Benefits of Energy Efficiency on the German Power Sector

Final report of a study conducted by
Prognos AG and IAEW

STUDY

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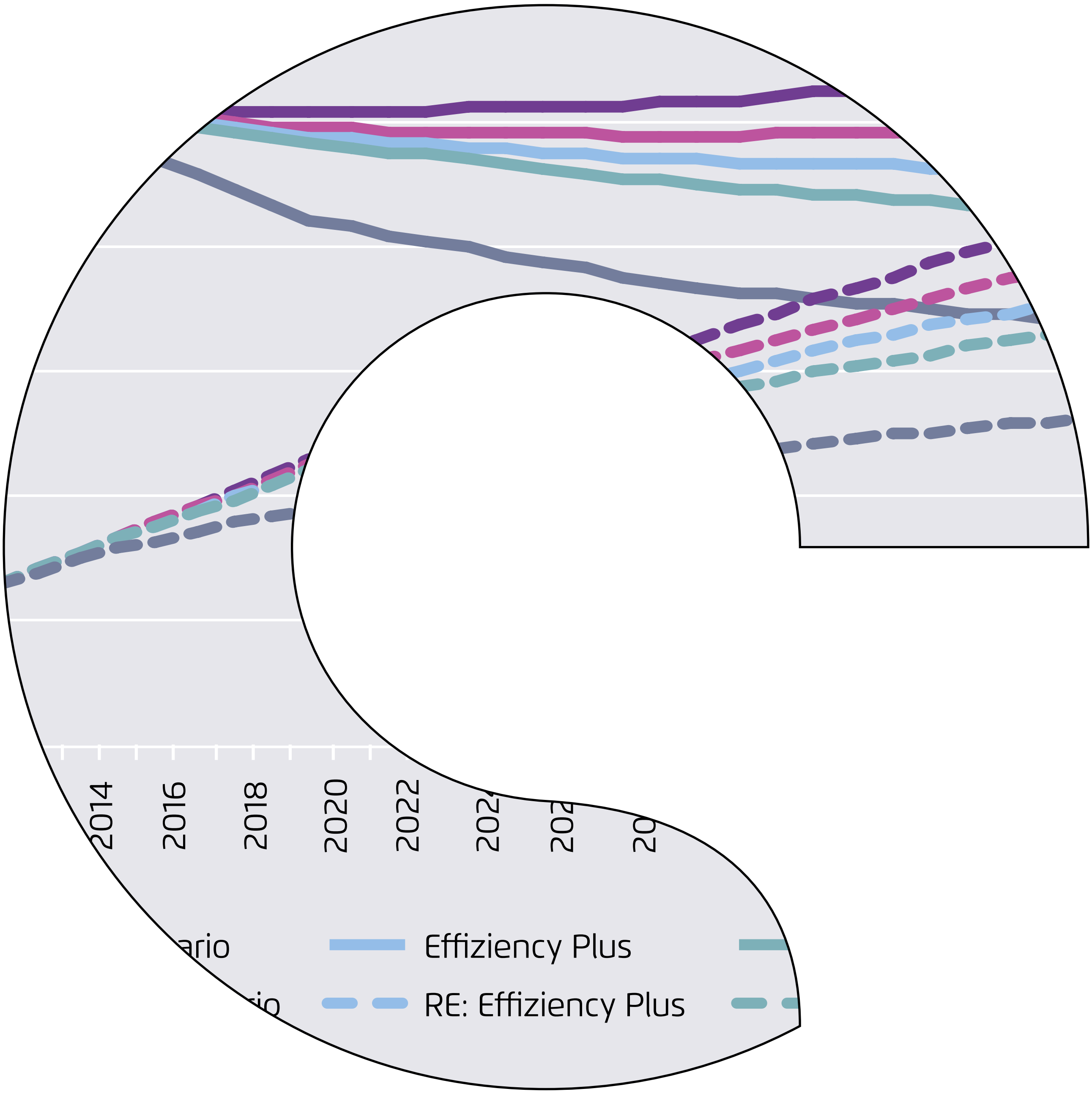

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IMPRINT

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CONSULTATIVE GROUP

We would like to thank the members of the consultative group for their input. The responsibility for the study and its results lies exclusively with Agora Energiewende, ECF and RAP as well as with the institutes involved.

The consultative group included representatives of:

- Federal Ministry for Economic Affairs and Technology
- Federal Ministry for the Environment, Nature Conservation and Nuclear Safety
- Bundesnetzagentur
- Bundesverband der Deutschen Industrie e. V.
- Bundesverband Neuer Energieanbieter e. V.
- Deutsche Unternehmensinitiative Energieeffizienz e. V.
- Deutscher Industrie- und Handelskammertag e. V.
- Forum Ökologisch-Soziale Marktwirtschaft e. V.
- Verband kommunaler Unternehmen e. V.
- Verbraucherzentrale Bundesverband e. V.
- World Wide Fund For Nature (WWF)

Preface

Dear readers,

Public debate on the energy transition is dominated by questions surrounding costs. Yet with increased energy efficiency, the energy transition can be implemented much more cost effectively. This is a sorely neglected issue.

The value of savings that could be achieved through greater efficiency in the power sector has not been previously quantified. Accordingly, this issue was examined in detail in a recent study by Agora Energiewende, the European Climate Foundation (ECF), and the Regulatory Assistance Project (RAP). Specifically, the study shows the extent to which the costs of electricity can be reduced through greater energy efficiency in conventional and renewable generation as well as in transmission and distribution grids. In this report, we are pleased to present the remarkable and quite surprising findings of this study.

The new German government is faced with the task of implementing decisive policies to promote the energy transition. Especially in the case of energy efficiency, there is pressure to take action in order to ensure the achievement of long-term goals: namely, to reduce primary energy consumption 50 percent by 2050 and to reduce power consumption 10 percent by 2020 and 25 percent by 2050.

Thus, the study should be understood in part as a plea to appreciate the importance of energy efficiency in the electricity sector, and as a call to grant efficiency a prominent role in the current energy policy debate.

With the implementation of the European Energy Efficiency Directive into national law and the announcement of the National Energy Efficiency Action Plan in Germany's coalition agreement, the need for greater attention to this issue is all the more pressing.

We hope you find this report both insightful and inspiring.

Yours
Patrick Graichen, Executive Director, Agora Energiewende
Johannes Meier, CEO, European Climate Foundation
Meg Gottstein, Principal, Regulatory Assistance Project

Key findings at a glance

1. **Improving energy efficiency would significantly lower the costs of the German electricity system.** Each saved kilowatt-hour of electricity reduces fuel and CO_2 emissions, as well as investment costs for fossil and renewable power plants and power grid expansion. If electricity consumption can be lowered by 10 to 35 percent by 2035 compared to the Reference scenario outlined in the study, the costs for electricity generation will reduced by 10 to 20 billion $euros_{2012}$.

2. **Improvements in the energy efficiency of the electricity sector can be achieved economically.** One saved kilowatt-hour of electricity would lead to reduced electrical system costs of between 11 to 15 euro $cents_{2012}$ by 2035, depending on the underlying assumptions. Many efficiency measures would generate lower costs than these savings, and would therefore be beneficial from an overall economic perspective.

3. **Reductions in future power consumption mean a lower need to expand the power grid.** A significant increase in energy efficiency can significantly reduce the long-term need to expand the transmission grid: between 1,750 and 5,000 km in additional transmission lines will be needed by 2050, down from 8,500 km under the "business as usual" scenario.

4. **Reducing power consumption would reduce both CO_2 emissions and import costs for fuel.** Reducing power consumption by 15 percent compared to the Reference scenario would lower CO_2 emissions by 40 million tonnes and would reduce spending on coal and natural gas imports by 2 billion $euros_{2012}$ in 2020.

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Objectives and scope of work

The aim of this study was to assess the economic benefits of different development paths for electricity consumption (referred to as "efficiency scenarios"). This assessment was performed by comparing various scenarios for the development of electricity consumption. In this connection, the overall costs of the electric power system were calculated and compared.

The costs of the electric power system are primarily attributable to three areas:

→ conventional generation of electricity (including storage and load management)
→ power generation from renewable energy sources
→ electrical grids (all voltage levels from 400 V up to 380 kV)

The calculations for all scenarios extend from 2012 to 2050. Due to demographic changes and technological progress that will occur over this time frame, significant changes in consumption across several sectors can be expected.

Scenarios and models at a glance

Five different scenarios are examined in this study. In addition to the reference scenario (see also Prognos, EWI & GWS, 2011), we consider four additional scenarios with varying power consumption trends. Three of these scenarios assume that considerable efforts will be undertaken to reduce power consumption. The fourth scenario depicts the continuation of existing trends without any regulatory activism (i.e. the "business as usual", or BAU, scenario). Furthermore, this scenario assumes an increase in power consumption. In all scenarios the share of electrical power generated from renewable energy will rise to 81 percent by 2050.

The four comparative scenarios as well as the reference scenario were not newly developed for this study. They are based on scenarios and associated assumptions previously developed and published by Prognos.

The Prognos Power Plant Model served as the basis for calculating the power generation from conventional sources that is required beyond the hourly feeding of electricity from renewable sources into the grid (i.e. residual load). The model simulates Germany's fleet of power stations and estimates the operation of power stations on an hourly basis according to merit order. This fleet of power stations is able to provide the generation capacity needed for the stability of the system at each moment. All scenarios consider an optimized use of load management in order to achieve a decrease in load peaks as well as the further expansion of electricity storage systems.

A specific transmission grid model developed by IAEW was used in order to quantify the necessity of expanding the electricity transmission grid. The applied transmission grid model covers both 220 kV and 380 kV lines, transformers as well as phase shifters. In total, the model consists of about 390 grid nodes and around 600 power line corridors. In order to determine the costs of transmission grid expansion, associated investment costs have been estimated.

As there are more than one million circuit kilometres and more than 860 grid operators to take into account, it is impossible to estimate how much the German distribution network needs to be expanded (as could be estimated for the transmission network). Accordingly, grid expansion was estimated by using a reference grid approach that relies on modelling five prospective grid types "dominated by strong wind", "dominated by wind", "mixed", "dominated by PV" and "urban".

Demand-side energy savings potential

The electricity savings projections detailed in this study are a result of many efficiency and savings measures in all sectors. To estimate the costs of implementing efficiency and savings measures on the demand side, a further and more detailed analysis of the costs for these measures would be necessary. However, this was not the focus of the present study.

Thus, while data on specific measures are lacking, we can draw attention to studies that indicate there is still a high potential for economically feasible savings in the area of electrical power. Studies that examine the cost aspects of energy savings were taken into account in our analysis (e.g. the EMSAITEK study by IZES, BEI, Wuppertal Institute, 2011; BDI & McKinsey, 2007; IFEU, Fraunhofer ISI, Prognos, GWS, et al., 2011). These three studies show that potential energy savings are large enough to allow adherence to the consumption corridor for 2020 allowed by the WWF as well as the consumption reductions set forth for 2030 by the German government's Energy Concept. Taking the long term view up to 2050, it must additionally be considered that starting from approx. 2020 or 2030, additional potentials for economic efficiency will presumably be explored that are not yet apparent and were not part of the analysed studies. We assume that it will be feasible to implement the majority of savings projected in the scenarios in an economic manner.

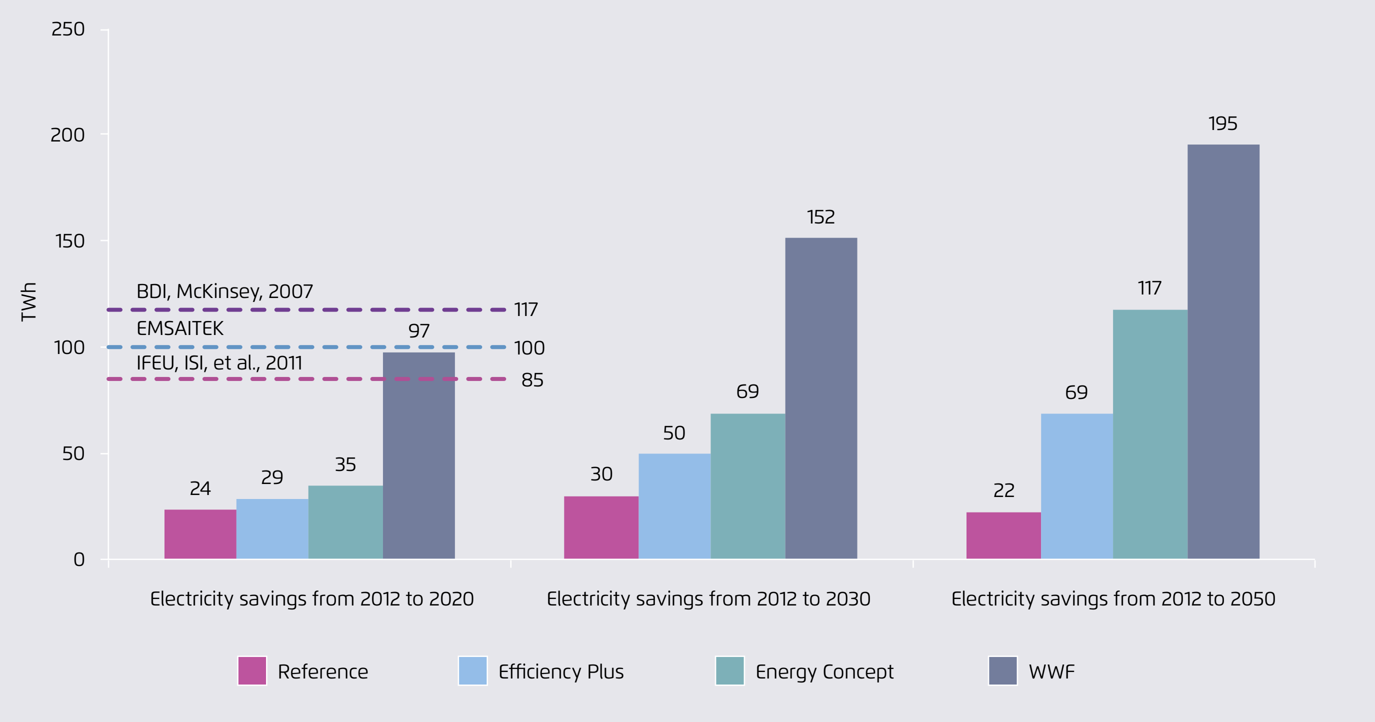
Costs of the power system: The results at a glance

In 2012 the costs for power generation and grid infrastructure amounted to approximately 50 billion $euros_{2012}$. Depending on electricity consumption trends, these costs will rise or fall on a long-term basis. The modelling we conducted for the power market and power grid shows the following results:

→ The BAU scenario exhibits the highest electricity consumption. Under this scenario, annual costs will rise up to 65 billion $euros_{2012}$ by 2035 and up to 72 billion $euros_{2012}$ by 2050.

The energy savings potential from different studies, as well as electricity savings compared to the BAU scenario

Figure 0-1



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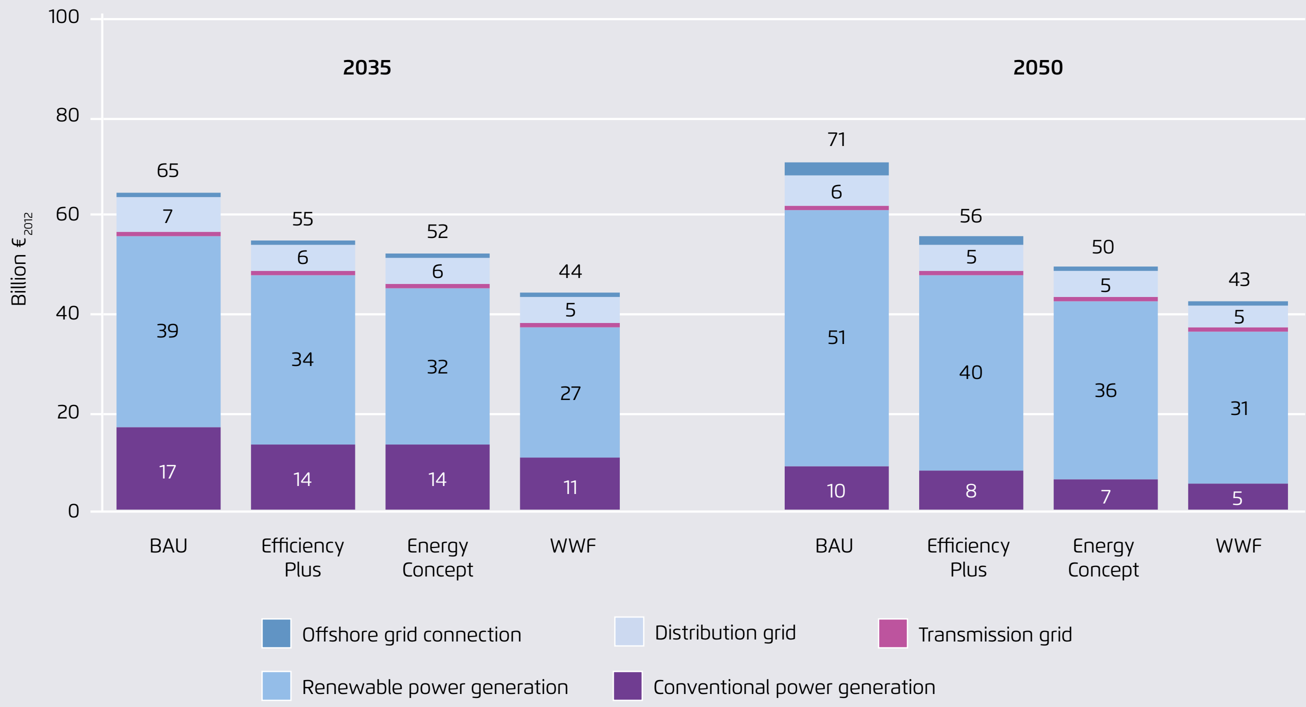
Total costs of electricity generation and network infrastructure

Figure 0-2



BNetzA (2012); BMU (2013); calculations by Prognos and IAEW

- Under the Efficiency Plus scenario, which forecasts a drop in electricity consumption of 16 percent compared to today's figures on a long-term basis, the overall costs will be 55 billion euros$_{2012}$ by 2035 and 56 billion euros$_{2012}$ by 2050, a 10 percent increase over the present level (2012).
- Under the Energy Concept scenario, a 25 percent reduction in final electricity consumption is expected compared to 2012 figures. Here, the overall costs will be 52 billion euros$_{2012}$ by 2035 and 50 billion euros$_{2012}$ by 2050, and will thus be equivalent to the present level.
- With a successful reduction in electricity consumption of 40 percent by the year 2050, as expected in the WWF scenario, the overall costs of the power system will be lower than the present level on a mid- and long-term basis. Savings will amount to 6 billion euros$_{2012}$ by 2035 and 7 billion euros$_{2012}$ by 2050.

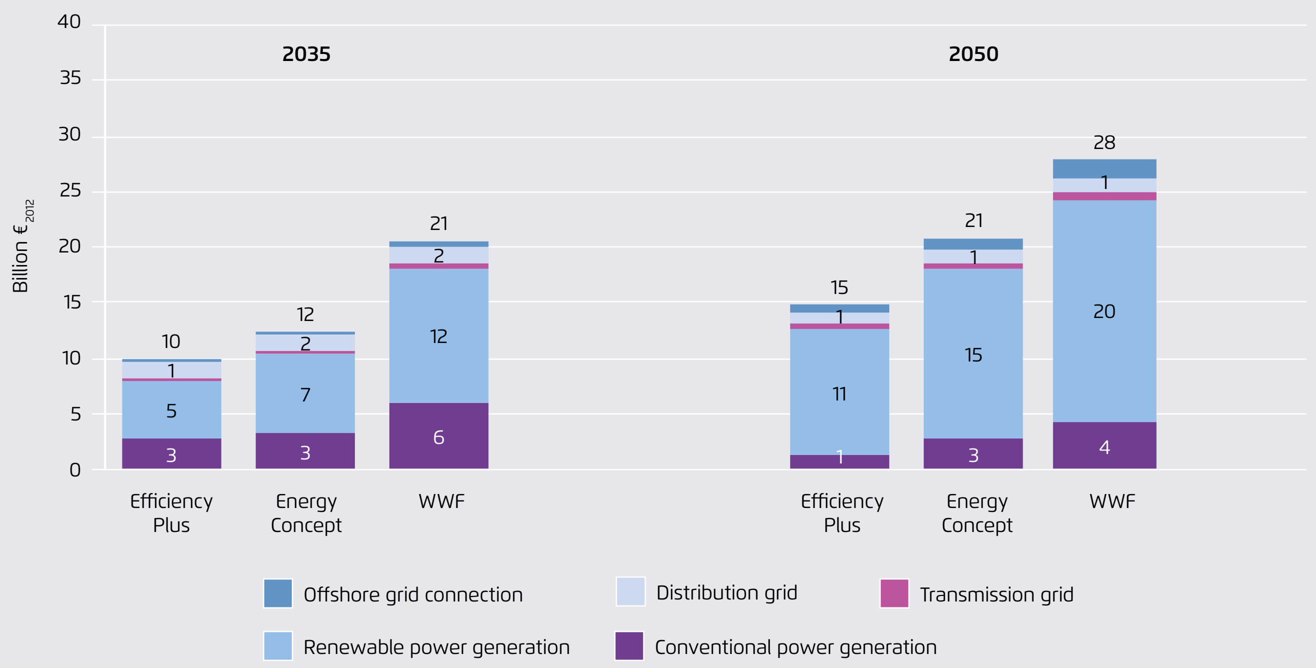
The above comparison shows that through a significant reduction in electricity consumption, the overall costs of the power system – even with greater use of renewable energy – can drop on a mid- to long-term basis.

In the more efficient scenarios cost savings will be between 10 and 20 billion euros$_{2012}$ by 2035 and between 15 and 28 billion euros$_{2012}$ by 2050 compared to the BAU scenario. Power generation from renewable sources will contribute the largest share. Renewable energy is on a whole the biggest cost factor, but can be significantly minimized by improving efficiency. The generation of electricity from renewables will represent more than half of savings by 2035, and some 70 percent of savings by 2050.

Costs per MWh of generated electricity and grid infrastructure are about the same in all scenarios at 120 euros$_{2012}$.

As expected, there are significant differences between scenarios regarding CO_2 emissions. Due to the high share of electricity from conventional sources in the BAU scenario, Electricity generation and grid infrastructure savings compared to the BAU scenario

Figure 0-3



BNetzA (2012); BMU (2013); calculations by Prognos and IAEW

CO_2 emissions are the highest in the scenario over the entire period until 2050. By contrast, the lowest emissions can be found in the WWF scenario due to lower electricity needs. Under this scenario, CO_2 emissions, which are directly connected to the generation of power, will be 35 million tonnes less than in the BAU scenario by 2030. Emissions savings will represent 19 million tonnes in 2050.

Through a decrease in electricity consumption the import costs for hard coal and natural gas are lower in the scenarios with more efficient trends. In comparison to the BAU scenario, the WWF scenario forecasts that imports can be lowered by 2 billion $euros_{2012}$ in 2020. On a long-term basis these savings drop to 1.8 billion $euros_{2012}$ per annum.

The lower the electricity consumption in each respective scenario, the lesser the need to expand the power supply grid. Our calculations show that by 2050, the need to expand the transmission grid can be significantly reduced: grid expansion needs equal 8,500 km under the BAU scenario, 5,000 km under the Efficiency Plus scenario, approximately 4,000 km under the Energy Concept scenario, and 1,750 km under the WWF scenario.[1]

Beyond monetary savings, a reduction in electrical energy consumption leads to further benefits that have not been assessed in this study, including lower pollutant emissions by conventional power plants and reduced land use due to less development of renewable energy.

1 The method used in our study to determine network expansion requirements diverges from the method applied by Germany's transmission network operators within the scope of the Network Expansion Plan (NEP). Accordingly, the figures for network expansion requirements presented here should not be compared directly with the figures from the federal expansion plan.

1 Goal and tasks

The present study had the goal to evaluate the economic benefits of electricity demand developments with varying efficiencies (i.e. efficiency scenarios) in relation to a less efficient development. For this purpose, we calculated and compared total costs of the electricity system. For all scenarios, the calculations covered the period between 2012 and 2050.

The full costs of the electricity system can be basically assigned to the following areas:

- → conventional electricity generation (including storage and demand-side management),
- → renewable electricity generation,
- → electricity transmission and distribution (all grid levels from 400 V to 380 kV).

In addition to the direct effects on the electricity supply system, we also calculated other benefit levels resulting from a reduced electricity demand, such as lower CO_2 emissions and reduced fuel imports.

For the three main cost areas – generation from conventional and renewable energy sources as well as the electricity grid – we computed the corresponding fixed and variable operating costs and the cost of capital. The following subchapters will describe the procedure in detail.

All considerations and calculations in this study refer to the system boundaries of Germany. The impact of the international electricity exchange was not included in this study. This approach made it possible to determine the effects that a reduced electricity consumption based on increased energy efficiency has in Germany.

In case of Europe-wide considerations, these effects would be superimposed by developments in the neighbouring countries that Germany hardly can influence. This includes the corresponding expansion of renewables, the development of electricity consumption as well as the use of nuclear energy in the neighbouring countries. Independent of the development of the electricity development in Germany, these may affect the German electricity generation and the required grid expansion. In the long term, it can be assumed though that most countries – in the annual average – will aspire to have a balanced electricity demand and generation in order to ensure local safety of supply and system stability. This means that electricity generation costs will converge with those of an exclusively national analysis. A diverging grid expansion demand based on European-wide considerations may result in different costs. However, as one result of this study showed, across all scenarios the costs for electricity grid expansion make up only a small share of total costs of the electricity system. This means that Europe-wide considerations of the scenarios and a resulting higher or lower electricity grid expansion would not significantly change the cost-related results of this study.

2 Approach and general assumptions

2.1 Consumption scenarios

All considerations and calculations in this study refer to the period between 2012 and 2050. During this period, demographic change and technological progress are expected to produce a substantially changed consumption in the individual sectors. In order to be able to evaluate electricity savings we had to determine an energy-economic base scenario for comparing the effects of additional efforts. For this scenario, we had to make assumptions regarding the development of electricity consumption according to sectors, the expansion of renewables, the development of fuel prices and of the European climate policy and the corresponding CO_2 price development.

The Reference scenario we used corresponds to the current reference scenario of the German government. This scenario was prepared in 2010 by Prognos together with the *Energiewirtschaftliches Institut an der Universität zu Köln* (EWI) and the *Gesellschaft für wirtschaftliche Strukturforschung* (GWS) and used by the German government to develop its Energy Concept. The Reference scenario represents a further development that assumes a continued adjustment of the current instruments – including in the area of energy efficiency.

In addition to the Reference scenario, we have looked at four additional scenarios with different electricity consumption curves. Three scenarios assume larger efforts for decreasing electricity consumption. The fourth scenario represents a forward projection of current developments (business as usual – BAU) and assumes an increase in electricity consumption.

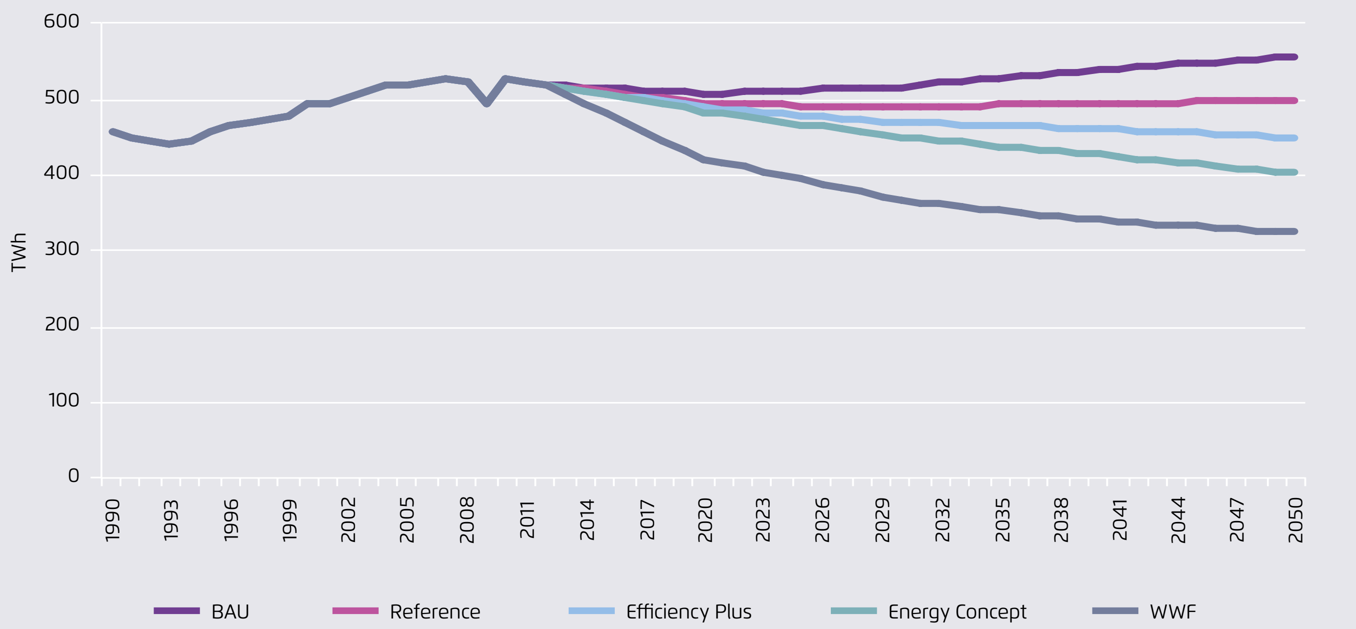
Similar to the Reference scenario, the four comparative scenarios were not developed from scratch for this study, but are based on scenarios – including their underlying assumptions – developed and published by Prognos.

- The Business-as-usual scenario (BAU) represents a modification of the Reference scenario and assumes less progress regarding energy efficiency. Current developments as well as existing instruments are continued, but not further developed and adjusted.
- The Efficiency Plus scenario also constitutes a modification of the Reference scenario and includes additional aspects of the energy-turnaround scenario. It assumes the introduction of additional instruments for improving energy efficiency due to the implementation of the European Efficiency Directive (EED).
- The Energy Concept scenario reflects the development goals set out in the German energy turnaround. Similar to the Reference scenario, it is part of the study *Energieszenarien für ein Energiekonzept der Bundesregierung* (energy scenarios for an energy concept of the German government) that was prepared by Prognos, EWI and GWS.
- The most ambitious efficiency scenario originates from the study *Modell Deutschland – Klimaschutz bis 2050* (*Model Germany – Climate protection until 2050*) that was commissioned by WWF in 2009 and prepared by Prognos together with *Öko-Institut* and Dr. Hans-Joachim Ziesing. In this study, it is called WWF scenario.

