0.25 hours

---

<sup>3</sup> Cf. European Commission (2019)

<sup>4</sup> The achievement of the European and German climate protection targets, which had not yet been redefined at the time the assumptions were finalised, against the background of the "EU Green Deal" was not examined in the two sensitivities for increased sector coupling.

per year in the examined sensitivities. That corresponds to a load balancing probability of 100% in the Reference Scenario and at least 99.997% in the scenarios examined. The Expected Energy Not Supplied (EENS) is zero in the reference scenario and at most 0.4 GWh per year in the sensitivities. Reserves outside the electricity markets, such as the German capacity reserve, are not taken into account here and would additionally be available in practice.

The scenarios differ mainly in the development of the sector coupling technologies, the underlying energy price scenarios, the market design, the development of the generation system, the development of flexibility options as well as the imports necessary for the adequacy of resources. The latter always remain significantly below the (future) available grid capacities for Germany.

Several reasons are responsible for the very high level of resource adequacy identified in Germany:

- The balancing group- 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 against potentially very high balancing energy prices by contracting sufficient generation and/or flexibility capacity, which directly or indirectly triggers corresponding investment incentives.
- The German and European electricity supply system currently has some overcapacities.<sup>5</sup> While market adjustments take place by reducing these overcapacities by shutting down existing plants for reasons of economic efficiency, there are certain inertial factors.
- New capacities are also created through the replacement of CHP plants to maintain heat supply and through the subsidised addition of renewable energy (RE) plants.

---

<sup>5</sup> In this report, overcapacity is understood to mean capacities that can be shut down with some lead time without, *ceteris paribus*, jeopardising the adequacy of resources in terms of the identified standard (threshold).

- Capacity markets abroad (considered here: France, Great Britain, Poland and Italy) create new capacities, which also positively influence the level of resource adequacy in Germany.<sup>6</sup>
- In the internal electricity market, there are considerable balancing effects with respect to the load and feed-in of renewable energies as well as the unplanned unavailability of power plants.
- Finally, there is considerable potential for increasing the flexibility of consumption (including "new" consumers and economically viable flexibility options in the field of voluntary industrial load reduction), public heating systems (including CHP) and bioenergy, as well as in emergency power systems.

These causes for the consistently high level of resource adequacy can in principle compensate each other: A weakening or even an elimination of one cause does not call the adequacy of resources into question, but would be compensated in the electricity market by adjustment reactions<sup>7</sup> elsewhere. Due to these substitution possibilities, there are many possible development paths that ensure resource adequacy and thus a balance of supply and demand on the electricity market at almost all times.

#### Definition of "the adequacy of resources" and description of the methodology

Resource adequacy, as an aspect of security of supply, is understood in this report as the long-term safeguarding of the balance between generation and consumption in the electricity supply system by means of a constant balancing of supply and demand in the electricity market. According to this, the adequacy of resources on the electricity market is ensured if those consumers can always purchase electricity whose willingness to pay (benefit) is greater than or equal to the market price (costs).

Against the background of the liberalisation of the EU internal market for electricity, security of supply must be considered across Europe, across countries and

---

<sup>6</sup> However, also without capacity markets abroad (cf. considered sensitivity "EOM - no capacity markets" in section 4.1), the adequacy of resources in Germany remains consistently high.

<sup>7</sup> The adjustment reactions are stimulated by changed price structures on the wholesale market for electricity.

accounting for dynamic market adjustment processes, including price elasticity of demand. In this supra-regional market, there are considerable balancing effects in terms of load, infeed of intermittent renewable energies and unplanned outages of power plants, which have a positive impact on ensuring resource adequacy. Balancing effects exist not only with regard to the (residual) annual peak load, but also reduce the effective risk from power plant outages to a considerable extent. The reason for this is that the simultaneous occurrence of a large total capacity of outages in several countries is less likely than when considered nationally.

Within the framework of this project, a consistent methodology, oriented towards the legal requirements of the EnWG for monitoring the adequacy of resources on the electricity market, was developed and implemented for the review horizon until 2030. This methodology also complies in essential parts with the requirements of the EU Electricity Market Regulation 2019/943.

For this purpose, a standard was first defined in the first project report. It was found that among the various possible indicators with which the adequacy of resources can be characterised, the probability of load excess (the term "Loss of Load Probability", LoLP for short, is used for this) is best suited for formulating a standard. This indicates the probability that not all consumers can be supplied via the electricity market according to their price preferences. Other parameters, such as the Expected Energy not Supplied (EENS) are useful to help classify an identified level of resource adequacy.

Based on conceptual analyses and literature research, a threshold value for the loss of load probability was derived as a standard for Germany in the amount of  $\widehat{LoLP} = 0.06 \%$ , which corresponds to a load balance probability of 99.94 %.<sup>8</sup>

The threshold value can be interpreted as follows: If the threshold is exceeded by the power supply system under review for a future year under consideration, then this is an indication that an economically efficient investment in generation or flexibility resources has not been made, i.e. that the professional stakeholders involved in electricity supply have, in the current market environment, not recog-

---

<sup>8</sup> Cf. r2b / Consentec (2019) Section 2.3.1.

nised the economic efficiency of such an investment or, in any case, have not exploited it.<sup>9</sup> By contrast, the further the loss of load probability is below the threshold, the more its costs would exceed the benefits on the consumer side (through avoided loss of load).

The above-mentioned threshold is a reasonable value, both in the sense of a manageable scale and in that it is within the usual range compared to other countries. Nevertheless, it is subject to unavoidable uncertainties, especially due to the uncertainty of the willingness to pay of consumers affected by load excess (Value of Lost Load, VoLL).

The concrete level of the threshold value also proves not to be decisive in the currently conducted investigations, as the adequacy of resources in Germany is clearly above this criterion in all scenarios of this project report.

Our methodological approach is guided by the following two core questions of resource adequacy monitoring:

1. How will the European electricity supply system develop over the period under review?
2. In this European electricity supply system, is the adequacy of resources in the electricity market ensured at an efficient level?

The first question arises from the fact that monitoring must look many years into the future in order to have sufficient time (if necessary) to take measures to ensure an adequate level of resource adequacy, depending on the outcome of the statutory review mandate. To answer the question, one or more scenarios of the development of the electricity supply system must be drawn up. Building on this, the second question must be answered by determining the level of resource adequacy for the respective scenario and ranking and assessing it by comparison with the defined standard.

---

<sup>9</sup> This would entail the examination of measures provided for in Section 51 (4) no. 2 EnWG, in particular the examination of still existing barriers and disincentives as well as the examination of whether a later "settling" is expected through market adjustment processes.

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 analysis of the adequacy of resources based on it) was developed and applied against the background of the legal requirements of the EnWG. This was done in coordination with the BMWi and in consultation with the stakeholders mentioned in the section "Mandate". The consistent coupling of the two models is performed with respect to the consideration of balancing effects and uncertainties in particular.

The basic methodological principle is in line with international practice. In particular, it corresponds in essential parts to the requirements of the EU Electricity Market Regulation. In recent years, various methodological approaches have been developed for monitoring and assessing resource adequacy with sufficient consideration of stochastics and the integration of national electricity markets into the European internal electricity market. In numerous resource adequacy analyses, such approaches are or have already been used.<sup>10</sup> Within the framework of this basic principle, however, the present study goes a significant step further: Economic market adjustment processes on the European internal electricity market are modelled by means of endogenous modelling of the development of the electricity supply system (first model stage) and the scenarios are examined with a consistent stochastic analysis of resource adequacy (second model stage).

The effect and significance of the market adjustment processes increases over the period under review. Since the first model stage simulates the market rules and the investment incentives they create, the development of the electricity supply system is increasingly driven by endogenously determined contributions. Given the market incentives for suppliers and consumers depicted in the model (due to the existing balancing group and imbalance settlement system), it can generally be

---

<sup>10</sup> Cf. e.g. e.g. Consentec /r2b (2015), PLEF (2015), PLEF (2018), ENTSO-E (2016), ENTSO-E (2017a), ENTSO-E (2018b), ENTSO-E (2019), ENTSO-E (2020d).

expected that the resources in the system will be adequate from a market perspective at least at the end of the period under consideration.<sup>11</sup> The main result in the long term is therefore a probable development path of the electricity supply system that is consistent with the assumptions made in the scenario generation.

This means the following when it comes to the task of detecting in advance any threat to the adequacy of resources and any obstacles to the use of available flexibilities:

- For the beginning of the period under review, the second model stage with the corresponding indicators provides an immediate basis for assessing the adequacy of resources.
- For the later part of the period under review, by contrast, the indicators can basically be expected to lie in the non-critical range if the incentives in the balancing group and imbalance settlement system are set correctly and corresponding market adjustment processes take effect. An assessment of the adequacy of the resources in this time range requires, in particular, that the endogenous parts of the development path of the electricity supply system be assessed in terms of their plausibility and feasibility and, in doing so, analysed for any barriers that may be present. The results of the second model stage are another building block for the plausibility of the development path, as they provide indications of how far the system is approaching the threshold values.

---

<sup>11</sup> Deviations from this can occur if, at the interface of the two model stages, adjustments required for computation time reasons to align different modelling depths lead to an overestimation of the resource demand in the second model stage and/or underestimation of the demand in the first model stage due to implicitly or explicitly conservative parameterisation. This primarily affects the peripheral countries with low import capacities to the core region in relation to the load.

## Scenarios

The reference scenario (*best guess-scenario*<sup>12</sup>) was generated on the basis of detailed research/preparatory analyses<sup>13</sup> and comparison with other studies/experts when depicting the legal framework conditions and goals that exist in reality. By means of sensitivity analyses, possible developments of the electricity supply system deviating from the reference scenario were examined.

The scenarios comprehensively depict the initial situation, planning and adjustment reactions in the European electricity market. A classification based on a comparison with scenarios of the German and European TSOs<sup>14</sup> shows that the reference scenario in Germany has slightly lower dispatchable resources (i.e. capacities of generation plants and flexibility options). In total, across all countries considered, the reference scenario shows significantly lower resources in some cases. This represents a realistic and (due to the lower capacity of dispatchable resources) rather conservative development of the electricity supply system compared to the scenarios of the German and European TSOs on the basis of the current market design and known developments in Europe.

## Accompanying measures to ensure the adequacy of resources

Some measures are necessary or recommended to ensure or safeguard the high level of resource adequacy identified. The implementation of necessary measures (for example to ensure the level of cross-border exchange capacities according to the EU Electricity Market Regulation), was assumed in the analyses since this can be considered realistic given the combination of legal obligations and corresponding lead time.

For instance, the level of import power required to ensure resource adequacy can basically be classified as low compared to the (future) existing network capacity. Nevertheless, certain preparatory steps need to be taken to exploit the stronger

---

<sup>12</sup> The calculations for this report were carried out from 15.09.2020, so that the "best-guess" scenario refers to the information situation between the end of April and the end of August 2020, as the research / updates for this 2nd project report were carried out during this period.

<sup>13</sup> For a detailed description of the preparatory analyses, see Section 3 in r2b / Consentec (2019).

<sup>14</sup> Cf. ENTSO-E (2020d).

role of cross-border compensation effects for resource adequacy in the European context in the future.

There is also a need for coordination and, if necessary, action with regard to the international coordination and binding nature of the market and operating rules in the event of shortages. It seems advisable to take the proactive step of clearly regulating the processes downstream of the day-ahead market at the international level in this regard.

The flexibility of generation and consumption is also significantly influenced by the regulatory framework, subsidy systems and the availability of intelligent measurement and control systems and communication technology. Electric mobility and heat pumps in particular can represent an important flexibility option if they are well integrated in terms of communication and receive corresponding incentives for flexibility. However, this is the subject of separate research projects. There is a need for further action, e.g. in the area of grid tariffs, especially with regard to the exemptions for atypical and intensive grid usage, which represent barriers to the flexibilization of industrial consumers.

Furthermore, measures to hedge against unpredictable extreme events<sup>15</sup> can be considered. Uncertain extreme events cannot be addressed efficiently (due to the unknown probability of occurrence of these events), neither in the electricity market 2.0 nor in capacity markets. Therefore, they cannot and must not be taken into account in the monitoring of resource adequacy in the electricity market when checking whether an efficient level of resource adequacy is achieved. The hedging of unpredictable extreme events (while accepting the associated costs) falls within the scope of state risk provisioning and should therefore be managed through the political process. Conversely, this then means that the organisation and implementation of this additional hedging takes place outside the regulatory framework of competitive electricity markets ('market design') and thus outside the scope of this study. The effects of unpredictable extreme events can be re-

---

<sup>15</sup> Such an event can be, for example, the simultaneous unavailability of many power plants due to a common cause, such as a serial fault or as a result of a prolonged period of heat or drought.

duced with reserves outside the electricity market in particular, such as the German capacity reserve. Therefore, these unpredictable events should also be taken into account when sizing the capacity reserve.

## Outlook

With regular forecasts on the development of the electricity supply system and the resource adequacy (RA) level, it can be assessed in advance whether compliance with the RA standard can be expected and, if necessary, whether there are still barriers, disincentives and whether a later "settling" can be expected through market adjustment processes. The forward-looking resource adequacy monitoring thus ensures that there is sufficient time for any necessary measures to ensure an appropriate RA level.

With the enactment of the KVBBG, the responsibility for monitoring resource adequacy has been transferred from the BMWi to the BNetzA from 2021. In addition, on the basis of the EU package "Clean Energy for all Europeans" (CEP<sup>16</sup>), the European Transmission System Operators for Electricity (ENTSO-E) developed a method for the implementation of the European and national monitoring of resource adequacy, which was approved by the Agency for the Cooperation of Energy Regulators (ACER) on 5 October 2020.<sup>17</sup> Future analyses of resource adequacy in the electricity markets - in particular ENTSO-E's European Resource Adequacy Assessment (ERAA) - must be based on this method. The ERAA will replace ENTSO-E's current Mid-Term Adequacy Forecast (MAF) from 2021.

---

<sup>16</sup> Cf. EU Electricity Market Regulation 2019/943.

<sup>17</sup> Cf. ACER Decision 24-2020.

## Table of contents

Executive Summary.....	3
Summary	5
1 Background and overview.....	1
1.1 Background.....	1
1.2 Task and research objectives .....	4
1.3 Consultation process .....	6
1.4 Overview of the chosen methodological approach .....	7
1.5 Classification of the evaluation approach and interpretability of the results .....	9
1.6 Structure of the study .....	11
2 Assumptions reference scenario.....	13
2.1 Market design assumptions.....	14
2.2 Assumptions on the (exogenous) development of the conventional power plants....	20
2.2.1 Assumptions on the development of nuclear energy .....	24
2.2.2 Assumptions on the development of coal-fired power plants.....	28
2.2.3 Assumptions on the development of cogeneration .....	35
2.3 Development of renewable energies and pumped storage power plants.....	43
2.3.1 Development of installed RE capacity in Germany .....	44
2.3.2 Development of RE generation in Germany .....	46
2.3.3 Development of storage and pumped storage power plants in Germany and their balancing DE / AT.....	49
2.3.4 Development of renewable energies in Europe.....	49
2.4 Development of flexibility options .....	52
2.4.1 Emergency power systems.....	53
2.4.2 Voluntary load reduction in the industry.....	55
2.5 Development of electricity demand .....	58

2.5.1	Development of final electricity consumption .....	59
2.5.2	Development of the transformation sector .....	71
2.5.3	Development of hourly demand .....	79
2.5.4	Modelling the load of new consumers .....	82
2.6	Technical and economic characteristics of conventional power plants .....	86
2.6.1	Investment and operating costs .....	86
2.6.2	Fuel and CO <sub>2</sub> prices .....	87
2.6.3	Availabilities of conventional power plants .....	94
2.7	Development of the balancing power .....	96
2.8	Development of cross-border import and export opportunities .....	102
2.8.1	General information .....	102
2.8.2	Assumptions on cross-border network expansion projects .....	104
2.8.3	Consideration of the requirements of the Clean Energy Package on electricity trading capacities .....	108
2.8.4	Development of import/export opportunities .....	110
2.9	Assumptions on the distribution of load excess among the bidding zones .....	112
3	Results reference scenario .....	114
3.1	Results of electricity market simulations .....	114
3.1.1	Development of resources in Germany .....	114
3.1.2	Development of resources in the foreign electricity markets considered .....	123
3.1.3	Classification of the reference scenario .....	129
3.2	Balancing effects in the common internal electricity market .....	132
3.3	Results RA analyses .....	138
3.4	Interim summary of results for the reference scenario .....	148
4	Sensitivities .....	150
4.1	Hypothetical sensitivity: "EOM - no capacity markets" .....	151
4.1.1	Sensitivity characterisation .....	151

4.1.2	Results of electricity market simulations.....	152
4.1.3	Results RA analyses .....	156
4.2	Sensitivity: "Increased Sector Coupling - Price Scenario: TYNDP Distributed Energy".....	166
4.2.1	Sensitivity characterisation .....	166
4.2.2	Results of electricity market simulations.....	173
4.2.3	Results RA analyses .....	179
4.3	Sensitivity: "Increased sector coupling - price scenario: WEO Sustainable Development". .....	186
4.3.1	Sensitivity characterisation .....	186
4.3.2	Results of electricity market simulations.....	189
4.3.3	Results RA analyses .....	195
4.4	Summary results including sensitivities .....	202
5	Accompanying measures and outlook.....	203
6	Bibliography .....	206

## List of figures

FIGURE 1-1:	OVERVIEW OVER THE STRUCTURE OF THE CONSISTENT TWO-STAGE MODELING APPROACH .....	8
FIGURE 2-1:	MARKET DESIGNS CONSIDERED IN THE COUNTRIES UNDER CONSIDERATION .....	18
FIGURE 2-2:	EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET) OF CONVENTIONAL POWER PLANTS IN 2021 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS ADDITIONS/REMOVALS).....	22
FIGURE 2-3:	EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET) OF NUCLEAR POWER PLANTS IN 2021 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS ADDITIONS/REMOVALS).....	25
FIGURE 2-4:	PLANNED PHASE-OUT DATES FROM COAL-FIRED POWER GENERATION IN THE MODEL REGIONS CONSIDERED. ....	28
FIGURE 2-5:	EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET, WITHOUT STRATEGIC RESERVES) OF COAL-FIRED POWER PLANTS AT THE BEGINNING OF 2021 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS ADDITIONS/REMOVALS).....	30
FIGURE 2-6:	DEVELOPMENT OF CHP-CAPABLE HEAT DEMAND.....	37
FIGURE 2-7:	DEVELOPMENT OF DISTRICT HEATING GENERATION BY TECHNOLOGY .....	38
FIGURE 2-8:	ASSUMPTIONS ON THE DEVELOPMENT OF (RESIDUAL) CHP HEAT DEMAND IN GERMANY COMPARED TO 2020 ("EXISTING").....	39
FIGURE 2-9:	ADDITION OF NEW NATURAL GAS CHP REPLACEMENT PLANTS COMPARED TO 2020 IN GERMANY (IN THE REFERENCE SCENARIO, CUMULATIVE).....	40
FIGURE 2-10:	CUMULATIVE ADDITION OF NEW CHP REPLACEMENT PLANTS COMPARED TO 2020 IN THE OTHER COUNTRIES CONSIDERED (WITHOUT GERMANY).....	43
FIGURE 2-11:	DEVELOPMENT OF AGGREGATED INSTALLED CAPACITY OF RENEWABLE ENERGIES IN THE COUNTRIES CONSIDERED EXCLUDING GERMANY .....	51
FIGURE 2-12:	DEVELOPMENT OF AGGREGATED ELECTRICITY GENERATION FROM RENEWABLE ENERGIES IN THE COUNTRIES CONSIDERED EXCLUDING GERMANY.....	52
FIGURE 2-13:	ECONOMICALLY EXPLOITABLE EMERGENCY POWER SYSTEM POTENTIAL IN 2021 IN THE FOREIGN COUNTRIES CONSIDERED .....	54
FIGURE 2-14:	ECONOMICALLY EXPLOITABLE LOAD REDUCTION POTENTIAL OF INDUSTRY IN GERMANY FOR 2021, 2023, 2025 AND 2030 .....	56

FIGURE 2-15:	ECONOMICALLY EXPLOITABLE LOAD REDUCTION POTENTIALS IN 2021 AND 2030 IN THE COUNTRIES CONSIDERED (EXCLUDING GERMANY) .....	58
FIGURE 2-16:	CROSS-SECTORAL DRIVERS OF ENERGY DEMAND (POPULATION AND GDP IN GERMANY) FOR THE PERIOD 2005 TO 2050 (EU 2017). .....	60
FIGURE 2-17:	SECTORAL ELECTRICITY DEMAND FOR THE PERIOD 2015 TO 2050(OWN CALCULATIONS). .....	62
FIGURE 2-18:	ELECTRICITY DEMAND INDUSTRY BY SUBSECTOR FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION). .....	64
FIGURE 2-19:	ELECTRICITY DEMAND HOUSEHOLDS BY APPLICATION FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION) . .....	65
FIGURE 2-20:	ELECTRICITY DEMAND GHD BY SECTOR FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION). .....	66
FIGURE 2-21:	ELECTRICITY DEMAND FOR TRANSPORT FOR THE PERIOD 2015 TO 2030 (OWN CALCULATIONS). .....	67
FIGURE 2-22:	DEVELOPMENT OF SECTORAL ELECTRICITY DEMAND IN THE NEIGHBOURING STATES BETWEEN 2015 AND 2050.....	70
FIGURE 2-23:	DEVELOPMENT OF ELECTRICITY CONSUMPTION OF OPENCAST MINES IN GERMANY .....	72
FIGURE 2-24:	DEVELOPMENT OF THE INSTALLED CAPACITY OF PTH (ELECTRIC HEATERS AND LARGE HEAT PUMPS) FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED. ....	73
FIGURE 2-25:	DEVELOPMENT OF INSTALLED CAPACITY AND ELECTRICITY CONSUMPTION OF PTG FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED. ....	75
FIGURE 2-26:	DEVELOPMENT OF INSTALLED CAPACITY OF LARGE-SCALE BATTERY STORAGE FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED. ....	76
FIGURE 2-27:	DEVELOPMENT OF GRID LOSSES FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED. ....	77
FIGURE 2-28:	DEVELOPMENT OF CONSUMPTION IN REFINERIES AND OTHER CONVERSION SECTORS FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED. ....	78
FIGURE 2-29:	DEVELOPMENT OF FINAL ELECTRICITY CONSUMPTION AND CONSUMPTION OF THE TOTAL TRANSFORMATION SECTOR FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED. ....	79
FIGURE 2-30:	PROCEDURE IN THE MODEL FOR GENERATING HOURLY LOAD FORECASTS BASED ON ANALYTICAL CONSUMPTION PROFILES (SCHEMATIC REPRESENTATION).....	81
FIGURE 2-31:	PRICE FORECASTS FOR CRUDE OIL, NATURAL GAS AND HARD COAL: WEO2019 (STATED POLICIES) COMPARED TO ALTERNATIVE PRICE PATHS.....	90

FIGURE 2-32:	PRICE FORECASTS FOR CO <sub>2</sub> ALLOWANCES (EUA): WEO2019 (STATED POLICIES) COMPARED TO ALTERNATIVE PRICE PATHS.....	93
FIGURE 2-33:	POSITIVE CONTROL RESERVE IN THE 14 COUNTRIES CONSIDERED .....	96
FIGURE 2-34:	SCHEMATIC REPRESENTATION OF THE USE OF POSITIVE BALANCING POWER IN A SITUATION WITHOUT SCARCITY ON THE SCHEDULED POWER MARKETS .....	98
FIGURE 2-35:	SCHEMATIC REPRESENTATION OF THE USE OF POSITIVE BALANCING POWER IN SITUATIONS OF SCARCITY ON THE SCHEDULED POWER MARKETS.....	99
FIGURE 2-36:	POSITIVE HIGH-FREQUENCY SHARES OF BALANCING POWER PER COUNTRY (2021) .....	102
FIGURE 2-37:	COMPARISON OF MAXIMUM (=EXPORT) AND MINIMUM (=IMPORT) NET POSITIONS OF THE BIDDING ZONE GERMANY/LUXEMBOURG BETWEEN FIRST AND SECOND PROJECT REPORT .....	111
FIGURE 3-1:	DEVELOPMENT OF THE CONVENTIONAL POWER PLANT FLEET, THE ANNUAL PEAK LOAD, AND CONTROLLABLE AS WELL AS VOLATILE FEED-IN CAPACITIES OF RENEWABLE ENERGIES .....	115
FIGURE 3-2:	DEVELOPMENT OF THE ANNUAL BASE PRICES IN GERMANY AVERAGED OVER ALL WEATHER YEARS IN THE REFERENCE SCENARIO.....	117
FIGURE 3-3:	COMPARISON OF THE HOUR OF THE ANNUAL PEAK LOAD WITH THAT OF THE RESIDUAL ANNUAL PEAK LOAD; YEAR 2030; WEATHER YEAR 2010. ....	119
FIGURE 3-4:	EXOGENOUSLY PREDICTED CUMULATIVE ADDITIONS AND DECOMMISSIONINGS COMPARED TO 2021 IN GERMANY.....	121
FIGURE 3-5:	EXOGENOUSLY PRESCRIBED VS ENDOGENOUS CUMULATIVE REDUCTIONS VS 2021 IN GERMANY .....	122
FIGURE 3-6:	DEVELOPMENT OF THE CONVENTIONAL POWER PLANT FLEET IN THE FOREIGN COUNTRIES CONSIDERED (WITHOUT GERMANY) .....	124
FIGURE 3-7:	EXOGENOUSLY SPECIFIED ADDITIONS AND DECOMMISSIONINGS IN THE CONVENTIONAL POWER PLANT FLEET OF FOREIGN COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030 COMPARED TO 2021 .....	126
FIGURE 3-8:	EXOGENOUS VS. ENDOGENOUS CUMULATIVE REDUCTIONS OF NATURAL GAS AND MINERAL OIL POWER PLANTS IN THE FOREIGN COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030 COMPARED TO 2021 .....	127
FIGURE 3-9:	EXOGENOUS VS. ENDOGENOUS CUMULATIVE REDUCTIONS OF COAL-FIRED POWER PLANTS IN THE COUNTRIES UNDER CONSIDERATION FOR 2023, 2025 AND 2030 COMPARED TO 2021.....	128

FIGURE 3-10:	DEVELOPMENT OF INSTALLED CAPACITIES FOR 2025 AND 2030 IN GERMANY COMPARED TO THOSE FROM THE "NATIONAL TRENDS" SCENARIO OF THE MIDTERM ADEQUACY FORECAST 2020 .....	130
FIGURE 3-11:	DEVELOPMENT OF INSTALLED CAPACITIES FOR 2025 AND 2030 IN THE 14 COUNTRIES CONSIDERED (EXCLUDING GERMANY) COMPARED WITH THOSE FROM THE "NATIONAL TRENDS" SCENARIO OF THE MIDTERM ADEQUACY FORECAST 2020.....	131
FIGURE 3-12:	ILLUSTRATIVE REPRESENTATION OF THE TEMPORAL DISPARITY OF THE ANNUAL PEAK LOADS (FORECAST YEAR 2025; WEATHER YEAR 2010).....	133
FIGURE 3-13:	LOAD BALANCING EFFECTS: SIMULTANEOUS VS. NON-SIMULTANEOUS ANNUAL PEAK LOAD OF ALL COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030 .....	134
FIGURE 3-14:	ILLUSTRATIVE REPRESENTATION OF THE NON-SIMULTANEITY OF RESIDUAL ANNUAL PEAK LOADS IN THE COUNTRIES CONSIDERED (FORECAST YEAR 2025; WEATHER YEAR 2010) .....	135
FIGURE 3-15:	BALANCING EFFECTS OF THE RESIDUAL LOAD: SIMULTANEOUS VS. NON-SIMULTANEOUS RESIDUAL ANNUAL PEAK LOAD OF ALL COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030.....	136
FIGURE 3-16:	INDICATORS IN THE REFERENCE SCENARIO FOR COUNTRIES WITH RATIOS GREATER THAN ZERO AND GERMANY/LUXEMBOURG .....	139
FIGURE 3-17:	REQUIRED* IMPORTS TO DE/LU IN THE REFERENCE SCENARIO .....	140
FIGURE 3-18:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE REFERENCE SCENARIO, YEARS UNDER REVIEW 2021 AND 2023.....	145
FIGURE 3-19:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE REFERENCE SCENARIO, YEARS UNDER REVIEW 2025 AND 2030.....	146
FIGURE 4-1:	EXPANSION OF RENEWABLE ENERGIES IN THE FOREIGN COUNTRIES TAKEN INTO ACCOUNT IN THE SENSITIVITIES FOR "INCREASED SECTOR COUPLING" .....	151
FIGURE 4-2:	ABSOLUTE AND DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN GERMANY: SENSITIVITY "EOM" VS. REFERENCE SCENARIO .....	153
FIGURE 4-3:	DEVELOPMENT OF THE BASE PRICE IN GERMANY AVERAGED OVER ALL WEATHER YEARS IN THE REFERENCE SCENARIO AND IN THE "EOM" SENSITIVITY .....	154
FIGURE 4-4:	DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN THE CONSIDERED FOREIGN COUNTRIES: SENSITIVITY "EOM" MINUS REFERENCE SCENARIO.....	155
FIGURE 4-5:	LOLP AND EENS IN SENSITIVITY "EOM - NO CAPACITY MARKETS" FOR COUNTRIES WITH RATIOS > 0 COMPARED TO THE REFERENCE SCENARIO .....	157
FIGURE 4-6:	REQUIRED* IMPORTS TO DE/LU IN SENSITIVITY "EOM - NO CAPACITY MARKETS".....	161

FIGURE 4-7:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "EOM - NO CAPACITY MARKETS", FOR THE YEARS 2021 AND 2023 .....	162
FIGURE 4-8:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "EOM - NO CAPACITY MARKETS", FOR THE YEARS 2025 AND 2030 .....	163
FIGURE 4-9:	TYPICAL EXCHANGE PATTERN IN SITUATIONS WITH LOAD EXCESS IN GERMANY/LUXEMBOURG IN SENSITIVITY "EOM - NO CAPACITY MARKETS". .....	165
FIGURE 4-10:	ENERGY PRICE SCENARIOS: REFERENCE VS. SENSITIVITY "INCREASED SECTOR COUPLING TYNDP - DISTRIBUTED ENERGY".....	167
FIGURE 4-11:	SENSITIVITY "ACCELERATED SECTOR COUPLING": DEVELOPMENT OF ELECTRICITY DEMAND FROM ELECTROMOBILITY (<3.5T), HEAT PUMPS AND OVERHEAD LINE TRUCKS (OH TRUCKS) .....	169
FIGURE 4-12:	CHANGED STRUCTURE OF HEAT GENERATION IN DISTRICT HEATING .....	173
FIGURE 4-13:	ABSOLUTE AND DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN GERMANY: SENSITIVITY "INCREASED SECTOR COUPLING - TYNDP" VS. REFERENCE SCENARIO.....	174
FIGURE 4-14:	COMPARISON OF THE COMPOSITION OF THE LOAD AT THE TIME OF THE ANNUAL PEAK LOAD BETWEEN SECTOR COUPLING SENSITIVITY AND REFERENCE SCENARIO IN GERMANY; YEAR 2030; WEATHER YEAR 2010 .....	176
FIGURE 4-15:	DEVELOPMENT OF THE ANNUAL BASE PRICE IN GERMANY AVERAGED OVER WEATHER YEARS IN THE REFERENCE SCENARIO AND IN THE SENSITIVITY "INCREASED SECTOR COUPLING - TYNDP DISTRIBUTED ENERGY". .....	177
FIGURE 4-16:	COMPARISON OF THE DEVELOPMENT OF RESOURCES BETWEEN SENSITIVITY "INCREASED SECTOR COUPLING" AND REFERENCE SCENARIO IN THE FOREIGN COUNTRIES CONSIDERED .....	178
FIGURE 4-17:	LOLP IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY" FOR COUNTRIES WITH VALUES > 0 AND GERMANY/LUXEMBOURG COMPARED TO THE REFERENCE SCENARIO.....	179
FIGURE 4-18:	REQUIRED* IMPORTS TO DE/LU IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY".....	180
FIGURE 4-19:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY", YEARS UNDER REVIEW 2021 AND 2023 .....	182
FIGURE 4-20:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY", YEARS UNDER REVIEW 2025 AND 2030 .....	183

FIGURE 4-21:	TYPICAL EXCHANGE PATTERNS IN SITUATIONS WITH LOAD EXCESS IN GERMANY/LUXEMBOURG IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY" .....	185
FIGURE 4-22:	COMPARISON OF ENERGY PRICE SCENARIOS: REFERENCE VS. SENSITIVITY "INCREASED SECTOR COUPLING WEO - SUSTAINABLE DEVELOPMENT" .....	187
FIGURE 4-23:	ABSOLUTE AND DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN GERMANY: SENSITIVITY "INCREASED SECTOR COUPLING - WEO SD VS. REFERENCE SCENARIO" .....	190
FIGURE 4-24:	COMPARISON OF THE COMPOSITION OF THE LOAD AT THE TIME OF THE ANNUAL PEAK LOAD BETWEEN SECTOR COUPLING SENSITIVITY AND REFERENCE SCENARIO IN GERMANY; YEAR 2030; WEATHER YEAR 2010 .....	192
FIGURE 4-25:	DEVELOPMENT OF THE ANNUAL BASE PRICE IN GERMANY AVERAGED OVER ALL WEATHER YEARS IN THE REFERENCE SCENARIO AND IN THE SENSITIVITY "INCREASED SECTOR COUPLING - WEO SUSTAINABLE DEVELOPMENT" .....	193
FIGURE 4-26:	COMPARISON OF THE DEVELOPMENT OF RESOURCES BETWEEN THE SENSITIVITY "INCREASED SECTOR COUPLING - WEO SUSTAINABLE DEVELOPMENT" AND THE REFERENCE SCENARIO IN THE FOREIGN COUNTRIES CONSIDERED (EXCLUDING GERMANY) .....	194
FIGURE 4-27:	LOLP IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT" FOR COUNTRIES WITH VALUES > 0 COMPARED TO THE REFERENCE SCENARIO .....	195
FIGURE 4-28:	REQUIRED* IMPORTS TO DE/LU IN THE "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT" SCENARIO .....	196
FIGURE 4-29:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT", YEARS UNDER REVIEW 2021 AND 2023 .....	198
FIGURE 4-30:	STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT", YEARS UNDER REVIEW 2025 AND 2030 .....	199
FIGURE 4-31:	EXCHANGE PATTERNS IN SITUATIONS WITH LOAD EXCESS IN GERMANY/LUXEMBOURG IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT" (2030).....	201

## List of tables

TABLE 2-1:	ASSUMPTIONS ON NATURAL GAS CHP REPLACEMENT PLANTS IN THE DIFFERENT FIELDS OF APPLICATION .....	41
TABLE 2-2:	DEVELOPMENT OF THE INSTALLED CAPACITY OF RENEWABLE ENERGIES IN GERMANY (END OF YEAR).....	45
TABLE 2-3:	DEVELOPMENT OF ELECTRICITY GENERATION FROM RENEWABLE ENERGIES IN GERMANY .....	48
TABLE 2-4:	SECTORAL ELECTRICITY DEMAND IN 2020 AND 2030, AND BREAKDOWN BY TRADITIONAL AND NEW APPLICATIONS (HEAT PUMP AND ELECTROMOBILITY). .....	63
TABLE 2-5:	DEVELOPMENT OF THE DRIVERS POPULATION AND GROSS DOMESTIC PRODUCT IN THE EUROPEAN COUNTRIES UNTIL 2030.....	69
TABLE 2-6:	ASSUMPTIONS ON THE DEVELOPMENT OF THE SHARES OF THE THREE CHARGING STRATEGIES UNTIL 2030.....	84
TABLE 2-7:	ASSUMPTIONS ON COSTS OF NEW CONVENTIONAL POWER PLANTS.....	87
TABLE 2-8:	ASSUMPTIONS ON UNAVAILABILITIES OF CONVENTIONAL POWER PLANTS .....	95
TABLE 2-9:	CROSS-BORDER NETWORK EXPANSION PROJECTS TAKEN INTO ACCOUNT, YEARS UNDER REVIEW FROM WHICH THEY ARE TAKEN INTO ACCOUNT IN THE MODEL AND CAPACITY INCREASE ACHIEVED IN COMPARISON BETWEEN FIRST AND SECOND PROJECT REPORT .....	106
TABLE 3-1:	CLASSIFICATION FOR THE EVALUATION OF THE LEEWAY STATUS.....	143
TABLE 3-2:	ASSUMPTIONS ON THE LEVEL OF STRATEGIC RESERVES (2021-2030) IN THE VARIANT CALCULATION FOR TECHNICAL RESOURCE ADEQUACY .....	147
TABLE 4-1:	DEVELOPMENT OF INSTALLED CAPACITIES AND ELECTRICITY CONSUMPTION OF LARGE-SCALE PTX TECHNOLOGIES IN 2030: REFERENCE VS. SENSITIVITIES FOR "ENHANCED SECTOR COUPLING" .....	171
TABLE 4-2:	AVERAGE REQUIRED IMPORT ENERGY OF DE/LU RELATED TO GROSS ELECTRICITY CONSUMPTION IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY" .....	181
TABLE 4-3:	AVERAGE REQUIRED IMPORT ENERGY OF DE/LU RELATED TO GROSS ELECTRICITY CONSUMPTION IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY" .....	197

## List of abbreviations

AGEB	Working Group on Energy Balances
AGEE	Renewable Energies Working Group
BEV	Battery electric vehicles
CHP	Combined heat and power plant
BMWi	Federal Ministry for Economic Affairs and Energy
CCS	Carbon Capture and Storage
CEP	Clean Energy Package
CoNE	Cost of New Entry
COP	Coefficient of Performance
CWE	Central West Europe
DSM	Demand Side Management
DWD	German Meteorological 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 Ordinance
ENTSO-E	European Transmission System Operators for Electricity
EOM	Energy-only market
FB approach	Flow-based approach
FCEV	Fuel Cell Electric Vehicle
FLH	Full Load Hours

FORECAST	FORecasting Energy Consumption Analysis and Simulation Tool
GHD	Trade, commerce and services
GIS	Geoinformation system
GTC	Grid Transfer Capacity
CCGT	Gas-and-steam combined cycle power plant
HEL	Heating oil extra light
HVDC	High-voltage direct current transmission
OH TRUCK	Hybrid overhead line truck
IBN	Commissioning date
IEA	International Energy Agency
CHP	Combined heat and power generation
KVVG	Act to reduce and end coal-fired power generation
KWSB	Commission for Growth, Structural Change and Employment
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
NTC	Net Transfer Capacity
NUTS	Nomenclature des unités territoriales statistiques
OCGT	Open Cycle Gas Turbine
PHEV	Plug-in hybrids

PST	Phase-shifting transformer
PTDFs	Power Transfer Distribution Factors
PtH	Power to Heat
QT	Cross-cutting technologies
RE	Renewable energy
SAIDI	System Average Interruption Duration Index
UBA	Federal Environment Agency
TSO	Transmission system operator
VoLL	Value of Lost Load
RA	Resource adequacy
WEO	World Energy Outlook
WTA	Willingness-to-accept
WTG	Working day
WTP	Willingness-to-pay
WZ	Industries

# 1 Background and overview

## 1.1 Background

The transformation process of the European energy and electricity supply system is characterised by the liberalisation of the European electricity markets, the establishment of a common European internal market for electricity and the expansion of the European interconnectors. It is also characterised by the progressive expansion of renewable energies (RE) in Germany and Europe, the increasing flexibilization of generation and consumption, and the increased coupling of the electricity, heat and transport sectors (sector coupling). These developments also require further methodological developments in the area of quantitative analyses of the supply of electricity and especially in analyses of the adequacy of resources as an important component of security of supply.<sup>18</sup>

Before this transformation process, the electricity industry was characterised by controllable centralised large-scale generation plants and relatively predictable consumption behaviour. Today and in the future, on the other hand, the energy industry is increasingly characterised by fluctuating, decentralised plants for electricity generation from renewable energies and flexible consumers, also against the background of the desired 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 grid infrastructure (interconnectors) between the EU member states as well as Switzerland and Norway has been expanded. Against this background, security of supply (and in particular the question of resource adequacy) must be considered on a European scale, taking into account dynamic market adjustment processes. In this supra-regional market, there are significant balancing effects in terms of load, the feed-in of supply-dependent renewable energies and unplanned outages of power

---

<sup>18</sup> In this report, resource adequacy is understood as ensuring the balance of generation and consumption in the electricity supply system in the sense of balancing supply and demand on the electricity market. In the following, the term "resource adequacy on the electricity market" or in short, "resource adequacy" is used for this purpose.

plants, which have a positive impact on ensuring resource adequacy and the associated costs.

The procurement of electricity at a high level of resource adequacy is also and especially essential 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 like Germany and to the general quality of life of private consumers. Monitoring and continuous evaluation of the security of electricity supply is therefore necessary in order to

- identify challenges in resource adequacy at an early stage,
- analyse any remaining barriers or disincentives that could affect a high level of resource adequacy, and
- to take measures, such as adjustments to the regulatory framework, to maintain a high level of resource adequacy in a timely manner, if necessary.

Against the background of current and future demands on the German and European electricity supply system, the following aspects are of high importance:

- (1) **Resource adequacy can only be considered on a cross-border basis** because the German electricity supply system is connected to the electricity supply systems of neighbouring countries via an extensive grid infrastructure and electricity is traded intensively across borders and transported over long distances in the European electricity market.
- (2) **Resource adequacy can only be considered on a probability basis (taking stochasticity into account).** On the one hand, one hundred percent protection of inflexible electricity consumption by generation plants is de facto not possible, especially due to stochastically occurring power plant outages. On the other hand, the question of economic efficiency is also a relevant evaluation criterion. Therefore, securing resource adequacy at a very high level exclusively on the generation side is not advisable because it would be highly inefficient in economic terms. Neither is the output of RE plants reliably available due to the dependence of their generation on weather conditions (e.g. onshore and offshore wind turbines and PV

plants), nor are conventional power plants reliably available to cover consumption in every situation due to unplanned outages (e.g. due to technical defects or material and safety issues) or difficulties in the fuel and cooling water supply. When monitoring or assessing resource adequacy, it is therefore basically only possible to determine what proportion of the inflexible electricity consumption can be covered in the expected value and what proportion of the inflexible electricity consumption cannot be covered in the expected value. This applies all the more in the case of the envisaged further transformation of the electricity supply system towards supply-dependent RE technologies and a further expansion of the European grid infrastructure. In particular, the expansion of the European grid infrastructure and the increased opening of the cross-border lines in the so-called market coupling offer the prerequisites for being able to make full use of existing balancing effects for loads, RE feed-in and unplanned power plant outages. Stochastics generally, and in particular cross-national stochastic balancing effects in supply-dependent RE feed-in, load structures, and unplanned power plant outages, must therefore be taken into account in methodological approaches in order to derive meaningful and reliable results.

- (3) **Resource adequacy can only be considered by taking into account the dynamics of markets, i.e. the adjustment processes inherent in markets on the supply and demand side.** In the event of overcapacity<sup>19</sup> on the supply side, as is currently the case in the European electricity market, power plant operators react for economic reasons with increased shutdowns or at least increased temporary shutdowns (preservation, so-called cold reserve) of power plants. In the event of a (frequent) shortage of generation capacity in the European electricity market and consequently high electricity price expectations, on the other hand, power plants would be kept in the market or put back into operation after temporary shutdowns. In

---

<sup>19</sup> In this report, overcapacity is understood to mean capacities that can be shut down with some lead time without, *ceteris paribus*, jeopardising the adequacy of resources in terms of the identified standard (threshold).

addition, investments in new generation plants and the development of flexibility options, such as load management and back-up power plants, would be stimulated.

- (4) **Resource adequacy must adequately take into account flexibility potentials such as load shifts, load reductions in individual shortage situations and (more generally) current and future expected developments in the price elasticity of demand.** The most favourable option for a secure balancing of supply and demand on the electricity market in very rare situations of shortage (e.g. low supply-dependent RE feed-in in combination with a high consumption load and extensive unplanned power plant outages) is the active integration of electricity consumers into the market. Flexibilities can be used, for example, in the form of load shifting and load reduction to balance supply and demand on the electricity market. Considerable potentials of consumption-metered consumers are available for this, also taking into account technical restrictions, which can contribute to balancing supply and demand on the electricity market with corresponding price signals from the market and appropriately designed regulatory framework conditions. In addition, this potential can be used to (financially) secure compliance with supply obligations entered into by market participants.

## 1.2 Task and research objectives

In recent years, methodological approaches for monitoring and assessing resource adequacy have been developed, taking adequate account of stochasticity and the integration of national electricity markets into the European internal electricity market, which take the first two aspects mentioned above into particular consideration. Appropriate approaches have already been used in numerous analyses of resource adequacy.<sup>20</sup>

---

<sup>20</sup> Cf. e.g. Consentec /r2b (2015), PLEF (2015), PLEF (2018), ENTSO-E (2016), ENTSO-E (2017a), ENTSO-E (2018b), ENTSO-E (2020d).

At the same time, corresponding further developments of the methodological approaches have led to adjustments of legal regulations both in the EU and in Germany.

The Federal Ministry for Economic Affairs and Energy (BMWi) was obliged to continuously monitor the resource adequacy until the end of 2020. This report and its development form an essential element for this monitoring in the area of the European electricity markets with an impact on the territory of the Federal Republic of Germany as part of the internal electricity market. In addition, this report serves as a basis for the BMWi to fulfil its reporting obligation according to § 63 para. 2 EnWG.

In the analyses on which the report is based, pursuant to § 51 (3) and (4) EnWG, the following in particular shall be taken into account

- the developments of generation, grids and consumption in Europe,
- Adjustment processes on the electricity markets based on price signals,
- cross-border balancing effects with neighbouring countries for feed-ins of RE, 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. taking stochasticity into account) methodological approach is to be chosen, and the measurement and assessment of resource adequacy in the electricity market is to be carried out using suitably defined indicators and their threshold values.

The adaptation of the legal framework for the assessment of resource adequacy in the electricity market in Germany thus takes into account the current state of science.<sup>21</sup> The EU Electricity Market Regulation also prescribes a transnational and probabilistic assessment of the adequacy of resources at national level in accordance with Article 24 in conjunction with Article 23. Article 23 (Assessment of

---

<sup>21</sup> Cf. European Parliament and Council (2019).

resource adequacy at European level), the EU Electricity Market Regulation also prescribes a transnational and probabilistic approach to monitoring resource adequacy from 2021 onwards. Key requirements of the EU Electricity Market Regulation (although not (yet) legally binding in the period in which the calculations were carried out) are already fulfilled in this report:

- by taking into account market adjustment processes through endogenous modelling in scenario generation, the analysis is based on "*appropriate central reference scenarios for projected supply and demand [...], including an economic assessment of the likelihood of shutdown, temporary closure and new construction of generation plants*".
- Consideration of the "*contributions of all resources, including existing and future opportunities for generation, energy storage, sectoral integration and load control*".
- Anticipation of the likely impact of (foreign) capacity mechanisms.
- Use of a market model and load flow-based modelling of the interconnectors.

Against this background, the BMWi invited tenders in 2016 for the project "**Definition and monitoring of resource adequacy in the European electricity markets**", which was commissioned to the consortium of r2b energy consulting GmbH, Consentec GmbH, Fraunhofer ISI and TEP Energy GmbH.

This report is the second and final project report under this project.

### **1.3 Consultation process**

The assumptions underlying the calculations and analyses, as well as large parts of the methodology applied, were extensively consulted with representatives of the Federal Network Agency (BNetzA), the four German transmission system operators (TSOs), the 16 competent state ministries as well as the Federation of German Industries (BDI), the Association of Municipal Enterprises (VKU), the German Chamber of Industry and Commerce (DIHK) and the German Association of Energy and Water Industries (BDEW). All participants in the consultation had the opportunity to submit written comments on the assumptions proposed by the

working group. Eight parties made use of this: TSOs, BNetzA, Baden-Württemberg, Bavaria, Berlin, Saxony, BDEW and VKU.

## 1.4 Overview of the chosen methodological approach

The first step was the further development of the definition of and the assessment scale for resource adequacy on the electricity market as well as further developing a methodology for modelling and monitoring RA on the European electricity market on the basis of existing concepts.<sup>22</sup> Subsequently, the resource adequacy was empirically analysed on the basis of the developed monitoring concept for the status quo and as a forecast for the following years as well as an outlook for the year 2030.

The concrete research objectives within the framework of the project "**Definition and monitoring of resource adequacy in the European electricity markets**" are defined as follows:

- Definition of one or more suitable indicators as well as corresponding threshold values for monitoring and assessing the resource adequacy of the electricity supply system;<sup>23</sup>
- Derivation of scenarios for the development of the electricity supply system based on detailed preliminary analyses<sup>24</sup> and using a dynamic European electricity market model, taking into account stochasticity, economic efficiency, market mechanisms and market adjustment reactions;
- Assessment of the level of resource adequacy 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 the resource adequacy on the basis of a consistent two-stage

---

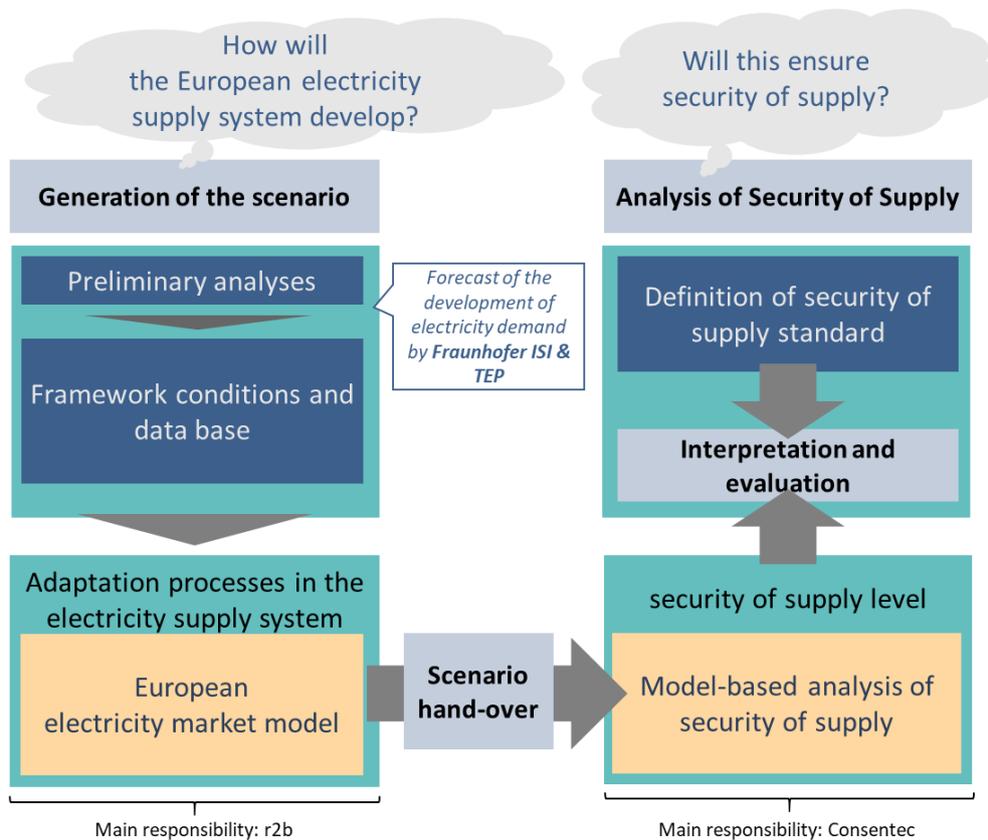
<sup>22</sup> For a detailed presentation of the study on the definition and assessment scale for security of supply, cf. chapter 2; for the methodology used, cf. Chapter 3 in r2b / Consentec (2019).

<sup>23</sup> Cf. Section 2 in r2b / Consentec (2019).

<sup>24</sup> For a detailed description of the preliminary analyses on which the calculations are based, see Section 3 in r2b / Consentec (2019).

approach. For this purpose, we have further developed both models in a methodologically consistent manner and coordinated them with each other. One focus here is the most consistent possible representation of stochastics in the two models.

**FIGURE 1-1: OVERVIEW OVER THE STRUCTURE OF THE CONSISTENT TWO-STAGE MODELING APPROACH**



Source: Own representation.

In the first stage, we perform an extensive preliminary analysis to determine the framework conditions and the data basis, and then carry out a dynamic simulation of the development of the electricity supply system based on an integrated investment and dispatch model of the European electricity market (Germany, its electrical neighbors, Scandinavia, Great Britain, and Italy), taking into account the stochasticity 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 resource adequacy using the probabilistic resource ad-

equacy model. As a result, we then determine the level of resource adequacy taking into account the probabilities 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 resource adequacy level is classified and evaluated on the basis of a proposal for a resource adequacy standard, the definition of which is also the subject of this project.<sup>25</sup>

## **1.5 Classification of the evaluation approach and interpretability of the results**

In accordance with the task, the chosen methodology is designed and suitable for determining the resource adequacy on the electricity market. In this report, the term resource adequacy 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. Accordingly, RA on the electricity market is given if those consumers can always obtain electrical energy whose willingness to pay (benefit) is greater than or equal to the market price (cost).

In the short term, at the beginning of the period under consideration, the adjustment processes of the market have only limited effects due to inherent inertia. In the model, we take this into account by specifying the development of the electricity supply system largely exogenously in the first model stage for the short-term perspective (for example, by excluding model-endogenous new construction of generation plants). Accordingly, the second model stage tends to provide a measurement of market resource adequacy as the central result for this short-term horizon.

By the end of the period under consideration, the adjustment processes of the market can unfold an increasing effect. Since the first model stage depicts the market rules and the investment incentives caused by them, the development of the electricity supply system is increasingly determined by model-endogenously determined shares. In view of the market incentives for suppliers and consumers,

---

<sup>25</sup> Cf. Section 2 in r2b / Consentec (2019).

depicted in the model, due to the existing balancing group and balancing energy system, it can generally be expected that the system will be adequate in terms of supply in the market sense at least at the end of the period under consideration.<sup>26</sup> The central result in the long term is therefore a probable development path of the electricity supply system that is consistent with the assumptions made in the scenario generation.

Given the task of anticipating any threat to resource adequacy on the electricity market and any obstacles to the use of available flexibilities, the following applies:

- For the beginning of the period under consideration, the second model stage with the corresponding resource adequacy indicators provides a direct basis for assessing the resource adequacy on the electricity market.
- For the later part of the period under consideration, on the other hand, it can generally be expected that the resource adequacy indicators will lie in the non-critical range if the incentives in the balancing group and balancing energy system are set correctly and corresponding market adjustment processes take effect. An assessment of the resource adequacy in this time range requires, in particular, that the endogenous components of the development path of the electricity supply system from the first model stage be assessed with regard to their plausibility and feasibility and, in doing so, analysed for any obstacles that may exist. The results of the second model stage are another building block for the plausibility of the development path, as they provide indications of how far the system is approaching the threshold values.

The classification of RA in the electricity market also includes the fact that the transmission system operators have various other measures at their disposal to secure supply even if supply and demand should diverge. These include strategic reserves outside the electricity market, such as the German capacity reserve.

---

<sup>26</sup> Deviations from this can occur if, at the interface of the two model stages, adjustments required for computation time reasons to align different modelling depths lead to an overestimation of the resource demand in the second model stage and/or underestimation of the demand in the first model stage due to implicitly or explicitly conservative parameterisation. This primarily affects the peripheral countries with low import capacities to the core region in relation to the load.

Therefore, in variant calculations, we estimate the technical resource adequacy by additionally taking into account the possibility of using strategic reserves in the second model stage.

## 1.6 Structure of the study

This second project report is essentially an update and partial extension of the first project report from January 2019 and describes results on the resource adequacy on the electricity market in Germany and its neighbouring countries<sup>27</sup> based on scenarios developed within the project for the years 2021, 2023, 2025 and 2030.

In preparing this report, we have avoided duplicating the first report wherever possible. Instead, we provide references to the relevant sections of the first project report where there are references to analyses already carried out and statements that remain valid. The explanations in chapters 2 and 3 of the first report, especially on the methodological basis, are still valid, even if they are not presented again here.

In [Chapter 2](#), we present the central framework assumptions of a reference scenario, which we have developed in consultation with the BMWi for this study and have comprehensively checked for plausibility by means of comparison with other studies and professional exchange with numerous scientific research projects. The reference scenario aims to represent a 'best guess' analysis of the relevant framework assumptions from the current perspective. In this chapter we also describe the methodological approach and the basics for deriving the framework assumptions of the reference scenario.

In [Chapter 3](#), we present the results for the Reference Scenario. First, we describe in detail the development of the electricity generation system and the availability and development of flexibility options over time. Furthermore, in the sub-section

---

<sup>27</sup> The focus of the analysis is on Germany - accordingly, the accuracy is also greatest here. In addition, exchanges with satellite regions are modelled in the electricity market model in a simplified way via aggregated import and export functions, taking into account cross-border exchange capacities; see r2b / Consentec (2019) Appendix A.3. The exchange profile fixed in this way for each weather and observation year is fixed in the RA assessment carried out below. Therefore, the results for foreign countries and especially for countries with not explicitly modelled geographic providers are only robust to a limited extent.

"Balancing effects in the European electricity market" we show to what extent a consideration of balancing effects between consumption loads, supply-dependent RE feed-in and unplanned power plant outages in the European context reduces the requirements for securing resource adequacy through generation capacities or other flexible resources. We then present the results of the simulation calculations to derive the indicators for monitoring and assessing the resource adequacy.

In [Chapter 4](#), we describe the framework assumptions and results of alternative scenarios (sensitivities to the reference scenario) developed and analysed in this study. In each of the alternative scenarios / sensitivities, we have made a central change to the framework assumptions of the reference scenario. In a first hypothetical sensitivity, in contrast to the reference scenario, we have assumed the fictitious situation that an "energy-only market" is implemented in all countries examined, i.e. no country-specific capacity markets are taken into account. In the second and third sensitivities, we have examined an increased sector coupling, i.e. a faster market penetration of electric mobility and electric heat pumps as well as more "power-to-X" in Germany and the foreign countries considered in the sense of a "what-if analysis". The two sensitivities for "increased sector coupling" differ on the one hand in the extent of the increase in annual electricity consumption compared to the reference scenario due to increased sector coupling and on the other hand in the respective underlying energy price scenarios.

In [Chapter 5](#), we give indications on accompanying measures to ensure resource adequacy as well as an outlook on the future German and European monitoring of resource adequacy in the electricity markets.

## 2 Assumptions reference scenario

The assumptions for the model calculations of the market simulations and the RA analyses are essential determinants for the quantitative results of the monitoring of the resource adequacy. 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 RA 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 the market simulations to forecast the development of the power supply system. In the following sections, we explain in detail the assumptions for the reference scenario.

The reference scenario is a *best-guess scenario*.<sup>28</sup> We have developed the assumptions on the basis of comprehensive and detailed research within the framework of the preliminary analyses as well as a comparison with other studies and exchange with external experts. This adequately reflects the most probable framework conditions, goals and current developments in Germany and Europe. Exceptions to the 'best guess' approach are the conservative cost parametrisation of the flexibility options "voluntary load reduction by industry" and "emergency power systems" from the first project report. We have retained these. We have examined the effects of these assumptions in a sensitivity analysis within the framework of the first project report.<sup>29</sup>

The final decisions on the so-called "EU Green Deal" were not available by the time the assumptions were finalized.<sup>30</sup> However, the main thrust of the decisions was foreseeable, so that key developments in this area could be included in the sensitivities for increased sector coupling (see sections 4.2 and 4.3). From today's point of view, special attention should therefore be paid to the sensitivities for

---

<sup>28</sup> The calculations for this report were carried out as of 17.09.2020, so the term "best-guess" scenario refers to the information situation between the end of May and the end of August 2020, as the research / updates for this project report were carried out during this period.

<sup>29</sup> Cf. r2b / Consentec (2019) Sections 4.1 and 4.2.

<sup>30</sup> Cf. European Commission (2019).

increased sector coupling, which already take into account more ambitious climate protection.<sup>31</sup>In the following Section 2.1 we describe the assumptions on market design regarding the reference scenario, i.e. whether and in what form we have assumed capacity mechanisms alongside the electricity exchanges. Subsequently, in Sections 2.2 and 2.3 describe exogenous assumptions on the development of the generation system: In Section 2.2 we present key assumptions on the developments of the available capacities of conventional power plants as well as the methodology and assumptions for deriving the development of CHP plants in Germany and the other countries considered. In Section 2.3 we present the assumptions made for the development of renewable energies in the model region. Subsequently, in Sections 2.4.1 and 2.4.2 we explain the assumptions regarding existing and future flexibility options (emergency power systems and voluntary load reduction in industry). In Section 2.5 we describe the assumed development of electricity demand as well as the derivation of the hourly structure of the electricity load, taking into account partly flexible new consumers. In Section 2.6 explain the assumptions on technical and economic characteristics of conventional power plants. In Section 2.7 we address the modelling of balancing power reserve, before finally describing the assumptions on the development of cross-border import and export opportunities in Section 2.8

## 2.1 Market design assumptions

For the model-based analyses of the future development of the electricity market, it is important to depict the political and regulatory framework and, among other things, the market design. In this section, we therefore describe the assumptions we have made regarding the market design for the depicted countries. We distinguish between an *energy-only market* (EOM), an electricity market design with (centralised and decentralised) capacity markets and an electricity market design with other capacity mechanisms (e.g. strategic reserves).

---

<sup>31</sup> The achievement of the European and German climate protection targets against the background of the "EU Green Deal", which had not yet been redefined when the assumptions were finalized, was not examined in the two sensitivities for increased sector coupling.

In view of the increasing share of renewable energies in the national generation systems, the associated decreasing demand for capacities from conventional power plant technologies (especially classic base-load and medium-load power plants) and the simultaneously growing importance of regionally available controllable generation capacity, some European countries have introduced capacity mechanisms or have resolved to introduce them in the last few years. The aim is to keep fossil fuel-fired power plants on the market or to stimulate investment in new plants and the development of load-side flexibility options. Different design variants are used for this purpose: in the case of capacity mechanisms that operate within the electricity market, payments are granted to plants that are simultaneously allowed to generate revenues on the electricity market (including balancing energy markets). These mechanisms include centralized capacity markets (e.g., Great Britain, Poland), in which a central planning body determines a certain amount of secured capacity and procures it in tenders, and decentralized capacity markets, in which certain market players are obligated to procure a certain amount of secured capacity through corresponding regulatory provisions (e.g., France).<sup>32</sup> In contrast, there is the variant of a strategic reserve (also called capacity reserve). Plants that are remunerated within the framework of the capacity mechanism must hold their capacity in reserve and are not allowed to offer it on the electricity market, but are only used at the request of the transmission system operators in extreme situations. The latter mechanisms outside the electricity market pursue the goal of separating investment and dispatch decisions on the electricity market from the capacity mechanism as far as possible. Capacity mechanisms within the electricity market, on the other hand, pursue the goal of integrating the trading of electrical energy on the electricity market and capacity development within the framework of a closed market design. In this context, the different variants of a market design with capacity mechanisms in the existing European legal framework

---

<sup>32</sup> In addition, the group of capacity mechanisms that operate within the electricity market also includes instruments based on price control, in which providers of secured capacity are granted administrative capacity payments in the event of availability in shortage situations on the electricity market.

are always to be regarded as so-called *second-best* solutions, which are only intended to serve as temporary solutions until the existing barriers or disincentives of an EOM are removed.<sup>33</sup>

In **Germany**, a strategic reserve was implemented with the *capacity reserve*.<sup>34</sup> The capacity reserve was approved by the European Commission under state aid law on 7 February 2018.<sup>35</sup> The approval of up to 2 GW of reserve capacity is valid for the period from 2019 to 2025. The procurement of the reserve capacity was organised by the TSOs in tenders and has been available since October 2020.<sup>36</sup>

**Belgium**, **Sweden** and **Finland** also have strategic reserves, where an *ex-ante* defined capacity is procured by the TSO via tenders and the awarded capacities from power plants (or flexible consumption loads) receive payments for holding their capacity outside the electricity market for a defined period of time. In Belgium, however, the possibility of procuring a strategic reserve will not be used in the period foreseeable at the time of writing. In addition, Belgium is striving to introduce a capacity market. In this regard, the European Commission has initiated an in-depth review, the outcome of which is open. Therefore, the adoption of a capacity market in Belgium has been refrained from. A special feature of the strategic reserves in Finland and Sweden is their joint use by the two countries: although the necessary reserve capacity is determined and procured individually for each country (at the time of writing 611 MW in Finland and 562 MW in Sweden), in critical situations the power plants in both countries are always called together, subject to minimising the overall costs.

In the **UK**, the introduction of a central capacity market was already started in 2014.<sup>37</sup> Its design was the first to be approved by the EU Commission under the

---

<sup>33</sup> Articles 21 and 22 of the EU Electricity Market Regulation published in the Official Journal of the European Union, see European Council and Parliament (2019).

<sup>34</sup> In addition to this reserve used on the market side, power is also held in the grid reserve, which is used to manage bottlenecks in the transmission grid (redispatch).

<sup>35</sup> Cf. European Commission (2018a).

<sup>36</sup> Cf. BMWi (2018) / TSO (2019).

<sup>37</sup> The first delivery period was October 2018.

new "Guidelines on State aid for environmental protection and energy".<sup>38</sup> France implemented a capacity market in 2017 (first delivery year), but its required capacity is not procured centrally by the TSO, but is organised in a decentralised manner by electricity suppliers via a regulatory obligation.<sup>39</sup>

Poland also currently has a strategic reserve, which will be dissolved at the beginning of the first delivery period of the central capacity market in 2021. In addition to the strategic reserve, capacity payments are also currently granted in Poland to plant operators whose offered generation capacities are available in excess of the market clearing quantity on the electricity market. These payments will also be terminated with the start of the capacity market.<sup>40</sup> Similar capacity payments are currently granted in Italy. Together with the Polish capacity market, the EU Commission also approved the planned capacity market in Italy in February 2018, the first delivery period of which is 2022 and will replace the previous capacity payments.<sup>41</sup> The design of the central capacity markets in Poland and Italy is based in key areas on the design of the capacity market in the UK. Norway, Denmark, the Netherlands, Luxembourg, Switzerland, Austria and the Czech Republic currently have no capacity mechanisms. An overview of the market design implemented in the model parametrisation (with the exception of the sensitivity "energy-only market") of the modelled countries is given in Figure 2-1.