The five scenarios assume different developments of energy consumption until 2050. Figure 2-1 presents the different development paths.

Development of the final-energy electricity consumption in the five analysed scenarios

Figure 2-1



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The scenarios cover a comparatively wide range of development options. In 2050, the BAU scenario shows the highest electricity consumption, with 556 TWh. The electricity consumption of the WWF scenario constitutes the lowest estimate with 324 TWh and is 40 percent lower than the electricity consumption of the BAU scenario.

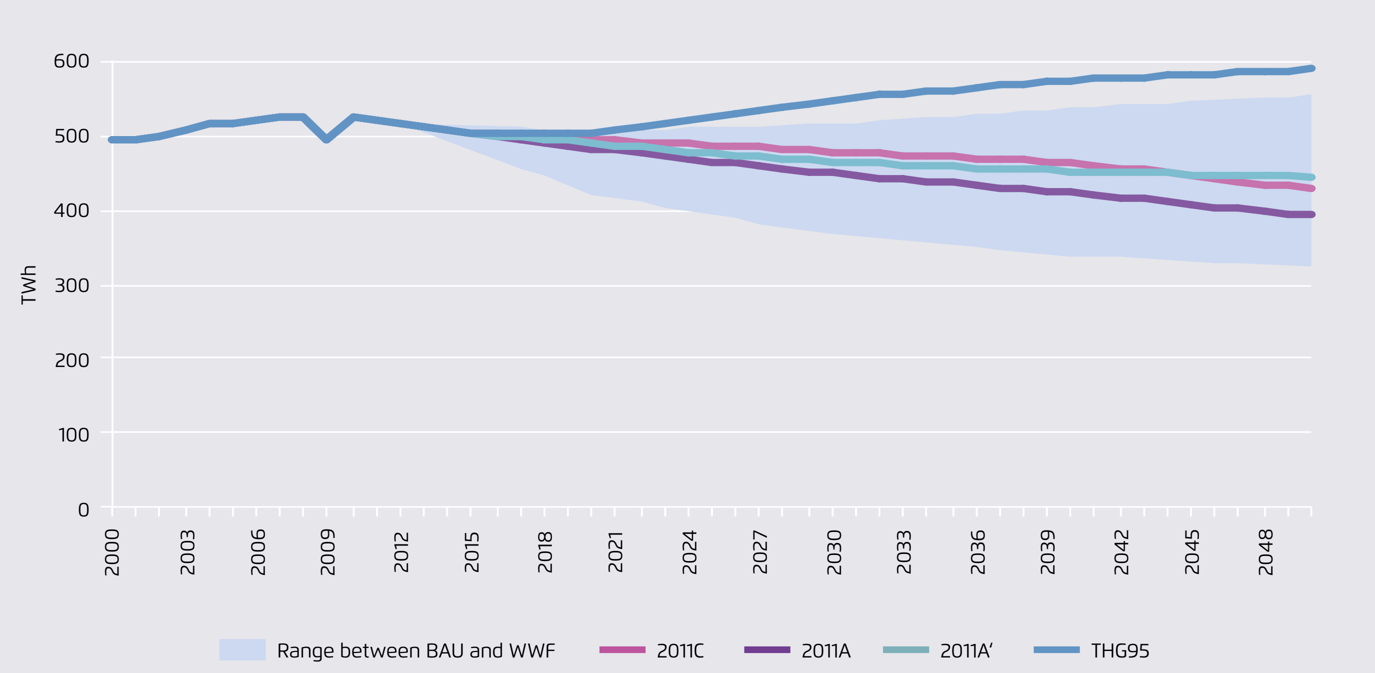
Also in comparison to scenarios in other studies, the WWF scenario represents a very ambitious efficiency development. There is hardly any other scenario that assumes similarly large savings of electricity consumption. The WWF scenario thus describes a development that can be assumed to approximate the lower limit of the feasible efficiency development.

As opposed to this, the BAU scenario as the highest estimate of this study does not constitute the extreme of the scenarios discussed in the literature. The THG95 scenario of the current Leitstudie 2011 describes a path resulting in an electricity consumption of almost 600 TWh in 2050. Further studies such as the *Energiekonzept 2050* by *Forschungs Verbund Erneuerbare Energien* (FVEE) from 2010 or the special report of the German Advisory Council on the Environment (SRU) from 2010 even include individual scenarios resulting in an increased energy consumption of 700 TWh by 2050. The high-consumption scenarios assume a large expansion of electromobility and a substantially increased importance of electricity for heat generation. In addition, the SRU scenario assumes a less ambitious efficiency development.

Even though a larger increase of electricity consumption than presented in the BAU scenario seems to be possible, the chosen scenarios are suitable for illustrating the effects of an ambitious efficiency strategy on the total economic system.

Figure 2-2 compares the range of this study's scenarios with four scenarios from the Leitstudie 2011. The scenarios in the Leitstudie follow the goals of the Energy Concept and – to a large extent – coincide with them. Regarding the expansion of renewables, scenario 2011A corresponds to the middle scenario. As opposed to this, scenario 2011A' illustrates

Comparison of the range of this study's scenarios with the scenarios from *Leitstudie* 2011 — Figure 2-2



Prognos, DLR et al. (2012)

a development that only includes current electricity consumers (without heat pumps, electromobility, and a possibly larger electricity consumption for process heat). Scenarios 2011B and 2011C correspond to the energy consumption and generation structures of scenario 2011A. They vary regarding the supply and use of methane in the transport sector. Finally, scenario THG95 shows the renewable energy expansion and efficiency development that would be required for achieving the upper limit of the Energy Concept's target range for the reduction of green-house emissions.

In all scenarios, the renewables share of net electricity generation is assumed to amount to over 80 percent in 2050. In addition to the development of the electricity demand, figure 2-3 represents the development of electricity generation from renewables; table 2-1 lists the absolute values of electricity consumption and generation from renewables in 2050 for the different scenarios.

The scenarios do not have a uniform data basis as they originate from different studies. The most important assumptions of the scenarios are included in the appendix. The WWF scenario is based on an older study than the Refer-

Electricity consumption and electricity generation from renewables in 2050 in the different scenarios — Table 2-1

	BAU	Reference scenario	Efficiency Plus	Energy Concept	WWF
Final energy electricity consumption 2050 in TWh	556	497	449	402	324
Net electricity generation 2050 in TWh	638	569	511	457	366
Electricity generation from renewables 2050 in TWh	517	461	414	370	297
Renewables share of net electricity generation 2050	81 %				

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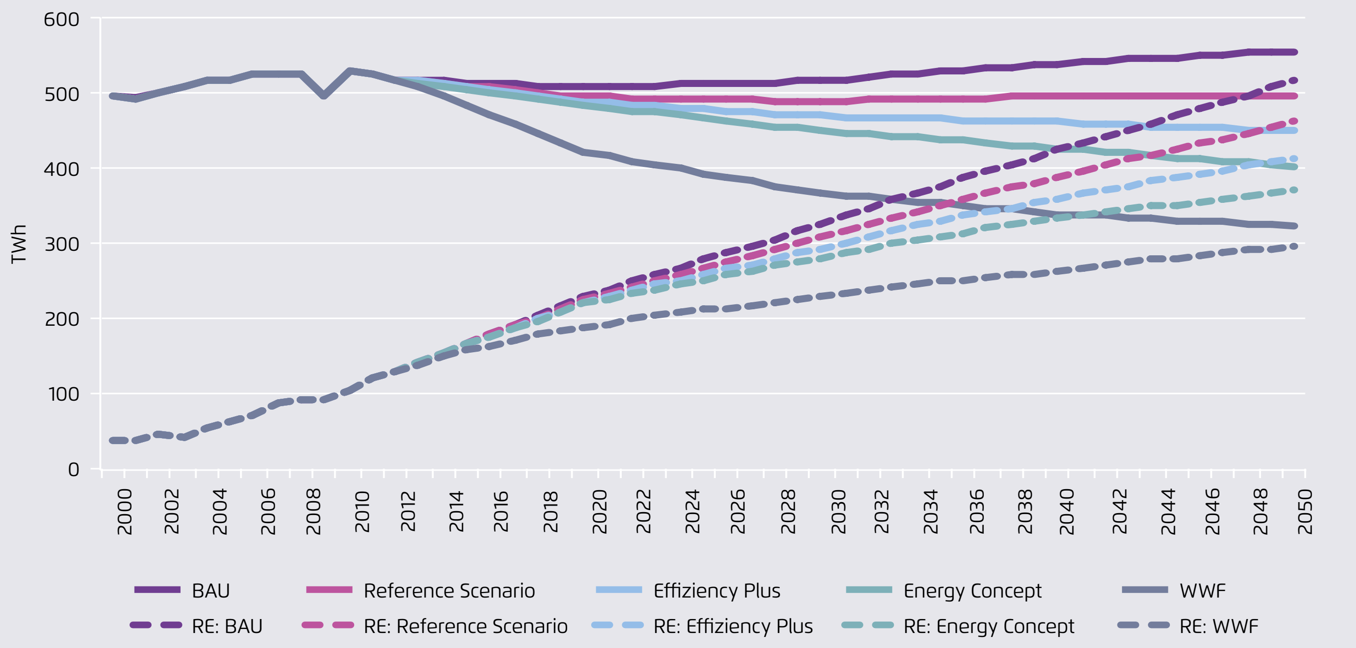
Development of final-energy electricity consumption and generation from renewables in the five scenarios — Figure 2-3



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ence and Energy Concept scenarios. Therefore, the scenarios contain diverging assumptions regarding the development of the electricity consumption of different applications, such as electromobility and heat pumps. For the purpose of the current study, we did not include the demand structure of the individual scenarios, but only used the accumulated electricity demand across all sectors in the scenarios. The main purpose of the evaluated energy-economic scenarios was to assess whether the corresponding development paths of total electricity demand can be applied to the total energy system, without the risk of system inconsistencies.

Therefore the results calculated in this study do not show how changed energy consumption patterns in different sectors affect the total cost of the electricity system. The results instead represent the effects that a certain amount of saved electricity has on generation and grid costs. Table 2-2 summarizes the framework assumptions of the five scenarios.

Framework data of the analysed scenarios — Table 2-2

	BAU	Reference scenario	Efficiency Plus	Energy Concept	WWF
Development of annual energy productivity between 2011 and 2050	1.3 %	1.8 %	2.1 %	2.4 %	2.6 %
Annual change in electricity consumption	+0.3 %	-0.1 %	-0.4 %	-0.6 %	-0.9 %
Change in electricity consumption between 2011 and 2050	+7 %	-5 %	-16 %	-20 %	-40 %
Change in electricity consumption in TWh between 2011 and 2050	+37 TWh	-22 TWh	-69 TWh	-117 TWh	-195 TWh

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For the grid-side analysis of this study, we had to disaggregate the annual total electricity demand according to consumer sectors and to differentiate them according to regions. For grid calculations, input data consisted of regional load curves, i.e. the hourly electricity demand at the level of the approximately 400 grid nodes in Germany. This regionalisation was carried out in three steps for base year 2012:

- → determining the sectoral electricity demand (work in GWh) at the level of the approximately 400 counties and independent cities
- → deriving the sectoral load curves (capacity in GW) at regional level taking into account the different industrial structures in the regions
- → combining the sectoral load curves of a region in a single regional load curve

We used a model-aided approach for the regionalisation and the corresponding derivation of the hourly regional energy demand (load curve) in the counties and independent cities. The calculations were based on the electricity demand and the 2012 load curve for Germany published by ENTSO-E as well as on standard load profiles produced by Munich Technical University.

Prognos disposes of a model for regionalising final-energy demand at county level that reliably represents both actual data and long-term forecasts for the whole of Germany at the level of counties and independent cities. The present study used the model to break down and calculate the scenarios' electricity demand (work in GWh) according to consumer sectors at the level of counties and independent cities.

In order to regionalise electricity demand for the base year, the model used – in addition to regionally available energy statistics and balances – a large number of regional variables, such as the structure of energy carriers and the size of the existing building stock (number of apartments, year of construction, surface area, vacancy), the specific fuel and electricity demand according to applications, employment and gross value added according to industry as well as demographic lead indicators (population, number of households). The results of the simulations represent the electricity consumption of the sectors at the level of counties and independent cities in Germany.

As a second step – starting from the regional electricity demand –, we modelled a regional load of the hourly electricity demand for each county and independent city. Here we used standard load profiles for transforming annual electricity demand of main consumer sectors into hourly values. For the consumer sectors Private Households as well as Trade, Commerce and Services (GHD), we applied the standard load profiles published by Munich Technical University. For the consumer sector Industry, there are no publicly available data. For this study, Prognos therefore modelled county-specific industrial profiles that take into account the corresponding industrial structure.

The last step was to combine the sectoral load profiles of the individual counties and independent cities into a single county-specific load curve. When testing against the ENTSO-E load curve published for Germany, the sum of the regional load curves across all counties and independent cities shows a good consistency with deviations of less than 10 percent. The deviations from actual data – which are common when standard load profiles are used – were eliminated applying hourly correction factors across sectors and counties.

In principle the same procedure was used for the results of the Reference scenario in order to derive future regional load curves. At first, the sectoral electricity demand was regionalised and then transposed into a single regional load curve. For the calculation, we used the standard load profiles calibrated for the base year for the individual sectors at regional level without any alterations.

In the Prognos regional energy model, the regionalisation of the future electricity demand does not only take into account the assumed efficiency development of the electricity applications, but also the development of other energy demand and the energy carrier structure as well as the development of demographic and economic parameters at county level. Thus the model makes it possible to represent future regional shifts resulting from local economic developments as part of the sectoral energy demand development. Prognos' regional economy model REGINA provides the economic and demographic parameters at county level. With regional input-output tables, the model is able to represent Germany-wide development trends at the level of individual counties.

Regionalising electricity demand from the Reference scenario results in a reliable distribution function of total electricity demand across the consumer sectors in the counties and independent cities until 2050. This distribution function – which was determined for the Reference scenario – was also used for transforming total electricity demand in the scenarios BAU, Efficiency Plus, Energy Concept and WWF to regional electricity demand. Also for these scenarios, calibrated regional standard load profiles were used to generate regional load profiles.

2.2 Energy-economic framework data

In addition to the electricity demand, the future development of the electricity system is affected by many other factors. In the following, the corresponding assumptions of this study are presented.

2.2.1 Political framework

Independent of the presented different consumer and efficiency paths, we assume the same political framework conditions in the scenarios:

- → reaching the minimum goals set out in the Renewable Energies Act (EEG) regarding the expansion of renewables in Germany
- → phasing out nuclear energy use according to the decision taken in 2011
- → Due to the current political and public resistance to carbon dioxide capture and storage (CCS) and the economic challenges to be expected in relation to an energy system characterised by fluctuating renewables and the corresponding high investment costs, we assume that CCS will not play any role in the German electricity system.

2.2.2 Fuel prices

Price levels of energy carriers in Germany, i.e. oil, natural gas and coal, are linked to prices on the world market. For oil and coal, they result from supply and demand on the world market; and for imported gas, they continue – to a large extent – to depend on the so called oil indexation where natural gas prices are linked to the price development of individual oil products. In addition, German import prices also include the exchange rate USD/Euro as well as transport costs (freight rates and pipelines).

Therefore, German cross-border prices for crude oil and coal follow the international price development.

As opposed to the oil price development, the average cross-border price for natural gas shows a more modest development in Germany and benefits, in the long term, from further supply diversification due to LNG as well as from German gas use shifting from heat to electricity generation. In the medium term, increasing gas-to-gas competition will increasingly decouple gas prices from oil prices.

Table 2-3 shows 2012 fuel prices and the assumptions for the price development until 2050.

2012 prices of fossil fuels and the assumed development until 2050 — Table 2-3

		2012	2020	2030	2040	2050
Oil price	$\$_{2012}$/Barrel	100	120	130	135	140
Natural gas price (power station) (calorific value)	€$_{2012}$/MWh	26	28	33	35	38
Coal price	€$_{2012}$/MWh	11	11	14	15	16

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2.2.3 CO_2 prices

With the introduction of emissions trading in Europe, CO_2 emissions from the major part of conventional electricity generation have received a price tag.

CO_2 certificate prices mainly depend on the design of the future climate policy. We assume that Europe continues to limit emissions and will adhere to the goals for the reduction of CO_2 emissions. In the medium term, the CO_2 price will have to significantly increase in relation to 2012 levels in order to trigger a shift towards low carbon-dioxide generation technologies in conventional power stations. Therefore a noticeable scarcity of certificates can be expected for the fourth trading period starting in 2020. Table 2-4 represents the assumed development of the CO_2 price until 2050.

2012 CO_2 price and the assumed development until 2050 — Table 2-4

		2012	2020	2030	2040	2050
CO_2 price	€$_{2012}$/t	4	20	30	40	50

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3 Calculation of electricity generation costs

3.1 Conventional electricity generation

Based on the presented energy-economic framework parameters, the Prognos power station model was used to calculate the conventional electricity generation required in the scenarios in addition to the generation from renewables. The model represents the German power plant fleet down to individual plant level and simulates the hourly power plant use according to the merit order. The resulting power plant fleet is able to provide the generating capacity required in each individual moment for maintaining system stability. All scenarios take into account an increased use of demand-side management in order to decrease load peaks as well as the expansion of electricity storage. The larger the future electricity consumption in the scenarios, the larger the assumed used demand-side management potential. A long-term demand-side management potential of 10 GW was assumed for the BAU scenario and of 6 GW for the WWF scenario. In the long term, the installed storage capacity in the BAU scenario increases from a current 6.5 GW to 8.5 GW; in the WWF scenario, storage capacity increases to only 7.5 GW in 2050. The following figures show the installed capacity of power stations, storages and a possible demand-side management as well as the generated amount of electricity for the different scenarios.

In all scenarios, the conventional power station fleet is the same at the beginning of the analysed period and then follows the individual scenarios regarding the further development of the required conventional electricity generation. The lower the required electricity generation in the scenarios, the lower the required conventional generation. Due to the assumption of a proportional reduction of peak load1 in case of a decreased electricity demand, the required capacity from controllable power stations and demand-side management shows a larger reduction in the more efficient scenarios.

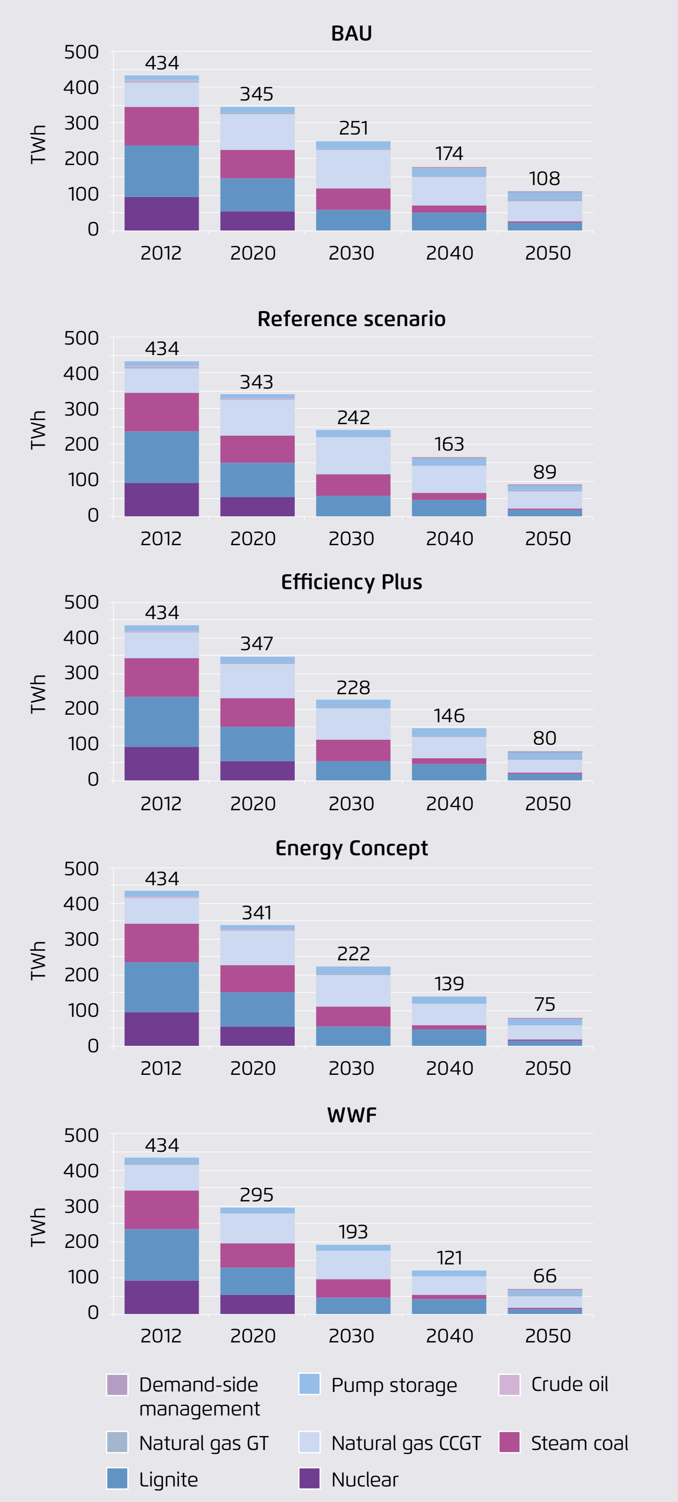
In all scenarios, the required conventional generation decreases due to the increased renewables utilisation. Under the assumed framework conditions regarding fuel and CO_2 prices and a heavily increasing share of fluctuating renewables, in the long term natural gas will become more and more important within the conventional electricity mix. The following summary shows the development of future fossil-thermal electricity generation for the individual scenarios.

Today, coal-operated and nuclear power stations correspond to approximately 60 percent of the conventional generation capacity. Phasing out nuclear energy utilisation and the construction of gas-fired power stations will in all scenarios in the medium and long term result in gas-fired power stations accounting for the largest part of conventional power station capacity. Existing coal-fired power stations will be maintained and financed for ensuring the required capacity – even though they will have a very low number of operating hours from 2040 onwards. The following summary shows the capacity development of the power station fleet in the individual scenarios.

In all scenarios, the sum total of installed capacity and demand-side management will decrease until the year 2050 from today's more than 100 GW. Renewables will increase their contribution to secured capacity, particularly through future – more electricity market-controlled – biomass power stations, through more uniform feed-in profiles of wind turbines as well as – in the long term – the use of geothermal plants. The decreased electricity demand in all scenarios – with the exception of the BAU scenario – results

1 In Germany, peak load occurs late on cold winter days. This means that a reduced electricity consumption of electrical heating and regarding lighting will result in an unproportionally large decrease of peak load. Savings with a different base-load characteristics (e.g. many industrial processes) as well as applications with demand peaks at different times (e.g. air conditioning, cooling) lead to a peak load decrease that is in line with or below the development of the consumption. Based on the calculated estimates we assume for Germany that peak load will develop in line with electricity demand.

Development of the fossil-thermal electricity generation structure, storage and demand-side management — Figure 3-1



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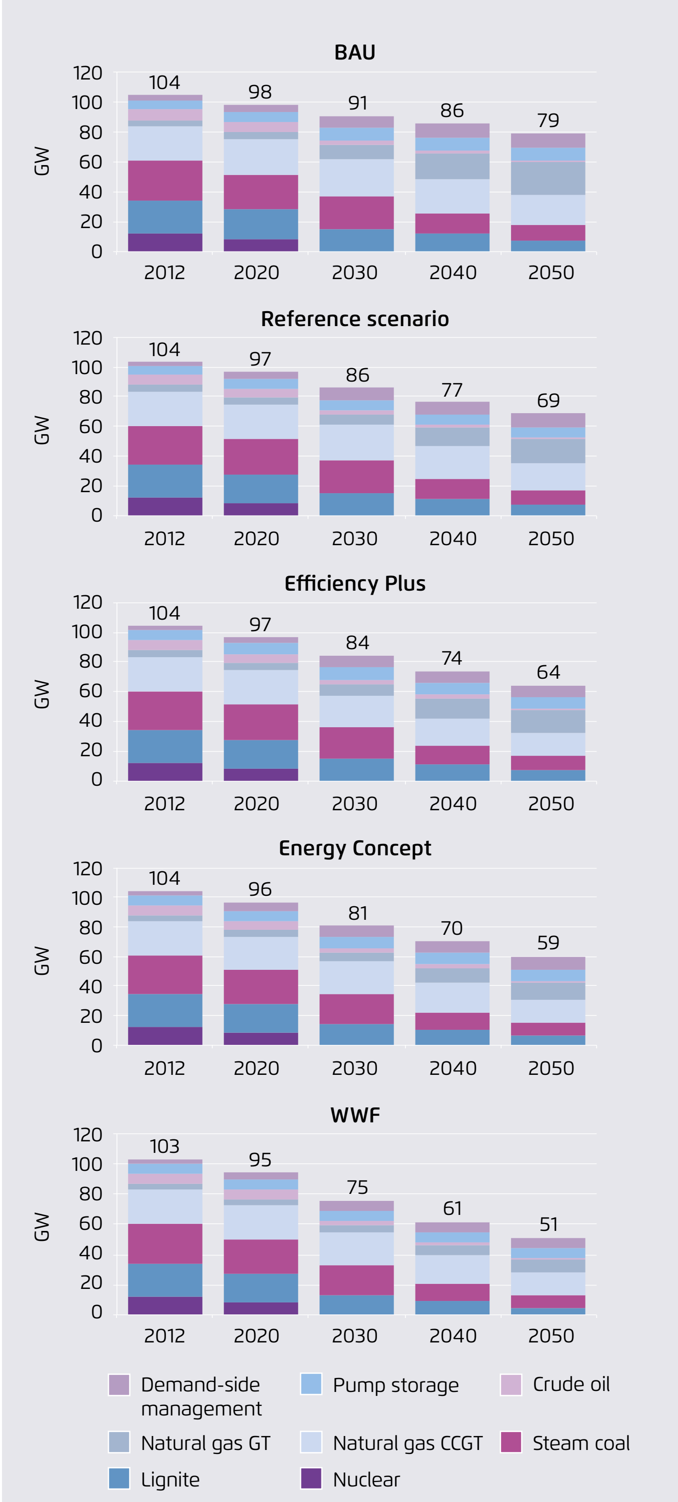
Installed capacity of fossil-thermal power stations, storage and demand-side management — Figure 3-2



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in a lower peak load in comparison to the current requirements.

Based on the results regarding electricity generation and capacity development in the individual scenarios, now total costs (full costs) were calculated for the modelled power station fleet and its electricity generation. Total costs include

- → fuel and CO_2 certificate costs that result from the modelled electricity generation (see table 2-3 and table 2-4),
- → variable operating costs for auxiliary and operating materials as well as maintenance due to plant operation,
- → fixed operating costs for regular maintenance, repair and staff, and
- → cost of capital that results from investment costs and the assumed weighted average cost of capital (WACC).

The following table shows the assumptions – regarding operating and investment costs of conventional power stations – used by Prognos AG for the calculations.

The following figures present the total costs of fossil-thermal electricity generation differentiated according to power station types and the respective energy carriers, on the one hand, and cost categories, on the other hand.

Today, total costs of conventional electricity generation amount to approximately 19 billion $euros_{2012}$. All scenarios

Assumptions regarding investment and operating costs of conventional electricity generation — Table 3-1

		2012	2020	2030	2040	2050
Coal						
Investment costs	$€_{2012}$/kW	1,500	1,500	1,500	1,500	1,500
WACC	in %	7	7	7	7	7
Fixed operating costs	$€_{2012}$/kW/a	24	24	24	24	24
Variable operating costs	$€_{2012}$/MWh	2.0	2.0	2.0	2.0	2.0
Lignite						
Investment costs	$€_{2012}$/kW	1,700	1,700	1,700	1,700	1,700
WACC	in %	7	7	7	7	7
Fixed operating costs	$€_{2012}$/kW/a	27	27	27	27	27
Variable operating costs	$€_{2012}$/MWh	2.5	2.5	2.5	2.5	2.5
Combined Cycle Gas Turbine (CCGT)						
Investment costs	$€_{2012}$/kW	1,000	1,000	1,000	1,000	1,000
WACC	in %	7	7	7	7	7
Fixed operating costs	$€_{2012}$/kW/a	20	20	20	20	20
Variable operating costs	$€_{2012}$/MWh	2.0	2.0	2.0	2.0	2.0
Gas turbine						
Investment costs	$€_{2012}$/kW	500	500	500	500	500
WACC	in %	7	7	7	7	7
Fixed operating costs	$€_{2012}$/kW/a	15	15	15	15	15
Variable operating costs	$€_{2012}$/MWh	2.0	2.0	2.0	2.0	2.0

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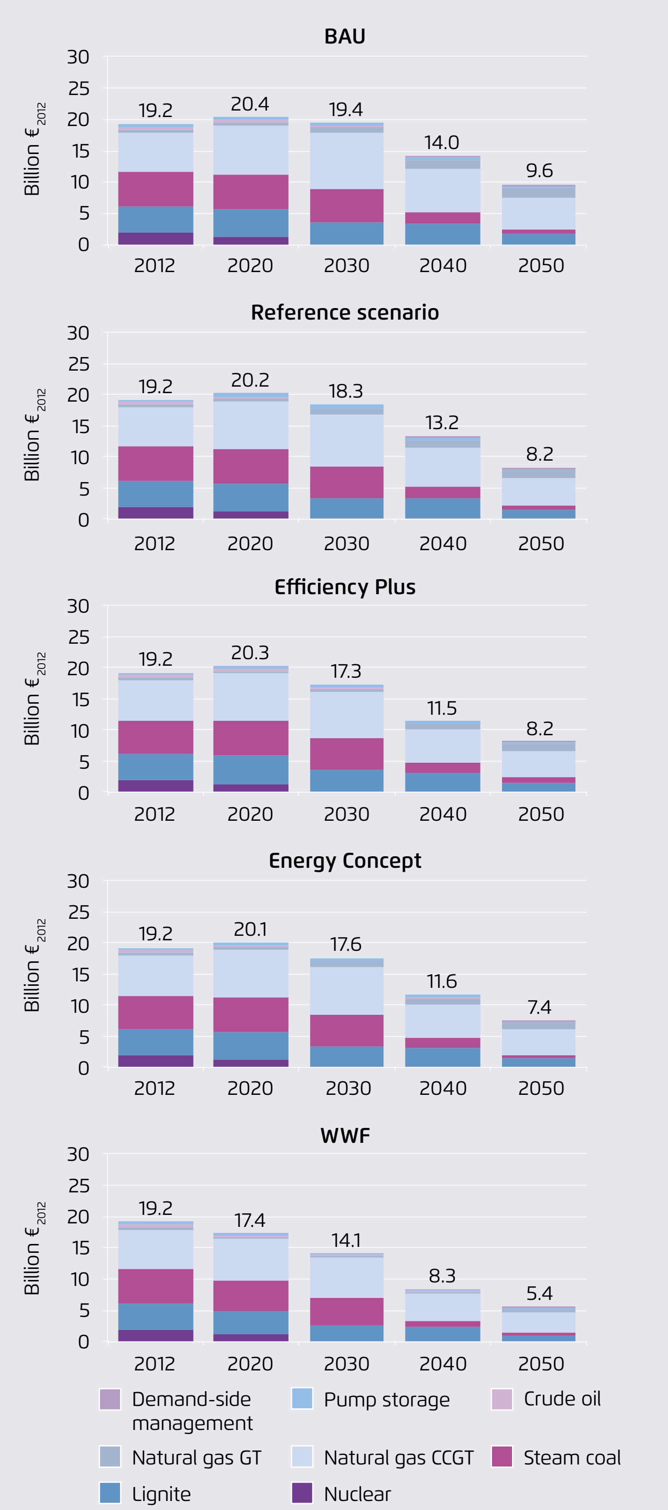
show a substantial reduction of these costs. According to the individual scenario they decrease to between 5.4 and 9.6 billion euros$_{2012}$ until 2050. Due to the future, larger share of gas-fired power stations as part of conventional generation and capacity reserve, gas-fired power stations also increase their share of total costs of the conventional power station fleet (see figure 3-3). As in all scenarios from 2020 onwards, all newly constructed power stations will be gas-fired, the related costs of capital show an even larger increase also in the long term.