---

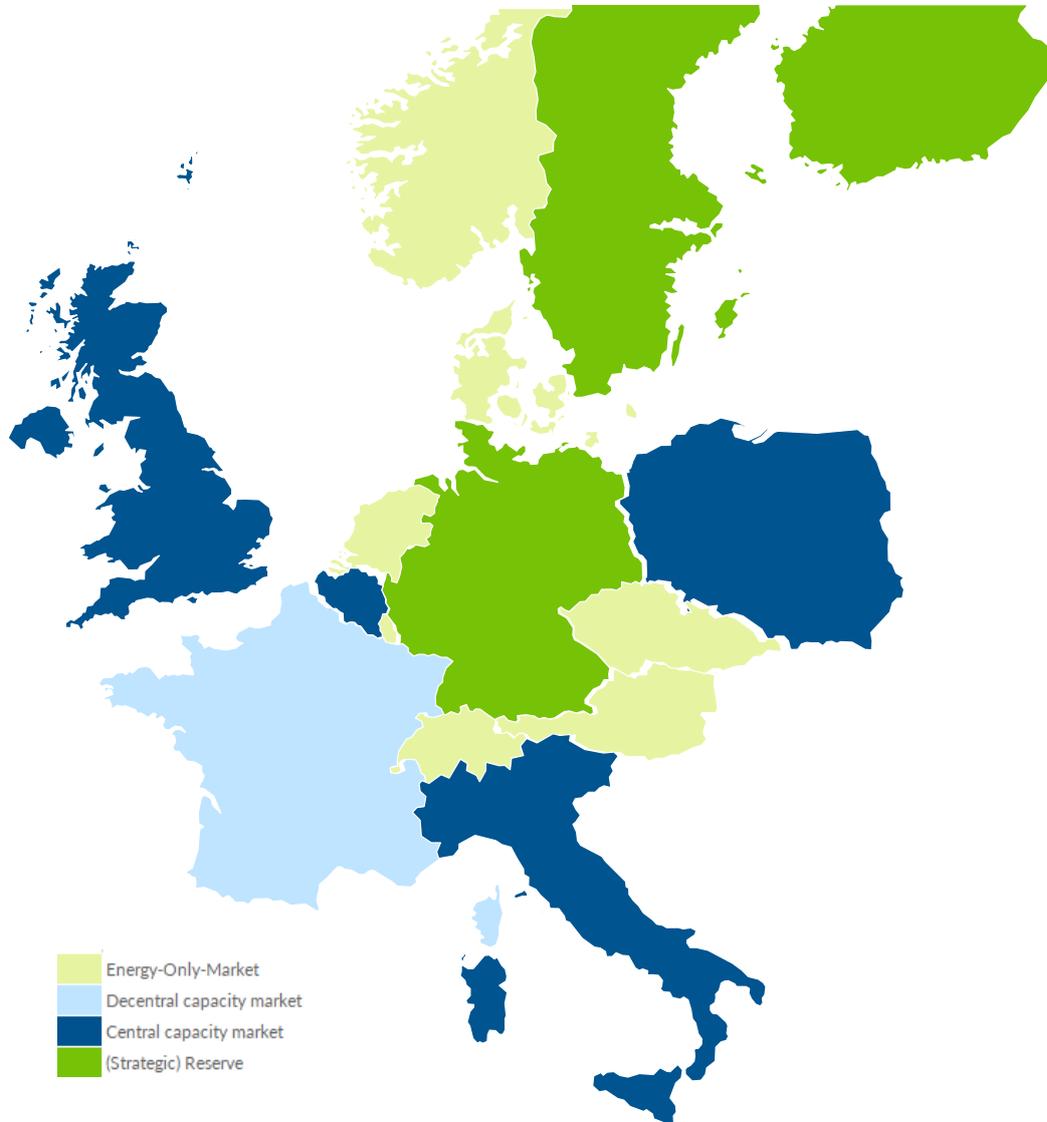
<sup>38</sup> Cf. European Commission (2014).

<sup>39</sup> Cf. European Commission (2016b).

<sup>40</sup> Cf. European Commission (2018b).

<sup>41</sup> Cf. European Commission (2018c).

FIGURE 2-1: MARKET DESIGNS CONSIDERED IN THE COUNTRIES UNDER CONSIDERATION



Source: Own representation.

The (strategic) reserves of the model countries were not (explicitly) taken into account when creating the scenarios for analysing the resource adequacy on the European electricity markets with the European electricity market model since the capacities contained therein are located outside the electricity market.<sup>42</sup> Only the

<sup>42</sup> The installed capacities of different energy sources presented in the remainder of this chapter therefore always exclude strategic reserves in these countries.

capacity available on the electricity market is depicted. In the quantitative resource adequacy analyses (RA<sup>43</sup> analyses), calculations are made without strategic reserves by default in order to show the resource adequacy on the electricity market. In exemplary variant calculations for estimating the technical resource adequacy, the strategic reserves are also taken into account.

The existing approved capacity markets in Great Britain, France, Poland and Italy, on the other hand, are taken into account in the modelling for the duration of their respective approvals by the EU Commission. Specifically, the British and French capacity markets are already accounted for in the model in the first forecast year 2021. The Polish capacity market is effective from the forecast year 2021 and until after 2030, whereby large plants that have already received multi-year contracts in the capacity market may not be shut down endogenously in the simulation calculations for reasons of economic efficiency. The first delivery period of the Italian capacity market is 2022, so we have assumed that the Italian capacity market takes effect from the first reference year after 2021 (i.e. in the forecast year 2023). All four capacity markets were initially approved by the EU Commission for a period of ten years. Due to the possibility of a premium for longer-term contracts in the capacity markets, we additionally assume that the effect of the central capacity markets in the UK, Poland and Italy will remain largely intact in part for a certain period after the official approval period has expired. For the French decentralised capacity market, on the other hand, we assume in the model only an effect until the end of its official approval period.

From a technical implementation perspective, for each of the countries with a capacity market, a capacity balance must be fulfilled in the electricity market model. We have parameterised this using the residual load of all six weather years, the *de-rated capacities* of the interconnectors<sup>44</sup> and the defined national RA level (all

---

<sup>43</sup> In the following, "resource adequacy" is abbreviated as "RA" as part of compound terms.

<sup>44</sup> *De-rated capacity* is the import capacity of the interconnectors reduced by a discount that is available for the participation of foreign capacities in the capacity market.

countries considered here have a LoLP of 0.034 %).<sup>45</sup> The capacity balances derived in this way must then be fulfilled in the model by means of the *de-rated capacity* of the national resources. For the potential capacity of load management in the industry, additional costs for the provision of capacity in the central capacity markets were assumed, which represent, among other things, the costs of a permanent provision of capacity and costs for trial calls of power. The capacity balance for the decentralised capacity market in France differs from the variant presented above in that no additional costs are incurred for the provision of capacity and trial activations.<sup>46</sup>

## 2.2 Assumptions on the (exogenous) development of the conventional power plants

The future development of the thermal power plants is, in principle, determined model-endogenously within the framework of the integrated investment and dispatch calculations with the European electricity market model, i.e. on the basis of an economic efficiency analysis. However, this endogenous determination takes into account currently known political requirements and measures, assumptions on technical lifetimes, and other information available on the market, which we specify exogenously in the electricity market model.

The starting point for our assumptions on the installed capacity in the model countries is the continually maintained, updated and expanded r2b power plant database, which we have created as part of many years of consulting activities and technical expertise.. On the one hand, it contains publicly available information, both commercial and non-commercial: on the European level, we have compared and, if necessary, updated the information 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 stakeholders (e.g. EEX, consultancies/analysts) and NGOs as well as civil society

---

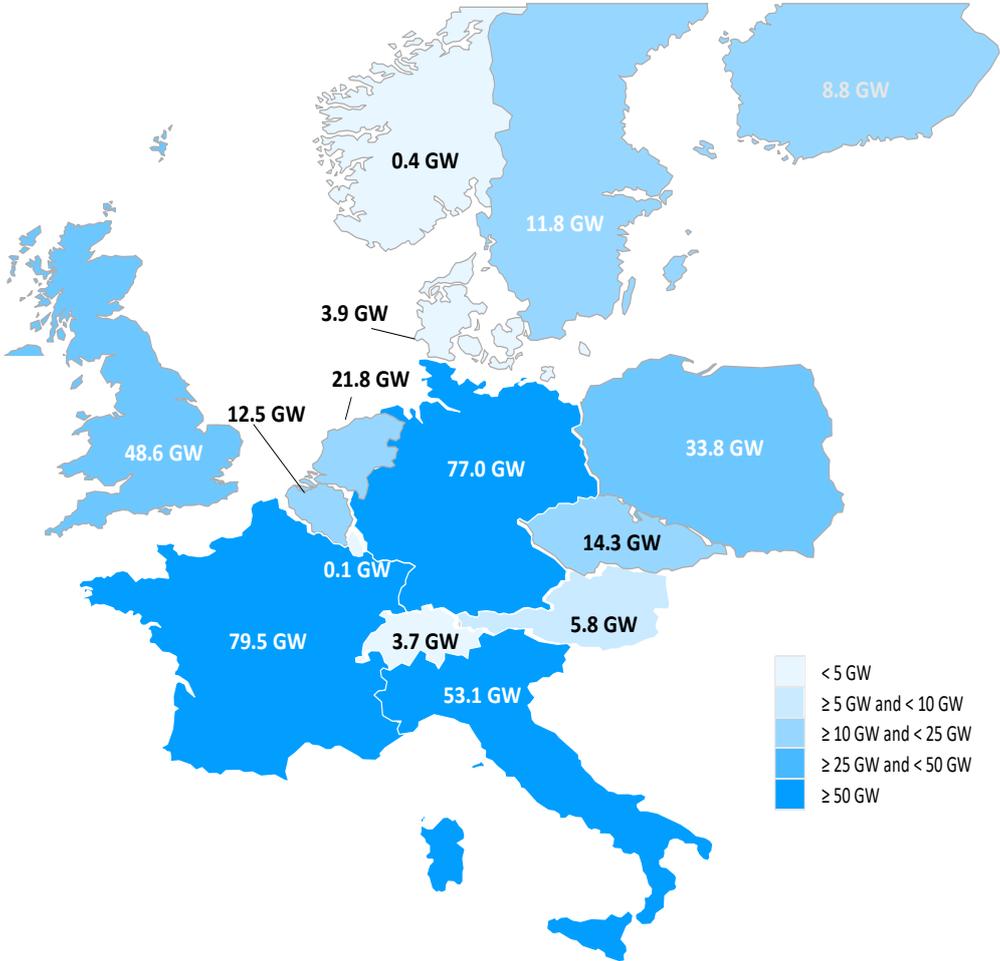
<sup>45</sup> We have defined the residual load as the load minus the feed-in from onshore and offshore wind energy, PV and run-of-river.

<sup>46</sup> In the decentralised capacity market in France, suppliers can also reduce their need for certificates by reducing their load using flexible loads, which is why we assume that no additional costs are incurred for the permanent provision of capacity on the capacity market or trial activations.

campaigns. We then compared this data again on the basis of national information from TSOs, regulatory authorities, ministries of economics and energy and private entities (e.g. power plant operators, think tanks, consultancies, power exchanges). On the other hand, we include information that we have received in the course of our consulting activities and that is not publicly accessible. In cases of doubt (inconsistencies of the collected information with previous information in the r2b database as well as between different data sources), we conduct additional individual research. Particularly with regard to planned additions and decommissionings of conventional power plants, we researched additional information based on national *resource adequacy reports*, energy strategies or concepts and other publications and compared it with the information already available in our power plant database.

The development of nuclear energy, coal-fired power plants and, to some extent, CHP plants are of high political importance and heavily regulated in all European countries. In these areas, the construction of new power plants is therefore largely determined exogenously with the support of model-based quantitative preliminary analyses. In contrast, possible investments in power plants based on natural gas (apart from CHP plants to maintain the heat supply) are completely model-endogenous. Temporary closures (*mothballing* or *cold reserve*) and early permanent closures (*disinvestment*) can be carried out by the model for all thermal power plant technologies with the exception of CHP plants for economic reasons. In the following subsections, we present the exogenous assumptions for the development of power plants based on nuclear energy, coal and CHP in detail (cf. Sections 2.2.1 to 2.2.3). First, however, in Figure 2-2 we provide an overview of the exogenous model specifications for the basic development of controllable conventional generation capacity at the European level (initial path of installed capacity), aggregated over the fuels. The exogenous specifications include already known planned closures and additions as well as specifications for the technical lifetime of the individual power plant units, which determine the latest possible closure date. In the model, early closures and model-endogenous additions can take place in deviation from the latest possible closure date.

**FIGURE 2-2: EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET) OF CONVENTIONAL POWER PLANTS IN 2021 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS ADDITIONS/REMOVALS)**



[GW]	2021	2023	2025	2030
Germany	77.000	61.446	66.053	60.200
Belgium	12.520	10.480	8.985	6.548
Denmark	3.933	4.054	3.994	3.833
Finland	8.836	10.446	10.413	10.409
France	79.472	78.220	77.016	73.355
Great Britain	48.606	45.064	41.029	42.135
Italy	53.120	53.832	52.839	46.112
Luxembourg	0.104	0.102	0.091	0.073
Netherlands	21.796	21.769	20.978	15.860
Norway	0.365	0.365	0.365	0.365
Austria	5.793	5.775	5.853	5.835
Poland	33.812	31.060	31.441	25.000
Sweden	11.825	10.939	10.272	10.199
Switzerland	3.682	3.682	3.682	2.952
Czech Republic	14.316	14.239	13.957	13.689
<b>Sum</b>	<b>375.180</b>	<b>351.473</b>	<b>346.968</b>	<b>316.565</b>

Source: Own representation.

Across all considered model regions, it can be seen that the total, exogenously specified, capacity in the initial path for all conventional, controllable generation plants declines over time. Thus, the total generation capacity of these plants<sup>47</sup> across the model regions decreases successively from approx. 370 GW in 2020 to approx. 271 GW in 2030. This decrease is driven by the fact that power plant

<sup>47</sup> These include: Nuclear energy, hard coal, lignite, natural gas, converter gas, blast furnace gas and waste (non-biogenic part).

units reach their technical lifetime. In addition, we take into account closures announced by power plant operators in the short term as well as political decisions in the short and medium term. The latter refer, for example, to the decommissioning of nuclear power plants in Germany or of coal-fired power plants in countries that have resolved a coal phase-out in electricity generation (cf. Sections 2.2.1 and 2.2.2). Conventional power plants under construction or at an advanced stage of planning are also taken into account in this representation of the exogenous capacity development as well as an exogenously specified, scenario-specific replacement of natural gas CHP plants determined on the basis of model-based preliminary analyses (for details, see Section 2.2.3). However, the additions cannot barely compensate for the assumed exogenous closures.

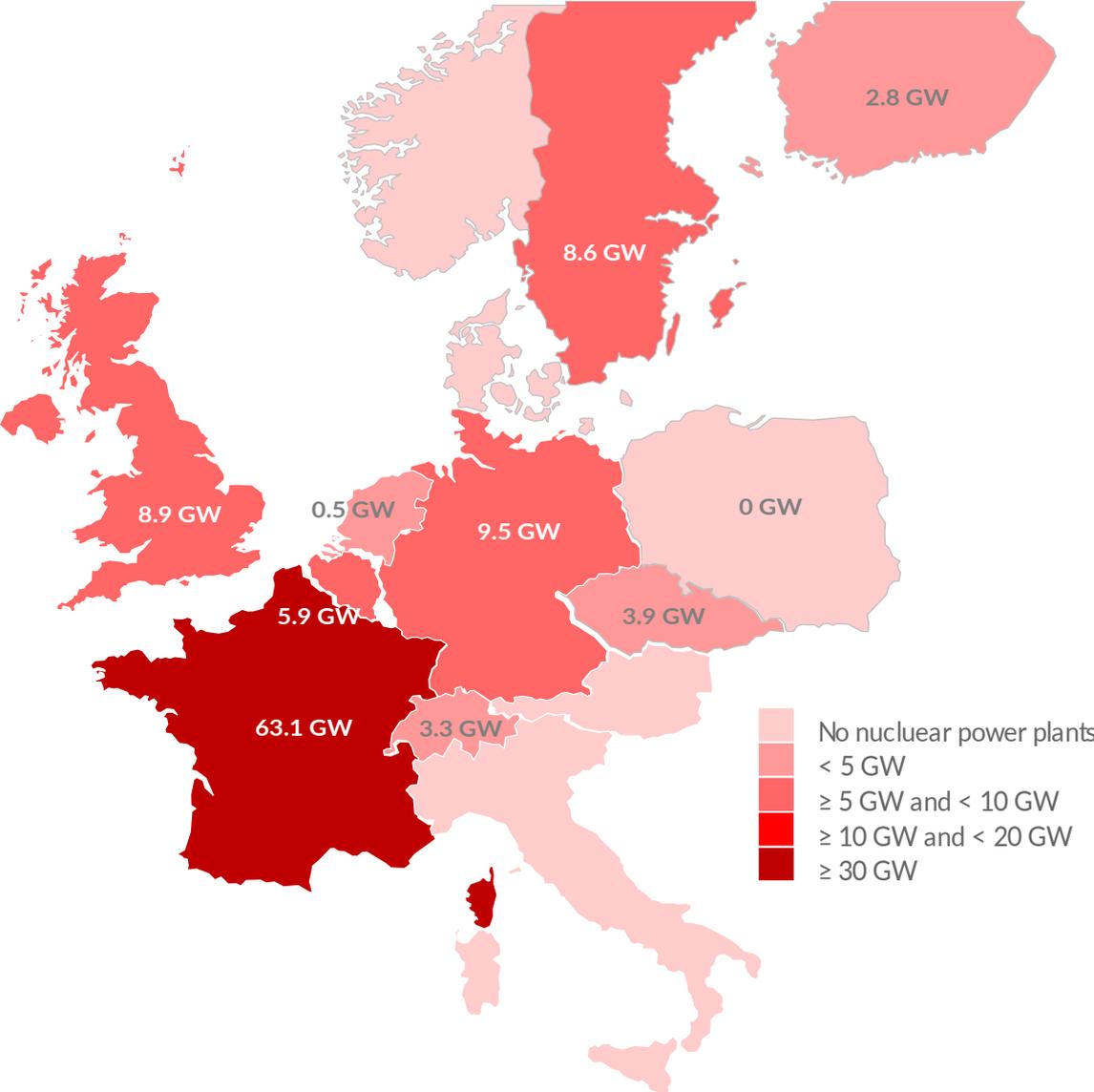
### **2.2.1 Assumptions on the development of nuclear energy**

Future developments in the field of electricity generation from nuclear energy are largely determined by decisions of the individual countries in the field of nuclear energy policy. This is done through phase-out decisions with fixed remaining lifetimes, through bans on new construction or politically adopted targets for the development of electricity generation from nuclear energy. It is also accomplished through political decisions to enter nuclear energy or to expand it. In view of this, the developments of the installed capacities of the nuclear power plants are exogenously specified in the electricity market modelling, i.e. both (latest) decommissioning dates of existing plants and planned additions are specified and not determined by the model. The starting point for the capacity developments is the installed capacity at the beginning of 2021 (Figure 2-3). The data basis for this is our European power plant database, in which all power plants are stored with all relevant technical data as well as current information on availabilities and currently valid operating times.<sup>48</sup>

---

<sup>48</sup> The database of our European power plants is regularly updated as part of ongoing research.

FIGURE 2-3: EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET) OF NUCLEAR POWER PLANTS IN 2021 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS ADDITIONS/REMOVALS).



[GW]	2021	2023	2025	2030
Germany	8.113	0	0	0
Belgium	5.918	3.904	2.433	0
Finland	2.779	4.379	4.379	4.570
France	61.370	62.110	61.200	57.640
Great Britain	8.883	5.811	6.293	7.498
Netherlands	0.482	0.482	0.482	0.482
Sweden	7.716	6.835	6.835	6.835
Switzerland	2.960	2.960	2.960	2.230
Czech Republic	3.930	3.930	3.930	3.930
<b>Sum</b>	<b>102.151</b>	<b>90.411</b>	<b>88.512</b>	<b>83.185</b>

Source: Own representation based on ENTSO-E (2020a), BEIS (2019) for GB and own research.

In order to obtain a consistent picture regarding the implementation of current policy decisions by the countries and their concrete effects on capacity developments, we base our assumptions of future capacity developments of nuclear energy on the corresponding current assumptions of the European Transmission System Operators for Electricity (ENTSO-E) from the *National Trends* scenario of the *TYNDP 2020*.<sup>49</sup> If there is more up-to-date, reliable information on the operating lives of individual nuclear power plants or more recent political decisions or laws that have not yet been taken into account in the ENTSO-E assumptions, we make different assumptions for individual countries or individual forecast years. In detail, we use the following sources for the assumptions, which deviate from those of ENTSO-E:

1. **United Kingdom:** Here we use the UK government's projections from the reference scenario of the *Updated energy and emissions projections 2018* from the *Department for Business, Energy & Industrial Strategy*.<sup>50</sup>

<sup>49</sup> Cf. ENTSO-E (2020a).

<sup>50</sup> BEIS (2019).

2. **Switzerland:** Based on our own research into the current operating times of Swiss nuclear power plants, a less rapid reduction in output is assumed than in the TYNDP 2020. In particular, there has been no decision to date to phase out nuclear energy, but only a ban on new construction according to the Energy Strategy 2050.<sup>51</sup>
3. **Sweden:** Here we have adopted the capacity development from the TYNDP 2020, with the only deviation that the first closures in our assumptions only take place after 2030. ENTSO-E already assumes a power reduction of 0.9 GW in 2030. In accordance with ENTSO-E, we assume the Swedish nuclear phase-out by 2040. The basis for the assumed nuclear phase-out is the target in Sweden's NECP to switch to 100 % renewable electricity generation by 2040.<sup>52</sup>
4. **Belgium:** In Belgium, the last three nuclear power plants will go offline in the second half of 2025<sup>53</sup> according to current guidelines. In our model, they are therefore still active for the reference year 2025.<sup>54</sup>

In **Germany**, the power development is mapped in accordance with Section 7<sup>55</sup> of the Atomic Energy Act and decreases from 9.5 GW at the beginning of 2019 due to the decommissioning of the Philippsburg 2 unit by 31 December 2019 to 8.1 GW in 2020. The decommissioning of the Gundremmingen C, Grohnde and Brokdorf units will follow at the end of 2021 and that of the remaining Neckarwestheim 2, Emsland and Isar 2 units at the end of 2022.

We have carried out additional plausibility checks on the basis of our own internet research on individual power plants, e.g. on the basis of press articles or information provided by the operators.

We break down the expected capacity developments at the national level into the operating times of individual power plant units. In doing so, we use, among other

---

<sup>51</sup> Cf. DETEC (2019).

<sup>52</sup> Ministry of the Environment and Energy (2017)

<sup>53</sup> Doel 2: closure on 01.12.2025; Thiang 3: closure on 01.09.2025; Thiang 1: closure on 01.10.2025

<sup>54</sup> In the assumptions of the MAF/TYNDP, Belgium's nuclear power output for 2025 is already given as 0.

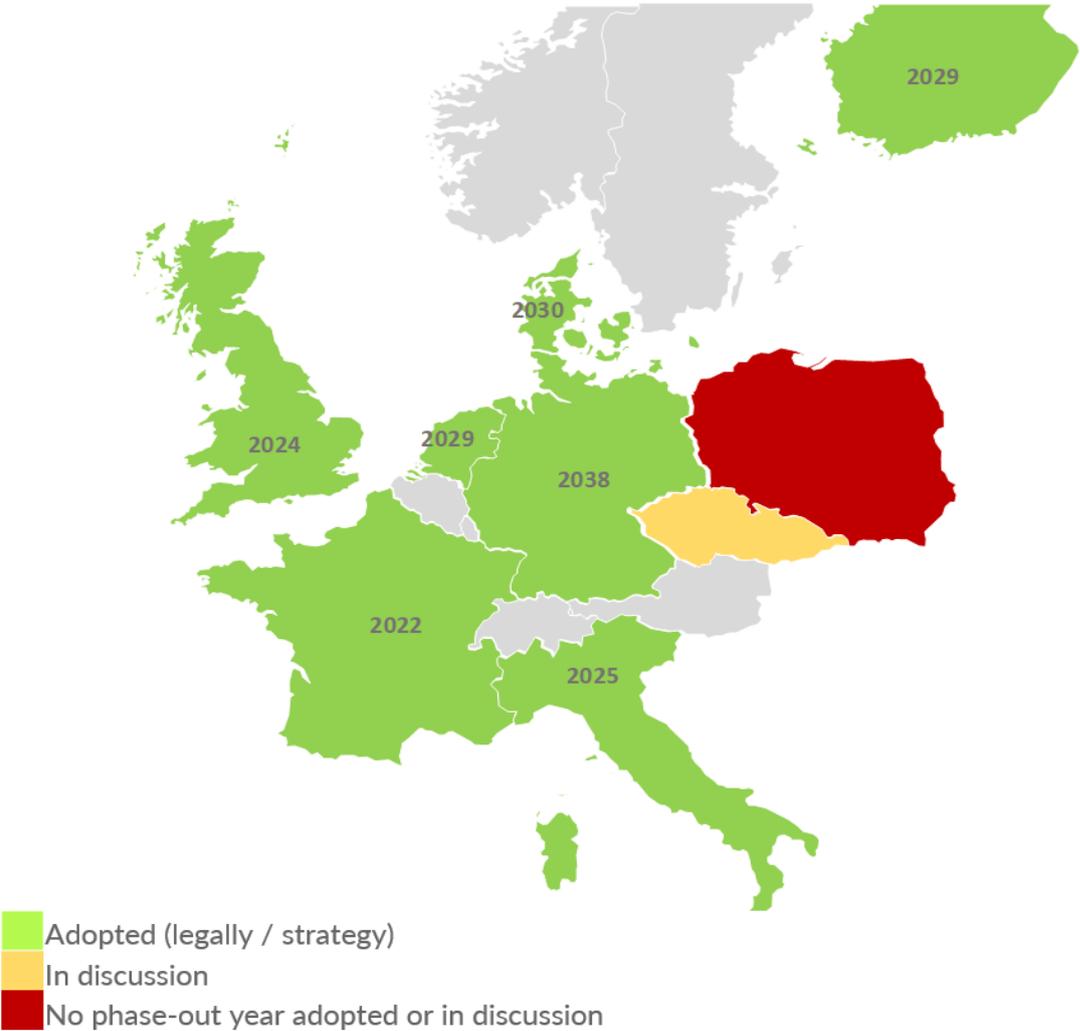
<sup>55</sup> AtG (2017).

things, decommissioning announcements by the operators, legally valid information on operating licenses or the age of the power plant as a basis. The resulting installed capacities for the years 2021 to 2030 are shown in Figure 2-3.

### 2.2.2 Assumptions on the development of coal-fired power plants

The trend towards the politically targeted reduction of the share of coal-fired power generation in the electricity generation mix in large parts of Europe (already described in the first project report), has continued in the meantime in the European regions considered. Figure 2-4 below shows the planned year of shutdown of the last coal-fired unit for each of the regions parameterised in our model.

**FIGURE 2-4: PLANNED PHASE-OUT DATES FROM COAL-FIRED POWER GENERATION IN THE MODEL REGIONS CONSIDERED.**



Source: Own research. The planned year of the shutdown of the last coal-fired unit is shown in each case.

In spring 2020, the last coal units were shut down in both [Austria](#) and [Sweden](#).<sup>56</sup> [Great Britain](#), the [Netherlands](#), [France](#), [Denmark](#), [Italy](#), [Finland](#) and [Germany](#) have published political strategies or passed laws defining an exit date from conventional coal-fired power generation.<sup>57</sup> The coal-fired power plants currently still in operation in these countries will therefore be decommissioned by the respective announced end dates (at the latest) for coal-fired power generation. For the Netherlands and Italy, in deviation from the assumptions of the first project report, we have no longer assumed that the hard-coal-fired power plants commissioned after 2000 will be converted to bioenergy and continue to be operated beyond the end date of coal-fired power generation, as these assumptions appear increasingly unrealistic in the light of current discussions in these countries. In addition, at the time of the analyses, the Netherlands brought forward a bill limiting the lifetime of Dutch coal-fired power plants to approximately 25%-35% of their maximum possible full load hours in the calendar years 2021, 2022 and 2023.<sup>58</sup> This bill was implemented in the model parameterisation. In the [Czech Republic](#), a coal commission was established in summer 2019 to develop initial recommendations for a reduction in coal-fired power generation by Q4 2020 and to conduct an official discussion on the coal phase-out.<sup>59</sup> [Poland](#) was not pursuing any official plans to end coal-fired power generation at the time of the model parameterisation.

In total, the installed capacity of coal-fired power plants in the countries under consideration gradually decreases from approx. 93 GW at the beginning of 2021 to just under 44 GW in 2030. Currently, or according to the model assumption at the beginning of 2021, Germany and Poland have the largest coal-fired power

---

<sup>56</sup> Cf. Verbund (2020), Stockholm Exergi (2020).

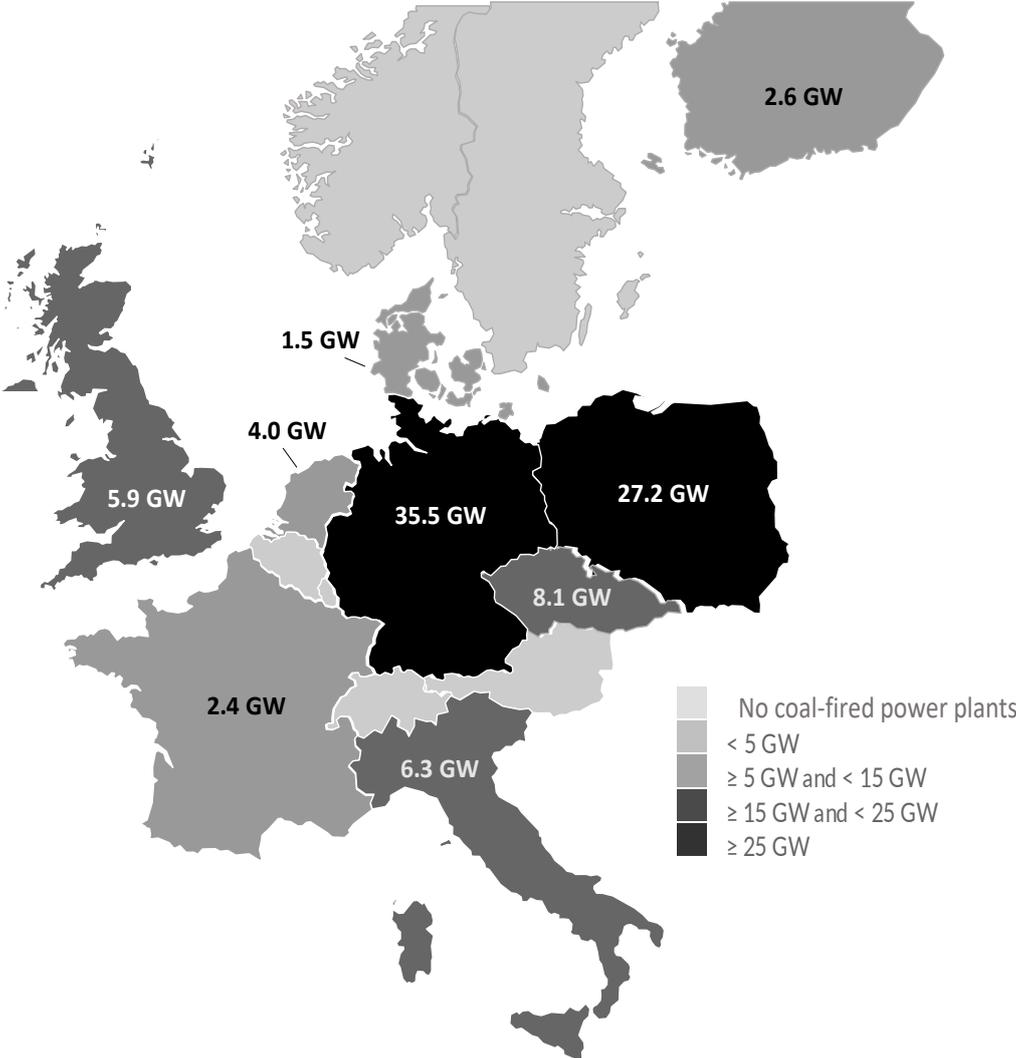
<sup>57</sup> See BEIS (2018), BEIS (2020); Ministry of Economic Development, Ministry of the Environment and Protection of Natural Resources and the Sea and Ministry of Infrastructure and Transport of Italy (2019), p. 8; Ministry of Economic Affairs and Climate Policy of the Netherlands (2019), p. 53; Gouvernement.fr (2018); Danish Ministry of Climate, Energy and Utilities (2019), p. 26; Ministry of Economic Affairs and Employment (2019), p. 12.

<sup>58</sup> Cf. Ministerie van Economische Zaken en Klimaat (2020).

<sup>59</sup> Cf. Wysokienapiecie.pl (2018), S&P Global (2019).

plant parks in Europe with about 35 GW and 27 GW, respectively.<sup>60</sup> They are followed (at some distance) by the UK, Italy and the Czech Republic, each with around 6 GW to 8 GW of installed coal-fired power plant capacity (cf. Figure 2-5).

**FIGURE 2-5: EXOGENOUS MODELLING INPUT FOR THE DEVELOPMENT OF INSTALLED CAPACITY (NET, WITHOUT STRATEGIC RESERVES) OF COAL-FIRED POWER PLANTS AT THE BEGINNING OF 2021 AND TABULAR OUTLOOK UP TO 2030 (DEVELOPMENT WITHOUT ENDOGENOUS ADDITIONS/REMOVALS).**



<sup>60</sup> For Germany, the capacity development of coal-fired power plants is fixed exogenously on the basis of the KWSB report. Cf. explanations below.

[GW]	2021	2023	2025	2030
Germany	35.470	25.876	23.143	16.938
Denmark	1.486	0.752	0.752	0.372
Finland	2.551	2.476	2.266	1.693
France	2.988	0	0	0
Great Britain	5.882	4.592	0	0
Italy	6.345	6.345	6.345	0
Netherlands	4.024	4.024	3.381	0
Poland	27.248	24.461	23.409	16.891
Czech Republic	8.071	8.037	7.901	7.815
<b>Sum</b>	<b>93.465</b>	<b>76.562</b>	<b>67.197</b>	<b>43.709</b>

Source: Own assumptions.

In the present analyses, coal-fired power plant units that were at an advanced stage of construction at the time of the model parameterisation were taken into account as exogenously assumed additions. However, this only applies to new constructions in Poland. In addition, model-endogenous new coal-fired power plant constructions are assumed to be extremely unlikely in the future in all countries considered due to political statements or requirements or social consensus and are therefore not permitted.

Power plant closures take place either in line with the model due to a lack of economic viability or after the expiry of an assumed maximum technical service life of usually 45 years.<sup>61</sup> Where available, decommissioning announcements by power plant operators, TSOs and regulatory authorities were also taken into account.

---

<sup>61</sup> In order to reflect very old power plants that are still in operation, technical lifetimes of up to 60 years were also applied in individual cases (e.g. for power plant units in Germany and Poland).

In **Germany**, the Commission for Growth, Structural Change and Employment (abbreviated to: KWSB) recommended a pathway for the gradual reduction, including an end date, of German coal-fired power generation in its final report submitted in January 2019. In August 2020, the German government then enacted the *Act to Reduce and End Coal-fired Power Generation and to Amend Other Laws* (abbreviated to: KVBG or Coal Phase-out Act), which imposes an obligation to end coal-fired power generation by 2038. While unit-specific decommissioning dates for lignite-fired power plants are anchored in law, the reduction of output from hard coal-fired plants will be implemented up to and including 2026 via tenders, in which the power plants with the lowest CO<sub>2</sub> avoidance costs will be identified and compensated for decommissioning in accordance with their bids.<sup>62</sup> From 2027 onwards, decommissioning will take place without compensation according to age (i.e. commencement of commercial operation).

This path is implemented in the reference scenario as follows: while at the beginning of 2021 a total of 35.5 GW is still installed in hard coal and lignite power plants, the installed capacity is reduced to 17 GW by 2030. Furthermore, it was assumed for the modelling in Germany in the reference scenario that no endogenous closures of lignite and hard coal plants (for economic reasons) will take place by the planned end of coal-fired power generation in 2038. The assumed coal path reflects the target data of the KVBG in terms of a maximum operating life of the coal-fired power plants.

In **Poland**, the use of coal in energy generation is extremely important. In 2019, around 48 % of Poland's total electricity generation of 161 TWh came from hard coal (77 TWh), and a further 27 % from lignite (43 TWh).<sup>63</sup> In its draft Polish Energy Policy 2040 (PEP2040) published in November 2018, the Polish government for the first time officially aims for a long-term decline in the share of coal-fired

---

<sup>62</sup> The hard coal output indicated up to and including 2025 does not include the Weiher III and Bexbach power plants, which have been provisionally notified to the BNetzA for decommissioning, as they do not participate in the market. However, as the plants are legally expected to return to the electricity market at any time, they must be included in the target quantities for reducing coal-fired generation pursuant to the KVBG. The capacity theoretically available to the market is thus just under 1.4 GW above the figures up to and including 2025.

<sup>63</sup> Cf. Agora Energiewende and Sandbag (2020).

electricity in the total electricity mix.<sup>64</sup> However, an exit target from coal-fired power generation is not mentioned.

The Polish coal-fired power plant park is assumed to have a total capacity of 27 GW available on the market at the beginning of 2021. Based on information from the Polish transmission system operator PSE, we have added the commissioning of two new coal-fired units in 2020 (a 910 MW hard coal unit in Jaworzno and a new lignite unit at the Turów site with a net capacity of 447.5 MW).<sup>65</sup> After the construction of Ostrołęka C, a 900 MW unit originally planned on the basis of hard coal and already considered by politicians to be the last new coal-fired power plant in Poland<sup>66</sup>, was cancelled by the operator in spring 2020, we assume that there will be no more coal-fired power plant additions in Poland.<sup>67</sup> Against this background, we have no longer admitted the construction of new coal-fired power plants in Poland.

At the beginning of 2021, coal-fired power plants with a total capacity of almost 6 GW are still on the market in the UK. With the British *carbon price floor*, an already existing emission standard that *de facto* excludes the construction of new coal-fired power plants without the use of carbon capture and storage (CCS) in the UK, and the additionally planned introduction of a further emission standard (which is also not achievable for conventional coal-fired power generation and that is to apply to existing power plants from 2025), three effective policy measures to reduce coal-fired power generation are now in force or in planning.<sup>68</sup> Already in recent years, the share of electricity generation from coal-fired power plants in the UK dropped significantly and amounted to only 2 % in 2019.<sup>69</sup> In line with these developments, the successive decommissioning of all coal-fired power

---

<sup>64</sup> Cf. Ministry of Energy of Poland (2018a).

<sup>65</sup> Cf. PSE (2019).

<sup>66</sup> See Ministry of Energy of Poland (2018b).

<sup>67</sup> Cf. Energate Messenger (2020).

<sup>68</sup> Cf. BEIS (2018).

<sup>69</sup> Cf. Agora Energiewende and Sandbag (2020).

plants in the UK by the end of 2024 at latest is assumed for modelling.<sup>70</sup> New construction or retrofitting of existing plants with CCS is not considered as an option.

At the beginning of 2021, the **Czech Republic** is expected to have about 8 GW of installed coal-fired power plant capacity, of which about 80 % are lignite-fired power plants. The operators of the power plants, three quarters of which are already 30 years old or even older, are facing a generally difficult market environment due to stricter emission regulations, significantly increased CO<sub>2</sub> prices and low wholesale electricity prices. Against this background, the Czech TSO CEPS assumes that a relatively large amount of capacity will be decommissioned in the early 2020s and a total of about 4 GW of old coal-fired units by 2030.<sup>71</sup>

In its 2015 *State Energy Policy of the Czech Republic* (SEK), on which the analyses of the Czech NECP are also based, the Czech government announced that the share of coal in electricity and heat generation would gradually fall to between 11 % and 21 % by 2040 (from the current level of more than 40 %).<sup>72</sup> In addition, a coal commission was set up in the summer of 2019 to identify transformation paths towards a diversification of the energy supply and thus a reduction in coal-based electricity generation by September 2020.<sup>73</sup> Against this background, we exclude the construction of new large-scale power plants based on coal in the model.

In **Italy**, 6.3 GW of hard coal-fired power plants are assumed to be in operation at the beginning of 2021. The Italian government announced in November 2017 that it would phase out coal-fired power generation by 2025.<sup>74</sup> Although no concrete measures to implement this goal were known at the time the model assumptions

---

<sup>70</sup> Insofar as corresponding plans for individual power plant units are known, we have assumed a conversion to bioenergy.

<sup>71</sup> Cf. CEPS (2018), CEPS (2019).

<sup>72</sup> Cf. Agora Energiewende and Sandbag (2020) and Ministry of Industry and Trade (2015).

<sup>73</sup> Cf. Government of the Czech Republic (2019), p. 315.

<sup>74</sup> Cf. Ministero dello Sviluppo Economico and Ministero dell'ambiente e della tutela del territorio e del mare (2017).

were set, the goal of phasing out coal by the end of 2025 is confirmed in the final Italian NECP and implemented accordingly in the model.<sup>75</sup>

### 2.2.3 Assumptions on the development of cogeneration

The combined generation of electricity and heat in power plants fired with hard coal, lignite, natural gas and petroleum products is very important in Germany and some other countries included in the analyses. In 2018, the absolute CHP electricity generation of these power plants in Germany was about 80 TWh<sub>el</sub>, which corresponds to a share of about 25 % of the total electricity generation based on 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 revenues when selling the heat or cost savings in the case of own consumption (electricity / heat) compared to uncoupled heat generation and in many cases receive additional direct or indirect subsidy payments. In return, the operators of these plants must meet their contractual obligations to supply heat or the operators must cover their own heat demand.

In view of this, the development of the installed capacity of CHP plants is not exclusively dependent on the development of the electricity markets, but in particular also on the developments of the (CHP-capable) heat demand, the development of alternative technologies for the provision of heat demand as well as developments in the promotion of CHP.

In the following subsections, we present the methodology for deriving and making assumptions regarding the development of the installed capacity of CHP plants in Germany and the European countries considered in the modelling. We first give a detailed presentation 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 similar methodological approach and subsequently present the key assumptions and resulting findings on the development of CHP plants.

---

<sup>75</sup> See Ministry of Economic Development, Ministry of the Environment and Protection of Natural Resources and the Sea and Ministry of Infrastructure and Transport of Italy (2019).

## Development of combined heat and power generation in Germany

We have developed framework assumptions for the future development of CHP in Germany that are consistent with the following current energy policy objectives of the German government in this area:

- Achieving a share of renewable energies in the district heating supply of 30 % by 2030 in accordance with the Federal Government's National Energy and Climate Protection Plan (NECP).<sup>76</sup>
- Achieve a CHP electricity generation volume of at least 120 TWh<sub>el</sub> by 2025 in accordance with the target set in the current CHP Act.
- Achieve a share of CHP electricity generation in the controllable electricity generation of 40 to 45 % by 2030 according to the target recommendation in the report on the evaluation of cogeneration.<sup>77</sup>

First of all, we have derived a development path for future "CHP-capable" heat demand on the basis of extensive literature research.<sup>78</sup> This includes district heating demand in public supply systems, industrial CHP heat as well as CHP heat in other areas, in particular from decentralised object CHP units (combined heat and power plants) and decentralised bioenergy plants. As a result, Figure 2-6 shows a development that in the sum of district heating, CHP heat generation in industry and CHP in other sectors increases moderately compared to the current level by 2030.

While CHP heat generation in industry decreases moderately and CHP heat generation in other sectors decreases significantly by 2030, heat demand in district heating increases significantly by 2030 compared to the historical year 2018.

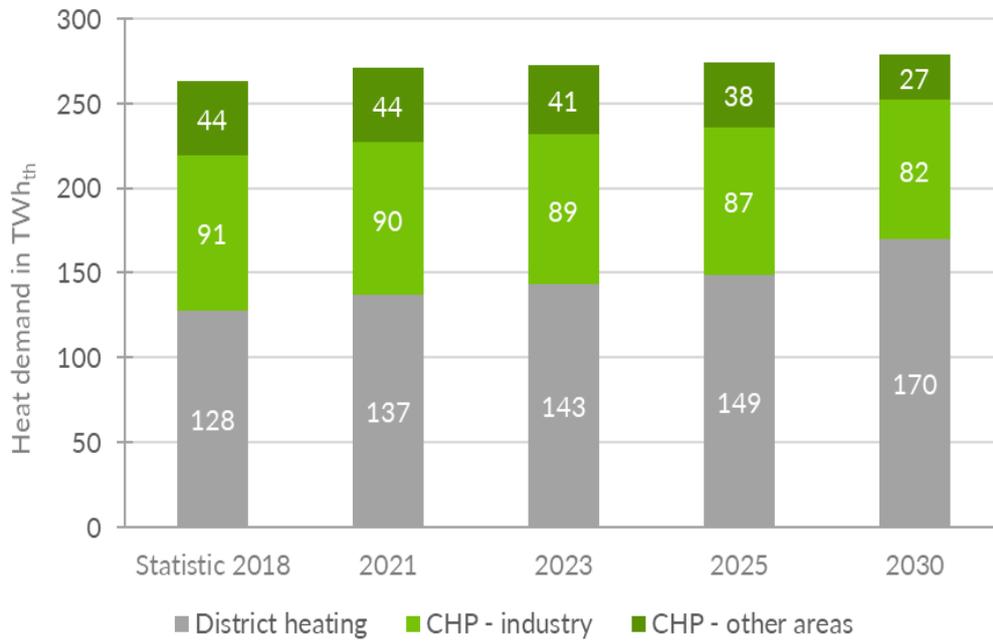
---

<sup>76</sup> Cf. BMWi (2019b).

<sup>77</sup> Cf. Prognos et al. (2019).

<sup>78</sup> The following sources, among others, were taken into account: AGFW (2018), BCG/Prognos (2018), FfE (2017), Fraunhofer ISI et al. (2017), Prognos et al. (2019).

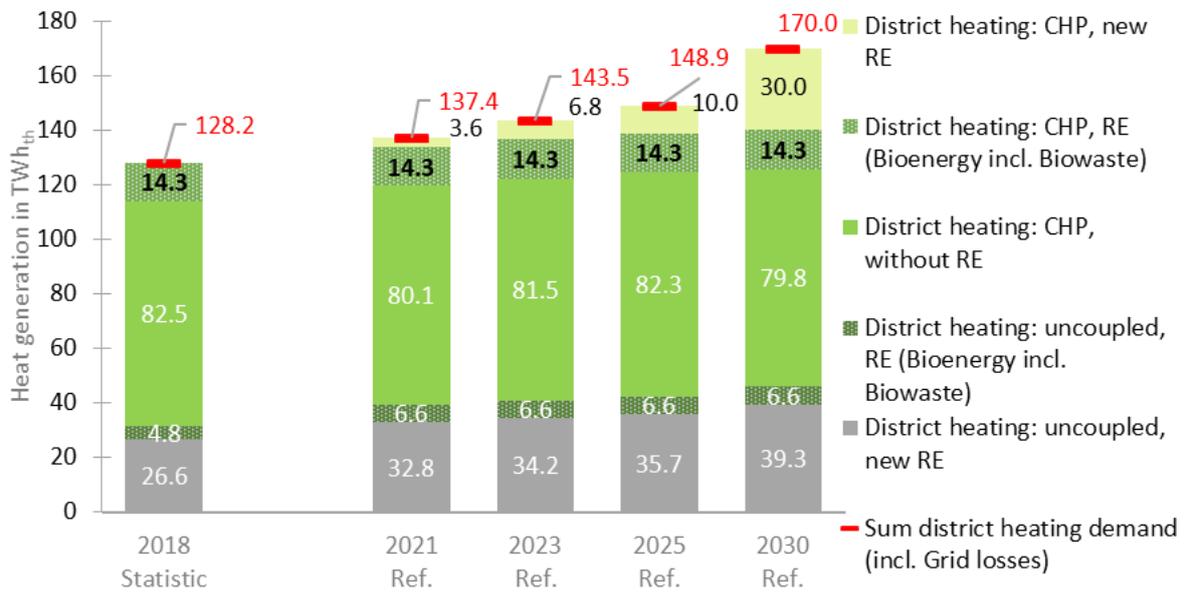
FIGURE 2-6: DEVELOPMENT OF CHP-CAPABLE HEAT DEMAND



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

In order to depict both the achievement of the RE expansion target of 30 % in district heating and the volume and share targets for CHP electricity, we have assumed a comparatively strong expansion of district heating systems. Figure 2-7 shows the resulting development and structure of heat generation in district heating. According to this, heat generation from CHP plants decreases only slightly despite the expansion of RE generation in district heating.

FIGURE 2-7: DEVELOPMENT OF DISTRICT HEATING GENERATION BY TECHNOLOGY



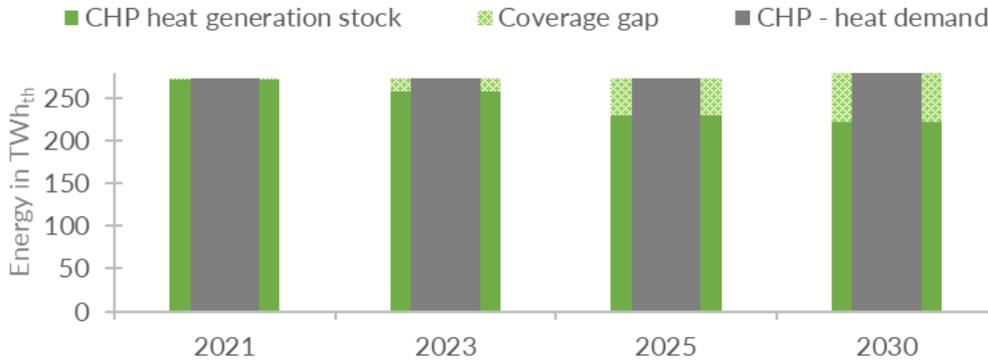
Source: Own representation based on research and calculations.

Based on this, we 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 as well as renewable heat technologies in the district heating systems.

Based on our power plant database and the assumptions made about CHP plant closures, we determine the CHP heat generation of existing plants over time. The starting point are the 2018 statistics on the total amount of CHP heat generation per fuel and application area (district heating/industry).

Due to the closures, a heat coverage gap arises that is covered in the model by newly added replacement CHP plants based on natural gas (cf. Figure 2-8).

FIGURE 2-8: ASSUMPTIONS ON THE DEVELOPMENT OF (RESIDUAL) CHP HEAT DEMAND IN GERMANY COMPARED TO 2020 ("EXISTING")

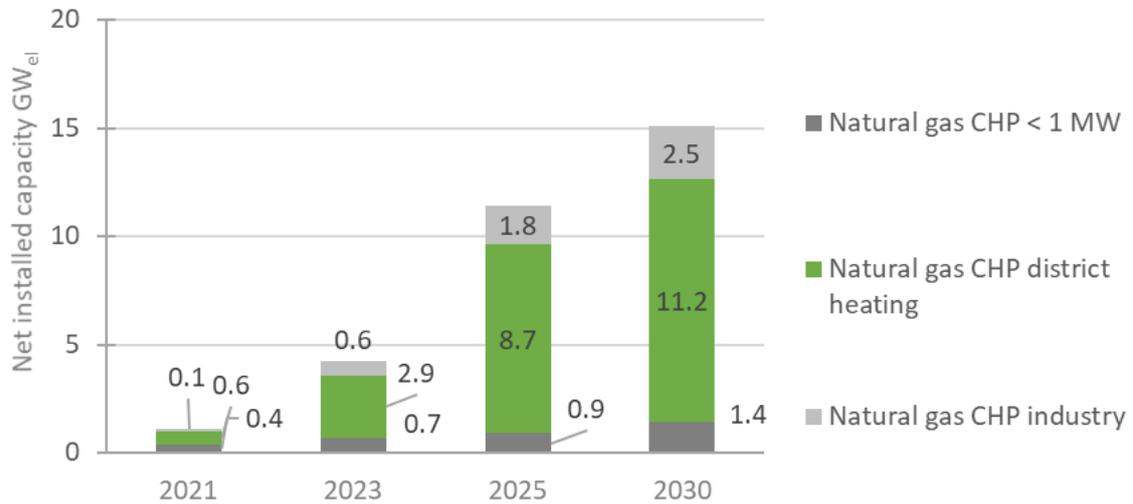


Source: Own calculations.

The heat generation quantities assigned to the individual power plant units are based on individual research about the CHP heat generation of the plants as well as assumptions about typical modes of operation depending on technical parameters and the design of the plants. The method for lignite-fired power plants with CHP heat generation forms an exception to this. For the allocation of CHP heat generation quantities for the lignite-fired power plant units, we have used the data in the study "The German Lignite Economy" by Agora / Ökoinstitut<sup>79</sup>, after checking the plausibility of the data. Assuming a realistic technology mix, typical output-related electricity ratios and utilisation rates of the plants in different areas, the coverage gap of heat generation results in the expansion shown in Figure 2-9, which is required to ensure a secure heat supply. Up to 2023, we have only accounted for known CHP new-build projects. Compared to 2020, this results in a cumulative gross addition of 15.1 GW of natural gas CHP plants by 2030.

<sup>79</sup> Cf. Ökoinstitut (2017).

FIGURE 2-9: ADDITION OF NEW NATURAL GAS CHP REPLACEMENT PLANTS COMPARED TO 2020 IN GERMANY (IN THE REFERENCE SCENARIO, CUMULATIVE)



Source: Own calculations.

In Germany, we differentiate between the following CHP application fields when deriving the expansion technology mix:

- District heating
- Industrial CHP
- Fossil-fired CHP units
- Bioenergy for building- or local heat-supply

For the new CHP replacement plants, we assume a realistic technology mix based on the assumption of electricity ratios and annual full load hours of heat generation. Table 2-1 assumed technology mix for CHP replacement plants based on natural gas for the different application areas.

TABLE 2-1: ASSUMPTIONS ON NATURAL GAS CHP REPLACEMENT PLANTS IN THE DIFFERENT FIELDS OF APPLICATION <sup>80</sup>

	Power-related electricity ratio	Power-related CHP electricity ratio	Energy-related CHP electricity ratio	Full load hours CHP heat in h/a
District heating	1.12	1.05	0.92	3750
Natural Gas CHP industry	0.65	0.65	0.65	5000
Local heat-supply	0.65	0.65	0.65	3500

Source: Own representation.

As a result, we get an addition of natural gas CHP replacement plants that

- is consistent with the assumptions of the residual heat demand,
- is consistent with the assumed decommissioning path / the existing decommissioning information on power plants,
- takes the known new CHP buildings into account, and
- represents a realistic scenario for replacement CHP technologies.

The **use of CHP plants** is differentiated between the CHP application fields. In the model, the CHP plants are used in largely heat-driven or flexible CHP operation, depending on the CHP plant technology. 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 electrode boilers and large heat pumps, which are used on the one hand for heat-side peak load coverage (exceeding the thermal CHP output), and on the

<sup>80</sup> The power-related electricity ratio describes the ratio between the nominal electrical power of the entire plant and maximum heat extraction. The power-based CHP electricity ratio describes the ratio between electrical output of the CHP slice and thermal output at maximum heat extraction. The work-related CHP electricity ratio describes the ratio between CHP electricity generation and CHP heat generation. The full load hours CHP heat describes the full load hours in relation to the amount of heat decoupled, i.e. at assumed maximum heat output.

other hand enable additional flexibility of the CHP plants when electricity prices are particularly high and low or negative.<sup>81</sup>

### Development of cogeneration in Europe

For the rest of Europe, we used basically the same methodology to determine CHP substitution as for Germany, although we did not make any additional differentiation between district heating, CHP in industry and CHP in other sectors due to the availability of data.

We have derived the residual heat demand on the basis of the data 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>82</sup>

In the development of the CHP heat output, we have assumed a development proportional to the development of the residual heat demand. Finally, the electrical output of the CHP plants is calculated on the basis of the technology assumptions for the electricity ratios of the CHP plants.

We have assumed a representative natural gas CHP technology as the CHP addition and CHP replacement technology in all countries. In Poland and the Czech Republic, we assumed in the first report that coal-fired CHP plants would also be added in the future. Due to a deterioration in the economic and political environment for coal, we assume in this report that decommissioned CHP plants in Poland and the Czech Republic will also be replaced exclusively by natural gas-fired plants.

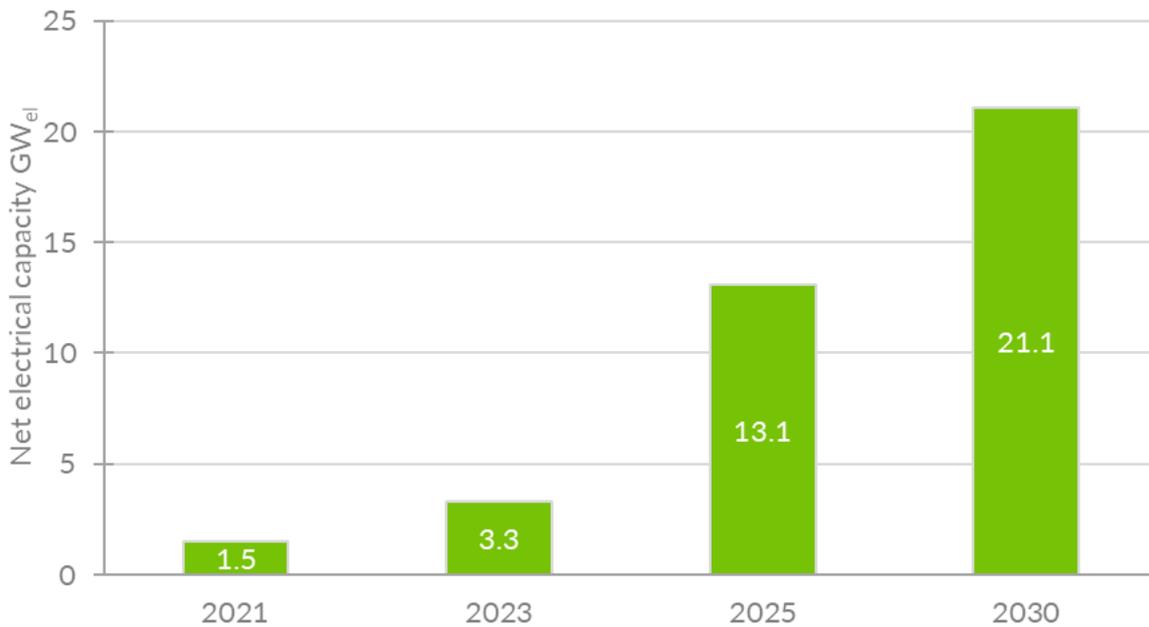
The resulting installed electrical capacity of new CHP plants, which mainly results from the replacement of old, decommissioned coal and gas CHP plants in the countries included in the analyses (except Germany), is shown in Figure 2-10.

---

<sup>81</sup> Thus, in the model, there is the possibility of a short-term increase in electricity generation from heat-driven plants in electricity-side shortage situations when electricity prices are high, based on the assumption of a bypass or an emergency cooler, or with flexibility to use the heat by means of heat storage.

<sup>82</sup> Cf. European Commission (2016c).

**FIGURE 2-10: CUMULATIVE ADDITION OF NEW CHP REPLACEMENT PLANTS COMPARED TO 2020 IN THE OTHER COUNTRIES CONSIDERED (WITHOUT GERMANY)**



Source: Own calculations.

This results in a gross increase in natural gas-fired CHP plants in other European countries of 21.1 GW by 2030.

In other European countries, we have also assumed a flexibilisation of CHP systems based on natural gas boilers and assume an increase in the number of Pth systems. Heat storage systems abroad were not modelled.

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

Since the development of RE enjoys a high political significance in all countries considered and the future expansion is accordingly significantly controlled by political decisions and requirements, we specify the assumptions on the development of RE exogenously to the model. In the following sections, we present our detailed assumptions on the expansion of RE and pumped storage power plants

in the electricity supply in Germany and the European countries considered in the modelling.<sup>83</sup>

### 2.3.1 Development of installed RE capacity in Germany

The scenario regarding the expansion of RE in Germany was developed together with the Federal Ministry of Economic Affairs and Energy. The development of installed capacity up to 2030 corresponds to the information in the Federal Government's Climate Protection Programme 2030<sup>84</sup> (assumptions for after 2030 are based on scenario B of the scenario framework for the Network Development Plan (NDP) 2021-35 approved by the BNetzA.<sup>85</sup> In particular, the expansion target defined in the coalition agreement<sup>86</sup> for the 19th legislative period was assumed to be met by 2030. According to this, the share of renewable energies in gross electricity consumption is to increase from approx. 42 % in 2019<sup>87</sup> to 65 % by 2030.

The development of the installed capacity of the individual RE technologies in Germany is shown in Table 2-2. The figures for the installed capacity of the respective technologies take into account both assumptions on the construction and decommissioning of RE plants. The values refer to the end of the year in each case.

Based on this, the installed capacity of **onshore wind energy** will increase by approx. 30 % between 2019 and 2030. In the coming years, the expansion of onshore wind energy will be based on the tendering regime stipulated in the EEG. Due to the phasing out of subsidies for older existing plants, increasing decommissioning of wind turbines in Germany is assumed from 2021 onwards. From

---

<sup>83</sup> Electricity generated in pumped storage power plants is only considered renewable energy if it comes from natural inflow. In the following section 2.3.2 only the electricity generated in pumped storage power plants with natural inflow is taken into account to illustrate electricity generation. In order to illustrate the installed capacity, however, the capacity of all pumped storage power plants is taken into account, i.e. also those pumped storage power plants that do not have a natural inflow.

<sup>84</sup> Cf. BMWi (2020a).

<sup>85</sup> Cf. BNetzA (2020a).

<sup>86</sup> Cf. CDU, CSU and SPD (2018).

<sup>87</sup> Cf. BMU (2019).

2021 onwards, an average annual gross expansion<sup>88</sup> of 3.5 GW is assumed for onshore wind energy.

TABLE 2-2: DEVELOPMENT OF THE INSTALLED CAPACITY OF RENEWABLE ENERGIES IN GERMANY (END OF YEAR)

Installed capacity [GW]	2019*	2021	2023	2025	2030
Wind Onshore	53.3	54.1	54.4	57.1	69.0
Wind Offshore	7.5	8.3	9.5	10.8	20.0
PV	49.0	58.2	67.1	76.0	98.0
Biomass	9.3	9.1	8.7	8.5	9.5
- of which share of biog. Waste	1.0	1.0	1.0	1.0	1.0
Water	5.6	5.6	5.6	5.6	5.6
Other RE	0.6	0.6	0.6	0.6	0.6
<b>Sum</b>	<b>125.2</b>	<b>135.9</b>	<b>145.9</b>	<b>158.5</b>	<b>202.6</b>

Source: Own representation. Statistical value according to BMWi (2020a).

The installed capacity of **offshore wind energy** is also assumed to increase significantly, reaching 20 GW in 2030. It is assumed that, in addition to the 15 GW expansion of offshore wind energy envisaged in the EEG 2017, a further 5 GW will be added by 2030.

In addition to wind energy, a significant expansion is also assumed for **photovoltaics** during the period under consideration. By 2030, an expansion of around 50 GW is assumed compared to 2019. Analogously to onshore wind energy, the additional tenders envisaged in the coalition agreement are also assumed for photovoltaics. From 2021, a gross annual expansion of 4.5 GW is assumed.

<sup>88</sup> The gross addition is defined as the addition of all plants, regardless of whether a plant is erected at a new location or replaces an older existing plant. In contrast, net additions also take into account decommissioning. The net addition thus reflects the change in installed capacity.

The installed capacity of **bioenergy plants** in 2019 was approx. 9.3 GW (incl. biogas share of waste in the amount of 1 GW). In 2023 and 2025, there will be a greater number decommissionings due to the increased expiry of EEG subsidies for old existing plants with an operating time of more than 20 years. At the same time, we take into account an increasing flexibilisation of biomass electricity generation in newly built plants. This is implemented by assuming a so-called "capacity over-development" in the amount of an additional 50 % of the originally assumed new construction. We assume this over-development from 2024 onwards. If all effects are aggregated, this results in an installed capacity of 8.5 GW of bioenergy plants in 2025 (incl. share of biowaste). By 2030, the installed capacity of bioenergy increases slightly again and then amounts to approx. 9.5 GW.

The installed capacity of **hydropower**<sup>89</sup> remains largely constant over the entire period under consideration at 5.6 GW. It is assumed that no additional plants will be built on a relevant scale in Germany due to high licensing hurdles, a lack of economic efficiency, acceptance problems and limited potential. At the same time, we assume that plants in need of refurbishment will be upgraded.

Other renewable energies include landfill and sewage gas as well as geothermal plants and biogenic waste. While increased closures are expected for landfill gas plants due to the increasing outgassing of landfills, a moderate increase is assumed for sewage gas and geothermal energy. Overall, the total installed capacity of other RE in Germany will remain constant until 2030.

### **2.3.2 Development of RE generation in Germany**

We use simulation models to determine the hourly infeed and the resulting annual electricity generation quantities of the supply-dependent RE onshore and offshore wind energy and PV. These models are used to derive generation hydrographs for the corresponding RE technologies, taking into account the assumed development of installed capacities in future years.<sup>90</sup> This is done on the basis of

---

<sup>89</sup> The values given here for hydropower include run-of-river and storage hydropower plants with natural inflow.

<sup>90</sup> In principle, forecasts up to the year 2050 can be carried out within the framework of the simulation model.

temporally and regionally high-resolution data on meteorological conditions (including 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 generation hydrographs and electricity generation quantities for run-of-river plants are based on historical, aggregated feed-in hydrographs.<sup>91</sup> The historical weather years 2009 to 2013 and 2017 were used as the data basis.

Table 2-3 development of electricity generation based on RE in Germany. According to this, RE generation increases from around 243 TWh in 2019 by around 53 % to 372 TWh in 2030.

For **onshore wind energy**, electricity generation increases more strongly compared to 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. For **offshore wind energy** and **photovoltaics**, capacity utilisation remains largely constant over the years under consideration.

---

<sup>91</sup> For a detailed description of the calculation of generation hydrographs of the supply-dependent technologies, see r2b / Consentec (2019) Appendix D.

TABLE 2-3: DEVELOPMENT OF ELECTRICITY GENERATION FROM RENEWABLE ENERGIES IN GERMANY

Expected electricity generation [TWh]	2019*	2021	2023	2025	2030
Wind Onshore	101.1	95.4	97.23	105.3	134.6
Wind Offshore	24.7	32.4	37.5	42.9	77.9
PV	46.4	52.8	61.2	69.6	90.5
Biomass	48.2	50.1	48.43	46.9	45.1
- of which solid/ liquid/ gaseous Biomass					
Biomass	42.4	44.1	42.4	40.9	39.1
- of which share of biog. Waste	5.8	6.0	6.0	6.0	6.0
Wasser	20.5	22.3	22.3	22.3	22.3
Other RE	2.0	2.5	2.5	2.5	2.5
Estimated RE curtailment	0.0	0.0	0.0	0.0	-0.7
<b>Sum</b>	<b>242.9</b>	<b>255.5</b>	<b>269.2</b>	<b>289.6</b>	<b>372.3</b>

Source: Values 2023-2030 based on own calculations for weather years 2009-2013 and 2017. \* Statistical value according to BMWi (2020a).