Figure 3-4 presents full costs according to cost category. We can clearly see that costs of CO_2 emission certificates change in proportion to total costs. In 2012, costs of CO_2 emission certificates still amounted to 10 percent of total costs; however, later on they represent 30 percent due to the comparatively large increase of emission prices. Until 2050, investment and capital costs as part of total costs substantially decrease because of a changed power station capacity mix and the overall decreasing new investments.

Full costs of fossil-thermal electricity generation and storage according to energy carriers

Figure 3-3



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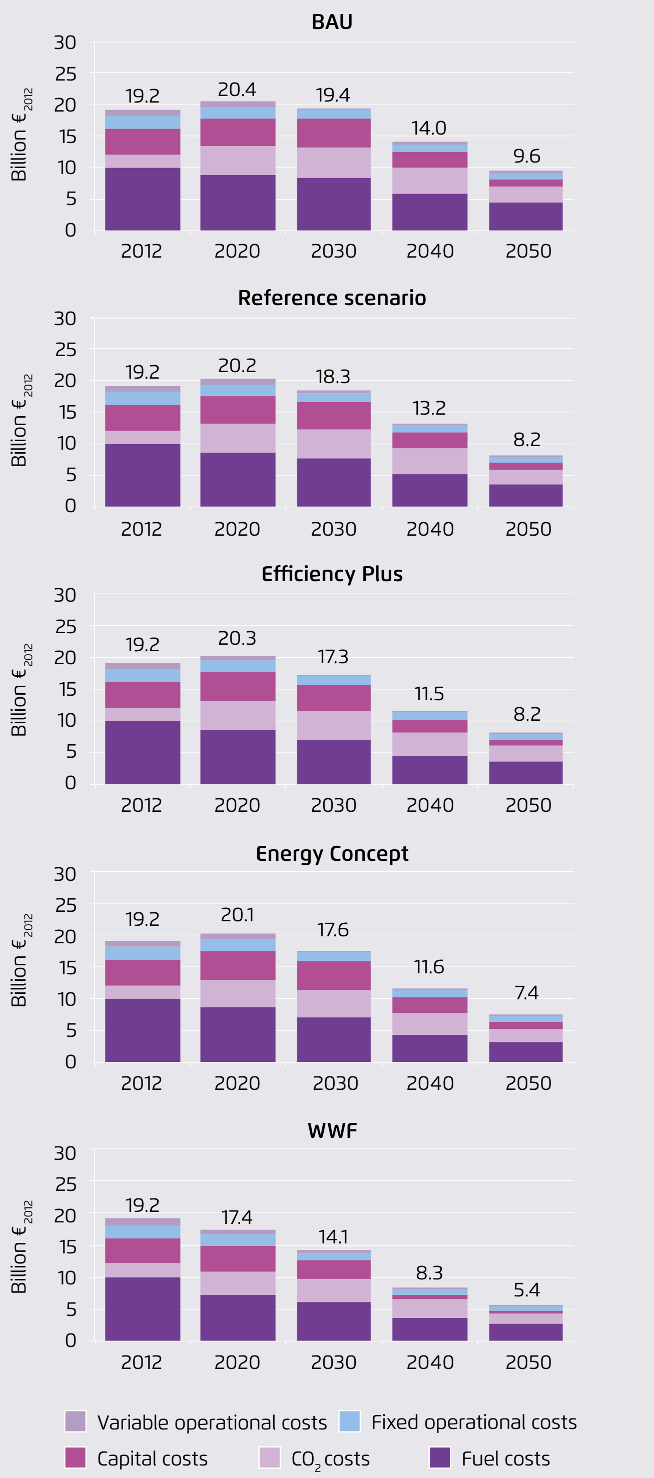
Full costs of fossil-thermal electricity generation according to cost category Figure 3-4



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3.2 Renewable electricity generation

In order to determine the cost of renewable electricity generation, we initially determined the generation required for supplying the electricity demand from renewables for the individual generation technologies. The goal was to arrive at a cost-minimized expansion of renewables. The cost evaluation will be mainly based on the specific full costs of electricity generation from renewables. Comparatively costly generation technologies, such as geothermal, will only be used after exhausting the potential of more cost-efficient technologies. This means that in the WWF scenario the required electricity generation from renewables will be ensured without using geothermal generation as the lower electricity demand in this scenario can be supplied in a more cost-efficient way by other generation technologies.

In addition, the development of the renewable power plant fleet will take into account technology-specific feed-in profiles as well as the controllability of plants. Here the goal was to avoid excess generation. Taking the example of photovoltaics, this means that – despite potentially decreasing full costs – in the long term its expansion path will be limited as the PV feed-in profile will otherwise lead to large temporary excess generation resulting in limited benefits from more PV generation plants despite low costs. The same approach was used for the other renewables.

As a third criterion – the technology's availability and the required surface area – determined the future renewable power station fleet. According to Prognos' assessment, particularly the expansion of onshore wind power will be the limited by the restricted availability of appropriate priority areas. Similar restrictions apply to the expansion of hydro power stations.

As opposed to other renewable generation technologies, electricity generation from biomass and biogas is independent of supply and can thus be controlled. Its expansion is however restricted by comparatively high full costs and the competing agricultural use of the areas.

Offshore wind power has comparatively high full costs in comparison to onshore wind power and open-space solar power. Due to a more constant feed-in profile in comparison to onshore wind power and the already existing infrastructure it can be assumed that offshore wind power will continue to expand despite high investment and maintenance costs and technical risks. In the medium term, the costs of offshore wind power will continue to decrease due to learning curve effects.

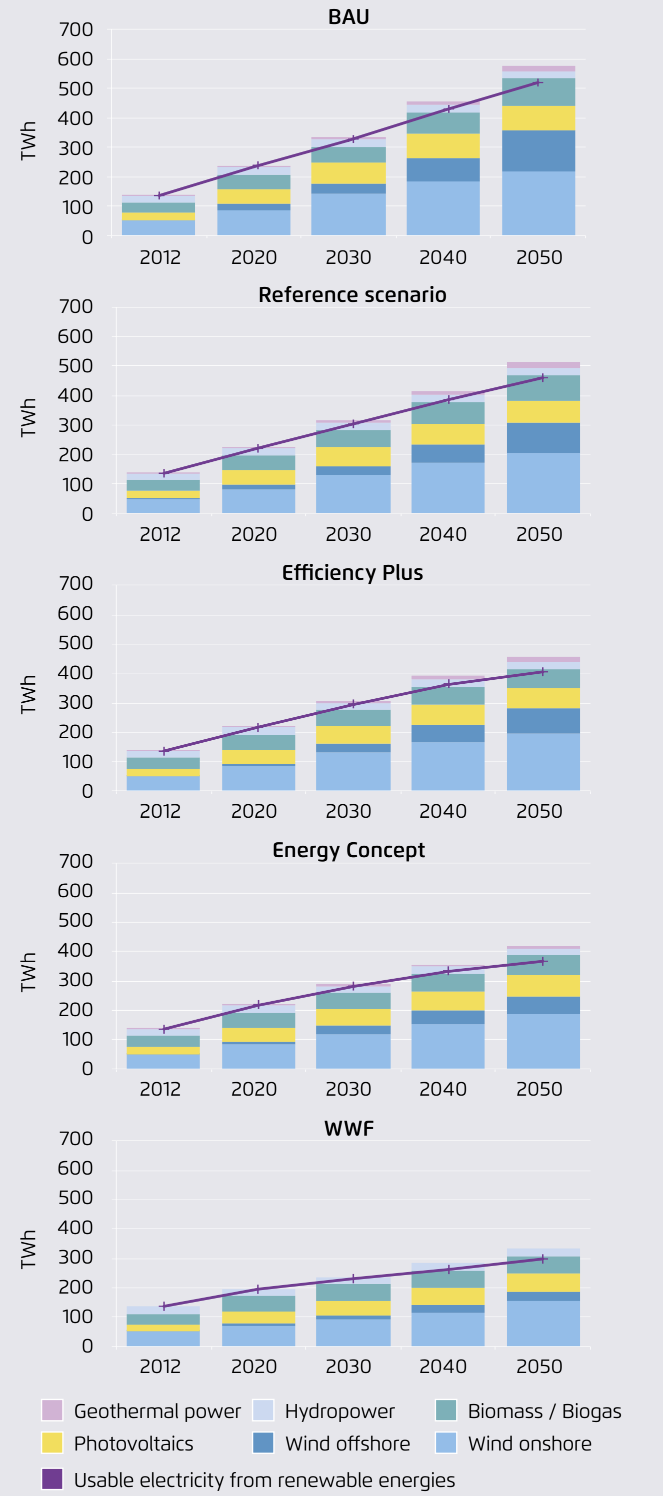
Figure 3-5 presents the assumed renewable generation structures for the scenarios, according to the share of electricity demand to be supplied by renewables.

Additionally we have to take into account that in the future, PV producers will increasingly utilise the self-generated electricity. If the amount of self-generated electricity exceeds the producer's demand of the producible PV electricity, generation can already be curtailed on site or used for other purposes. These electricity quantities are not included in figure 3-5 as they neither affect the grid nor constitute a traditional electricity application (e.g. power-to-heat).

As figure 3-5 shows the produced electricity quantities diverge clearly from the useable quantities in the medium and long term. For high solar radiation and high wind speeds, the electricity that can be produced from renewables may exceed the electricity demand. This excess electricity has to be curtailed unless it can be stored or exported to other countries.

In addition, the calculations carried out by Prognos assume that also in the future parts of system services, such as regulating power and reactive power compensation, will be provided by fossil-thermal power stations. The fossil-thermal minimum capacity – which is partially determined by how CHP plants are operated during so called must-run situations – substantially decreases until 2050 and thus – in the long term – also reduces the usable electricity generation from renewables. If it was possible to decrease fossil-thermal minimum capacity faster than assumed here renewables would not have to be curtailed to the same extent in times of high generation. As such situations also in the

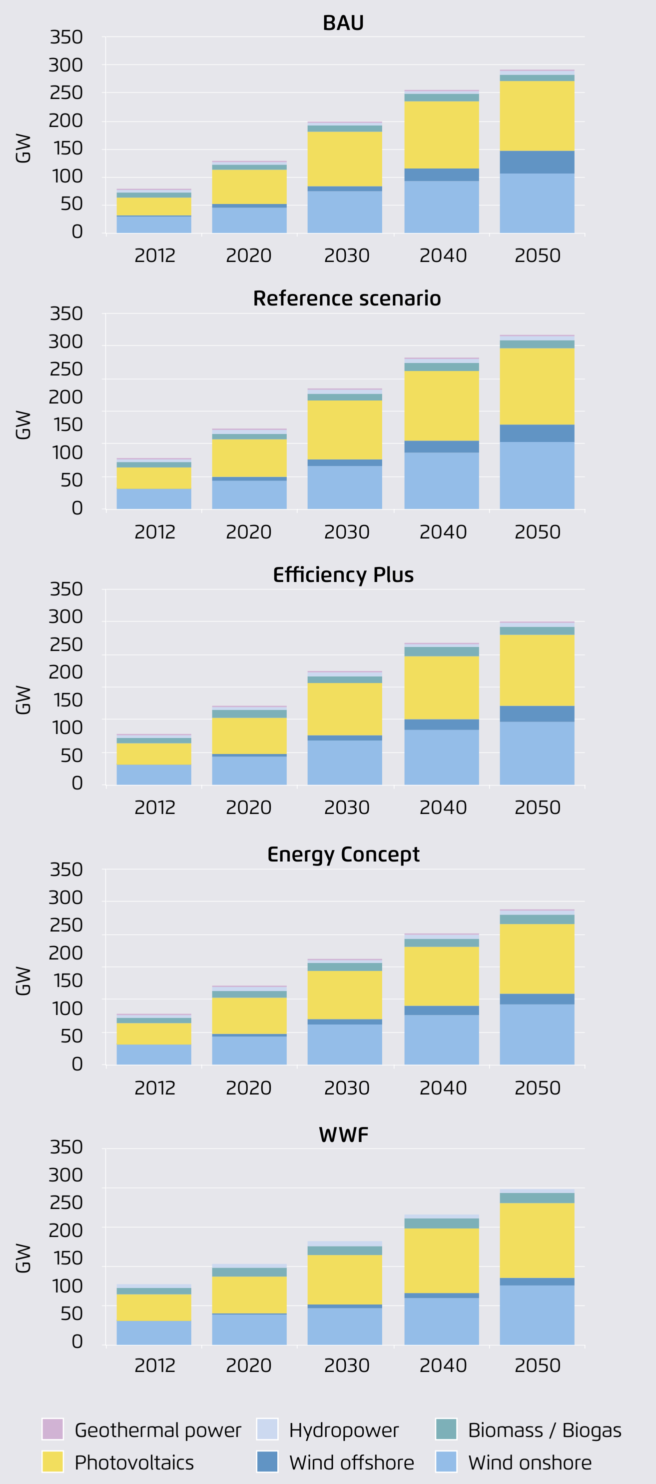
Development of the producible and useable amount of electricity from renewables — Figure 3-5



Prognos; BMU (2013): Time series of the cost development of the German Renewable Energy Act (EEG)

Development of the installed renewables capacity

Figure 3-6



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long term only will occur during few hours and as the curtailing potential of fossil-thermal minimum loads is limited to 5 GW, the effect on the results of this study would be comparatively small.

These two effects can be partially compensated by the long-term utilisation of demand-side management potentials. Prognos assumed for the following calculations that due to the use of additional storage capacity and a shift in demand until 2050 compared to today, the useable electricity generation from renewables increases by 5 GW for each hour.

Fossil-thermal minimum capacity

Table 3-2

	2012	2020	2030	2040	2050
All scenarios	19 GW	16 GW	12 GW	8 GW	5 GW

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In addition, there are further potentials for reducing excess generation due to cross-border electricity exchange. However, the effect of increasing cross-order trading capacities – such as assumed in the Germany-wide network development plan for electricity (Netzentwicklungsplan Strom) – were not included in our calculations as this study focusses on Germany.

Based on these framework assumptions, we calculated the levelized cost of energy (LCOE) of the individual renewable generation technologies. The levelized cost of energy always refers to the construction year of the plant and corresponds to the average costs over the lifetime of the respective generation plant. It is calculated as the sum of the present values of annual operating costs and capital expenditure, divided by the present value of the total electricity generation over the lifetime. The following calculation formula was used to determine the levelized cost of energy (LCOE):

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{el}}{(1+i)^t}}$$

LCOE	levelized cost of energy in euros/MWh
I_0	capital expenditure in euros
A_t	annual total costs in euros in year t
M_{el}	produced electricity in the corresponding year in MWh
i	weighted average cost of capital in %
n	economic operating lifetime
t	individual year of lifetime (1, 2, …n)

Investment costs include all costs that are incurred leading to the investment decision and during the construction phase. Operating costs contain staff and rental cost as well as maintenance costs, for instance. The annual electricity generation of the generation technologies wind power, hydro power and photovoltaics depend on supply, i.e. the meteorological conditions, as well as on the technical configuration of the plant. Especially, hub height and rotor diameter of onshore wind turbine generators can be expected to increase in the future. In addition, it can be assumed that generator capacity will not increase proportionally to rotor swept area. Consequently, the utilisation of the plant in relation to the generator capacity – or its full-load hours – will increase.

In this study, the real-term discount rate is determined using the weighted average cost of capital that produces the rate-of-return of debt and equity. The different weighted average costs of capital (WACCs) of the individual generation technologies result from the risk-related rate-of-return requirements and the financing structure. Here it applies that: The riskier an investment is the larger the required rate-of-return for the project.

The economic operating lifetime also depends on technology. As opposed to fossil-thermal plants that can usually reach an operating life of 40 to 50 years, the lifetime of renewable electricity generating plants is usually assumed to be 20 years. It should be noted though that the here presented values do not necessarily correspond to the real economic use of the plants. Similar to the remuneration stated in the German Renewable Energy Act (EEG), the levelized cost of energy (LCOE) of photovoltaics is calculated for 20 years. The plants can be expected to generally operate during 25 years, though. This larger lifetime will be included in our further considerations regarding electricity generation.

Table 3-3 presents the cost assumptions for determining the levelized cost of energy (LCOE). The assumptions are based on Prognos' assessments. In current discussions, we can also find diverging assumptions. For instance, the *Deutsches Institut für Wirtschaftsforschung* DIW (2013) assumes – similar to Agora/Consentec (2013) – that investment costs for renewable technologies are up to 20 percent lower. In order to evaluate the cost, we do not only have to look at the corresponding investment costs, but also at the structure and equipment of the power station fleet – such as whether costs are mainly related to plants at preferred sites or not. Therefore, a direct comparison of individual studies is of limited significance.

Assumptions regarding the calculation of total costs of renewable electricity generation — Table 3-3

		2015	2020	2030	2040	2050
Wind onshore						
Investment costs	$€_{2012}$/kW	1,560	1,490	1,388	1,362	1,325
WACC	in %	6	6	6	6	6
Operating costs	% of investment costs	4	4	4	4	4
Annual electricity generation	MWh/MW	2,150	2,200	2,300	2,450	2,600
Lifetime	Years	20	20	20	20	20
Wind offshore						
Investment costs	$€_{2012}$/kW	4,000	3,400	3,100	2,950	2,850
WACC	in %	7	7	7	7	7
Operating costs	% of investment costs	4	4	4	3	3
Annual electricity generation	MWh/MW	4,000	4,100	4,200	4,300	4,300
Lifetime	Years	20	20	20	20	20
Photovoltaics						
Investment costs	$€_{2012}$/kW	1,150	1,050	930	785	740
WACC	in %	5	5	5	5	5
Operating costs	% of investment costs	2	2	2	2	2
Annual electricity generation	MWh/MW	930	930	930	930	930
Lifetime	Years	20	20	20	20	20
Biomass / Biogas						
Investment costs	$€_{2012}$/kW	3,000	2,950	2,850	2,750	2,650
WACC	in %	7	7	7	7	7
Operating costs	% of investment costs	3	3	3	3	3
Annual electricity generation	MWh/MW	6,500	5,000	4,700	4,700	4,700
Lifetime	Years	20	20	20	20	20
Electrical efficiency	%	33	33	36	38	38
Fuel prices	$€_{2012}$/MWh	23	23	25	26	27

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The above presented assumptions result in the levelized cost of energy (LCOE) provided in table 3-4. For existing plants that are subsidized according to the German Renewable Energy Act (EEG), the feed-in tariffs that are paid over up to 20 years are included.

In general it can be assumed that the levelized cost of energy (LCOE) of renewable plants will continue to decrease over the next decades. A particularly large reduction can be discerned for photovoltaics plants. Only in the last two years, costs of crystalline modules have gone down by 50 percent. Also after 2030, we assume a continued cost degression. Large cost reduction potentials can also be expected for offshore wind power. Especially in the medium term, economies of scales and standardisation result in decreasing investment costs for simultaneously increasing full-

EEG feed-in tariffs for 2012 and levelized cost of energy (LCOE) – independent of curtailment Table 3-4

		2012 (1)	2020	2030	2040	2050
Photovoltaics (2)	ct_{2012}/kWh	18.0	10.6	9.4	7.9	7.4
Wind onshore	ct_{2012}/kWh	9.4 (1a) 5.5 (1b)	8.3	7.4	6.8	6.2
Wind offshore	ct_{2012}/kWh	19.0 (1a) 3.5 (1b)	10.5	9.2	8.4	7.9
Biomass / Biogas	ct_{2012}/kWh	16.0	14.3	14.9	15.0	15.0
Geothermal (3)	ct_{2012}/kWh	25.0	21.4	17.8	14.7	11.4
Hydro (4)	ct_{2012}/kWh	6.3	6.9	7.2	7.1	7.1

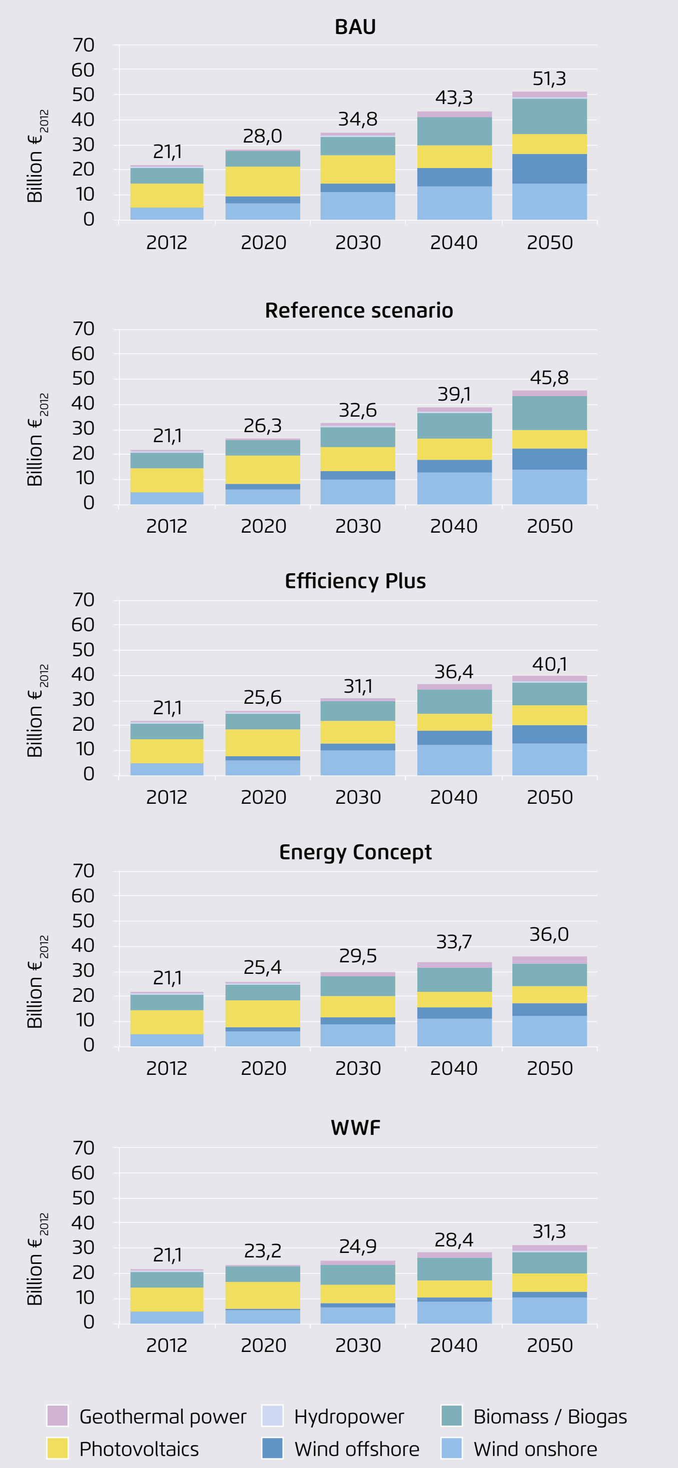
(1) Average feed-in tariffs according to EEG 2012
(1) Initial feed-in tariff according to EEG
(1b) Base tariff according to EEG
(2) Levelized cost of energy (LCOE): Weighted average of roof and open-space surface at a ratio of 9 to 1
(3) Related to enhanced geothermal systems without heat utilisation. Source: DLR/ BMU (2010): *Leitstudie* 2010 and EEG 2012
(4) Related to hydro power plants between 1 and 10 MW. Sources: DLR/ BMU (2010): *Leitstudie* 2010

EEG 2012 und Prognos

load hours. For onshore wind power, investment costs can be expected to decrease too. Together with a higher plant utilisation, this leads to a reduced levilized cost of energy. The cost degression potentials of electricity generation from bio-energies are significantly lower. Here, the levelized cost of energy (LCOE) is mainly affected by increasing fuel prices and by only slightly decreasing investment costs. For hydro power, the levelized cost of energy (LCOE) is even expected to increase due to the limited total potential and the ever decreasing plant size.

As the last step for determining the costs of electricity generation from renewables, we calculated the annual total costs of renewable electricity generation (full costs) using the producible electricity quantity and the specific levelized cost of energy. Figure 3-7 summarizes them.

All scenarios show a substantial increase of total costs of electricity generation from renewables. The opposite is the case in relation to the produced kilowatt hours. In order to arrive at the average levelized cost of energy of the plant fleet for individual years, we divided annual total costs (full costs) by the useable electricity generation from renewables. Figure 3-8 illustrates that the average levelized cost of energy (LCOE) of existing plants substantially decreases until 2035 and then remains comparatively stable. As the costs of renewable plants already have decreased during the last years and will continue to go down, new plants will result in a future decreasing mean LCOE. It is however remarkable that for all scenarios LCOE slightly increases between 2035 and 2040. This is due to this study's assumption of a diverging economic and technical lifetime of PV plants. Between 2030 and 2038, electricity generation is dominated by PV plants that are already depreciated and therefore contribute very low operating costs to total costs. In the period 2035 to 2043, these PV plants have to be replaced resulting in a higher cost of capital. The figure also shows that there are only minor differences between the individual scenarios. Even though the scenarios with higher electricity consumption include a larger amount of more costly technologies, Full costs of renewable electricity generation according to energy carrier — Figure 3-7



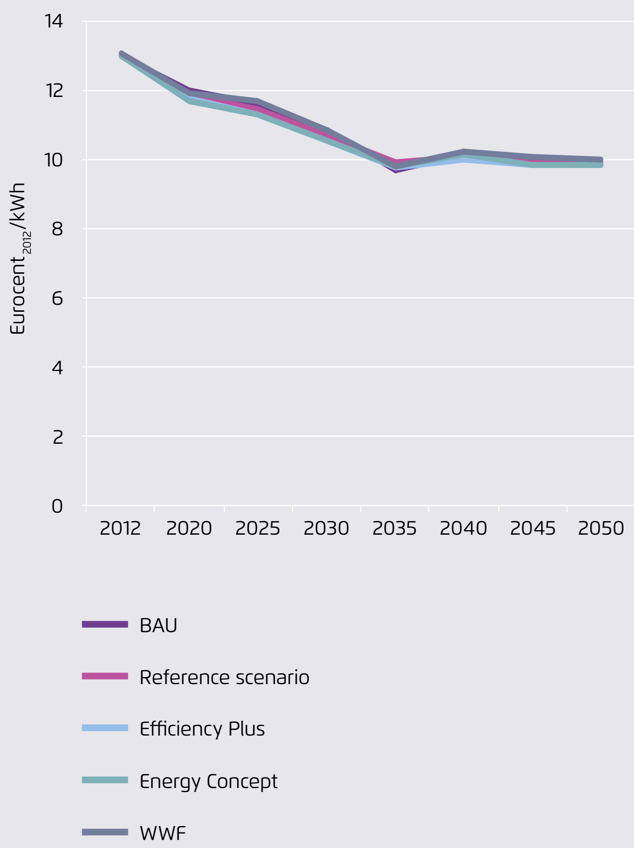
Prognos; BMU (2013): Time series of the cost development of the German Renewable Energy Act (EEG)

such as biomass and offshore wind, this is compensated by the feed-in profiles of these technologies which are better adjusted to the total system.

Offshore connection cost

The presented investment costs for offshore wind include the cost of the actual offshore wind farm and the wind farm transformer platform, but not the connection to the onshore electricity grid. Therefore, these "grid connection costs" have to be additionally included, even though they have to be stated separately from the levelized cost of energy (LCOE) according to German legal regulations. Discounting 25 per-

Average levelized cost of energy (LCOE) of renewable electricity generation (in relation to the electricity quantity that can be used in the electricity system) — Figure 3-8



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cent from the cost data presented in the 2013 German offshore grid development plan (*Offshore-Netzentwicklungsplan 2013 – Zweiter Entwurf O-NEP 2013*) – which experts have assessed to be too high –, grid connection and electricity transfer costs can be expected to amount to about an average of 1,600 euros$_{2012}$ per kilowatt hour of transmission capacity.[2] This discount is justified as connection costs – in line with the increasing experience of the offshore industry – are also expected to decrease accordingly in the long run.

According to IEAW calculations, it is not possible to use the entire electricity generation from offshore wind farms in the downstream electricity grid. Due to cost reasons, wind farms are therefore not connected with their full capacity, but only with the capacity that can be used by the system.