The utilisation rate of **bioenergy** decreases due to the assumption that newly added bioenergy plants have a lower utilisation rate than existing plants due to the assumed "capacity over-development". This is to be expected mostly due to the current subsidies under the Renewable Energy Sources Act (EEG), as these encourage increased flexibility in the case of new constructions or plant expansions, which is to be achieved by decreasing capacity utilisation. For (small) bioenergy plants, the generation structure is based on historical values. However, these plants can feed in at nominal capacity during individual price peaks on the electricity market.

Electricity generation from **hydropower**<sup>92</sup> remains constant over time, as we do not expect an increase in installed capacity. The reason for the lower electricity

<sup>92</sup> The values given here for hydropower include run-of-river, reservoir and pumped storage power plants with natural inflow.

generation in Table 2-3 in 2019 is that this is a historically measured value, whereas for the forecast years the average electricity generation is shown over the six water condition years considered, 2009 to 2013 and 2017.

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

### **2.3.3 Development of storage and pumped storage power plants in Germany and their balancing DE / AT**

In 2020, around 6.7 GW of storage and pumped storage power plants were installed on the territory of the Federal Republic of Germany.<sup>93</sup> In the context of these analyses, we assume that this value will remain constant until 2030. For the modeling in this project report and in deviation from the first project report, we have recently taken into account a regional distinction on the basis of European market areas and not an accounting on the basis of national borders. This means that in this report we allocate 3.3 GW of storage and pumped storage power plants from Austria, which feed into to the German market area grid. Accordingly, we show 3.3 GW less storage and pumped storage capacity in Austria compared to the first project report.

### **2.3.4 Development of renewable energies in Europe**

The forecast development of renewable energies in the other European countries considered outside Germany (neighbouring countries bordering Germany as well as the Scandinavian countries, Great Britain and Italy)<sup>94</sup> is based on the ENTSO-E "National Trends" scenario for the TYNDP 2020 for the supply-dependent RE technologies photovoltaics, onshore wind energy and offshore wind energy.<sup>95</sup>

The starting point for the installed capacity for hydropower is the extensive database on hydropower in Europe by r2b energy consulting GmbH. The data on hy-

---

<sup>93</sup> Cf. BNetzA (2020b).

<sup>94</sup> Since 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>95</sup> Cf. ENTSO-E (2020a).

dropower includes run-of-river power plants as well as storage and pumped storage power plants with and without natural inflow. The addition of storage and pumped storage power plants is based on ENTSO-E's<sup>96</sup> *TYNDP 2020 Project List* and our own research.

The development of the installed capacity of bioenergy and other renewable energies is also based on ENTSO-E's "*TYNDP 2020 National Trends*" and supplementary research of our own.<sup>97</sup>

Figure 2-11 shows the development of the installed capacity of renewable energies<sup>98</sup> and pumped storage aggregated across the countries considered outside Germany. According to this, the installed capacity of renewable energies including pumped storage power plants increases from around 348 GW in 2021 to 558 GW in 2030. In absolute terms, the installed capacities of photovoltaics and onshore wind energy in particular will increase. In addition, however, the energy sources offshore wind and bioenergy can also record significant increases.

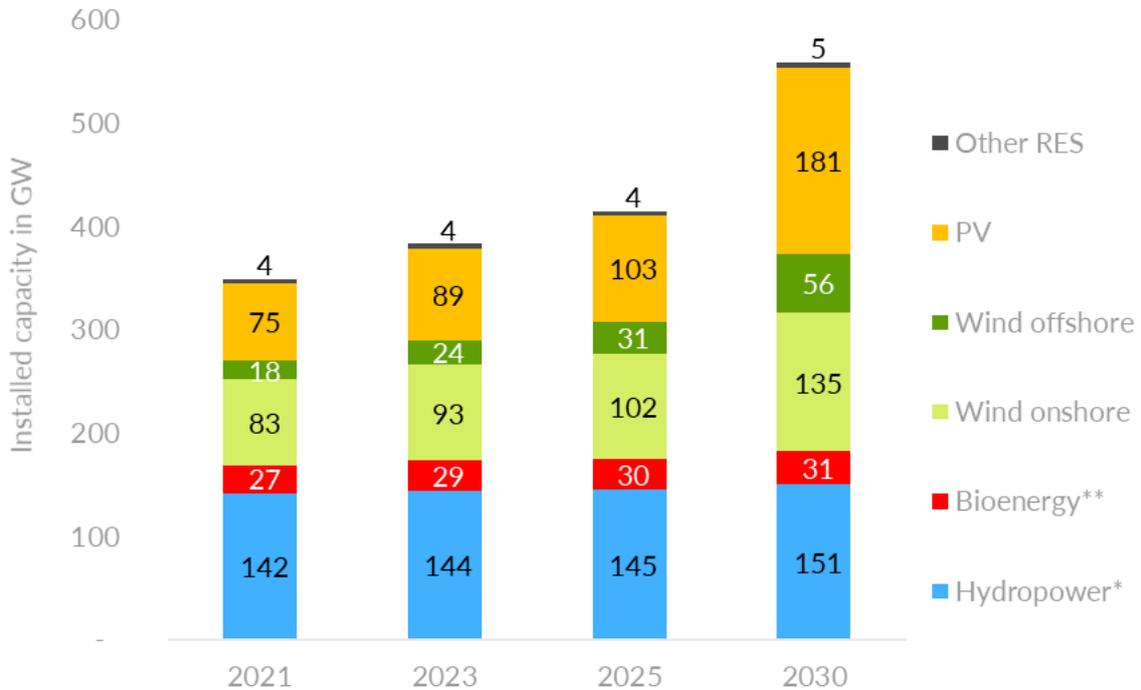
---

<sup>96</sup> Cf. ENTSO-E (2020b).

<sup>97</sup> Cf. European Commission (2016d).

<sup>98</sup> In addition to renewable energies, Figure 2-11 also includes the installed capacity for pumped storage power plants without natural inflow.

**FIGURE 2-11: DEVELOPMENT OF AGGREGATED INSTALLED CAPACITY OF RENEWABLE ENERGIES IN THE COUNTRIES CONSIDERED EXCLUDING GERMANY**



\* incl. pumped storages with natural inflow  
 \*\* incl. biogenic waste

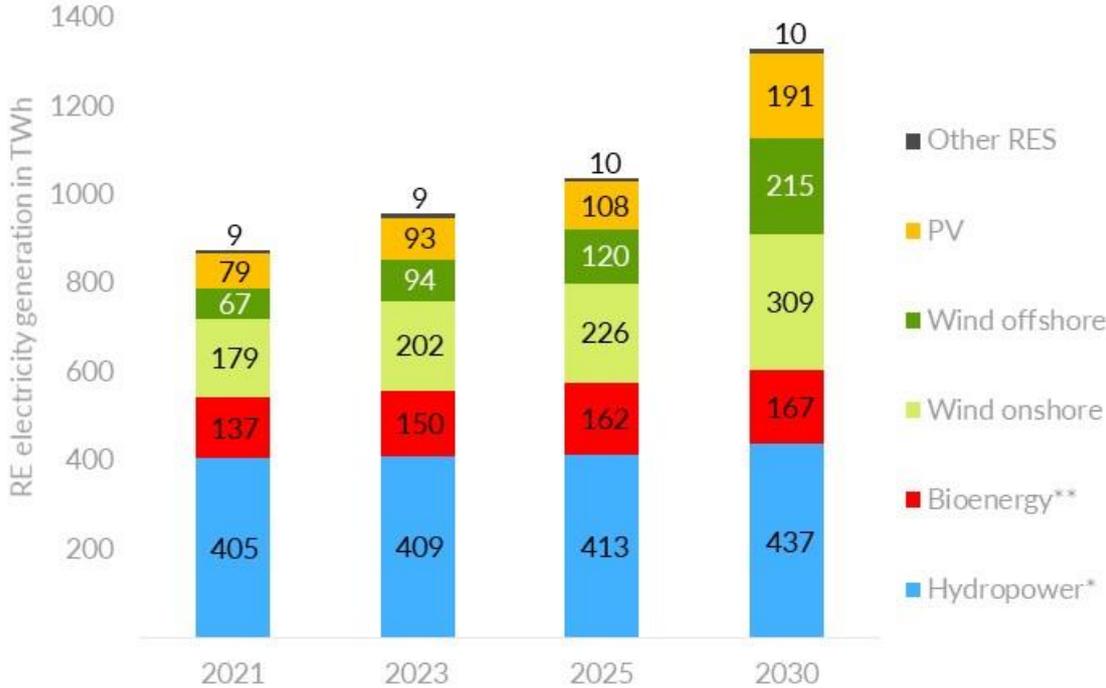
Source: Own presentation based on ENTSO-E (2020a) and own calculations.

Figure 2-12 shows the development of RE electricity generation volumes aggregated across the countries considered, excluding Germany, on the basis of installed capacity. For the technologies onshore wind energy, offshore wind energy and photovoltaics, own calculations based on the detailed RE model of r2b energy consulting GmbH (taking into account high-resolution weather data as well as detailed technical parameters and regional distribution), were carried out to determine the electricity generation volumes in analogy to the methodology in Germany.<sup>99</sup> For hydropower, the data includes electricity generation from 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 as well

<sup>99</sup> For a detailed description of the calculation of generation hydrographs of the supply-dependent technologies, see r2b / Consentec (2019), Appendix D.

as on the generation based on natural inflows of the storage and pumped storage power plants for the years 2009 to 2013 and 2017.

**FIGURE 2-12: DEVELOPMENT OF AGGREGATED ELECTRICITY GENERATION FROM RENEWABLE ENERGIES IN THE COUNTRIES CONSIDERED EXCLUDING GERMANY**



\* incl. pumped storages with natural inflow  
 \*\* incl. biogenic waste

Source: Own calculations.

Accordingly, the electricity generation volumes in the countries considered excluding Germany increase from around 876 TWh in 2021 to 1,329 TWh in 2030. The growth is in line with the installed capacity, in particular due to the expansion of onshore wind energy, offshore wind energy, photovoltaics and bioenergy.

**2.4 Development of flexibility options**

In the electricity market model, different flexibility options are taken into account in addition to the different generation plants (conventional, CHP, renewable), as

described in the first project report.<sup>100</sup> In addition to the depiction of partially flexible "new consumers" (cf. Section 2.5.4), this includes, on the generation side, usable potentials of emergency power systems, which are kept in many consumption facilities to protect particularly vulnerable consumers against local grid failures (cf. Section 2.4.1). As a flexibility option on the consumption side, we also take into account voluntary load reduction potential in industry (cf. Section 2.4.2.).

### **2.4.1 Emergency power systems**

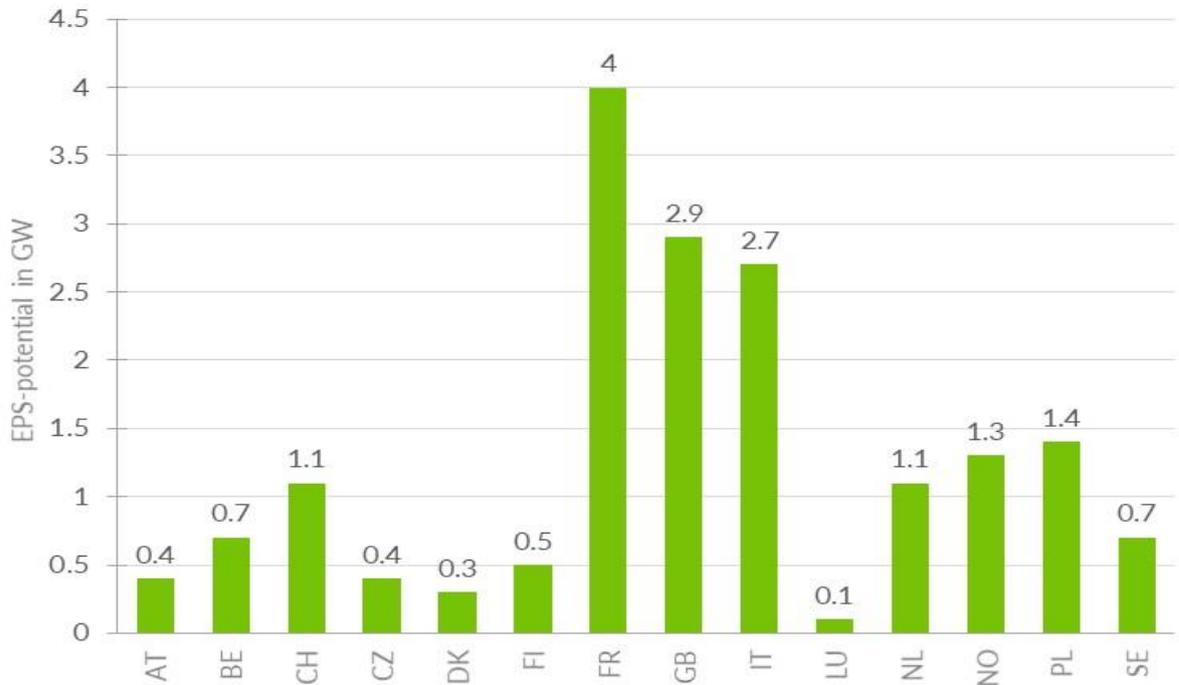
Emergency power systems (EPS), which are used to provide emergency power in case of (local) supply interruptions, usually consist of a diesel or natural gas powered engine and a generator. In the event of a (local) supply interruption, e.g. due to the failure of a grid resource, essential infrastructure facilities or processes for which a power failure would cause significant material or immaterial damage are securely supplied with the help of such EPS until the supply from the power grid is restored. Analogous to the explanations in the first project report, we have assumed that the economically feasible installed capacity in EPS in Germany is in the order of 4.5 GW.

The following figure provides an overview of the assumptions regarding the economically viable potentials in the foreign countries considered, which were again applied analogously to the explanations in the first project report. In total for all countries considered (excluding Germany), the developable capacity of EPS amounts to 17.7 GW.

---

<sup>100</sup> Cf. r2b / Consentec (2019) Section 4.4.

FIGURE 2-13: ECONOMICALLY EXPLOITABLE EMERGENCY POWER SYSTEM POTENTIAL IN 2021 IN THE FOREIGN COUNTRIES CONSIDERED



Sources: Own research and assumptions

For emergency power systems, we have assumed the following variable and fixed operating costs as well as development costs in a conservative approach similar to the first project report:

- **Variable operating costs:** The starting point is the price of light heating oil (HEL) with an assumed EPS efficiency of 30 % and a 50 % surcharge for start-up and shut-down costs.
- **Fixed annual operating costs:** € 5,000 p.a. per MW <sup>101</sup>
- **Development costs:** € 20,000 per MW <sup>102</sup>

<sup>101</sup> This assumption does not correspond to our *best-guess*, which we developed on the basis of information from discussions with marketers of emergency power systems. In the reference scenario of the first project report (cf. r2b / Consentec 2019), we applied higher and thus more conservative fixed annual operating costs in agreement with the BMWi. In our *best-guess cost assumptions*, whose influence on the results of the endogenous scenario and the RA analyses we examined in a sensitivity analysis in the first project report, the fixed annual operating costs amount to €3,000 per MW. See also r2b / Consentec (2019) Section 4.1.

<sup>102</sup> Assumption based on information from discussions with marketers of emergency power systems. These are, for example, costs for the grid connection and / or for upgrades to ensure permissible parallel grid operation.

## 2.4.2 Voluntary load reduction in the industry

The strongly increasing shares of electricity generation from supply-dependent renewable energies not only put the supply side, i.e. the conventional power plant park, under pressure to adapt, but also stimulate the flexibilisation of demand. For the efficient integration of renewable energies into the market and from a business management point of view of the companies, an increasing flexibilisation of demand based on market mechanisms is a sensible option to increase competitiveness. In addition, potential price peaks can be reacted to or their cost risks can be hedged.

We consider the potential for voluntary load reduction by industry in the same way as in the first project report.<sup>103</sup> In the second project report, we also assume that the technically available potentials can be fully exploited economically by 2030. As a development path for the share of economically exploitable potentials in the technically available potentials, we assume around 57 % in 2021, 75 % in 2023, 84 % in 2025 and 90 % from 2030.<sup>104</sup>

Within the framework of this project, we have adjusted both the technically available and the economically feasible potentials of the individual economic sectors for the key years considered to the respective forecast annual consumption of the industries<sup>105</sup> over time. This means that the load reduction potentials rise or fall on an annual basis with the total demand of an industry. As a result, we assume total potentials in Figure 2-14 that the electricity market model can economically develop within the framework of the simulation calculations.

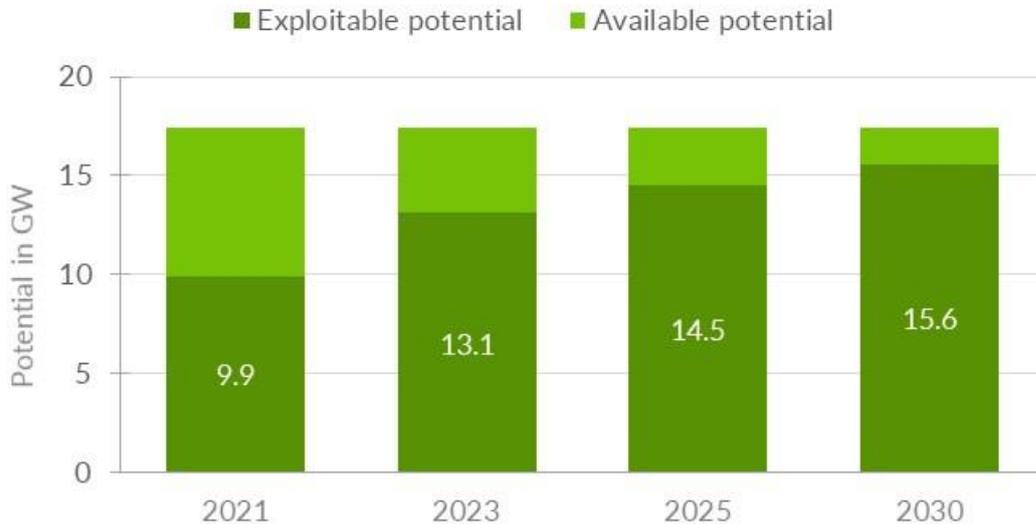
---

<sup>103</sup> Cf. r2b / Consentec (2019) Section 4.4.2.

<sup>104</sup> These are the maximum shares of the technically available potentials that can be exploited in the electricity market model within the framework of the simulation calculations for economic reasons.

<sup>105</sup> For the derivation of electricity demand, see Section 2.5

FIGURE 2-14: ECONOMICALLY EXPLOITABLE LOAD REDUCTION POTENTIAL OF INDUSTRY IN GERMANY FOR 2021, 2023, 2025 AND 2030



Sources: Own representation.

The preliminary results of the monitoring of the contribution of load management to resource adequacy in the electricity sector carried out by the BNetzA in cooperation with the BMWi also support these assumptions on load reduction by industry. As part of this monitoring pursuant to Section 51a of the Energy Industry Act, all companies with a total electricity consumption of at least 50 gigawatt-hours (GWh) across all of their consumption points in the past calendar years are surveyed at least once a year about their load management potential and possible obstacles. We have the results of the survey rounds from 2017, 2018 and 2019.<sup>106</sup>

The preliminary results for the years 2017 and 2018 of the evaluation with regard to a load reduction for one hour show that extensive potentials for voluntary, market-based load reduction by industry have been tapped but are still unused. The ‘tapped but untapped’ potentials of flexible business locations<sup>107</sup> amount to

<sup>106</sup> A detailed account of the methodology and final results of the analysis of the 2017, 2018 and 2019 survey rounds is expected to be published in the first half of 2021.

<sup>107</sup> These potentials are still untapped, as the current wholesale prices on the electricity market do not encourage their use.

approximately 2 GW, depending on the survey year considered.<sup>108</sup> In addition, we have estimated those potentials that have not yet been tapped. According to our estimate, the untapped potential of inflexible company locations<sup>109</sup> amounts to approx. 4.7 to 4.9 GW, depending on the survey year considered. By determining the coverage rates of the surveyed company locations, we have extrapolated the determined potentials approximately to the entire sector.<sup>110</sup> The extrapolation to the entire sector increases the tapped but still untapped potential of flexibilised business locations from about 2 GW (certain tapped potential) to about 3.4 to 3.6 GW (probable tapped potential). In addition, the estimate of the untapped potential of still inflexible business locations increases from about 4.7 to 4.9 GW to 14.6 to 16 GW when extrapolating.

In agreement with the BMWi, we have also assumed more **conservative cost assumptions** in this project report compared to our "best guess" assumptions in the area of flexibility options (voluntary load reduction by industry and emergency power systems) and have set annual fixed costs of €8,000 per MWa for voluntary load reduction.<sup>111</sup>

The assumptions used in our quantitative analyses for this second project report regarding economically feasible load reduction potential in the European countries considered for the years 2021 and 2030 are identical to those of the first project report and can be seen in Figure 2-15.<sup>112</sup> In total, across all countries considered (excluding Germany), the developable capacity of voluntary load reduction amounts to 31 GW in 2021 and 54 GW in 2030.

---

<sup>108</sup> In the first project report on RA monitoring, we estimated slightly different potentials of approx. 2.5 GW. The differences are due to a methodological refinement. Cf. r2b / Consentec (2019).

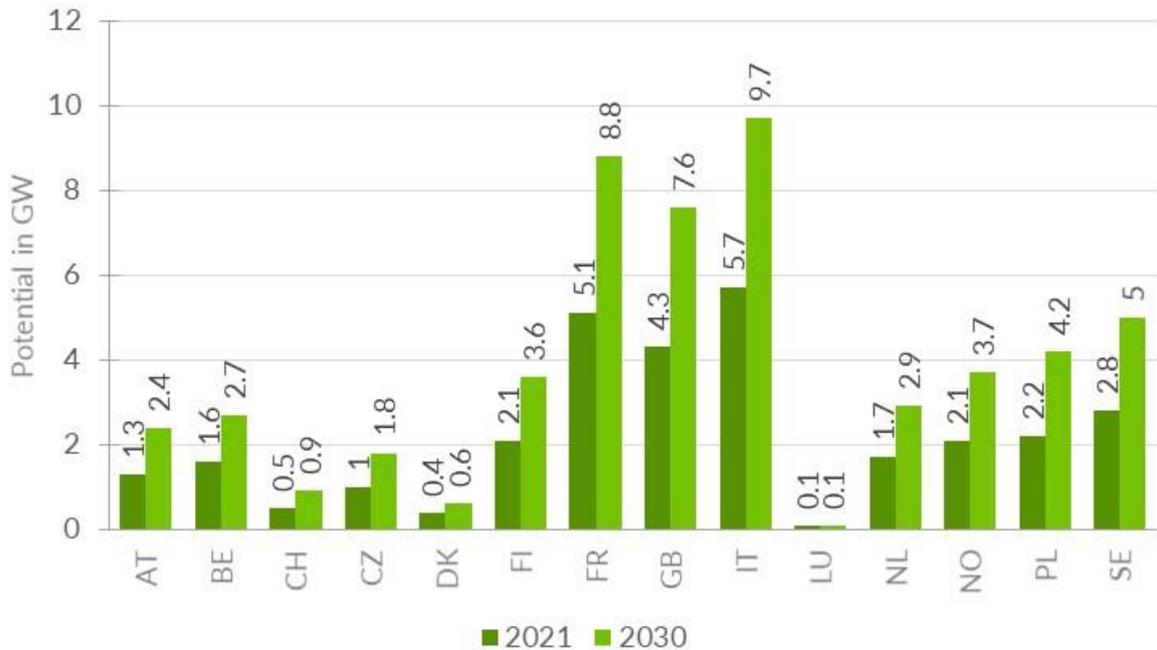
<sup>109</sup> Inflexible business locations are those locations for which it was stated that they are currently not load-flexible in relation to the wholesale electricity price.

<sup>110</sup> Here we have made the assumption of structurally identical load management potentials at the company (locations) not included in the data survey.

<sup>111</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 totalling € 4,000 / MWa.

<sup>112</sup> Cf. r2b / consentec (2019).

FIGURE 2-15: ECONOMICALLY EXPLOITABLE LOAD REDUCTION POTENTIALS IN 2021 AND 2030 IN THE COUNTRIES CONSIDERED (EXCLUDING GERMANY)



Sources: Own research and assumptions.

## 2.5 Development of electricity demand

In addition to depicting the generation-side supply options and load-side flexibility options as realistically as possible, it is important for the analysis to estimate the development of electricity demand as realistically as possible. Based on a forecast of the development of annual electricity consumption differentiated by application areas (cf. Section 2.5.1) and the development of the transformation sector (cf. Section 2.5.2), we derive the development of hourly electricity demand (cf. Section 2.5.3). The conversion sector also includes the large-scale sector coupling technologies in the area of *power-to-X*, i.e. *power-to-gas* (PtG) as well as *power-to-heat* (PtH). Subsequently, in Section 2.5.4 assumptions we have made for the development of electricity demand from so-called *new consumers* (load-side flexibility). New consumers in the context of this study are central sector coupling technologies to the areas of heat and transport, whose electricity demand is partially flexible under certain conditions. This includes electric heat pumps, electric mobility and OH trucks.

## 2.5.1 Development of final electricity consumption

### Methodological approach

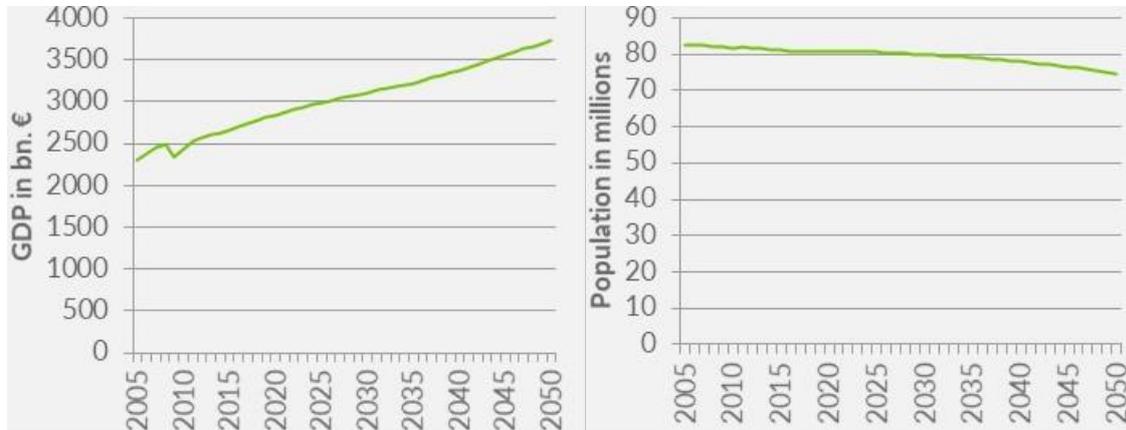
The bottom-up model FORECAST is used for the analysis of future sectoral electricity demand. FORECAST is a techno-economic simulation model that exploratively describes the annual energy and electricity demand in Germany and neighbouring European countries at a high level of technological granularity (Fraunhofer ISI, 2018). The model is modular and structured according to the sectors households, tertiary sector, industry and transport in order to reflect the heterogeneity of the individual sectors accordingly; for example, while the industry sector focuses on processes, the household sector focuses on individual applications. The main electricity-based sector coupling options in this study are heat pumps, electromobility in passenger transport and OH trucks.

With regard to the methodological design, FORECAST is characterised by an extensive consideration of structural and technological change. Structural change is modelled using exogenous framework parameters (e.g. sectoral gross value added), while technological change is described using both epidemic and discrete choice approaches. Despite a focus on electricity-based applications, non-electricity-based energy sources are also modelled 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 of the first project report.

### Frame parameters

The input data for the techno-economic demand model can be divided into cross-sectoral and sector-specific drivers. Cross-sectoral input data are population development and economic development (gross domestic product and sectoral gross value added). Figure 2-16 shows the development of the population and the gross domestic product, which are taken from the EU Reference Scenario 2016 (EU 2017). Here, an annual economic growth of 1.8 % on average and a decline of the population to a level below 75 million in 2050 is assumed. Further cross-sectoral input data are energy carrier prices and CO<sub>2</sub> prices, which are discussed in Section 2.6.2.

FIGURE 2-16: CROSS-SECTORAL DRIVERS OF ENERGY DEMAND (POPULATION AND GDP IN GERMANY) FOR THE PERIOD 2005 TO 2050 (EU 2017).



Sources: EU (2017)

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

In the industrial sector, the central framework data is the production volume in tonnes per product, which is derived from the sectoral value added. In principle, moderate economic growth is assumed, with energy-intensive industries growing less strongly. Further sector-specific input data for the modelling of the industrial sector are the employees per subsector. 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 variables. The number of households or buildings is derived from the level of the population and a trend towards fewer persons per household. Furthermore, an increase in the equipment rates of ICT applications is assumed. For household appliances, the minimum efficiency standards will be further tightened and new efficiency classes will be introduced. The main influence on heat demand in buildings is due to renovation measures. For this, an increase in the renovation rate to 1.8 % is specified, while the depth of renovation is determined model-dependent. A tightening of

the guidelines (e.g. EEWärmeG) and further promotion of renovation measures (e.g. KfW programme) are assumed.

In the tertiary sector, economic development is described by gross value added and the number of employees in the individual subsectors. In line with actual developments, the projection also assumes stronger economic growth than for the manufacturing sector. The main technological trend in the tertiary sector is the increasing mechanisation as well as the increase in ICT-based electricity applications (e.g. servers). The heat demand is determined in a similar way to the household sector using a predefined renovation rate and an endogenously determined renovation depth.

The development of electricity demand in the transport sector is mainly driven by the proliferation of electric drives 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 transport, overhead lines are being built on the busiest stretches of motorways in Europe, leading to the proliferation of hybrid overhead line (OH) trucks in freight transport. The utilisation of freight and passenger rail transport will increase moderately, corresponding to the further electrification of new lines.

## Results

The starting point for the explorative analysis is the historical development of electricity demand, which is used as the basis for calibration: For Germany, the statistics of the AG Energiebilanzen (AGEB 2019) and for the neighbouring countries from Eurostat (Eurostat 2019a) are used. The system boundary is always the demand in the household, tertiary, industry and transport sectors.

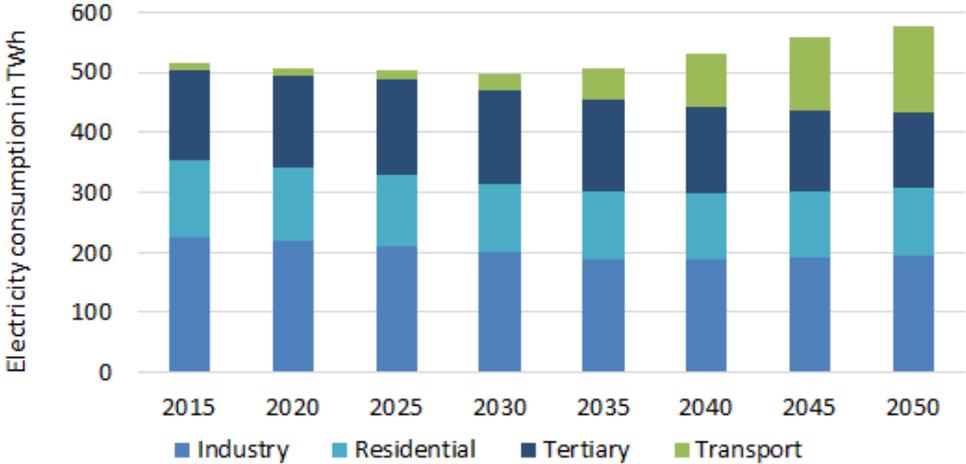
In the following, the cross-sectoral results of the national electricity demand until 2030 are discussed, supplemented by an outlook until 2050. This is followed by an analysis of the main developments in the sectors industry, households, tertiary sector and transport.

### *Electricity demand across sectors*

The development of annual electricity demand until 2050 is shown in Figure 2-17. Until 2030, there is a decrease in electricity demand (- 3 % compared to 2015 /

499 TWh in 2030), which is mainly due to the increase in efficiency of traditional consumers (e.g. efficiency gains in industrial cross-section technologies). From 2030 onwards, there is an increase in electricity demand driven by the penetration of new technologies, especially in the transport sector and heat pumps (+ 12 % compared to 2015 / 578 TWh in 2050). This change in trend from 2030 onwards leads to a characteristic curve of the aggregated electricity demand, which makes it clear that a simplified extrapolation for the years 2030 to 2050 is not appropriate.

**FIGURE 2-17: SECTORAL ELECTRICITY DEMAND FOR THE PERIOD 2015 TO 2050(OWN CALCULATIONS).**



Sources: Own calculations.

In Table 2-4 the results are broken down sectorally by classic applications and new applications for the reference period until 2030. Heat pumps play only a very minor role in industry until 2030, in contrast to residential and non-residential buildings. In transport, demand increases by 2030 due to the rising stock of electric cars and OH trucks.

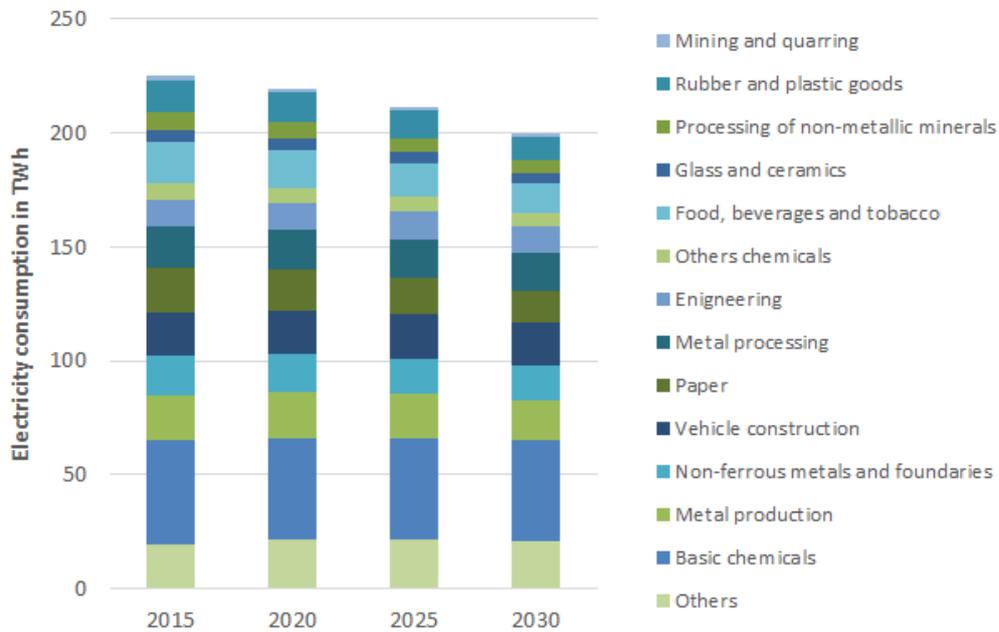
TABLE 2-4: SECTORAL ELECTRICITY DEMAND IN 2020 AND 2030, AND BREAKDOWN BY TRADITIONAL AND NEW APPLICATIONS (HEAT PUMP AND ELECTROMOBILITY).

TWh	2020			2030		
	Total	Classic applications	New applications	Total	Classic applications	New applications
Households	123.2	110.8	12.4	114.6	98.4	16.3
GHD	152.6	148.4	4.3	156.1	149.7	6.4
Industry	219.6	219.6	0	199.5	199.5	0
Traffic	12.2	11.5	0.8	28.5	11.4	17.1
Total	507.6	490.2	17.4	498.8	458.9	39.8

#### *Electricity demand industry*

Electricity demand decreases continuously until 2030 (Figure 2-18). The main decline in electricity demand is due to the efficiency progress in motor-based cross-sectional technologies (e.g. pumps, compressed air). Substitution effects in process technologies towards electricity-based applications (e.g. electric steel), on the other hand, only lead to an increase in electricity demand to a limited extent. The use of heat pumps plays only a negligible role in the generation of space and process heat in the industrial sector. Overall, the electricity demand of energy-intensive industries (e.g. steel, cement and paper production) decreases more than the electricity demand of non-energy-intensive industries (e.g. mechanical engineering and vehicle construction).

FIGURE 2-18: ELECTRICITY DEMAND INDUSTRY BY SUBSECTOR FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION).

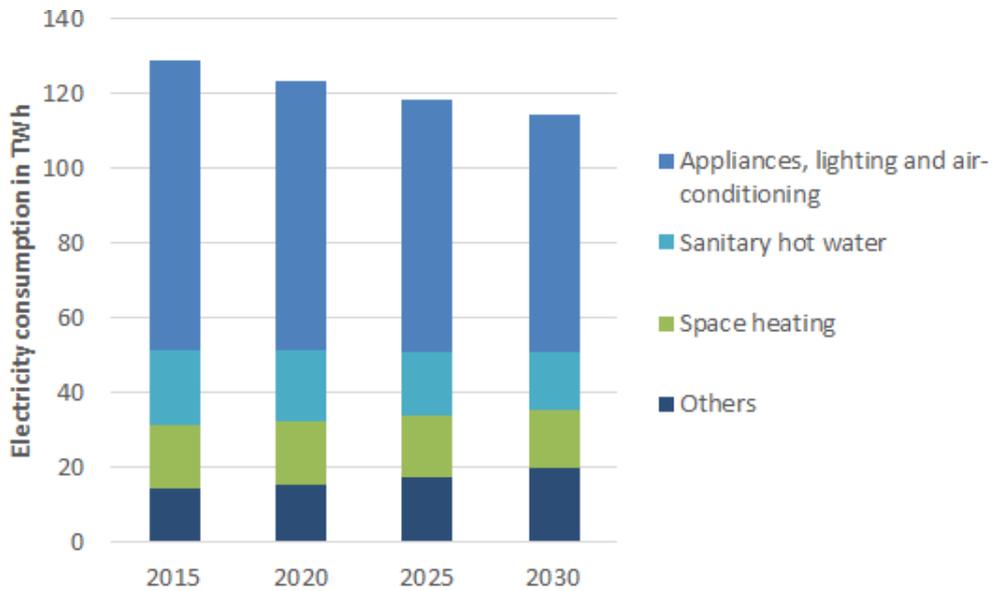


Sources: Own calculations.

### Electricity demand households

Electricity demand in the household sector is continuously decreasing until 2030. The largest change of electricity demand is due to large appliances and lighting (Figure 2-19). Due to the already implemented and planned guidelines on minimum efficiency standards, their specific electricity consumption is decreasing. Since appliances, especially white goods, are already close to market saturation, this directly decreases the absolute electricity demand. Applications such as electronic appliances and ICT applications lead to an increase in sectoral electricity demand due to an increase in equipment rates. In the electricity-based generation of hot water and space heating, electricity demand is almost constant until 2030, as old night storage heaters and inefficient boilers are phased out and heat pumps, on the other hand, achieve higher market shares.

FIGURE 2-19: ELECTRICITY DEMAND HOUSEHOLDS BY APPLICATION FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION) .

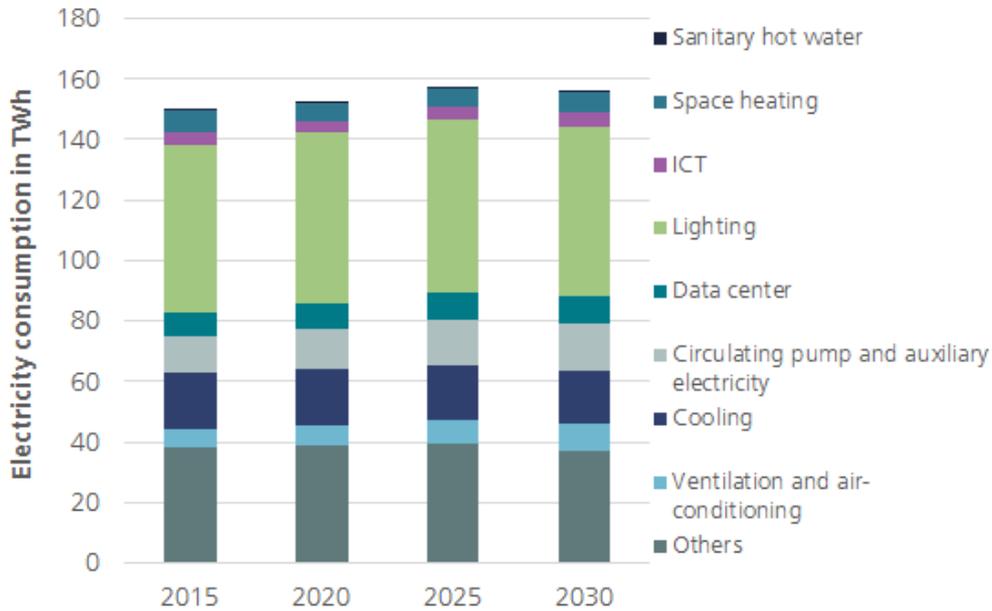


Sources: Own calculations.

#### Electricity demand GHD (trade, commerce and services)

In the tertiary sector, there is an increasing trend in electricity demand until 2025, with a slight decline thereafter (Figure 2-20). The increase in electricity demand is due to a growing trend towards mechanisation and an increasing equipment of non-residential buildings with ventilation or air conditioning. In contrast, efficiency gains in lighting in particular lead to an opposite trend in electricity demand. The share of electricity-based space heating and hot water supply by heat pumps amounts to 6.5 TWh in 2030.

FIGURE 2-20: ELECTRICITY DEMAND GHD BY SECTOR FOR THE PERIOD 2015 TO 2030 (OWN CALCULATION).

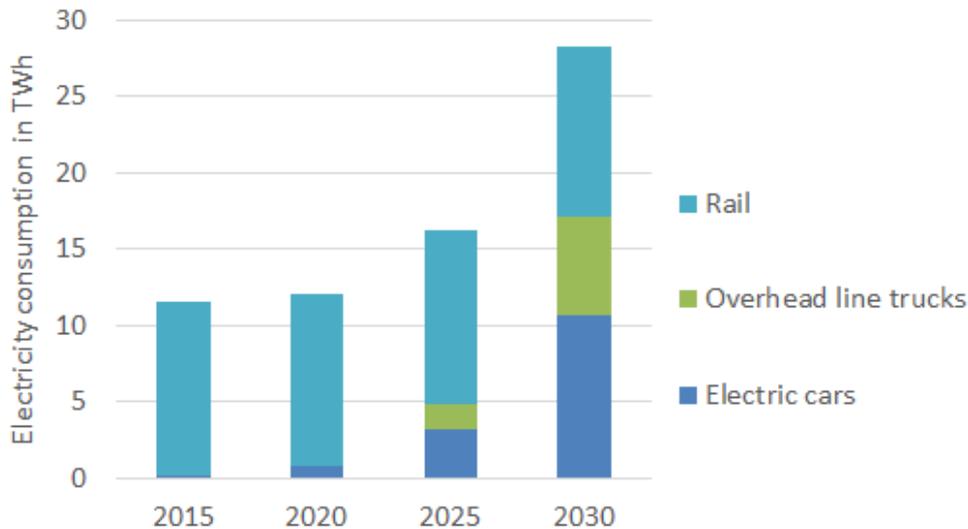


Sources: Own calculations.

### Electricity demand Transport

Electricity demand in transport is made up of passenger and freight transport by road and rail. In the case of rail transport, the increase in electrified transport performance is compensated by efficiency gains, so that electricity demand remains almost constant at 11 TWh. The market ramp-up of electromobility for vehicles smaller than 3.5 t leads to an additional electricity demand of about 11 TWh in 2030. This corresponds to a total of 4.5 million electric cars, with almost equal market shares of battery electric (BEV) and plug-in hybrid (PHEV) vehicles (Figure 2-21). In freight transport, overhead line (OH) trucks lead to an increase in electricity demand of 6 TWh.

FIGURE 2-21: ELECTRICITY DEMAND FOR TRANSPORT FOR THE PERIOD 2015 TO 2030 (OWN CALCULATIONS).



Sources: Own calculations.

#### Electricity demand Neighbouring countries

In addition to the national analysis, the energy system analysis also requires an analysis of all EU countries that exchange electricity with Germany. 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 as the analysis of Germany (see Appendix C of the first report). In analogy to the analysis of Germany, the main European policies were taken into account in the modelling for all countries considered. The following countries were considered:

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

The main socio-economic drivers of electricity demand are the development of the gross domestic product and the population development. Table 2-5

**TABLE 2-4: SECTORAL ELECTRICITY DEMAND IN 2020 AND 2030, AND BREAKDOWN BY TRADITIONAL AND NEW APPLICATIONS (HEAT PUMP AND ELECTROMOBILITY).**

shows that the largest increase in population by 2030 is expected in Belgium and Sweden, while a population decline of about 1 million is assumed for Poland. In terms of gross domestic product per capita, an increase of between 32% and 51% is assumed for Poland, Spain and Portugal in particular.

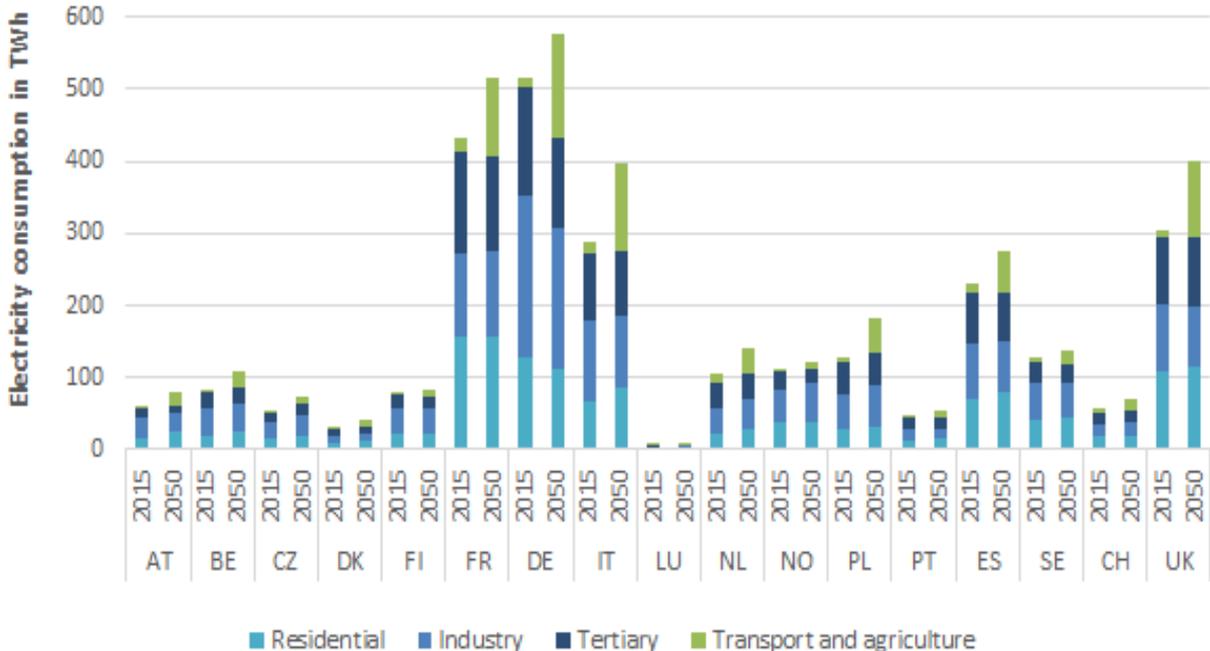
**TABLE 2-5: DEVELOPMENT OF THE DRIVERS POPULATION AND GROSS DOMESTIC PRODUCT IN THE EUROPEAN COUNTRIES UNTIL 2030**

	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 RE-PUBLIC</b>	10.6	10.8	2%	11.445	14.654	28%
<b>UNITED KING-DOM</b>	65.1	71.0	9%	33.334	37.523	13%

The aggregated results of the analysis are shown in Figure 2-22. This shows that, analogous to Germany, there will be an increase in electricity demand by 2050, mainly driven by electromobility and other electricity-based sector coupling technologies. The sectoral shifts as well as savings from the exploitation of energy efficiency potentials and technology proliferation vary from country to country depending on the technological composition. In Northern European countries,

electricity-based heating has a high market share, so increasing penetration of heat pumps leads to a decrease in electricity consumption for space heating. These countries also have on average the highest population growth, which also has a reinforcing effect on demand. In the Eastern European countries, the progress in efficiency and the 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, advancing efficiency and a moderate increase in population, which leads to a moderate increase in electricity demand in relation to the other European regions.

**FIGURE 2-22: DEVELOPMENT OF SECTORAL ELECTRICITY DEMAND IN THE NEIGHBOURING STATES BETWEEN 2015 AND 2050**



Sources: Own calculations.

## 2.5.2 Development of the transformation sector

While the development of final electricity demand was described in the previous paragraph, the development of electricity consumption in the transformation sector is described below. The consumption of the transformation sector, in that energy is consumed to produce another form of energy, is accounted for in the following transformation industries:

- Opencast lignite mines
- Large-scale electric heat generation (PtH) in the form of electrode boilers and large-scale heat pumps
- Power-to-gas (power-to-hydrogen and power-to-methane)
- Large battery storage
- Grid losses in the transport of electrical energy (distribution and transmission grid)
- Refineries and other conversion areas

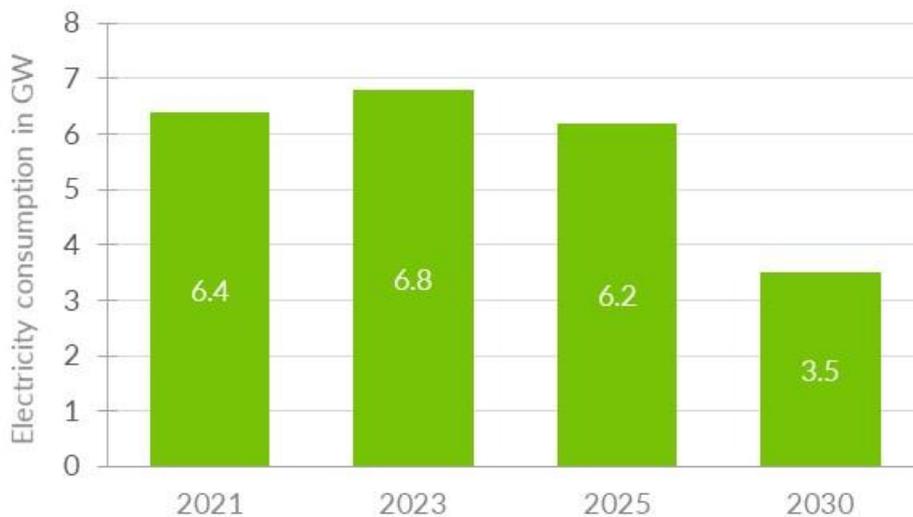
The development of electricity consumption in these industries of the transformation sector are described individually below. Finally, the development of total electricity consumption is presented, taking the transformation sector into account.

### Development of opencast lignite mines

Opencast lignite mines have a relatively high electricity consumption. In addition to the electricity needed for excavating and transporting the coal to the power plants, extensive pumping systems are usually required to drain the groundwater, which continuously consume electricity. With the phase-out of coal by 2038, as recommended in the KWSB final report, the electricity consumption of opencast mines will decline accordingly and eventually cease. Since opencast mines usually still have to be renaturalized at relatively high cost after the coal has been mined for combustion, and since pumping and excavator movements are still necessary for this purpose, we have assumed a time lag of five years between the end of coal mining and the actual end of electricity consumption in an opencast mine. We have determined the share of electricity consumption of the opencast mines

in the electricity generation of the lignite-fired power plants on the basis of the Agora study "The German Lignite Industry" and extrapolated it for the future.<sup>113</sup> The resulting development of electricity consumption by opencast mines in Germany is shown in Figure 2-23.

**FIGURE 2-23: DEVELOPMENT OF ELECTRICITY CONSUMPTION OF OPENCAST MINES IN GERMANY**



Source: Own representation.

### Development of large-scale electrical heat generation

Electricity is also increasingly being used on a large scale to provide heat. Here, we differentiate between direct heat generation using electric boilers (E-heaters) and indirect heat generation using environmental heat by means of large heat pumps. In the modelling, we have derived the assumptions for these two technologies on the basis of scenario B of the approved scenario framework of the NDP 2021-35, initially for Germany.<sup>114</sup>

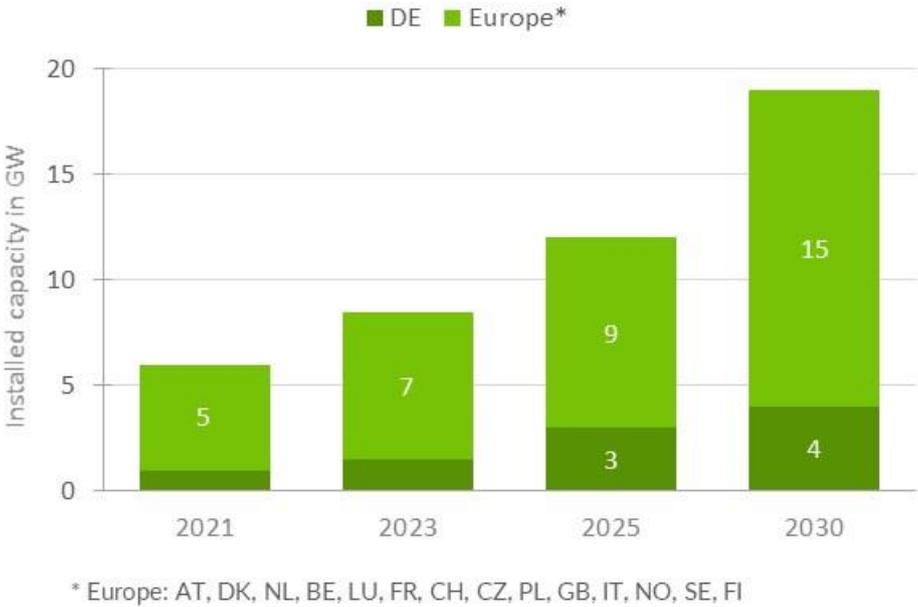
The electricity consumption of the electric heaters is determined by the model. Here, electricity-led operation is assumed, in which the opportunity corresponds to the heat price that would result from the operation of a natural gas-fired boiler. The annual electricity consumption of the large heat pumps, on the other hand, is

<sup>113</sup> Cf. Agora (2017) "The German Lignite Industry".

<sup>114</sup> Cf. BNetzA (2020a).

completely exogenous to the model for other countries.<sup>115</sup> For Germany, on the other hand, only an upper limit is implemented – so the model allows less electricity to be consumed. The large heat pumps in Germany are optimised in the model against CHP power plants, boilers, electric heaters and heat storage units. The installed capacity of electric heaters and large heat pumps is shown in Figure 2-24. The capacity of large heat pumps in Germany increases continuously over time from 2021 with a few hundred MW (pilot plants and innovation projects) to 2.7 GW by 2030. The installed capacity of electric heaters in Germany increases moderately from approx. 900 MW in 2021 to approx. 1,600 MW in 2030.

**FIGURE 2-24: DEVELOPMENT OF THE INSTALLED CAPACITY OF PTH (ELECTRIC HEATERS AND LARGE HEAT PUMPS) FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED.**



Source: Own representation.

We derived the corresponding assumptions for the installed capacity of both technologies and the electricity consumption of large heat pumps for the foreign countries considered on the basis of the assumptions for Germany. For this purpose,

<sup>115</sup> For the large heat pumps, 2,200 full utilisation hours (implemented as the upper limit for Germany) are assumed. We have based this on the information in the approved NDP scenario framework 2021-35, where 3,000 FLH are assumed for large heat pumps. Due to the lower RE feed-in in 2030 compared to 2035, we have assumed 2,200 VBS on the basis of internal calculations.

we used the historical ratio (2017 statistics) of the district heating consumption of the respective country to the German district heating consumption.

### Development of power-to-gas (power-to-hydrogen and power-to-methane)

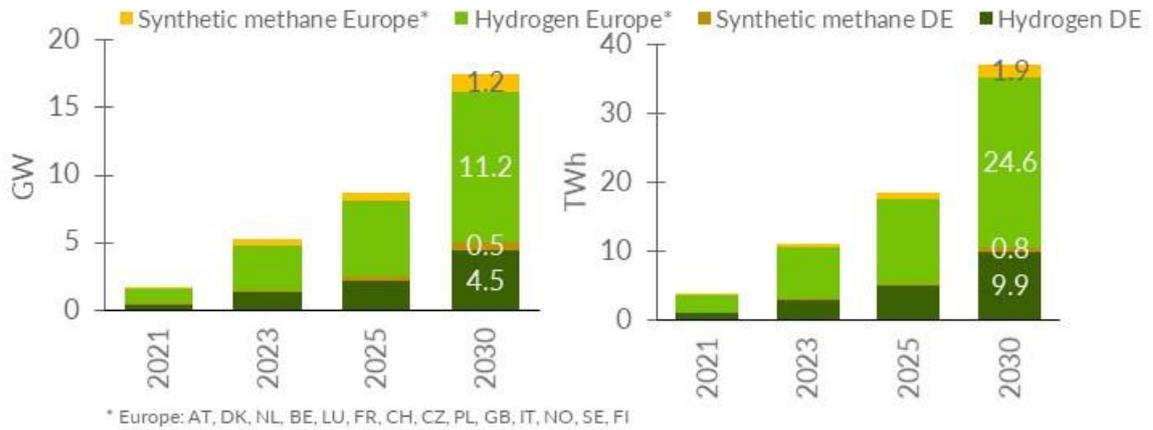
In the area of the use of electricity for the production of hydrogen and synthetic methane for the transport and industry sectors and, if necessary, for reconversion into electricity, increased investment activities have been observed in recent years. These technologies have also recently gained in importance in the political and social discourse on the long-term decarbonisation of the energy supply. On 10 June 2020, the German government adopted the *National Hydrogen Strategy*<sup>116</sup>, in which targets and measures for the development of hydrogen for further decarbonisation are anchored. The development of the installed capacity and the annual consumption quantities are exogenously specified in the model. The dispatch of these technologies is endogenous. For Germany, we take into account the data on installed capacity and electricity consumption of PtG differentiated by power-to-hydrogen (PtH<sub>2</sub>) and power-to-methane (PtM) of the *National Hydrogen Strategy* and Scenario B of the approved scenario framework of the NDP 2021 – 2035.<sup>117</sup> Intermediate years were interpolated.

---

<sup>116</sup> Cf. BMWi (2020b)

<sup>117</sup> Cf. BNetzA (2020a)

FIGURE 2-25: DEVELOPMENT OF INSTALLED CAPACITY AND ELECTRICITY CONSUMPTION OF PTG FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED.



Source: Own representation.

For the foreign countries considered, we have transferred the assumptions for Germany. For PtG (PtM, PtH<sub>2</sub>), we have transferred the assumption for Germany of the historical ratio (2017 statistics) of natural gas consumption in industry and the tertiary sector to the foreign countries considered.

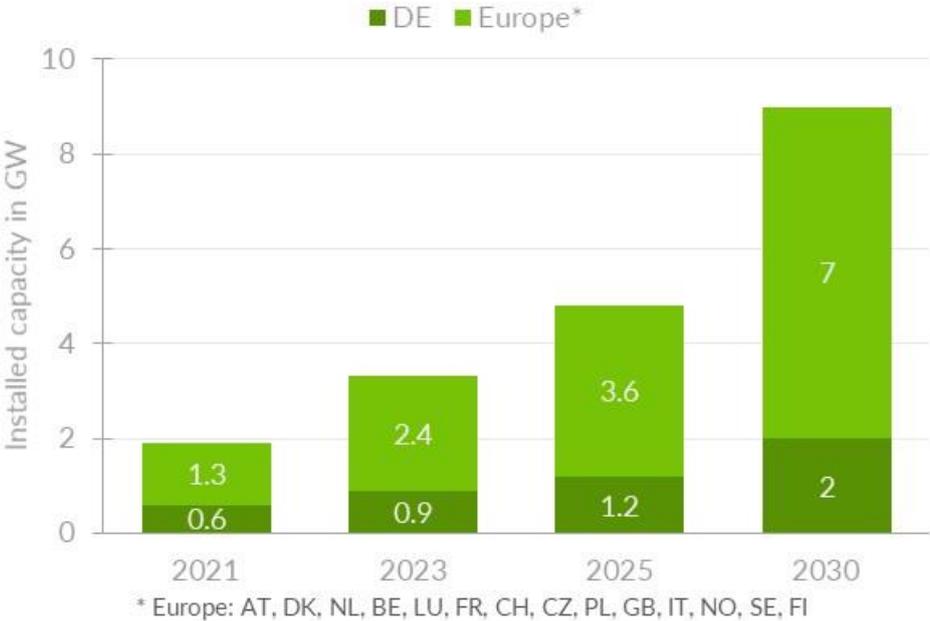
### Development of large battery storage

For some years now, more and more large-scale batteries have been built and marketed on the electricity markets. The areas of application range from system services, direct participation in the competitive wholesale markets for electricity as well as so-called "behind-the-meter" applications, in which the storage systems are used to make purchases from the general supply grid more flexible and / or to increase self-consumption.

The development of the installed capacity is exogenous to the model, while the use of the plants is determined model-endogenously. Our assumptions for Germany in this area are based on the information on large-scale battery storage (> 150 kW) in scenario B of the approved scenario framework of the NDP 2021 -

2035, which assumes an installed capacity of 3.4 GW in 2035.<sup>118</sup> In the course of time from 2020 to 2030, the installed capacity increases successively from approx. 600 MW in 2020 to 2 GW.<sup>119</sup> The development of the installed capacity of large-scale battery storage for Germany and the foreign countries considered is shown in Figure 2-26.

**FIGURE 2-26: DEVELOPMENT OF INSTALLED CAPACITY OF LARGE-SCALE BATTERY STORAGE FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED.**



Source: Own representation.

For the foreign countries considered, we first determined the current installed capacity on the basis of a worldwide database.<sup>120</sup> For the future development of installed capacity, we have set the development of the ratio of the final electricity

<sup>118</sup> We have not taken into account the output of private PV storage systems in the household sector and commercial applications, as it cannot be assumed that these will be used in line with the market (i.e. on the basis of wholesale prices).

<sup>119</sup> The installed capacity of approx. 600 MW in 2021 is based on an interpolation of the value for 2020 (446 MW) of the current power plant list of the BNetzA (as of 1.4.2020) to 2 GW in 2030.

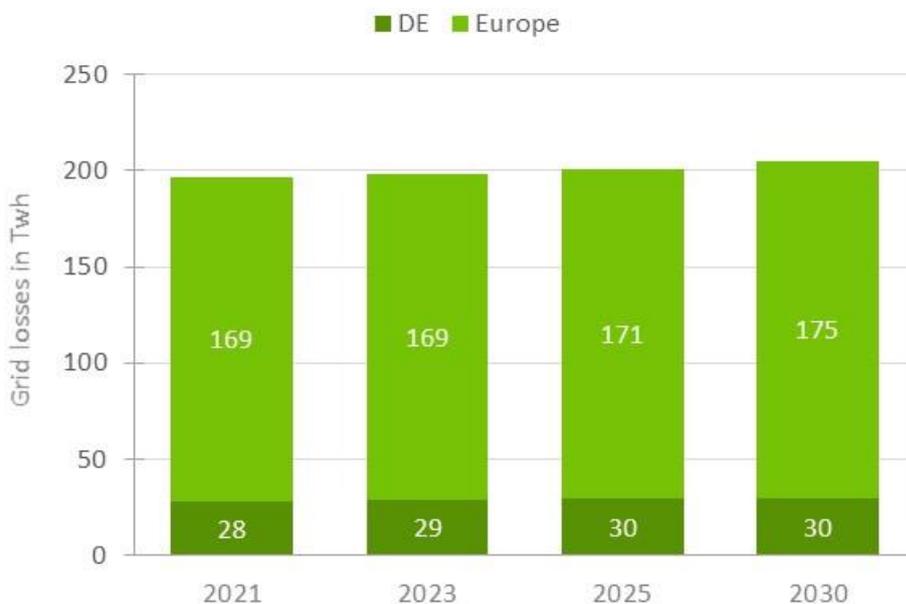
<sup>120</sup> Cf. DOE Global Energy Storage Database, last accessed on 8.7.2020. Only plants larger than 1 MW whose status was "in operation" were considered.

consumption of the respective country in relation to the development of the German final electricity consumption.

### Development of losses in the transmission and distribution grid

During the transmission and distribution of electricity to the end consumers, losses occur in both the distribution and the transmission grid. We specify these grid losses exogenously to the model. We have taken the annual quantities of grid losses for Germany from scenario B of the approved scenario framework of the NDP 2019 - 2030. For the intermediate years and for the countries considered, we have scaled these assumptions on the basis of final electricity consumption. The resulting grid losses for Germany and the countries considered are shown in Figure 2-27.

FIGURE 2-27: DEVELOPMENT OF GRID LOSSES FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED.



\* Europe: AT, DK, NL, BE, LU, FR, CH, CZ, PL, GB, IT, NO, SE, FI

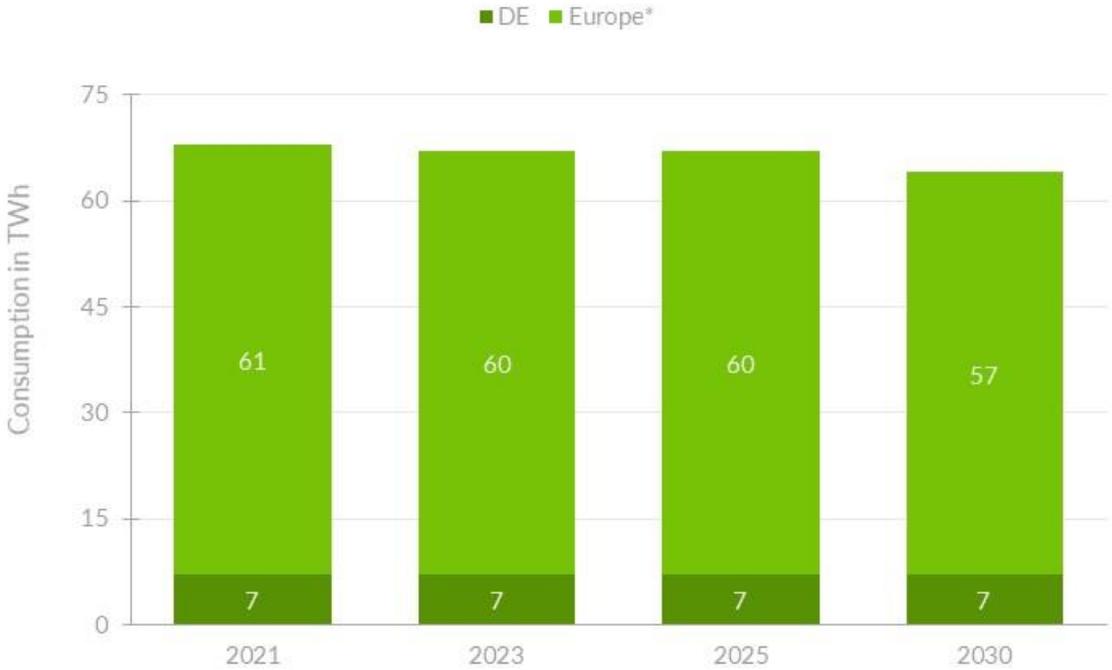
Source: Own representation.