3.3 CO_2 emissions in the scenarios

All scenarios assume a uniform renewables proportion of total electricity generation. This means that the lower the electricity demand in the scenarios, the lower the required conventional generation. Taking into account the conventional electricity generation structure this results in different CO_2 emissions for the individual scenarios. The following table shows the CO_2 emissions that are directly linked to electricity generation (without upstream chain).

Over the entire period – as was to be expected – emissions are highest in the BAU scenario, due to its larger share of conventional electricity in comparison to the other scenarios. The lowest emissions result from low electricity demand in the WWF scenario. In 2030, in this case CO_2 emissions directly related to electricity generation are 22 percent or 35 million tonnes lower than those of the BAU scenario. In 2050, the difference is 37 percent or 19 million tonnes.

Direct CO_2 emissions of electricity generation in the scenarios — Table 3-5

	2012 in million t	2020 in million t	2030 in million t	2040 in million t	2050 in million t
BAU	315	215	156	101	51
Reference	315	212	153	96	43
Efficiency Plus	315	208	146	87	40
Energy Concept	315	206	141	84	38
WWF	315	174	121	72	32

Prognos

3.4 Import costs of primary energy carriers for electricity generation

The demand of primary energy carriers used for conventional electricity generation in Germany can only partially be supplied from sources within the country.

Nuclear energy use is identical for all scenarios; therefore there are no differences regarding used quantities and import costs between the individual scenarios. Lignite-fired power stations are currently – and also in the future – supplied exclusively from open-cast mining in Germany; this means, there are no import costs.

The demand of natural gas and coal is already today to a large extent supplied through imports. This share will continue to increase in the future, due to the agreed phasing-out of coal mine operations and decreasing natural gas exploitation in Germany. The use of fracking and a subsequent increased natural gas exploitation could change this situation; at this point however, it is not included because of the existing uncertainties and resistance.

The following table summarizes Germany's coal and natural gas exploitation until 2050.

2 Offshore-Netzentwicklungsplan 2013 (Zweiter Entwurf der Übertragungsnetzbetreiber); Szenario B 2033, p. 89 ff.; http://www.netzentwicklungsplan.de/ONEP_2013_2%20Entwurf_Teil%20I.pdf

Natural gas and coal exploitation in Germany — Table 3-6

	2008 in PJ	2020 in PJ	2030 in PJ	2040 in PJ	2050 in PJ
Natural gas	492	350	200	50	0
Coal	519	0	0	0	0

Prognos/EWI/GWS (2011)

From 2018 onwards, the total demand of coal for electricity generation has to be covered by imports. Regarding natural gas, exploitation within Germany will at least supply a small part of the demand until about 2040. For an expected total annual natural gas demand of 2,000 to 2,500 PJ in 2030 (Prognos/EWI/GWS), at least 90 percent of the demand have to be supplied by imports.

The higher the savings of coal and natural gas in the scenarios due to increased energy efficiency, the lower the required imports. Based on the energy prices (or therein included cross-border prices) presented in chapter 2.2.2, we arrive – for the individual scenarios – at the following costs for fuel imports that are used in electricity generation.

Import costs for natural gas and coal used for electricity generation — Table 3-7

	2020 in billion $€_{2012}$	2030 in billion $€_{2012}$	2040 in billion $€_{2012}$	2050 in billion $€_{2012}$
BAU	7.4	7.0	5.6	4.4
Reference	7.0	6.3	5.0	3.6
Efficiency Plus	6.3	5.4	4.3	3.4
Energy Concept	6.2	5.3	4.1	3.1
WWF	5.4	4.6	3.4	2.6

Prognos

Already in 2020, a very ambitious efficiency development (WWF scenario) can decrease the cost for importing coal and natural gas by 2 billion euros_{2012} as compared to the costs of 7.4 billion euros_{2012} in the BAU scenario. In the long term, savings slightly decrease to 1.8 billion euros_{2012} per annum.

3.5 Regionalising the data for grid modelling

The starting point for regionalising electricity demand and generation is the current IAEW model of the transmission grid with a total of almost 400 grid nodes.

In the following we will describe how both the hourly electricity demand and generation from conventional (or controllable renewable) power stations are allocated to these grid nodes.

The Prognos regional energy model and standard load profiles were used in order to derive the hourly electricity demand at county level (counties and independent cities). For each grid node, radiuses were determined in order to model the supply areas and assign them to the corresponding grid nodes. A computer algorithm was used and the radiuses were determined in a way that

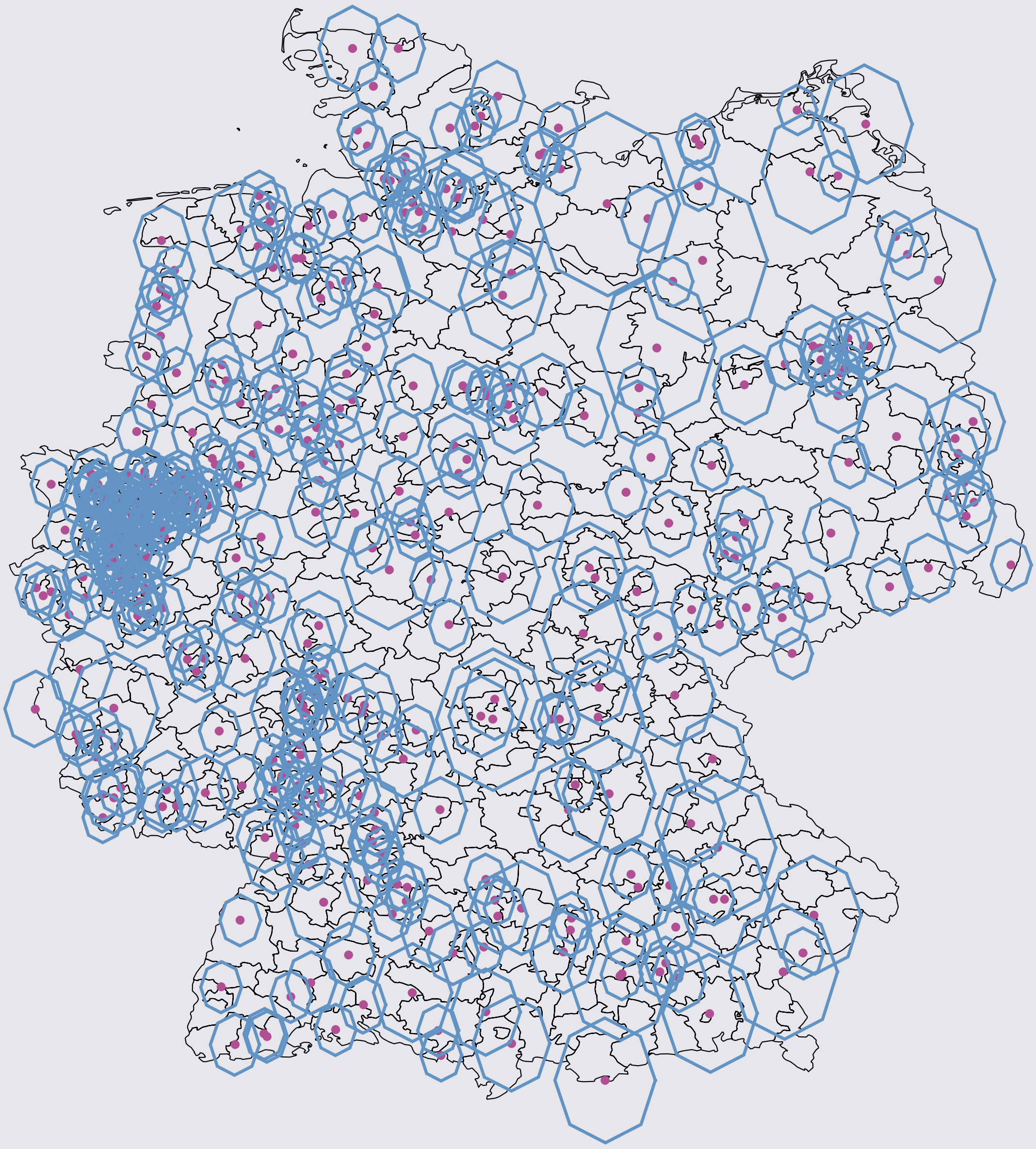
- → each county overlaps with at least one supply area,
- → supply areas are as small as possible, however
- → adjacent supply areas have a similar size.

In order to reduce computing time, supply areas were modelled as octagons and not as circles; the radiuses are interpreted as circumradiuses.

Figure 3-9 illustrates the result of this computation. The red dots represent grid nodes; the blue octagons represent supply areas.

In a second computation, for each county (counties or independent cities) the intersection with the supply areas of the grid nodes was determined. Now, the county's electricity demand was proportionally allocated to the intersections of the supply areas. When allocating the generation from conventional or controllable power stations to the grid nodes, we assumed the power stations to feed into the closest grid node.

Grid nodes and assigned supply areas | Figure 3-9



Prognos, map: German Federal Agency for Cartography and Geodesy (BKG)

4 Calculation of grid costs

4.1 Grid costs components

In Germany, the operation of electricity grids is regulated. Electricity grid operators raise grid tariffs that have to be paid by electricity consumers. The total grid costs to be paid by consumers correspond to the sum total of the grid tariffs charged by grid operators. Today these costs are not published as part of any official statistical information.

The Federal Network Agency (*Bundesnetzagentur*) however publishes in its monitoring reports average weighted grid tariffs for the sectors Households, Trades and Industries. Using the electricity consumption of these sectors, the 2012 grid costs can be estimated to amount to about 19 billion euros.

According to the monitoring report of *Bundesnetzagentur*, grid infrastructure costs account for about seven billion euros. Costs for balancing energy, losses, re-dispatch and provision of system services correspond to about one billion euros. Costs for billing, measuring and operating of measuring points amount to a further billion euros. In summary, grid costs of nine billion euros can be traced based on published data.

In comparison to the estimate of 19 billion euros of grid tariff revenues, there remains a difference of 10 billion euros. The exact amount and composition of this cost item cannot be determined based on the available information. Given an efficient incentive regulation, these costs can be expected to decrease in the future. However due to the rather intransparent data situation, the size of the corresponding savings potential cannot be estimated. A reliable forward projection and the corresponding forecast of total future grid costs is therefore not possible.

In the following, we only use the specifically named grid cost components for the forecast. For an interpretation of the results, it should be noted that the presented grid costs only comprise a part of total grid costs.

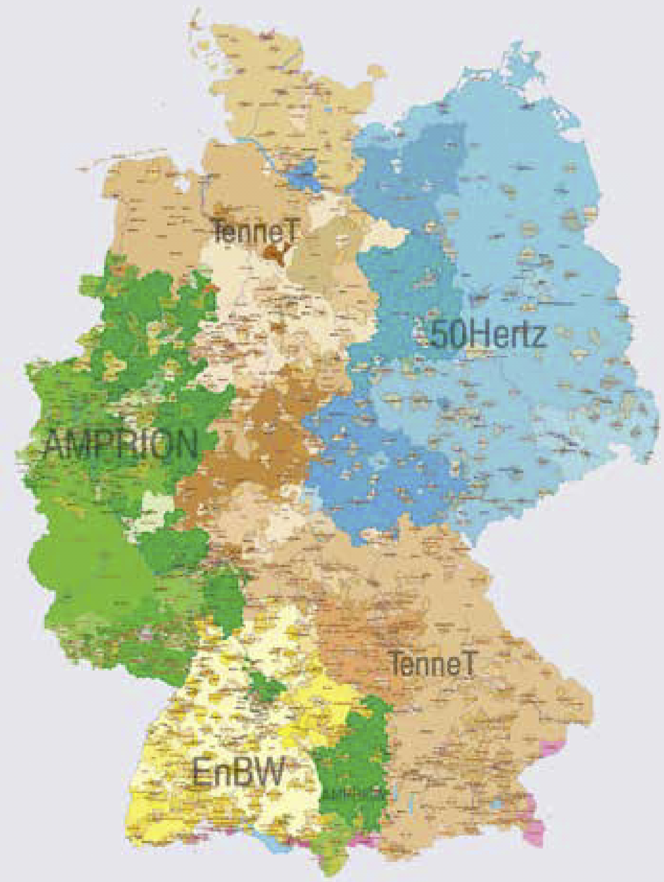
4.2 Grid-modelling approach

For an integrated analysis of the effects of energy efficiency measures in the German electricity sector, we have to include the costs for the necessary transmission and distribution grid infrastructure in addition to the costs of the generation system. The German transmission grid consists of highest-voltage grid (380/220 kV) operated by the four German transmission network operators. The distribution grid consists of many high- (110 kV), medium- (35/20/10 kV) and low-voltage (0.4 kV) grids that cover areas of different sizes, though in general the size increases with the voltage level. They are operated by more than 860 distribution network operators. Figure 4-1 shows the four control areas of the transmission network operators in different colours, with the corresponding operators of the downstream low-voltage grids being colour-shaded.

Due to the largely different quantities, we applied two different approaches for calculating the grid expansion requirements in the transmission and distribution grid. The diverging quantities can be illustrated by the lengths of the power lines. The transmission grid comprises power lines of an approximate length of 35,000 km. The total length of the power lines of all distribution grids amounts to over 1,000,000 km. Due to the manageable size of the German transmission grid, it is possible to use an explicit grid model including the lines and stations to calculate the expansion demand. For the distribution grid, this approach is not feasible due to the large number of different high-, medium- and low-voltage grids. Therefore, grid expansion requirements of the distribution grid were are determined using a model grid approach that has been proven in practice.

Due to the time-consuming modelling and required computing time it is not possible to calculate the grid expansion demand for each scenario and each selected year. Therefore, we will only look at the BAU scenario, the Efficiency Plus scenario and the WWF scenario as they represent the highest, medium and lowest energy consumption. The results thus constitute the enveloping algebra of the other scenarios. For each of these scenarios we will analyse the years 2035 and 2050.

Map of the German low-voltage grid operators — Figure 4-1



ene't (2013)

4.3 Transmission grid

4.3.1 Methodology

Figure 4-2 represents the methodology used for quantifying the expansion demand of the transmission grid and its expression in monetary terms.

Initially, the input data provided by Prognos – consisting of time series for load, generation from the conventional power station fleet as well as generation from renewables (RE) – was processed. Here, we determined at first the generation from renewable sources that – for energy balance reasons – cannot be integrated into the German electricity market and therefore has to be curtailed (see chapter 4.3.2). Then we regionalised the generation (see chapter 4.3.4) from photovoltaics (PV), onshore and offshore wind turbine generators to determine feed-in time series for the individual nodes – in order to be able to simulate the grid.

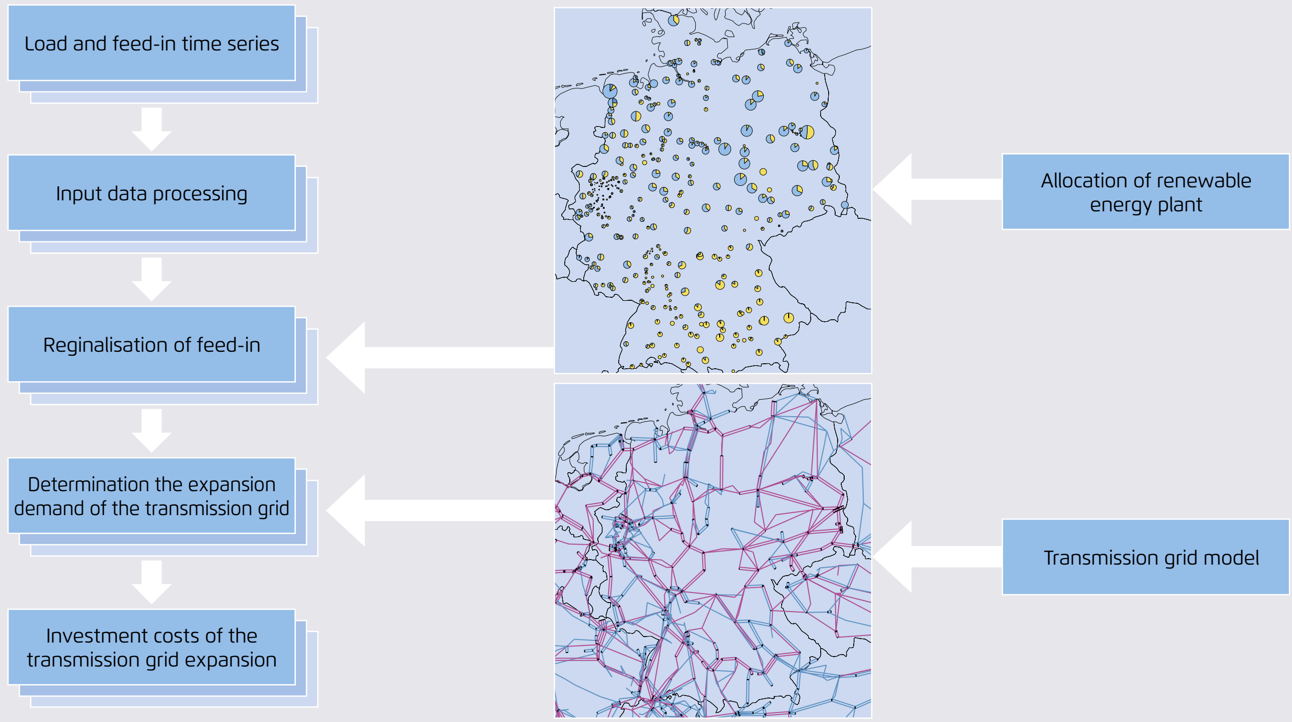
Based on the thus prepared input data, we used a transmission grid model – that was developed by IAEW and is based on public data – to determine the required transmission grid expansion (see chapter 4.3.3). As we included different scenarios we were able to quantify the impact of the efficiency measures on the annuity-based infrastructure costs of the transmission grid expansion. They comprise investment, maintenance and repair costs for the corresponding required grid expansion.

4.3.2 Processing the input data

As described in chapter 4.3.1, initially the generation and load input data provided by Prognos had to be processed. They consist of time series for RE generation, feed-in or withdrawal from the conventional power station fleet as well as of load time series. For ensuring a stable grid frequency, load and generation have to be balanced at all times. For energy balance reasons, this occasionally requires curtailment of RE generation. In reality, this curtailment is part of the market result; curtailment is for instance used if prices are threatened to become negative. During data processing, we determined the required amount of curtailment and correspondingly adapted the time series of RE generation.

Methodology for determining the costs of the transmission grid expansion

Figure 4-2



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Based on the installed capacity of the individual renewable technologies – photovoltaics (PV), onshore and offshore wind turbine generators – specified for the respective scenarios as well as onmeteorological time series, we determined for each simulated year feed-in time series taking into account the plants' characteristic curve. Subsequently, hourly load time series as well as feed-in or withdrawal from the conventional power station fleet were determined. Subtracting non-available RE generation and heat-controlled CHP generation from load, we arrived at the residual load that has to be supplied by the conventional generation fleet as well as through imports and exports. By neglecting imports and exports, the calculations assumed that the residual load is exclusively supplied by the German conventional power station fleet.

In the different scenarios, the large installed renewable generation capacities result in a negative residual load during some hours. This means that generation from PV, onshore and offshore wind turbine and other renewable generators exceeds the load and the available storage capacity. As the European markets are neglected and excess generation cannot be exported, in such situations curtailment has to be used in order to balance generation and load and thus maintain grid frequency. This means that for all hours with negative residual load, renewable generation was curtailed. The model represents this curtailment by reducing the generation time series for PV, onshore and offshore wind turbine generators, proportionally to the respective generation.

Amount of energy to be curtailed due to energy balance reasons

Figure 4-3

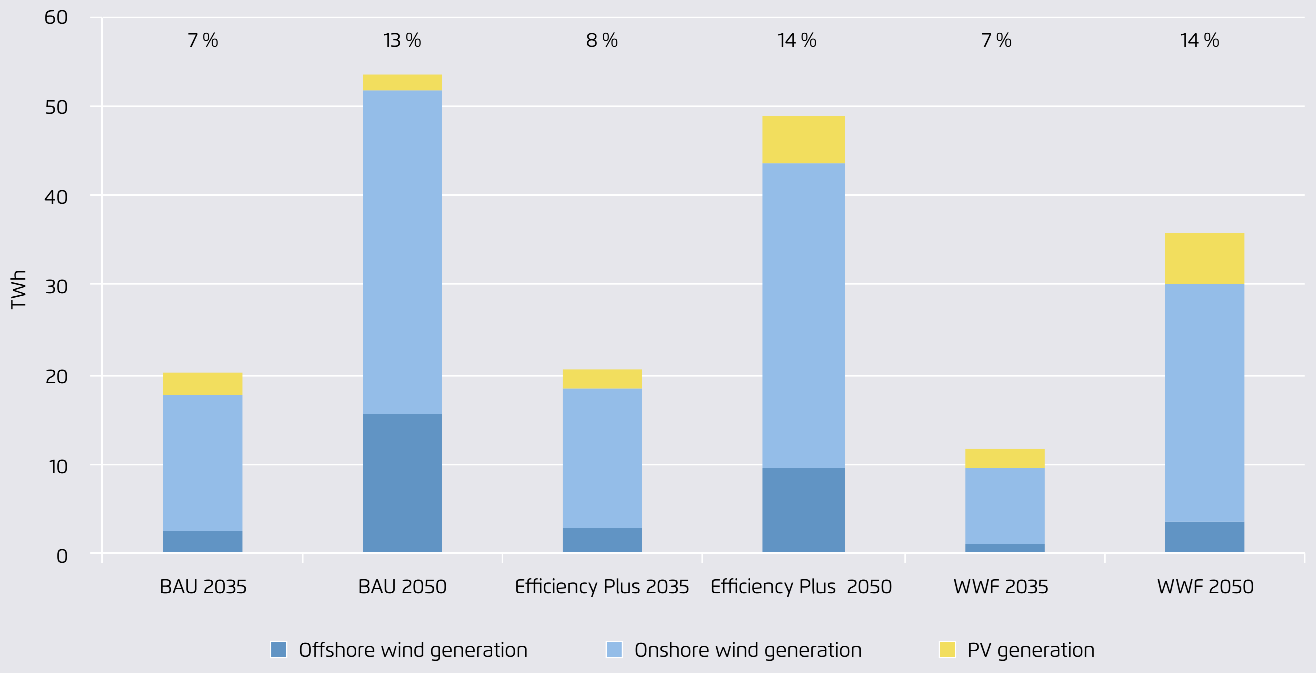

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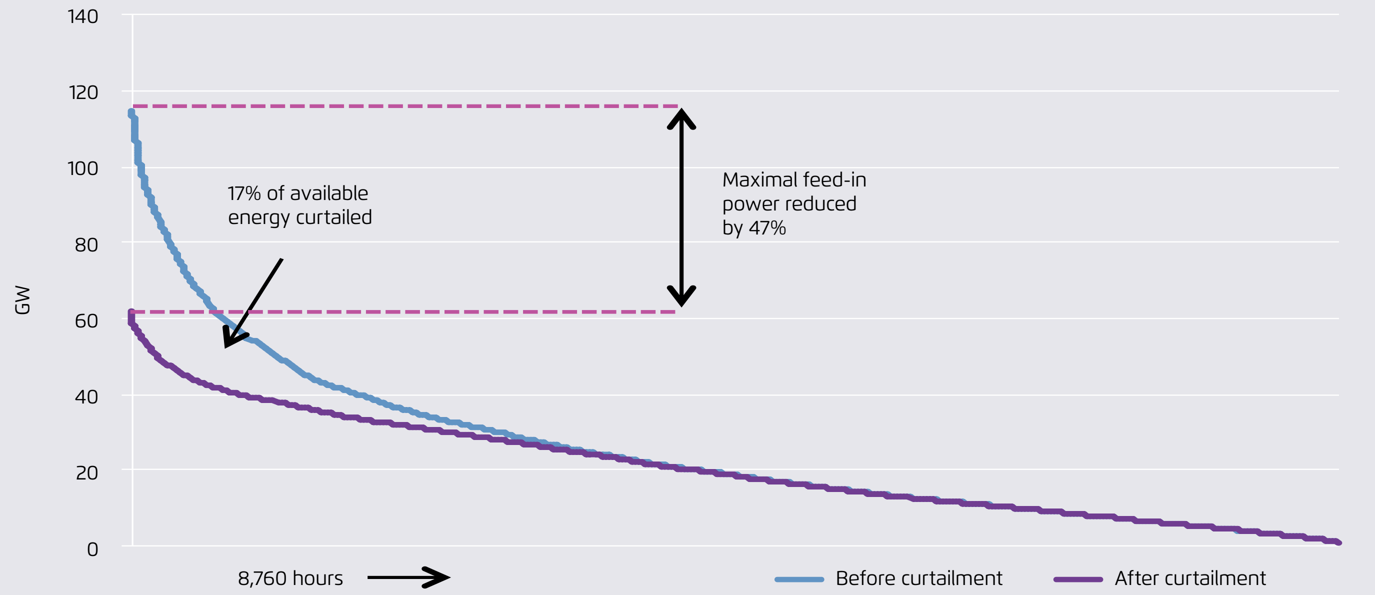
Figure 4-3 shows the amount of energy to be curtailed according to generation technology. In addition, it provides the percentage of energy to be curtailed as part of the total supply of RE generation. We can see that the curtailed percentage of RE generation particularly in 2050 is rather substantial with 14 percent. Curtailment does not only affect the energy fed into the electricity system, but also the maximum feed-in capacity that in return has a large impact on the required grid expansion.

In order to illustrate this relationship, figure 4-4 shows the annual load duration curve of generation from onshore wind turbine generators before (turquoise) and after (purple) simulated curtailment in scenario BAU 2050. The area between both curves corresponds to the energy to be curtailed which in this case amounts to about 17 percent of supply. This way curtailment drastically reduces the maximum feed-in capacity. Prior to curtailment the maximum feed-in capacity is about 114 GW, whereas after curtailment – to the maximum feed-in capacity that can be actually absorbed by the electricity market – maximum feed-in capacity only amounts to 61 GW. This corresponds to a reduction of almost 50 percent and has a large impact on the required grid expansion. As particularly the renewable feed-in capacity has a significant effect on grid expansion demand, we should therefore not look at the capacity defined in the scenarios, but rather at maximum feed-in capacity after such a curtailment.

Figure 4-5 represents this capacity for the individual scenarios before and after curtailment according to technologies. Particularly in the scenario BAU 2050, maximum feed-in capacity is reduced by 40 percent as generation has to be curtailed due to energy balance requirements.

Annual load duration curve of generation from onshore wind turbine generators before and after simulated curtailment in scenario BAU 2050 — Figure 4-4



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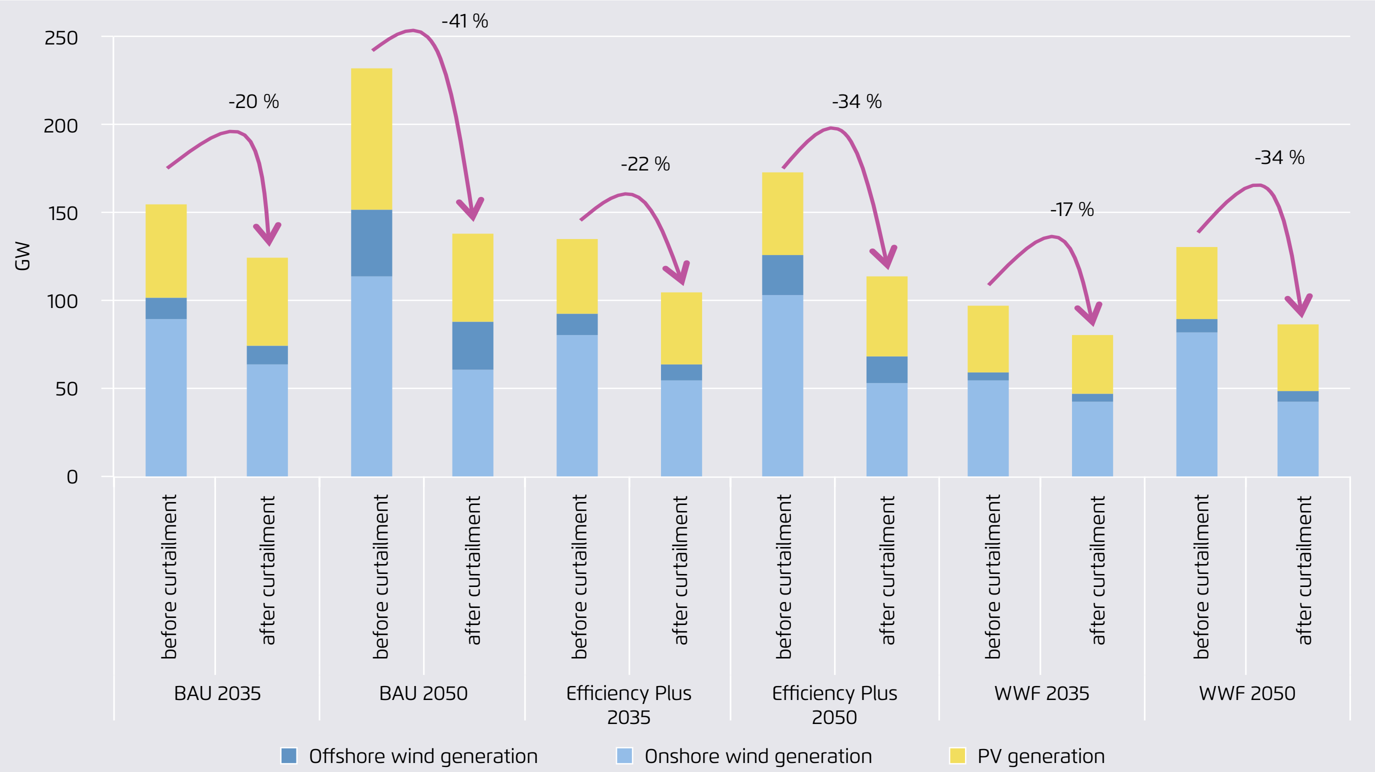
Maximum renewable feed-in capacity from RE plants before and after curtailment — Figure 4-5



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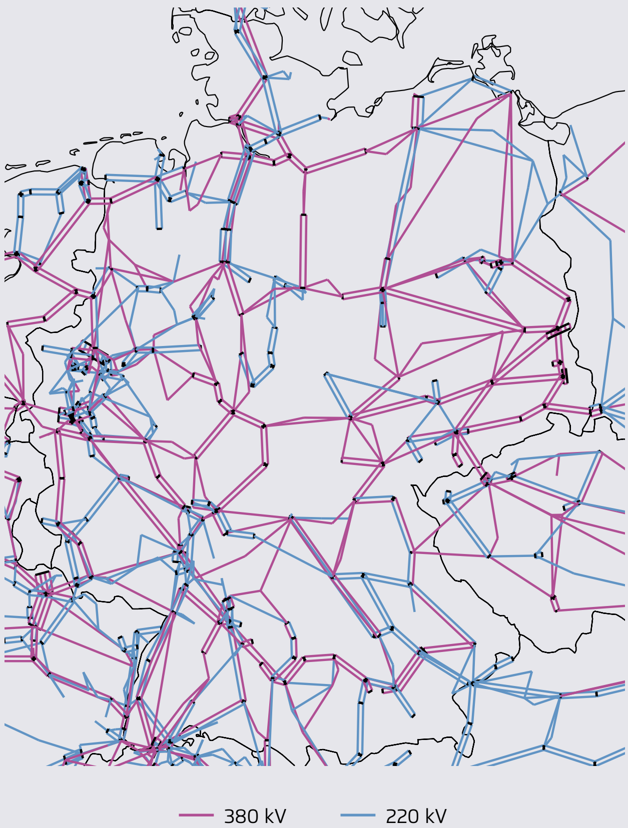
Including other European markets would substantially reduce curtailment due to energy balance requirements. Via coupling lines in the transmission grid, it is possible to export or import electricity to or from neighbouring countries. Taking into account technical safety margins, it is possible to determine the net transfer capacity (NTC) for such imports and export from the transmission capacity of the coupling line (ENTSO-E, 2001). In 2011, the German maximum net transfer capacity for exports on a winter weekday was more than 14,000 MW (ENTSO-E, 2013). The planned construction of further coupling lines (ENTSO-E, 2012) is assumed to result in an increase of these capacities. It should be noted though that the amount of energy that can be exported does not only depend on the net transfer capacity, but to a large extent also on the future generation system of the individual neighbouring countries. If there was a simultaneous large expansion of the installed renewable capacity, excess generation would coincide with other countries' excess capacity and could not be exported. However it should be assumed that including neighbouring countries in general results in a significant reduction of renewables curtailment due to energy balance requirements and thus also in an additional increase of grid expansion demand.

4.3.3 Transmission grid model

A dedicated transmission grid model was used to quantify the required expansion in the transmission grid. The model was developed by IAEW and is exclusively based on public data (Hermes et al., 2009). It is used as the basis for load-flow simulations in the European transmission grid. Within in the framework of this study, other European countries were represented in a simplified way due to the sole focus on Germany. In order to avoid externalising the grid expansion demand, we did not use any equivalent network modelling – that takes into account the behaviour of neighbouring networks – and only analysed the German transmission grid without connections abroad. The required grid expansion was thus determined using the assumption that the German network cannot unload loop flows to neighbouring countries or vice versa.

The transmission grid model (including neighbouring countries in this figure) presented in figure 4-6 comprises lines at the 220 kV and 380 kV voltage level, step-up and step-down transformers between these two voltage levels as well as phase-shifting transformers. The model for Germany comprised a total of about 390 stations and about 600 line corridors. If possible, the parametrisation of assets was based on published real data or common standard average operating data. Expert knowledge only available to grid operators, such as special switching statuses, was not included in the grid model. The representations of loads and feed-in capacities were aggregated at the corresponding stations. The regionalisation of the input data that was required for this purpose is described in chapter 4.3.4.

Transmission grid model Germany (including neighbouring countries) Figure 4-6



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Even though the grid model is only an approximation based on public data, it is sufficiently exact for general load-flow calculations. This was repeatedly proven in the past by comparison with reference load flows published by transmission grid operators.

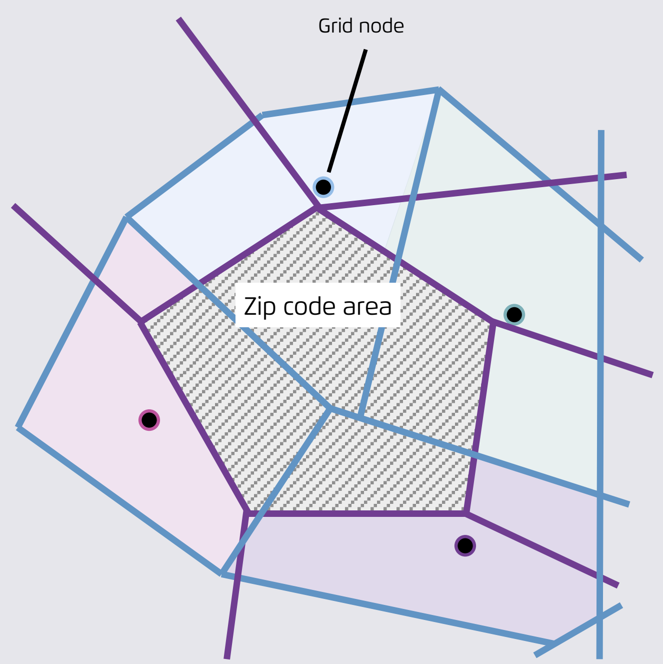
4.3.4 Regionalising generation

In order to use the transmission grid model described in chapter 4.3.3, we needed to allocate load and generation to individual nodes, which is also called regionalisation. The regionalisation and allocation of load and conventional generation to nodes was carried out by Prognos. Aggregated feed-in time series were used for allocating RE generation to individual nodes.

At first real data was used to carry out a regionalisation for the year 2012. For regionalising PV generation we used the current EEG-Anlagen-Register (renewable plants register; *EEG-Anlagenstammdaten* 2013), and for regionalising generation from onshore wind turbine generators, we used the commercial data base Windpower.net (The Windpower, 2013). In addition to the plant's installed capacity, the *EEG-Anlagen-Register* contains the address of the corresponding plant location. The zip code areas were used to assign the plant to the stations of the transmission grid. Here as a first step we used a mathematical procedure to assign each transmission grid node – in the following grid node – to a supply area. Then, the zip code areas were assigned to the supply areas – in proportion to the relative area intersection – and thus to the grid nodes (Dierkes et al. 2013). Figure 4-7 provides an exemplary illustration and is not true to scale. By aggregating the corresponding proportional capacity, we were able to determine the installed capacity of the PV plants per grid node.

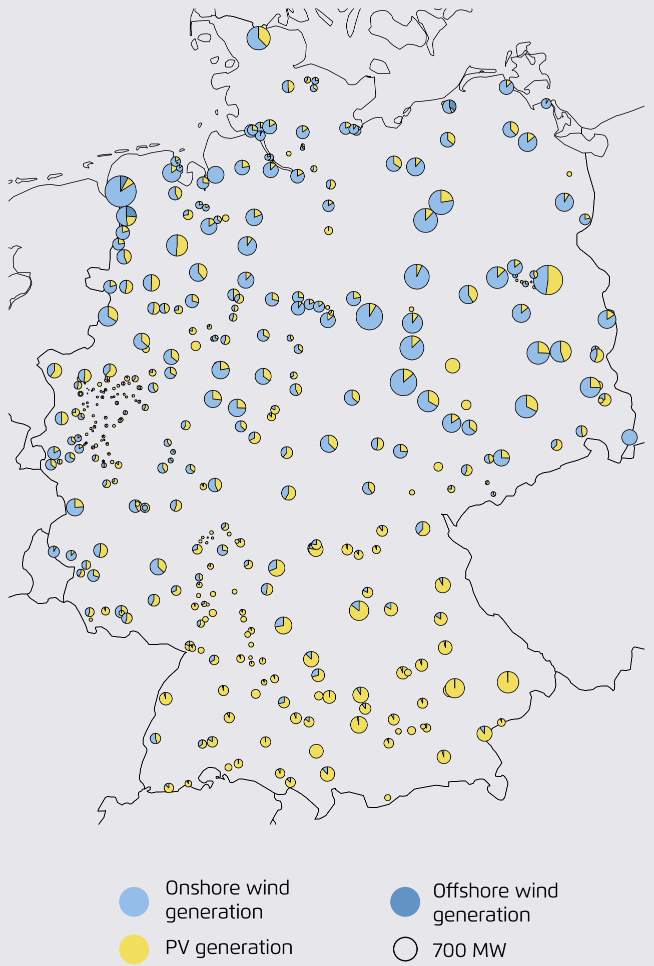
The data base Windpower.net was used to regionalise the generation from onshore wind turbine generators. It comprises comprehensive data sets of the European wind turbine generators including installed capacity and coordinates. The coordinates are used to assign the plants to their closest grid nodes. Generation from offshore wind turbine generators is assigned to the actual landing points (Offshore-*Netzentwicklungsplan* 2013). Figure 4-8 presents the resulting distribution of PV and wind power generation. It shows that wind turbine generators are mainly concentrated in Northern and Middle Germany and PV plants in Southern and Eastern Germany.

Assigning supply areas using Voronoi decomposition — Figure 4-7



Dierkes et al. (2013)

Allocation of RE plants in 2012 Figure 4-8



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Taking the 2012 values as the starting point, regionalisation was carried out for the years 2035 and 2050. The Offshore-*Netzentwicklungsplan* including installed capacities at the respective landing points (Offshore-*Netzentwicklungsplan* 2013) was used to allocate offshore wind turbine generators. A regionalisation of the generation from onshore wind power and PV plants based on 2012 allocations resulted in a substantial distortion of future distributions as – diverging from the historical distribution – PV plants can be expected to be increasingly installed also in Northern Germany as well as wind turbine generators in Southern Germany. Therefore we have used the *Netzentwicklungsplan Szenario* B2033 (*Netzentwicklungsplan* 2013) with its allocation to individual Federal States in order to scale the installed capacity per Federal State. Subsequently, an allocation to grid nodes was carried out.

Figure 4-9 illustrates the scaling. In the Federal State of Bavaria we can see a substantially larger relative increase of the installed capacity of wind turbine generators (259 percent) in comparison to the installed PV capacity (70 percent). Similarly we can see for Northern Germany a stronger increase of the installed PV capacity. The here presented increase only applies to the regionalisation. The absolute capacity assigned to the grid nodes depends on the individual scenarios and corresponds to the maximum feed-in capacity after curtailment presented in chapter 4.3.2.

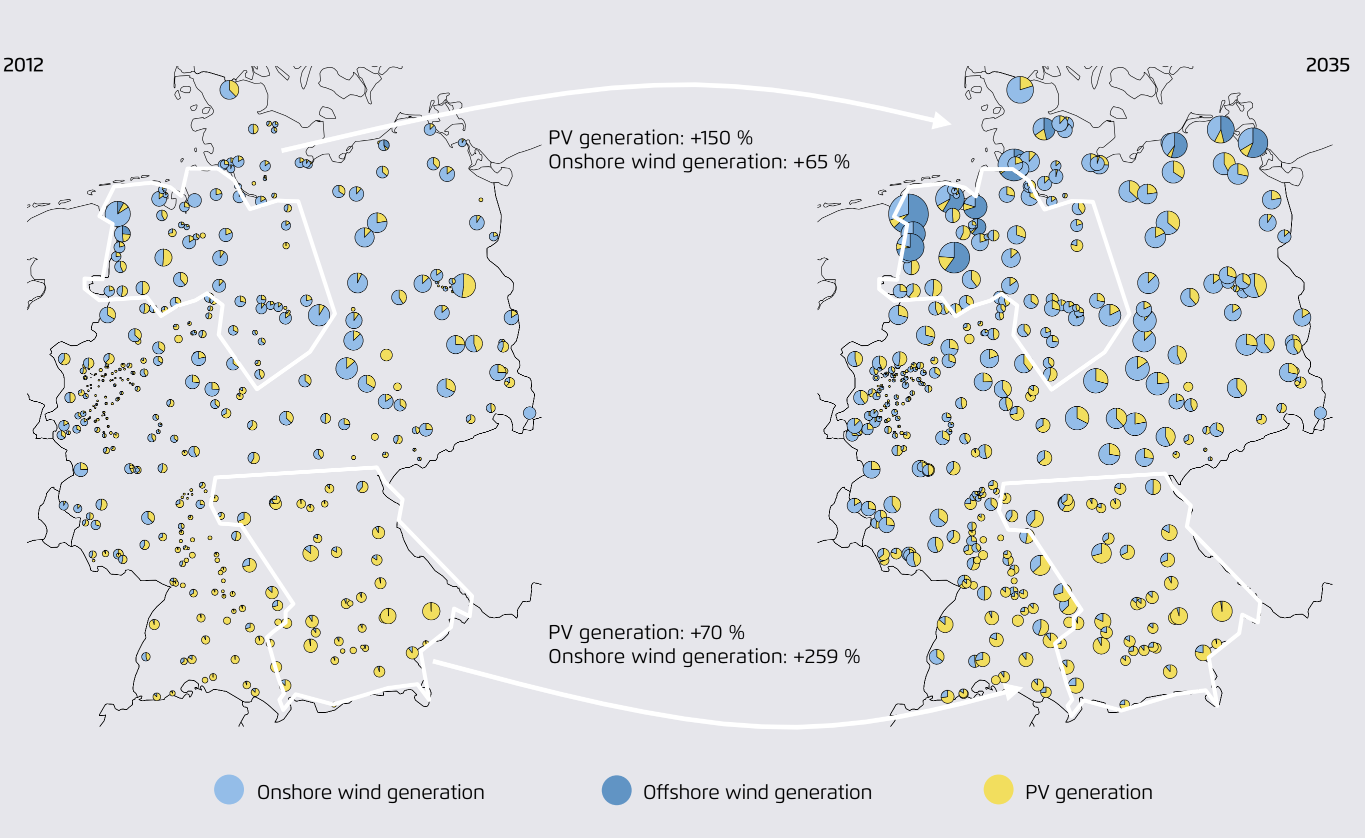
4.3.5 Methodology for determining the expansion demand of the transmission grid

Today's transmission grid is not up to the transfer tasks in the considered future scenarios. This means that a grid expansion is necessary and will make the total economic system more efficient in most cases. In this study the demand was determined using an approach that identifies additional lines. This chapter describes the approach in more detail.

Grid expansion aims at maintaining the security of supply. There are several technical prerequisites that need to be taken into account. These include, among others, thermal limiting currents, voltage limits, short-circuit current limits and voltage stability limits. Regarding the latter, we have to distinguish between stationary and transient stability. As opposed to other publications – such as the Netzentwicklungsplan – this study exclusively focussed on the criterion of maintaining thermal limiting currents. The thermal limiting current has not only to be maintained for base load, but also in case of failure of any equipment ((n-1) case) in order to prevent cascading faults.

Figure 4-10 shows a schematic representation of the approach for determining the expansion demand in the transmission grid. Based on the transmission grid model presented in chapter 4.3.3 and the hourly regionalised load and feed-in time series, we carried out an hourly (n-1) contin-

Changes in allocation of RE plants until 2035 based on own data and on *Netzentwicklungsplan* Figure 4-9



IAEW; *Netzentwicklungsplan* 2013

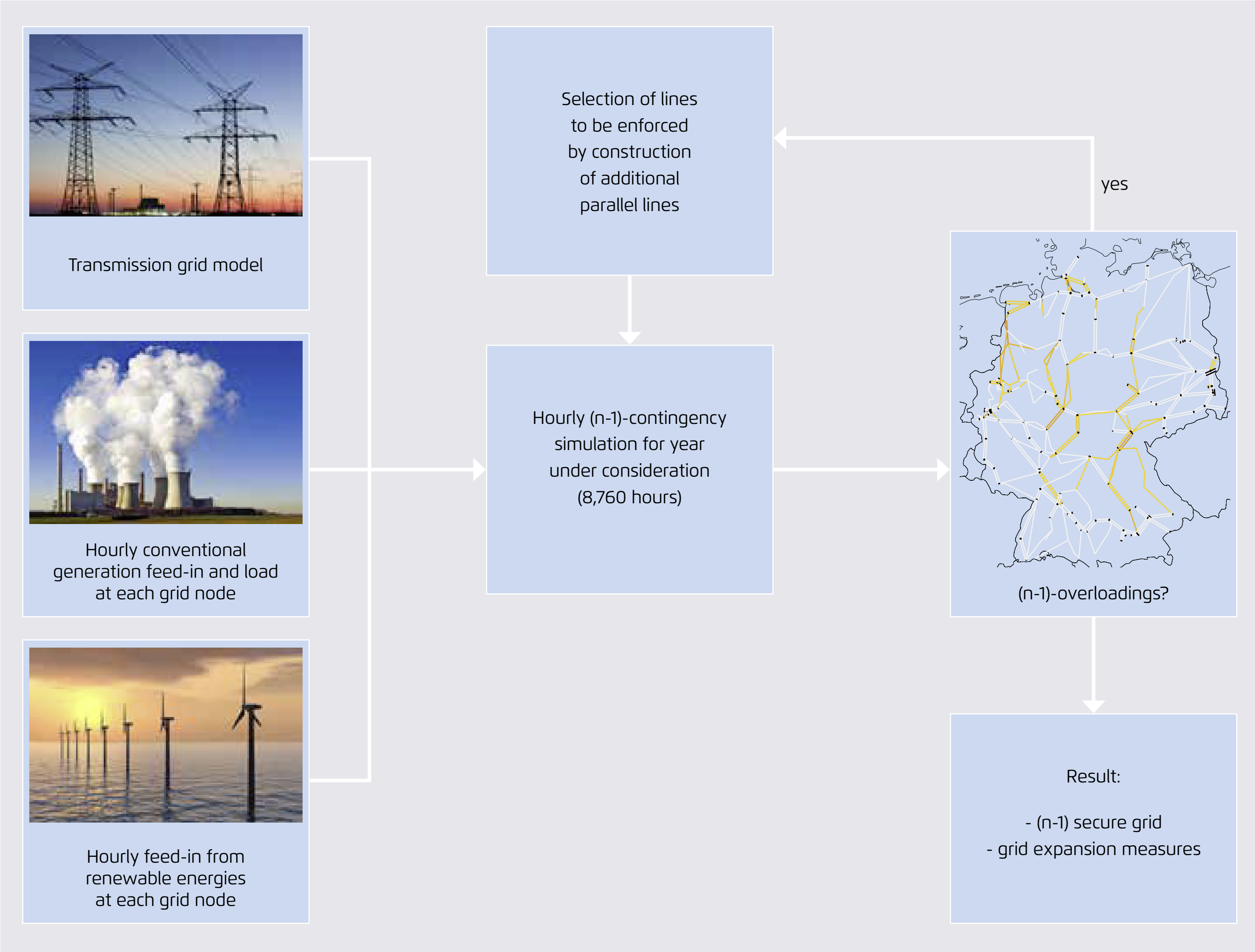
gency simulation. Here we simulated for each hour of the year the effects of a fault in each line and determined for each line the current following a fault in another line. In a (n-1) secure network this neither violates base load flow nor – following the fault in another line – the line's corresponding thermal limiting current.

Figure 4-11 shows the example of a non-(n-1)secure grid. The colour of the lines does therefore not provide any information regarding the absolute value of the line overloading, but visualises during how many hours per year the corresponding line is overloaded in the base load flow or after the fault of another line.

For estimating grid expansion costs this study always assumed line construction parallel to existing corridors. Therefore, the calculations do not include costs for opening up new routes. The construction of HVDC transmission was not included either. However, some of the lines that are already under construction, such as the South-West Coupling Line, were taken into account for the expansion. For determining the required expansion, new circuits were added iteratively until reaching an (n-1) secure grid status and until there was no more overloading ("copper plate approach").

The goal of the calculation was to arrive at a cost-efficient grid expansion without bottlenecks in each relevant case of grid application using the allowed degrees of freedom. The selection of new parallel lines was based on a cost-benefit ratio where the reduction of bottlenecks was a measure of the benefit and line length a measure of costs. The termination condition of this iterative addition of lines was a (n-1) secure grid status. This means that there was no overloading for any grid use case.

Methodology for determining the grid expansion demand of the transmission grid — Figure 4-10



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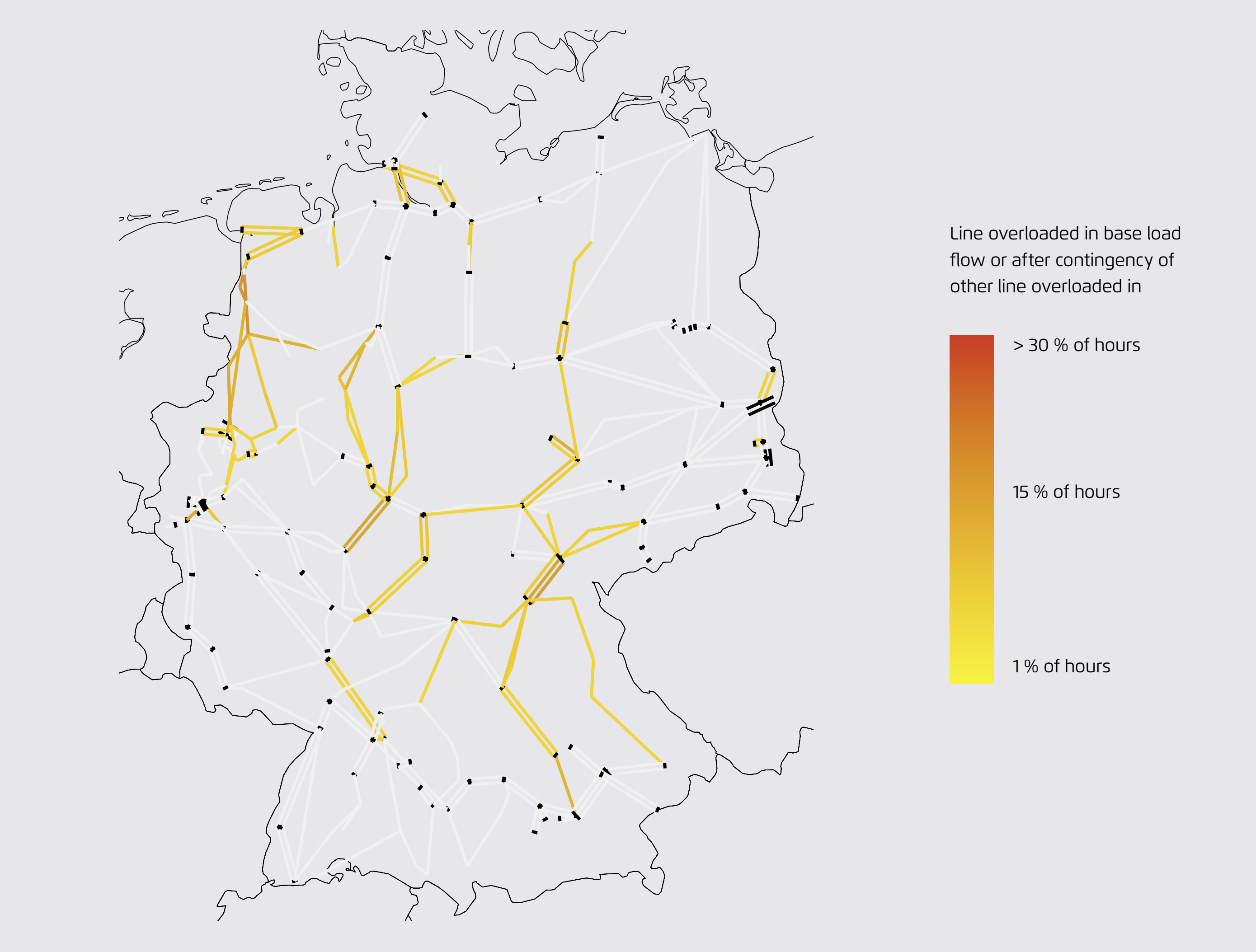
This copperplate approach for the expansion of the transmission grid does not take into account operational measures for increasing transfer capacity, such as overhead line monitoring (Ringelband 2011), a short-term allowable increase of current load in the lines due to their thermal inertia and switching operations. This operational measures can reduce the grid expansion demand. They require, however, specialist knowledge as well as experience on part of the respective transmission grid operator. Therefore this study used a simplified estimate ("adjusted approach"). We applied a softer (n-1) criterion as we allowed an overloading of lines for a maximum of 2 percent of annual hours and a maximum utilisation of 130 percent in order to take into account the above describes additional degrees of freedom. In addition, the adjusted methodology included that overloaded 220 kV lines with a length exceeding 50 kilometres can be upgraded to 380 kV. An upgrading of 220 kV lines shorter than 50 kilometres was not considered in the calculation of the required grid expansion.

Chapter 4.3.6 represents the differences between the derived grid expansion demand of the copperplate approach and the adjusted approach.

Part of an exemplary result of a (n-1) fault simulation (only 380 kV lines) Figure 4-11



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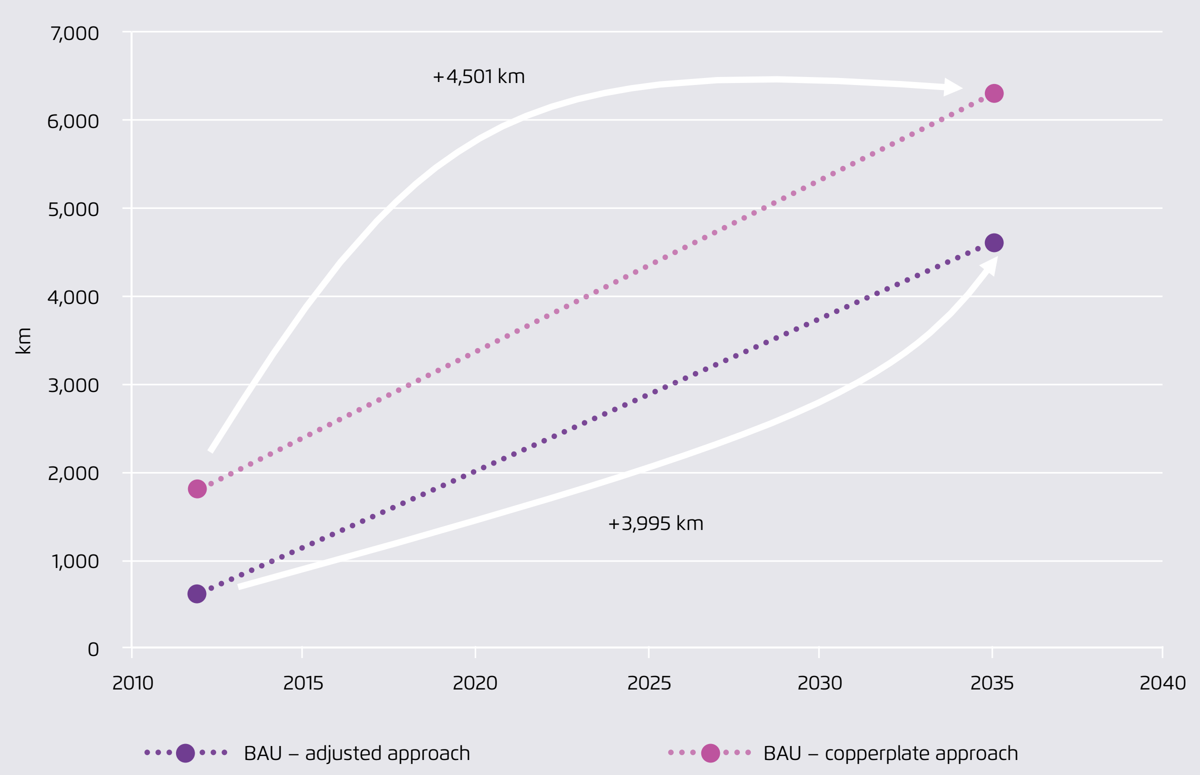
4.3.6 Results of the transmission grid expansion

Due to neglecting other European countries (see chapter 4.3.3), we had to initially determine the grid expansion demand for the year 2012 using the base scenario prepared by Prognos. Already there, the grid has to be expanded in order to maintain an (n-1) secure grid. This expansion demand results, among others, from the situation that already today an (n-1) secure grid state can – partially – only be reached because transmission grid operators interfere with power station use (re-dispatch); it is also due to the fact that we only considered the German transmission grid.

Figure 4-12 represents the difference of the approaches – presented in chapter 4.3.5 – for determining grid expansion demand for the years 2012 and 2035 in the BAU scenario. It becomes obvious that the copperplate approach – using only the construction of new lines to maintain an (n-1) secure grid – arrives at an almost 40 percent higher expansion demand than the adjusted approach that allows – for a simplified modelling of operational measures for increasing transfer capacity – the overloading of a line in base load flow or after a fault of another line during a maximum of 2 percent of the hours. The results presented in the following are all determined based on the adjusted approach and thus show

Development of the grid expansion demand in order to ensure an (n-1) secure grid — Figure 4-12



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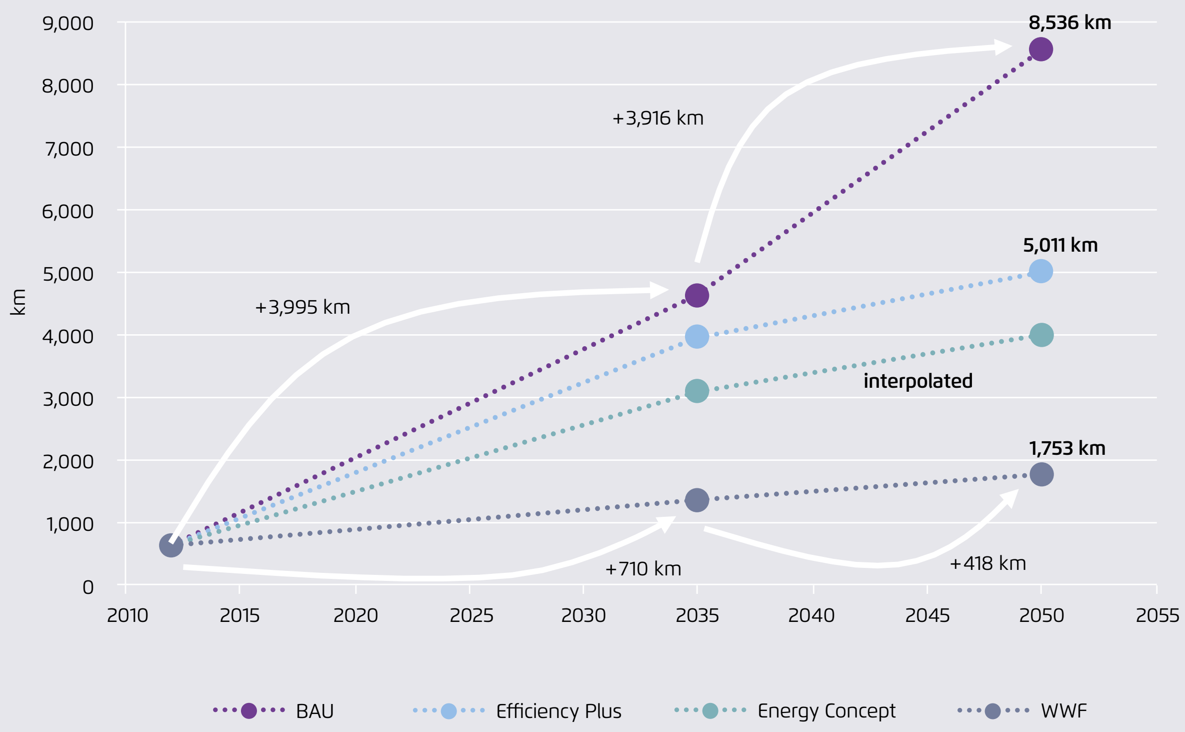
a lower expansion demand than those of the copperplate approach. Figure 4-13 illustrates the results. In 2012 an initial grid expansion of 650 km is required which is caused by today's existing bottlenecks as well as by neglecting the transmission grids of neighbouring countries. The future grid expansion demand varies substantially for the individual scenarios. The line length required in the BAU scenarios until 2050 is five times as large as in the WWF scenario. This is due to the different installed capacities of onshore and, particularly, offshore wind turbine generators, that prove to be the main driver of the required grid reinforcements. Until 2035, the BAU and Efficiency Plus scenarios arrive at very similar installed capacities, which results in similar grid expansion demands. Regarding the required grid expansion, the Energy Concept scenario is comparable to the Efficiency Plus scenario. Due to the slightly lower installed capacities, the expansion demand is somewhat lower. We have not explicitly calculated the expansion demand for the Energy Concept scenario. It is mainly an estimate based on the results of the other scenarios and the installed capacity of onshore and, particularly, offshore wind turbine generators.