### Development of the refineries and other conversion areas

We have determined the electricity consumption of refineries and other conversion sectors in Germany and abroad on the basis of the statistics (year 2017) and

extrapolated it into the future using the forecast of industrial electricity consumption. The resulting development of consumption in refineries and other conversion sectors for Germany and Europe is shown in Figure 2-28.

**FIGURE 2-28: DEVELOPMENT OF CONSUMPTION IN REFINERIES AND OTHER CONVERSION SECTORS FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED.**



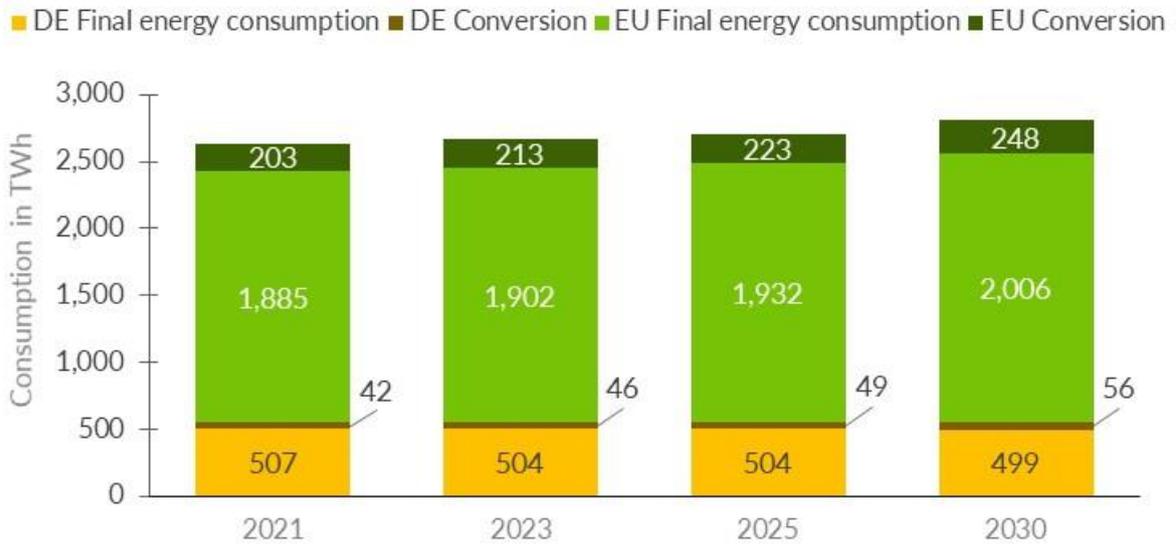
\* Europe: AT, DK, NL, BE, LU, FR, CH, CZ, PL, GB, IT, NO, SE, FI

Source: Own representation.

**Development of electricity consumption of all areas of the transformation sector**

Finally, Figure 2-29 shows the aggregation of all previously presented electricity consumption in the transformation sector as well as the development of final electricity consumption (cf. Section 2.5.1).

**FIGURE 2-29: DEVELOPMENT OF FINAL ELECTRICITY CONSUMPTION AND CONSUMPTION OF THE TOTAL TRANSFORMATION SECTOR FOR GERMANY AND THE FOREIGN COUNTRIES CONSIDERED.**



\* EU hier: AT, DK, NL, BE, LU, FR, CH, CZ, PL, GB, IT, NO, SE, FI

Source: Own representation.

This sum almost corresponds to the model electricity demand in our European electricity market model for the weather year 2011. The electricity demand of temperature-sensitive application purposes varies accordingly in other weather years. In addition, the model-derived consumption of pumped storage and Pth (only electric heaters) is added.

### 2.5.3 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 for the future demands on the European electricity supply system. In this context, not only the hourly total load of a country is relevant, but in particular developments in the individual sectors and applications must also be differentiated. Above all, consumption structures that are likely to change significantly in the future must be considered, as well as those applications that can be made increasingly flexible in the future. In addition to the flexibility options described in Section 2.4.2 whose

potential varies with the hourly load, these primarily include applications with storage options, such as electric mobility and heat pumps.<sup>121</sup>

In order to be able to take the current consumption patterns of electrical energy and their future developments into account in our electricity market modelling, we use a model developed specifically for this purpose to generate hourly load forecasts.<sup>122</sup> In doing so, we follow a *bottom-up approach* with which we generate load structures for individual consumption applications and derive a residual structure for other electricity consumption in total. In addition to historical consumption data, a number of fundamental factors influencing electricity consumption are taken into account in the analytical creation of application-specific load structures. These contain weather and temperature data as well as times and calendar data. Furthermore, specific assumptions on the future development of individual applications are used, such as increasing air conditioning of residential and commercial premises or the rise of electromobility in various forms.

Within the framework of 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 quantity. For the individual applications, load structures are first developed per “typical day” and weather type (if dependency exists). These are typical consumption patterns depending on which day of the week, at which time of day (and at which temperature or sun position) the electricity is drawn for the respective application.<sup>123</sup> Subsequently, the typical day-based load profiles are rolled out to the forecast and weather years, taking into account the respective daily and weather structure. A schematic representation of the procedure is given in Figure 2-30.

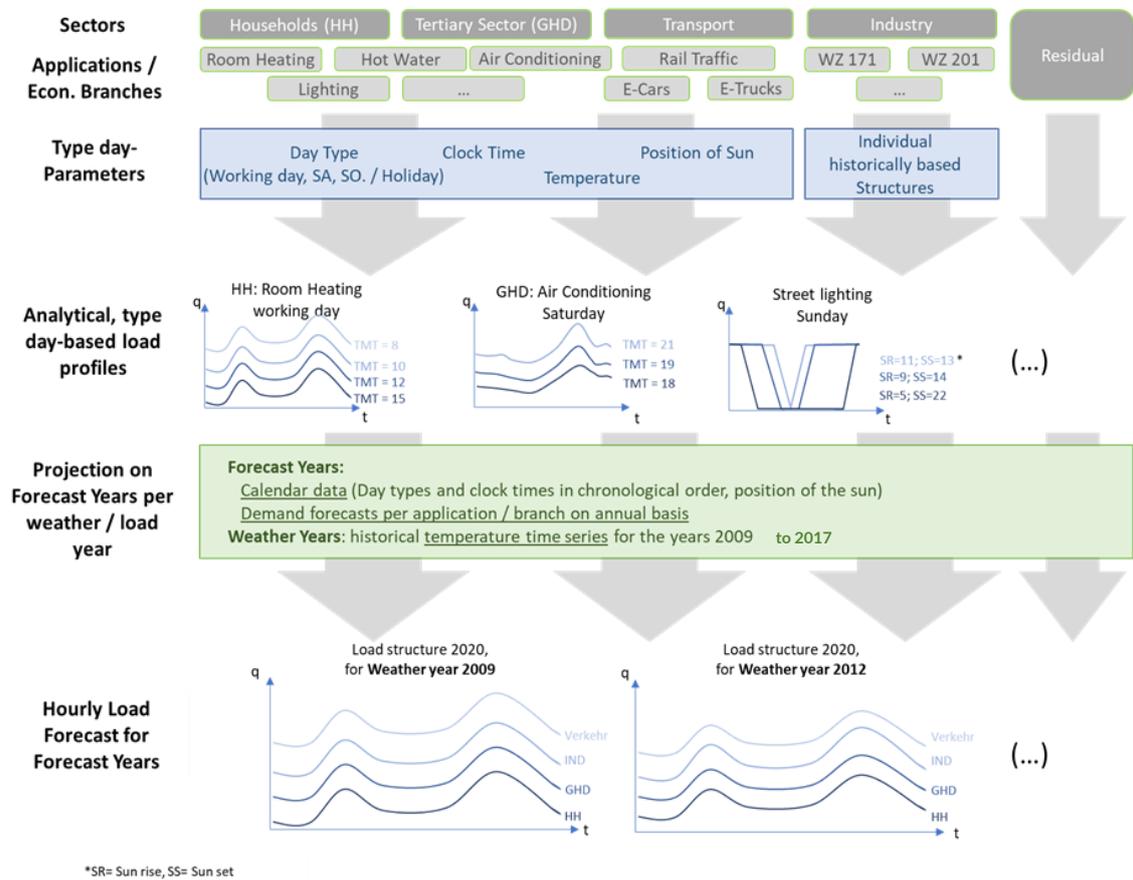
---

<sup>121</sup> For modelling of new consumers, see separate presentations in the following Section 2.5.4

<sup>122</sup> A detailed description of our model for generating hourly load structures can be found in Appendix E in r2b / Consentec (2019).

<sup>123</sup> Typical day-based load structures are load structures that describe the load depending on the combination of typical day parameters (influencing factors). Typical day parameters are, for example, the day of the week, the time or the temperature. Ultimately, the typical day parameter combination determines the user behaviour and thus the power consumption of an application that consumes final energy.

FIGURE 2-30: PROCEDURE IN THE MODEL FOR GENERATING HOURLY LOAD FORECASTS BASED ON ANALYTICAL CONSUMPTION PROFILES (SCHEMATIC REPRESENTATION)



Source: Own representation.

The assumptions on annual final energy consumption of the sectors, applications and branches of the economy mapped for the base year 2011 as well as their developments in the forecast period are given to the model and in the present project originate from analyses by Fraunhofer ISI (cf. Section 2.5.1).

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

## 2.5.4 Modelling the load of new consumers

### Modelling in the electricity market model

In the context of this study, the central sector coupling technologies electric heat pumps, electric mobility in passenger and freight transport with light commercial vehicles, and trolley trucks are defined as *new consumers*. The electricity demand of these consumers is partly flexible under certain additional conditions. We have therefore taken into account existing load shifting or load reduction potential in each case in the analysis. In the following, we explain how we modelled the hourly demand structure of electric heat pumps, electric vehicles and overhead line trucks in detail.

To depict electromobility in **passenger and freight transport with light commercial vehicles**, we first carry out separate preliminary analyses in the "Electromobility Load Tool" available from r2b energy consulting, in which synthetic charging profiles are generated for different user groups: The tool first differentiates between public and non-public charging and according to the typical days "Monday", "other working day", "Saturday" and "Sunday = public holiday".<sup>124</sup> While we base the representation of public normal and fast charging on profiles from literature data, we draw on the typical driving behaviour of different user groups for the modelling of non-public charging based on literature data:<sup>125</sup> non-working people, working people with different commuting behaviour, different leisure and shopping habits, company cars, etc. For each of these user groups, start and arrival times as well as daily mileage are stored, each taking into account simultaneity factors. Based on this, a simulation of the daily driving behaviour and the idle times for the individual user groups is carried out. Based on this information and on assumptions about consumption, charging capacity at different parking locations ("at home" or "at work") and average battery capacities of the vehicles, load structures are developed for different user groups, typical days and reference years. A distinction is

---

<sup>124</sup> When simulating the driving and charging behaviour, the driving behaviour of the previous day is taken into account for the night-time charging behaviour; therefore, it is necessary to model Monday separately.

<sup>125</sup> Cf. Hacker et al. (2011), Morrissey et al. (2016) and Schröder and Traber (2012).

also made between purely battery-electric vehicles and plug-in hybrid vehicles.<sup>126</sup> The resulting structures per user group are weighted based on literature data and aggregated to the overall profiles "private non-public charging", "commercial non-public charging" and "public charging".

For non-public charging of cars and light commercial vehicles, we have additionally assumed that the vehicles can be charged in three different modes:

- *Uncontrolled charging:* After arrival at the parking location, charging continues at full charging power until the vehicle battery is fully charged again.
- *Reduced charging:* It is assumed that the vehicle is charged at reduced power for the entire idle time, so that the vehicle battery is fully charged again at the end of the idle time.
- *Intelligent charging:* Within the idle time, charging is optimised according to the wholesale prices on the electricity market. For the modelling, hourly structures such as "consumption while driving", "battery filling level" and "maximum possible purchase power" are determined, which are used as input parameters in the fundamental electricity market model. Charging is then optimised according to the wholesale prices on the electricity market so that the storage system never "runs out" or "overflows" and the amount of electricity charged in an hour is limited to the available charging capacity of the vehicles on the electricity grid.

The assumed shares of these three charging strategies in the total number of charging processes vary over time: While the majority of charging processes are uncontrolled in the short term, the shares of reduced and intelligent charging increase in the medium and long term (cf. Table 2-6). This development is based on the assumption that with increasing shares of electric vehicles in the stock and increasing electricity consumption through electromobility, it can be assumed that

---

<sup>126</sup> Cf. Gnann et al. (2015) and IEA (2018b).

this demand will be increasingly intelligently controlled according to the mechanisms of action of the market and taking into account challenges for the distribution network.

**TABLE 2-6: ASSUMPTIONS ON THE DEVELOPMENT OF THE SHARES OF THE THREE CHARGING STRATEGIES UNTIL 2030.**

Distribution of charging strategies				
	2021	2023	2025	2030
Uncontrolled	91%	82%	73%	50%
Reduced	6%	11%	17%	30%
Smart	4%	7%	11%	20%

Source: Own assumptions.

In the case of both *uncontrolled charging* and *reduced charging*, we model a load structure within the "Electromobility Load Tool", which is then incorporated into the load tool and rolled out to the base years considered in the present analyses. The electricity market model is therefore given a structured, non-changeable consumption profile for each of these two charging strategies. In the case of *smart charging*, the time series relevant for optimisation are transferred directly to the fundamental electricity market model.

In our analyses, we assume that **trolley trucks** or overhead line trucks (OH-trucks) will also be used starting with the reference year 2021. In order to map the resulting electricity demand within an hourly consumption profile, we first derived a structured consumption profile based on literature data on traffic volumes.<sup>127</sup> The overhead line trucks are hybrid vehicles that use a diesel drive in addition to an electric drive and can therefore also drive independently of an overhead line for longer periods of time. The OH-trucks can therefore "drive off" the derived structured consumption profile either using electricity in line operation or - when electricity prices are high - switch to diesel operation.<sup>128</sup> In this case, the flexibility

<sup>127</sup> Cf. Hacker et al. (2014).

<sup>128</sup> For the replacement costs of diesel operation, the price development of light heating oil was assumed, taking into account taxes and other regulated price components as well as their differences in the various countries considered.

provided consists of the corresponding load reduction of the trucks running in electricity mode.

We do not model the possibility of electricity being fed back into the public supply grid by electric vehicles and OH trucks.

We also modelled the electricity demand of **electric heat pumps**, taking into account a load shift potential. First, we derived assumptions on consumption behaviour and coefficients of performance (COPs) depending on the outdoor temperature and technology mix in the different regions of use. Based on this, we model (analogous to the modelling of smart charging for electric vehicles) the possibility of a consumption shift of up to four hours. On the one hand, this approximates the thermal inertia of cooling and heating a building and, on the other hand, the combined use of heat pumps with heat storage units.

#### Modelling in the RA assessment

The flexibility of the new consumers in the sense of the aforementioned definition is also reproduced in the model step of the RA assessment. Compared to the first report, a model extension was implemented in order to account for the increasing relevance of these flexibility options.

For reasons of manageability, aggregation takes place compared to the electricity market model. Thus, flexible consumption of e-mobility and heat pumps are aggregated<sup>129</sup> and are to be covered within a maximum shift period<sup>130</sup> in the RA valuation. Only those electric vehicles and heat pumps are used that actually have a price-sensitive consumption in the electricity market simulation. All other electric vehicles and heat pumps continue to be considered inflexibly in the residual load hydrograph.

PtG plants (cf. Section 2.5.2) are also taken into account with their flexibility in the RA assessment. These are characterised by the fact that their plant operators "schedule" consumption when it can be covered at favourable electricity prices on

---

<sup>129</sup> In model terms, these are represented by storage with negative inflow.

<sup>130</sup> This is modelled by limiting the storage level.

the market. In this respect, it can be assumed that the amount of energy consumed by these plants is flexibly required over the course of the year and that this consumption would be waived in shortage situations. Therefore, this amount of energy is included in the RA assessment without restrictions on the shift duration.<sup>131</sup> A technical restriction, however, is the maximum installed capacity of these plants, which may also not be exceeded in the RA valuation.

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

In order to forecast the development of the electricity supply system as realistically as possible on the basis of a model, different parameters must be defined in the area of conventional power plants. These are economic parameters on the one hand and technical parameters on the other. The economic parameters consist of investment costs, fixed and other variable operating costs (cf. Section 2.6.1) as well as variable operating costs for fuel use and for CO<sub>2</sub> certificates (cf. Section 2.6.2). In addition to the installed capacity, the required technical parameters are electrical efficiencies, duration of start-up and shutdown processes, minimum partial load conditions, load gradients as well as planned and unplanned unavailabilities of thermal power plants and pumped storage power plants, as these are not operational throughout the year due to overhauls or technical malfunctions. Section 2.6.3 shows the assumptions on planned and unplanned unavailabilities of thermal power plants and pumped storage power plants. In the case of CHP plants, fuel utilisation rates, electricity ratios and electricity loss ratios in particular are also added.

### **2.6.1 Investment and operating costs**

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

---

<sup>131</sup> In model terms, this is done by means of storage tanks with an initial fill level of zero and a final fill level equal to the annual consumption.

Within the framework of the simulation calculations, we have used the cost parameterisation for conventional power plants shown in Table 2-7 analogously to the first project report.<sup>132</sup> Since, according to our assumptions, we no longer allow an endogenous expansion of lignite and hard coal power plants in any of the countries considered in this second project report, the costs presented here for these technologies have no relevance for the results in this second project report.

**TABLE 2-7: ASSUMPTIONS ON COSTS OF NEW CONVENTIONAL POWER PLANTS**

Parameter	Unit	CCGT - cond.	Open gas turbine	Engine power plant	Lignite	Hard coal
Net installed capacity	MW <sub>el</sub>	>400	>100	>20	>800	>700
Investment cost (without interest rates for construction)	€ <sub>2020</sub> per KW <sub>el</sub>	786	430	409	1,781	1,519
Fixed operating cost	€ <sub>2020</sub> per KW <sub>el</sub> p.a.	21	9	6	47	44
Other variable cost	€ <sub>2020</sub> per MWh <sub>el</sub>	2	1.0	0.1	1.8	1.4

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

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

The main drivers of the variable costs of electricity generation in conventional power plants are the fuel costs and the costs for CO<sub>2</sub> emission allowances. The level of fuel costs is in turn determined by the prices of the fuels used, i.e. the

<sup>132</sup> Cf. r2b / Consentec (2019) Section 4.6.1.

primary energy sources lignite, hard coal, natural gas and petroleum products, in addition to the efficiency of the power plants.

The prices for crude oil, natural gas and hard coal are set in dependence on the global energy markets, as these energy sources are transported and traded worldwide. Particularly in the case of natural gas, however, it is important to recognize 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 (e.g. for LNG), high costs of the necessary gas grid infrastructure as well as different production costs stand in the way of a harmonised world market price, even in the longer term. For Germany, the decisive factor is the cross-border price for natural gas in Europe.

In our analyses in this study, we base our assumptions on the future development of prices for **crude oil**, **natural gas** and **hard coal** in the medium and long term (from 2030) on the *Stated Policies Scenario of the World Energy Outlook (WEO 2019)* of the *International Energy Agency (IEA)*.<sup>133</sup> For the short term (up to 2023), we use current forward market prices for natural gas, crude oil and hard coal on the relevant trading exchanges.<sup>134</sup> For the period between 2023 and 2030, we use linear interpolated price forecasts. Although the IEA already offers price forecasts for 2025 in the WEO 2019, we conclude that the IEA's forecasts for 2025 should already be considered outdated, as some of the prices forecast by the IEA for 2025 are much higher than the current level on the futures markets. Finally, to avoid implausible price jumps from 2023 to 2025, we use the WEO price forecasts only from 2030.

In the WEO 2019, the *Stated Policies Scenario* represents the current 'best guess' scenario of the IEA and depicts the developments in the relevant areas that were

---

<sup>133</sup> Cf. IEA (2019).

<sup>134</sup> The mean value of the daily prices of all trading days in the period from 31.01.2020 to 29.02.2020 was used for the following products and trading platforms: Crude oil: Brent Crude Oil Futures ('Last') of the ICE (cf. CME Group, 2020a); natural gas: weighted average of NCG and GPL base year futures (GOBY and G2BY, 'Settlement') of the EEX (cf. EEX, 2020a); hard coal: API2 CIF ARA monthly futures (Settlement) of the CME (cf. CME Group, 2020b).

considered most likely when the study was prepared.<sup>135</sup> In the scenario, the authors take into account all national and international policy measures and regulations in the areas of environmental, climate protection and energy policy that have already been adopted (some of which have not yet entered into force) at the time the study was prepared (by mid-2019), as well as announced measures and decisions whose implementation is considered very likely.

The price paths used are shown in Figure 2-31 in comparison to alternative price paths of the *WEO 2019* and to the price paths of ENTSO-E in the TYNDP 2020.<sup>136</sup> In the respective diagram, the selected price path is marked by its own data series (blue, solid line).

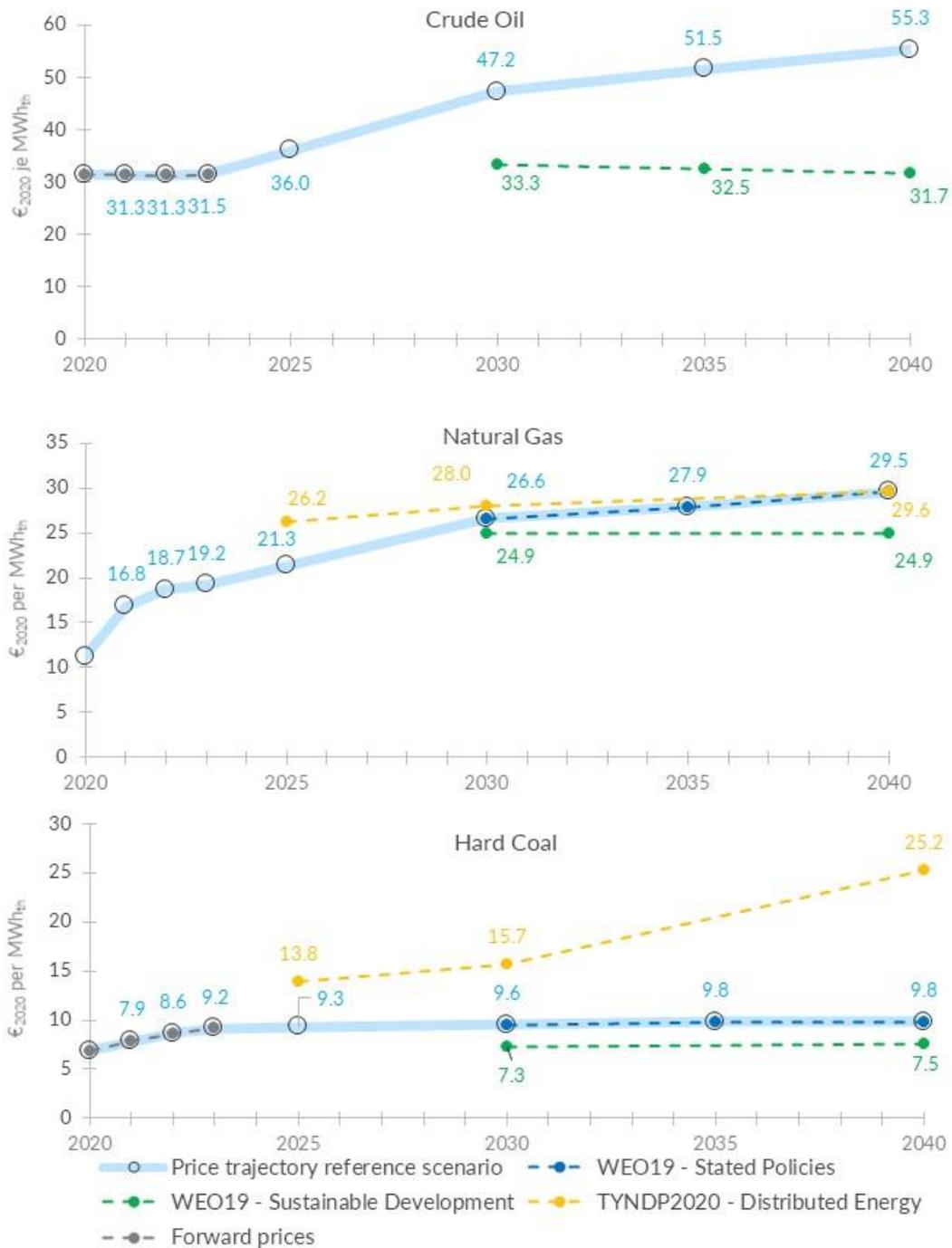
For **light and heavy heating oil**, there is no global or European trade on a relevant scale that could form the basis for corresponding trade prices. However, the corresponding prices can be derived very well from the development of crude oil prices by means of statistical analyses. Cost premiums result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

---

<sup>135</sup> The *Stated Policies* scenario replaces the *New Policies* scenario in WEO 19, which was used as the 'best guess' scenario in previous versions of WEO up to and including WEO 18.

<sup>136</sup> Cf. ENTSO-E (2020a)

**FIGURE 2-31: PRICE FORECASTS FOR CRUDE OIL, NATURAL GAS AND HARD COAL: WEO2019 (STATED POLICIES) COMPARED TO ALTERNATIVE PRICE PATHS**



Source: Own representation based on: Forward prices natural gas: EEX (2020a), forward prices coal: CME Group (2020b), forward prices crude oil: CME Group (2020a), WEO19: IEA (2019), TYNDP2020: ENTSO-E (2020 137); own conversion of original values in €2020 per MWhth as European wholesale prices without surcharges for transport or similar.

There is also no world market price for lignite, as its electricity generation is (almost) exclusively in the vicinity of the mines due to high transport costs. Instead, the costs of open-cast mining are to be regarded as the relevant reference value. According to Öko-Institut (2017), the full costs of lignite production in opencast mines amount to around €6.5 per MWh<sub>Br,th</sub> on average in 2017. These full costs are made up of various fixed or variable cost components, which depend in different ways on the short-, medium- and long-term operating plans of the lignite-fired power plants:

- First, approx. 1.0 €<sub>2017</sub> per MWh<sub>Br,th</sub> (as a share of the above-mentioned full costs in the amount of 6.5 €<sub>2017</sub> per MWh<sub>Br,th</sub>) are considered as fully sunk costs. These costs include refinancing costs for investments already made as well as recultivation costs.
- A second share of 1.5 €<sub>2017</sub> per MWh<sub>Br,th</sub> is to be considered as a variable cost component directly dependent on the short-term operation of the lignite-fired power plants. This share is directly allocated to the lignite-fired power plants as variable fuel procurement costs.
- Another share, also amounting to 1.5 €<sub>2017</sub> per MWh<sub>Br,th</sub>, is to be considered as a share of the fixed costs of opencast mining that can be reduced in the short term (by reducing the production volume). This share is added to the coal-fired power plants' annual fixed operating costs.<sup>138, 139</sup>
- Finally, 2.5 €<sub>2017</sub> per MWh<sub>Br,th</sub> must be considered as a share of the fixed costs of coal extraction in opencast mining, which can only be reduced in the medium term by reducing capacity, i.e. reducing the maximum extraction rate. From today's perspective, this possible fixed cost saving can be

---

<sup>137</sup> No price path for the TYNDP 2020 is shown in the diagram for crude oil, as such a path is not specified in the TYNDP 2020.

<sup>138</sup> For the allocation of the 1.5 €<sub>2017</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 these power plants of 7,000 full utilisation hours is assumed. The resulting fixed cost mark-up in € per kW<sub>el</sub> finally depends on the efficiency of the respective power plant.

<sup>139</sup> The fixed cost surcharge described here is not yet included in the fixed operating costs for lignite-fired power plants shown in Section 2.6.1

realised, with sufficient planning lead time, by reducing the maximum annual production volume from 2025 onwards. In the modelling, these costs are allocated to the variable fuel procurement costs of the lignite-fired power plants from 2025 onwards.

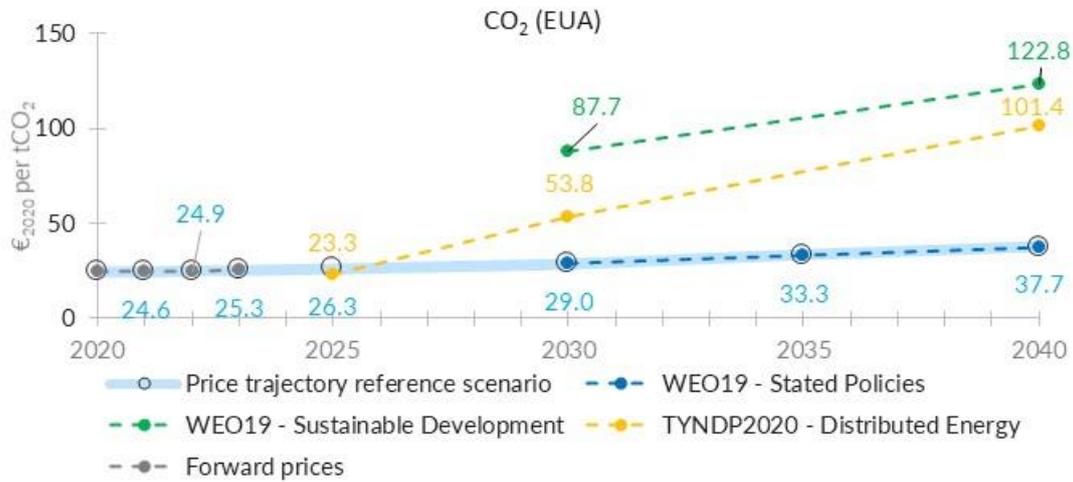
For hard coal and natural gas, further price components have to be taken into account in the **fuel costs free power plant**. In the case of hard coal, these are essentially transport costs from the European seaports to the German border and from the German border to the power plant. In total, 1.25 €<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 must be taken into account. For Germany, we assume these to be 0.5 €<sub>2018</sub> per MWh<sub>th, Hu</sub>. For light and heavy fuel oil, we assume 0.3 €<sub>2018</sub> per MWh<sub>th</sub>.

For the prices of **CO<sub>2</sub> certificates**, we proceed analogously to our assumptions for fuels such as crude oil, natural gas and hard coal. While we use trading quotes for EEX futures for the years up to 2023,<sup>140</sup> we use the forecasts of the *New Policies* scenario of the *WEO 2019* for the years from 2030 onwards. Interpolated prices are used in the years in between. The selected price path is shown in the following Figure 2-32 in comparison with the alternative price paths of the *WEO 2019* and the forecasts *in the TYNDP 2020*. The selected price path is marked as a separate time series (green line).

---

<sup>140</sup> The mean value of the price quotations from 31.01.2020 to 29.02.2020 for the FEUA (Settlement) product of EEX was used, cf. EEX (2019b).

FIGURE 2-32: PRICE FORECASTS FOR CO<sub>2</sub> ALLOWANCES (EUA): WEO2019 (STATED POLICIES) COMPARED TO ALTERNATIVE PRICE PATHS



Source: Own representation based on: Term prices: EEX (2020b), WEO19: IEA (2019), TYNDP2020: ENTSO-E (2020); own conversion of original values in €<sub>2020</sub> per tCO<sub>2</sub>

In addition to the CO<sub>2</sub> price of the EU ETS, we have also taken into account **national CO<sub>2</sub> prices** for the UK and the Netherlands that apply or are currently being introduced:

In 2013, the United Kingdom established a national minimum CO<sub>2</sub> price for the power plant sector in the form of a CO<sub>2</sub> component of the energy tax rates for the use of energy sources for electricity generation. The CPF is made up of two components: (i) the EU ETS price and (ii) an additional CO<sub>2</sub> price component that tops up the EU ETS price to meet the CPF target. In line with applicable benchmarks, we have fixed the national Carbon Support Rate (CSR) (national surcharge on the ETS price) in the model at £18/tCO<sub>2</sub> until 2021/22. We then assumed the continuation of the national CSR in line with the original path of the CPF price target. In 2030, this is nominally GBP 70/tCO<sub>2</sub>.<sup>141</sup>

As the UK's membership in the EU ETS finished at the end of the BREXIT transition period on 31 December 2020, the British government announced the introduction of its own UK ETS from 2021, the planned regulations of which are, how-

<sup>141</sup> Cf. Hirst (2018).

ever, strongly oriented towards the regulations of the EU ETS. The CO<sub>2</sub> price burden on British power plants is therefore unlikely to change significantly as a result of the UK leaving the European Union.<sup>142</sup>

The Dutch government is also currently in the process of introducing a national minimum CO<sub>2</sub> price for electricity generation, which is to supplement the EU ETS price as soon as it falls below the nationally set limit. For the modelling, we have used the price path envisaged in the Dutch government's NECP of a nominal initial €12.30/tCO<sub>2</sub> with a subsequent gradual increase to €31.90/tCO<sub>2</sub> in 2030.<sup>143</sup>

### **2.6.3 Availabilities of conventional power plants**

The output of controllable generation plants, such as thermal power plants or pumped storage power plants, is not available all year round. On the one hand, plants are not available on a scheduled basis, e.g. due to maintenance work within the scope of overhauls. On the other hand, plants can also malfunction if, for example, a technical defect makes operation (at nominal capacity) impossible. These unavailabilities of conventional power plants must be taken into account in the monitoring of resource adequacy, both in the simulations for forecasting the development of the electricity supply system and in the probabilistic simulation as part of the analysis of the level of resource adequacy.

In the context of this second project report, we have made analogous assumptions about the planned and unplanned unavailabilities of thermal power plants and pumped storage power plants. These are shown in Table 2-8.

---

<sup>142</sup> Cf. Pinsent Masons (2020).

<sup>143</sup> Cf. Ministry of Economic Affairs and Climate Policy (2019).

TABLE 2-8: ASSUMPTIONS ON UNAVAILABILITIES 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%	
	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%
<b>Nuclear Power (2005 - 2015)</b>	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).

For the parameterization of the RA analysis, we divided the unavailabilities into the component's average failure frequency and average failure duration<sup>144</sup> and used failure frequencies according to Haubrich and Consentec (2008) as in the first report.<sup>145</sup> The outage durations were calculated by dividing the unplanned unavailabilities given in Table 2-8 by these frequencies.

<sup>144</sup> Cf. r2b / Consentec (2019) section 3.3.5.

<sup>145</sup> Partial failures were added proportionally to the frequency of total failures.

## 2.7 Development of the balancing power

As in the first project report, when generating scenarios with the European electricity market model, we model the restriction that part of the output of power plants that is held in reserve for providing balancing power cannot be marketed on the electricity market for scheduled energy.

In our analyses, we assume a constant demand for balancing power over time. The amount of positive balancing power provided is shown in Figure 2-33; the values of the first report have been retained here.

FIGURE 2-33: POSITIVE CONTROL RESERVE IN THE 14 COUNTRIES CONSIDERED



Source: Own presentation based on ENTSO-E (2020a) and ENTSO-E (2020c).

As explained in the first project report<sup>146</sup>, the capacity of the generation plants held in reserve to cover high-frequency positive parts of the balancing power demand is not used in the RA analysis to cover the residual load. However, the generation plants reserved for the remaining part of the balancing power are available to the model to cover the residual load and are taken into account accordingly in the RA analysis.

<sup>146</sup> Cf. r2b / Consentec (2019) Section 3.3.3.

This separation results logically from the task of assessing the resource adequacy on the electricity market. Adequacy is present when a balance between supply and demand is achieved as a result of all market processes. It is therefore examined whether load coverage is achieved with flexibilities that must ensure their economic viability from the revenues of the different electricity market segments. This does not require separate consideration of the individual segments.

The separation between market processes on the one hand and non-market processes on the other hand should therefore not be based on the chronological sequence of technical processes, but on the way in which the use of generation plants and other flexibilities is determined. In particular, although balancing power is technically used in real time by the TSOs, this is done according to (price) criteria that were previously determined in the market-based process of the balancing power procurement.<sup>147</sup> Market processes thus explicitly do not only include processes of the so-called scheduling market, e.g. day-ahead and intraday markets, which result in schedule nominations of the balancing group responsible parties.

In situations that are not critical from the RA point of view, in which there is no shortage of flexibility, the use of balancing power is a regular and normal process. The costs incurred by the market players for the use of balancing power are included in their economic calculations.<sup>148</sup>

Such a "normal" situation for the use of positive balancing power is shown schematically in Figure 2-34. The x-axis shows the lead time before the operating time  $t_0$ . On the y-axis, different powers are shown. One of them is the actual load (red), which is of course only known in real time at time  $t_0$ .<sup>149</sup> A distinction must be made between this and the load forecast (blue), which here means the collective (total) load forecast of all market participants. This also has a value before the operating

---

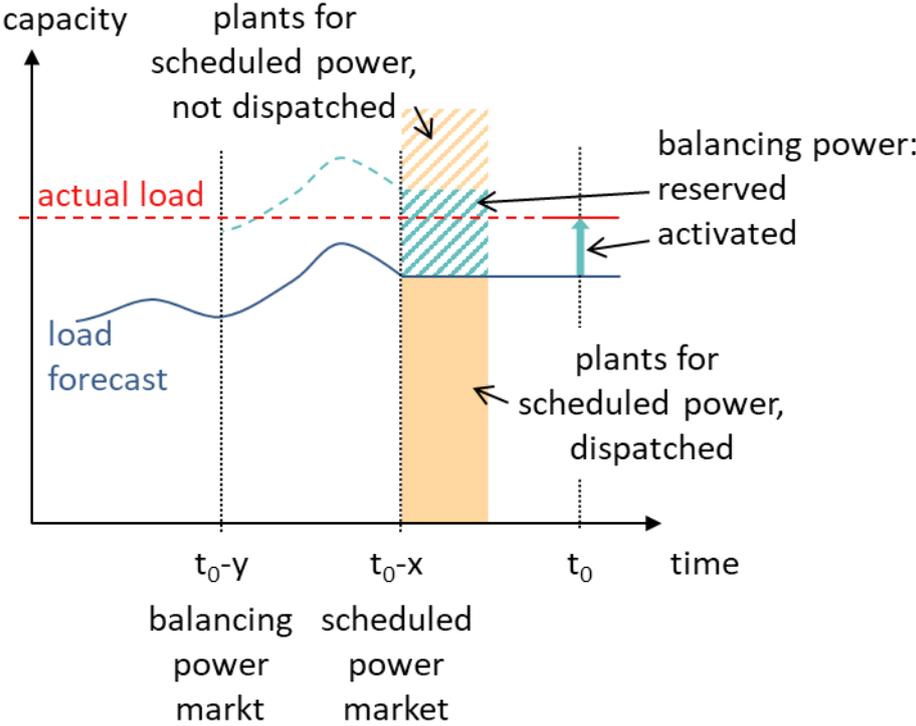
<sup>147</sup> This was described in the first project report as "balancing supply and demand after all market processes have been completed", cf. r2b / Consentec (2019) p. 63.

<sup>148</sup> This refers to the balancing group responsible parties weighing up the effort to improve their forecasting quality against the possible reduction in their balancing energy costs. A strict distinction must be made between this and a non-permissible systematic use of balancing energy.

<sup>149</sup> Strictly speaking, this is also only a simplified formulation, because in fact it is not the load that is known in absolute terms in real time, but the system balance as the difference between load and generation. However, this is irrelevant for the question discussed here.

time  $t_0$ , which changes over time because forecasts are updated repeatedly. At time  $t_0-x$ , i.e. a certain time before the operating time, the last segment of the scheduling markets (the national intraday market) closes. This is the last time at which the market participants can adjust generation to their load forecast by buying or selling on the scheduled power market.<sup>150</sup> In the example, the load forecast is below the actual load, and accordingly power plants are only used for the scheduled power market to the extent of the last forecast (filled yellow column). In the example, there would definitely have been more power plant capacity for the scheduled power market (shaded yellow column), but this is not used due to the forecast error.

**FIGURE 2-34: SCHEMATIC REPRESENTATION OF THE USE OF POSITIVE BALANCING POWER IN A SITUATION WITHOUT SCARCITY ON THE SCHEDULED POWER MARKETS**



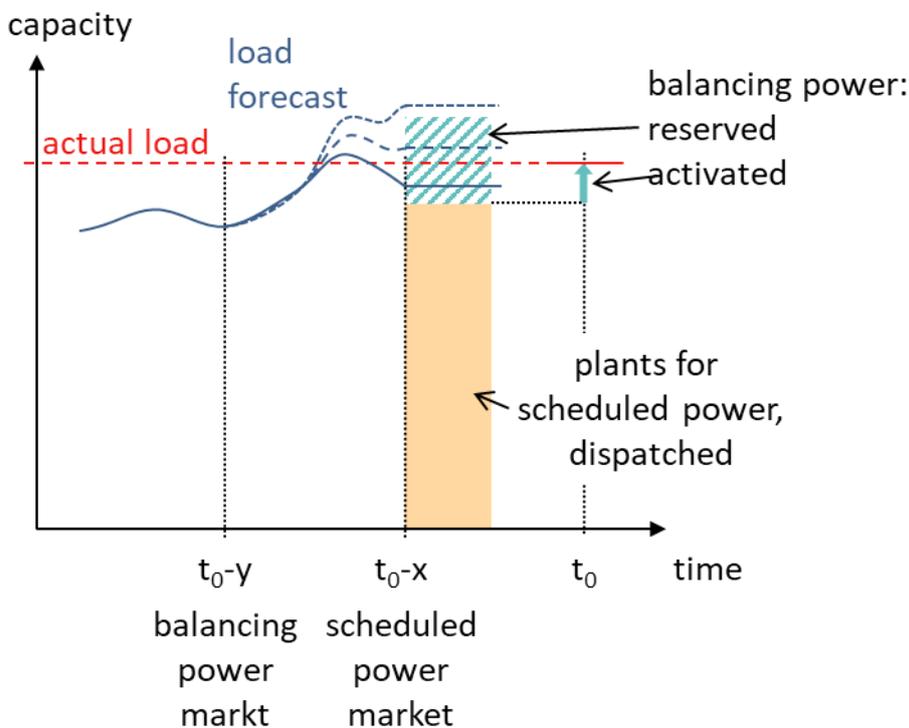
Source: Own representation.

<sup>150</sup> The generation in own plants can also still be adjusted in real time, as the settlement of the balancing energy takes place retrospectively on the basis of metered values.

Instead, the TSO uses part of the balancing power available to close the gap between the load forecast and the actual load. This use of the balancing power technically takes place at time  $t_0$ . However, the balancing power was already procured at time  $t_0-y$ , which was before the end of the scheduled power market. Thus, the load is ultimately covered exclusively by market-based dispatch of power plants.

But then, this also applies if there is a shortage on the scheduled power markets, provided that the balancing power can compensate for this. Figure 2-35 shows this case in schematic form. Here, the load forecast at the closing of the scheduled power market ( $t_0-x$ ) is higher than the power plant capacity available for the scheduled power market. The latter is therefore fully dispatched (yellow column). As in the "normal" case, the gap between the scheduled power plants dispatched and the actual load is covered by the use of balancing power.

**FIGURE 2-35: SCHEMATIC REPRESENTATION OF THE USE OF POSITIVE BALANCING POWER IN SITUATIONS OF SCARCITY ON THE SCHEDULED POWER MARKETS**



Source: Own representation.

It is irrelevant how far the load forecast exceeds the power plant capacity available for scheduled operation (see dashed blue lines with alternative forecast

curves). Even if the forecast is greater than the sum of the power plants for scheduled power and balancing power, there is neither a technical nor a market-related load excess. This is because the only decisive factor here is that the actual load can be covered by the sum of the scheduled power plants and the balancing power.<sup>151</sup> This is illustrated by the turquoise arrow in the figure, which has the same size regardless of the hypothetical load forecast curves .

From this it can be concluded that even in scarcity situations on the scheduled power markets, the mere use of balancing power<sup>152</sup> must not be interpreted as a lack of balance between supply and demand on the electricity market (as a whole). In Germany, this also becomes evident from the fact that the rule according to which the balancing energy price must be at least 20 T€/MWh only applies when the capacity reserve (Kapazitätsreserve) is actually used. Any precautionary activation of the capacity reserve is not decisive for this. If the balancing power is sufficient to cover the load after the capacity reserve has been activated, still the normal rules for balancing energy pricing on the basis of the balancing power prices apply. Consequently, even if there is no market clearing in the scheduled power market, "normal" balancing energy prices can still occur . A critical situation from the point of view of resource adequacy in the sense of this study therefore only exists if the actual load is greater than the sum of the power plants on the scheduled power market and the balancing power (such that, for example, the capacity reserve would have to be used).

The differentiation between load forecast and actual load does not take place in the abstraction of the RA analysis carried out here (as is usual for such simulations). Instead, only the actual (residual) load is considered, abstracting from the sequence of market processes. Forecast errors, which are compensated for by the balancing power, are already included therein. Likewise, uncertainties in the availability of power plants for the scheduled power market are taken into account by

---

<sup>151</sup> It also follows from this that the assessment of resource adequacy does not change if, *ceteris paribus*, power plants are reallocated between "available for the scheduled power market" and "reserved for balancing power".

<sup>152</sup> In the example, the balancing group responsible parties (or a part of them) do not undersupply themselves out of strategic consideration, but because they cannot procure sufficient power on the scheduling market.

explicit modelling of power plant outages. Consequently, the RA analysis in principle analyses the coverage of residual load by the sum of scheduled and balancing power plants<sup>153</sup> i.e., in the schematic representation of the above figures, the ratio of the sum of yellow and turquoise generation capacities to the red line.

The only exceptions to this are those parts of the balancing power that are held in reserve to compensate for high-frequency uncertainties (such as load and RE noise, ramps, schedule jumps). Such uncertainties lead to short-term fluctuations of the load around the hourly mean value and are not taken into account in the hourly residual load of the RA analysis. In particular, positive high-frequency components of the balancing power activation, which manifest themselves in an increase in load, can be critical in scarcity situations. The capacity of the plants held in reserve to cover these balancing power components may therefore not be used to cover the residual load. This is respected in the RA analysis.

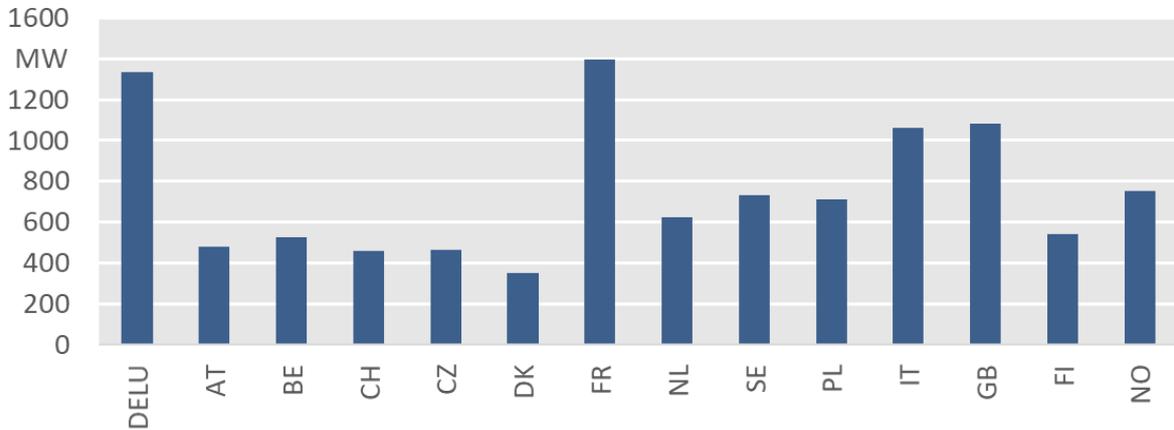
The high-frequency positive shares of the balancing power requirement were determined in accordance with the methodology described in the first project report based on 2016 data for Germany/Luxembourg and transferred to the other bidding zones in proportion to square roots of the ratios of the annual peak loads. In addition to the procedure in the first report, an analogous adjustment to the years under consideration<sup>154</sup> was made for the present report. However, since this only results in changes of a few percent, the following figure is limited to the assumptions for 2021.

---

<sup>153</sup> The acceptance of partial coverage of load by balancing power, as in the example mentioned, where there is an undersupply of balancing groups on the scheduling market, is therefore considered as a possibility in the RA model. In fact, this case occurs extremely rarely, such that a systematic or even strategic use of balancing power does neither exist nor is assumed to be permissible in the model.

<sup>154</sup> For each year under consideration and bidding zone, the mean value of the annual peak load (before a possible activation of load flexibility) was calculated across all weather years.

**FIGURE 2-36: POSITIVE HIGH-FREQUENCY SHARES OF BALANCING POWER PER COUNTRY (2021)**



Source: Own representation.

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

### 2.8.1 General information

The extent of long-distance transport of electricity is limited by the transmission capacity of the networks. In the European internal electricity market this is taken into account by the fact that Europe is divided into so-called bidding zones - which in most cases comprise one country each.<sup>155</sup> The exchange of power between bidding zones is limited by so-called transmission capacities, which are determined in advance by the TSOs. This results in a uniform market price for electricity per bidding zone, while price differences may arise between bidding zones if cross-border (ie cross-zonal) transmission capacity is insufficient for full price convergence.

When assessing the resource adequacy on the electricity market, the market structure must be appropriately reflected. This also applies to the consideration of transmission capacity. Consequently, it is necessary to reflect the future development of cross-border transmission capacities. On the one hand, this influences the international market price structure that market players take into account

<sup>155</sup> Germany and Luxembourg form a common bidding zone. Sweden, Norway, Denmark and Italy each have several bidding zones.

when making investment and disinvestment decisions. On the other hand, determines the feasible level of cross-border assistance if this is necessary to ensure security of supply and is possible by exploiting balancing effects.

Within bidding zones, by contrast, the internal electricity market abstracts from any restrictions on transmission capability. To the extent that intra-zonal congestion does occur, this is eliminated by the TSOs outside the market, for example by so-called redispatch, possibly using grid reserves. Such interventions are neutral from the point of view of the electricity market, i.e. they neither influence the price of electricity nor market-based cross-border exchanges. Therefore, they do not need to be taken into account when assessing security of supply on the electricity market. Rather, ensuring sufficient intra-zonal transmission capability is the subject of other processes that cover various time horizons, from network expansion planning to annual demand analyses to the network reserve to operational preparation and implementation of redispatch.

In the first project report, we extensively documented the procedure for modelling and parameterising the cross-border transmission capacities.<sup>156</sup> Briefly summarised, for the borders between Germany/Luxembourg, Belgium, France, Italy, the Netherlands, Poland, Austria, Switzerland and the Czech Republic, we build a flow-based model taking into account network security requirements (N-1 criterion) and required minimum capacities. At the other borders, the transmission capacities are described by NTC values.

For this second report, the concept of modelling transmission capacities and thus also the structure and resolution of the network capacity model basically remain the same. We make changes in two respects:

1. We update the assumptions on cross-border network expansion projects on the basis of updates to the relevant information bases that have in the meantime become available.

---

<sup>156</sup> Cf. r2b / Consentec (2019) Section 3.3.4 and Appendix B

2. We adapt the models to the requirements of the Clean Energy Package that has since come into force, in particular the introduction of so-called action plans.

We address these two adjustments in the following sections 2.8.2 and 2.8.3 respectively. In section 2.8.4 we show which changes in export and import capacities result from this compared to the first report.

## 2.8.2 Assumptions on cross-border network expansion projects

The assumptions on cross-border network expansion projects essentially follow the approach of the first report. Starting from the identical base year 2016, models are parameterised for the future observation years by simulating the effect of cross-border network expansion projects on transmission capacities. For this purpose, the data basis is brought up to date, which is explained in more detail below. This is followed by an overview of all relevant grid expansion projects and concrete changes to the first report.

### Updating the data basis

Two main data sources were used for the research of cross-border network expansion projects. These are the Ten Year Network Development Plan (TYNDP) of ENTSO-E and the Network Development Plan (Netzentwicklungsplan, NEP) of the German TSOs. While the current version of the TYNDP was still that of 2016 in the course of the first report, the 2018 version was available when the investigations for this second report were carried out. On the basis of this version, we have updated all reported cross-border network expansion projects. This resulted in particular in adjustments to the commissioning years. However, the effect on the level of exchange capacities was also examined. There is a fundamental difference here compared to the TYNDP 2016, in which an increase in grid transfer capacity (GTC) was specified for the effect of each grid expansion project, in which the effect of each grid expansion project was expressed as an increase in Grid Transfer Capacity (GTC), which describes the effect of the project on the permissible physical power flows per bidding zone border. In contrast, the TYNDP 2018 shows the respective increase in the Net Transfer Capacity (NTC), which describes the upper limit of the bilateral commercial power exchange between

two neighbouring bidding zones. However, a comparison based on unchanged network expansion projects shows that the same numerical values are given in both cases. Accordingly, we assume that changed capacities between TYNDP 2016 and TYNDP 2018 are not due to a change in the definition of the capacity measure, but to an actual change in the forecast of the impact of the network expansion project in question.

In addition, there are projects that were not considered in the first report, but whose status has changed in such a way that we now consider it appropriate to consider them in the second report.

A newer version (2019) of the NEP is now also available, updating the one used in the first report (2017). For this reason, we have again compared the years of commissioning. In the case of a difference between TYNDP and NEP, the NEP is still assumed to be the leading source.

In the course of the consultation, the assumptions on commissioning years were checked by the BNetzA and the German TSOs and largely confirmed. Only for one project did a comparison with the BNetzA's<sup>157</sup> monitoring reveal a discrepancy. In this case the more up-to-date information from the monitoring was adopted.

### Grid expansion projects considered

The table below lists all network development projects that have been considered in the first and/or this second project report. Both the year under review, from which on we take the expansion into account in the model, and the impact on the NTC of the respective border as assumed for this report are provided. For comparison purposes, the year under review and the GTC increase used in the first report are shown to the right. All changes to the first report (including project numbers or names) are highlighted in bold face.

---

<sup>157</sup> [www.netzausbau.de](http://www.netzausbau.de)

**TABLE 2-9: CROSS-BORDER NETWORK EXPANSION PROJECTS TAKEN INTO ACCOUNT, YEARS UNDER REVIEW FROM WHICH THEY ARE TAKEN INTO ACCOUNT IN THE MODEL AND CAPACITY INCREASE ACHIEVED IN COMPARISON BETWEEN FIRST AND SECOND PROJECT REPORT**

TYNDP project no.	Identifier	Country 1	Country 2	Taken into account from		NTC increase		GTC increase	
				Report 2	Report 1	2nd report		1st report	
						1->2 [MW]	2<-1 [MW]	1->2 [MW]	2<-1 [MW]
36	Kriegers Flak CGS	EN	DKE	2021	2018	400	400	150	400
113	Doetinchem - Lower Rhine	EN	NL	2018	2018	1500	1500	1100	1100
172	ElecLink	FR	GB	2021	2018	1000	1000	1000	1000
21	Italy-France	IT	FR	2021	2020	1000	1200	1000	1200
25	IFA2	FR	GB	2021	2020	1000	1000	1000	1000
37	NordLink	EN	NO	Phase-in: 2021 2023 2025	2020	700 1050 1400	700 1050 1400	1400	1400
39	DKW-DE, step 3	EN	DKW	2021	2020	1000	720	1000	720
71	COBRA cable	DKW	NL	2021	2020	700	700	700	700
74	Thames Estuary Cluster (NEMO)	GB	BE	2021	2020	1000	1000	1000	1000
92	ALEGrO	EN	BE	2021	2020	1000	1000	1000	1000
94	GerPol Improvements	EN	PL	2023	2020	500	1500	2000	1000
245	Upgrade Meeden - Hallway	EN	NL	2021	2020	300	300	300	n.a.
26	Reschenpass Interconnector Project	IT	AT	2021	2020	300	300	1000	1100
313	Isar-St. Peter	EN	AT	2028	2020	2000	2000	Included in project 47	
250	Merchant line "Castasegna (CH) - Mese (IT)	IT	CH	2021	2020	100	100	100	100
23	France-Belgium Phase 1	FR	BE	2023	2023	1000	1000	800	800
31	Italy-Switzerland	CH	IT	2025	2023	750	750	1100	600
40	Belgium-Luxembourg-Germany: long-term perspective	LU	BE	not considered	2023	500	500	900	900

TYNDP project no.	Identifier	Country 1	Country 2	Taken into account from (reference scenario)		NTC increase		GTC increase	
				Report 2	Report 1	2nd report		1st report	
						1->2 [MW]	2<-1 [MW]	1->2 [MW]	2<-1 [MW]
47	Vöhringen-Westtirol	EN	AT	not considered	2023	600	600	2900	2900
110	Norway-Great Britain North Sea Link	NO	GB	2021	2023	1400	1400	1400	1400
150	Italy-Slovenia	AT	IT	2025	2023	1000	1000	1000	800
153	France-Al-derney-Britain	FR	GB	2023	2023	1400	1400	1400	1400
167	Viking DKW-GB	DKW	GB	2023	2023	1400	1400	1400	1400
174	Greenconnector	CH	IT	2023	2023	850	850	800	800
183	DKW-DE, West-coast	EN	DKW	2021	2023	500	500	500	500
190	NorthConnect	GB	NO	2023	2023	1400	1400	1400	1400
198	Area of Lake Constance	AT	CH	not considered	2025	Included in project no. 263		1000	1000
263	Lake Constance East	DE/ CH	AT/ CH	not considered	2023	CH-AT 200/100 DE-CH 250/600 DE-AT 1000/1000		0	
16	Biscay Gulf	FR	ES	2025	2025	2200	2200	2200	2600
111	3rd AC Finland-Sweden north	FI	SE	2025	2025	800	900	800	500
176	Hansa Power-Bridge 1	EN	SE	2028	2025	700	700	700	700
187	St. Peter - Pleinting	EN	AT	2025	2025	1500	1500	1500	1500
225	2nd inter-connector Belgium - Germany	EN	BE	not considered	2025	1000	1000	1000	1000
228	Muhlbach - Eichstetten	EN	FR	2025	2025	300	300	300	300
231	Concept Project DE-CH	EN	CH	not considered	2025	1000	1000	700	700
270	FR-ES project - Aragon-Atlantic Pyrenees	FR	ES	2028	2025	1500	1500	1500	1500
276	FR-ES project - Navarra-Landes	FR	ES	2028	2025	1500	1500	1500	1500
229	GerPol Power Bridge II	EN	PL	not considered	2030	1500	0	1500	0
244	Vigy - Uchtelfangen area	EN	FR	not considered	2030	1500	1500	1500	1500

TYNDP project no.	Identifier	Country 1	Country 2	Taken into account from (reference scenario)		NTC increase		GTC increase	
				Report 2	Report 1	2nd report		1st report	
						1->2 [MW]	2<-1 [MW]	1->2 [MW]	2<-1 [MW]
<b>New projects</b>									
247	AQUIND Interconnector	GB	FR	2023	not considered	2000	2000	2000	2000
262	Belgium-Netherlands: Zandvliet-Rilland	NL	BE	2023		1000	1000	1000	1000
285	GridLink	FR	GB	2023		1400	1400	1500	1500
309	NeuConnect	EN	GB	2023		1400	1400	1400	1400
375	Lienz (AT) - Veneto region (IT) 220 kV	AT	IT	2025		150	150	Included in project 26	

Source: Own representation.

### 2.8.3 Consideration of the requirements of the Clean Energy Package on electricity trading capacities

For the first report, we had assumed, on the basis of the then draft status of the electricity market regulation of the Clean Energy Package (CEP), that in future, (formulated in a simplified way) a minimum capacity of 75 % of the transmission capacity of the interconnectors should be made available for cross-border electricity trading.

Such a minimum capacity is also provided for in the version of the CEP (more precisely: the Electricity Market Regulation<sup>158</sup>) that has since come into force. Formally, it is now expressed as a numerical value of 70 %, but at the same time the definition has changed slightly because the so-called flow reliability margin may no longer be counted towards the minimum capacity. Within the scope of the accuracy achievable here, this leads to approximately identical specifications.

<sup>158</sup> Cf. European Parliament and Council (2019).

In the first report, however, we had assumed this for all years under review from 2020 onwards. In contrast, the final CEP foresees the possibility for member states to gradually increase to the 70% target by introducing action plans.

In Germany, an action plan has been in place since 2020, so that the minimum capacity will be raised in annual steps from a starting value to the final value of 70 %, which will apply from 2026 according to the CEP.

For the replication of this so-called trajectory in our model, we take into account that a minimum capacity of 20 % has already applied in the Central West Europe (CWE) region since 2018. Translated into the definition of the Electricity Market Regulation, this represents an even higher value than 20 %, since in CWE the power flows from non-CWE exchanges are not included in the 20 %. The requirement under the Electricity Market Regulation, on the other hand, applies to the total flows from all cross-border capacities.

Furthermore, we take into account the fact that we built our model from 2016, i.e. the historical NTC values from 2016 continue to be the "anchor" of the model.

As in the first report, we use the maximum and minimum net position of the bidding zone Germany/Luxembourg as a reference value for parameterising the model.

Degrees of freedom for the parameterisation are the two scaling factors that we also used for the first report, i.e.

- the scaling of the Maximum Border Flows (MBF)<sup>159</sup> and
- the scaling of the fitted NTCs<sup>160</sup> in such a way that the maximum possible export or import capacities of the bidding zone Germany/Luxembourg fall to a predefined proportion of the value that would result without the restriction by the fitted NTCs.

Both factors were 0.9 for the first project report. We retain the identity per year under review, but now allow the factors to differ from year to year. The flow-

---

<sup>159</sup> Cf. r2b / Consentec (2019) Appendix B.1

<sup>160</sup> Cf. r2b / Consentec (2019) Appendix B.2

based model for our analysis is thus "shrunk" with scaling factors that are individual for each year under review.

The sequence is as follows:

- The scaling factors are chosen for 2016 in such a way that the mean value of the amounts of maximum and minimum net position in the flow-based model is equal to the mean value of the maximum and minimum net positions that resulted from the historical NTCs in 2016.
- The scaling factors are increased linearly for the following years, so that in 2026 they mathematically reach the value that was applied in the first report.

We thus assume that if the flow-based model had already applied in 2016, it would have yielded the maximum/minimum net positions of the actual NTCs, and from there it would be raised linearly to the target value of 70 % minimum capacity by 2026. Thus, certain minimum capacities would also already apply in 2018, which was indeed the case in reality. Ultimately relevant for this study are the capacities for the years under review 2021, 2023, 2025 and 2030.

#### **2.8.4 Development of import/export opportunities**

As a benchmark to illustrate the effect of the changed assumptions, we use the indicator of maximum possible import or export capacity, which was also used in the first project report.<sup>161</sup>

Figure 2-37 shows three lines per direction for the bidding zone Germany/Luxembourg. The darker line represents the values of the first report, the lighter solid line those of the second report. The dashed light line represents the export/import capacities that would result if only the assumptions regarding the Electricity Market Regulation (trajectory) were changed compared to the first report.

---

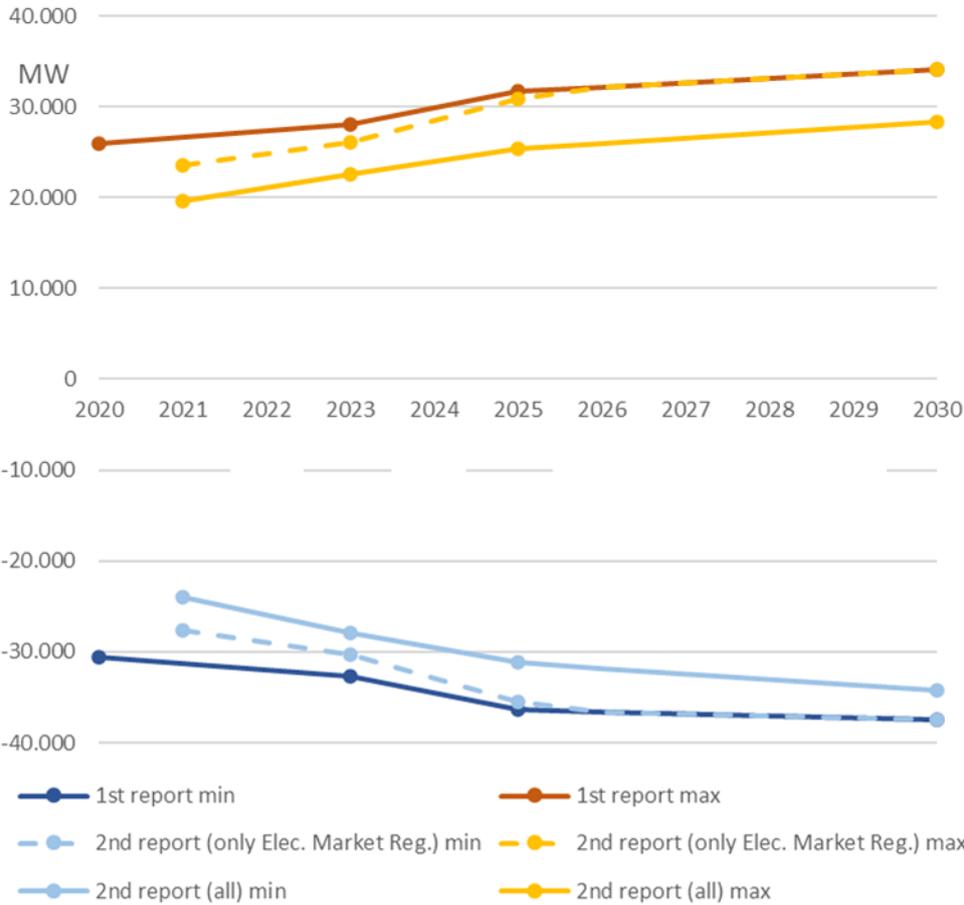
<sup>161</sup> These values are calculated separately per bidding zone and direction and cannot be realised simultaneously. Rather, to achieve the maximum export or import of a bidding zone, a special constellation of the exports or imports of the other bidding zones may be required. See also r2b / Consentec (2019) Appendix B.2.

The dashed lines clearly show that the gradual increase in minimum capacity has a greater impact on the earlier years than on the later ones. In 2030, the dashed light and solid dark lines converge by definition.

The additional consideration of the updated grid expansion plans shows that, apart from a few exceptions where the values remain the same, this essentially results in further reductions in export/import capacities. This is due to the delay of a significant number of grid expansion projects.

Overall, this results in a reduction of 5.5 GW (export) and 4.8 GW (import) in 2023 compared to the first report, which increases to 5.8 GW (export) and decreases to 3.3 GW (import) by 2030.

**FIGURE 2-37: COMPARISON OF MAXIMUM (=EXPORT) AND MINIMUM (=IMPORT) NET POSITIONS OF THE BIDDING ZONE GERMANY/LUXEMBOURG BETWEEN FIRST AND SECOND PROJECT REPORT**



Source: Own representation

## 2.9 Assumptions on the distribution of load excess among the bidding zones

When carrying out the RA analysis, it must be determined how the balancing of load excess in different bidding zones is to be carried out. This is because cross-border assistance can be used within the framework of transmission capacities to shift load excess partially or completely between bidding zones. In the first report, we explained that in this project, cross-border assistance is only permitted to the extent that it does not result in an (additional) load excess in the bidding zone providing assistance.<sup>162</sup> This specification helps to localise the cause of the load excess. In terms of modelling, this was implemented in such a way that cross-border power exchanges were slightly penalised so that they are only carried out insofar as the total sum of the load excess can be reduced as a result.

However, this can theoretically lead to indifference in the calculation model, which could result in arbitrary result contributions in certain constellations. We have remedied this by refining the model, as explained below.

If a bidding zone can provide assistance (to a limited extent but not completely) to two or more other bidding zones, which are simultaneously dependent on imports to avoid load excess, then the distribution of the assistance between the bidding zones with import requirements could previously be arbitrary.

For example, a point in time is considered at which Germany/Luxembourg has an import demand of 4 GW with 70 GW of load. At the same time, Belgium has an import demand of 2 GW with a load of 10 GW. It is assumed that France (taking into account the grid restrictions) can help Belgium and/or Germany/Luxembourg with a maximum of 4 GW of exports. Thus, on balance, there is a load excess of 2 GW in total.

In reality, the final distribution of the assistance would depend on the behaviour of the entities in all successive market stages (especially day-ahead and intraday). This cannot be modelled precisely due to the lack of international harmonisation of the rules of relevant market processes and their possible adjustment after the

---

<sup>162</sup> See r2b / Consentec (2019), Section 3.3.6.

occurrence of corresponding scarcity situations. Therefore, this project, as mentioned above, focuses on identifying the geographical cause of the load excess. In the example considered, this is located in Germany/Luxembourg as well as in Belgium.

In the previous modelling, several solutions would have been formally equivalent in such a situation: After the full exhaustion of the French assistance, load excess could have remained only in Germany/Luxembourg, only in Belgium or in both bidding zones to a lesser extent, because all these situations have both the same summary loss of load of 2 GW and the same amount of cross-border exchanges of 4 GW.

In order to exclude such an indifference, the model was adjusted for this report so that the total remaining load excess is shared among the bidding zones with import demand in proportion to their load. In the example,  $2 \text{ GW} * 70 / (70+10) = 1.75 \text{ GW}$  remain in Germany/Luxembourg and  $2 \text{ GW} * 10 / (70+10) = 0.25 \text{ GW}$  in Belgium. It is therefore ensured that in such cases all bidding zones with import demand always have a load excess and that its share of the load in these bidding zones is identical (2.5 % in the example).

The model implementation is based on the design of the European day-ahead market coupling<sup>163</sup> - not because this would determine the final result in reality (cf. above statement on later market processes), but because there is an established method for distributing excess demand. It consists of two elements: ensuring that load excess is only allocated to bidding zones with import demand, and equalizing the share of loss of load in the load among these bidding zones.

---

<sup>163</sup> NEMO Committee (2019).

### 3 Results reference scenario

In this chapter, we first present the results of the electricity market simulations for the reference scenario with regard to the development of power plants and the development of flexibility options for Germany and the European countries considered. The years under consideration are 2021, 2023, 2025 and 2030.

Subsequently, in Section 3.2, we present the benefits in terms of load balancing effects, feed-in of supply-dependent renewables, and unplanned outages of conventional power plants in a common internal market, specifically in the electricity markets of 15 countries considered simultaneously in this study.

In Section 3.3 we present the results of the RA analyses for the reference scenario. The chapter concludes with a short interim conclusion in Section 3.4.

The model calculations on which this report is based were carried out in the second half of 2020.

[Here we will integrate a summary of the thoughts of the consultation participants after the results have been consulted].

#### 3.1 Results of electricity market simulations

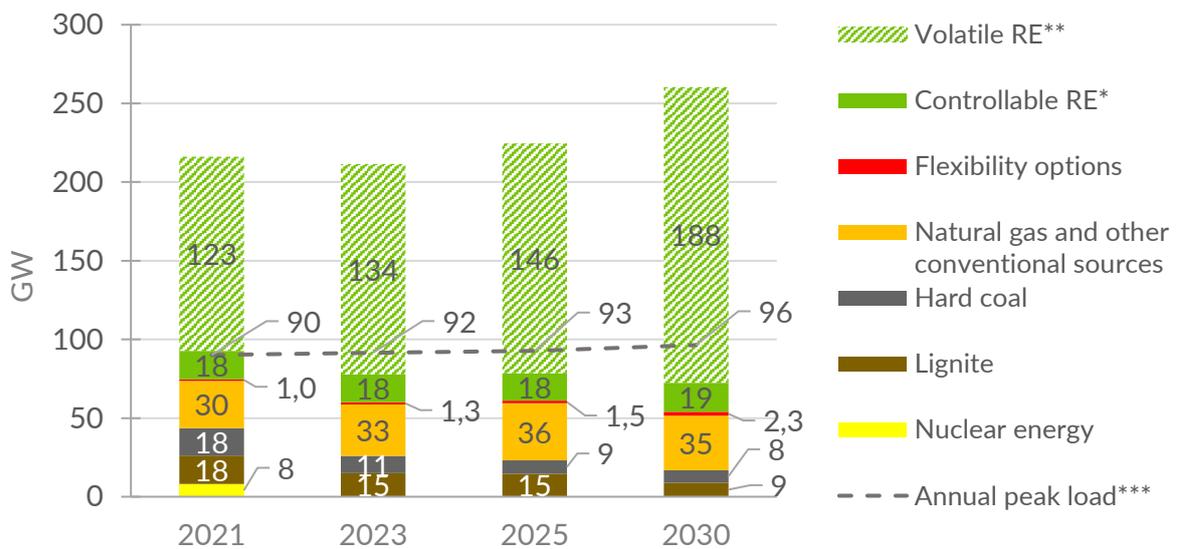
In this section, we first describe in Section 3.1.1 how power plants and flexibility options in Germany develop over time. In doing so, we show which developments are due to exogenous requirements and which ones result from model-induced market adjustment processes due to price signals on the wholesale electricity market. In Section 3.1.2 we then show the development of power plants and the development of flexibility options for the considered foreign markets.

##### 3.1.1 Development of resources in Germany

The development of power plants and the development of flexibility options are the central result of the dynamic and stochastic simulation calculations with the European electricity market model of r2b energy consulting GmbH and are shown in Figure 3-1. We only present those capacities that are actually available for the market. Both regulatory reserves and power plant capacities conserved in the longer term (so-called cold reserves) are not taken into account in the information on capacity development or in the downstream quantitative RA analyses. In the

figure, we have differentiated between controllable output and the output of volatile renewable energies.<sup>164</sup>

**FIGURE 3-1: DEVELOPMENT OF THE CONVENTIONAL POWER PLANT FLEET, THE ANNUAL PEAK LOAD, AND CONTROLLABLE AS WELL AS VOLATILE FEED-IN CAPACITIES OF RENEWABLE ENERGIES**



- \* Controllable RE: storage- and pump storage, biomass (incl. bio waste) and other RE.
- \*\* Volatile RE: wind, PV and run-of-river plants.
- \*\*\* Maximum over all six weather years incl. all flexibility options (excluding electricity for pumping)

Source: Own calculations.

The volatile feed-in capacity from onshore and offshore wind energy, PV and run-of-river energy amounts to 123 GW in 2021 and increases continuously to approx. 188 GW in 2030. This is in line with the Federal Government's resolutions on the share of RE in gross electricity consumption of 65 %.<sup>165</sup> The overall installed capacity of controllable electricity generation plants, on the other hand, decreases. Compared to the sensitivity "Achievement of climate protection targets" from the first project report<sup>166</sup>, there are only minor differences regarding the development of resources in Germany, e.g. in the installed capacity of volatile

<sup>164</sup> In practice, both have a positive impact on RA, as these are reserves that represent additional available capacity to meet demand with little lead time.

<sup>165</sup> For detailed assumptions on the expansion of renewable energies in Germany, see Sections 2.3.1 and 2.3.2.

<sup>166</sup> Cf. r2b / Consentec (2019).

renewable energies or the time plan for the implementation of the recommendations of the Commission "Growth, Structural Change and Employment" compared to the KVBG, that has been adopted in the meantime.

The installed capacity from storage and pumped storage, bioenergy and other renewable energies will remain largely constant at approx. 18 to 19 GW until 2030. The installed capacity of power plants fired by natural gas, oil and other non-renewable energy sources increases after a decline to about 30 GW in 2021, as about 4.9 GW are temporarily placed in cold reserve due to a lack of economic efficiency and are no longer available to the market to about 33 GW in 2025 and about 35 GW in 2030, mainly driven by the expansion of natural gas CHP (see Figure 2-9). The capacity of coal-fired power plants, on the other hand, decreases significantly over time. For the reference scenario in Germany, we do not allow coal-fired power plants to be closed for economic reasons, i.e. before the exogenously stipulated closure date is reached, because of the hard coal closure tenders and the legally stipulated latest closure dates for lignite pursuant to the KVBG. The decommissioning dates of the German coal-fired power plants are thus exogenously specified for the model in the reference scenario.<sup>167</sup> We have based this on the regulations of the KVBG.<sup>168</sup>

For hard coal and lignite, the installed capacity in 2021 is still approx. 18 GW each and then falls to approx. 15 GW for lignite and approx. 11 GW for hard coal in 2023, in accordance with the KWSB decision. In 2025, the market capacity of lignite plants will be approx. 15 GW and that from hard coal approx. 9 GW. The hard coal capacity indicated up to and including 2025 does not include the Weiher III and Bexbach power plants (which have been provisionally notified to the BNetzA for decommissioning), as they do not participate in the market. However, as the plants are legally expected to return to the electricity market at any time,

---

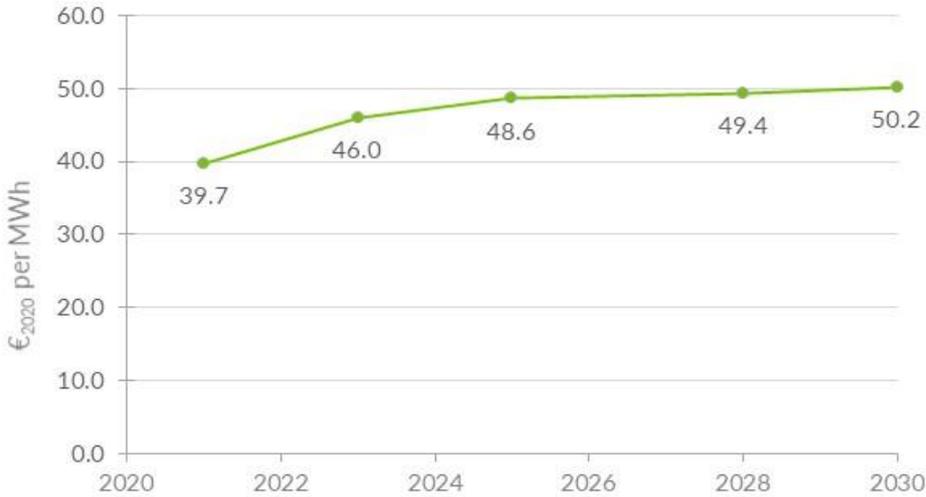
<sup>167</sup> In the two scenarios for "enhanced sector coupling", on the other hand, premature endogenous closures are permissible, since premature coal closures cannot be considered improbable, especially with the more ambitious CO<sub>2</sub> price developments assumed there (cf. also Sections 4.2 and 4.3).

<sup>168</sup> The assumption that coal-fired power plants in Germany cannot be decommissioned due to a lack of economic viability adequately reflects the current situation following the enactment of the KVBG, as compensation payments for operators are forthcoming in the context of mutually agreed power plant decommissioning.

they must be included in the target quantities for reducing coal-fired power generation in accordance with the KVBG.<sup>169</sup> The capacity theoretically available to the market is thus approx. 1.4 GW above the figures in this report up to and including 2025 (e.g. in Figure 3-1). By 2030, the installed capacity of hard coal-fired power plants declines further to just under 8 GW and for lignite to just under 9 GW. According to the Nuclear Energy Phase-out Act, the installed capacity of nuclear energy is already completely off the grid in 2023. The flexibility options DSM (voluntary load reduction by industry), EPS (emergency power systems) and large-scale battery storage are only being developed in Germany to a moderate but increasing extent over time. The developed capacity of these flexibility options amounts to approx. 1.0 GW in 2021 and then increases to approx. 1.5 GW in 2025 and further to approx. 2.3 GW by 2030.

The base price (average hourly price of a year; average over all weather years 2009-2013 and 2017) increases slightly over time, as shown in Figure 3-2, and is approximately €<sub>2020</sub> 50 per MWh in 2030.

**FIGURE 3-2: DEVELOPMENT OF THE ANNUAL BASE PRICES IN GERMANY AVERAGED OVER ALL WEATHER YEARS IN THE REFERENCE SCENARIO**

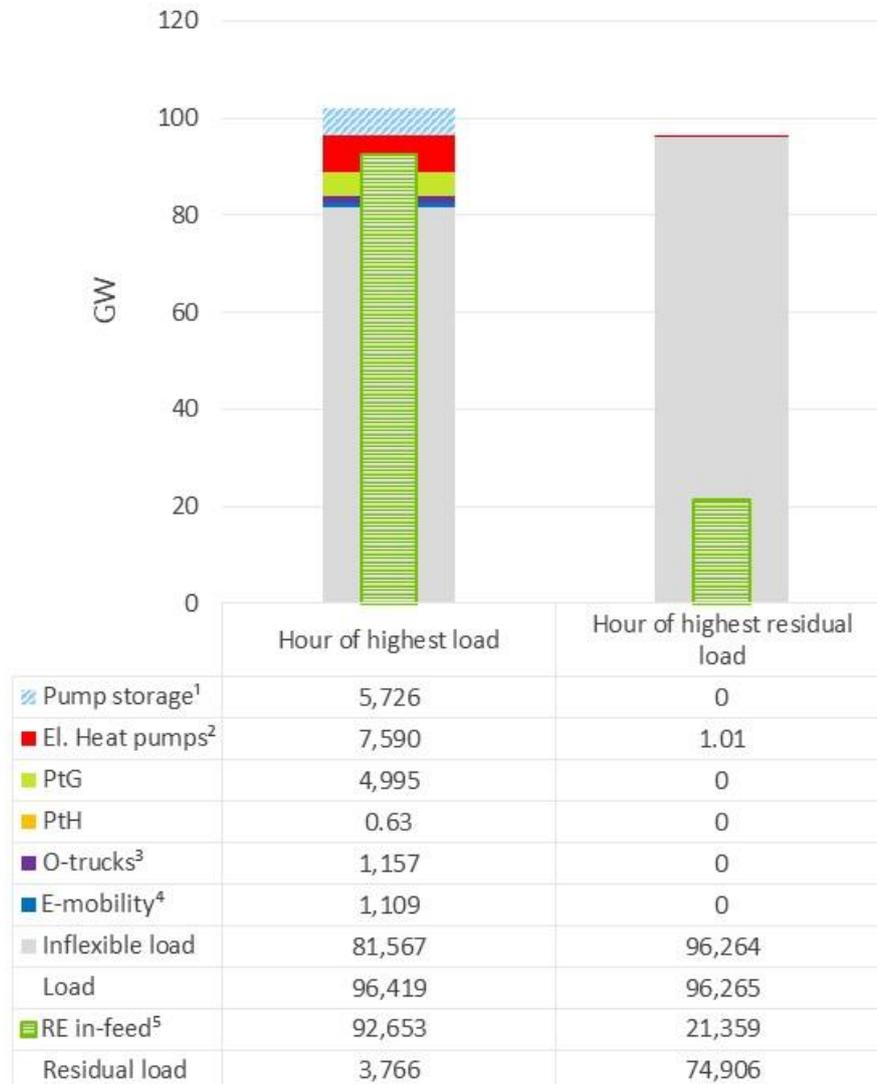


Source: Own calculations.

<sup>169</sup> This procedure also represents the conservative approach from RA's point of view, as the output from these two power plants is not available to the market in the simulation calculations, although in reality they can return to the market in the short term.

The annual peak load now (also in contrast to the first project report) increases over time. This is mostly due to the addition of further sector coupling technologies in the form of PtH (electric heaters and large heat pumps) and PtG (PtH<sub>2</sub> and PtG methane). As can be seen by the example of 2030 in Figure 3-3, the hour of the annual peak load is not a shortage situation on the electricity market, since at this particular hour a large amount of volatile RE plants also feed into the grid. Even the maximum unplanned power plant outages of approx. 11.6 GW occurring in this hour, which occur in one of 350 Monte Carlo simulation hours of this hour in the context of the RA analysis, do not lead to a tight supply situation. The reason for this is that the share of flexible electricity applications in the total load is comparatively high, although these reference loads could have been shifted at least partially. The overhead contact line trucks, which are operated in bivalent mode, also do not switch to diesel operation during this hour in order to reduce the power load on the grid. The annual peak load in 2030 is therefore an economic market result due to low electricity prices on the wholesale market and therefore not challenging in terms of meeting demand.

FIGURE 3-3: COMPARISON OF THE HOUR OF THE ANNUAL PEAK LOAD WITH THAT OF THE RESIDUAL ANNUAL PEAK LOAD; YEAR 2030; WEATHER YEAR 2010.



- 1) The electricity consumption of the pump storages' pumps is not accounted for in the annual peak load and is shown here for information purposes only. The electricity consumption of the pump storages' pumps is not accounted for in the annual peak load and is shown here for information purposes only. The amount is also not included in the total load.
- 2) Only the flexible share of the heat pumps' electricity consumption is shown.
- 3) Overhead-line trucks are hybrid trucks, which switch to diesel mode at high electricity prices.
- 4) Only the share of electric vehicles with controlled charging is displayed.
- 5) Volatile EE: wind. PV and run-of-river.

Source: Own calculations.

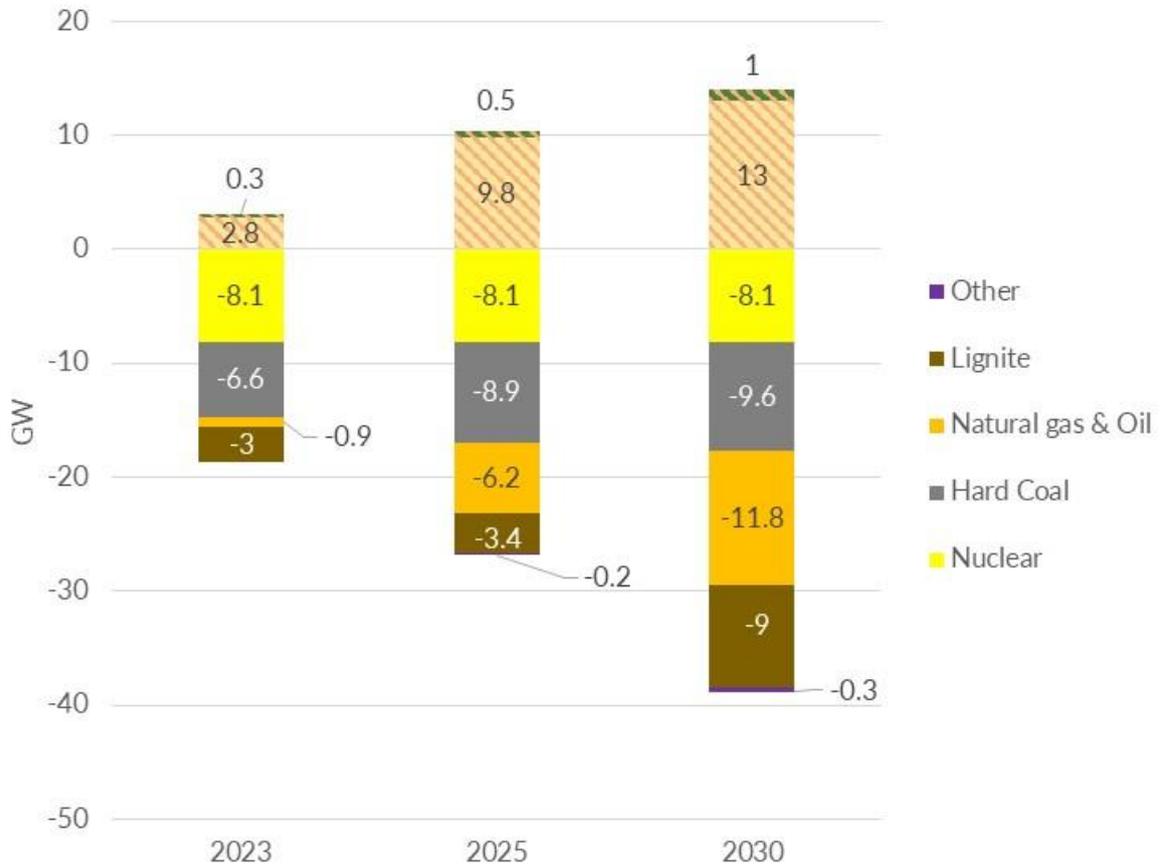
More decisive for the assessment of resource adequacy is the level of the residual peak load, which is also shown in the figure (right), which peaks at 72.6 GW in the

relevant weather year 2010. The residual annual peak load is defined as the maximum remaining load when the feed-in from volatile renewables is deducted (in comparison: the residual load at the time of the annual peak load is very low at just under 4 GW).

The time of the residual annual peak load is thus characterised by a high proportion of non-controllable (inflexible) load with simultaneously very low feed-in from volatile RE. Then, by definition, the load of the flexible new consumers is very low at this time. The smart charging part of the electric cars does not draw any power in this hour, the electric heat pumps are only operating to a very small extent and the overhead line trucks have switched to diesel operation. Thus, the inflexible load in this hour is almost equal to the total load. Even in this shortage situation, the maximum unplanned power plant outages of approx. 11.5 GW, (which occurs in one out of 350 Monte Carlo simulation hours of this hour in the RA analysis) do not lead to a load excess.

Due to the assumptions regarding the technical lifetimes of the power plants, the replacement of decommissioned CHP plants (cf. Section 2.2), the coal phase-out according to the KVVG and the nuclear phase-out, the results take into account the following decommissionings and additions, which are exogenously given to the model (cf. Figure 3-4).

FIGURE 3-4: EXOGENOUSLY PREDICTED CUMULATIVE ADDITIONS AND DECOMMISSIONINGS COMPARED TO 2021 IN GERMANY



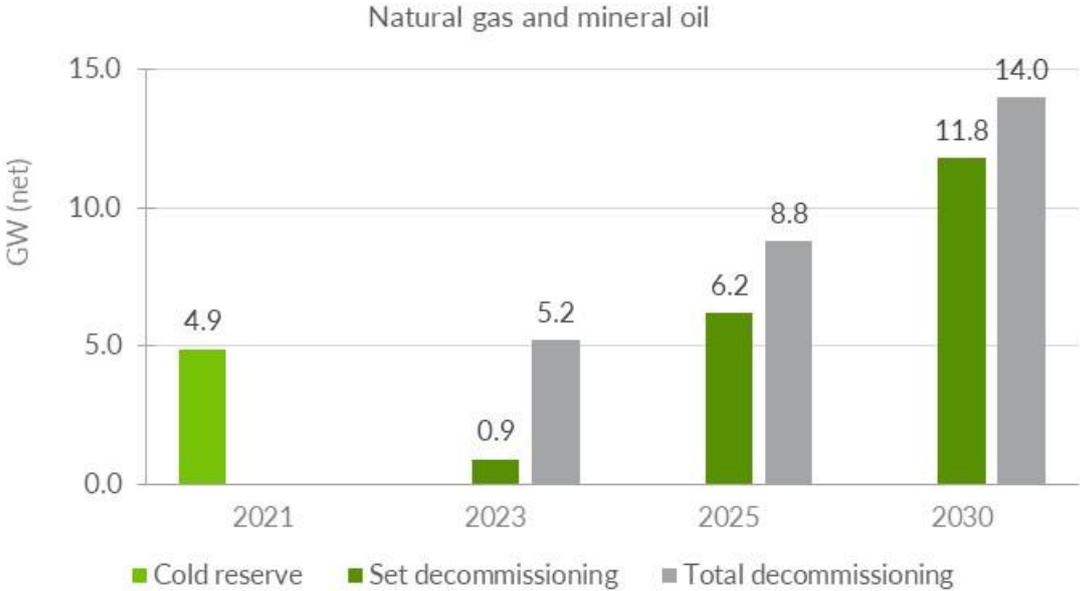
Source: Own assumptions.

In 2023, compared to 2021, we provide the model a total of about 18.7 GW for decommissioning and 3.1 GW of additions. The closures consist of 8.1 GW of nuclear energy, 3.0 GW of lignite, 6.6 GW of hard coal, 0.9 GW of natural gas & mineral oil and 50 MW of plants that are operated with other fossil fuels. The additions include 300 MW of CHP (each smaller than 1 MW) and 2.8 GW of natural gas CHP in industry and district heating supply. Cumulative decommissioning naturally continues to increase successively over time. They amount to approx. 26.8 GW in 2025 and 38.7 GW in 2030. The cumulative exogenously specified expansion based on natural gas CHP also continues to increase over time. This amounts to approx. 10.3 GW in 2025 and approx. 14 GW in 2030. The exogenously specified net capacity decline compared to 2021 thus amounts to approx. 24.7 GW in 2030.

In contrast to the reference scenario from the first report, the decommissioning dates of the coal-fired power plants in Germany are exogenously specified in this report's reference scenario, in accordance with the KVBG.<sup>170</sup> Accordingly, in the model, early closures for economic reasons in the reference scenario are only possible for gas and oil-fired plants. For these plants, the latest decommissioning dates are specified instead of exact decommissioning dates, in particular, with assumptions on maximum technical service life.

The power plant units can thus be decommissioned either earlier (disinvestment) or temporarily (cold reserve) in line with the model, if the economic operation of the plants is (temporarily) no longer ensured (cf. Figure 3-5).<sup>171</sup>

**FIGURE 3-5: EXOGENOUSLY PRESCRIBED VS ENDOGENOUS CUMULATIVE REDUCTIONS VS 2021 IN GERMANY**



Source: Own calculations.

<sup>170</sup> Cf. Section 2.2.2.

<sup>171</sup> For the model logic of temporary closures (*cold reserve*) and final closures, see r2b / Consentec (2019) Section 3.2.2.

In 2021, final endogenous closures are not allowed in the model.<sup>172</sup> However, 4.9 GW will be transferred to the cold reserve. By 2023, 0.9 GW will be decommissioned exogenously due to specified technical lifetimes, and in addition there will be endogenous early decommissioning of approx. 4.3 GW. In the reference years 2025 and 2030, there are also fewer natural gas and mineral oil-fired plants on the market due to the endogenous early closures. The decommissioned plants are open gas turbines and older gas-fired steam power plants. Modern CCGT power plants are not decommissioned endogenously.

There will be no endogenous expansion of generation plants in Germany in the period up to 2030. Only a small number of flexibility options (voluntary load reduction by industry and emergency power systems) will be developed. The reasons why no conventional generation plants will be built in Germany beyond the exogenous requirements are the extensive cross-border balancing effects and, in some cases, overcapacities in the foreign countries considered with capacity markets.

### **3.1.2 Development of resources in the foreign electricity markets considered**

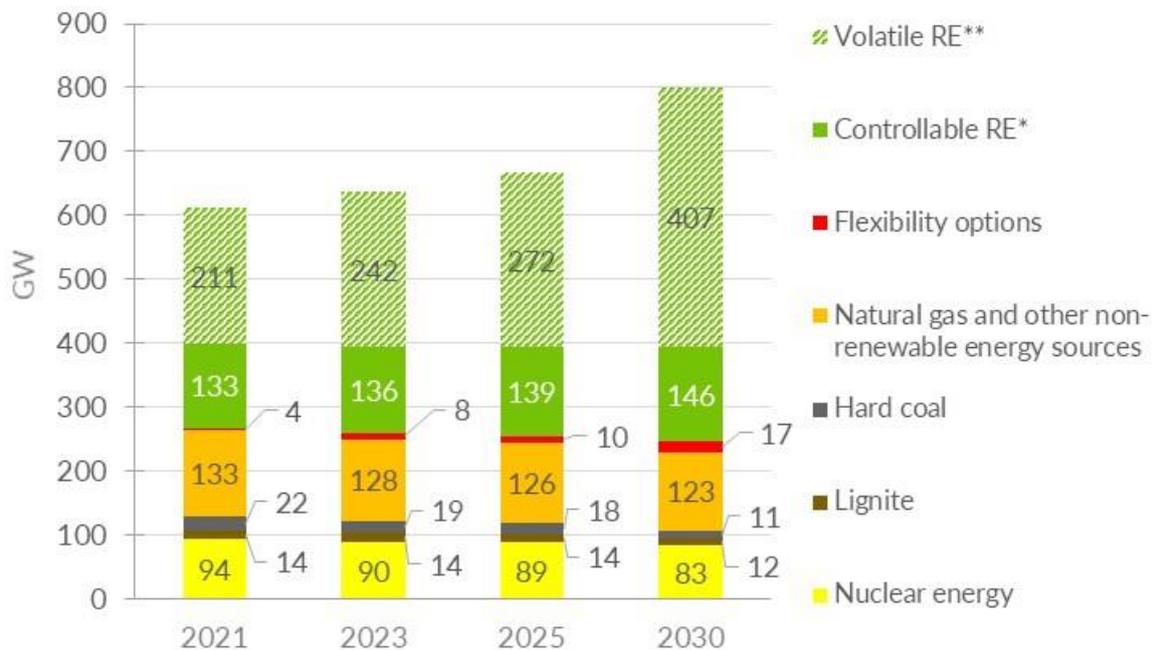
In the European countries under consideration (AT, CH, FR, GB, IT, LU, BE, DK, NL, PL, CZ, FI, SE, NO), the development of power plants is also characterised by a strong increase in the volatile feed-in of renewable energies, onshore and offshore wind energy and PV. In total, the installed capacity of volatile renewable energies (wind, PV, run-of-river) increases significantly from 211 GW in 2021 to 407 GW in 2030.<sup>173</sup>

---

<sup>172</sup> Strictly speaking, the model would have shut down part of the cold reserve in 2021 already. However, while we allow temporary closures in the reference year 2021 in agreement with the BMWi, final closures are only allowed in the reference year 2023. Therefore, part of the natural gas cold reserve will be temporarily decommissioned in the reference year 2021 and then permanently in the reference year 2023. Irrespective of this, we do not include plants in the cold reserve in the downstream quantitative resource adequacy analyses to use a conservative approach.

<sup>173</sup> For detailed information on the development of renewable energy in the foreign countries under consideration, see Section 2.3.4.

FIGURE 3-6: DEVELOPMENT OF THE CONVENTIONAL POWER PLANT FLEET IN THE FOREIGN COUNTRIES CONSIDERED (WITHOUT GERMANY)



- \* Controllable RE: storage- and pump storage, biomass (incl. bio waste) and other RE.
- \*\* Volatile RE: wind, PV and run-of-river plants.
- \*\*\* Maximum over all six weather years incl. all flexibility options (excluding electricity for pumping)

Source: Own calculations.

The installed capacity of controllable renewables (storage, pumped storage and bioenergy) increases by about 13 GW over time between the years 2021 and 2030 and amounts to 146 GW in 2030. Of these 146 GW, 115 GW are accounted for by storage and pumped storage plants and a further 31 GW by bioenergy plants.

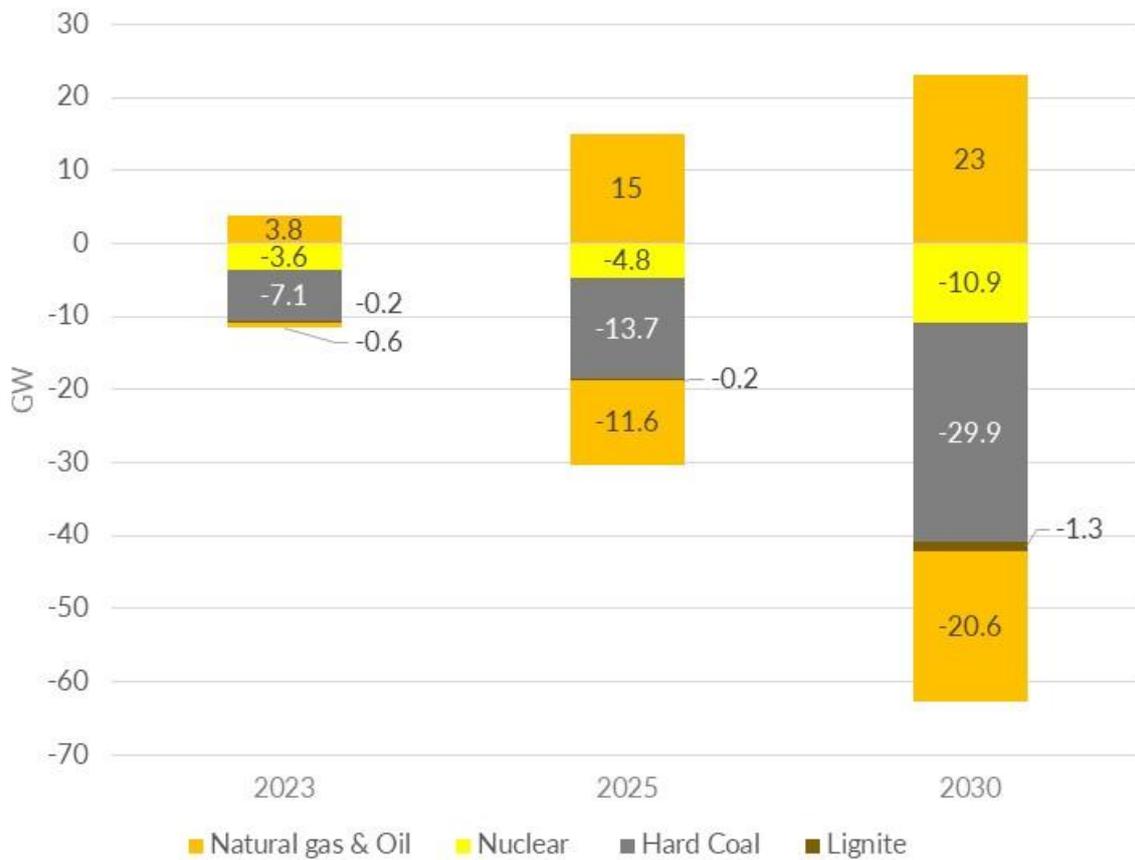
In contrast to renewable energies, the installed capacity of conventional power generation plants also decreases significantly over time in the other European countries considered. The installed capacity of power plants based on coal, natural gas, oil and other fossil fuels as well as nuclear power plants on the market still amounts to approx. 287 GW in 2021 and then declines continuously over time.<sup>174</sup>

<sup>174</sup> In addition, approx. 38 GW of these technologies are still in cold reserve in 2021, as the model is not allowed to prematurely decommission endogenously in the short term, i.e. in the first reference year 2021. The plants will be decommissioned in the next modelled year.

In 2030, the installed capacity of conventional power plants is only about 216 GW. The decline in the installed capacity of conventional power plants is partially compensated for by the slight increase in controllable RE capacity and the moderate development of flexibility options in the form of emergency power systems (EPS) and voluntary load reduction by industry (DSM). The tapped capacity of these flexibility options plus the capacity of large-scale batteries amounts to approx. 3.6 GW in 2021 and increases to 17.4 GW by 2030. Compared to the first project report, there are differences. In particular, in the development of resources due to more nuclear power capacity in France, fewer endogenous closures / cold reserves of coal and natural gas power plants in 2021 or the installed capacity of renewable energies in 2030, which are expanded significantly higher in this report, with approx. 553 GW, compared to 476 GW in the first report.

Some of the developments in the conventional power plant fleets of the countries considered are based on exogenous model specifications for the technical service life, the maintenance of heat supply by CHP plants, political specifications for the construction or decommissioning of coal-fired power plants or nuclear power plants (cf. Section 2.2.1). These exogenous requirements are shown in Figure 3-7 as changes compared to 2021. In contrast to the other technologies/fuels, only the net development of installed capacity is shown for nuclear energy.

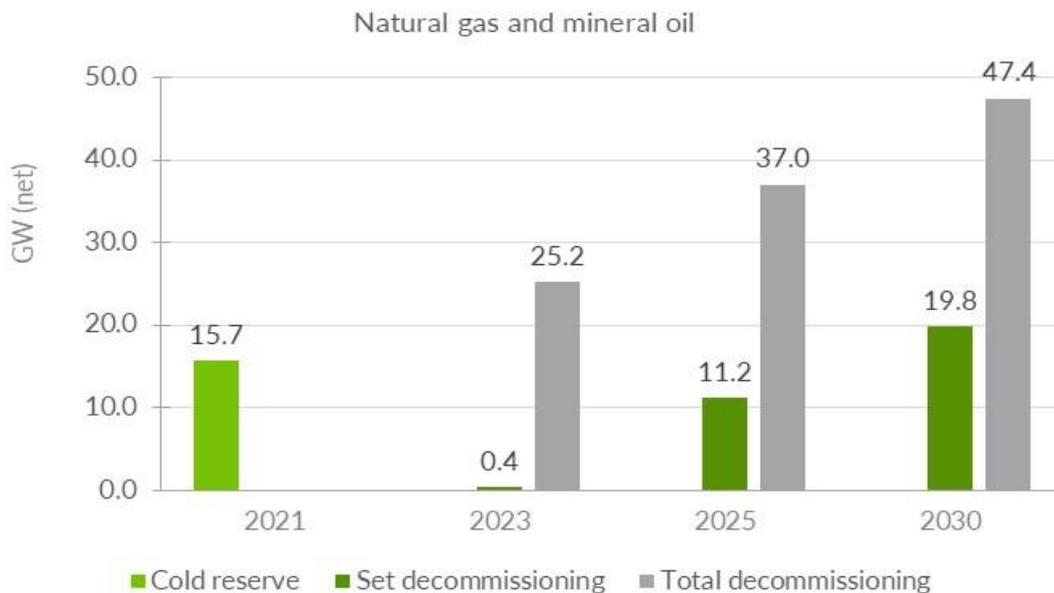
FIGURE 3-7: EXOGENOUSLY SPECIFIED ADDITIONS AND DECOMMISSIONINGS IN THE CONVENTIONAL POWER PLANT FLEET OF FOREIGN COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030 COMPARED TO 2021



Source: Own assumptions.

However, additional early closures (i.e. earlier than the exogenously set decommissioning) can also be carried out endogenously by the model in the foreign countries considered. For 2021, the given and conducted cumulative closures and cold reserves are shown in total for all the countries considered abroad in Figure 3-8 for natural gas and mineral oil power plants as well as in Figure 3-9 for hard coal and lignite power plants.

**FIGURE 3-8: EXOGENOUS VS. ENDOGENOUS CUMULATIVE REDUCTIONS OF NATURAL GAS AND MINERAL OIL POWER PLANTS IN THE FOREIGN COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030 COMPARED TO 2021**



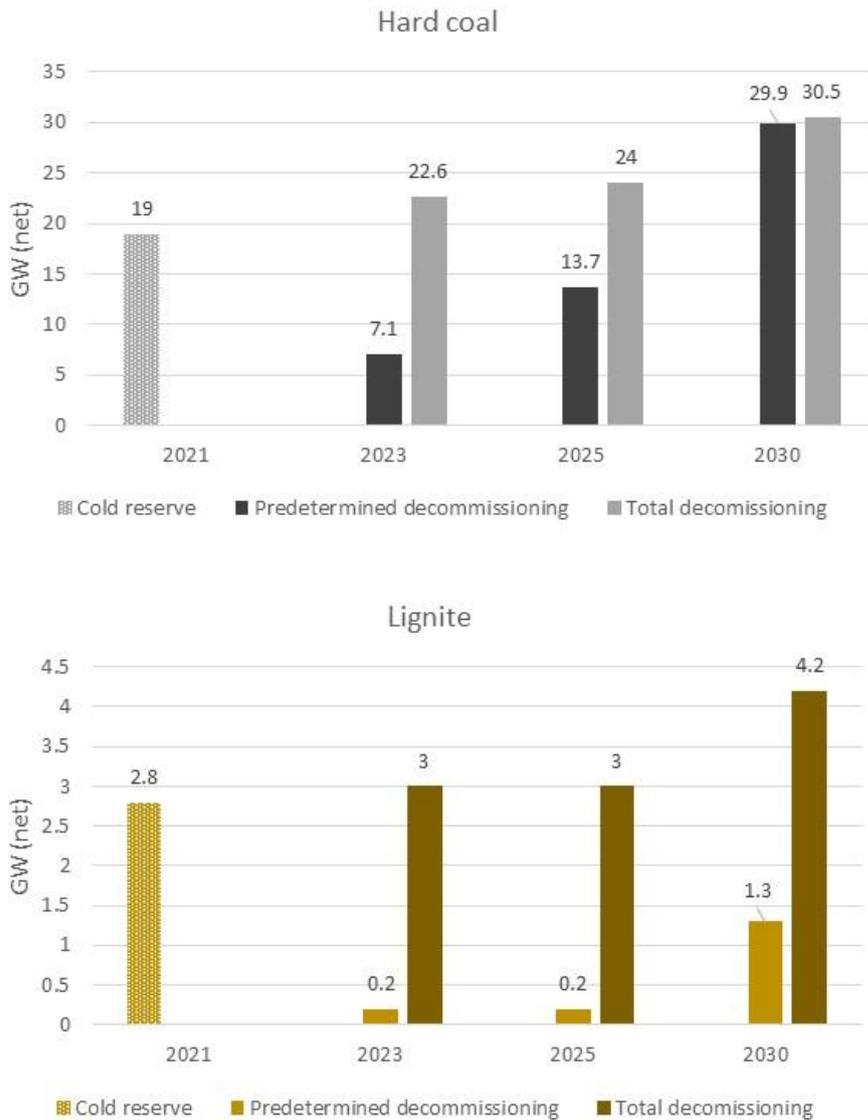
Source: Own calculations.

In the case of the lignite-fired power plants in the foreign countries considered (in particular Poland and the Czech Republic), 2.8 GW will be placed in cold reserve in 2021 and then decommissioned endogenously, starting from 2023. In 2030, 2.9 GW fewer lignite-fired power plants are on the market than exogenously specified due to endogenous decommissioning. In the case of hard coal-fired power plants, approx. 19 GW will be placed in cold reserve in 2021 due to insufficient economic viability and approx. 15.5 GW will be decommissioned endogenously in 2023. In 2030, only marginally (0.6 GW) fewer hard-coal-fired power plants will still be on the market than exogenously specified, as by then the majority of the endogenously decommissioned power plants would also have been decommissioned exogenously due to reaching the end of their technical lifetimes or due to political requirements known today. In the case of power plants based on natural gas and mineral oil, approx. 15.7 GW will initially be transferred to cold reserve in 2021.<sup>175</sup> Then, in 2023, significant early endogenous closures take

<sup>175</sup> Here again, it must be taken into account that, in agreement with the BMWi, temporary closures are permitted in the reference year 2020, but final closures can only take place in the reference year 2023.

place in the amount of approx. 24.8 GW, increasing to 25.8 GW by 2025. In 2030, the early endogenous closures then amount to around 27.6 GW.<sup>176</sup>

**FIGURE 3-9: EXOGENOUS VS. ENDOGENOUS CUMULATIVE REDUCTIONS OF COAL-FIRED POWER PLANTS IN THE COUNTRIES UNDER CONSIDERATION FOR 2023, 2025 AND 2030 COMPARED TO 2021**



Source: Own calculations.

<sup>176</sup> In the case of endogenous decommissioning, it should be noted that we have prohibited very short-term decommissioning in 2021 in the model for reasons of economic efficiency. The plants are then first transferred to the cold reserve and then decommissioned in the next forecast year 2023. Therefore, no final early endogenous closures are to be reported in 2021 - but considerable capacities are in cold reserve in 2021. For the applied des-/investment logic in the model, see r2b / Consentec (2019) Section 3.2.2.

Apart from the development of flexibility options in the form of voluntary load reductions by industry and emergency power plants (cf. Figure 3-6), there is no model-derived expansion of conventional power plants in the foreign countries considered in the reference scenario.

This is an economic optimisation of the system through endogenous modelling in which market adjustment reactions take place: The mothballing of existing power plants with comparatively high fixed operating costs and simultaneous development of flexibility options with significantly lower fixed operating costs thus lead to lower overall costs. The endogenous mothballing (cold reserves) in the countries considered (excluding Germany) amounting to approx. 37.5 GW and 4.9 GW in Germany are offset by newly developed flexibility options amounting to 4 GW in other European countries and 1 GW in Germany. In addition, there is still extensive potential available for voluntary load reduction by industry and emergency power systems in the entire region under consideration. In 2023, the developed capacities of these flexibility options correspond to just under 8 percent of the developable potentials of the entire region under consideration. Due to these substitution options, there are many different possible development paths that ensure a secure electricity supply.

### **3.1.3 Classification of the reference scenario**

In model-based scenario generation, the expected market adjustment processes are analysed and simulated.<sup>177</sup> These are necessarily idealised to a certain extent, in that an undelayed action by always rational market entities is made possible within the framework of the respective specifications. However, the extent of this idealisation is limited in order to take account of inertias and obstacles that exist in reality:

- In the short term, the scenarios are largely determined by exogenous parameters based on extensive preliminary analyses.
- Endogenous degrees of freedom only become relevant for later observation years, where sufficient lead times for adjustment processes are given.

---

<sup>177</sup> Cf. r2b / Consentec (2019) Section 3.2.2.

In the following, we provide a classification of the results in the form of a comparison with scenarios of the German and European TSOs. For this purpose, we have compared the development of the installed capacity of all controllable generation plants (excluding run-of-river) and developed flexibility options as well as the volatile renewable energies of the reference scenario with the "National Trends" scenario of the *Midterm Adequacy Forecast 2020 (MAF2020)* of ENTSO-E for the years 2025 and 2030 in Figure 3-10.<sup>178</sup>

**FIGURE 3-10: DEVELOPMENT OF INSTALLED CAPACITIES FOR 2025 AND 2030 IN GERMANY COMPARED TO THOSE FROM THE "NATIONAL TRENDS" SCENARIO OF THE MIDTERM ADEQUACY FORECAST 2020**



\* Controllable RE: storage- and pump storage, biomass (incl. bio waste) and other RE.  
 \*\* Volatile RE: wind, PV and run-of-river plants.

Source: Own representation based on own calculations and ENTSO-E (2020d).

The reference scenario developed in this study has a lower to equal installed generation capacity (incl. the flexibility options voluntary load reduction by industry

<sup>178</sup> The possibilities for comparison are limited due to limited data availability and partly different framework assumptions. Therefore, we have used a different aggregation of technologies / fuels here than in the corresponding figures in Chapters 5 and 6.

and emergency power systems as well as large batteries) compared to the ENTSO-E scenarios. With 0.9 GW lower output of controllable resources in 2025 and in 2030, the reference scenario represents a realistic to conservative development of the electricity supply system in Germany.

**FIGURE 3-11: DEVELOPMENT OF INSTALLED CAPACITIES FOR 2025 AND 2030 IN THE 14 COUNTRIES CONSIDERED (EXCLUDING GERMANY) COMPARED WITH THOSE FROM THE "NATIONAL TRENDS" SCENARIO OF THE MIDTERM ADEQUACY FORECAST 2020**



\* Controllable RE: storage- and pump storage, biomass (incl. bio waste) and other RE.  
 \*\* Volatile RE: wind, PV and run-of-river plants.

Source: Own representation based on own calculations and ENTSO-E (2020).

A comparison of the foreign countries considered shows clearer differences in the installed capacities. This is presumably since in some cases considerable model-endogenous decommissioning takes place in the model-based scenarios. With approx. 54 GW lower capacities of controllable resources in 2025 and approx. 61 GW, the reference scenario represents a rather conservative development of the electricity supply system in the countries considered compared to ENTSO-E. This is based on the current market design and known developments in Europe.

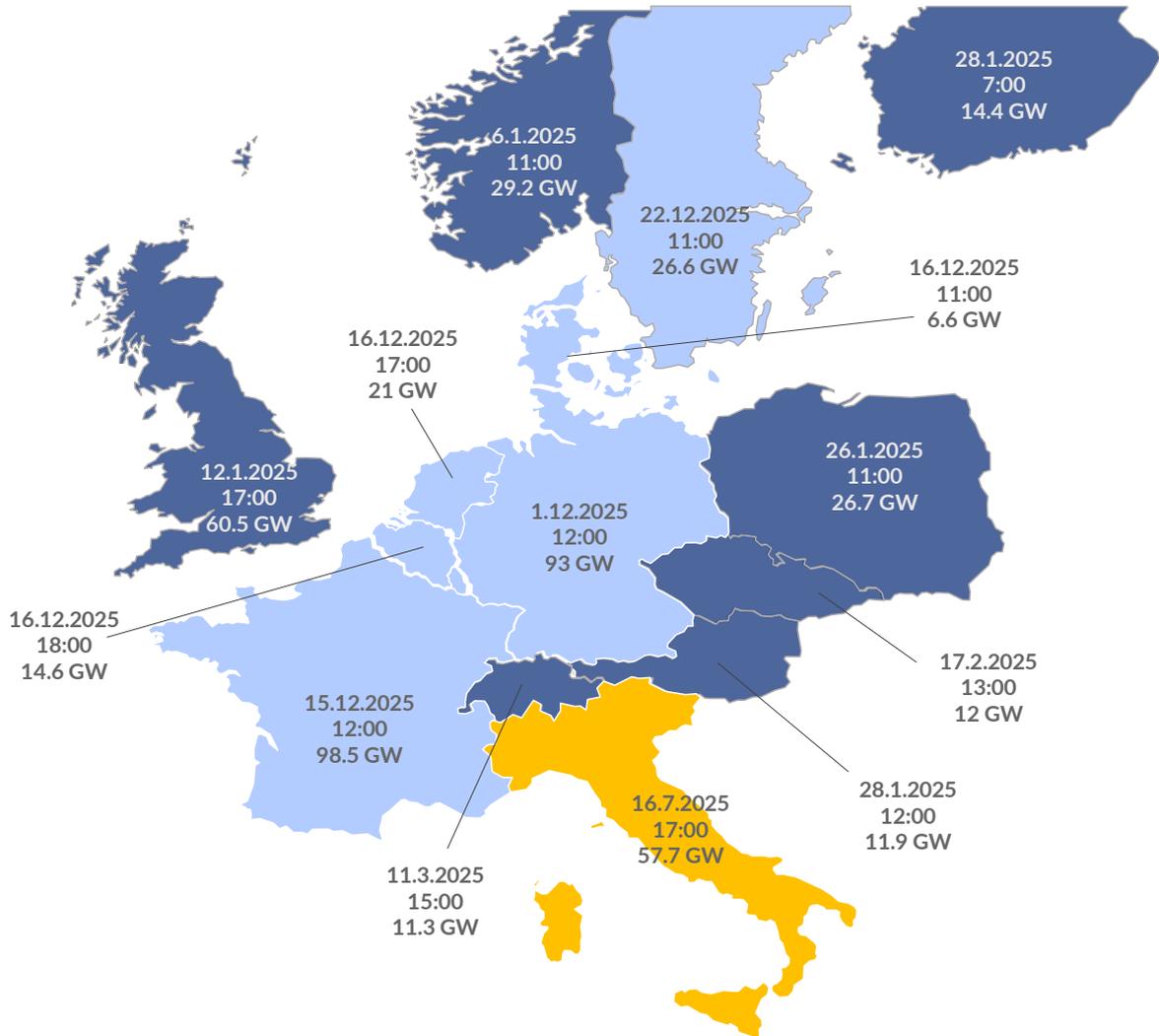
### **3.2 Balancing effects in the common internal electricity market**

If, in accordance with the integration of the European internal electricity market, the electricity supply systems of several countries are considered simultaneously, there are balancing effects in the load and the feed-in of renewable energies. Together, this represents the balancing effects of the residual load, as well as balancing effects in the case of unplanned unavailability of power plants.

The balancing effects for load and residual load shown below are due to the fact that the annual peak load and the residual annual peak load do not occur at the same time in the countries under consideration.

First of all, this is illustrated in Figure 3-12, where the times of the annual peak load for the forecast year 2025 (weather year 2010) are plotted as an example.

FIGURE 3-12: ILLUSTRATIVE REPRESENTATION OF THE TEMPORAL DISPARITY OF THE ANNUAL PEAK LOADS (FORECAST YEAR 2025; WEATHER YEAR 2010)

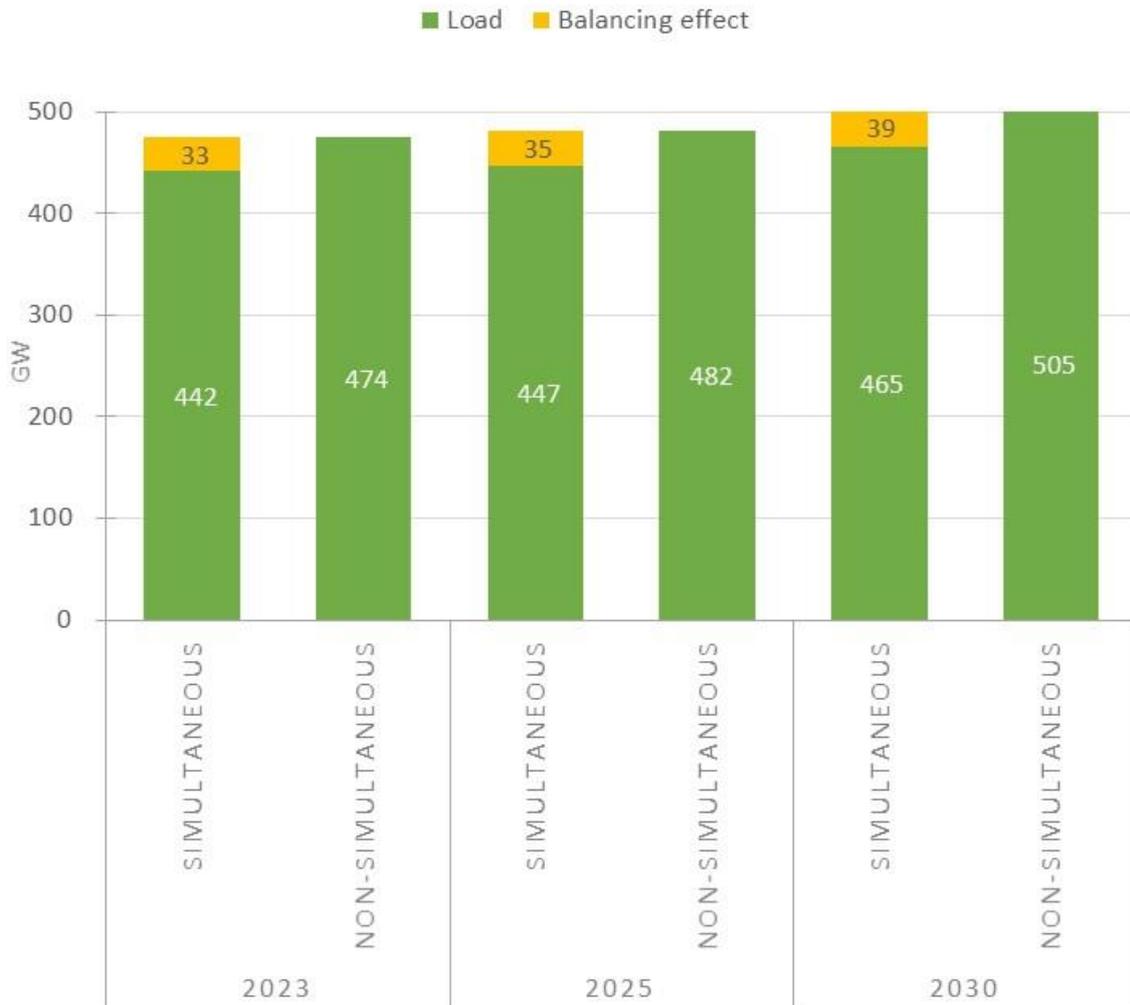


Source: Own calculations;

Colouring: Light blue: first half of winter; dark blue: second half of winter; yellow: summer.

The balancing effects of the load are shown in Figure 3-13 by comparing the simultaneous annual peak load of all countries considered with the non-simultaneous annual peak load. The difference between these results in the balancing effect of the load, which is between 33 and 39 GW depending on the reference year.

FIGURE 3-13: LOAD BALANCING EFFECTS: SIMULTANEOUS VS. NON-SIMULTANEOUS ANNUAL PEAK LOAD OF ALL COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030



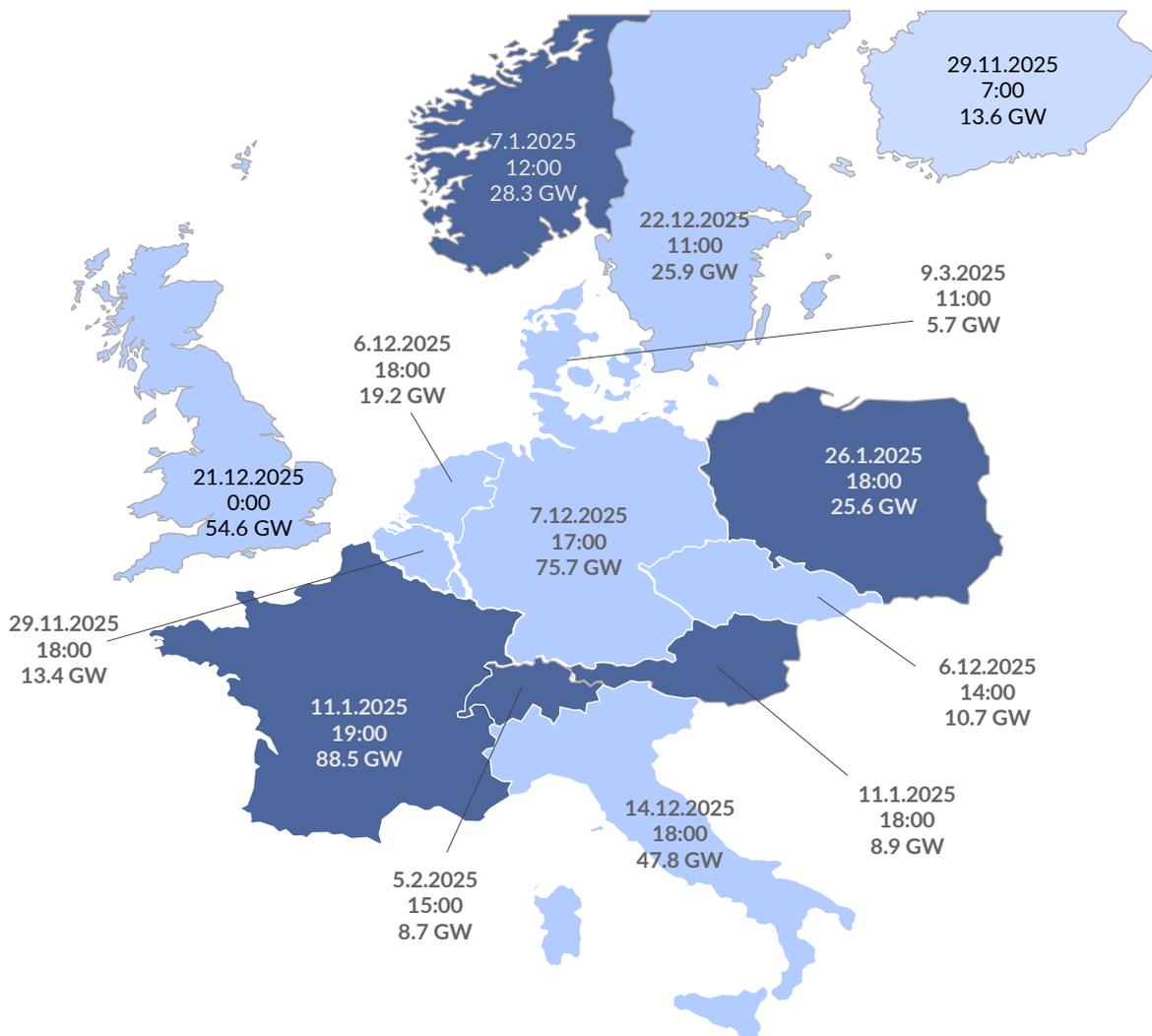
Source: Own calculations; averaged over all 6 weather years.

As the country with the highest electricity consumption, Germany contributes substantially to the simultaneous and non-simultaneous annual peak load. The maximum annual peak load in Germany over all six base years is approx. 90 GW in 2021 and then shows a slight upward trend over time. In 2023 it is approx. 92 GW, in 2025 approx. 93 GW and in 2030 approx. 96 GW.

The supply-dependent feed-in of renewable energies (wind, PV and run-of-river) lead to a further intensification of these balancing effects, as low feed-in levels neither occur simultaneously in all countries nor at the same time as the respective peak load. First, Figure 3-14 shows an example of the non-simultaneity of residual

annual peak load of the countries considered for the year 2025 (weather year 2010).

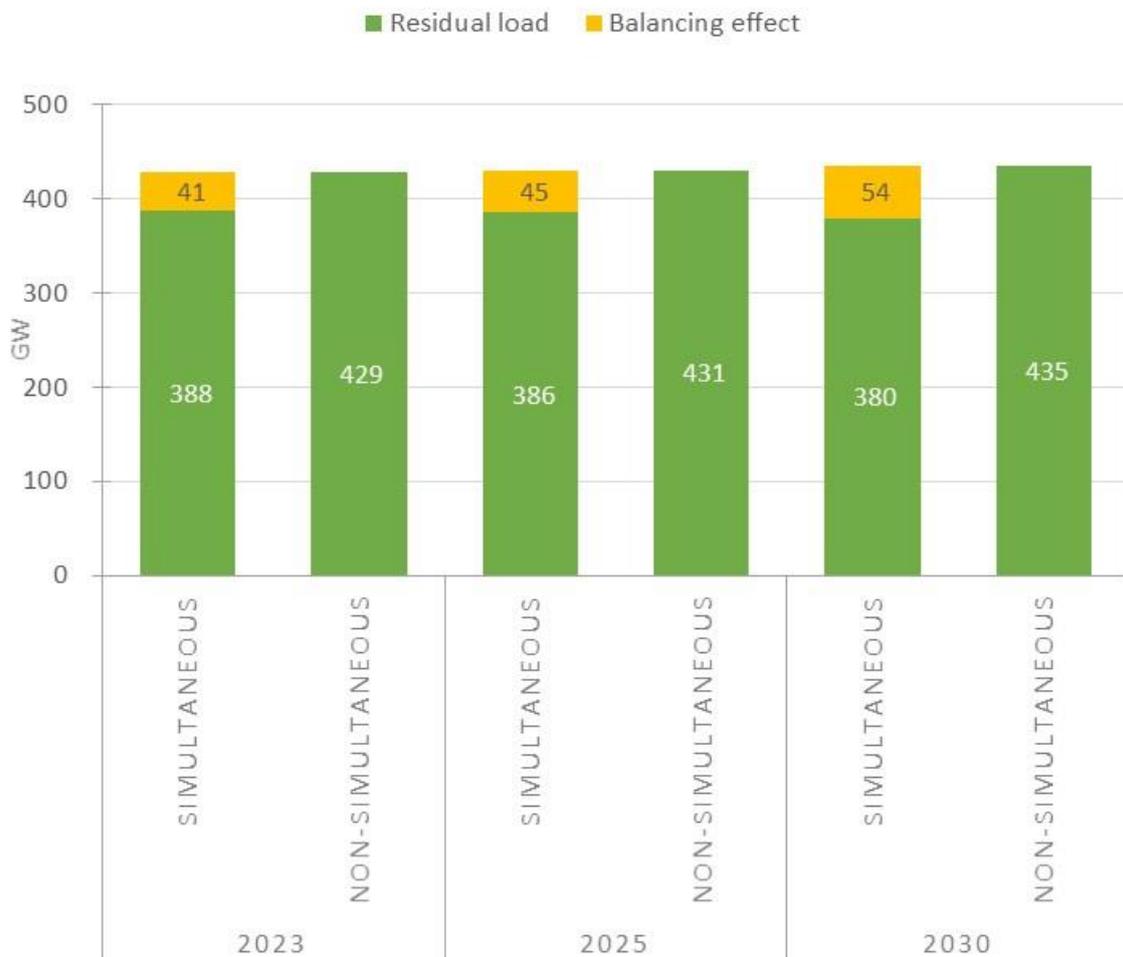
**FIGURE 3-14: ILLUSTRATIVE REPRESENTATION OF THE NON-SIMULTANEITY OF RESIDUAL ANNUAL PEAK LOADS IN THE COUNTRIES CONSIDERED (FORECAST YEAR 2025; WEATHER YEAR 2010)**



Source: Own calculations; colouring: light blue: first half of winter; dark blue: second half of winter.

In order to quantify the effect of non-simultaneity, in Figure 3-15 we compare the simultaneous residual annual peak load of all countries considered with the sum of the non-simultaneous residual annual peak loads. The difference represents the balancing effect of the residual load considered here, which amounts to between 41 and 54 GW depending on the sample year.

FIGURE 3-15: BALANCING EFFECTS OF THE RESIDUAL LOAD: SIMULTANEOUS VS. NON-SIMULTANEOUS RESIDUAL ANNUAL PEAK LOAD OF ALL COUNTRIES CONSIDERED FOR 2023, 2025 AND 2030



Source: Own calculations; averaged over all 6 weather years.

The absolute residual annual peak load in Germany (averaged over all six weather years) is approx. 78 GW in 2021 and then shows a slightly decreasing development over time. In 2023 and 2025 it is approx. 77 GW and in 2030 approx. 75 GW.

Balancing effects exist not only regarding the (residual) annual peak load, but also reduce the effective risk from power plant outages to a considerable extent. The reason for this is that the simultaneous occurrence of high outages in several countries is less likely than in a national perspective.

In order to show the magnitude of this effect, we have evaluated the 350 simulated annual series of hourly outages for the year 2023<sup>179</sup> as an example.

If, for example, the cumulative outage power, which is exceeded 20 % of the time, is determined for each country individually, and these country values are added up over all countries considered in the model, the result is a value of approx. 53 GW. If this is compared with the distribution of the cumulative outage power over all modelled countries (in which the sum over all countries is formed hourly and thus simultaneity is taken into account), the value of 53 GW is exceeded only 1.5 % of the time.

The balancing effect is even stronger if one looks at the outage power per country, which is exceeded nationally only in 10 % (instead of 20 %) of the time. Their sum of 58 GW is exceeded only 0.02 % (instead of 1.5 %) of the time when viewed internationally.