In addition to the grid expansion demand in absolute values, we also looked at the regional distribution. For this purpose, figure 4-14 represents the respective grid expansion projects.

It shows clearly that particularly the North-South connections are expanded. This applies particularly to the already well-known bottlenecks, such as the corridor Redwitz-Remptendorf. Here the large effect of close-to-shore onshore and, particularly, offshore electricity generation from wind turbine generators becomes obvious.

Development of the grid expansion demand in the transmission grid

Figure 4-13



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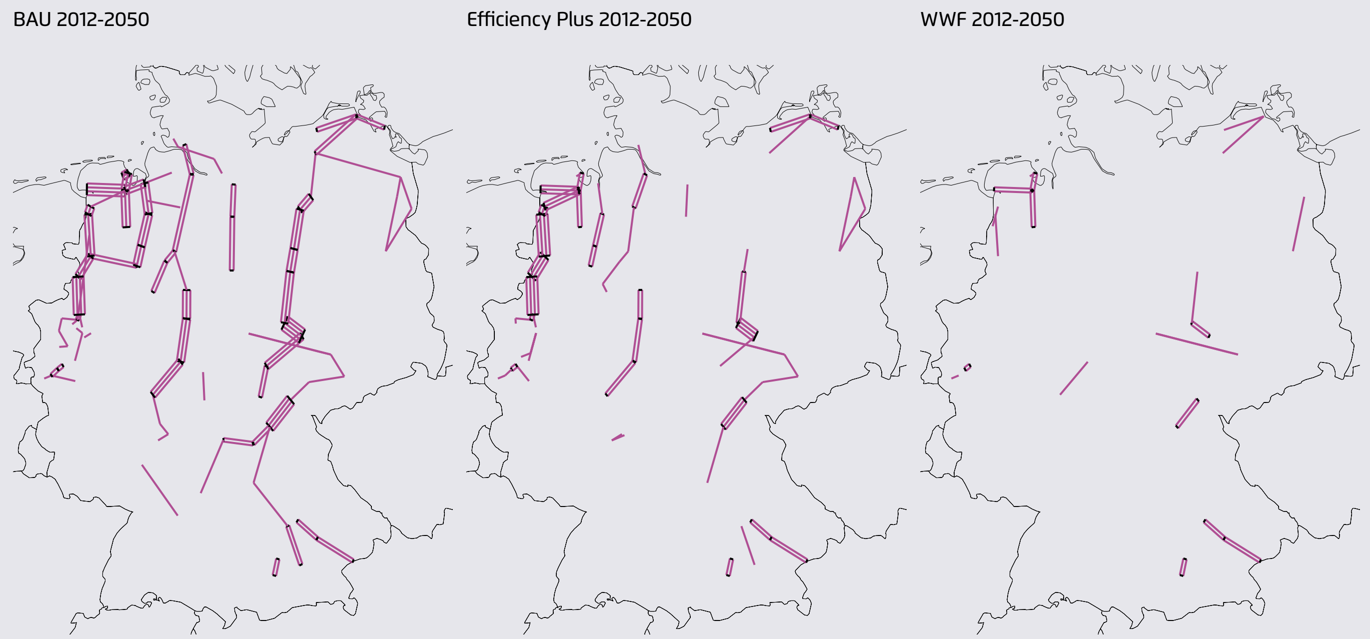
Therefore a direct comparison of the grid expansion demands of the different scenarios is only of limited significance as the absolute, but also relative generation from offshore wind turbine generators varies significantly between the scenarios. This is illustrated in figure 4-15. It shows the aggregated energy amount at each location in 2012 and 2050 for the BAU and WWF scenarios. The generation in Northern Germany is especially relevant for transmission as the German load centres are situated in the Ruhr, Rhein-Main area and in Southern Germany. In 2012, generation in Northern Germany is mainly dominated conventional generation and wind power. A comparison with the generation in the WWF scenario 2050 shows that the absolute generation quantity hardly changes. Generation from conventional plants will be mainly substituted by offshore wind turbine generators (27 TWh, 5.6 GW maximum generation capacity after market-side curtailment). As opposed to this, the BAU scenario 2050 shows a substantial increase in the aggregated generation for Northern Germany. It is mainly composed of generation from onshore and offshore wind turbine generators. Here the quantity of energy fed in by offshore wind turbine generators amounts to 126 TWh with a maximum feed-in capacity of 26 GW. The energy share of the generation from offshore wind turbine generators as part of total consumption in Germany goes up to 21 percent in the BAU scenario 2050 and only to 8 percent in the WWF scenario. The required grid expansion reflects the substantially higher maximum feed-in capacity that is related to the higher energy amount.

For a plausibility check of the absolute expansion demand, it was compared to the expansion demand determined in the dena study *Integration der erneuerbaren Energien in den deutsch-europäischen Strommarkt*. For 2050 the dena study arrives at an expansion demand of 12,900 km (dena 2012). This exceeds the demand of 8,536 km determined for the

Regional distribution of the grid expansion demand

Figure 4-14



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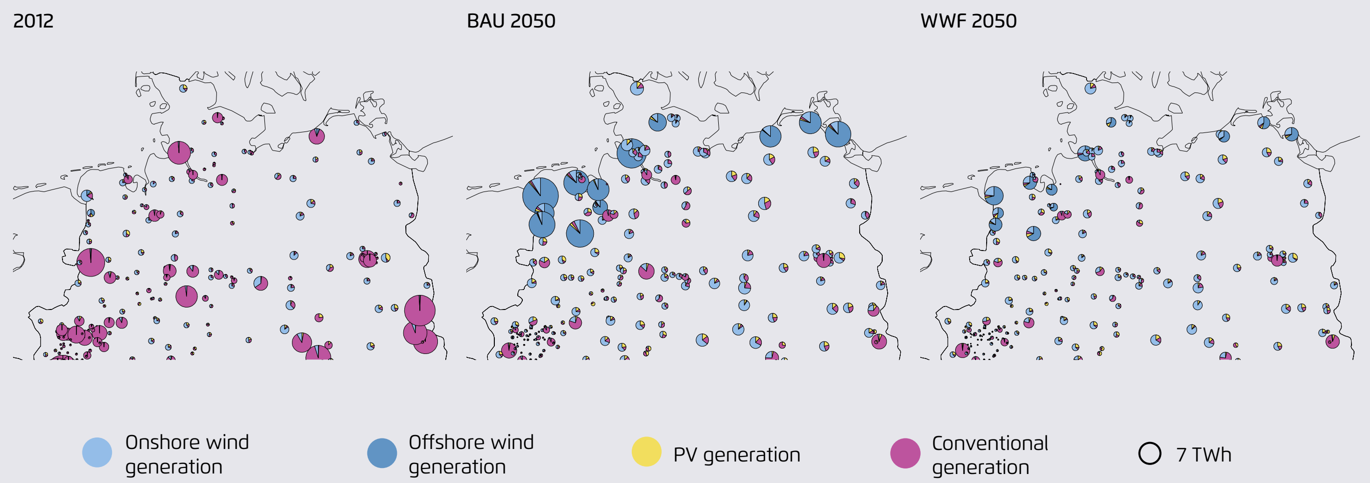
Annual amount of electricity generation in Northern Germany

Figure 4-15



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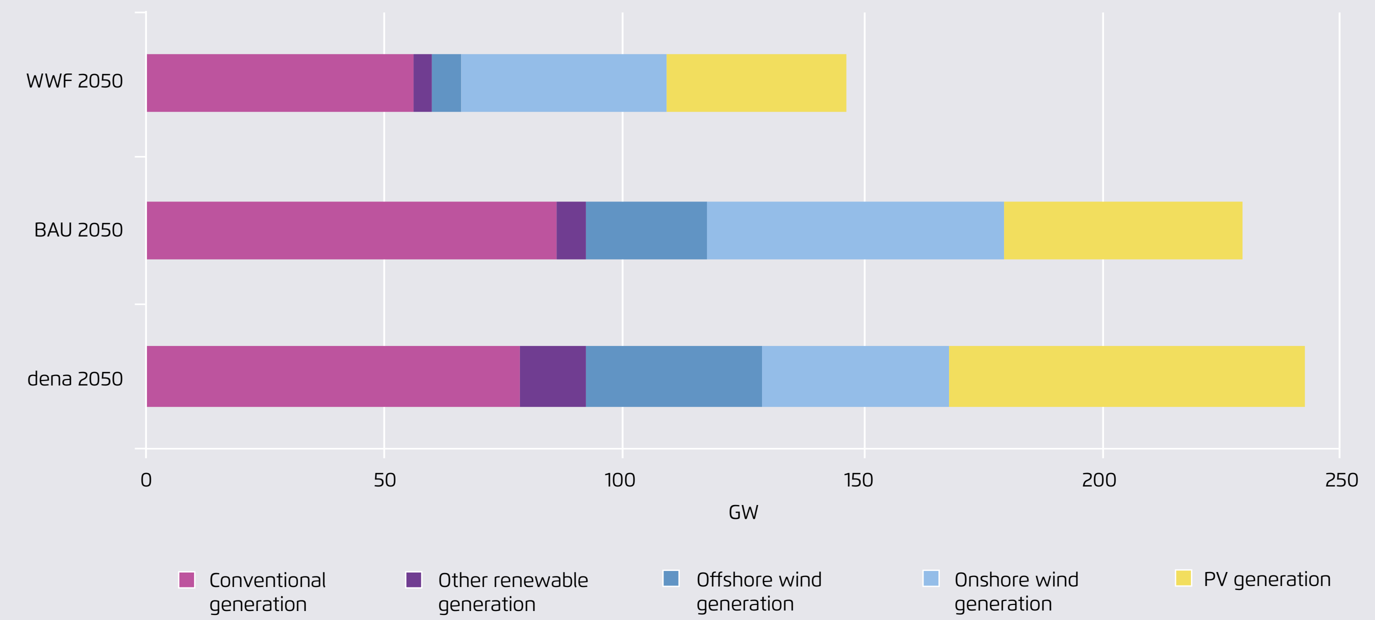
BAU scenario 2050. We have to take into account differences in the approach of the analysed scenario though. The dena study considers only a single grid use case and a complete grid expansion for this case (copper plate approach). As opposed to this, our study used – in order to include a simplified model of operational measures for increasing transfer capacity – a year-based simulation where lines were allowed to be overloaded during 2 percent of the annual hours in the base load flow or after the fault of any other line. In addition, there are differences regarding the installed generation capacities.

These are represented in figure 4-16. It becomes obvious that the installed capacity and here especially RE plants in the scenario dena 2050 substantially exceed maximum generation in the BAU scenario 2050. The difference of maximum generation from offshore wind turbine generators amounts to 11 GW; which means that against the background of considerably lower transfer requirements and the diverging approach, the lower result of 8,500 km appears to be plausible.

For arriving at the cost for the transmission grid expansion it was necessary to determine investment costs for the corresponding grid expansion. There is a large number of assumptions regarding average operating costs. Particularly due to the different number of circuits in the individual corridors and towers, we only used an estimate as the cost progression from single to double circuit was not taken into account. We assumed a cost of 1.2 million euros per kilometre and 380 kV line. In addition, we included costs of 4 million Euro per bay. The resulting aggregated investment costs are represented in figure 4-17. The aggregated investment cost of all expansion projects amount to between 2.3 and 11.4 billion euros.

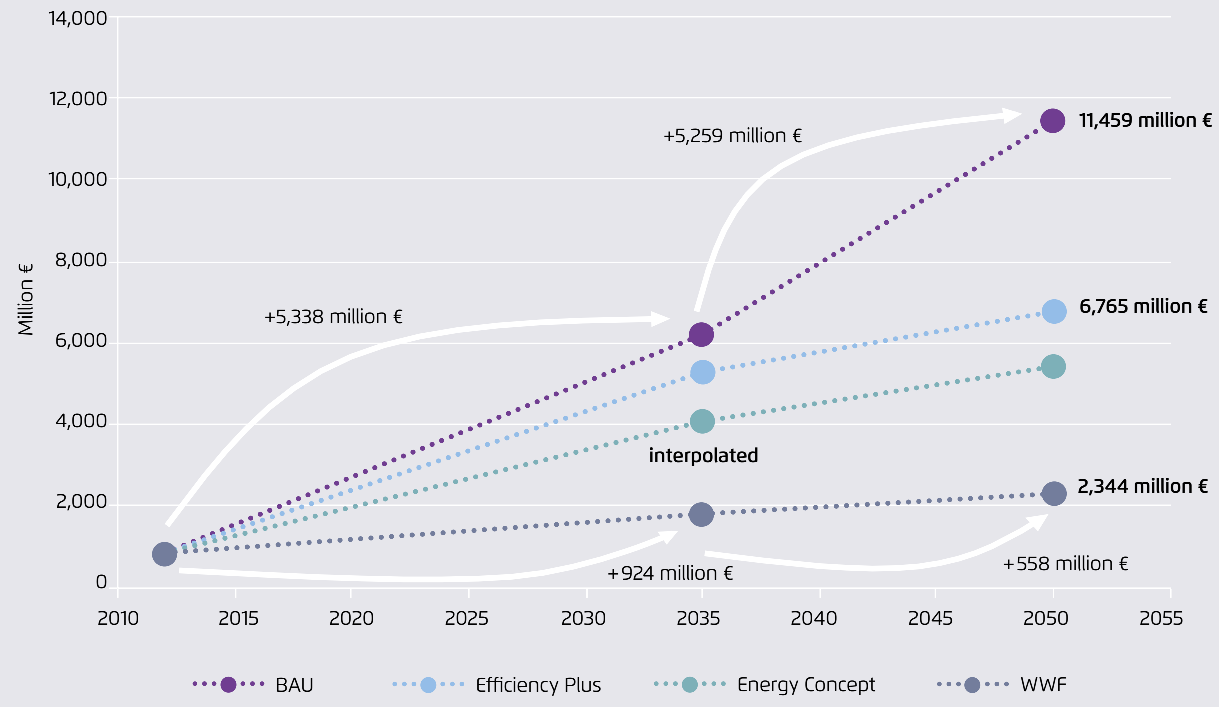
Comparison of maximum generation in the BAU and WWF scenarios with the dena study — Figure 4-16



IAEW; dena (2012)

Investment costs of the transmission grid expansion

Figure 4-17



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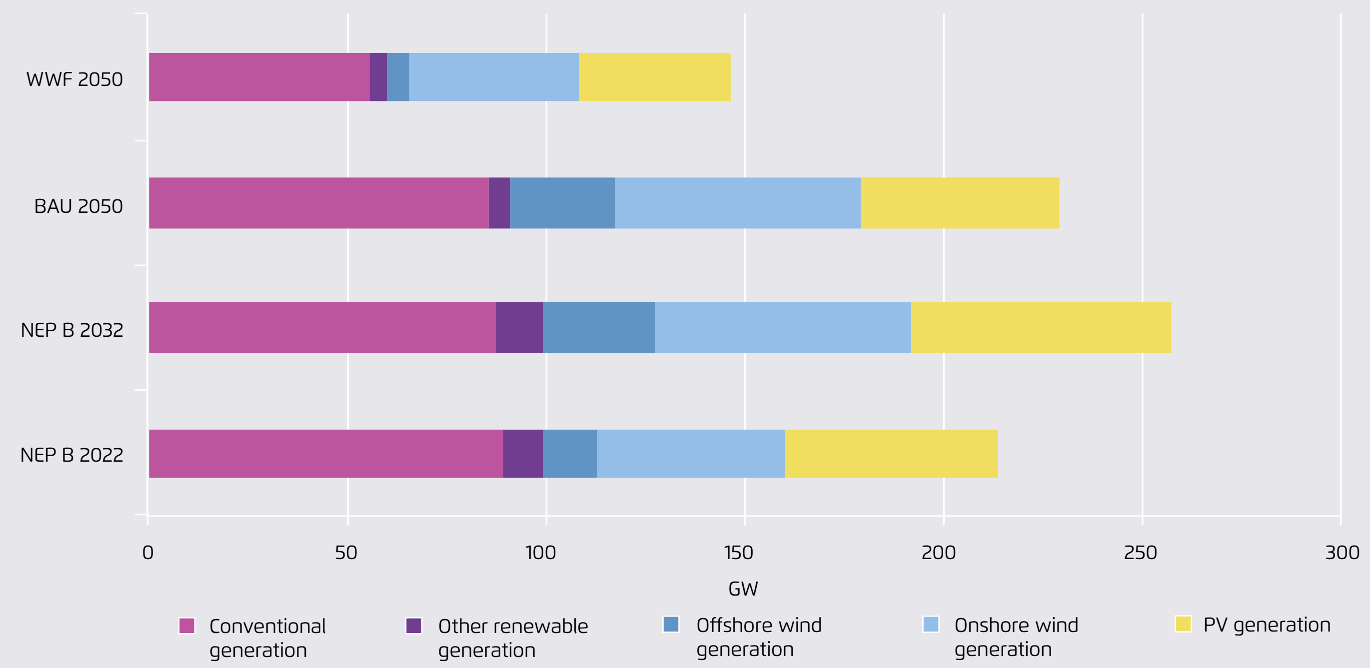
For a better evaluation of the investment costs, we compared them with the costs included in the current *Bundesbedarfsplan* (German Federal Demand Plan). Here aggregated investment costs amount to slightly less than 20 billion euros until 2022. However, this number is an initial estimate as the actual corridors and implementation will have a further effect on costs. The difference between the grid expansion costs in the *Netzentwicklungsplan* and the 11.4 billion euros determined for scenario BAU 2050 has a variety of reasons.

The main differences, however, are due to the applied methodology and the considered scenarios: For the *Netzentwicklungsplan* – which forms the basis of the *Bundesbedarfsplan* –, transmission grid operators designed an (n-1) secure grid for a given scenario. It does not only comply with all requirements regarding thermal limiting currents, but also with all other technical requirements regarding voltage stability and transient stability. As opposed to this, the current study only takes into account thermal limiting currents and tolerates an overloading of 2 percent of annual hours. For verifying the (n-1) criterion, the *Netzentwicklungsplan* does not only take into account single line faults – which is the case in this study –, but also situations with faults of entire multiple-curcuit lines or busbars. The *Netzentwicklungsplan* assumes the total integration of all RE plants, whereas this studies considers Germany in an isolated way and allows curtailment of RE generation for energy balance reasons. The *Netzentwicklungsplan* includes – as opposed to this study – cases of more cost-intensive operating equipment, such as cable, high-temperature conductors and DC technology and reactive power compensation required for voltage stability.

Due to its stricter technical framework conditions, the *Netzentwicklungsplan* arrives at a substantially larger grid expansion demand and correspondingly higher investment costs. Also within the framework of the scenarios analysed in this study, verifying and maintaining the corresponding

Comparison of maximum generation with *Netzentwicklungsplan** Figure 4-18



IAEW; *Netzentwicklungsplan* 2013

* The capacities provided for the WWF and BAU scenario correspond to the maximum generation after curtailment. The numbers from *Netzentwicklungsplan* represent the installed capacities in the respective scenario.

technical prerequisites would lead to a substantial increase in investment costs.

In addition to technical framework conditions and methodology, there are further differences regarding maximum generation. A comparison is provided in figure 4-18.
The investment costs determined in this study are lower than those of the *Netzentwicklungsplan*. However, there are far-reaching differences regarding methodology and input data which means that a direct comparison of the results is only of limited significance due to different assumptions and methods.

4.3.7 Costs of the transmission grid

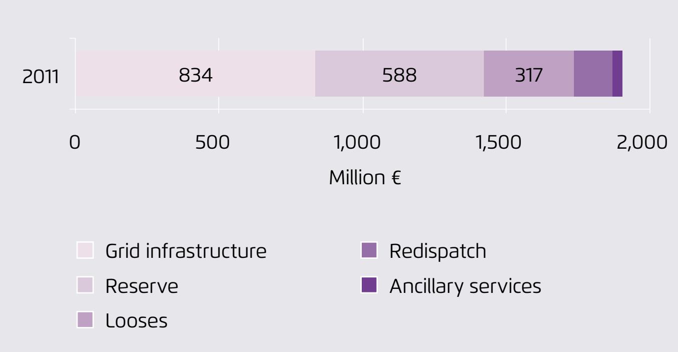
As a last step, we quantified the annual costs of the German transmission grid. Figure 4-19 represents the costs of 1.9 billion euros that transmission grid operators incurred in 2011 (BNetzA 2012). They were divided into grid infrastructure, reserve, losses, re-dispatch and system services.

Reserve costs were already included in the generation costs determined by Prognos. Also losses were estimated upfront and considered in the power plant resource planning. Correspondingly, these costs also were already included in the generation costs. For planning an (n-1) secure grid, we did not need to take into account re-dispatch costs. We therefore looked at grid infrastructure costs that would have to be determined for future scenarios.

They can be further subdivided as shown in figure 4-20. About one fourth corresponds to maintenance and repair costs, the remainder consists of investment for new construction and for replacement or upgrading.

In this study, costs for repair and maintenance were assumed to be proportional to line length. The investment costs for the required transmission grid expansion presented in chapter 4.3.6 were converted to annuity-based

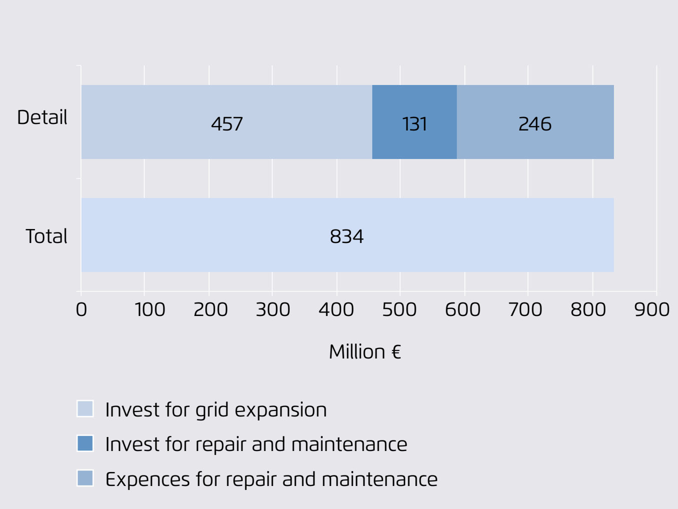
Components of transmission grid costs 2011 — Figure 4-19



IAEW; BNetzA (2012)

costs.[3] Thus future annual transmission grid costs are the sum of the forward projection of past investment costs, future scaled expenditure for repair and maintenance as well as annuity-based investment costs for the specified new

Subdivision of transmission grid infrastructure costs — Figure 4-20



IAEW; BNetzA (2012)

lines. The goal of this study was to compare specific costs of individual scenarios with diverging efficiency ambitions, therefore annual total costs were divided by the corresponding energy consumption of the individual scenarios.

3 Depreciation period: 40 years, interest rate: 7 percent

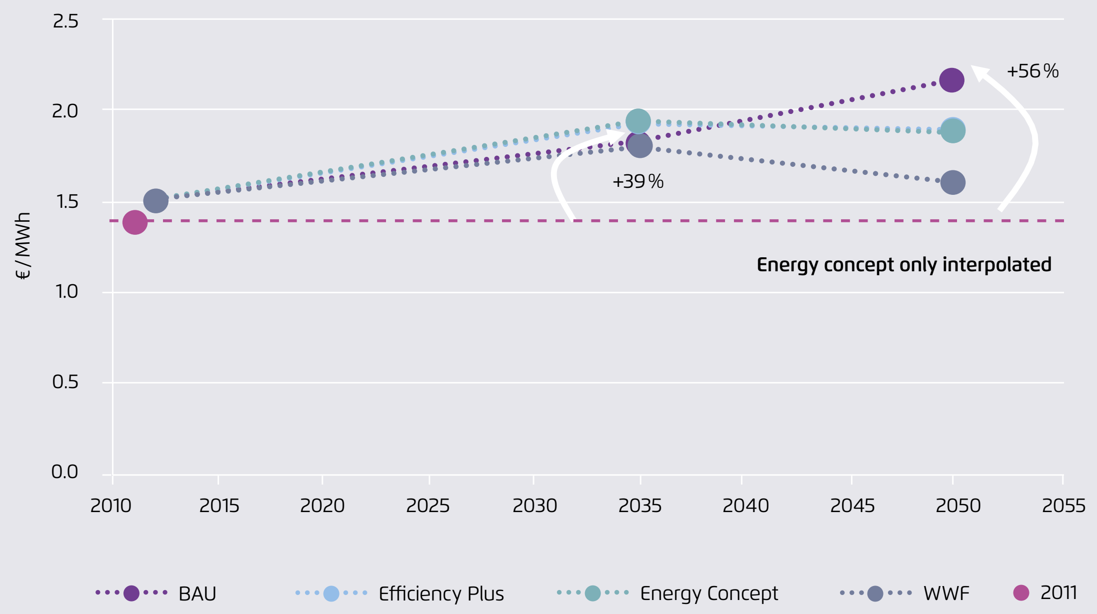
Figure 4-21 illustrates the specific transmission grid infrastructure costs.

We can see, that the specific costs particularly in the Efficiency Plus scenario will initially increase by approximately 39 percent as energy consumption decreases faster than costs in this scenario. Until 2050 however, relative costs in the Efficiency Plus scenario decrease as the required grid expansion demand is very low. As opposed to this, in the BAU scenario costs increase due to the larger required grid expansion.

It should be noted that the specific infrastructure costs in the analysed scenarios are rather similar. This is due to the fact that in the WWF scenario expansion costs are lower, but these costs are also spread over a lower energy consumption. The BAU scenario results in a higher expansion demand and higher costs that are, however, spread over a larger amount of energy. In summary, we can conclude from the comparison of specific costs of the generation plant fleet that costs for transmission grid infrastructure only constitute a small share (less than 1 percent) of total costs. Even for significantly higher investment costs, relative transmission grid infrastructure costs would still amount to only a small share of total costs. Nonetheless, the transmission grid and transmission grid operators will continue to play a decisive role regarding the security of supply and system security; and the transmission grid expansion – as assumed in this study – has to keep up with the restructuring and expansion of the generation system.

Specific transmission grid infrastructure costs

Figure 4-21



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4.4 Distribution grid

4.4.1 Methodology

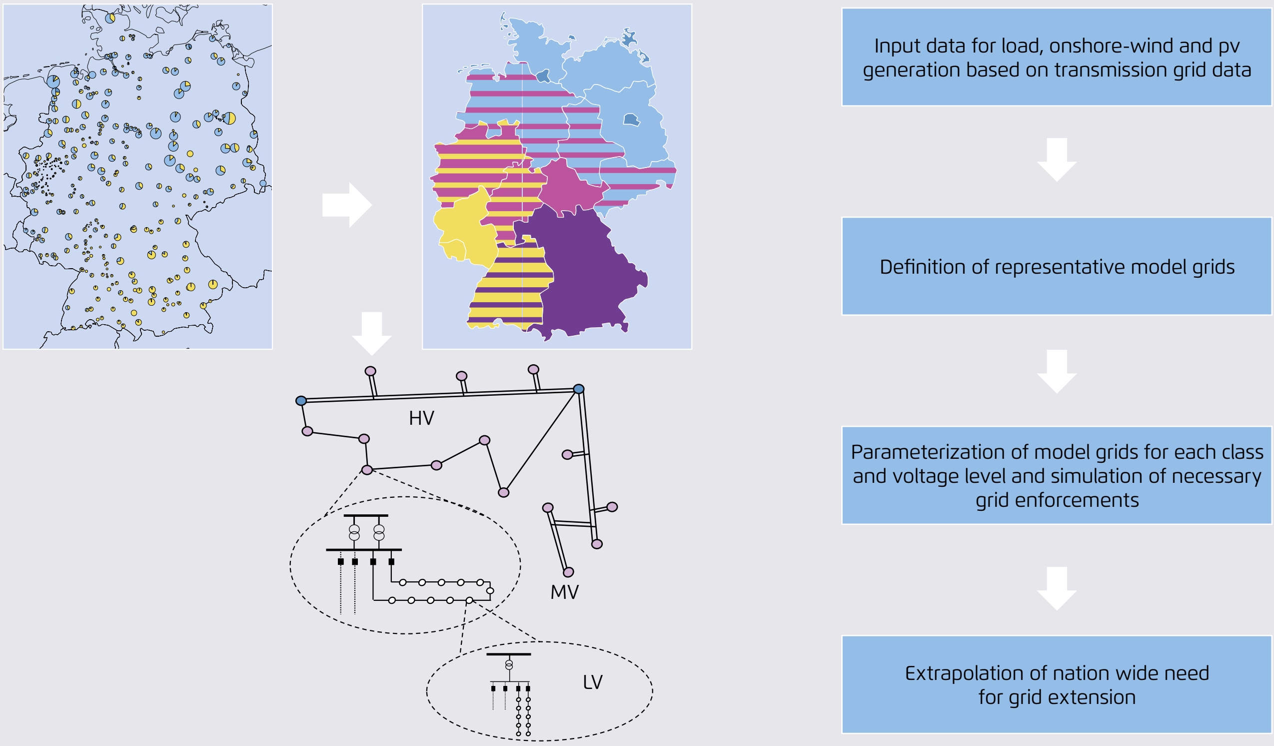
As described earlier, there are over one million kilometres of lines and more than 860 grid operators; and it is not possible to simulate the required expansion of the distribution grid analogously to the transmission grid individually for each high-, medium- and low-voltage grid. Instead we used a model grid approach for determining the required grid expansion. The procedure is described in figure 4-22 and based on an expansion of the methodology presented in (Katzfey et al. 2011).