The relative advantage of the compensation effect, i.e. the relative reduction in the risk of exceeding a certain default power, therefore becomes greater the smaller the risk level is. In other words, the rarer (but potentially more serious) the cases become, the more the compensation effect reduces the residual risk. This is not a random effect of the concrete outage depiction, but a systematic effect that can be theoretically understood, for example, on the basis of normal distributions.<sup>180</sup>

The above explanations show that the European balancing effects have a considerable scope. Their benefit in terms of resource adequacy is that in times when a country (or a bidding zone) needs imports, countries with a current surplus of generation capacity can assist. This lowers the requirements for ensuring resource adequacy on the electricity markets compared to a purely national approach. Full utilisation of the balancing effects is only possible if corresponding cross-border

---

<sup>179</sup> The figures for the first project report were evaluated on the basis of the reference scenario. For other scenarios and years under consideration, balancing effects of the same magnitude occur.

<sup>180</sup> It should also be mentioned that more extreme cases than the 10% probability of exceedance mentioned above could not be meaningfully evaluated here. For if we determine, for example, the failure power that is exceeded per country in no less than 5 % of the time, we find that their sum does not occur at all in the total distribution of all countries (with compensation effect). This means that in more than 3 million simulated hours there was not a single one that exceeded this value in the sum of the failure power across all countries.

transport capacities are available. In view of the transport capacities that already exist today and the future considerable further grid expansion, a large part of the balancing effects can be used.

The amount of cross-border assistance is limited in the RA model in two respects: firstly, the transport capacities of the transmission grid are taken into account<sup>181</sup> and secondly, assistance is only provided to the extent that no (additional) load excess occurs in the bidding zone providing assistance.<sup>182</sup>

In practice, the provision of such cross-border assistance to the extent that is technically possible is to be expected since it is extremely lucrative for market players to supply them with electricity due to high market prices in the bidding zone with import demand.

In the results of the RA analysis presented below, cross-border assistance is described by a dedicated indicator, namely the import required to avoid load excess.<sup>183</sup>

### 3.3 Results RA analyses

#### Loss of Load Probability and Expected Energy Not Supplied

The characterisation of the adequacy of resources is primarily based on the so-called loss of load probability (LoLP). LoLP is given without units or as a percentage. It indicates the probability that not all consumers can be supplied via the electricity market according to their price preferences. The resource adequacy threshold derived as a RA standard in the first project report is formulated in terms of  $\widehat{LoLP} = 0,06\%$ .<sup>184</sup>

---

<sup>181</sup> Cf. r2b / Consentec (2019) Section 3.3.4.

<sup>182</sup> Cf. r2b / Consentec (2019) Section 3.3.6 including the discussion there on possible alternatives.

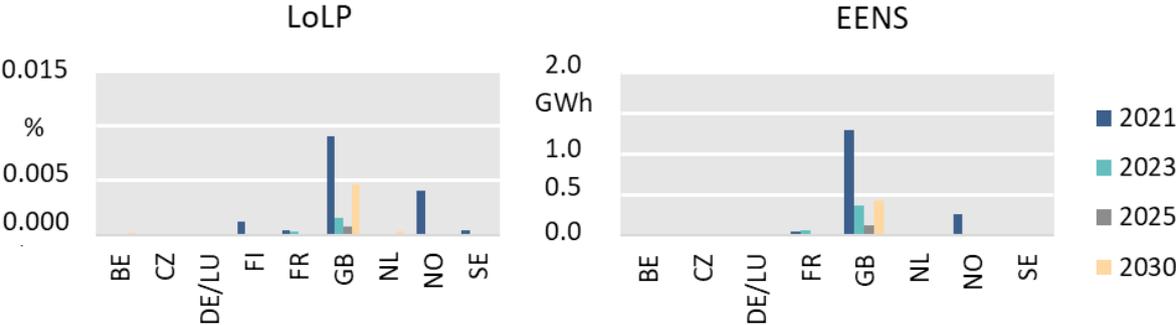
<sup>183</sup> Cf. r2b / Consentec (2019) Section 2.2.3.

<sup>184</sup> The threshold value can be interpreted as follows: If the threshold is exceeded by the power system under review for a future year, this is an indication that an economically efficient investment in generation or flexibility resources has not been made, i.e. that the entities active in the electricity supply have not recognised the economic efficiency of such an investment in the current market environment, or at least have not ex-

In addition to the LoLP, the Expected Energy Not Supplied (EENS) is shown below as a secondary indicator. This indicates the expected value of the demand energy that cannot be met on the electricity market and is expressed as an amount of energy (e.g. GWh) per year.

Figure 3-16 shows the LoLP and EENS indicators for the four years under review. For reasons of clarity, the presentation is limited to those countries in which a value greater than zero occurs in at least one observation year, as well as Germany/Luxembourg.<sup>185</sup>

**FIGURE 3-16: INDICATORS IN THE REFERENCE SCENARIO FOR COUNTRIES WITH RATIOS GREATER THAN ZERO AND GERMANY/LUXEMBOURG**



Source: Own representation.

DE / LU form a common bidding zone in the electricity market, therefore DE results also apply to LU

It can be seen that in the present study German consumers can be securely supplied at all times. LoLP and EENS have values of zero in all years under review. This corresponds to a load balancing probability of 100 %.

exploited it. This would entail the examination of measures provided for under section 51(4)(2) EnWG, in particular the examination of any remaining barriers and disincentives, as well as the examination of whether a later "settling" is expected through market adjustment processes.

On the other hand, the further the loss of load probability is below the threshold, the more its costs would exceed the benefits on the consumer side (through avoided load excess).

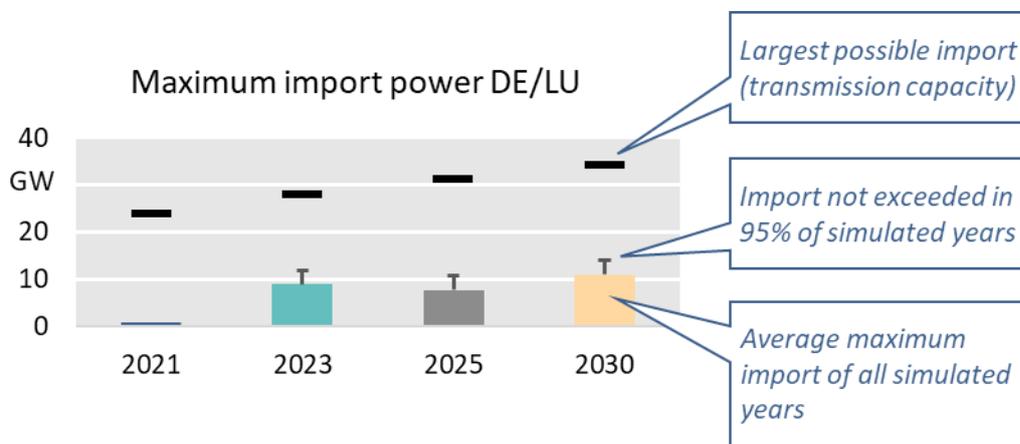
<sup>185</sup> Some of the non-zero values are so small that they are hardly or not at all distinguishable from zero in the graphical representation.

Notable (but non-critical), LoLP and EENS values only occur for the UK (2021 and 2030) and Norway (2021).<sup>186</sup> The average level of load excess<sup>187</sup> which can be determined from the ratio of EENS and LoLP, is approx. 0.75-1.5 GW.

### Required imports

Figure 3-17 shows the level of imports to Germany/Luxembourg that are required to avoid loads excess. The representation is based on the maximum values of the required import capacity that occur in each simulated year. The height of the columns per year under review indicates which maximum import occurs on average over all 2,100 simulation years.<sup>188</sup> The "antennae" above the columns mark the import capacity that is not exceeded in any hour in 95 % of the simulation years. As a benchmark, the maximum possible import capacity is indicated 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 (cf. Section 2.8).

**FIGURE 3-17: REQUIRED\* IMPORTS TO DE/LU IN THE REFERENCE SCENARIO**



Source: Own representation. Required imports to avoid load excess. Market imports may deviate from this.

<sup>186</sup> However, the result figures for abroad are subject to uncertainties due to their peripheral location in the model, cf. r2b / Consentec (2019) Section 3.2.

<sup>187</sup> Average load excess =  $EENS / (LoLP \cdot 8760 \text{ h/a})$

<sup>188</sup> For an explanation of the concept of examining an observation year through many simulation years, see r2b / Consentec (2019) Section 3.3.6.

Compared to the first report, it is noticeable that the required imports to Germany/Luxembourg in the year under review 2021 decrease significantly compared to the year 2020, which was considered there as the first. The reduction in the required imports compared to the first project report is due to various causes:

- The corrected allocation of 3.3 GW of Austrian hydropower plants to the Germany/Luxembourg bidding zone
- In the first report, an additional approx. 4 GW of CCGT in Germany was placed in cold reserve in the 2020 reference year
- More ambitious RE expansion in Germany (i.e. lower residual load)

From 2023 onwards, significant import capacities are required - at least in individual hours and depending on the combination of modelled uncertainties. These are higher than currently observed import maxima; for example, the maximum import capacity to Germany/Luxembourg in 2019 was approx. 11.7 GW.<sup>189</sup> The reasons for this are, on the one hand, the fact that the range of uncertainties modelled in the RA analysis is wider than the range of situations that actually occurred in that year and, on the other hand, the decline in dispatchable generation capacity in Germany discussed in Section 3.1.1

However, the maximum import power required for resource adequacy is consistently significantly below the respective maximum import capacity. The gap even increases over time because due to the grid expansion the import capacity increases more than the required import power.

Imports are also only required for a short period of time to the extent shown here: the average required import energy - that is the annual integral over the hourly required import power - is less than 0.1 % of gross electricity consumption in all years under review.<sup>190</sup>

The temporary necessity of imports to ensure resource adequacy is in line with the concept of the internal electricity market and is related to the intended use of

---

<sup>189</sup> Source: Own evaluation based on data from smard.de

<sup>190</sup> Imports in the context of the RA analyses are not market imports, as imports in the RA model always represent the last option for load coverage after all domestic options have been exhausted. The market imports therefore differ from those in the RA analyses.

balancing effects (cf. Section 3.2). Consequently, this by no means only concerns Germany/Luxembourg. Rather, necessary imports occur in all countries considered, i.e. mutual assistance takes place. The import power, which is not exceeded in any hour in 95 % of the simulation years (corresponding to the "antennae" in Figure 3-17) is (depending on the year under review) for example approx. 8 to 14 GW for France, approx. 4 to 9 GW for Belgium and approx. 4 to 6 GW for the Netherlands. While the values for most countries increase over the period under review, a downward trend can be observed in France.

As mentioned above, the level of imports to Germany/Luxembourg required for resource adequacy is to be considered low compared to the (future) existing grid capacity. It should be noted, however, that certain preparations must nevertheless be made for the stronger role of cross-border balancing effects in the future. First, this relates to the examination and, if necessary, implementation of measures to realize the exchange capacities required by the EU Electricity Market Regulation (and assumed in this study), while maintaining grid security.<sup>191</sup> Second, preparations should be made for international exchange patterns<sup>192</sup> that are already permissible today (within the framework of the allocation of cross-border transmission capacities) but are still unusual in practice. This concerns not only temporarily higher imports to Germany, but also, for example, increased exports from Italy. In this context, adjustments to operational planning processes, but also grid-related measures, such as the installation of equipment for reactive power control, may be necessary.<sup>193</sup>

### Leeway status

The two essential indicators for the assessment of the RA level, LoLP and EENS, refer to those situations (hours) in which load excess occurs. For a more general, qualitative assessment of the RA level, it is also of interest how "far away" the

---

<sup>191</sup> Cf. r2b / Consentec (2019) Section 3.3.4.

<sup>192</sup> The total import capacities to Germany/Luxembourg already amounted to approx. 14 GW in 2016 (without the Austrian border, which was still integrated at that time and for which a further 4.9 GW is to be added with the introduction of separate congestion management from 1.10.2018).

<sup>193</sup> A contribution to preparing for future changes in electricity trading patterns is already provided by the annual grid reserve demand analyses carried out by the German TSOs.

power supply system is from load excess in the remaining hours, i.e. to what extent there is leeway for which no load excess would occur even in the case of more serious events than those explicitly modelled in the stochastic simulation. For example, there is more leeway in an hour in which domestic conventional generation capacity is not fully used than in an hour in which it is. There is even less leeway in an hour in which import is required to avoid a load excess.

The evaluation of the required imports presented in the previous subsection is thus already an important building block for the general assessment of the RA level. However, it is limited to hours with import requirements. In the following, a generalised classification is made by means of which a so-called leeway status can be assigned to all simulation hours. The principle of such a classification is based on a similar evaluation of the Pentalateral Energy Forum.<sup>194</sup> For the concrete classification, however, we use the fact that in the RA analysis carried out here, the level of imports required to avoid load excess can be determined. On this basis, for a bidding zone under consideration, each simulation hour is assigned one of the statuses listed in the following table.

Table 3-1: CLASSIFICATION FOR THE EVALUATION OF THE LEEWAY STATUS

Classification in ascending criticality	Description
A	Neither required import nor export <u>or</u> <sup>195</sup> export with remaining free conventional capacity
B	Export and no free remaining conventional capacity
C	Required import without load excess
D	Load excess

<sup>194</sup> Cf. PLEF (2018), p. 58f.

<sup>195</sup> At first glance, it might seem obvious to separate hours with export as a separate category from hours without any export or import. However, it cannot be clearly determined in the simulation result whether the occurrence of an export from a certain bidding zone A was mandatory in a given simulation hour. This is because the export results from the necessary import of (at least) another bidding zone B in order to avoid

Source: Own representation.

The export hours are differentiated exclusively according to free conventional capacity, i.e. flexibilities with energy quantity restrictions (e.g. storage power plants) are not taken into account. This is a conservative definition, as of course in principle these flexibilities can also contribute to load coverage and thus increase the leeway in relation to the RA level. However, given the limited storage volume, it is not unambiguous to what extent the capacity of these resources can be attributed to individual hours. If, for example, the storage content in three consecutive hours is sufficient for one full load hour, then full power could be generated in each of these three hours, but not in all three hours.

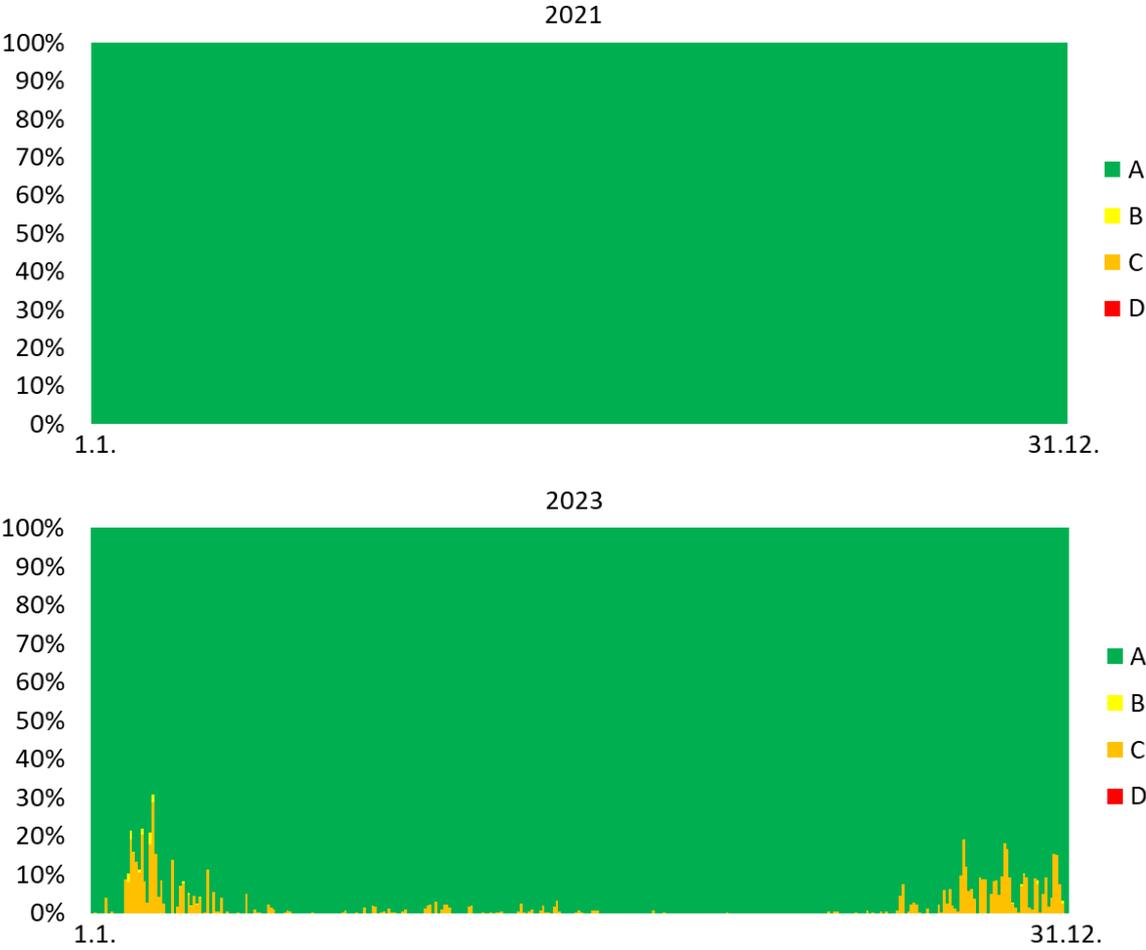
The following two diagrams show the result of the evaluation of the leeway status of Germany/Luxembourg for the four years under review. In each diagram, the 365 days of the year are plotted from left to right. For each day, the colours show how the simulation hours of that day are distributed among the categories of the leeway status according to [Table 3-1](#). Each day is based on 50,400 data points (24 hours, 6 weather years, 350 simulation years each).

---

or reduce loss of load there. However, it could be that, as an alternative to A, a third bidding zone C could also provide the export to B. In such an hour, some kind of export is necessary, but not necessarily an export from A. Thus, one cannot clearly differentiate between a situation without import or export and a situation with export (because this could possibly be taken over alternatively by another bidding zone).

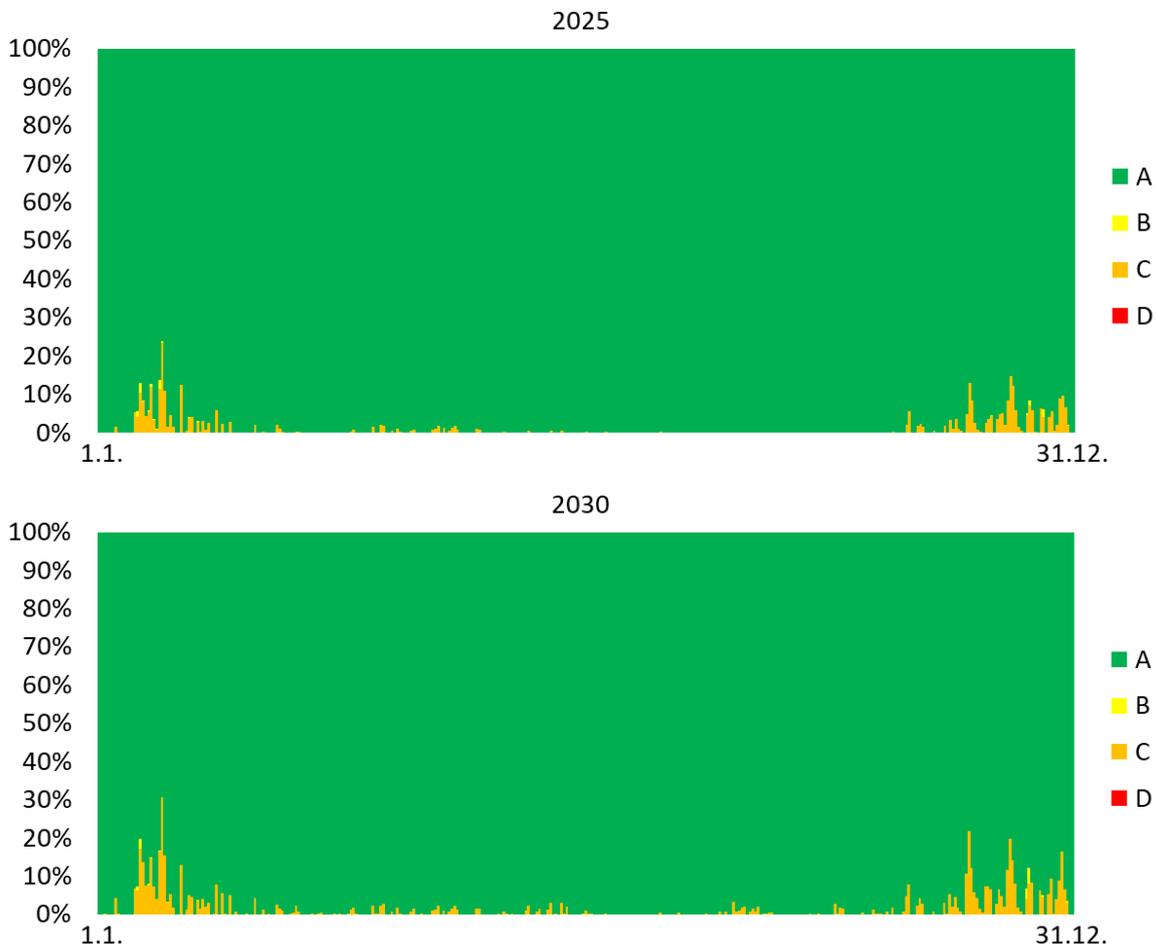
Hours in which conventional capacity is fully exhausted during export (category B) are nevertheless shown in order to be able to mark the frequency of this exhaustion. Due to the aforementioned indifference, this is an upper estimate of the frequency with which domestic conventional capacity must be exhausted in order to help out other bidding zones.

FIGURE 3-18: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE REFERENCE SCENARIO, YEARS UNDER REVIEW 2021 AND 2023



Source: Own representation. Categories A to D according to Table 3-1

**FIGURE 3-19: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE REFERENCE SCENARIO, YEARS UNDER REVIEW 2025 AND 2030**



Source: Own representation. Categories A to D according to Table 3-1

In 2021, as already discussed, there is practically no import required, so that visually only category A is perceived. In 2023, significant proportions of hours with required import (category C) only occur in the winter half-year. The highest value is 29 %, i.e. there is one day in the year on which the probability of an import requirement is 29 %. However, the vast majority of hours in 2023 are still those with free conventional power and/or no need for exports or imports (Category A). Category B hours, in which the conventional capacity is fully utilised by cross-border assistance (export), are very rare, and hours with load excess do not occur, as in all years under review.

In 2025 and 2030, the distribution of leeway status is similar to that for 2023. In 2030, the highest daily share of hours with import demand (category C) is 31%.

### Technical resource adequacy (including strategic reserves)

In order to estimate the technical resource adequacy (as distinct from the resource adequacy on the electricity market, cf. Section 1.5), we carry out a variant calculation in which we additionally take into account the possibility of using strategic reserves (such as the German capacity reserve) in the RA analysis model stage. By considering strategic reserves only in this model stage, we take account of the fact that strategic reserves have no repercussion on the market and therefore play no role in the investment calculus (which is simulated in the model stage of the electricity market simulation).

For the modelling of the strategic reserves, we assume that they are only used in the event of a market-related load excess in the respective bidding zone and that in such a case they are used after all market segments have been closed. They thus only reduce the load excess of their own bidding zone. In the RA analysis model, this is implemented in such a way that the determined load excess per simulation hour can be reduced in a subsequent step up to the level of the respective assumed strategic reserve. Only simulation hours in which this is sufficient to reduce the load excess to zero then still make a contribution to the technical probability of load excess.

We have parameterised the amount of strategic reserves in the four countries or bidding zones in which they occur as follows: Firstly, in the sense of a "what if" analysis, it is taken into account that in principle an extension of the authorisation beyond the current authorisation periods is conceivable. Secondly, it is assumed as a plausible (rough) estimate that the current level of the strategic reserve (cf. Section 2.1) remains constant in each case. The numerical values used are shown in the following table.

Table 3-2: ASSUMPTIONS ON THE LEVEL OF STRATEGIC RESERVES (2021-2030) IN THE VARIANT CALCULATION FOR TECHNICAL RESOURCE ADEQUACY

DE/LU	BE	FI	SE
2,000 MW	0 MW	611 MW	562 MW

Source: Own representation.

As there is no load excess in Germany/Luxembourg in the reference scenario, the use of the capacity reserve is not necessary under the assumptions made. In Sweden and Finland, the simulation shows that the strategic reserves there can reduce the (low) LoLP and EENS values determined for the year of review 2021 by approximately one order of magnitude and reduce the even lower values to zero in later years of review (here only Sweden).

### 3.4 Interim summary of results for the reference scenario

The reference scenario represents the approach of a *best-guess analysis*.<sup>196</sup> Current developments and political framework conditions in Germany and Europe are depicted. The output and thus the electricity generation of nuclear power plants and coal-fired power plants decline and are replaced in Germany and Europe by the expansion of renewable energies with simultaneous flexibilisation of the electricity supply system. To ensure public heat supply and process heat supply through CHP plants, coal-fired CHP plants in Germany and Europe are essentially being replaced by natural gas-fired CHP plants. Overcapacities<sup>197</sup> of fossil-fuelled power plants are being reduced in Germany and Europe with temporal inertia within the framework of market adjustment processes. The controllable conventional generation capacity in Germany and Europe is decreasing over time as national markets continue to grow together and with the use of balancing effects.

The RA analysis for the reference scenario shows that the RA level on the electricity market in Germany remains very high throughout the entire period under consideration until 2030. German consumers can be reliably supplied at all times in the present study. The calculated loss of load probability (LoLP) has an amount of zero in the entire observation period from 2021 to 2030.

The very high RA level determined is due to the causes already discussed in the first project report:

---

<sup>196</sup> The calculations for this report were carried out from 15.09.2020, so that the "best-guess" scenario refers to the information situation between the end of April and the end of August 2020, as the research / updates for this 2nd project report were carried out during this period.

<sup>197</sup> See footnote 19.

- Due to the balancing group and balancing energy system, there are high incentives for suppliers to meet their delivery obligations. It is rational for market players to hedge against 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 currently has overcapacities. There are certain inertias in market adjustments by reducing these overcapacities through the decommissioning of existing plants for economic reasons.
- New capacities are also created through the replacement of CHP plants to maintain the heat supply and through the subsidised addition of RE plants.
- Capacity markets abroad (here considered: France, Great Britain, Poland and Italy) create new overcapacities, which also positively influence the RA level in Germany in the market.<sup>198</sup>
- In the internal electricity market, there are considerable balancing effects in the load and feed-in of renewable energies as well as in the case of unplanned unavailability of power plants.
- Finally, there is great potential for flexibilisation of consumption (including "new" consumers and a large capacity of economically developable flexibility options in the area of voluntary load reduction in industry), CHP and bioenergy, as well as emergency power systems.

These causes for the consistently high RA level are partly substitutive: A weakening or even an elimination of one cause does not call the RA level into question but would be compensated in the electricity market by adjustment reactions elsewhere. Due to these substitution possibilities, there are many possible development paths that ensure a secure electricity supply.

---

<sup>198</sup> However, without capacity markets abroad (cf. considered sensitivity "EOM - no capacity markets" in Section 4.1), the adequacy of resources in Germany also remains consistently high.

## 4 Sensitivities

Starting from the reference scenario, we calculated various sensitivities (alternative scenarios to the reference) in order to quantify the effects of deviating assumptions on the development of the electricity supply system and the resulting changes in the respective downstream RA analyses in terms of "what-if analyses". In doing so, we carried out three sensitivity calculations:

- 1) Hypothetical sensitivity "EOM - no capacity markets"
- 2) Sensitivity "Increased Sector Coupling - Price Scenario: TYNDP Distributed Energy"
- 3) Sensitivity "Increased Sector Coupling - Price Scenario: WEO Sustainable Development"

The first hypothetical sensitivity examines how the absence of capacity mechanisms in Europe affects resource adequacy in Germany and the development of resources - i.e. which adjustment reactions of the markets would be expected without them. In contrast, the two sensitivities on "Increased Sector Coupling" examine how resource adequacy develops and affects the development of resources in the case of increased coupling of the electricity, heat and transport sectors in two different energy price scenarios<sup>199</sup> that are alternative to the reference, as well as a more ambitious European RE expansion. The assumed energy price scenarios are characterised by a more ambitious CO<sub>2</sub> price path. Since more ambitious CO<sub>2</sub> price developments improve the economic viability of CO<sub>2</sub>-free electricity generation from renewables (in deviation from the reference scenario), the endogenous early closure of coal-fired power plants in Germany and Poland with long-term contracts in the capacity market is also permitted.<sup>200</sup> Due to the more ambitious CO<sub>2</sub> price path, the RE expansion in Europe is also based on the more ambitious TYNDP "Distributed Energy" scenario in the two sensitivities for "Increased Sector Coupling" instead of the "Stated Policies" scenario on which the

---

<sup>199</sup> Energy price scenario is defined in this context as the prices for primary energy sources and CO<sub>2</sub> allowances on which the scenario is based.

<sup>200</sup> However, this does not abstract from the Polish capacity market as in the "EOM" sensitivity.

European RE expansion in the reference scenario is based. The RE expansion in Germany, on the other hand, was not adjusted in the sensitivities. The following figure shows the expansion of renewable energies in the foreign countries considered for the two sensitivities for "Increased Sector Coupling".

**FIGURE 4-1: EXPANSION OF RENEWABLE ENERGIES IN THE FOREIGN COUNTRIES TAKEN INTO ACCOUNT IN THE SENSITIVITIES FOR "INCREASED SECTOR COUPLING"**



Source: Own representation.

The two different alternative energy price scenarios to the reference for the two sensitivities to "Increased Sector Coupling" are presented in the respective specific Sections 4.2 and 4.3

## 4.1 Hypothetical sensitivity: "EOM - no capacity markets".

### 4.1.1 Sensitivity characterisation

In the hypothetical sensitivity "EOM - no capacity markets", we have deviated from the reference scenario and fictitiously assumed that the comprehensive capacity markets considered in the reference scenario do not exist in France, Great Britain,

Poland and Italy.<sup>201</sup> The use of strategic reserves, such as the German capacity reserve, is also abstracted from in the quantitative RA analyses in this hypothetical scenario. The EU Electricity Market Regulation, which does not yet provide a legal basis for this monitoring, requires in Article 24 (in conjunction with Article 23) that resource adequacy shall be examined with and without the existing capacity markets. In the context of this project, this sensitivity serves exclusively to show whether and to what extent resource adequacy in Germany is influenced by foreign capacity markets and what market adjustment reactions would result without these instruments.

#### **4.1.2 Results of electricity market simulations**

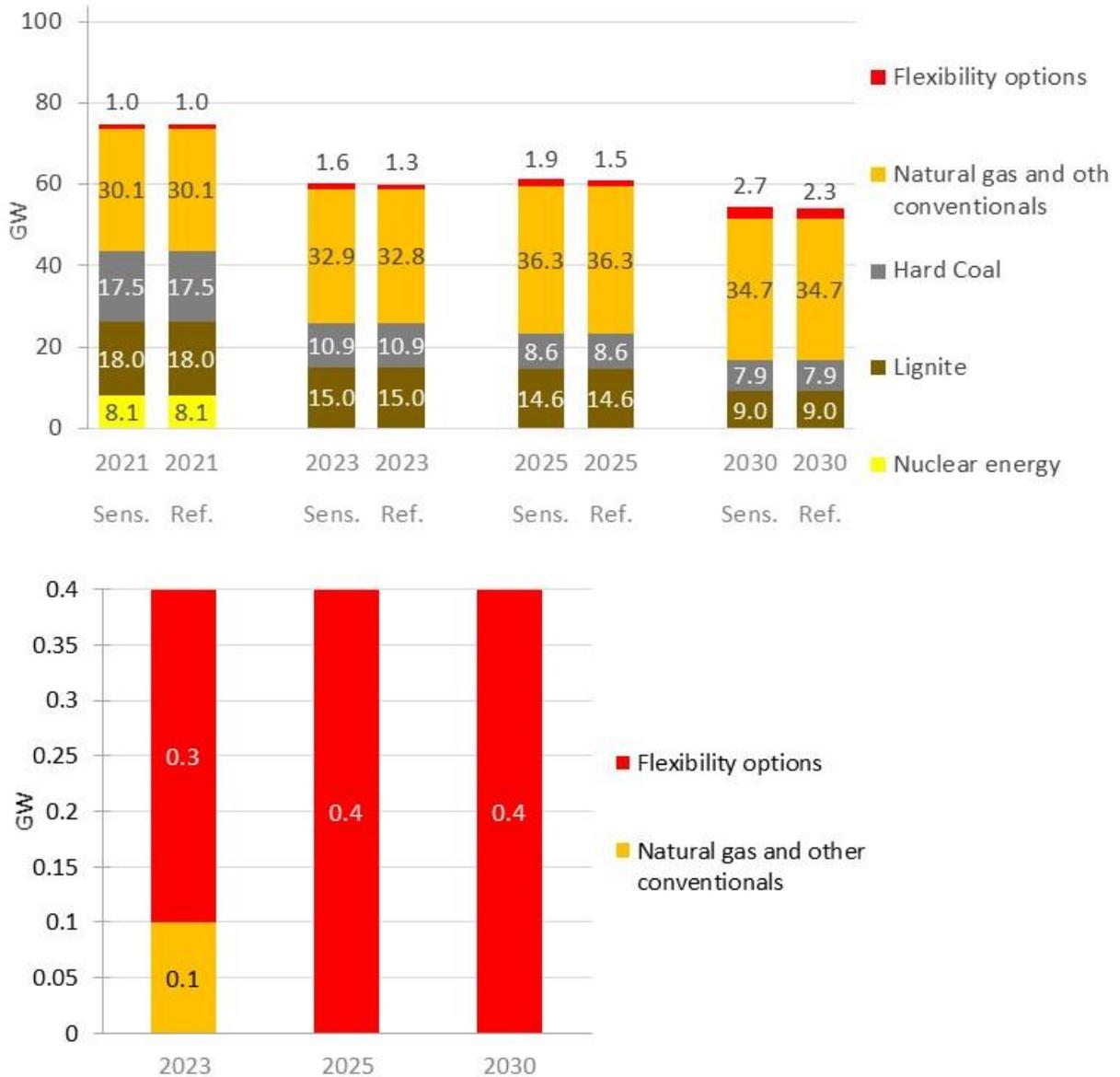
In this section, we show how the assumption of pure energy-only markets (EOM), which differs from the reference scenario, affects the development of power plants and the development of flexibility options on the electricity market in Germany as well as on the electricity markets in the other countries considered. First, Figure 4-2 shows the differences in the development of the installed capacity of the German power plants and the development of flexibility options compared to the reference scenario.<sup>202</sup>

---

<sup>201</sup> This also abstracts from long-term contracts already concluded with large-scale power plants, so that in the hypothetical sensitivity EOM, these (can) be shut down prematurely by model endogeneity if they are not economical.

<sup>202</sup> In Germany, no changes result in the sensitivity "EOM" in the reference year 2021, as no comprehensive capacity mechanism is installed in Germany. For the foreign countries considered (some with comprehensive capacity mechanisms), the resulting adjustments in the first reference year 2021 are also shown (cf. Figure 4-4).

FIGURE 4-2: ABSOLUTE AND DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN GERMANY: SENSITIVITY "EOM" VS. REFERENCE SCENARIO

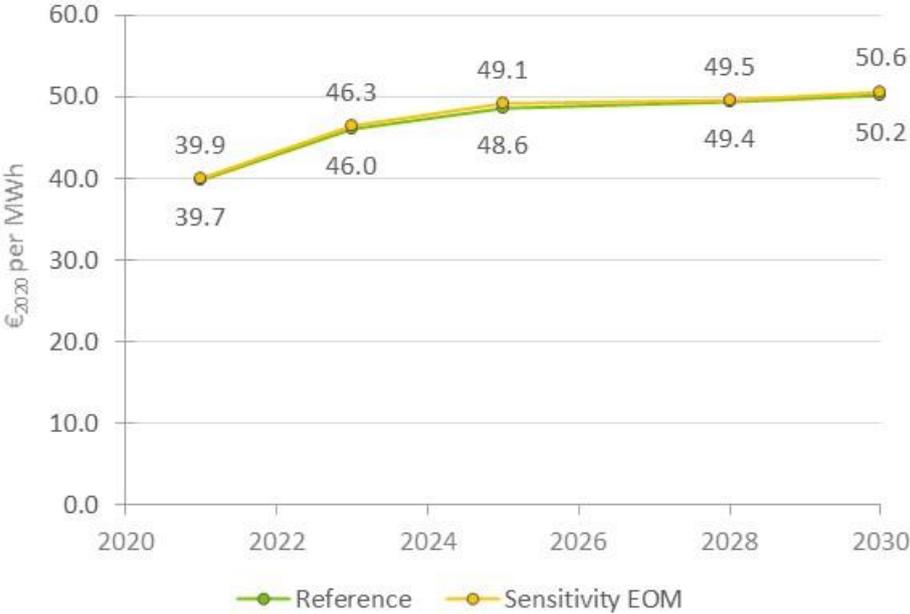


Source: Own calculations.

The assumption of an EOM in all the countries studied 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. 0.1 GW above the capacity in the reference scenario. In addition, in the forecast years 2023, 2025 and 2030, approx. 0.3 to 0.4 GW more flexibility options are developed in the form of voluntary load reduction by industry and emergency power systems.

The annual base price averaged over all weather years (2009-2013, 2017) increases slightly over time, as shown in Figure 4-3, and is €<sub>2020</sub> 50.6 per MWh in 2030. Compared to the reference scenario, the base price in the sensitivity is minimally higher in all sample years.

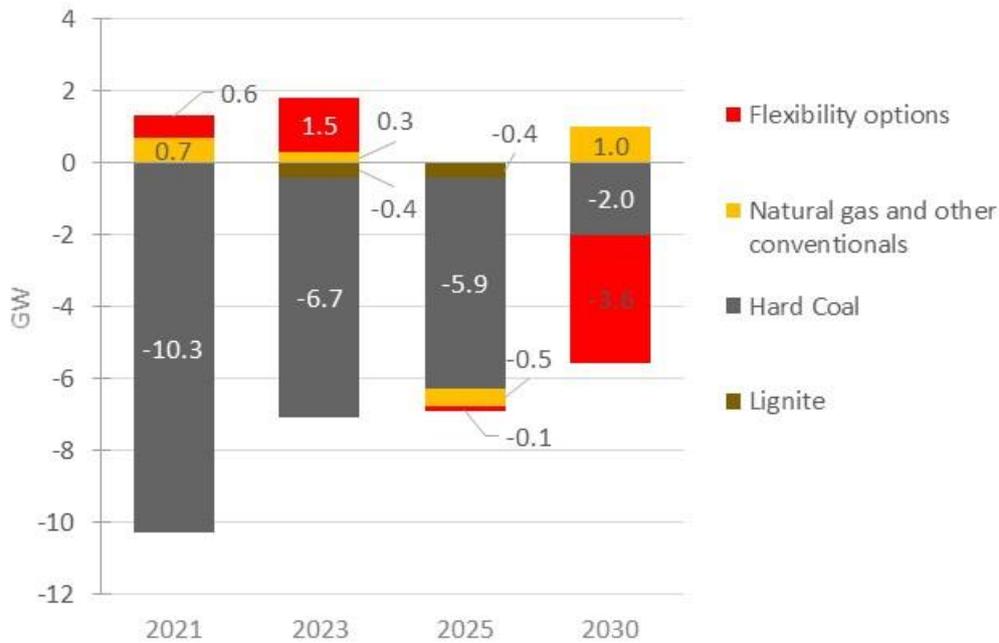
**FIGURE 4-3: DEVELOPMENT OF THE BASE PRICE IN GERMANY AVERAGED OVER ALL WEATHER YEARS IN THE REFERENCE SCENARIO AND IN THE "EOM" SENSITIVITY**



Source: Own calculations.

The effects of the assumption of an EOM in all countries considered on the development of flexibility options as well as the development of power plants in the foreign countries considered are shown in Figure 4-4.

FIGURE 4-4: DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN THE CONSIDERED FOREIGN COUNTRIES: SENSITIVITY "EOM" MINUS REFERENCE SCENARIO



Source: Own calculations.

In the foreign countries considered in this hypothetical sensitivity, significantly more coal-fired power plants are prematurely decommissioned endogenously compared to the reference scenario. The coal capacity on the market in 2021 is approx. 10.3 GW below the capacity in the reference scenario. This is almost entirely due to additional closures in Poland, where, in deviation from the reference scenario, power plants (coal) that are bound in the Polish capacity market in the reference scenario may also be closed.<sup>203</sup> In the first reference year 2021, the model prohibits endogenous closures for economic reasons, which is why this capacity is initially transferred to the cold reserve. Over time, the reduced capacity of the coal-fired power plants decreases compared to the reference scenario, as coal-fired plants also leave the market there. The additional capacity of coal-fired power plants in the reference scenario decreases continuously and amounts to only 6.7 GW in 2023, then 5.9 GW in 2025 and finally only approx. 2 GW in 2030.

<sup>203</sup> In the reference scenario, the model-endogenous decommissioning of power plants in Poland that have a contract in the capacity market is prohibited.

In 2023, approx. 1.5 GW more flexibility options are developed, and the natural gas capacity is approx. 300 MW above that of the reference. In addition, in 2030 there are approx. 1 GW more natural gas power plants on the market compared to the reference scenario. Furthermore, in 2023 and 2025 there are approx. 0.4 GW fewer lignite-fired power plants on the market in Poland than in the reference.

Up to and including 2023, as much as 1.5 GW more flexibility options will be developed in the form of voluntary load reduction by industry and emergency power systems than in the reference. In contrast, in 2030 approx. 3.6 GW less of these flexibility options will be developed in the EOM when the British and French capacity markets have expired or no longer have any effect.<sup>204</sup>

### 4.1.3 Results RA analyses

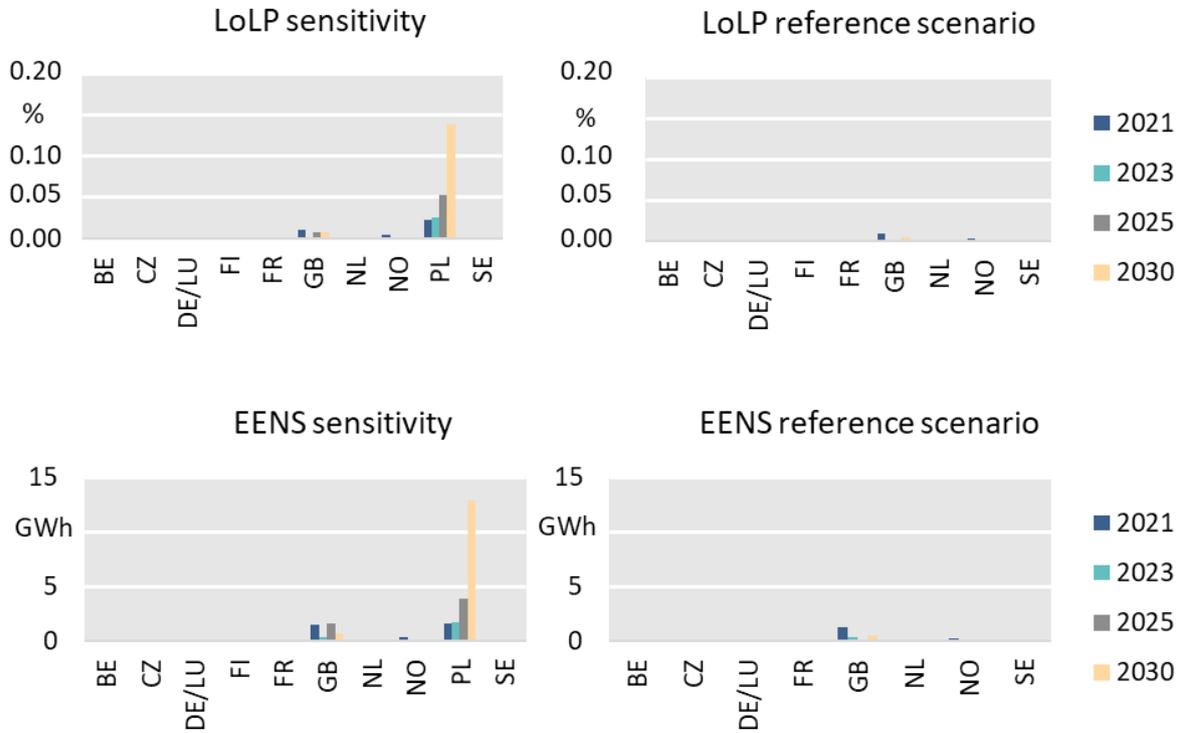
#### Loss of Load Probability and Expected Energy Not Supplied

Figure 4-5 compares the LoLP and EENS values of the sensitivity "EOM - no capacity markets" with those of the reference scenario. As in the discussion of the reference scenario, for reasons of clarity the presentation is limited to those countries in which a value greater than zero occurs in at least one year under review. To facilitate the comparison, the scaling of the y-axes for the reference scenario was adapted to the range of values of the sensitivity results.

---

<sup>204</sup> We have assumed that the contracts for large power plants in the context of central comprehensive (market-wide) capacity markets continue to have an effect for 5 years after the expiry of the respective capacity market.

FIGURE 4-5: LOLP AND EENS IN SENSITIVITY "EOM - NO CAPACITY MARKETS" FOR COUNTRIES WITH RATIOS > 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 LoLP values of the sensitivity continue to be zero for Germany/Luxembourg in the period under consideration until 2025, corresponding to a load balancing probability of 100 %. For 2030, a very low LoLP of 0.00015 % is determined. This is a factor of 400 below the threshold value of 0.06 % derived as the RA standard in the first project report and corresponds to a load balancing probability of 99.99985%.

In Norway and the UK, the minor LoLP and EENS values observed in the reference basically remain at similar levels in the sensitivity, with the exception of an increase (but still at a low level) in the UK in the year under review 2025. One reason for this could be the modelled abandonment of the capacity market in the electrically neighbouring country France.

An increase in LoLP would also be plausible for Poland due to the modelled discontinuation of the capacity market there. However, the increase seems surprisingly high (especially in 2030) because at the end of the period under consideration, an at least satisfactory level of RA could be expected due to the endogenous modelling of investment incentives in the electricity market model (cf. Section 1.5).

An analysis of the detailed results of the two model stages, electricity market model for scenario generation and RA model for determining the RA indicators, shows that the combination of several effects plays a role here, which cause the RA level determined for Poland to be significantly less robust than the results for Germany/Luxembourg.

First, model accuracy is lower at the peripheries of the observation area than in Germany, which is the focus of this study. This applies in particular to the modelling of electricity exchanges between the core region (Germany and its neighbouring countries, Scandinavia, Great Britain, and Italy) and the neighbouring countries, the so-called satellite regions.<sup>205</sup> In the electricity market model, the exchange with satellite regions (in the case of Poland: Slovakia and Lithuania) is determined using price elasticities and NTCs for import/export capacities. In the subsequent RA analysis, the exchange per weather year and year under review is fixed to the temporal profile determined in this manner. However, in the RA analysis, due to the independent modelling of the stochastic power plant unavailabilities (350 year simulations per weather year and year under review), a high import demand from a satellite region to a border country of the core region can occur in different hours than in the electricity market simulation. The lack of flexibility in the RA model for imports from satellite regions can thus lead to an overestimation of resource scarcity in the border country (here: Poland). However, it is also conceivable that an overestimation of the import possibilities from satellite regions can occur in the electricity market model, since corresponding resources in the satellite regions are assumed to be available at this point in time. This leads to a

---

<sup>205</sup> In the electricity market simulations for scenario generation, the Iberian Peninsula with its interconnectors to France was mapped as an additional core region due to the high dependencies between the French and German electricity markets.

reduced overall robustness of the RA results in peripheral countries with neighbouring satellite regions, whereby it is open whether the net effect leads to an overestimation or underestimation of the RA level there. This parameterisation without a priori specification of a trend is a deliberate model decision: Alternatively, it would be possible to assume the feasibility of importing from the satellite regions at the level of the respective NTC at any time. However, this would clearly overestimate the RA level in the peripheral countries, since an unlimited availability of resources in the satellite regions would be implicitly assumed. Variant calculations based on interim results have shown that such a release of possible imports from satellite regions is sufficient to reduce the LoLP determined for Poland significantly - namely below the threshold value of 0.06% proposed for Germany. Secondly, at the interface between the two model levels, a compromise is required with regard to the model depth of time-variable flexibilities including dynamic sector coupling technologies. In the RA model, these flexibilities are aggregated more strongly than in the electricity market model. A conservative approach was chosen for the conversion required for this in order to avoid overestimating the effect of such flexibilities in the RA analysis.

And thirdly, a broader distribution of power plant unavailability in all bidding zones is modelled in the RA model.<sup>206</sup> This means that larger amounts of unavailable generation capacity are simulated than in the electricity market model, although these are included in the results with a correspondingly lower probability of occurrence. Similarly, lower unavailabilities than in the electricity market model are also modelled, so that the unavailabilities in the RA model and the electricity market model are the same on average. For most bidding zones, the broader distributions of unavailability taken into account have only a minor impact on the ability to cover load, because higher unavailability in the domestic market can very likely be compensated by lower unavailability abroad or at least by sufficient available generation capacity abroad overall. A simultaneous occurrence of high unavailability in many bidding zones, is, as realistically considered in the RA model, so rare

---

<sup>206</sup> The modelling of a lower stochasticity of power plant unavailabilities in the electricity market model is necessary to limit the complexity to an extent that is still technically manageable for the electricity market model with justifiable computing times.

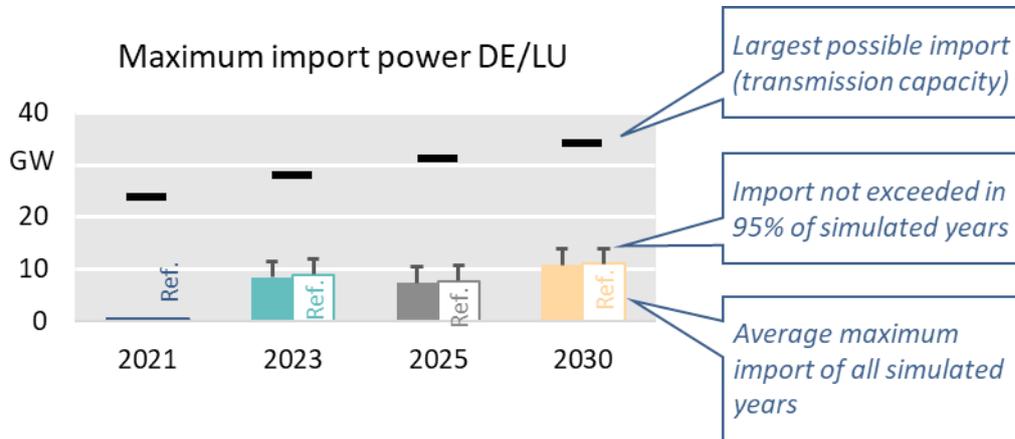
that it hardly affects the results in terms of LoLP. This is the result of the balancing effects mentioned previously. In Poland, however, the constellation is unique in that in the RA model the import capacity from countries of the core region (without satellite countries, see above) is significantly lower there than in the other bidding zones of the core region, especially in relation to the respective levels of load. As a result, in the RA model, during simulation hours with high local power plant unavailability, although sufficient foreign resources would most likely be available for back-up, grid restrictions can cause that the back-up cannot always be imported to Poland in the required amount to prevent load excess. The relatively low cross-border transmission capacities thus prevent a full use of balancing effects here.

To summarise, the high LoLP values for Poland determined in this sensitivity are the result of a generally lower robustness of the results in peripheral countries of the observation area with adjacent satellite regions, and two effects due to adjustments required at the interface of the two model stages. The latter two contribute to an overall conservative parameterization of the model chain and thus to an underestimation of the RA level due to different modelling focus and depth in the two model stages.

### Required imports

The maximum import capacities to Germany/Luxembourg required to avoid load excess remain practically the same compared to the reference scenario (Figure 4-6). Their slight decrease is consistent with the slight increase in resources in Germany (cf. Section 4.1.2).

FIGURE 4-6: REQUIRED\* IMPORTS TO DE/LU IN SENSITIVITY "EOM - NO CAPACITY MARKETS".



Source: Own representation.

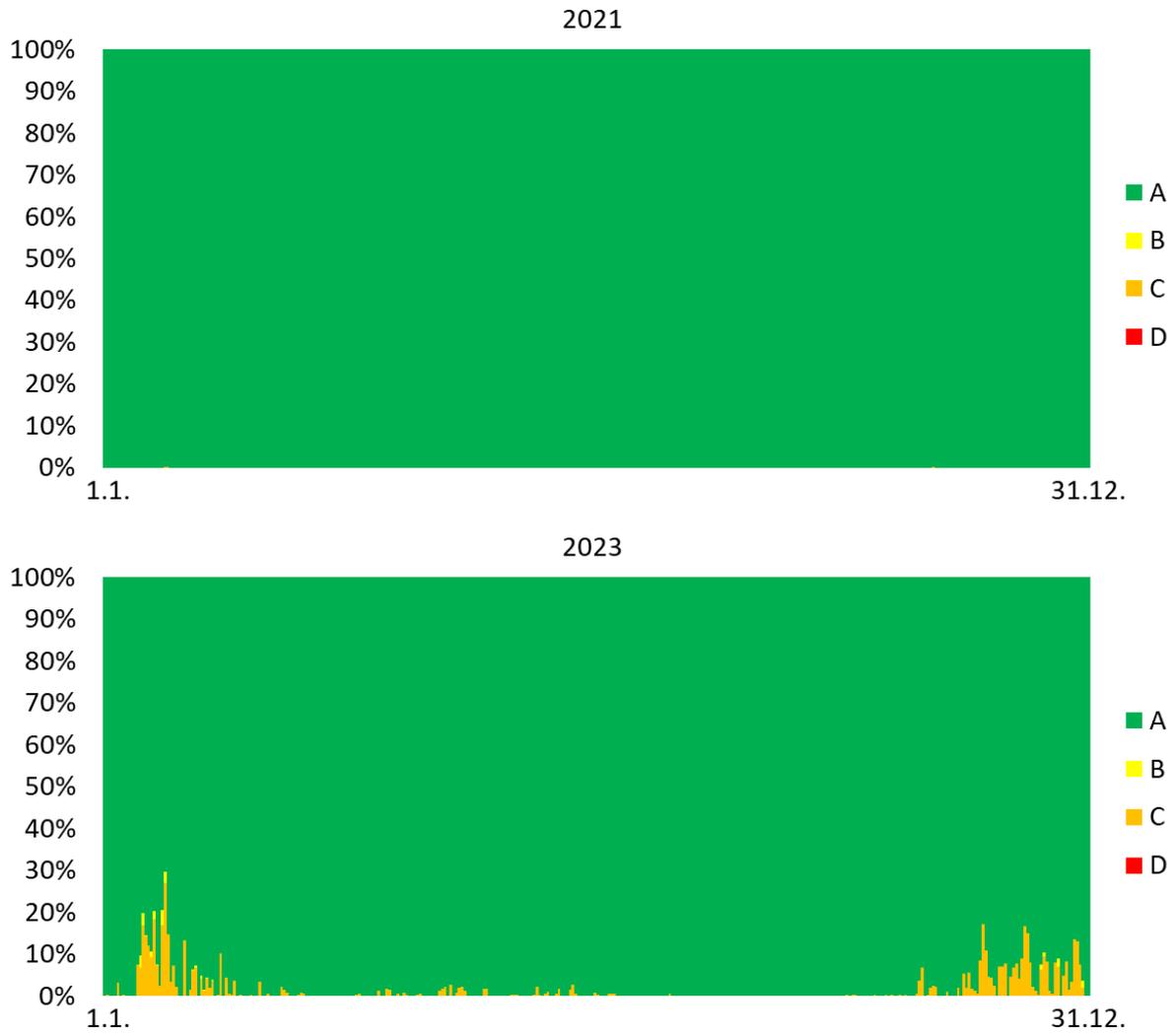
Required imports to avoid load excess. Market imports may deviate from this.

Overall, the RA level on the electricity market in Germany remains very high throughout the entire observation period until 2030, even in this sensitivity, and German consumers can be securely supplied at practically any time.

### Leeway status

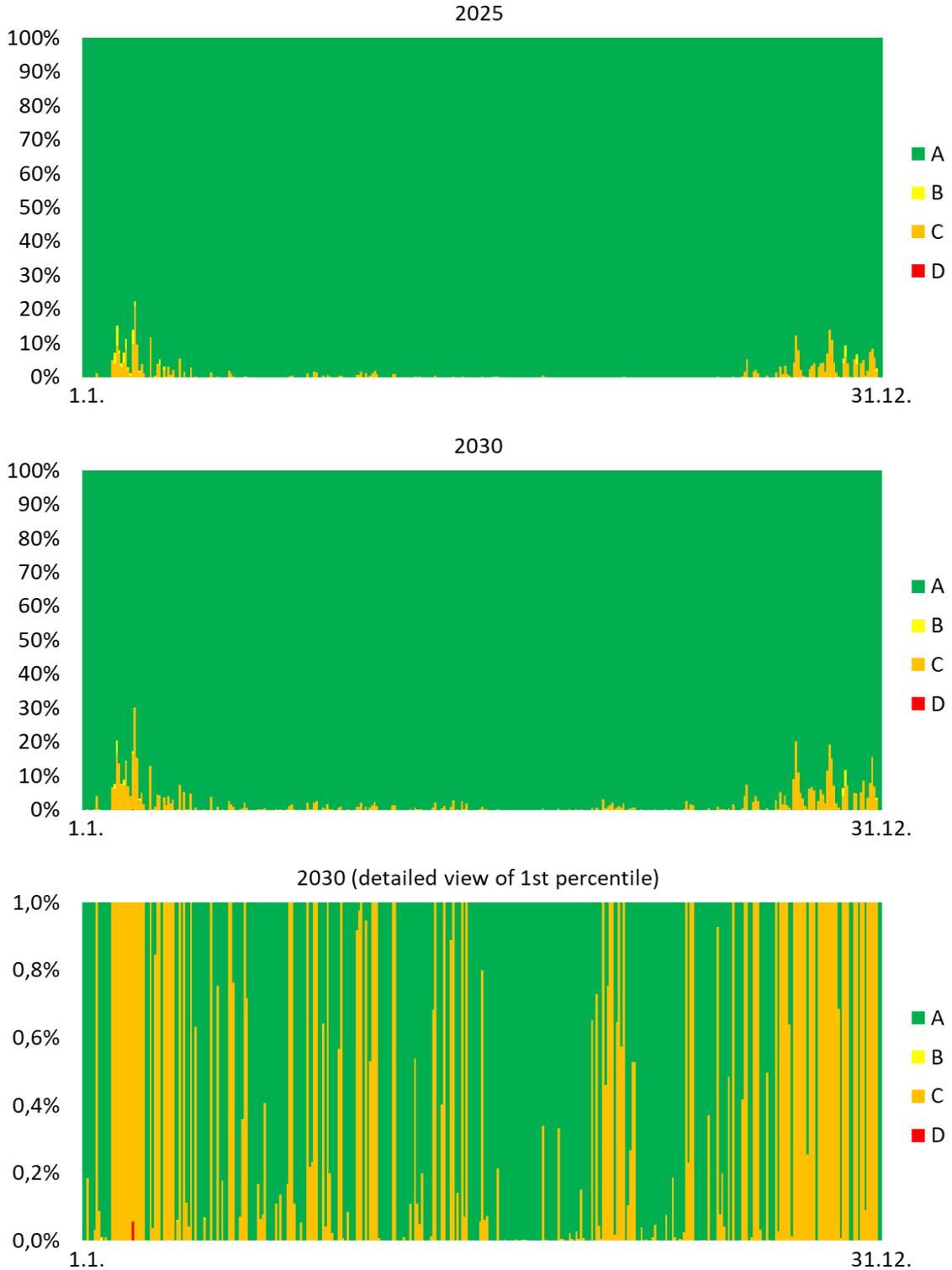
Analogous to the reference scenario, we also evaluate the leeway status for this sensitivity, which indicates how far the electricity supply system is still "away" from load excess in the remaining hours (cf. introduction in Section 3.3, subsection "Leeway status "). The following two diagrams show the result of the evaluation of the leeway status of Germany/Luxembourg for the four years under review. In each diagram, the 365 days of the year are plotted from left to right.

FIGURE 4-7: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "EOM - NO CAPACITY MARKETS", FOR THE YEARS 2021 AND 2023



Source: Own representation. Categories A to D according to Table 3-1

FIGURE 4-8: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "EOM - NO CAPACITY MARKETS", FOR THE YEARS 2025 AND 2030



Source: Own representation. Categories A to D according to Table 3-1

The results differ only slightly from the reference scenario in purely visual terms, which is consistent with the small change in required imports (see above). In order to make the load excess occurring in 2030, which leads to a very low LoLP value greater than zero in the sensitivity in this year, recognisable in this representation, a sectional enlargement is shown in Figure 4-8, in which only the first percentile, i.e. the lowest "edge" of the diagram above is shown. Even in this hundredfold magnification, category A occupies only a very small part of the diagram area. This illustrates the low probability of the occurrence of a load excess.

#### Detailed analysis of (simulation) hours with loss of load in Germany/Luxembourg

Despite this low probability of occurrence, it may be of interest to characterise in more detail the situations with load excess in Germany/Luxembourg that occur in the simulation for 2030. For example, the question arises as to how high the import power is in such situations and from which foreign bidding zones the corresponding exports are provided.

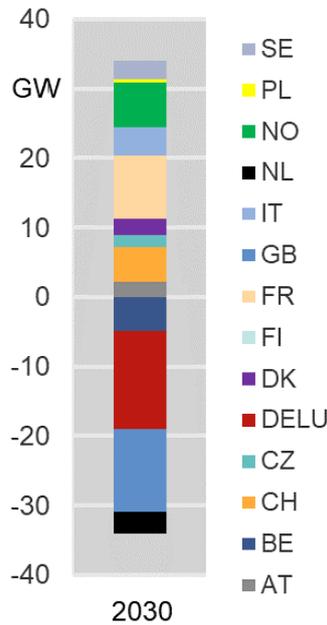
The import power in hours with load excess in Germany/Luxembourg is at least 16 GW below the maximum import capacity. Its median is about 20 GW below the maximum import capacity, which is yet significantly lower. This indicates that load excess in Germany/Luxembourg occurs primarily in situations with transnational momentary resource scarcity and not due to limited grid capacity.

Cluster analysis can be used to determine the typical pattern of cross-border power exchanges for simulation hours with load excess in Germany/Luxembourg, which is shown in the following figure.<sup>207</sup>

---

<sup>207</sup> For this purpose, the net positions (export or import balances) of all bidding zones are represented as a vector for each hour with load excess. Then the vector that best characterises the group of all vectors is determined. First, a so-called k-means clustering is carried out. Then the real vector is determined that lies closest to the calculated cluster centre. The Euclidean distance of the net position vectors is used as a criterion for this.

FIGURE 4-9: TYPICAL EXCHANGE PATTERN IN SITUATIONS WITH LOAD EXCESS IN GERMANY/LUXEMBOURG IN SENSITIVITY "EOM - NO CAPACITY MARKETS".



Source: Own representation.

In hours with load excess in Germany/Luxembourg, it is typically Belgium, Great Britain and the Netherlands that import at the same time as Germany/Luxembourg, while the other countries provide exports.

#### Technical resource adequacy (including strategic reserves)

In this sensitivity, in contrast to the reference scenario, a non-zero LoLP occurs in Germany/Luxembourg. It has a non-critical level. Nevertheless, we quantify the technical resource adequacy for this sensitivity.

Using the capacity reserve, the LoLP in Germany/Luxembourg can be reduced by more than one order of magnitude from the already very low initial level. This is practically equivalent to zero having regard to the model accuracy.

## 4.2 Sensitivity: "Increased Sector Coupling - Price Scenario: TYNDP Distributed Energy".

### 4.2.1 Sensitivity characterisation

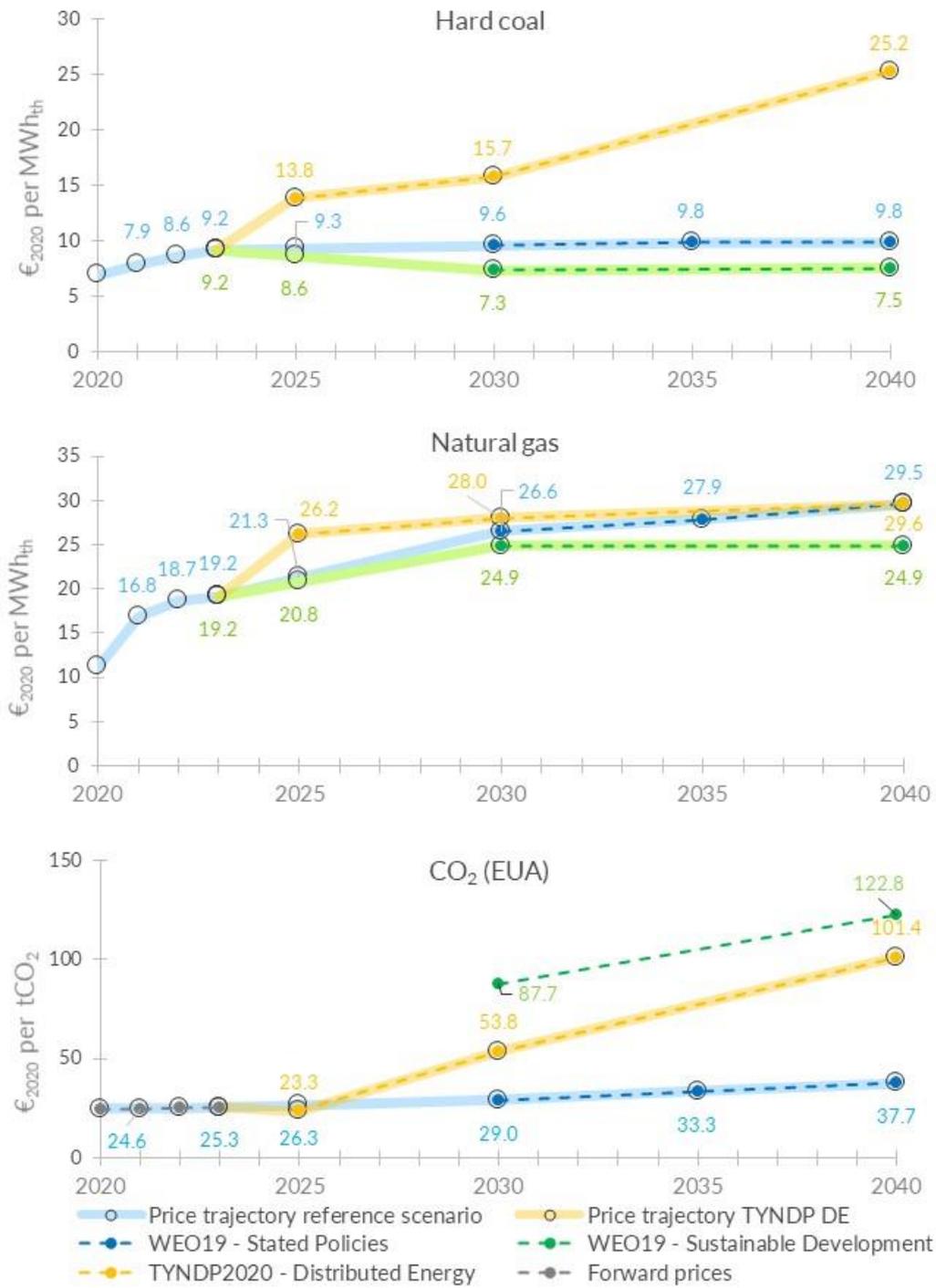
In this sensitivity, we examine an accelerated market penetration of technologies for sector coupling within the framework of the energy price scenario assumed in the "Distributed Energy" scenario of the TYNDP 2020 of ENTSO-E and RE expansion in the foreign countries considered. The energy price scenario is characterised by a more ambitious CO<sub>2</sub> price path compared to the reference in combination with a price development for natural gas comparable to the reference, but significantly higher prices for hard coal imports to Europe. The RE expansion in other European countries is also more ambitious than in the reference scenario.<sup>208</sup> In the following figure, the developments of the primary energy source and CO<sub>2</sub> prices of this sensitivity are compared with those of the reference.<sup>209</sup>

---

<sup>208</sup> For a presentation of the identical RE expansion in the two scenarios for "increased sector coupling" in the foreign countries considered compared to that of the reference scenario, cf. Section 4.