Based on the curtailed maximum feed-in capacity presented in chapter 4.3.2 and the regionalisation of transmission grid nodes, we defined representative model grids consisting of high-voltage (HS), medium-voltage (MS) and low-voltage (NS) grids. Subsequently, the grid expansion demand was determined for each model grid and each voltage level. Eventually we determined the annual specific costs for the distribution grid infrastructure and the individual scenarios with their diverging efficiency levels.

4.4.2 Input data and the derivation of model grids

In order to arrive at results that are consistent with the transmission grid part, parametrisation was carried out in order to determine the expansion demand in the distribution grid using the same values as for determining the transmission grid expansion. This means, that the maximum feed-in capacities introduced in chapter 4.3.2 were used for this purpose and not the installed capacities defined in the individual scenarios. The maximum feed-in capacities result from the required energy balance related curtailment and are partially considerably lower than the installed capacities. In addition to the maximum feed-in capacities of onshore wind turbine generators and PV plants we also looked at loads. The regionalisation of RE generation

Methodology for modelling distribution grids | Figure 4-22



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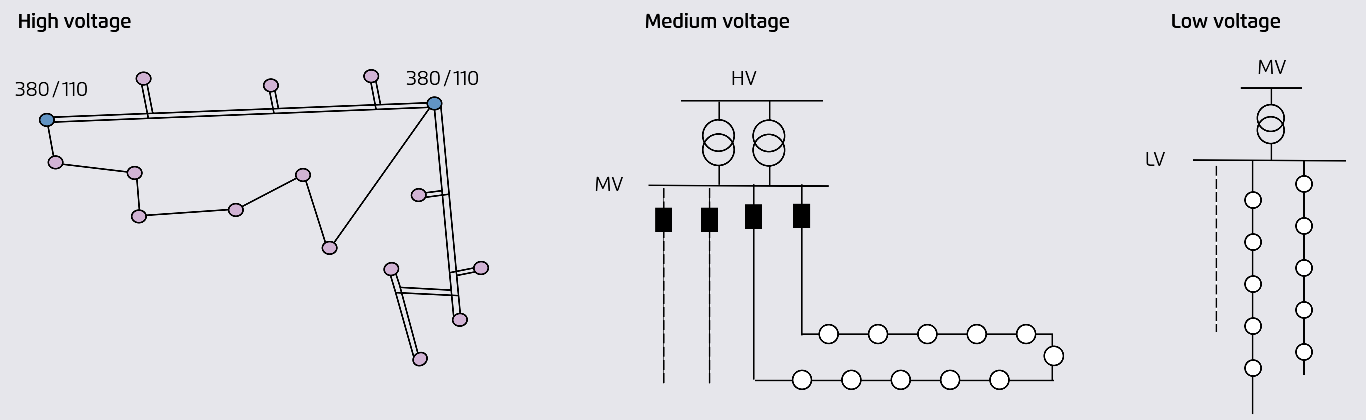
and load was based on the distribution presented in chapter 4.3.4.

Based on regionalised installed capacities we determined five model grid classes: "largely characterised by wind power", "characterised by wind power", "mixed characteristics", "characterised by PV" and "urban". They each represent a group of grids with similar supply tasks. Using the frequency of the occurrence of these grids it is possible to later on extrapolate the expansion demand determined for the whole of Germany.

Figure 4-23 represents the model grid structure underlying each voltage level.

For the high-voltage level – which in Germany is operated at a nominal voltage of 110 kV parametrisation we used two different, typical synthetic grid models for rural and urban areas. In all cases, we used meshed structures. In Germany, the high-voltage grid has downstream medium-voltage grids operated at 10 kV or 20 kV. For this study, they were modelled as an openly operated ring grid network. This network structure type is very common and constitutes for many grid operators the desired status of their grid as it combines high reliability of supply and fast fault clearance at comparatively low costs. Due to historical developments, we can also find radial networks and even slightly meshed medium-voltage grids. Regarding low-voltage grids, we used a radial layout. As opposed to transmission grids, the low- and medium-voltage level does not have grid security as its major goal, but rather the supply of the consumers. Therefore, at these voltage levels we did not test the (n-1) criterion. In the event of a fault, the supply of costumers at the medium-voltage level is mainly ensured by switching

Structure of the model grids | Figure 4-23



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actions. At the low-voltage level – depending on the grid structure – mobile emergency generators may be required during faults to resume short-term supply.

Structural data of individual grids, such as the mean feeder length and number, are parametrised based on published grid structure data according to model grid class.

4.4.3 Methodology for determining the expansion demand of the distribution grid

The installed RE capacity in a grid has a significant effect on the required grid expansion demand and is very inhomogeneously distributed over the individual grids. If we determined grid expansion based on average installed capacity, we would heavily underestimate it as the correlation between installed capacity and grid expansion demand is largely non-linear as can be seen in figure 4-24.

Therefore, we carried out a Monte Carlo simulation that determined the expansion demand varying the regional distribution and installed capacity of the distributed generation from RE plants and subsequently calculated the probability-based expectancy value of the grid expansion demand.

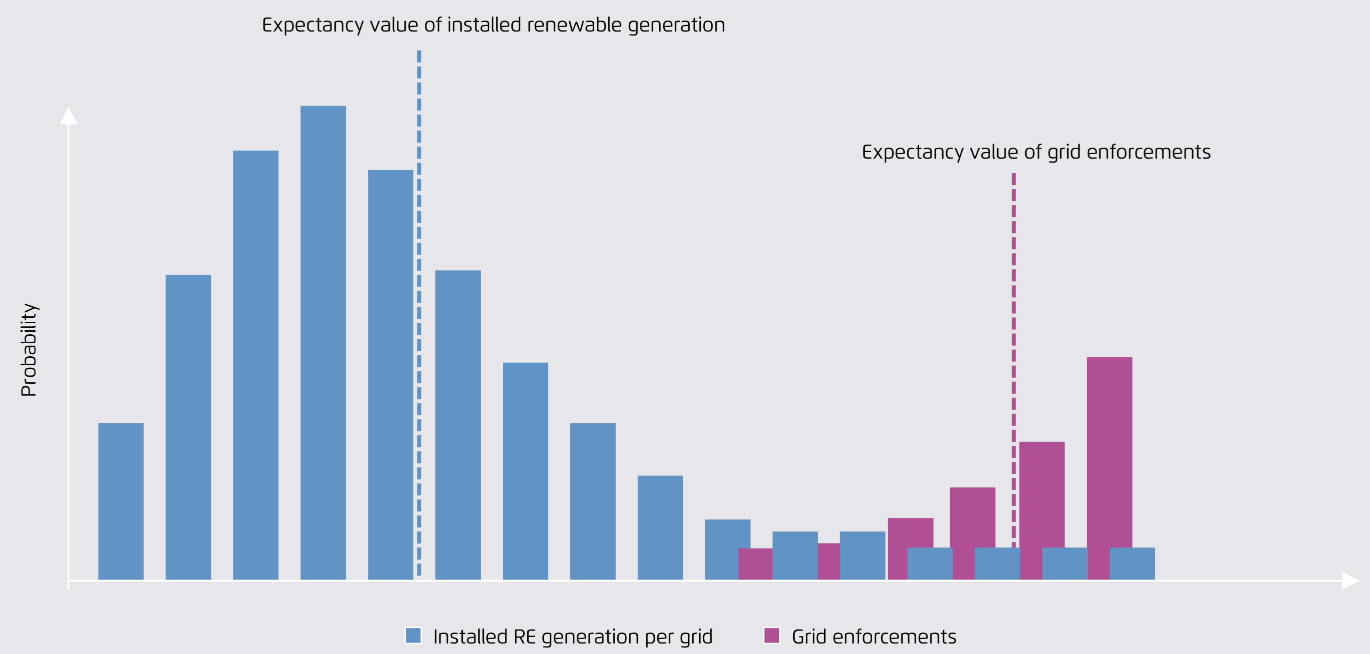
Analyses of distribution grids in Germany show that the installed RE capacity per grid can be approximated using a Weibull distribution with an expectancy value that corresponds to the mean installed RE capacity of each model grid class. Figure 4-25 provides an exemplary distribution that describes the frequency distribution of PV plant capacity.

In addition to the installed capacity, also the spatial distribution of the plants has a significant effect on the grid expansion demand, as a PV plant at the end of a low-voltage feeder is more likely to result in a voltage band violation than a plant at the beginning of the feeder. This means that we have to include a permutation of the installed plant capacity as well as the regional distribution of the capacity in the corresponding model grid. For this purpose, a Monte Carlo simulation with several thousand individual grids was carried out.

For the actual decision whether a grid expansion is necessary or not, compliance with technical restrictions has to be tested. These vary according to voltage level.

At the 110 kV level, the (n-1) criterion was used similar to the transmission grid in order to be able to maintain the technical average operating limits even in case of a fault at a line or transformer. In addition to maintaining the thermal limiting current, the voltage band is tested. The study as-

Qualitative correlation between installed RE capacity and grid expansion — Figure 4-24



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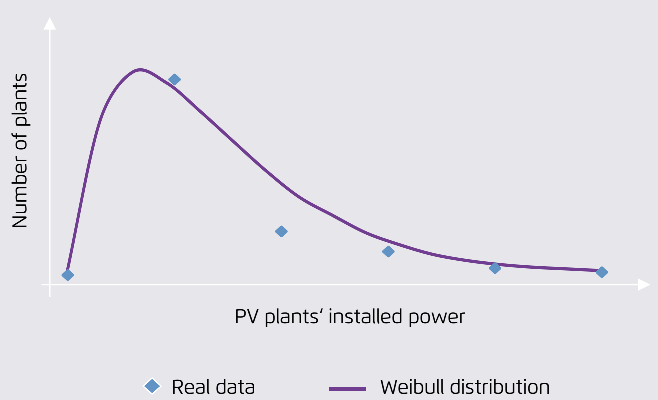
sumed an allowable voltage band of ± 10 percent as transformers equipped with voltage controls decouple the voltage level from the upstream and downstream voltage level. The required voltage quality sets the limits for this band.

Exemplary Weibull distribution in order to describe the frequency distribution of PV plant capacity — Figure 4-25



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At the medium-voltage level, (n-1) security is mainly only ensured after switching or using emergency generators. In order to ensure compliance with the thermal limiting current in the analysed open ring grids also after switching, the allowable maximum current was set at 50 percent of the thermal limiting current. The limits for voltage changes result from the BDEW guidelines *Technische Richtlinie – Erzeugungsanlagen im Mittelspannungsnetz* that specifies that the voltage raise due to a distributed generation plant must not exceed 2 percent of the voltage without the generation plant (BDEW 2008).

Similar to the medium-voltage level, the critical limit for the voltage at the low-voltage level is defined by the maximum voltage raise that is caused by a distributed generation plant. This limit is set according to VDE-*Anwendungsregel* VDE-AR-N 4105 at 3 percent of the voltage without the distributed generation plant (VDE-AR-N 4105, 2012).

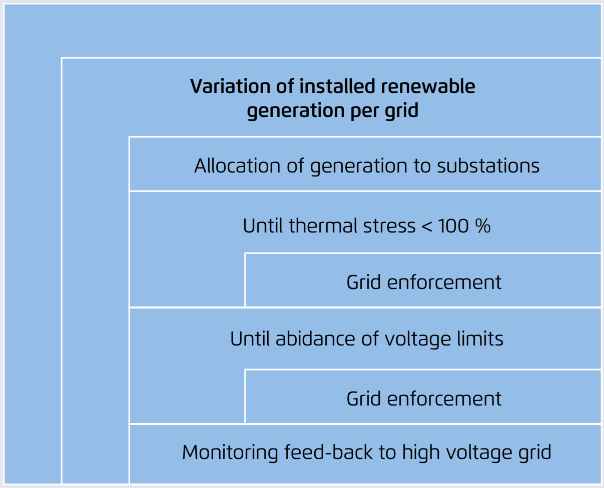
Figure 4-26 illustrates the actual process of determining the grid expansion demand using the example of the medium-voltage level.

A Monte Carlo simulation was used to determine the installed RE capacity in the grid and its regional distribution applying a random generator based on a Weibull distribution. After assigning the installed capacity to the corresponding station, a load flow simulation was carried out. If the thermal limiting current was violated, iterative lines were added until reaching the limiting value. The same procedure is used in case of voltage limit violations. The last step is to test the electrical feedback into the upstream high-voltage grid and if necessary to add another transformer. As opposed to the methodology applied in the transmission grid, here we considered only one actual point in time. The expansion demand was determined for the maximum generation which is the relevant case for dimensioning a grid with a very large share of renewables.

In addition to the installed distributed generation, the load in each grid affects the required grid expansion. The dimensioning is influenced by whether the demand is synchronous, i.e. occurs at the same time. According to the current status of technology, the so called simultaneity factor between distributed generation and load is set at 0.4 for the high-voltage level, at 0.3 for the medium-voltage level and at 0.2 for the low-voltage level.

The grid expansion demand resulting from the individual model grid classes and voltage levels was then – based on weighted model grid classes – extrapolated to arrive at a Germany-wide grid expansion demand. For this purpose the expansion demand determined for the individual grid classes was projected based on the corresponding frequency of the grid type. When comparing the results of this model grid approach with approaches based on real distribution grids, we can observe a high level of coincidence regarding the development of grid costs. The spread between low-, medium- and high-voltage level can vary due to different assumed expansion strategies.

Process of determining the grid expansion demand at the medium-voltage level — Figure 4-26



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4.4.4 Results of the distribution grid expansion

In 2012, no expansion of the distribution grid is required as currently all distribution grid operators comply with their individual supply task. However, operating measures such as curtailment of distributed generation are partially necessary. The grid expansion calculated in this study is based on a grid operation that complies with the technical requirements named in the previous chapter without the necessity of bottleneck-related curtailment of RE plants. Based on the average operating costs published in the dena distribution grid study, we determined the aggregated investment costs of the required distribution grid expansion in the individual scenarios with different efficiency ambition levels until 2050. These are presented in table 4-1.

It becomes obvious that the expansion of distributed generation plants is the main driver of the required grid expansion. Particularly at the medium- and low-voltage level, expansion measures are driven by the violation of voltage limits. Due to the strong correlation of expansion demand and installed RE capacity, scenarios BAU 2035 to 2050 do not require any further expansion as the maximum generation from onshore wind turbine generators and PV plants hardly changes between 2035 and 2050. In the WWF scenario the expansion demand also is small due to lower maximum generation. For individual situations, load reduction – which for the WWF scenario is larger than the increase of the maximum distributed generation – can result in an increased expansion demand. This is the case at the medium-voltage level, for instance, where the changed ratio of generation and load more often leads to voltage band violation as the grids have to increasingly transfer electrical energy from renewable sources to the upstream grid levels.

For a better assessment of the resulting investment costs, figure 4-27 compares the results with those of the dena distribution grid study. We can see that the aggregated investment costs in the scenario BAU 2050 are somewhat lower than the value determined in the dena study for the year 2030. However also maximum feed-in capacities are clearly lower than the installed capacities assumed in the dena

Aggregated investment costs for the grid expansion at the distribution grid level from today until 2035 and from today until 2050, respectively — Table 4-1

	Bau	Efficiency Plus	WWF
Until 2035 in million €	19,609	14,656	12,755
Until 2050 in million €	19,802	16,197	14,503

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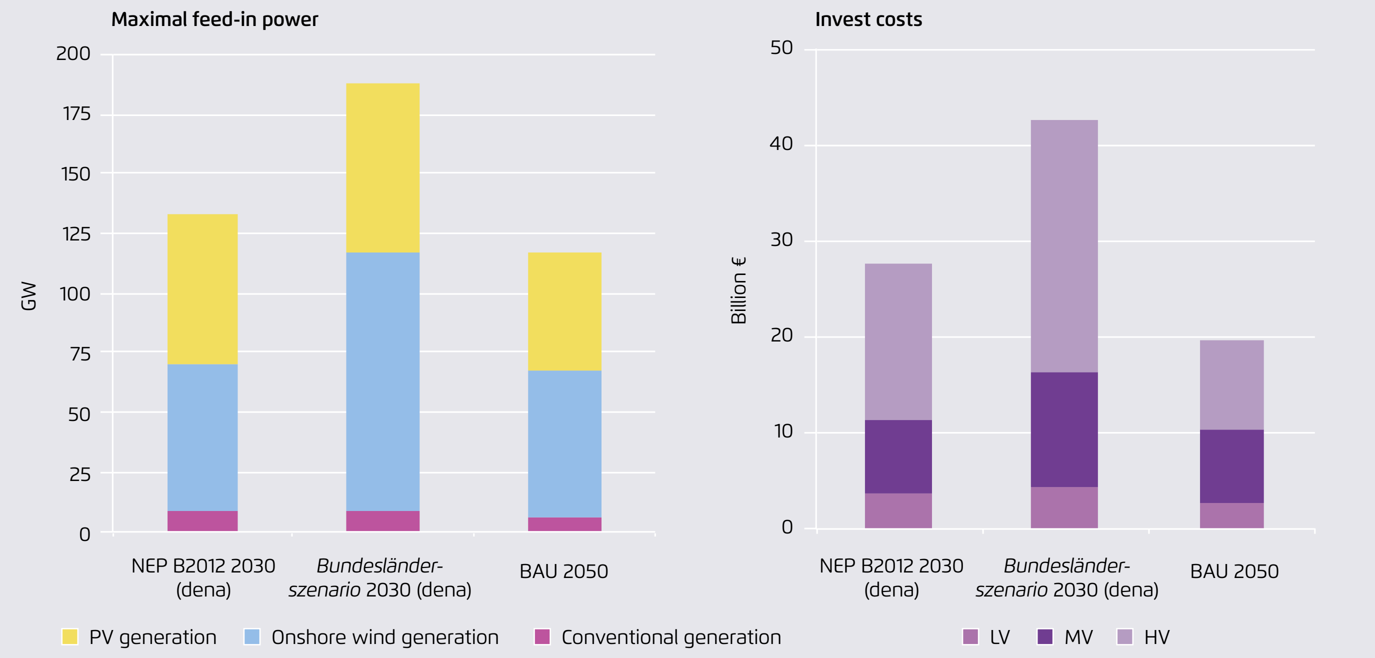
study. Also the costs are spread slightly differently across the individual voltage levels which is due to methodological differences. Grid planning in the dena distribution grid study is based on real grids, whereas this study exclusively used the presented model grid structures.

The grid expansion demand determined in this study may be reduced by applying smart-grid technologies, such as onload tap changes in medium-to-low-voltage substations or new voltage-control concepts that in return result in investment costs, though. Curtailment or restricting the feed-in capacity of distributed generation plants would allow for a further reduction. However, the analysis of these technologies is beyond the scope of this study and the here presented values can be interpreted as a rough estimate based on a planning according to the current technological status. The dena distribution grid study analyses in more detail the impact of smart-grid technologies, for instance (dena 2013). There the use of innovative grid equipment is estimated to have a reduction potential of almost 50 percent regarding the grid expansion demand. A grid-driven use of storage also offers reduction potential. However, these measures are also related to costs that have to be compared to the savings from lower grid expansion demand. The study *Moderne Verteilernetze in Deutschland* recently commissioned by the German Federal Ministry for Economic Affairs and Energy (BMWi) will prepare a corresponding quantitfication.

Comparison of investment costs and generation capacity with the dena distribution grid study* Figure 4-27



IAEW; dena (2013)

* The capacities provided for the BAU scenario correspond to maximum generation capacity after curtailment. The numbers from the dena study represent the installed capacities in the scenario.

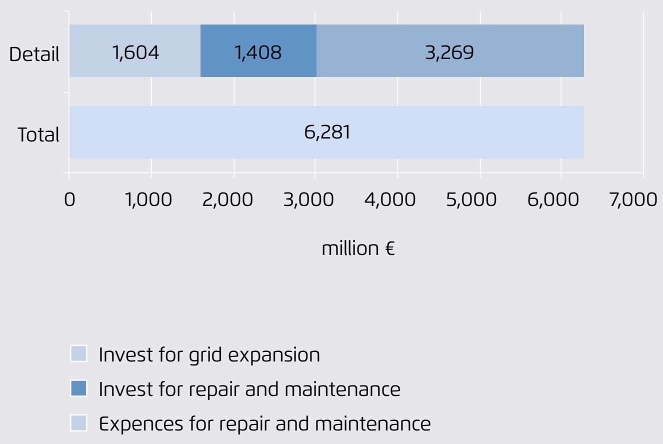
4.4.5 Costs of the distribution grid

Analogously to the transmission grid, we finally determined the specific costs for the distribution grid. For this purpose, figure 4-28 represents a break-down of the costs incurred for the German distribution grid infrastructure in 2011 (Bundesnetzagentur, Monitoringbericht 2012, 2013).

In 2011, total costs for the distribution grid infrastructure amounted to 6.2 billion Euro. This means that distribution grid infrastructure costs are almost eight times higher than those of the transmission grid infrastructure. They can be subdivided into investments for new construction and expansion, investments for replacement and upgrading as well as repair and maintenance costs. Due to the total line length, repair and maintenance costs constitute the largest part with more than 50 percent.

As described in chapter 4.3.7, costs for repair and maintenance are assumed to be proportional to line length. The investment costs for the required grid expansion were con-

Costs of the distribution grid costs in 2011 Figure 4-28



IAEW; BNetzA (2012)

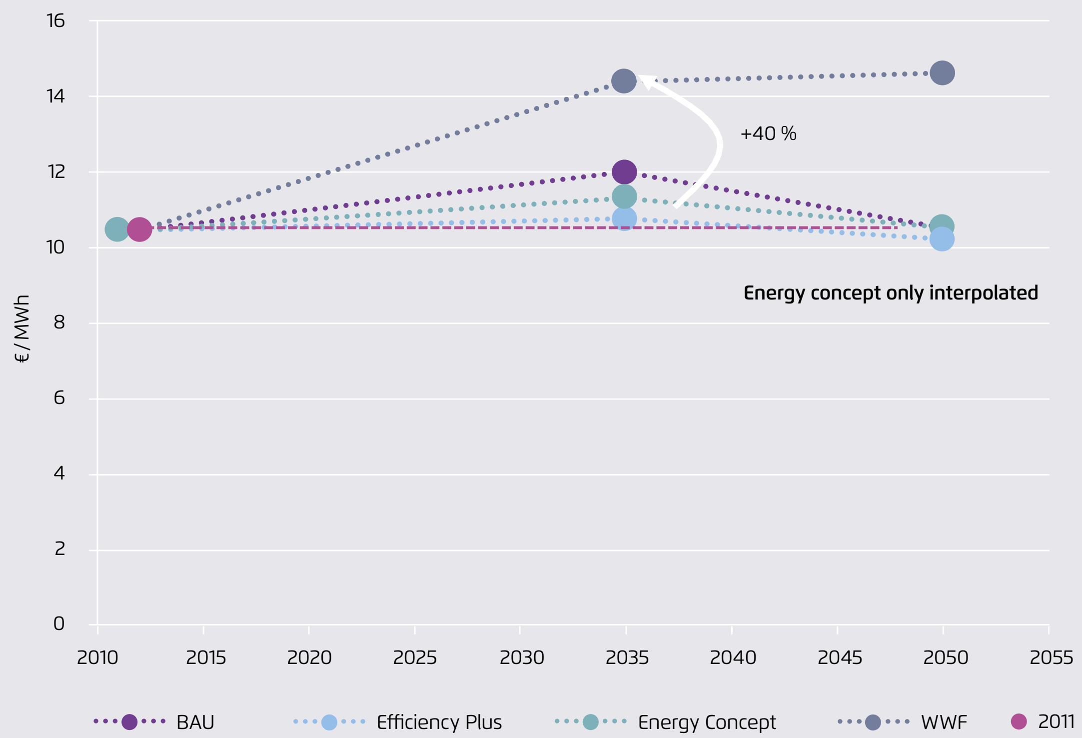
verted to annuity-based costs.[4] Thus future annual distribution grid costs are the sum of the forward projection of past investment costs, future scaled expenditure for repairs as well as annuity-based investment costs for the specified new lines. In order to determine the specific costs, these are divided by the energy consumption of the individual scenarios that have diverging efficiency ambitions. Figure 4-29 represents the development of the specific costs of the distribution grid infrastructure.

We can see that relative costs in the Efficiency Plus scenario remain at today's level. Also in the BAU scenario, in the long term the value will stabilise at about 10 euros/MWh. As opposed to this, the WWF scenario shows a significant increase (40 percent) of the relative costs for the distribution grid infrastructure. This is the result of a large reduction of the annual energy consumption which decreases more than the absolute cost for the infrastructure in this scenario. The grid costs have to be spread over less energy that is transferred. In all scenarios, both specific and absolute costs are dominated by repair and maintenance costs for the distribution grid infrastructure. Compared to the specific costs of the transmission grid infrastructure, we see that those are by factor five lower. When comparing with the specific costs of generation, it becomes obvious that the costs for the distribution grid infrastructure constitute a non-negligible portion.

4 Depreciation period 40 years, interest rate 7 percent

Development of the specific distribution grid in-frastructure costs

Figure 4-29



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5 Total cost of the electricity system

5.1 Results of the cost calculations

The total costs of the electricity system are the sum of the costs of conventional and renewable power generation as well as network costs.

The costs of electricity generation and grid infrastructure were around 50 billion $euros_{2012}$ in 2012. Depending on electricity consumption trends, these total costs will increase or decrease over the long term:

- Electricity consumption is highest under the BAU scenario. Under this scenario, annual costs rise to 65 billion $euros_{2012}$ by 2035 and to 72 billion $euros_{2012}$ by 2050.
- Under the Efficiency Plus scenario, which forecasts a drop in electricity consumption by 16 percent compared to today's figures on a long-term basis, overall costs will be 55 billion $euros_{2012}$ by 2035 and 56 billion $euros_{2012}$ by 2050, a 10 percent increase over the present level (2012).
- Under the Energy Concept scenario a 25 percent reduction in final electricity consumption is expected compared to 2012 figures. Under this scenario, overall costs will be 52 billion $euros_{2012}$ by 2035 and 50 billion $euros_{2012}$ by 2050, and will thus be comparable to present levels.
- With a successful reduction in electricity consumption of 40 percent by 2050, as expected in the WWF scenario, the overall costs of the power system will be below the present level on a mid- to long-term basis. Savings will amount to 6 billion $euros_{2012}$ by 2035 and 7,000 billion $euros_{2012}$ by 2050.

Our results show that through significant efficiency improvements, the total cost of the power system would be likely to fall in the medium to long term, even with a strong expansion of renewable energy.

Electricity generation is responsible for the largest cost changes in the overall system in all scenarios. The further expansion of renewable energy and its increasing share in electricity generation (which is similar in all scenarios) result in increased total costs. In 2050, renewable electricity generation will account for 56 percent of total system costs under the WWF scenario, and for 61 percent of costs under the BAU scenario. Due to a decline in costs for conventional electricity, absolute costs decline, despite an assumed rise in fuel and CO_2 prices as well as the need to maintain a larger conventional power plant fleet. Today, fossil-thermal generation accounts for costs equal to some 19 billion $euros_{2012}$. By 2050 the costs for conventional electricity generation will fall to 10 billion $euros_{2012}$ (under the BAU scenario) or even to less than 5 billion $euros_{2012}$ (under the WWF scenario).

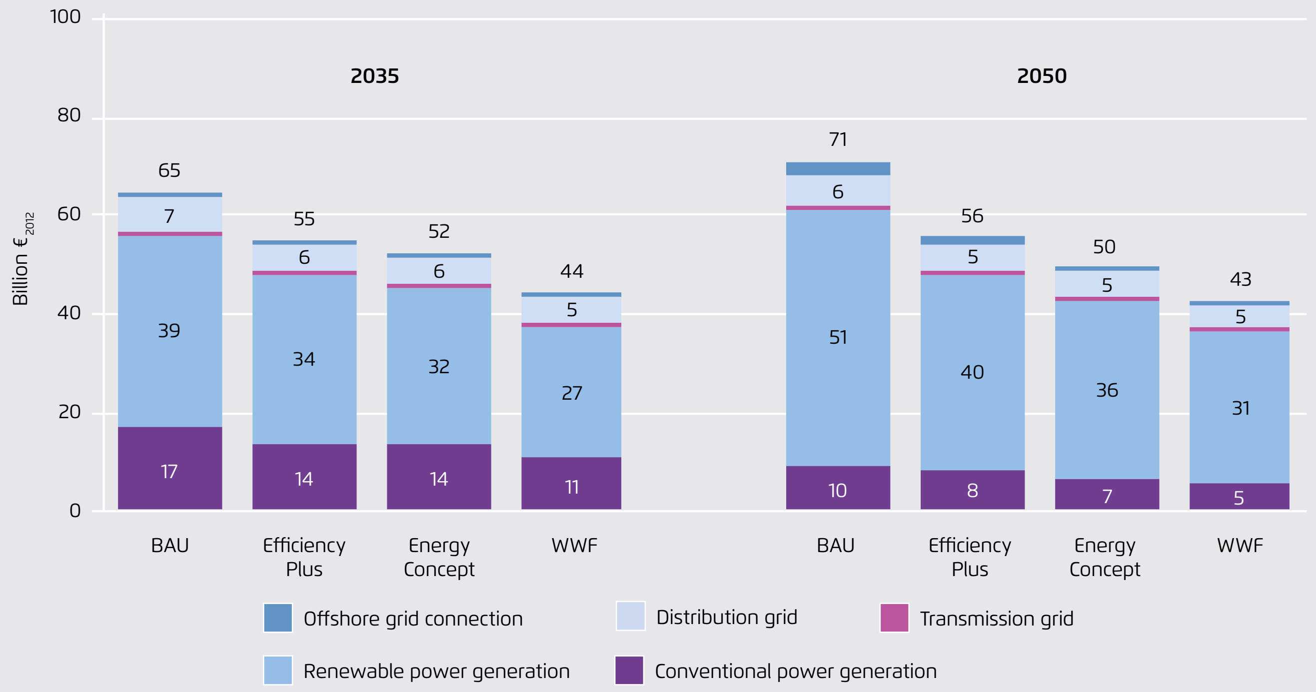
The costs for electricity grid infrastructure differ only slightly in all scenarios, despite variation in expansion and investment demand. In 2035 infrastructure costs for the transmission network will be between 900 million $euros_{2012}$ (BAU scenario) and 700 million $euros_{2012}$ (WWF scenario). In 2050 these costs increase to between 1.4 billion $euros_{2012}$ (BAU scenario) and 900 million $euros_{2012}$ (WWF scenario). The costs of the distribution networks, which includes all voltage levels from 400 V to 110 kV, will be between 700 million $euros_{2012}$ (BAU scenario) and 5.5 billion $euros_{2012}$ (WWF scenario) in 2035. By 2050, the costs will decline slightly and will amount to between 6.3 billion $euros_{2012}$ (BAU scenario) and 5 billion $euros_{2012}$ (WWF scenario).