<sup>209</sup> No price paths are given for crude oil in the TYNDP. For this scenario, we have taken the prices for light and heavy heating oil directly from the TYNDP 2020. Since crude oil as well as light and heavy heating oil only play a very minor role in Europe's electricity supply systems, they are not considered separately here.

FIGURE 4-10: ENERGY PRICE SCENARIOS: REFERENCE VS. SENSITIVITY "INCREASED SECTOR COUPLING TYNDP - DISTRIBUTED ENERGY".



Source: Own representation based on forward prices natural gas: EEX (2020a), forward prices coal: CME Group (2020b), forward prices EUA: EEX (2020b), WEO19: IEA (2019), TYNDP2020: ENTSO-E (2020); own conversion of original values in €<sub>2020</sub> per MWh<sub>th</sub> as European wholesale prices without surcharges for transport or similar.

The technologies for sector coupling considered in this study are, on the one hand, so-called "new consumers" (cf. Section 2.5.4) electromobility (< 3.5 t), overhead line trucks, electric heat pumps in Germany and the foreign countries considered in the private household and tertiary sector. On the other hand, the large-scale PtX technologies large-scale heat pumps, e-heaters and power-to-gas in Germany and Europe gain importance in such a scenario in the context of decarbonisation of further sectors (besides electricity generation). Furthermore, based on the approved scenario framework of the NDP 2021-35, we have assumed additional electricity consumption for the "digitalisation and decarbonisation of trade and industry".

The faster ramp-up of the sector coupling technologies described above is driven by the increasing competitiveness and market maturity of electrified technologies in the heat and transport sectors in such an energy price scenario, as well as national (subsidies) policies in the field of residential, commercial and industrial PtX applications.

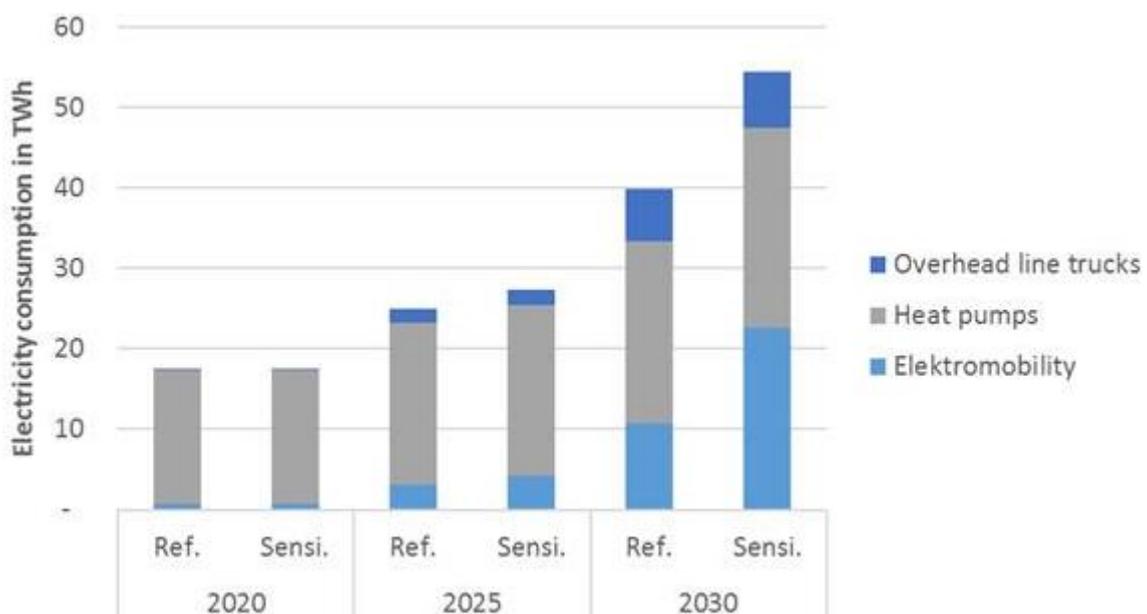
The sensitivity for electric mobility (<3.5 t), electric heat pumps and overhead line trucks is mapped based on increasing market penetration. The following assumptions were made:

- **Electromobility (<3.5 t):** The framework for additional market penetration is compliance with the fleet limits. By 2025, there will be an increase of 440,000 vehicles compared to the reference development, as it is assumed that the infrastructure is not yet substantially better developed by 2025. By 2030, the number of the fleet finally increases to 9.4 million (compared to 4.5 million in the reference).
- **Heat pumps:** The main framework conditions for the additional market penetration of installed heat pumps are the heating demand of the buildings, the age of the heating systems and the availability of trained craftsmen. This is reflected by the mapping of path dependencies and by a certain system inertia. For the year 2030, this leads to t 4.9 million heat pumps (compared to 4.5 million in the reference).
- **Overhead Line Trucks:** The increasing expansion of OH trucks infrastructure is also accompanied by an increasing use of the infrastructure, as this

is necessary for economic viability. An additional increase in the fleet of OH trucks is assumed to a total of 72,600 in 2030 (compared to 66,000 in the reference).

These assumptions result in an increase in German electricity demand of 2.5 TWh for the year 2025 and 14.7 TWh for the year 2030.

**FIGURE 4-11: SENSITIVITY "ACCELERATED SECTOR COUPLING": DEVELOPMENT OF ELECTRICITY DEMAND FROM ELECTROMOBILITY (<3.5T), HEAT PUMPS AND OVERHEAD LINE TRUCKS (OH TRUCKS)**



Source: Own representation.

In addition to these sector coupling technologies, the electricity quantities of newly planned large-scale electricity consumers were also taken into account. These are the electricity consumption of planned projects in industry and commerce that focus on the increasing digitalisation of processes and decarbonisation measures and have a connected load greater than 5 MW. The data basis for this is based on the consumption group "decarbonisation and digitalisation in industry and commerce" of the approved scenario framework 2021-2035 of the network development plan for electricity.

The data collection for this consumption group was carried out by the distribution system operators and the validation was carried out by the assigned transmission system operators. The data for the individual projects are available differentiated

according to the following parameters: Status of implementation, time of commissioning, reported electricity consumption, reported nominal load and an assessment of the project realisation probability.

The consumption group "decarbonisation and digitalisation in industry and commerce" involves the consideration of additional electricity consumption that is not explicitly mapped via the endogenous decision logic of the energy demand model and thus flows exogenously into the balancing. The estimate for this sensitivity is based on scenario B of the network development plan for electricity and leads to an additional electricity consumption of 8 TWh in 2030.

The sensitivities of electric mobility (<3.5 t), heat pumps, overhead line trucks and additional decarbonisation and digitalisation efforts were also mapped for the neighbouring countries, under consideration of using faster market penetration or analogy conclusions. In line with the study of the reference, the structural differences in the individual countries were taken into account. Thus, a consistent set of framework parameters was used as a basis for the sensitivity analysis for the sector coupling technologies already established today.

Increased electricity consumption is also assumed for the conversion sector in the sensitivity. The main sector coupling technologies in the conversion sector are large-scale PtX technologies, large-scale heat pumps and electric boilers for integration into the district heating supply as well as power-to-gas plants for the production of hydrogen or methane.

In the reference scenario, we have largely based our assumptions on the development of these technologies on scenario B of the approved scenario framework of the grid development plan 2021-35 and the "National Hydrogen Strategy" (NHS) of the German government (cf. Section 2.5.2). For the sensitivity "Accelerated sector coupling", on the other hand, we base the assumptions on scenario C of the approved scenario framework of the network development plan 2021-35, considering the NHS.<sup>210</sup> The assumptions were adjusted as follows:

---

<sup>210</sup> As the approved scenario framework of the network development plan 2021-35 only shows the year 2035, the data for the year 2030 was interpolated or assumptions were made for the ramp-up of the technologies.

- **Power-to-heat (PtH) in district heating:** For the capacity development of PtH in the form of large-scale heat pumps and electric boilers in large-scale heat supply, we have assumed an accelerated expansion according to scenario C of the NDP 2021-35.
- **Power-to-gas: For power-to-methane and power-to-hydrogen** (hydrogen), we have also based the capacity development on scenario C of the NDP 2021-35 and the NHS, while assuming an accelerated expansion after 2030. Until 2030, the development of installed capacity is assumed to be identical - however, we assume higher utilisation rates due to the higher RE expansions compared to the reference.

Table 4-1 shows the assumptions for the two sensitivities for "Increased Sector Coupling" compared to the assumptions for large-scale PtX technologies used in the reference scenario.

Table 4-1: DEVELOPMENT OF INSTALLED CAPACITIES AND ELECTRICITY CONSUMPTION OF LARGE-SCALE PTX TECHNOLOGIES IN 2030: REFERENCE VS. SENSITIVITIES FOR "ENHANCED SECTOR COUPLING"

Technology	Reference	Sensitivities for "Increased Sector Coupling"
PtG	5 GW	5 GW
	10.7 TWh	16.5 TWh
PtH	4.3 GW	5.7 GW
	12.2 TWh	14.2 TWh

Source: Own representation.

In total, the electricity consumption for large-scale PtX technologies in the sensitivities for increased sector coupling is about 8 TWh above the reference scenario. No further adjustments have been made in the conversion sector.

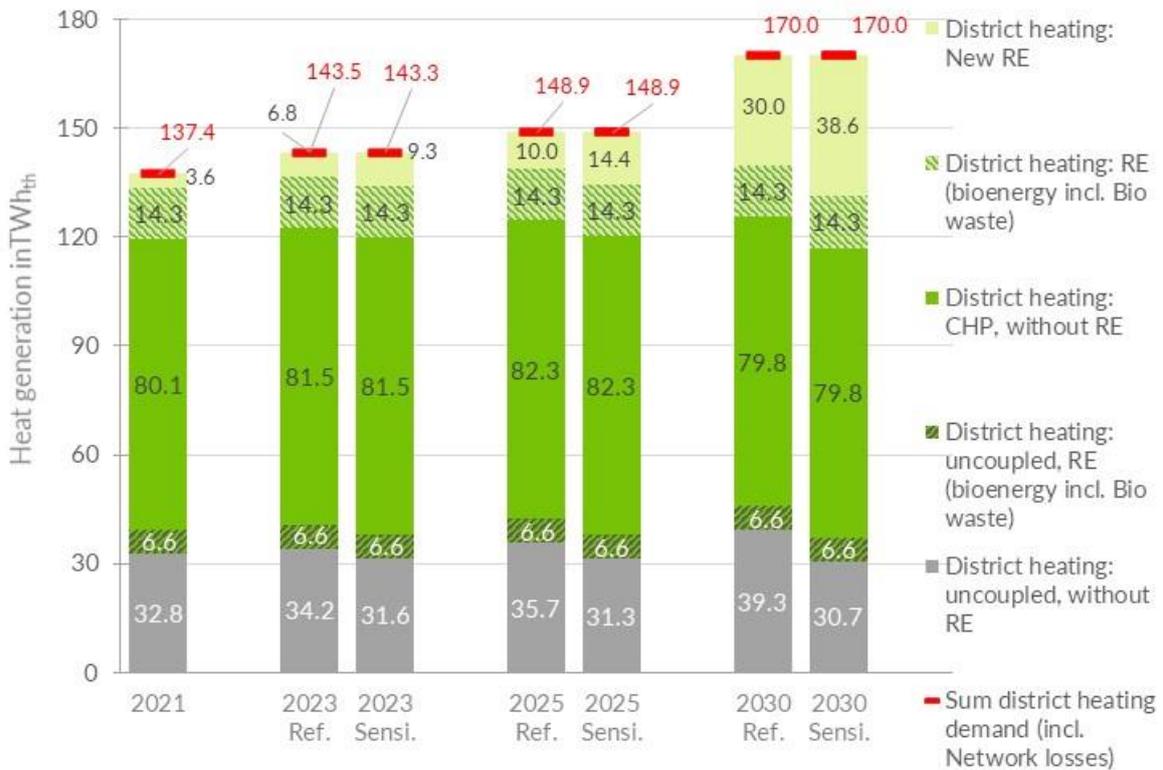
The total gross electricity consumption in Germany in this sensitivity is approx. 615 TWh in 2030 - compared to the reference scenario, the electricity consumption in this sensitivity is thus approx. 33 TWh higher.

In order to establish consistency with the changed assumptions for the sector coupling technologies, we have adjusted the predefined development of the public heat demand to be covered by conventional CHP plants ('heat scenario') in Germany. While the reference scenario prescribes the achievement of the target of the 'National Energy and Climate Plan' (NECP) of 30 % renewable heat in district heating in 2030, this was increased to 35 % in the two sensitivities for 'enhanced sector coupling'.<sup>211</sup> The extra 5 % is made up of additional heat from the PtH sector coupling technologies large heat pumps and electric heaters as well as an increased expansion of solar thermal and geothermal energy. The additional RE heat reduces the necessary heat supply from fossil uncoupled generation (heat generation from gas boilers) by the same amount. The total district heating demand and the district heating from CHP plants are thus the same in both scenarios (see Figure 4-12). We also assume that the incentive structure of the CHP Act changes in the long term so that CHP plant operators are encouraged to operate flexibly according to market price signals. We have implemented this by reducing the subsidised full utilisation hours for new plants by 2.5% annually from 2025. With heat extraction from CHP power plants remaining unchanged, this will lead to a slightly higher capacity expansion of CHP power plants by 0.8 GW in 2030.

---

<sup>211</sup> For the reference scenario, see Section 2.2.3.

FIGURE 4-12: CHANGED STRUCTURE OF HEAT GENERATION IN DISTRICT HEATING

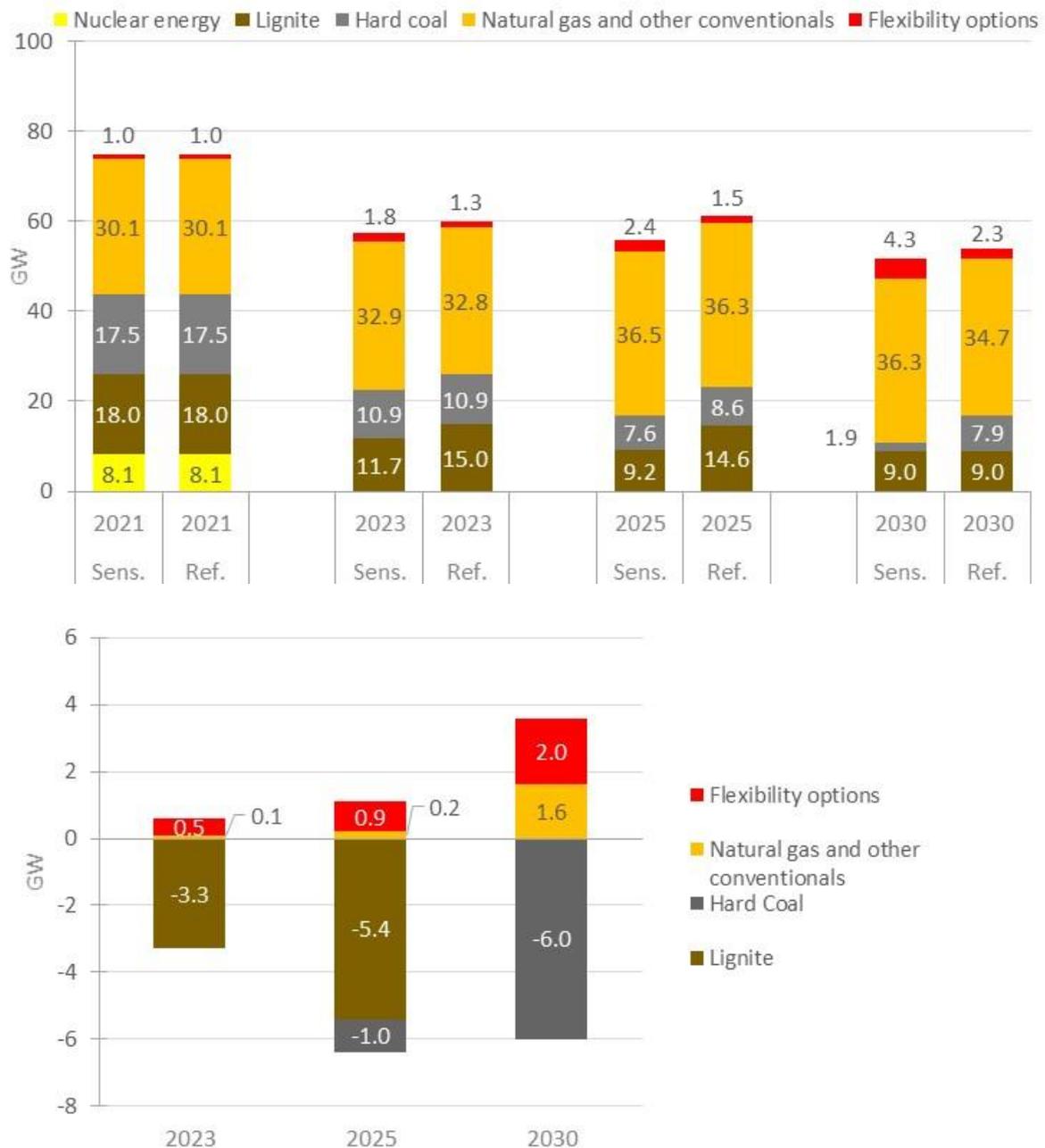


Source: Own representation based on research and calculations.

#### 4.2.2 Results of electricity market simulations

In this section, we show how the assumptions of an increased market penetration of sector coupling technologies, an alternative energy price scenario and a more ambitious RE expansion in the countries considered affect the development of the power plants and the development of flexibility options on the electricity market in Germany and on the electricity markets in the other countries considered. First, Figure 4-13 shows the development of the installed capacity of German power plants and the development of flexibility options in comparison with the reference scenario.

FIGURE 4-13: ABSOLUTE AND DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN GERMANY: SENSITIVITY "INCREASED SECTOR COUPLING - TYNDP" VS. REFERENCE SCENARIO



Source: Own calculations.

Compared to the reference scenario, the capacity of lignite-fired power plants in 2023 is already approx. 3.3 GW lower. This is due to the lower economic efficiency of lignite-fired power plants compared to the reference scenario because of the comparatively highest CO<sub>2</sub> intensity of all relevant primary energy sources

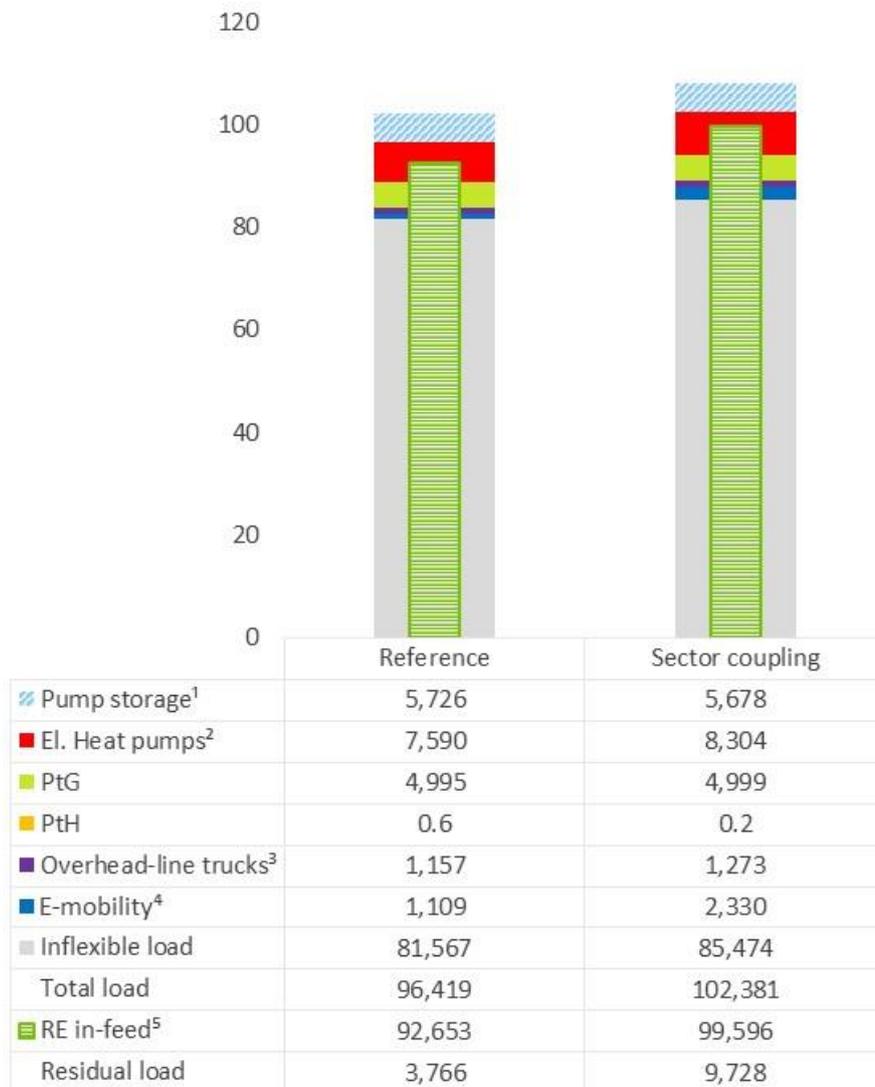
with significantly higher CO<sub>2</sub> price developments - with the consequence of model-endogenous closures for economic reasons. In 2025, the reduction in lignite output will then be approx. 5.4 GW. In 2030, the installed capacity of lignite-fired power plants in this sensitivity is identical with the reference scenario. In the case of hard coal, the sensitivity shows that in 2025 there would be approx. 1 GW and in 2030 approx. 6 GW less capacity on the market than in the reference. This is also attributable to model-endogenous closures due to the more ambitious CO<sub>2</sub> price path and significantly higher prices for hard coal compared to the reference scenario. Opposite effects can be seen in the case of natural gas-fired power plants and the flexibility options of voluntary load reduction by industry and emergency power systems. Thus, the additional capacity from natural gas-fired power plants in the sensitivity scenario amounts to approx. 200 MW in 2025 and approx. 1.6 GW in 2030. In the flexibility options, approx. 500 MW more are developed compared to the reference in 2023, just under 1 GW in 2025 and approx. 2 GW in 2030. In addition, the annual peak load in 2030 is a roughly 102 GW, approx. 6 GW above the annual peak load in the reference scenario.<sup>212</sup>

However, this increase in the annual peak load does not represent a shortage situation. As shown in Figure 4-14 the feed-in of volatile technologies in this hour is just under 93 GW and the sector coupling technologies have comparatively high loads. Since the output of the sector coupling technologies is higher in the sensitivity, the annual peak load also increases here compared to the reference.

---

<sup>212</sup> For an analysis of the situations of annual peak load and residual annual peak load, see Section 3.1.1

FIGURE 4-14: COMPARISON OF THE COMPOSITION OF THE LOAD AT THE TIME OF THE ANNUAL PEAK LOAD BETWEEN SECTOR COUPLING SENSITIVITY AND REFERENCE SCENARIO IN GERMANY; YEAR 2030; WEATHER YEAR 2010



- 1) The electricity consumption of the pump storages' pumps is not accounted for in the annual peak load and is shown here for information purposes only. The electricity consumption of the pump storages' pumps is not accounted for in the annual peak load and is shown here for information purposes only. The amount is also not included in the total load.
- 2) Only the flexible share of the heat pumps' electricity consumption is shown.
- 3) Overhead-line trucks are hybrid trucks, which switch to diesel mode at high electricity prices.
- 4) Only the share of electric vehicles with controlled charging is displayed.
- 5) Volatile EE: wind, PV and run-of-river

Source: Own calculations.

The changed assumptions in this sensitivity also have an impact on electricity prices. The annual base price, averaged equally over all weather years, increases over time, as shown in Figure 4-15, and is €<sub>2020</sub> 71.5 per MWh in 2030. Compared to the reference scenario, the base price in the sensitivity is about €<sub>2020</sub> 21 per MWh higher in 2030. This is due to the assumptions on the development of fuel and CO<sub>2</sub> prices as well as the higher electricity consumption due to increased sector coupling.

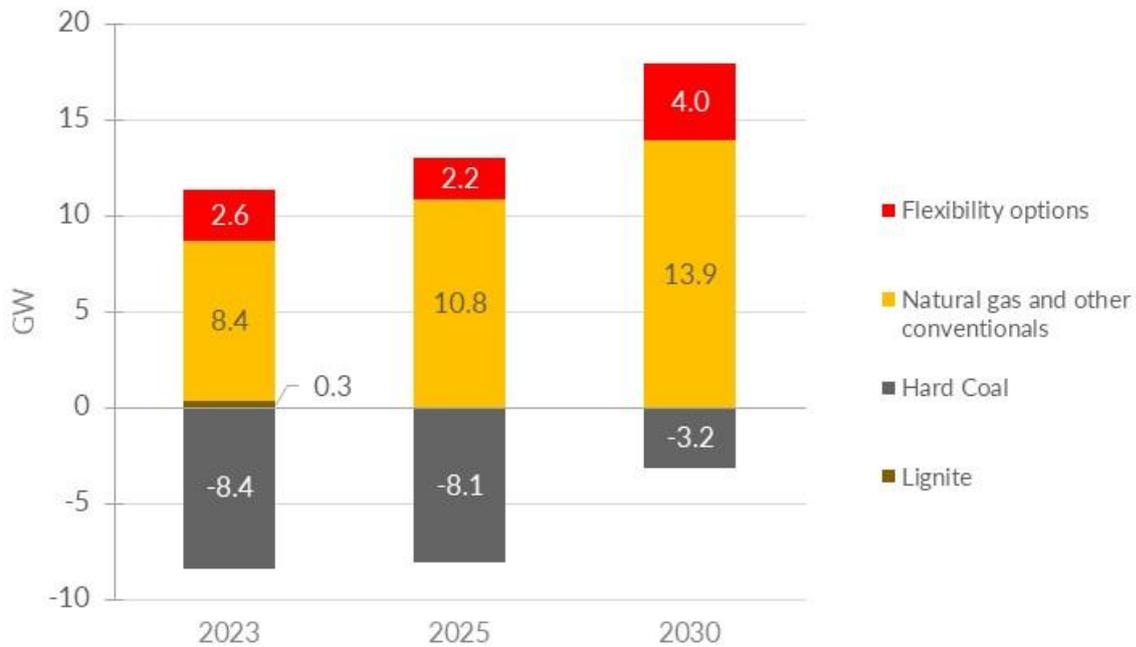
**FIGURE 4-15: DEVELOPMENT OF THE ANNUAL BASE PRICE IN GERMANY AVERAGED OVER WEATHER YEARS IN THE REFERENCE SCENARIO AND IN THE SENSITIVITY "INCREASED SECTOR COUPLING - TYNDP DISTRIBUTED ENERGY".**



Source: Own calculations.

The effects of the assumptions of increased sector coupling, an alternative energy price scenario and a more ambitious RE expansion in the foreign countries considered on the development of power plants and the development of flexibility options on the electricity market in the countries considered (excluding Germany) are shown in Figure 4-16.

FIGURE 4-16: COMPARISON OF THE DEVELOPMENT OF RESOURCES BETWEEN SENSITIVITY "INCREASED SECTOR COUPLING" AND REFERENCE SCENARIO IN THE FOREIGN COUNTRIES CONSIDERED



Source: Own calculations.

Also, in the foreign countries considered, more hard coal capacities are closed prematurely endogenously compared with the reference. In 2023, the shortfall in output from hard coal is about 8.4 GW, in 2025 it is another 8.1 GW, and in 2030 it is 3.2 GW. This is largely due to the more ambitious CO<sub>2</sub> price path. This also contributes to the fact that natural gas power plants become more economical in terms of sensitivity compared to hard coal and lignite, which in combination with the higher gross electricity consumption (due to increased sector coupling) leads to higher installed capacities of natural gas power plants and a higher development of flexibility options. The additional capacity from natural gas-fired plants amounts to approx. 8.4 GW in 2023, approx. 10.8 GW in 2025 and almost 14 GW in 2030. The additional flexibility options developed compared to the reference add up to about 2.5 GW by 2025 and about 4 GW by 2030. In addition, about 300 MW more lignite capacity remains on the market in the reference year 2023.

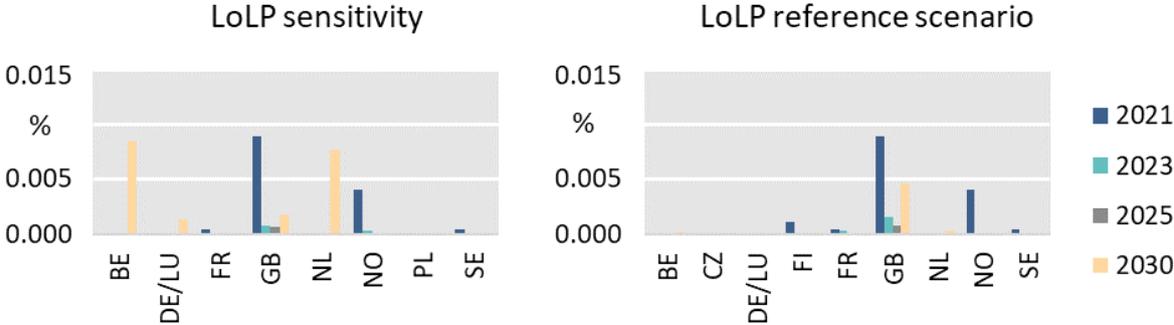
In total, across Germany and all other countries considered, the effects of an increased sector coupling are rather moderate. The controllable capacity in the entire model region (i.e. incl. Germany) is approx. 13 GW above that of the reference scenario in 2030.

### 4.2.3 Results RA analyses

#### Loss of Load Probability

Figure 4-17 compares the LoLP values of the sensitivity "Increased sector coupling - price scenario: TYNDP Distributed Energy" with those of the reference scenario. Again, for reasons of clarity, the representation is limited to those countries in which a value greater than zero occurs in at least one year under consideration, as well as Germany/Luxembourg.

**FIGURE 4-17: LoLP IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY" FOR COUNTRIES WITH VALUES > 0 AND GERMANY/LUXEMBOURG 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, a very small non-zero LoLP of less than 0.0001% is determined for 2023. In the year under review 2030, a LoLP of 0.0013 % occurs. This is more than a factor of 40 below the threshold  $\widehat{LoLP}$  of 0.06% derived as the RA standard in the first project report and corresponds to a load balancing probability of at least 99.9986% over the entire period under review.

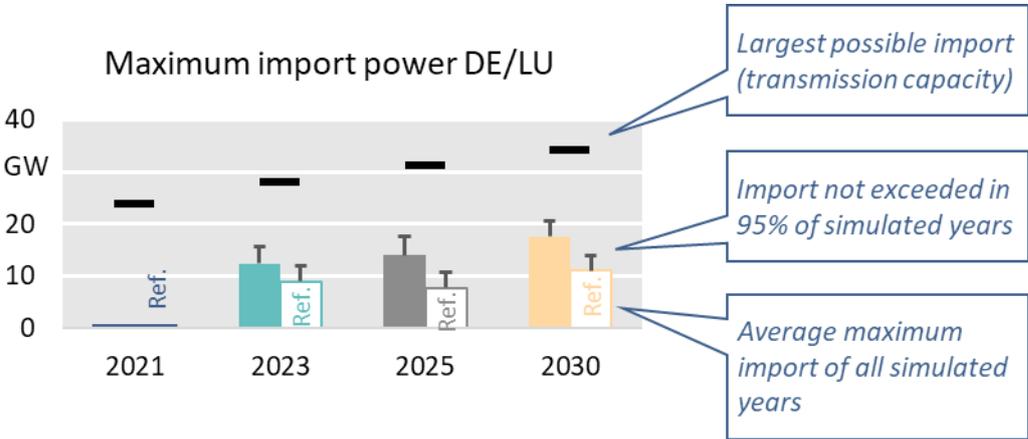
Abroad, the values remain largely stable. Only in Belgium and the Netherlands are there increases in LoLP to a still non-critical level in the year 2030.

The reason for the rather limited change in LoLP is that although demand is increased in this sensitivity compared to the reference scenario, this is largely accounted for by flexible consumers. The slightly decreasing total capacity of flexible resources, that is endogenously obtained in the model, therefore does not have to compensate for a rigid, but rather a temporally highly flexibilised increase in demand. The stable or, in some countries, only slightly increasing LoLP values show that this represents an appropriate adjustment of capacities.

**Required imports**

The maximum import power to Germany/Luxembourg required to avoid load excess increases significantly compared to the reference scenario (Figure 4-18). However, even in this sensitivity, it is consistently well below the maximum import capacity. The gap remains roughly the same over time because due to the grid expansion the import capacity increases just as much as the required import power.

**FIGURE 4-18: REQUIRED\* IMPORTS TO DE/LU IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY".**



Source: Own representation.  
 Required imports to avoid load excess. Market imports may deviate from this.

The average required import power also increases compared to the reference scenario (where it is below 0.1 % of gross electricity consumption in the entire period under review), but remains low (Table 4-2).

Table 4-2: AVERAGE REQUIRED IMPORT ENERGY OF DE/LU RELATED TO GROSS ELECTRICITY CONSUMPTION IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY".

2021	2023	2025	2030
<0.01%	0.22%	0.28%	0.34%

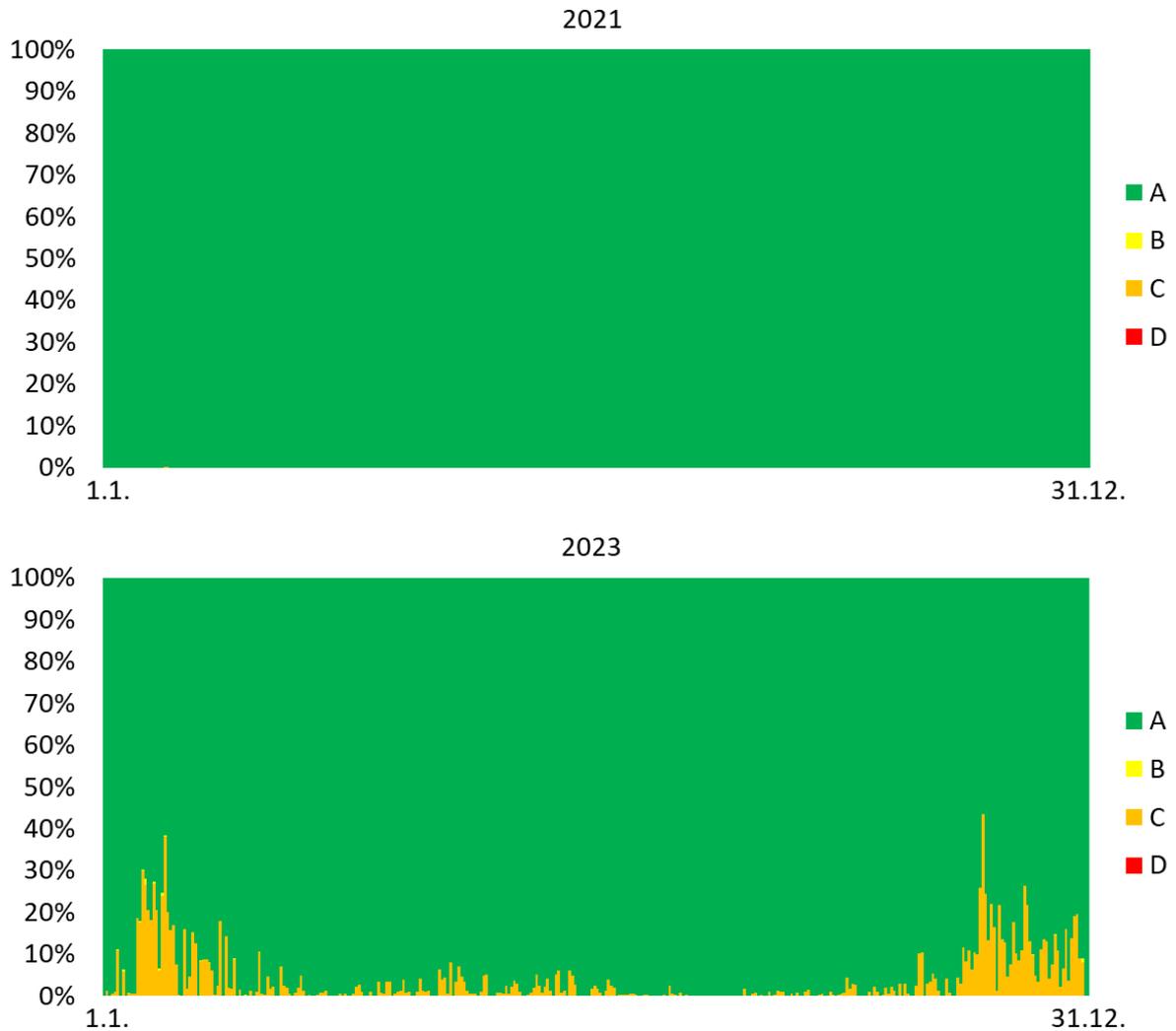
Source: Own representation

Overall, the RA level on the electricity market in Germany remains very high throughout the entire period under review until 2030, even in this sensitivity, and German consumers can be securely supplied at practically any time.

### Leeway status

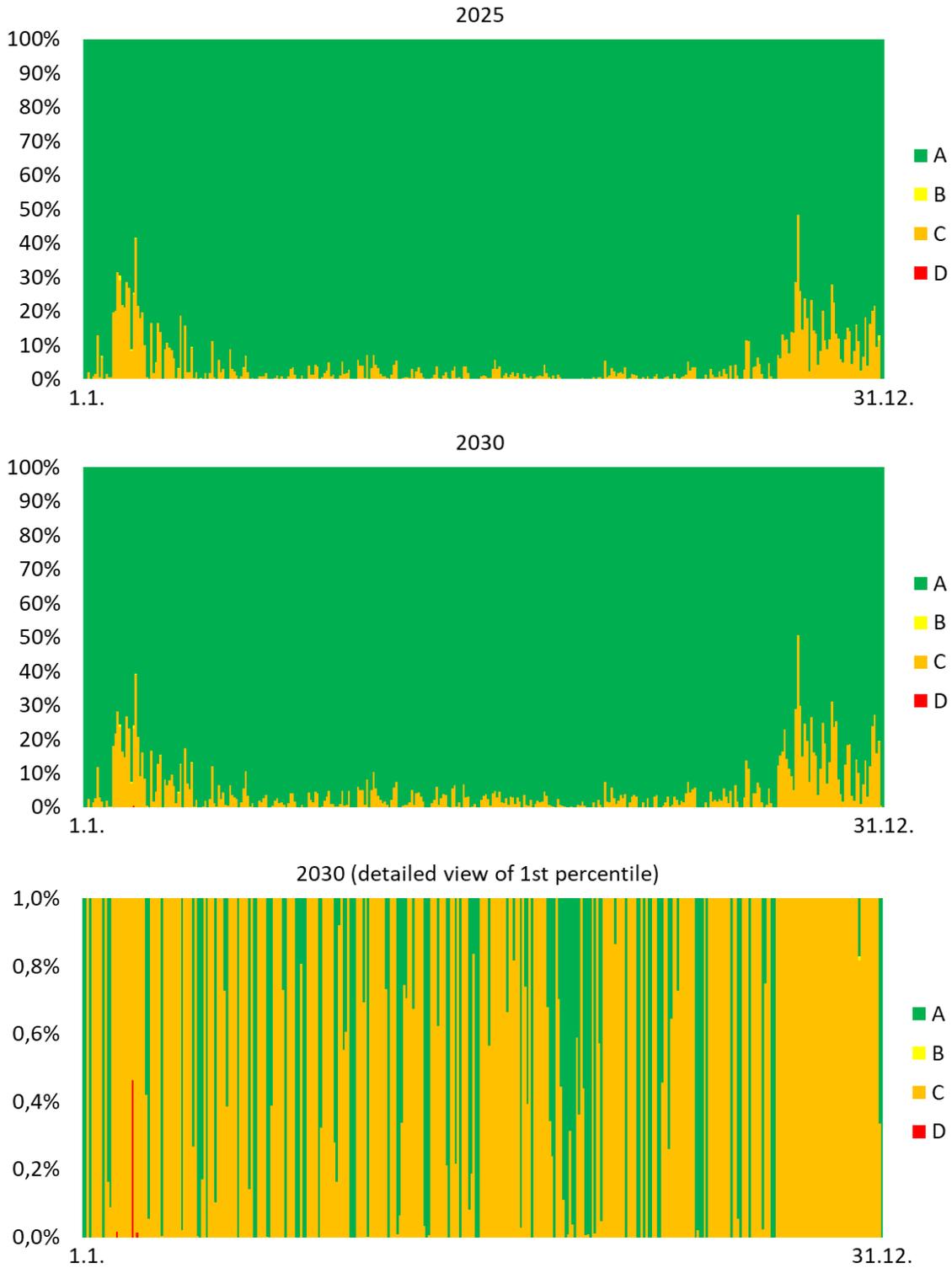
For this sensitivity, we again evaluate the leeway status, which indicates how far the electricity supply system is still "away" from load excess in the remaining hours (cf. introduction in Section 3.3, subsection "Leeway status "). The following two diagrams show the result of the evaluation of the leeway status of Germany/Luxembourg for the four years under review. In each diagram, the 365 days of the year are plotted from left to right.

FIGURE 4-19: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY", YEARS UNDER REVIEW 2021 AND 2023



Source: Own representation. Categories A to D according to Table 3-1

FIGURE 4-20: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY", YEARS UNDER REVIEW 2025 AND 2030



Source: Own representation. Categories A to D according to Table 3-1

The increase in required imports observed in this sensitivity compared to the reference scenario (see above) is reflected in the leeway status in larger shares of hours with import requirements (category C). In contrast to the reference scenario, such hours are now also clearly visible in the summer months from the year under review 2023 onwards, although the probability of import demand in these periods always remains below 10 %. The highest probabilities for import demand again occur in winter and amount to between 44 % (2023) and 51 % (2030) in this sensitivity compared to 29 % to 31 % in the reference scenario.

In order to identify the load excess occurring in 2030, which leads to a very low LoLP value greater than zero in the sensitivity, Figure 4-20 shows a section enlargement in which only the first percentile (i.e. the lowest "edge" of the diagram shown above it) is depicted. Even in this hundredfold magnification, category A occupies only a very small part of the diagram area. This illustrates the low probability of the occurrence of load excess even in this sensitivity.

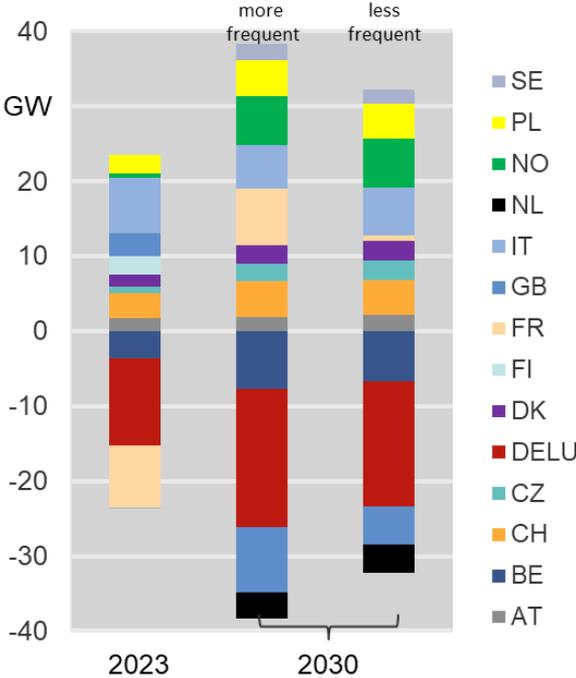
#### Detailed analysis of (simulation) hours with load excess in Germany/Luxembourg

Despite this low probability of occurrence, it may also be of interest with this sensitivity to characterise in more detail the situations with load excess in Germany/Luxembourg that occur in the simulation for 2030 (and even more rarely for 2023).

The import power in hours with load excess in Germany/Luxembourg is at least 12 GW below the maximum import capacity from a grid perspective. Their median is approx. 17 GW (2023) and 16 GW (2030) below the respective maximum import capacity and thus again significantly lower. As with the previously discussed sensitivity, this indicates that load excess in Germany/Luxembourg occurs primarily in situations of momentary resource scarcity across countries and not due to limited grid capacity.

The following figure shows the typical patterns of cross-border power exchanges for simulation hours with load excess in Germany/Luxembourg, which were determined using cluster analysis.<sup>213</sup> Positive values mean export, negative values mean import.

**FIGURE 4-21: TYPICAL EXCHANGE PATTERNS IN SITUATIONS WITH LOAD EXCESS IN GERMANY/LUXEMBOURG IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY "**



Source: Own representation.

In the year under review 2023, there is typically a simultaneous import demand to Belgium and France in hours with load excess in Germany/Luxembourg.

In the year under consideration 2030, France is typically among the exporting, i.e. assisting countries in hours with a load excess in Germany/Luxembourg, while Great Britain, the Netherlands and again Belgium import at the same time as Germany/Luxembourg. In contrast to the previously discussed sensitivity, two different groups of exchange patterns can be distinguished. These differ primarily in

<sup>213</sup> For methodology see footnote 207.

terms of the level of imports from Germany/Luxembourg and Great Britain and the power export of France.

#### Technical resource adequacy (including strategic reserves)

Although the level of LoLP values determined in this sensitivity for Germany/Luxembourg is not critical, we again quantify the technical resource adequacy.

Using the capacity reserve, the LoLP in Germany/Luxembourg can be reduced by more than a factor of six from the already very low initial level.

### 4.3 Sensitivity: "Increased sector coupling - price scenario: WEO Sustainable Development".

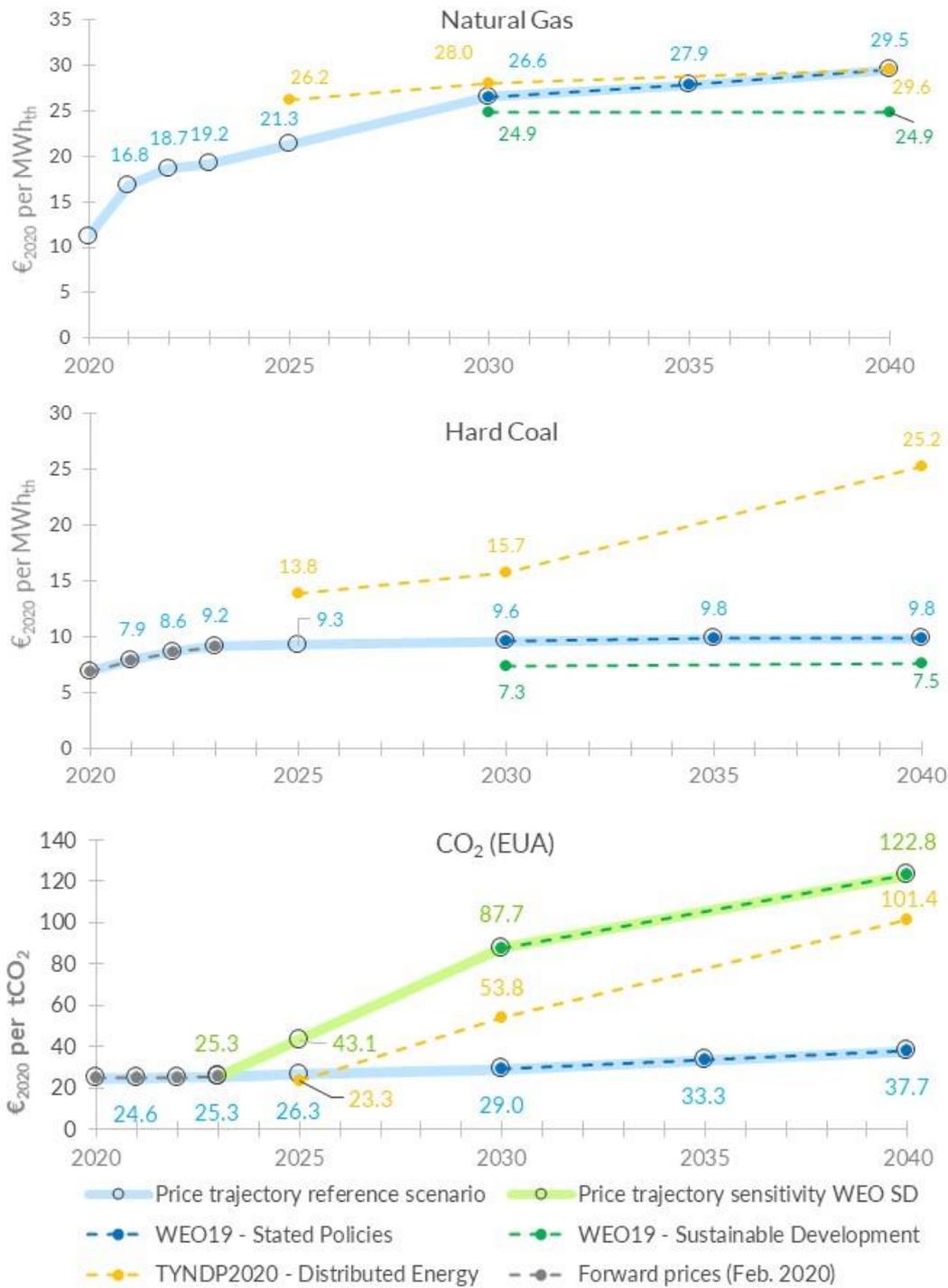
#### 4.3.1 Sensitivity characterisation

In this sensitivity, compared to the first sensitivity for "increased sector coupling" with TYNDP prices, the energy price scenario of the "Sustainable Development" scenario of the WEO 2019 is now used. Compared to the reference, this is characterised by an even more ambitious CO<sub>2</sub> price development than the first sector coupling sensitivity, while the prices for natural gas are slightly below those of the reference and the first sector coupling sensitivity. The hard coal price in this sensitivity is also slightly below the price path of the reference scenario and very clearly below the prices of the sensitivity based on TYNDP 2020 Distributed Energy. The price development for primary energy and CO<sub>2</sub> certificates in this sensitivity is compared with that of the reference scenario in the following figure.<sup>214</sup>

---

<sup>214</sup> Since crude oil as well as light and heavy heating oil now play only a very minor role in Europe's electricity supply systems, no separate consideration is given here.

FIGURE 4-22: COMPARISON OF ENERGY PRICE SCENARIOS: REFERENCE VS. SENSITIVITY "INCREASED SECTOR COUPLING WEO - SUSTAINABLE DEVELOPMENT"



Source: Own representation based on: Forward prices natural gas: EEX (2020a), forward prices coal: CME Group (2020b), forward prices EUA: EEX (2020b), WEO19: IEA (2019), TYNDP2020: ENTSO-E (2020); own conversion of original values in €<sub>2020</sub> per MWh<sub>th</sub> as European wholesale prices without surcharges for transport or similar.

Consumption in the PtX areas of the conversion sector as well as those of the new consumers, i.e. electromobility, electric heat pumps and overhead line trucks, are unchanged compared to the first sensitivity to "increased sector coupling".<sup>215</sup>

In this sensitivity, additional incentives for decarbonisation and digitalisation in industry and commerce are created by the significantly more ambitious CO<sub>2</sub> price path. Based on the estimation of the consumption group "decarbonisation and digitalisation in industry and commerce" of the Grid Development Plan for Electricity, this sensitivity assumes a higher probability of realisation of planned projects and associated capacity expansions, which are oriented towards Scenario C of the Grid Development Plan for Electricity.

This leads to an additional electricity consumption of 12.8 TWh in 2030. Considering the electricity quantities of the sensitivity of the price scenario "TYNDP Distributed Energy" (8 TWh in 2030), this leads to a total electricity consumption of 20.8 TWh in 2030 for the consumption group "decarbonisation and digitalisation in industry and commerce".

The gross electricity consumption in Germany in this sensitivity is 628 TWh in 2030. Compared to the reference scenario, the electricity consumption in this sensitivity is approx. 47 TWh higher and approx. 14 TWh higher than in the first sensitivity for increased sector coupling.

The expansion of renewable energies in the foreign countries considered corresponds to that of the first sensitivity for "Increased sector coupling" and thus to the "Distributed Energy" scenario of the TYNDP 2020.<sup>216</sup> The expansion of renewable energies in Germany also corresponds to that of the reference scenario in this sensitivity.<sup>217</sup>

---

<sup>215</sup> Cf. Section 4.2.

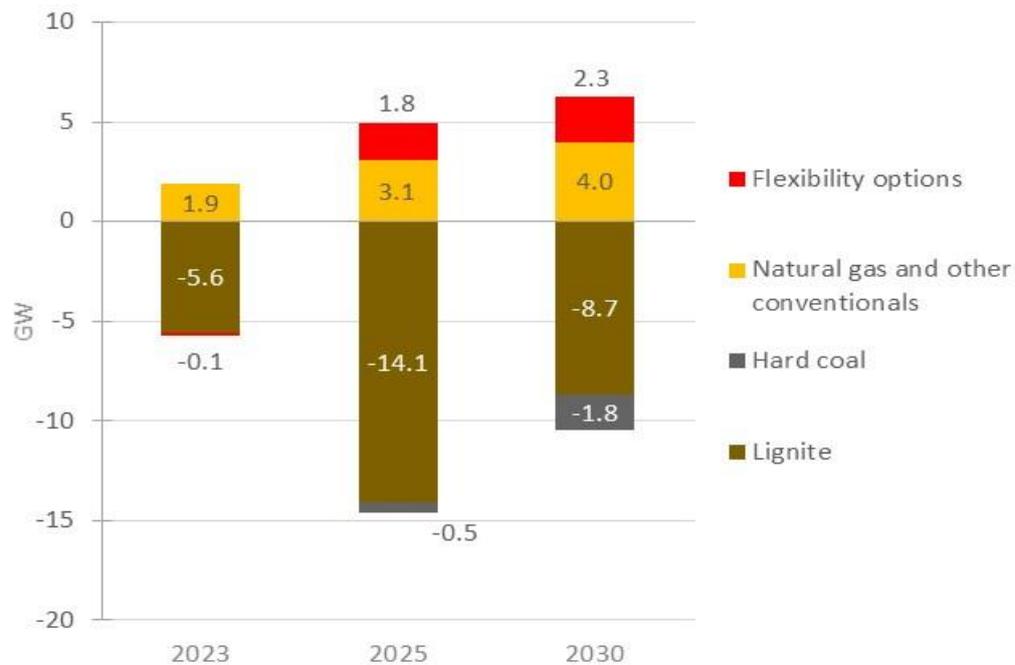
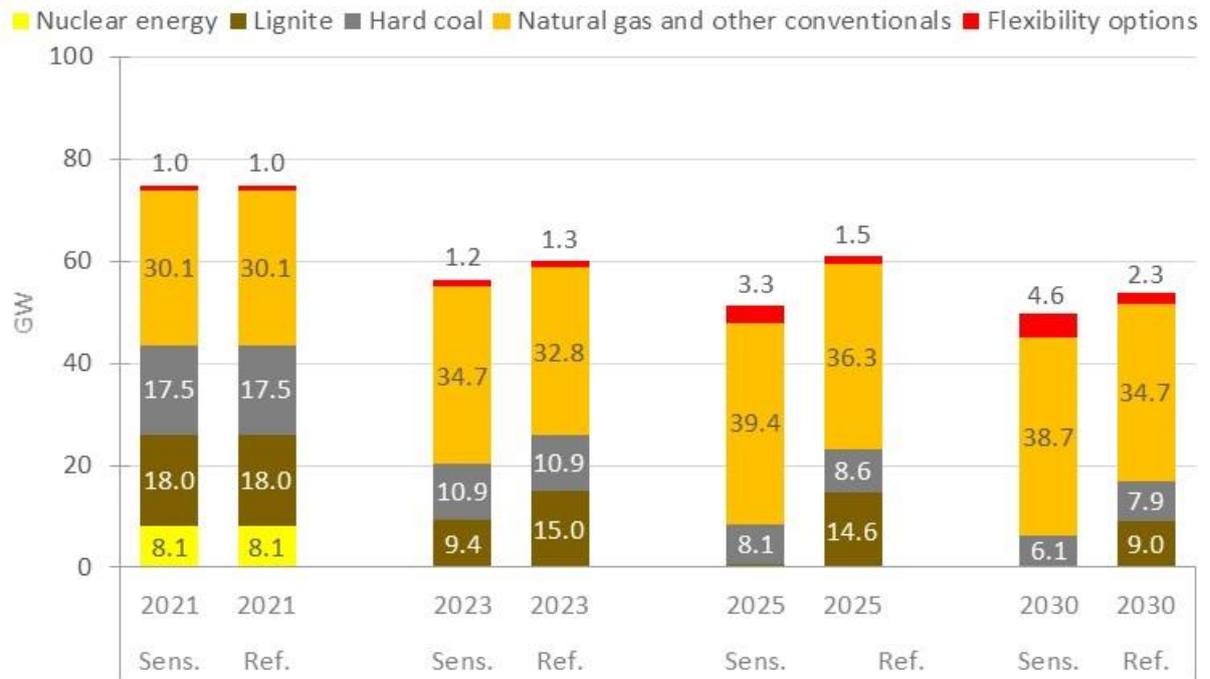
<sup>216</sup> Cf. Section 4.2.

<sup>217</sup> Cf. Sections 2.3.1 and 2.3.2

### 4.3.2 Results of electricity market simulations

In the second sensitivity for "increased sector coupling", the assumptions on electricity consumption, the energy price scenario and the RE expansion abroad, which vary compared to the reference, also lead to market adjustment reactions in the European electricity market model. This results in differences in the development of power plants and the development of flexibility options. In Figure 4-23 we first present the effects of the varied assumptions on German power plants and the development of flexibility options in Germany.

FIGURE 4-23: ABSOLUTE AND DIFFERENTIAL ANALYSIS OF THE DEVELOPMENT OF RESOURCES IN GERMANY: SENSITIVITY "INCREASED SECTOR COUPLING - WEO SD VS. REFERENCE SCENARIO "



Source: Own calculations.

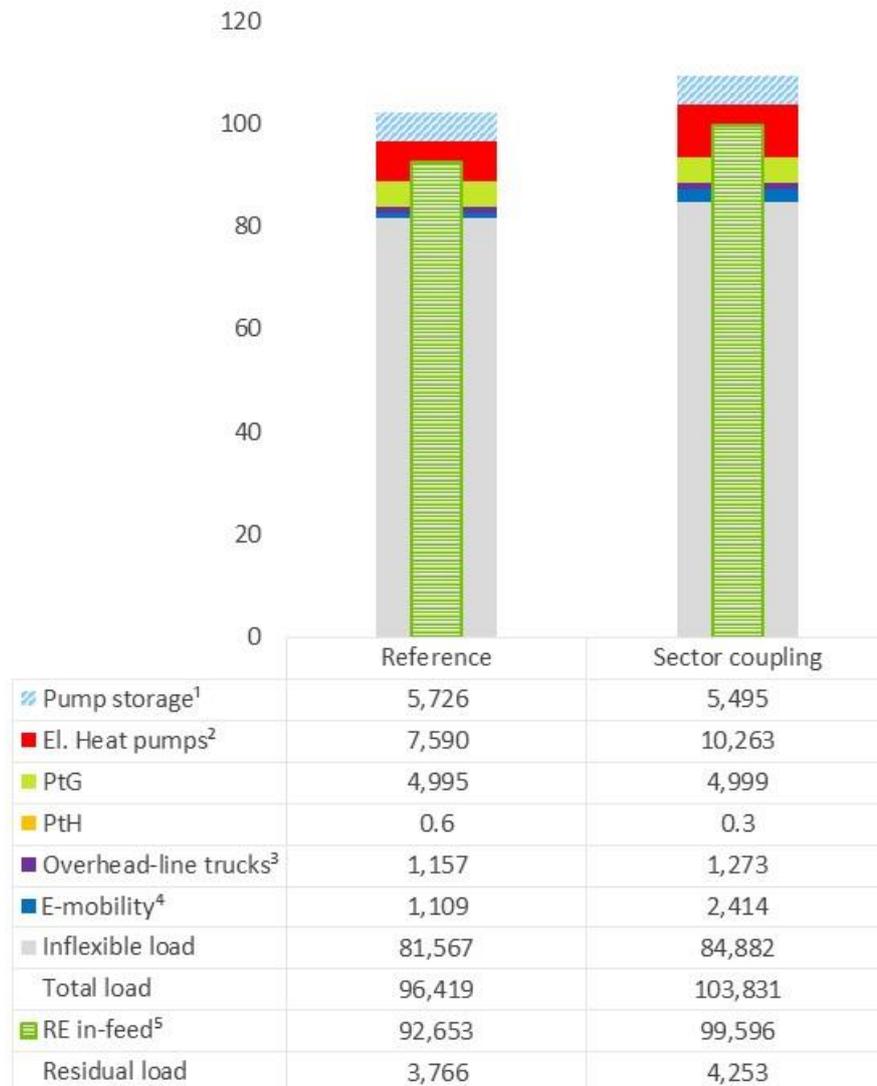
The repercussions of the changed assumptions on power plants and the development of flexibility options are significant in this sensitivity. In particular, the significantly higher prices for CO<sub>2</sub> emissions and the moderately developing price for hard coal have an impact on the economic viability of lignite-fired power plants in this sensitivity. The reduction in lignite output compared to the reference is approx. 5.6 GW in 2023, just over 14 GW in 2025 and approx. 8.7 GW in 2030. In the case of hard coal, there is a slight reduction in output compared to the reference scenario due to early closures for economic reasons. At the same time, there are fewer endogenous closures of natural gas power plants (excluding CHP), as well as earlier natural gas replacements for the coal-fired CHP plants that were closed prematurely for endogenous reasons compared to the reference scenario. In 2023, there is approx. 1.9 GW more natural gas capacity on the market. At the same time, approx. 100 MW less flexibility options are developed in 2023. In 2025 and 2030, the capacity of natural gas power plants increases further compared to the reference. In 2025, the additional capacity compared to the reference is approx. 3.1 GW and approx. 4 GW in 2030. The exploited capacity from flexibility options is also above the reference. In 2025, the additional capacity from emergency power systems and voluntary industrial load reduction compared to the reference scenario is approx. 1.8 GW and in 2030 approx. 2.3 GW.

In addition, the annual peak load in this sensitivity rises to approx. 104 GW in 2030, which again (as in the reference scenario) does not represent an RA-critical situation, but is market-driven. This means that the annual peak load in the second sensitivity for enhanced sector coupling is again approx. 1.4 GW above that of the first sensitivity for increased sector coupling. A comparison of the hourly peak load in the reference scenario and this sensitivity is shown in the following figure.<sup>218</sup>

---

<sup>218</sup> For a comparison of the hourly annual peak load with that of the residual annual peak load, see Section 3.1.1

FIGURE 4-24: COMPARISON OF THE COMPOSITION OF THE LOAD AT THE TIME OF THE ANNUAL PEAK LOAD BETWEEN SECTOR COUPLING SENSITIVITY AND REFERENCE SCENARIO IN GERMANY; YEAR 2030; WEATHER YEAR 2010

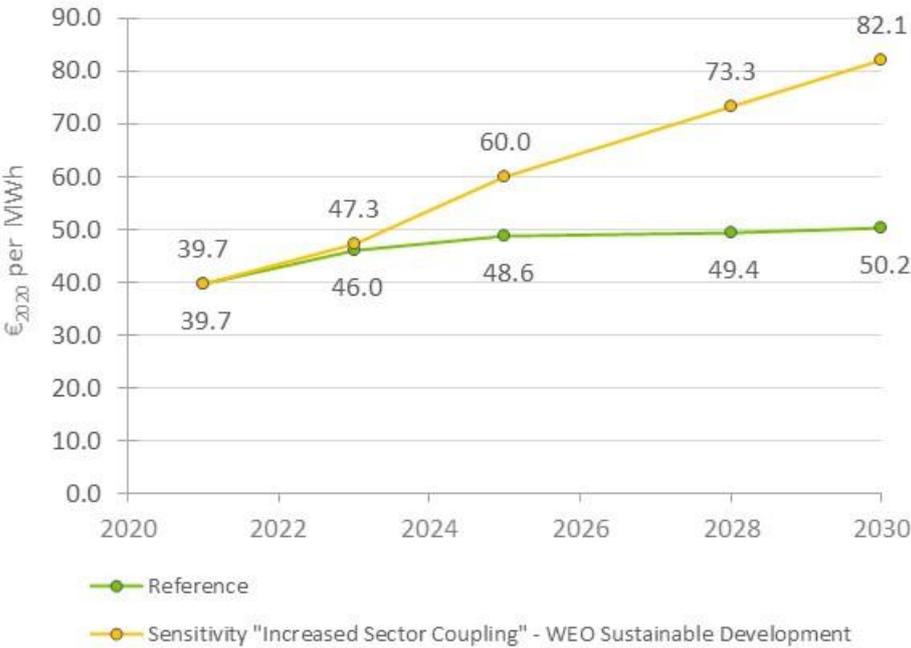


- 1) The electricity consumption of the pump storages' pumps is not accounted for in the annual peak load and is shown here for information purposes only. The electricity consumption of the pump storages' pumps is not accounted for in the annual peak load and is shown here for information purposes only. The amount is also not included in the total load.
- 2) Only the flexible share of the heat pumps' electricity consumption is shown.
- 3) Overhead-line trucks are hybrid trucks, which switch to diesel mode at high electricity prices.
- 4) Only the share of electric vehicles with controlled charging is displayed.
- 5) Volatile EE: wind, PV and run-of-river

Source: Own calculations.

The changed assumptions in this sensitivity also have an impact on electricity prices. The base price averaged over all weather years increases over time, as shown in Figure 4-25, resulting in €<sub>2020</sub> 82.1 per MWh in 2030. Compared to the reference scenario, the base price in the sensitivity scenario is approximately €<sub>2020</sub> 32 per MWh higher in 2030. This is due to the assumptions on the development of fuel and CO<sub>2</sub> prices as well as the higher electricity consumption due to increased sector coupling. Thus, the price in the second sensitivity for increased sector coupling is again almost €<sub>2020</sub> 10 per MWh above that of the first sensitivity for increased sector coupling, which is due to the even more ambitious CO<sub>2</sub> price path.

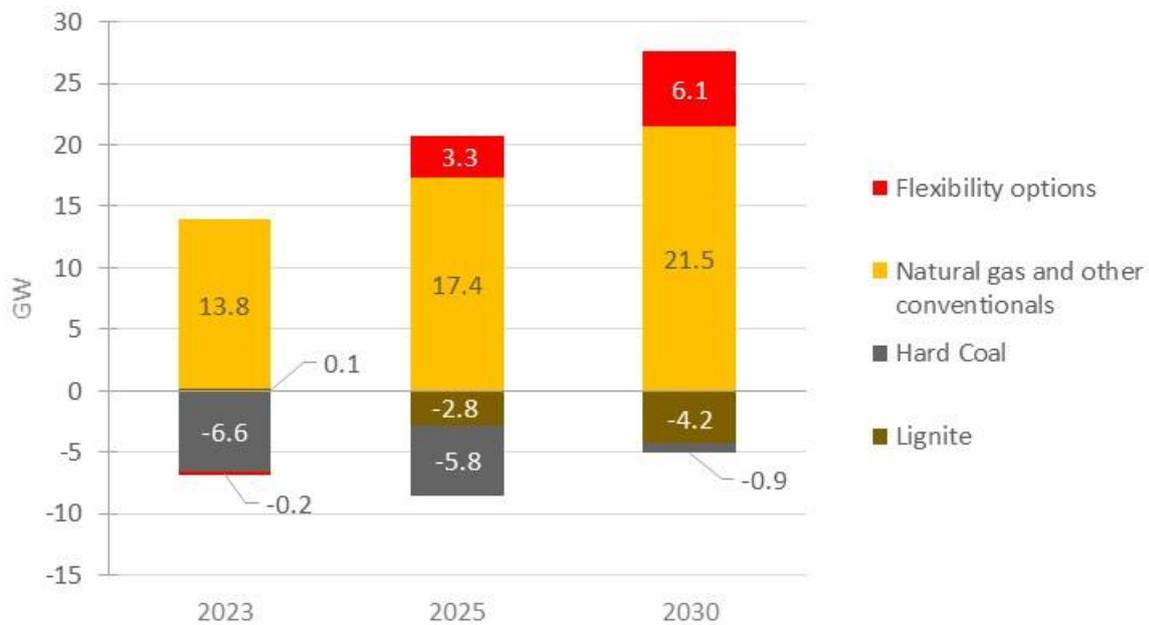
**FIGURE 4-25: DEVELOPMENT OF THE ANNUAL BASE PRICE IN GERMANY AVERAGED OVER ALL WEATHER YEARS IN THE REFERENCE SCENARIO AND IN THE SENSITIVITY "INCREASED SECTOR COUPLING - WEO SUSTAINABLE DEVELOPMENT "**



Source: Own calculations.

In Figure 4-26, we present the effects of enhanced sector coupling with WEO price scenario on the development of power plants in the other countries considered as well as the development of flexibility options.

FIGURE 4-26: COMPARISON OF THE DEVELOPMENT OF RESOURCES BETWEEN THE SENSITIVITY "INCREASED SECTOR COUPLING - WEO SUSTAINABLE DEVELOPMENT" AND THE REFERENCE SCENARIO IN THE FOREIGN COUNTRIES CONSIDERED (EXCLUDING GERMANY)



Source: Own calculations.

In the foreign countries considered there are more comprehensive market adjustment reactions within the framework of the second sensitivity to "increased sector coupling". On the one hand, the changed assumptions also lead to an increased number of coal-fired power plants being closed prematurely endogenously in the European countries. In 2023, compared to the reference, approx. 6.6 GW more hard coal-fired power plants will be closed prematurely for economic reasons. In 2025, the capacity from hard coal plants is reduced to approx. 5.8 GW and an additional 2.8 GW of lignite-fired power plants will be shut down prematurely. In 2030, the capacity from hard coal plants is only approx. 900 MW and that from lignite approx. 4.2 GW below that of the reference scenario. On the other hand, the changed assumptions for "increased sector coupling" lead to improved economic efficiency of natural gas-fired plants combined with fewer endogenous premature closures and, from 2025 onwards, to greater development of flexibility options. Thus, the additional capacity of natural gas-fired power plants amounts to approx. 13.7 GW in 2023, approx. 17.4 GW in 2025 and approx. 21.54 GW in 2030. This also includes 2.1 GW of new natural gas-fired power plants (excluding

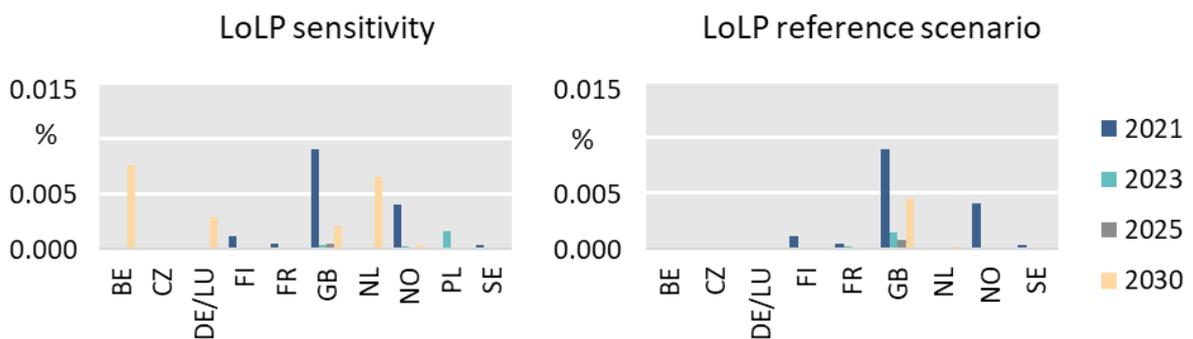
CHP) to be built in 2030. In addition, approx. 3.3 GW more flexibility options will be developed in 2025 and approx. 6.1 GW in 2030 (compared to reference).

### 4.3.3 Results RA analyses

#### Loss of Load Probability

Figure 4-27 compares the LoLP values of the sensitivity "Increased sector coupling - price scenario: WEO Sustainable Development" with those of the reference scenario. Again, for reasons of clarity, the presentation is limited to those countries in which a value greater than zero occurs in at least one year under consideration.

**FIGURE 4-27: LoLP IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT" FOR COUNTRIES WITH VALUES > 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, the LoLP remains at zero in 2021. In 2023 and 2025, very low LoLP values of less than 0.0001 % occur. In the year under consideration 2030, the LoLP rises to 0.003 %, which is still a factor of 20 below the threshold value  $\widehat{LoLP}$  of 0.06 % derived as the RA standard in the first project report and is thus not significant. This RA level corresponds to a load balancing probability of at least 99.997 %. The fact that, compared to the previous sector coupling sensitivity ("Increased sector coupling - Price scenario: TYNDP Distributed Energy"), the LoLP in Germany/Luxembourg increases somewhat more strongly is consistent with the framework conditions of the scenario. Namely, the load increase

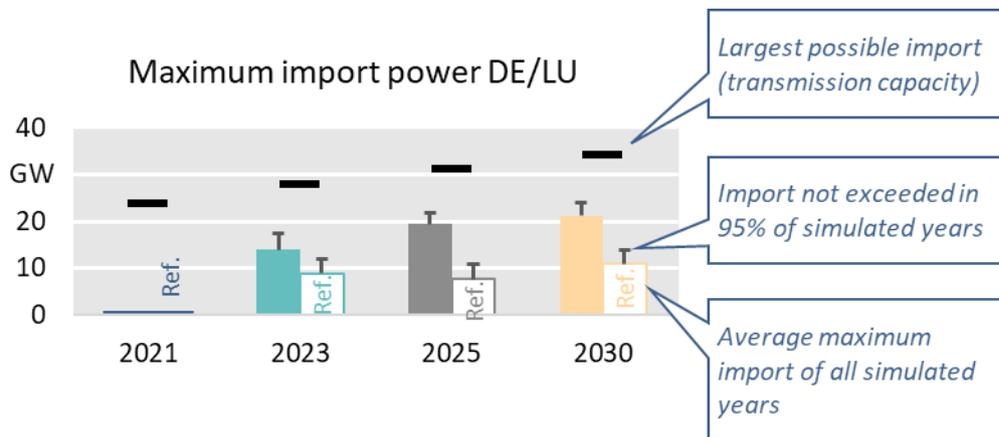
is now partly accounted for by inflexible demand, and there is a stronger net decrease in resources in Germany (Figure 4-23) than in the previous sensitivity (Figure 4-13).

Abroad, in part changes similar to those for Germany/Luxembourg occur for the same reasons. Belgium and the Netherlands also show a discernible increase in LoLP in 2030 to levels that also remain non-critical.

### Required imports

The maximum import power to Germany/Luxembourg required to avoid load excess increases significantly compared to the reference scenario and is also higher than in the sensitivity "Increased sector coupling - price scenario: TYNDP Distributed Energy" (Figure 4-28). However, they are still consistently well below the maximum import capacity in the sensitivity examined here. The gap remains roughly the same over time because due to the grid expansion the import capacity increases just as much as the required import capacities.

**FIGURE 4-28: REQUIRED\* IMPORTS TO DE/LU IN THE "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT" SCENARIO**



Source: Own representation. Required imports to avoid load excess. Market imports may deviate from this.

The average required import energy also increases compared to the reference scenario (where it is below 0.1 % of gross electricity consumption in the entire period under consideration) and also compared to the sensitivity "Increased Sector Coupling - Price Scenario: TYNDP Distributed Energy" (Table 4-3). It remains, however, on a low level.

Table 4-3: AVERAGE REQUIRED IMPORT ENERGY OF DE/LU RELATED TO GROSS ELECTRICITY CONSUMPTION IN SENSITIVITY "INCREASED SECTOR COUPLING - PRICE SCENARIO: TYNDP DISTRIBUTED ENERGY".

2021	2023	2025	2030
<0.01%	0.32%	0.95%	0.7%

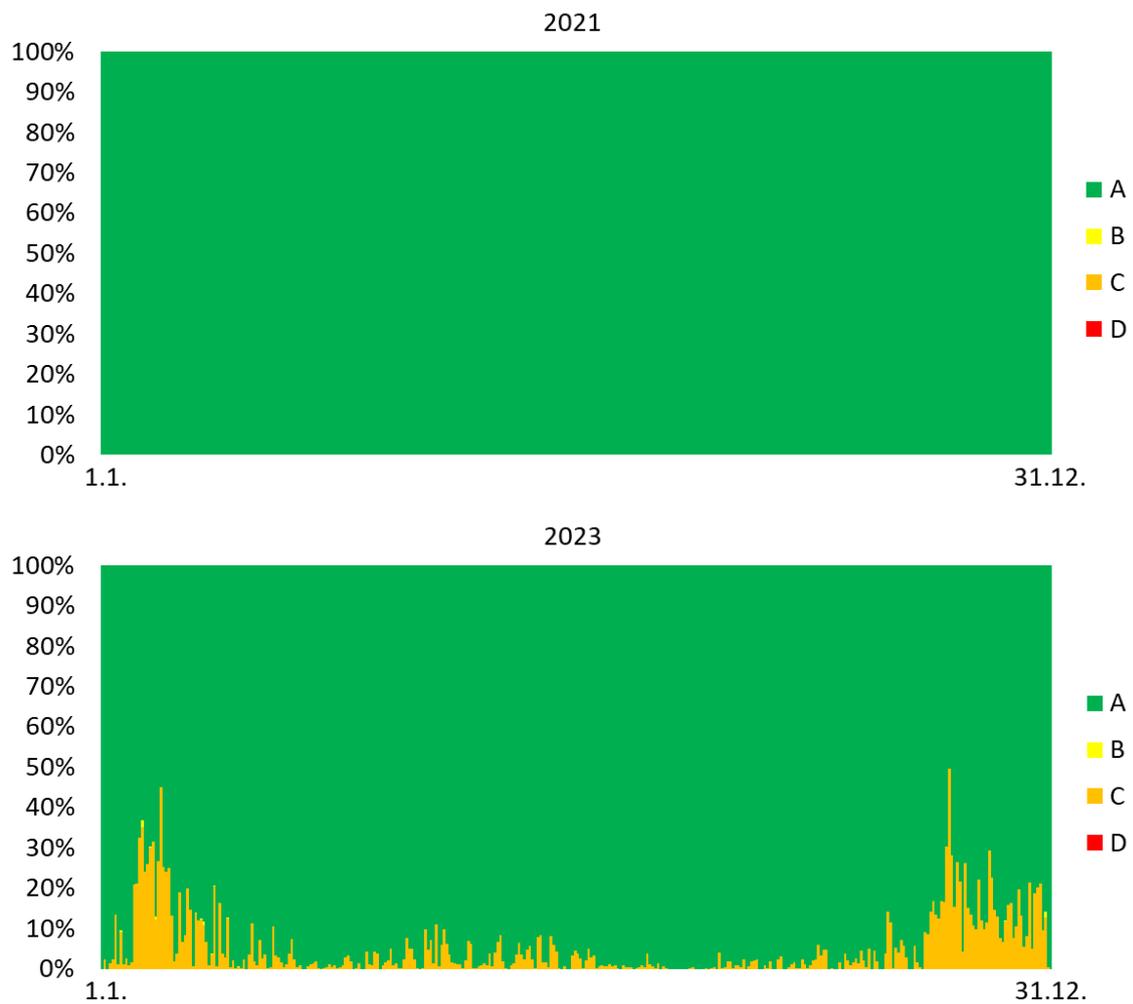
Source: Own representation

Overall, the RA level on the electricity market in Germany remains very high throughout the entire observation period until 2030, even in this sensitivity, and German consumers can be securely supplied at practically any time.

### Leeway status

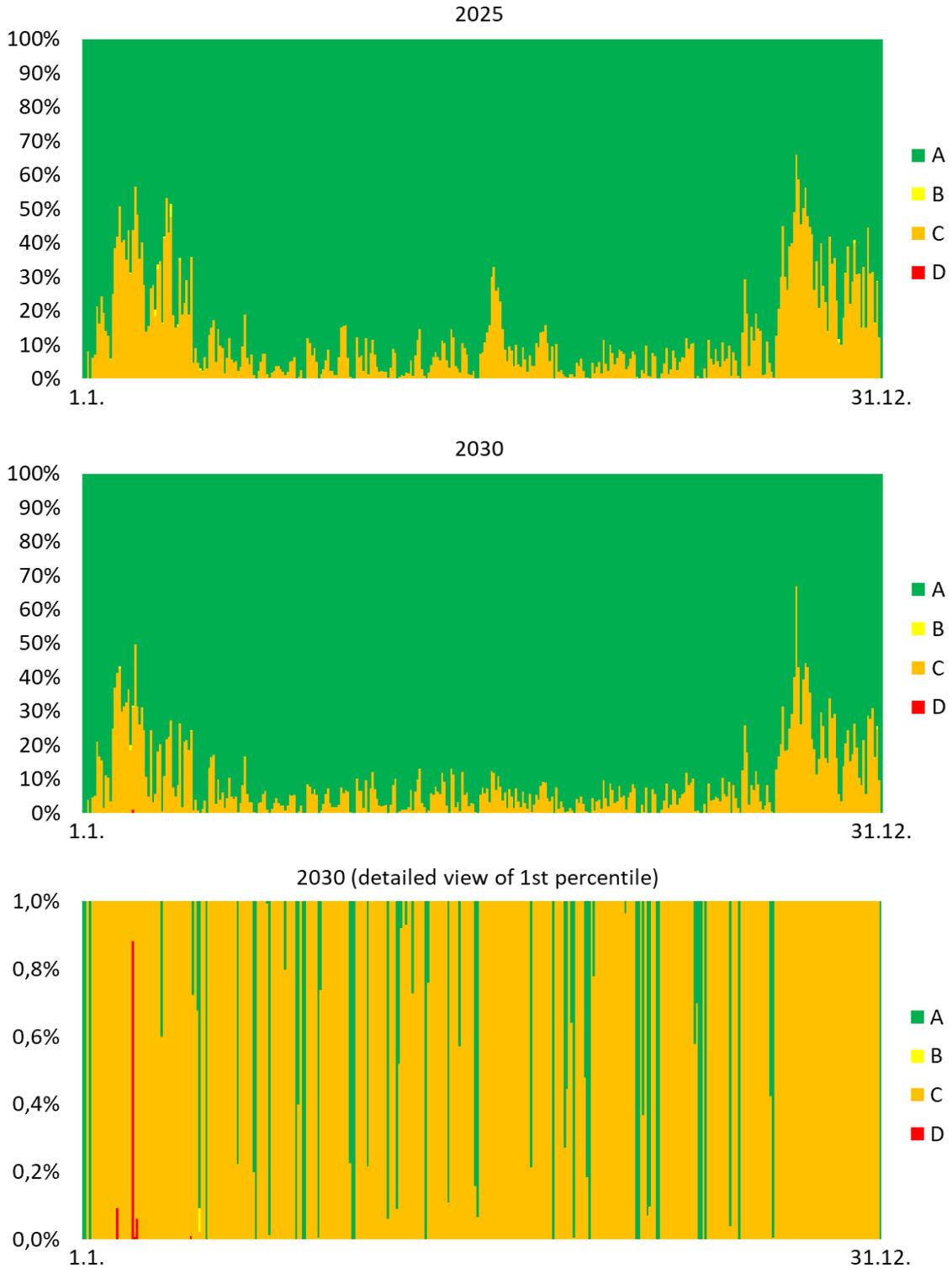
For this sensitivity, we again evaluate the leeway status, which indicates how far the electricity supply system is still "away" from load excess in the remaining hours (cf. introduction in Section 3.3, subsection "Leeway status "). The following two diagrams show the result of the evaluation of the leeway status of Germany/Luxembourg for the four years under review. In each diagram, the 365 days of the year are plotted from left to right.

FIGURE 4-29: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT", YEARS UNDER REVIEW 2021 AND 2023



Source: Own representation. Categories A to D according to Table 3-1

FIGURE 4-30: STATISTICAL DISTRIBUTION OF THE LEEWAY STATUS OF DE/LU IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT", YEARS UNDER REVIEW 2025 AND 2030



Source: Own representation. Categories A to D according to Table 3-1

The increase in required imports observed in this sensitivity compared to the previously considered sensitivity "Increased sector coupling - price scenario: TYNDP Distributed Energy" is reflected in noticeably larger shares of hours with import requirements (category C) in the leeway status from 2025 onwards. This affects all seasons. The highest probabilities for import demand again occur in winter and amount to 50% (2023), 66% (2025) and 67% (2030) in this sensitivity.

In the year under review 2030, the average probability of import demand decreases compared to 2025, analogous to the evaluation of the amount of required import energy earlier in this section (cf. Table 4-3).

Hours with load excess in the years under review 2023 and 2025 occur with such a low probability that they are not visually recognisable here. In order to make the load excess occurring in 2030 (which leads to a LoLP value of 0.003 % in the sensitivity in this year) recognisable, a sectional enlargement is shown in Figure 4-30 in which only the first percentile, i.e. the lowest "edge" of the diagram above it is shown. Even in this hundredfold magnification, category A occupies only a very small part of the diagram area. This illustrates the low probability of the occurrence of load excess in this sensitivity.

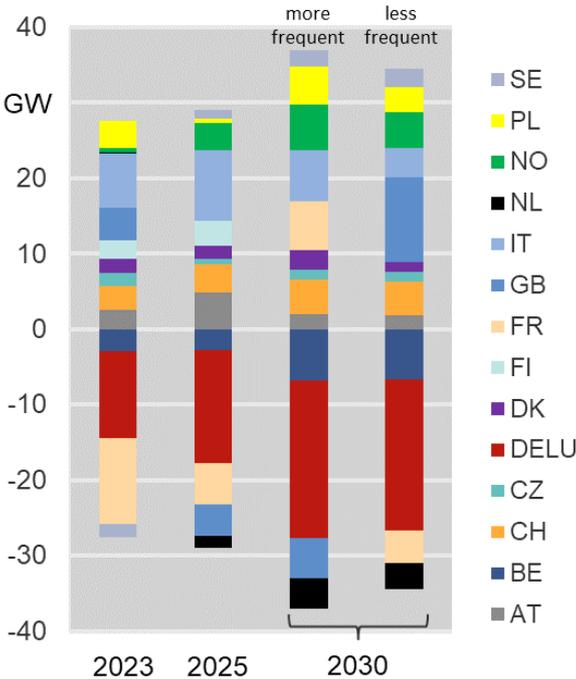
#### Detailed analysis of (simulation) hours with load excess in Germany/Luxembourg

Despite this low probability of occurrence, it may also be of interest with this sensitivity to characterise the situations with load excess in Germany/Luxembourg that occur in the simulation in more detail.

The import capacity in hours with load excess in Germany/Luxembourg is at least 8 GW below the maximum possible import capacity from a grid perspective. Their median is approx. 12 GW (2023), 14 GW (2025) and 21 GW (2030) below the respective maximum import capacity and thus again significantly lower. This indicates, as with the previously discussed sensitivities, that load excess in Germany/Luxembourg occurs primarily in situations with transnational momentary resource scarcity and not due to limited grid capacity.

The following figure shows the typical exchange patterns determined by clustering in simulation hours with load excess in Germany/Luxembourg.<sup>219</sup> Positive values mean export, negative values mean import. For 2023 and 2025, one cluster each was formed, while for 2030 with its slightly higher number of affected simulation hours, two different typical exchange patterns can be identified.

**FIGURE 4-31: EXCHANGE PATTERNS IN SITUATIONS WITH LOAD EXCESS IN GERMANY/LUXEMBOURG IN THE SCENARIO "INCREASED SECTOR COUPLING - PRICE SCENARIO: WEO SUSTAINABLE DEVELOPMENT" (2030)**



Source: Own representation.

In 2023 and 2025, hours with load excess in Germany/Luxembourg typically coincide with import demand of France and Belgium. This also applies to Belgium in 2030. France, on the other hand, is one of the countries assisting in 2030 in the clearly predominant part of the hours with load excess in Germany/Luxembourg (left exchange pattern 2030) and only rarely (right exchange pattern 2030) one of the countries importing at the same time. The UK also alternates - with the opposite sign - between simultaneous import and provision of export power. In this scenario, the countries that can consistently provide exports in the case of load

<sup>219</sup> For methodology see footnote 207.

excess in Germany/Luxembourg include Austria, Switzerland, Italy, Norway, Poland and Denmark.

#### Technical resource adequacy (including strategic reserves)

Although the level of LoLP values determined in this sensitivity for Germany/Luxembourg is not critical, we again quantify the technical resource adequacy.

Using the capacity reserve, the LoLP in Germany/Luxembourg can be reduced from the already very low initial level to zero in the years under consideration 2023 and 2025 and by more than two thirds to an amount below 0.001% for 2030.

#### 4.4 Summary results including sensitivities

The analyses consistently show a very high level of resource adequacy on the electricity market in Germany. This also applies for the most part (taking into account the lower model accuracy there) to the neighbouring countries modelled. In all scenarios examined here up to 2030, the adequacy of resources on the electricity market in Germany is guaranteed - even in the event of a market-driven closure of coal-fired power plants that goes beyond the KVVG as a result of ambitious European climate protection. Consumers can be securely supplied. The load excess probability (LoLP) determined for Germany (in the reference scenario with an amount of zero) also has a low amount of no more than 0.003 % in the alternative scenarios examined as sensitivities, which is thus below the threshold value derived as the RA standard in the first project report by at least a factor of 20. Converted into the internationally frequently used indicator "Loss of Load Expectation" (LoLE), where the loss of load probability is expressed in hours per year, this results in 0 hours per year in the reference scenario and a maximum of 0.25 hours per year in the examined sensitivities. This corresponds to a load balancing probability of 100 % in the reference scenario and at least 99.997 % in the scenarios examined. The Expected Energy Not Supplied (EENS) is zero in the reference scenario and at most 0.4 GWh per year in the sensitivities.

## 5 Accompanying measures and outlook

### Accompanying measures to ensure resource adequacy

Some measures are necessary or recommended to ensure or safeguard the high level of resource adequacy identified. The implementation of necessary measures (for example to ensure the level of cross-border exchange capacities according to the EU Electricity Market Regulation) was assumed in the analyses because this can be considered realistic in the combination of legal obligations and corresponding lead time.

Thus, the level of import power required to ensure resource adequacy can basically be classified as low compared to the (future) existing network capacity. Nevertheless, certain preparations need to be made in order to harness the stronger role of cross-border balancing effects for resource adequacy in the European context in the future.

There is also a need for coordination and, if necessary, action with regard to the international coordination and binding nature of the market and operating rules in the event of shortages. It seems advisable to take the precaution of clearly regulating the processes downstream of the day-ahead market at the international level.

The flexibility of generation and consumption is also significantly influenced by the regulatory framework, subsidy systems and the availability of intelligent measurement and control systems and communication technology. Electric mobility and heat pumps in particular can represent an important flexibility option if they are well integrated in terms of communication and receive corresponding incentives for flexibility. However, this is the subject of separate research projects. There is a need for further action, e.g. in the area of grid tariffs, especially with regard to the exemptions for atypical and intensive grid usage, which represent barriers to the flexibilisation of industrial consumers.

In addition, measures to hedge against uncertain extreme events can be considered. Such an event can be, for example, the simultaneous unavailability of many power plants due to a common cause, such as a serial fault or as a result of a prolonged period of heat or drought. Uncertain extreme events can (due to the

unknown probability of occurrence of these events) neither be efficiently addressed in the electricity market 2.0 nor in capacity markets. Therefore, they cannot and must not be taken into account in the monitoring of resource adequacy in the electricity market when checking there whether an efficient level of resource adequacy is achieved. The hedging of uncertain extreme events, accepting the associated costs, falls within the scope of state risk provisioning and should therefore be organised at the political level. Conversely, however, this means that the organisation and implementation of this additional hedging takes place outside the regulatory framework of competitive electricity markets ('market design') and thus outside the scope of this study. The effects of uncertain extreme events can be reduced in particular with reserves outside the electricity market, such as the German capacity reserve. Therefore, these uncertain events should also be taken into account when dimensioning the capacity reserve.

## Outlook

This report marks the conclusion of the project "Definition and monitoring of resource adequacy in the European electricity markets".

With regular forecasts on the development of the electricity supply system and the RA level, it can be checked in advance whether compliance with the RA standard can be expected and, if necessary, whether there are still barriers and disincentives and, if necessary, whether a later "settling" can be expected through market adjustment processes. The forward-looking RA monitoring thus ensures that there is sufficient time for any necessary measures to ensure an appropriate RA level.

With the enactment of the KVBG, responsibility for monitoring resource adequacy will be transferred from the BMWi to the BNetzA from 2021. In addition, on the basis of the EU package "Clean Energy for all Europeans" (CEP<sup>220</sup>), ENTSO-E has developed a method for the implementation of the European and national

---

<sup>220</sup> Cf. EU Electricity Market Regulation 2019/943.

monitoring of resource adequacy, which was approved by the Agency for the Co-operation of Energy Regulators (ACER) on 5 October 2020.<sup>221</sup> Future analyses of resource adequacy in the electricity markets - in particular ENTSO-E's European Resource Adequacy Assessment (ERAA) - must be based on this methodology. The ERAA will replace the Mid-Term Adequacy Forecast (MAF) from 2020.

The authors are confident that within the framework of the project now coming to a close, they have laid and expanded methodological foundations and introduced them into the expert discussion, which largely fulfil the requirements for European and national analyses on the adequacy of resources in the electricity markets applicable from now on.

---

<sup>221</sup> Cf. ACER Decision 24-2020.

## 6 Bibliography

**50Hertz Transmission GmbH et al. (2019):** Network Development Plan 2030, Version 2019, Second Draft of the Transmission System Operators, Last accessed on 17.06.2020 at <https://www.netzentwicklungsplan.de/de/netzentwicklungsplaene/netzentwicklungsplan-2030-2019>.

**ACER (2020):** DECISION No 24/2020 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS. Last accessed on 03.12.2020 at: [https://www.acer.europa.eu/Official\\_documents/Acts\\_of\\_the\\_Agency/Individual%20decisions/ACER%20Decision%2024-2020%20on%20ERAA.pdf](https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2024-2020%20on%20ERAA.pdf).

**AEE (2012):** Renewable Energy Agency, Comparison of Studies: Development of Investment Costs of New Power Plants. Last accessed on 05.03.2014 at: [http://www.energiestudien.de/uploads/media/AEE\\_Dossier\\_Studienvergleich\\_Investitionskosten\\_nov12.pdf](http://www.energiestudien.de/uploads/media/AEE_Dossier_Studienvergleich_Investitionskosten_nov12.pdf).

**AF Mercados, E-Bridge, REF-E. (2016):** Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market. doi:10.2832/08949.

**AG Energiebilanzen (2013):** Website of the , Working Group on Energy Balances, <http://www.ag-energiebilanzen.de/DE/daten-und-fakten/daten-und-fakten.html>, 2014.

**AGFW (2018):** 70/70 Strategy, Concept and Results, Last accessed on November 05, 2019, at <https://www.agfw.de/energiekonzepte/7070-4040-strategie/>.

**Arbeitsgemeinschaft Energiebilanzen (AGEB) (2017):** Published information 1990 - 2016, last accessed 10.08.2017.

**Agora Energiewende and Sandbag (2020):** The European Power Sector in 2019 - Up-to-Date Analysis on the Electricity Transition. Last accessed on 02.09.2020 at: [https://static.agora-energiewende.de/fileadmin2/Projekte/2019/Jahresauswertung\\_EU\\_2019/172\\_A-EW\\_EU-Annual-Report-2019\\_Web.pdf](https://static.agora-energiewende.de/fileadmin2/Projekte/2019/Jahresauswertung_EU_2019/172_A-EW_EU-Annual-Report-2019_Web.pdf).

**AtG (2011):** Thirteenth Act amending the Atomic Energy Act. Of 31 July 2011. Last accessed on 22.07.2020 at: [https://www.bgbl.de/xa-ver/bgbl/start.xav?start=%2F%2F\\*%5B%40attr\\_id%3D%27bgbl111s1704.pdf%27%5D#\\_bgbl\\_%2F%2F\\*%5B%40attr\\_id%3D%27bgbl111s1704.pdf%27%5D\\_1530189966584](https://www.bgbl.de/xa-ver/bgbl/start.xav?start=%2F%2F*%5B%40attr_id%3D%27bgbl111s1704.pdf%27%5D#_bgbl_%2F%2F*%5B%40attr_id%3D%27bgbl111s1704.pdf%27%5D_1530189966584).

**AtG (2017):** Act on the Peaceful Use of Nuclear Energy and Protection against its Hazards (Atomic Energy Act) of 20.07.2017. Last accessed on 03.08.2020 at: <https://www.gesetze-im-internet.de/atg/AtG.pdf>.

**BCG/Prognos (2018):** Klimapfade für Deutschland, Study commissioned by the BDI, Last accessed on 21.07.2020 at [https://www.prognos.com/uploads/tx\\_at-wpubdb/20180118\\_BDI\\_Studie\\_Klimapfade\\_fuer\\_Deutschland\\_01.pdf](https://www.prognos.com/uploads/tx_at-wpubdb/20180118_BDI_Studie_Klimapfade_fuer_Deutschland_01.pdf).

**BDEW (2015)** Wie heizt Deutschland? Last accessed on 29.06.2018 at: <https://www.bdew.de/energie/bdew-studie-wie-heizt-deutschland/>.

**BEIS (2016):** Department for Business, Energy and Industrial Strategy: Electricity Generation Costs. Last accessed on 25.06.2020 at: <https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016>.

**BEIS (2018):** Department for Business, Energy and Industrial Strategy: Implementing the End of Unabated Coal by 2025. Government Response to Unabated Coal Closure Consultation. Last accessed 30.11.2020 at: [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/672137/Government\\_Response\\_to\\_unabated\\_coal\\_consultation\\_and\\_statement\\_of\\_policy.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/672137/Government_Response_to_unabated_coal_consultation_and_statement_of_policy.pdf).

**BEIS (2019):** Department for Business, Energy and Industrial Strategy: Updated energy and emissions projections 2018. Last updated 16/05/2019, Last accessed 12/08/2020 from: <https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2018>.

**BEIS (2020):** Department for Business, Energy and Industrial Strategy: End of coal power to be brought forward in drive towards net zero. Last accessed on 12.08.2020 at: <https://www.gov.uk/government/news/end-of-coal-power-to-be-brought-forward-in-drive-towards-net-zero>.

**BMU (2019):** Climate Protection Program 2030 of the Federal Government for the Implementation of the Climate Protection Plan 2050. Last accessed on 03.08.2020 at: [https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?\\_\\_blob=publicationFile&v=33](https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?__blob=publicationFile&v=33).

**BMWi (2015):** An Electricity Market for the Energy Transition. Results paper of the Federal Ministry for Economic Affairs and Energy (White Paper). Last accessed on 02.07.2020 at: [https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?\\_\\_blob=publicationFile&v=33](https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?__blob=publicationFile&v=33).

**BMWi (2018):** EU Commission approves reserve to safeguard the electricity market. Press release dated 07.02.2018. Last accessed on 12.06.2020 at: <https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2018/20180207-eu-kommission-genehmigt-reserve-zur-absicherung-des-strommarktes.html>.

**BMWi (2019):** Time series on the development of renewable energies in Germany (as of August 2019). Last accessed on 05.11.2019 at: [https://www.erneuerbare-energien.de/EE/Redaktion/DE/Downloads/zeitreihen-zur-entwicklung-der-erneuerbaren-energien-in-deutschland-1990-2018-excel.xlsx?\\_\\_blob=publicationFile&v=20](https://www.erneuerbare-energien.de/EE/Redaktion/DE/Downloads/zeitreihen-zur-entwicklung-der-erneuerbaren-energien-in-deutschland-1990-2018-excel.xlsx?__blob=publicationFile&v=20).

**BMWi (2019b):** Draft of the integrated national energy and climate plan (NECP). Last accessed on 03.07.2020 at: [https://www.bmwi.de/Redaktion/DE/Downloads/E/entwurf-des-integrierten-nationalen-energie-und-klimaplans.pdf?\\_\\_blob=publicationFile&v=12](https://www.bmwi.de/Redaktion/DE/Downloads/E/entwurf-des-integrierten-nationalen-energie-und-klimaplans.pdf?__blob=publicationFile&v=12).

**BMWi (2020a):** Time series on the development of renewable energies in Germany. Last accessed on 03.11.2020 at: [https://www.erneuerbare-energien.de/EE/Navigation/DE/Service/Erneuerbare\\_Energien\\_in\\_Zahlen/Zeitreihen/zeitreihen.html](https://www.erneuerbare-energien.de/EE/Navigation/DE/Service/Erneuerbare_Energien_in_Zahlen/Zeitreihen/zeitreihen.html).

**BMWi (2020b):** The National Hydrogen Strategy. Last accessed on 03.11.2020 at: [https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/die-nationale-wasserstoffstrategie.pdf?\\_\\_blob=publicationFile&v=16](https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/die-nationale-wasserstoffstrategie.pdf?__blob=publicationFile&v=16).

**BNetzA (2019):** Approval of the Scenario Framework 2019-2030. Last accessed on 01.07.2020 at: [https://www.netzausbau.de/SharedDocs/Downloads/DE/2030\\_V19/SR/Szenariorahmen\\_2019-2030\\_Genehmigung.pdf;jsessionid=3339E09243860130B9015AC6D095C338?\\_\\_blob=publicationFile](https://www.netzausbau.de/SharedDocs/Downloads/DE/2030_V19/SR/Szenariorahmen_2019-2030_Genehmigung.pdf;jsessionid=3339E09243860130B9015AC6D095C338?__blob=publicationFile).

**BNetzA (2020a):** Approval of the Scenario Framework 2021-2035. Last accessed on 03.11.2020 at: [https://www.netzausbau.de/SharedDocs/Downloads/DE/2035/SR/Szenariorahmen\\_2035\\_Genehmigung.pdf?\\_\\_blob=publicationFile](https://www.netzausbau.de/SharedDocs/Downloads/DE/2035/SR/Szenariorahmen_2035_Genehmigung.pdf?__blob=publicationFile).

**BNetzA (2020b):** Power Plant List. Last accessed on 03.11.2020 at: [https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen\\_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html](https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html).

**CDU, CSU, SPD (2018):** A new dawn for Europe. A new dynamic for Germany. A new cohesion for our country. Coalition agreement between CDU, CSU and SPD. 19th legislative period. Last accessed on 14.07.2020 at: [https://www.bundesregierung.de/Content/DE/Anlagen/2018/03/2018-03-14-koalitionsvertrag.pdf?\\_\\_blob=publicationFile&v=6](https://www.bundesregierung.de/Content/DE/Anlagen/2018/03/2018-03-14-koalitionsvertrag.pdf?__blob=publicationFile&v=6).

**CEPA (2018):** Study on the Estimation of the Value of Least Load of Electricity Supply in Europe, ACER/OP/DIR/08/2013/LOT 2/RFS 10, Final Report, 06 July 2018.

**CEPS (2017):** Mid-term Generation Adequacy Forecast. Last accessed 27.04.2018 at: <https://www.ceps.cz/en/generation-adequacy>.

**CEPS (2018):** Assessment of Generation Adequacy of the CR Electricity System until 2030. Last accessed on 10/07/2020 at: <https://www.ceps.cz/en/generation-adequacy>.

**CEPS (2019):** Resource Adequacy Assessment of the Czech Power System until 2040 (MAF CZ). Last accessed on 03.06.2020 at: [https://www.mpo.cz/assets/cz/energetika/jaderna-energetika-a-nove-jaderne-zdroje/rozvoj-novych-jadernych-zdroju/2020/10/Hodnoceni-zdrojove-primerenosti-ES-CR-do-roku-2040-\\_MAF-CZ\\_.pdf](https://www.mpo.cz/assets/cz/energetika/jaderna-energetika-a-nove-jaderne-zdroje/rozvoj-novych-jadernych-zdroju/2020/10/Hodnoceni-zdrojove-primerenosti-ES-CR-do-roku-2040-_MAF-CZ_.pdf).

**CEP (2019):** Clean Energy for all Europeans. Last accessed on 12.08.2020 at: [https://op.europa.eu/en/publication-detail/-/publication/b4e46873-7528-11e9-9f05-01aa75ed71a1/language-en?WT.mc\\_id=Searchresult&WT.ria\\_c=null&WT.ria\\_f=3608&WT.ria\\_ev=search](https://op.europa.eu/en/publication-detail/-/publication/b4e46873-7528-11e9-9f05-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=null&WT.ria_f=3608&WT.ria_ev=search).

**CME Group (2020a):** Brent Crude Oil Futures Settlement. Last accessed on 01.03.2020 at: [https://www.cmegroup.com/trading/energy/crude-oil/brent-crude-oil\\_quotes\\_settlements\\_futures.html#tradeDate=06%2F22%2F2020](https://www.cmegroup.com/trading/energy/crude-oil/brent-crude-oil_quotes_settlements_futures.html#tradeDate=06%2F22%2F2020).

**CME Group (2020b):** Coal (API2) CIF ARA (ARGUS-McCloskey) Futures Settlements. Last accessed 01.03.2020 at: [https://www.cmegroup.com/trading/energy/coal/coal-api-2-cif-ara-argus-mccloskey\\_quotes\\_settlements\\_futures.html?optionProductId=8394#tradeDate=11%2F25%2F2020](https://www.cmegroup.com/trading/energy/coal/coal-api-2-cif-ara-argus-mccloskey_quotes_settlements_futures.html?optionProductId=8394#tradeDate=11%2F25%2F2020).

**Cohen, J., Moeltner, K., Reichl, J., & Schmidthaler, M. (2017):** Effect of global warming on willingness to pay for uninterrupted electricity supply in European nations. doi:10.1038/s41560-017-0045-4.

**Consentec (2010):** Expert opinion on the dimensioning of the control power requirement under the NRV, study commissioned by the Federal Network Agency., 17.12.2010, last accessed on 12.06.2020 from <https://www.regel-leistung.net/ext/download/dimensionierungBnetza>.

**Consentec et al. (2010):** Consentec, EWI, IAEW: Analysis and evaluation of the resource adequacy in electricity supply. Study commissioned by the Federal Ministry of Economics and Technology (BMWi). Last accessed on 10.06.2020 at: <https://www.consentec.de/wp-content/uploads/2011/12/analyse-und-bewertung-der-versorgungssicherheit-in-der-elektrizitaetsversorgung-2010.pdf>.

**Consentec and r2b (2015):** Resource adequacy in Germany and its neighboring countries: cross-national monitoring and assessment, study commissioned by the Federal Ministry for Economic Affairs and Energy, final report, 06.03.2015.

**Danish Ministry of Climate, Energy and Utilities (2019):** Denmark's Integrated National Energy and Climate Plan. Last accessed on 12.08.2020 at:

[https://ec.europa.eu/energy/sites/ener/files/documents/denmark\\_draft-necp.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/denmark_draft-necp.pdf).

**Department of Energy & Climate Change (2013):** Annex C: Reliability Standard Methodology. Last accessed on 11.06.2020 at: <https://www.gov.uk/government/consultations/consultation-on-the-draft-electricity-market-reform-delivery>.

**EEX (2020a):** Market Data Natural Gas Futures (GasFuturesDEHistory\_EURO\_2020.xls). Download via SFTP server. Last accessed on 01.03.2020.

**EEX (2020b):** Market data European Emission Allowances (EUA)-Futures (EmissionFuturesHistory\_2020.xls). Download via SFTP server. Last accessed on 01.03.2020.

**Federal Department of the Environment, Transport, Energy and Communications (DETEC) (2019):** Energy Strategy 2050. Last accessed on 28.07.2020 at: <https://www.uvek.admin.ch/uvek/de/home/energie/energiestrategie-2050.html>.

**Energate Messenger (2020):** End for hard coal-fired power plant unit "Ostroleka C". Last accessed on 12.08.2020 at: <https://www.energate-messenger.de/news/200338/aus-fuer-steinkohle-kraftwerksblock-ostroleka-c->.

**ENTSO-E (2016):** European Network of Transmission System Operators for Electricity: Mid-term Adequacy Forecast 2016 Edition. Last accessed on 19.06.2020 at: [https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/MAF\\_2016\\_FINAL\\_REPORT.pdf](https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2016_FINAL_REPORT.pdf).

**ENTSO-E (2016):** TYNDP. Last accessed on 18.06.2020 at: <https://tyndp.entsoe.eu/2016/>.

**ENTSO-E (2017a):** European Network of Transmission System Operators for Electricity: Mid-term Adequacy Forecast 2017 Edition. Last accessed on 29.06.2020 at: [https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/MAF\\_2017\\_report\\_for\\_consultation.pdf](https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2017_report_for_consultation.pdf).

**ENTSO-E (2017b):** Winter Outlook Report 2017 / 18. Last accessed on 18.06.2020 at: [https://www.entsoe.eu/Documents/Publications/SDC/Winter\\_Outlook\\_2017-18.pdf](https://www.entsoe.eu/Documents/Publications/SDC/Winter_Outlook_2017-18.pdf).

**ENTSO-E (2018a):** European Network of Transmission System Operators for Electricity: Ten Year Network Development Plan 2018. Last accessed 08.06.2020 at: <https://tyndp.entsoe.eu/tyndp2018/>.

**ENTSO-E (2018b):** European Network of Transmission System Operators for Electricity: Mid-term Adequacy Forecast 2018 Edition. Last accessed 09.06.2020 at: <https://www.entsoe.eu/Documents/SDC%20documents/MAF/2018/MAF%202018%20Methodology%20and%20Detailed%20Results.pdf>.

**ENTSO-E (2018c):** European Network of Transmission System Operators for Electricity: Ten Year Network Development Plan 2018 - TYNDP Project List 2018 (February 2018). Last accessed on 11.06.2020 at: [https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/TYNDP\\_2018\\_Project\\_List.xlsx](https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/TYNDP_2018_Project_List.xlsx).

**ENTSO-E (2019):** European Network of Transmission System Operators for Electricity: Mid-term Adequacy Forecast 2019. Last accessed on 19 November 2019 from: <https://www.entsoe.eu/outlooks/midterm/>.

**ENTSO-E (2020a):** European Network of Transmission System Operators for Electricity: TYNDP 2020 - Scenario Report. Last accessed on 02.12.2020 at: <https://www.entsos-tyndp2020-scenarios.eu/>.

**ENTSO-E (2020b):** European Network of Transmission System Operators for Electricity: TYNDP 2020 Project Portfolio (February 2020). Last accessed 27.11.2020 at: [https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/200226\\_TYNDP2020\\_projects\\_portfolio.xlsx](https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/200226_TYNDP2020_projects_portfolio.xlsx).

**ENTSO-E (2020c):** European Network of Transmission System Operators for Electricity: Summer Outlook 2020 and Winter Review 2019/20. Last accessed on 26.11.2020 at: <https://www.entsoe.eu/outlooks/seasonal/>.

**ENTSO-E (2020d):** European Network of Transmission System Operators for Electricity: Mid-term Adequacy Forecast 2020. Last accessed on 03.12.2020 at: <https://www.entsoe.eu/outlooks/midterm/>.

**Eurostat (2017a):** Complete energy balances - annual data [nrg\_110a], Eurostat database, last accessed 10.08.2017.

**European Union (2017):** EU Reference Scenario, Brussels, 2017.

**European Commission (2014):** State aid: Commission authorises UK Capacity Market electricity generation scheme. Press release of 23.07.2014. Last accessed on 17.07.2020 at: [http://europa.eu/rapid/press-release\\_IP-14-865\\_en.htm](http://europa.eu/rapid/press-release_IP-14-865_en.htm).

**European Commission (2016a):** Communication from the Commission (COM2016) 860 of 30.11.2016: Clean Energy for All Europeans. Last accessed on 18.06.2020 at: <https://eur-lex.europa.eu/legal-content/DE/TXT/HTML/?uri=CELEX:52016DC0860&from=EN>

**European Commission (2016b):** State aid: Commission approves revised market-wide capacity mechanism in France. Press release of 06.11.2016. Last accessed on 22.06.2020 at: [http://europa.eu/rapid/press-release\\_IP-16-3620\\_de.pdf](http://europa.eu/rapid/press-release_IP-16-3620_de.pdf).

**European Commission (2016c):** Mapping and analyses of the current and future (2020 - 2030) heating/cooling fuel deployment (fossil/renewables). Last accessed on 28.05.2020 at: <https://ec.europa.eu/energy/en/studies/mapping-and-analyses-current-and-future-2020-2030-heatingcooling-fuel-deployment>.

**European Commission (2016d):** EU Reference Scenario 2016. Energy, transport and GHG emissions. Trends to 2050. Last accessed on 22.05.2020 at: [https://ec.europa.eu/energy/sites/ener/files/documents/20160713%20draft\\_publication\\_REF2016\\_v13.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/20160713%20draft_publication_REF2016_v13.pdf).

**European Commission (2018a):** State aid: Commission approves six electricity capacity mechanisms to ensure resource adequacy in Belgium, France, Germany, Greece, Italy and Poland. Press release 07.02.2018. Last accessed 27.05.2020 at: [http://europa.eu/rapid/press-release\\_IP-18-682\\_en.htm](http://europa.eu/rapid/press-release_IP-18-682_en.htm).

**European Commission (2018b):** State aid No. SA.46100 (2017/N) - Poland - Planned Polish Capacity Mechanism. Communication on the Commission Decision to the Member State. Last accessed on 28.05.2020 at: [http://ec.europa.eu/competition/elojade/isef/case\\_details.cfm?proc\\_code=3\\_SA\\_46100](http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_46100).

**European Commission (2018c):** State Aid SA.42011 (2017/N) - Italy - Italian Capacity Mechanism. Communication on the Commission Decision to the Member State. Last accessed 01.06.2020 at: [http://ec.europa.eu/competition/elojade/isef/case\\_details.cfm?proc\\_code=3\\_SA\\_42011](http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_42011).

**European Commission (2019):** A European Green Deal - Striving to be the first climate-neutral continent, 11.12.2019. Last accessed 31.03.2021 at: [https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal\\_en](https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en).

**European Parliament and Council (2019):** REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market in electricity (new version). Last accessed on 23.06.2020 at: <https://eur-lex.europa.eu/legal-content/DE/TXT/PDF/?uri=CELEX:32019R0943&from=HR>.

**EWI / gws / Prognos (2010):** Energy scenarios for an energy concept of the Federal Government. Last accessed on 21.07.2020 at: [https://www.prognos.com/uploads/tx\\_atwpubdb/100827\\_Prognos\\_Studie\\_\\_Energieszenarien\\_fuer\\_ein\\_energiekonzept\\_der\\_Bundesregierung.pdf](https://www.prognos.com/uploads/tx_atwpubdb/100827_Prognos_Studie__Energieszenarien_fuer_ein_energiekonzept_der_Bundesregierung.pdf).

**FFE (2017):** Flexibilization of combined heat and power generation; short report commissioned by the German TSO., November 2017; Last accessed on 30.07.2020 at: <https://www.ffe.de/attachments/article/761/Flexibilisierung%20der%20Kraft-Waerme-Kopplung.pdf>.

**Forum Energii (2017):** Polish energy sector 2050 - 4 Scenarios. Last accessed on 29.06.2018 at: [http://forum-energii.eu/en/news/polish\\_mix\\_2050.html](http://forum-energii.eu/en/news/polish_mix_2050.html).

**Fraunhofer ISI (2018):** FORECAST website, <http://www.forecast-model.eu/forecast-en/index.php>, last accessed 20.06.2018.

**Fraunhofer ISI et al. (2017):** Fraunhofer ISI, consentec, IFEU, TU Wien, M-Five, TEP Energy GmbH: ong-term scenarios for the transformation of the energy system in Germany, Module 3: Reference scenario and baseline scenario. Study commissioned by the Federal Ministry for Economic Affairs and Energy. Last accessed on 27.05.2020 at: [https://www.bmwi.de/Redaktion/DE/Downloads/B/berichtsmodul-3-referenzszenario-und-basisszenario.pdf?\\_\\_blob=publicationFile&v=4](https://www.bmwi.de/Redaktion/DE/Downloads/B/berichtsmodul-3-referenzszenario-und-basisszenario.pdf?__blob=publicationFile&v=4).

**Frontier Economics (2015):** Future potential for DSR in GB. A report prepared for DECC by Frontier Economics with support from LCP and Sustainability First. Last accessed on 29.05.2020 at [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/467024/rpt-frontier-DECC\\_DSR\\_phase\\_2\\_report-rev3-PDF-021015.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf).

**Renewable Energy Sources Act [EEG]:** New version of 21.07.2014. Date of entry into force: 01.08.2014, last amended on 08.08.2020. Available online at: [https://www.gesetze-im-internet.de/eeg\\_2014/](https://www.gesetze-im-internet.de/eeg_2014/).

**Act on the Maintenance, Modernisation and Expansion of Combined Heat and Power Generation [KWKG]:** new version of 21.12.2015. Date of entry into force: 01.01.2016, last amended: 08.08.2020. Available online at: [https://www.gesetze-im-internet.de/kwkg\\_2016/](https://www.gesetze-im-internet.de/kwkg_2016/).

**Electricity and Gas Supply Act (Energiewirtschaftsgesetz - EnWG):** new version of 07.07.2005. Date of entry into force: 13.07.2005, last amended: 22.11.2020. Available online at: [http://www.gesetze-im-internet.de/enwg\\_2005/index.html](http://www.gesetze-im-internet.de/enwg_2005/index.html).

**Act to reduce and end coal-fired power generation and to amend other laws (Coal Phase-out Act):** Date of entry into force: 14.08.2020. Available online at: <https://www.bmwi.de/Redaktion/DE/Artikel/Service/kohleausstiegsgesetz.html>.

**Government of the Czech Republic (2019):** National Energy and Climate Plan of the Czech Republic. Last accessed on 03.06.2020 at: [https://ec.europa.eu/energy/sites/ener/files/documents/cs\\_final\\_necp\\_main\\_en.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/cs_final_necp_main_en.pdf).

**Gouvernement.fr (2018):** Programmation pluriannuelle de l'énergie : quelle ambition?. Last accessed on 30.11.2020 at: <https://www.gouvernement.fr/programmation-pluriannuelle-de-l-energie-quelle-ambition>.

**Gnann, Till, Patrick Plötz, André Kühn and Martin Wietschel (2015):** Modelling market diffusion of electric vehicles with real world driving data - German market and policy options. Transportation Research Part A 77. p. 95-112.

**Hacker, Florian, Ralph Harthan, Hauke Hermann, Peter Kasten, Charlotte Loreck, Dominik Seebach, Christof Timpe and Dr. Wiebke Zimmer (2011):** Consideration of the potential for environmental benefits from the increased use of small, battery-electric vehicles as part of the "E-Mobility" project. Final report within the framework of the funding of the Electromobility Model Regions of the Federal Ministry of Transport, Building and Housing. Berlin, October 2011.

**Hacker, Florian, Ruth Blanck, Friederike Hülsmann, Peter Kasten, Charlotte Loreck, Dr. Sylvie Ludig, Moritz Mottschall and Dr. Wiebke Zimmer (2014):** eMobil 2050 - Scenarios on the potential contribution of electric transport to long-term climate protection. Joint final report on the projects "Scientific support for the development of scenarios on the possible contribution of electric mobility to long-term climate protection" (FKZ: UM 11 96 106) and "Scenarios on the possible contribution of electric mobility in freight and public passenger transport to long-term climate protection" (FKZ: 16 EM 1001). Berlin, September 2014.

**Hirst, David (2018):** Carbon Price Floor (CPF) and the price support mechanism. House of Commons Library. Briefing Paper Number 05927. Last accessed 30.06.2020 at: <http://researchbriefings.files.parliament.uk/documents/SN05927/SN05927.pdf>.

IAEA (2016): International Atomic Energy Agency: 47th Annual Report

**IEA (2018b):** Global EV Outlook 2018 - Towards cross-modal electrification. Last accessed on October 11, 2019, at: [https://webstore.iea.org/download/direct/1045?fileName=Global\\_EV\\_Outlook\\_2018.pdf](https://webstore.iea.org/download/direct/1045?fileName=Global_EV_Outlook_2018.pdf).

**IEA (2019):** International Energy Agency: World Energy Outlook 2019. Last accessed on 30/09/2020 at: <https://webstore.iea.org/world-energy-outlook-2019>.

**LeighFisher Ltd. (2016):** Electricity Generation Costs and Hurdle Rates. Lot 3: Non-Renewable Technologies. A report prepared for the Department of Energy and Climate Change (DECC). Last accessed 20.05.2020 at: [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/566803/Leigh\\_Fisher\\_Non-renewable\\_Generation\\_Cost.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566803/Leigh_Fisher_Non-renewable_Generation_Cost.pdf).

**London Economics (2013):** The Value of Lost Load (VoLL) for Electricity in Great Britain. Final Report for OFGEM and DECC. Last accessed 02.07.2020 at: <https://www.gov.uk/government/consultations/consultation-on-the-draft-electricity-market-reform-delivery>.

**LSE et al. (2011):** LSE, Grantham Research Institute on Climate Change and the Environment, RWE nPower: Demanding times for energy in the UK. A report commissioned by RWE nPower. Last accessed 29.06.2018 at: [http://www.vivideconomics.com/wp-content/uploads/2015/03/Demanding\\_times\\_for\\_energy\\_in\\_the\\_UK.pdf](http://www.vivideconomics.com/wp-content/uploads/2015/03/Demanding_times_for_energy_in_the_UK.pdf).

**Ministère de la Transition écologique et solidaire (2019a):** Programmations pluriannuelles de l'énergie (PPE). Last accessed on 09.07.2020 at: <https://www.ecologique-solidaire.gouv.fr/programmations-pluriannuelles-lenergie-ppe>.

**Ministère de la Transition écologique et solidaire (2019b):** Cadre européen énergie-climat. Last accessed on 14.07.2020 at: <https://www.ecologique-solidaire.gouv.fr/cadre-europeen-energie-climat#e4>.

**Ministerie van Economische Zaken en Klimaat (2020):** wijziging van de Wet verbod op kolen bij elektriciteitsproductie in verband met beperking van de CO<sub>2</sub>-emissie - VOORSTEL VAN WET. Last accessed 20.07.2020 at: <https://www.internetconsultatie.nl/productiebeperkingkolen/document/6049>.

**Ministero dello Sviluppo Economico and Ministero dell'ambiente e della tutela del territorio e del mare (2017):** Italy's National Energy Strategy 2017. Last accessed 21.05.2020 at: [http://www.sviluppoeconomico.gov.it/images/stories/documenti/BROCHURE\\_ENG\\_SEN.PDF](http://www.sviluppoeconomico.gov.it/images/stories/documenti/BROCHURE_ENG_SEN.PDF).

**Ministry of Economic Affairs and Climate Policy of the Netherlands (2019):** Integrated National Energy and Climate Plan 2021 - 2030. Last accessed on

12/08/2020 from: [https://ec.europa.eu/energy/sites/ener/files/documents/nl\\_final\\_necp\\_main\\_en.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/nl_final_necp_main_en.pdf).

**Ministry of Economic Affairs and Employment (2019):** Finland's Integrated Energy and Climate Plan. Last accessed on 12.08.2020 at: [https://ec.europa.eu/energy/sites/ener/files/documents/fi\\_final\\_necp\\_main\\_en.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/fi_final_necp_main_en.pdf).

**Ministry of Economic Development, Ministry of the Environment and Protection of Natural Resources and the Sea and Ministry of Infrastructure and Transport of Italy (2019):** Integrated National Energy and Climate Plan. Last accessed on 12.08.2020 at [https://ec.europa.eu/energy/sites/ener/files/documents/it\\_final\\_necp\\_main\\_en.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/it_final_necp_main_en.pdf).

**Ministry of Energy of Poland (2018a):** Energy Policy of Poland until 2040 - Abstract. Last accessed on 10.06.2020 at <https://www.gov.pl/attachment/376a6254-2b6d-4406-a3a5-a0435d18be0f>.

**Ministry of Energy of Poland (2018b):** Energy Policy of Poland until 2040 - FAQ. Last accessed on 10.06.2020 at: <https://www.gov.pl/attachment/b921ca74-cc46-484c-b71d-d650831684e4>.

**Ministry of Industry and Trade (2015):** State Energy Policy of the Czech Republic. Last accessed on 13.07.2020 at: [https://www.mpo.cz/assets/en/energy/state-energy-policy/2017/11/State-Energy-Policy-\\_2015\\_\\_EN.pdf](https://www.mpo.cz/assets/en/energy/state-energy-policy/2017/11/State-Energy-Policy-_2015__EN.pdf).

**Ministry of the Environment and Energy (2017):** Sweden's draft integrated national energy and climate plan. Last accessed on 29.05.2020 at: <https://www.government.se/48ee21/contentassets/e731726022cd4e0b8ffa0f8229893115/swedens-draft-integrated-national-energy-and-climate-plan>.

**Morrissey, Patrick, Peter Weldon and Margaret O'Mahony (2016):** Future standard and fast charging infrastructure planning: An analysis of electric vehicle charging behaviour. Energy Policy 89, pp. 257-270.

**National Grid (2017):** National Grid EMR Electricity Capacity Report, 31.5.2017.

**NEMO Committee (2019):** EUPHEMIA Public Description, Single Price Coupling Algorithm, 10.04.2019. Last accessed on 28.05.2020 at: <https://www.bsp->

[southpool.com/files/documents/Zacasno/Euphemia%20Public%20Description%20version%20NEMO%20Committee.pdf](https://southpool.com/files/documents/Zacasno/Euphemia%20Public%20Description%20version%20NEMO%20Committee.pdf).

**NPE - Nationale Plattform Elektromobilität (2018):** Subject: Charging infrastructure. Last accessed on 02.07.2020 at: <http://nationale-plattform-elektromobilitaet.de/themen/ladeinfrastruktur/#tabs>.

**Öko-Institut (2017):** The German Lignite Industry. Historical developments, resources, technology, economic structures and environmental impacts. Study commissioned by Agora Energiewende and the European Climate Foundation. Last accessed on 29.06.2020 at: [https://www.agora-energiewende.de/fileadmin2/Projekte/2017/Deutsche\\_Braunkohlenwirtschaft/Agora\\_Die-deutsche-Braunkohlenwirtschaft\\_WEB.pdf](https://www.agora-energiewende.de/fileadmin2/Projekte/2017/Deutsche_Braunkohlenwirtschaft/Agora_Die-deutsche-Braunkohlenwirtschaft_WEB.pdf).

**Öko-Institut / Fraunhofer ISI (2015):** Climate protection scenario 2050. 2nd Final Report. Study commissioned by the Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety. Last accessed on 03.08.2020 at: [https://www.isi.fraunhofer.de/content/dam/isi/dokumente/ccx/2015/Bericht\\_Runde\\_2.pdf](https://www.isi.fraunhofer.de/content/dam/isi/dokumente/ccx/2015/Bericht_Runde_2.pdf).

**Parsons Brinckerhoff (2013):** Electricity Generation Cost Model - 2013 Update of Non-Renewable Technologies. A report prepared for the Department of Energy and Climate Change (DECC). Last accessed 08.07.2020 at: <https://www.gov.uk/government/publications/parsons-brinckerhoff-electricity-generation-model-2013-update-of-non-renewable-technologies>.

**Pinsent Masons (2020):** The UK's emissions trading scheme from 2021. Last accessed 03.09.2020 at: <https://www.pinsentmasons.com/out-law/guides/uk-emissions-trading-scheme-2021>.

**PCR (2016):** EUPHEMIA Public Description, PCR Market Coupling Algorithm, Version 1.5, 05/12/2016, last accessed 24/9/2018 at <https://www.nordpool-group.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf>.

**PLEF (2015):** Pentalateral Energy Forum SG2: Generation Adequacy Assessment. Last accessed on 01.07.2020 at: [https://www.bmwi.de/Redaktion/DE/Downloads/G/gemeinsamer-versorgungssicherheitsbericht.pdf?\\_\\_blob=publicationFile&v=3](https://www.bmwi.de/Redaktion/DE/Downloads/G/gemeinsamer-versorgungssicherheitsbericht.pdf?__blob=publicationFile&v=3).

**PLEF (2018):** Pentalateral Energy Forum SG2: Generation Adequacy Assessment Jan. 2018. Last accessed 01.07.2020 at: [https://www.bmwi.de/Redaktion/DE/Downloads/P-R/plef-sg2-generation-adequacy-assessment-2018.pdf?\\_\\_blob=publicationFile&v=4](https://www.bmwi.de/Redaktion/DE/Downloads/P-R/plef-sg2-generation-adequacy-assessment-2018.pdf?__blob=publicationFile&v=4).

**Prognos et al. (2019):** Evaluation of cogeneration, analyses of the development of cogeneration in an energy system with a high share of renewable energies.. Report commissioned by the BMWi. Last accessed on 30.06.2020 at: [https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/evaluierung-der-kraft-waerme-kopplung.pdf?\\_\\_blob=publicationFile&v=4](https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/evaluierung-der-kraft-waerme-kopplung.pdf?__blob=publicationFile&v=4).

**PSE (2019):** Informacje o zasobach wytwórczych KSE (wg stanu na 29.11.2019). Last accessed on 02.06.2020 at: <https://www.pse.pl/documents/20182/f6bcb852-387b-4158-be1c-8ef58d25adb0?safeargs=646f776e6c6f61643d74727565https://www.pse.pl/documents/20182/e2ab899a-0cc3-4610-b95e-083d695db4e7?safeargs=646f776e6c6f61643d74727565>.

**r2b energy consulting (2014):** WP 3 of the Electricity Market Lead Study on behalf of the BMWi - Work Package EOM Functionality & Impact - Analyse Capacity Mechanisms, July 2014, Cologne/Berlin.

**r2b energy consulting (2015a):** WP 3 of the Lead Study Electricity Market 2015. Study commissioned by the BMWi. Cologne/Berlin. Available online at: [https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/leitstudie-strommarkt-2015.pdf?\\_\\_blob=publicationFile&v=9](https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/leitstudie-strommarkt-2015.pdf?__blob=publicationFile&v=9).

**r2b energy consulting (2015b):** Electricity market design of the future. Study commissioned by the Federal Environment Agency. Available online at: [https://www.umweltbundesamt.de/sites/default/files/medien/378/publikationen/climate\\_change\\_20\\_2015\\_strommarktdesign\\_der\\_zukunft\\_0.pdf](https://www.umweltbundesamt.de/sites/default/files/medien/378/publikationen/climate_change_20_2015_strommarktdesign_der_zukunft_0.pdf).

**r2b / Consentec (2019):** First Project Report, " Monitoring the security of supply on the European electricity markets ", Available online at:

[https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strom-maerkten.pdf?\\_\\_blob=publicationFile&v=18](https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strom-maerkten.pdf?__blob=publicationFile&v=18).

**Schröder, Andreas and Thure Traber (2012):** The economics of fast charging infrastructure for electric vehicles. Energy Policy 43, pp. 136-144.

**Stockholm Exergi (2020):** Värtaverket. Last accessed 12.08.2020 at: <https://www.stockholmexergi.se/nyheter/kvv6/>.

**S&P Global (2019):** Czech coal commission targets phaseout plan by Q4 2020. Last accessed on 10/06/2020 at: <https://www.spglobal.com/platts/en/market-insights/latest-news/coal/082719-czech-coal-commission-targets-phaseout-plan-by-q4-2020>.

**URE (2019):** Informacja Prezesa Urzędu Regulacji Energetyki Nr 10 /2019. Last accessed on 08.07.2020 at: <https://www.ure.gov.pl/download/9/9800/InformacjaPrezesaUrzeduRegulacjiEnergetykinr102019.pdf>.

**NB (2019):** 50Hertz Transmission GmbH, Amprion GmbH, TenneT GmbH, TransnetBW GmbH: Capacity Reserve. Last accessed on 24.07.2020 at: <https://www.netztransparenz.de/EnWG/Kapazitaetsreserve>.

**Verbund (2020):** Innovative system solutions added to Mellach power plant site. Last accessed on 12.08.2020 at: <https://www.verbund.com/de-de/ueber-verbund/news-presse/presse/2020/04/17/letzte-kohle-mellach>.

**VGB (2016):** VGB PowerTech e.V.: Availability of power plants 2006 to 2015.

**VGB (2017):** VGB PowerTech e.V.: Analysis of the unavailability of power plants 2007 - 2016.

**Wysokienapiecie.pl (2018):** Minister Energii: Ostrołęka to ostatnia taka inwestycja węglowa w Polsce. Last accessed 31.07.2020 at: <https://wysokienapiecie.pl/2529-minister-ostroleka-to-ostatnia-elektrownia-weglowa>.