In addition, costs will arise for connecting offshore wind turbines to the grid. Once again, projected costs depend on the power consumption trends underlying each scenario. Higher power consumption will require greater expansion of offshore wind power. Consequently, offshore grid connection costs will also increase.

In 2035, offshore grid connection costs are expected to be between 600 million $euros_{2012}$ (WWF scenario) and 1.3 billion $euros_{2012}$ (BAU scenario). The further expansion of off-

Total costs of electricity generation and network infrastructure

Figure 5-1



BNetzA (2012) *Monitoringbericht*; BMU (2013): Time series for the cost development of the German Renewable Energy Act (EEG); calculations by Prognos and IEAW

shore wind turbines will result in a rise in annual costs by 2050 of up to 700 million $euros_{2012}$ under the WWF scenario and 3.4 billion $euros_{2012}$ under the BAU scenario.

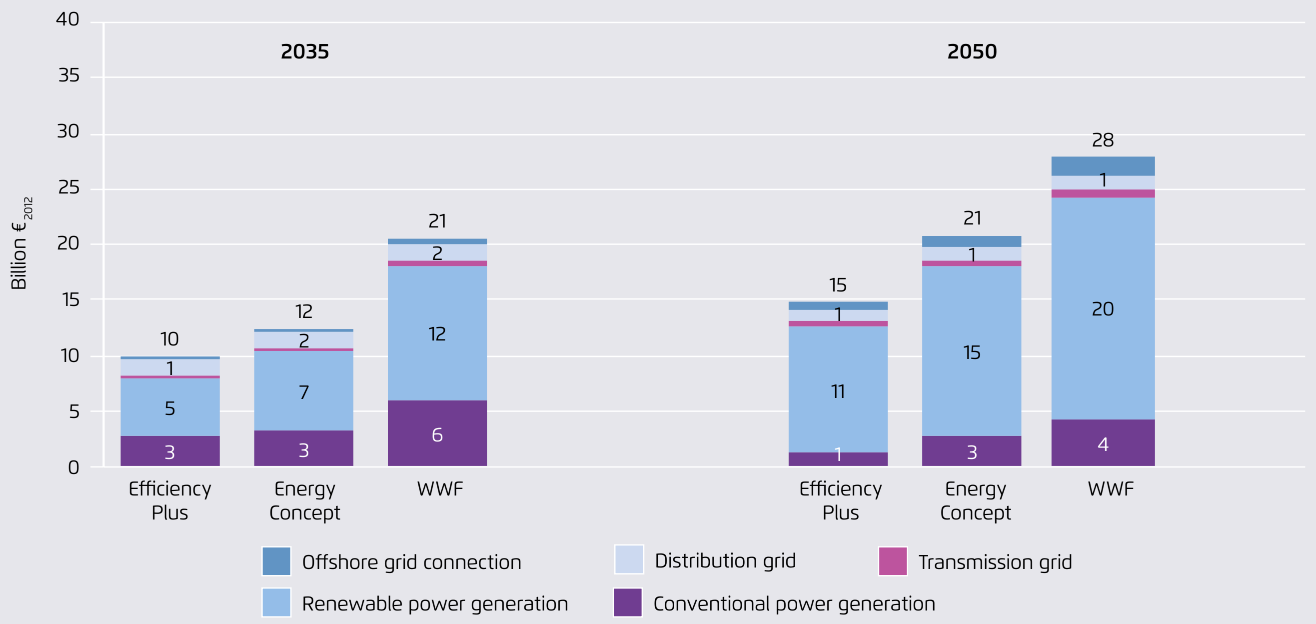
Compared to the BAU scenario, savings can be achieved under the more efficient scenarios of 10 to 20 billion $euros_{2012}$ by 2035 and 15 to 28 billion $euros_{2012}$ by 2050. Renewable power generation is the largest contributor to these cost savings. Although this cost component is responsible for the majority of total costs, it can be significantly reduced by improving efficiency. Renewable electricity generation is predicted to account for more than half of cost savings by 2035 and more than 70 percent of cost savings by 2050.

The unit costs per MWh for electricity generation and network infrastructure are roughly equal in all scenarios at around 120 $euros_{2012}$ per MWh. This is because total costs are largely determined by the costs of electricity generation, which, in the long-term, are approximately the same in all scenarios per MWh. By contrast, grid costs differ strongly in each scenario, but account for only a small share of total costs.

Compared to the BAU scenario, specific savings by 2035 from forecasted consumption reductions are equal to 149 $euros_{2012}$/MWh under the Efficiency Plus scenario, 133 $euros_{2012}$/MWh under the Energy Concept scenario, and 114 $euros_{2012}$/MWh under the WWF scenario. In 2050, savings per MWh in relation to the BAU scenario equal 130–140 $euros_{2012}$ under the more efficient scenarios.

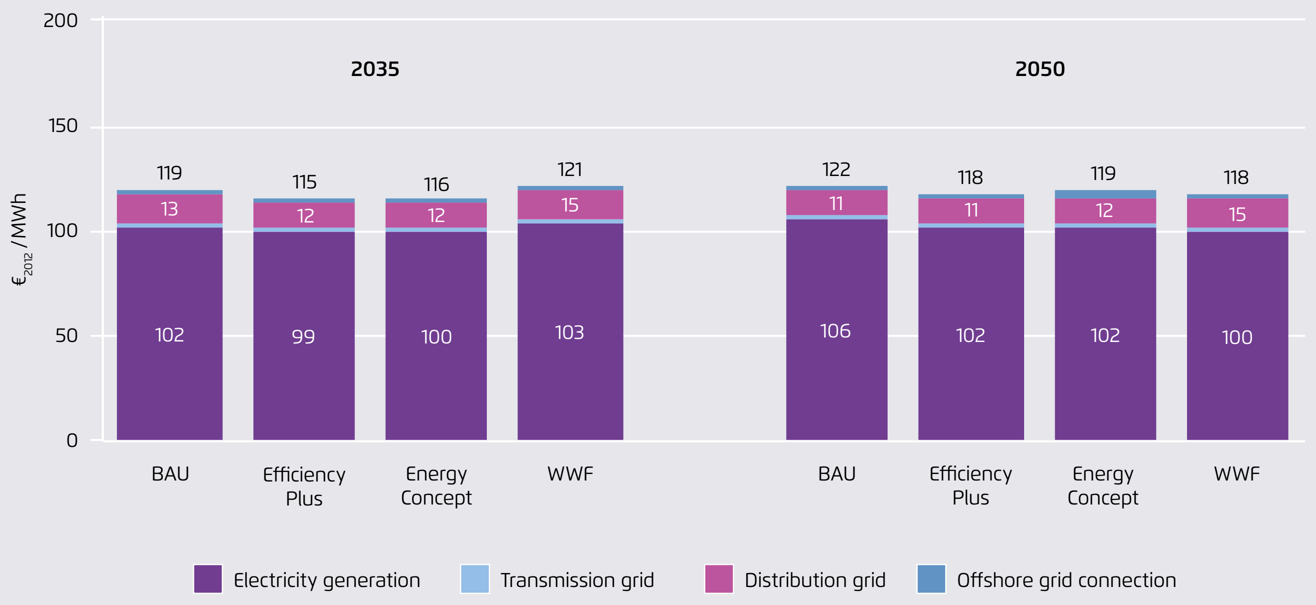
Compared to the BAU scenario, the biggest savings in CO_2 emissions are found in the WWF scenario. In 2020, avoided emissions will amount to 40 million tonnes. By 2050, these savings will decrease to 20 million tonnes. This is because electricity generated from renewable energy increases during this time frame in the BAU scenario to 81 percent, and power generation causes increasingly lower emissions. The

Electricity generation and grid infrastructure savings compared to the BAU scenario — Figure 5-2



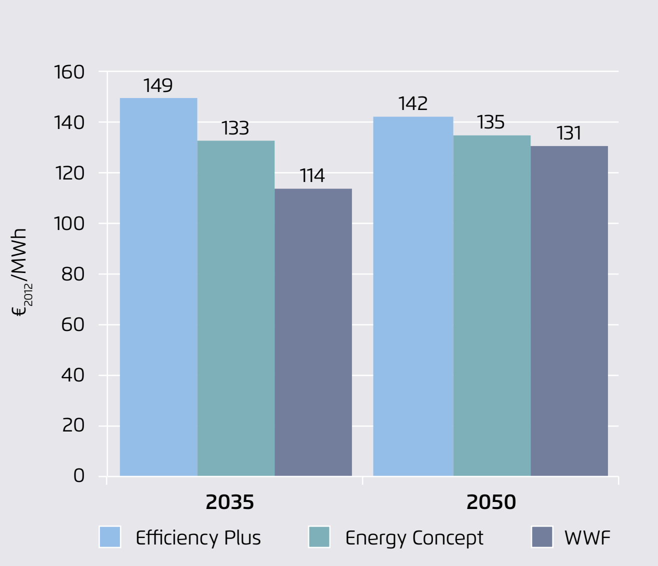
BNetzA (2012): *Monitoringbericht*; BMU (2013): Time series for the cost development of the German Renewable Energy Act (EEG); calculations by Prognos and IEAW

Specific costs of electricity and grid infrastructure — Figure 5-3



BNetzA (2012): *Monitoringbericht*; BMU (2013): Time series for the cost development of the German Renewable Energy Act (EEG); calculations by Prognos and IEAW

Specific cost savings in comparison to the BAU scenario Figure 5-4



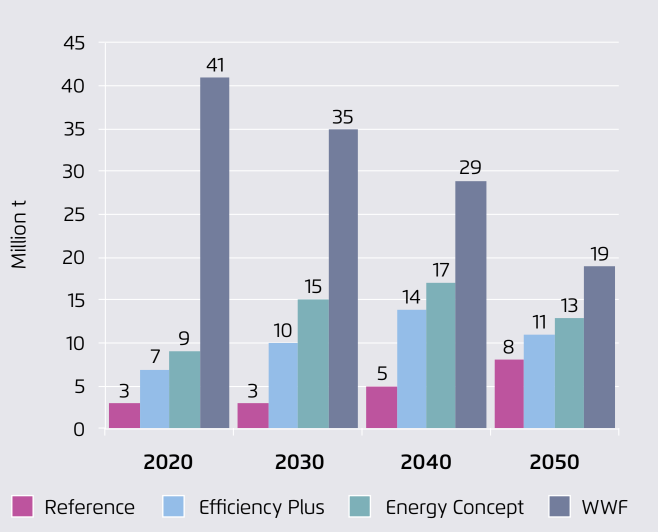
Calculations by Prognos and IEAW

Reference scenario, the Efficiency Plus scenario and the Energy Concept scenario all show lower emission savings than the WWF and BAU scenarios. In contrast to the WWF scenario, the amount of avoided emissions under these scenarios will increase by 2040, and reverses only slightly by 2050. In 2050, emission savings will be between 8 million tonnes (Reference scenario) and 13 million tonnes (Energy Concept scenario).

Compared to the BAU scenario, significant electricity cost savings result under the Reference, Efficiency Plus, Energy Concept and WWF scenarios due to avoided import expenditures for natural gas and hard coal, as less fossil-thermal power plants will be needed. In all scenarios, the avoided costs of imports are the highest in 2030. From 2030 to 2050 savings levels decline. This is because from 2030 onward, all scenarios will be impacted by the high share of electricity from renewables. In 2050, avoided import expenditures will range between 800 million euros$_{2012}$ (Reference scenario) and 1.8 million euros$_{2012}$ (WWF scenario) compared to the BAU scenario.

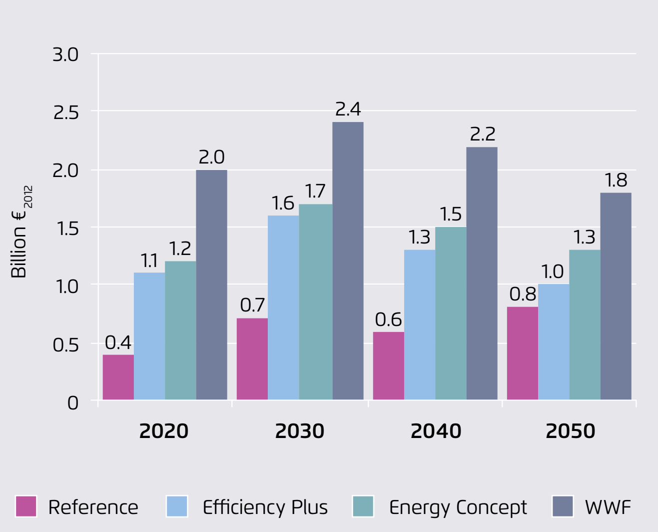
Because the fuel costs for conventional energy are already accounted for, the value of savings in this area is already included in the above totals. However, it is not clear to what extent power generation will become more independent of (increasingly expensive) imports.

Avoided CO_2 emissions of the electricity generation in 2020, 2030, 2040, 2050 compared to the BAU scenario Figure 5-5



Prognos

Avoided import costs for natural gas and coal in comparison to the BAU scenario Figure 5-6



Prognos

5.2 Assessment of the results

The aim of the study was to determine the future macroeconomic costs of electricity generation depending on varying electricity consumption trends. The above summary highlighted the forecasted costs for electricity generation and distribution under five different power consumption scenarios. The comparison of the different scenarios enables an estimate of the cost savings that could be achieved by reducing power consumption.

To assess what the saving of energy will ultimately cost, a further and more detailed analysis of energy saving measures would be necessary. However, this was not the focus of the study.

To assess these results in relation to other studies, in this section we briefly discuss other studies that have dealt with the cost aspects of power savings. The direct comparison of these studies is not possible because of the different assumptions underlying each of the studies. Indeed, there are several significant points of divergence between these studies, including, for example, whether the costs of efficiency measures are considered from a macroeconomic point of view or from a customer perspective.

The following three studies analyse, among other things, the costs of efficiency measures:

→ **EMSAITEK (IZES, BEI, Wuppertal Institute, 2011)**
This study determines the energy saving potential associated with about 70 different technologies, both from a customer as well as macroeconomic point of view until the year 2020. The considered measures apply to three consumption sectors (households, industry and commercial). The calculated economic electricity savings amount to 100 TWh by 2020. This corresponds to the consumption path of the WWF scenario.

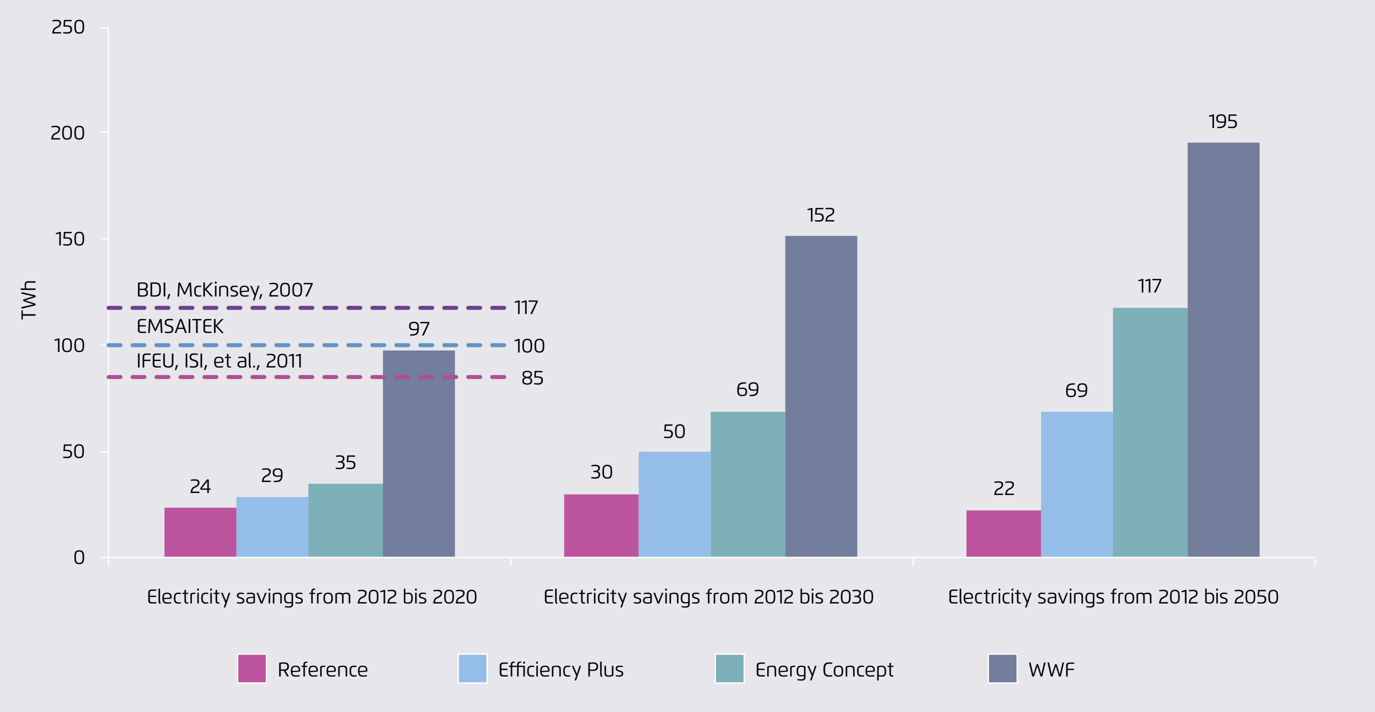
→ **Costs and Potentials of Greenhouse Gas Abatement in Germany (BDI, McKinsey, 2007)**
This study determined the costs and potentials of measures to avoid greenhouse gas emissions in the sectors energy, industry, buildings, transport, waste management and agriculture. In total, the study looked at the costs of greenhouse gas avoidance for some 300 different measures from the perspective of investors. The implementation of the economic measures would mean a decline in gross electricity production of 117 TWh by 2020. This approximately corresponds to the path of the WWF scenario.

→ **Energy efficiency: Potentials, economic effects and innovative action and support fields for the National Climate Initiative (IFEU, Fraunhofer ISI, Prognos, GWS et al., 2011)**
This study analysed the potentials for achieving energy efficiency by 2030. To quantify this potential, 43 measures were examined. A promising potential (i.e. both economically feasible and realistic in terms of implementation) of 85 TWh in electricity savings was determined for 2020 and 123 TWh for 2030 compared to a "frozen efficiency" scenario. The "frozen efficiency" forecast is similar to the BAU scenario considered here. The savings come close to that found in the WWF scenario.

These three studies indicate that the potential for energy savings by 2020 and 2030 is large enough to allow adherence to the consumption corridor for 2020 allowed for by the WWF as well as the consumption reductions set forth for 2030 by the federal government's Energy Concept. Taking the long term view up to 2050, it must additionally be considered that starting from approximately 2020 or 2030, additional potentials for economic efficiency will presumably be explored that are not yet apparent and were not part of the analysed studies. We assume that it will be feasible to implement the majority of savings projected in the scenarios in an economic manner.

The energy savings potential from different studies, as well as electricity savings compared to the BAU scenario

Figure 5-7



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6 Conclusions

The main conclusions of this study are:

- The costs of converting the electricity system can be significantly decreased by increasing energy efficiency. The more energy consumption can be decreased based on increased energy efficiency, the lower the future costs of the power system. The Efficiency Plus scenario assumes a decline in electricity consumption of 16 percent by 2050 compared to today. In 2050 the costs of the power system will amount to 56 billion $euros_{2012}$. By contrast, under the WWF scenario electricity consumption will drop by 40 percent and costs will be 43 billion $euros_{2012}$. In comparison to the Efficiency Plus scenario, costs under the WWF scenario are 25 percent lower.

- Based on the underlying assumptions, an average annual rise in energy efficiency of 2.1 percent (as seen under the Efficiency Plus scenario) will result in savings of 10 billion $euros_{2012}$ in 2035 and 15 billion $euros_{2012}$ in 2050. The cost savings from energy efficiency diverge considerable from the BAU scenario, which assumes an annual efficiency rise of only 1.3 percent.

- If an annual increase in efficiency of 2.4 percent is achieved (as forecast by the Energy Concept scenario) cost savings compared to the BAU scenario will equal 13 billion $euros_{2012}$ in 2035 and 21 billion $euros_{2012}$ in 2050.

- If electricity consumption in Germany can be significantly lowered, the costs of the power system could be stabilised or even reduced despite increasing fuel and CO_2 costs and despite a growing share of renewable energy. Under the WWF scenario, which assumes annual efficiency rise of 2.6 percent up to 2050, annual costs for power generation and distribution will be between 6 and 7 billion $euros_{2012}$ lower compared to 2012 figures.

- Depending on the underlying scenario, one saved MWh of electricity will lead to a cost reduction of between 114 and 149 $euros_{2012}$ per MWh in 2035 and between 130 and 140 $euros_{2012}$ per MWh in 2050.

- By changing the structure of the power generation system, costs will shift in the direction of renewable energy. As the costs for the expansion of renewable energy are mainly driven by the capital-intensive technologies of wind and photovoltaic, these two technologies will largely determine the overall capital costs for the future power grid. In this connection, the weighted average ROCE will have a significant impact on overall costs.

- The lower the electricity consumption in each respective scenario, the lower the need to expand the power supply grid. The study's calculations indicate that improved energy efficiency can significantly reduce the long-term need to expand the German transmission grid: while the BAU scenario indicates a need for 8,500 km of additional transmission lines by 2050, expansion requirements are 5,000 km under the Efficiency scenario, 4,000 km under the Energy Concept scenario and just 1,750 km under the WWF scenario.

- The differences in infrastructure costs between the BAU and WWF scenarios (1.9 billion $euros_{2012}$ in 2035 and 2.1 billion $euros_{2012}$ in 2050) are relatively small compared to the differences in generation costs.

- Due to the high share of electricity from conventional sources in the BAU scenario compared to the other scenarios, CO_2 emissions are the highest in this scenario over the entire period until 2050. The lowest emissions can be found in the WWF scenario due to lower electricity consumption. Under the WWF scenario, CO_2 emissions, which are directly connected to the generation of power, will be 35 million tonnes less than in the BAU scenario. This difference will amount to 19 million tonnes by 2050.

- Scenarios with lower electricity consumption are associated with reduced import costs for hard coal and natural gas. Compared to the BAU scenario, import costs in 2020 are 2 billion $euros_{2012}$ lower in the WWF scenario. On a long-term basis these savings drop to 1.8 billion $euros_{2012}$ per annum.

→ Beyond monetary savings, a reduction in electrical energy consumption leads to further benefits that have not been assessed in the study, including lower pollutant emissions by conventional power plants and reduced land use due to less development of renewable energy.

→ The electricity savings forecasted in the study are a result of numerous efficiency and saving measures across all sectors. However, an analysis of the costs of implementing efficiency and savings measures on the demand side was not a focus of the study. Nevertheless, the savings potential for electricity identified in various studies indicate that the majority of these savings can be achieved economically.

7 Appendix

7.1 Detailed description of the analysed scenarios

7.1.1 General framework

The five scenarios reflect different development options for electricity consumption. In the following, the underlying assumptions are described in more detail. Table 7-1 represents the key data regarding the scenarios.

Key data of the five scenarios

Table 7-1

	BAU	Reference	Efficiency Plus	Energy Concept	WWF
Efficiency development					
Energy productivity (BIP/PEV)	1.2 to 1.3 %/a	1.7 to 1.9 %/a	2.0 to 2.2 %/a	2.3 to 2.5 %/a	2.6 %/a
Development of electricity consumption	+0.3 %/a	-0.1 %/a	-0.3 to -0.4 %/a	-0.6 %/a	-0.9 %/a
Developments of the energy consumption until 2050 related to 2011	+7 %	-5 %	-10 % to -15 %	-20 % to -25 %	-40 %
Absolute change in energy consumption until 2050 related to 2012	+37 TWh	-22 TWh	-69 TWh	- 117 TWh	-195 TWh
Electromobility (development until 2050)					
Portion of e-cars		36 %		55 %	46 %
Number of e-cars		17 Million		25 Million	21 Million
Electricity consumption of e-cars		34 TWh		53 TWh	28 TWh

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7.1.2 Assumptions regarding the efficiency development in the consumer sectors

Assumptions of the scenarios regarding the development of the industrial sector — Table 7-2

Industry	
BAU	Based on the observed historical trends, technology development and structural change continue with the same growth level. Energy-intensive production will decrease. Growth will be exclusively generated by less energy-intensive, more knowledge-based industries. The autonomous efficiency trend driven by the general development of world market prices will continue. Market penetration of the best available technologies will increase, but lie only slightly above the autonomous trend. There are no additional policy instruments that aim at efficiency increase or climate protection.
Reference	Different to BAU scenario: Market penetration of the best available technologies occurs faster than in the BAU scenario. Awareness of and motivation for energy-efficient technologies will increase. Existing instruments will continue and be further developed.
Efficiency Plus	In addition to the Reference scenario introduction of a commitment system (About 500 energy companies participate in the commitment system (0.5 percent energy savings per year).) The committed parties implement highly economic efficiency measures in the industry. Intensified activities of energy service companies that carry out energy savings on behalf of the committed parties.
Energy Concept	Increasing introduction of innovative technology developments from nano-technology, biotechnology, micro-system technology and system integration. Technology development is accelerated in comparison to the reference scenario. All policy instruments for efficiency increase are enhanced. Specific support measures for research and development are implemented. Investments in energy efficiency measures that do not amortise during the first two years are specifically promoted.
WWF	For all materials used along the process chain, special attention is given to resource and energy efficiency. There will be a “second efficiency revolution” that results in a substantial decrease of electricity consumption and mechanical energy use. Intensified introduction of regulatory instruments, together with financial incentives. Investments in efficiency measures that do not amortise during the first half year are specifically promoted.

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Assumptions of the scenarios regarding the development of the private household sector — Table 7-3

	Private households
BAU	Increase of living space per capita, larger equipment rate of electrical gadgets and increased installation of heat pumps result in an increasing electricity consumption that compensates efficiency gains. The increasing installation of heat pumps leads to additional electricity consumption. The upgrading rate decrease from 1.1 to 0.5 percent until 2050 due to the demographic development. The upgrading efficiency remains at the current level.
Reference	Efficiency gains are higher than in the BAU scenario. Despite an increased living space per capita, larger equipment rate of electrical gadgets and increased installation of heat pumps, electricity consumption goes down. The upgrading rate decreases to 0.5 percent until 2050 due to the demo-graphic development. The upgrading efficiency remains at the current level. Existing policy instruments are continued and adjusted. The Energy Saving Ordinance (EnEV) contains stricter requirements regarding energy demand. KfW Bank Group programs are continued and receive more funding. Contracting services are implemented to a larger extent. The Eco-Design directive is implemented throughout the country.
Efficiency Plus	In addition to the Reference scenario introduction of a commitment system (about 500 energy companies participate in the commitment system [0.5 percent energy savings per year]). The committed parties implement more energy consulting and particularly promote measures such as replacing heating equipment and the use of renewables for heat supply.
Energy Concept	Increased efficiency development in comparison to the Reference scenario. The upgrading rate and efficiency are doubled. All existing instruments are intensified. Specific promotion of investments for energy efficiency in new buildings (introduction of passive house standards as a minimum requirement in 2020). Specific support measures for existing buildings (annual funding about 5 billion Euro).
WWF	Reaching the passive house standard in the buildings sector until 2020. Until 2050 average heat energy demand of 5 kWh/m². The upgrading rate and efficiency are more than doubled compared to today. Intensified introduction of regulatory instruments, together with financial incentives. Specific promotion of investments for energy efficiency in new buildings (introduction of zero-emission house standards as a minimum requirement in 2020). Specific support measures for existing buildings (annual funding about 7.5 billion Euro).

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Assumptions of the scenarios regarding the development of the trade, commerce and service sector (GHD) Table 7-4

Trade, Commerce, Services (GHD)	
BAU	The energy consumption of the GHD sector is expected to increase. Until 2050, the growth of this sector is expected to be 50 percent. Energy demand for cooling will substantially increase.
Reference	The energy consumption the GHD sector is expected to increase. Until 2050, the growth of this sector is expected to be 50 percent. Energy demand for cooling will substantially increase. Efficiency increases result from the introduction of stricter requirements regarding climate and cooling technology. Contracting services are expanded. The Eco-Design directive is implemented. Small- and medium-sized companies are specifically informed and provided with consultancy services. Technology-specific target values and efficiency standards are defined.
Efficiency Plus	In addition to the Reference scenario introduction of a commitment system about 500 energy companies participate in the commitment system (0.5 percent energy savings per year).) The committed parties implement economic efficiency potentials in public and commercial real estate. Intensified activities of energy service providers.
Energy Concept	Increased efficiency development in comparison to the Reference scenario. All instruments are intensified. Specific promotion of energy-efficiency investments regarding public buildings.
WWF	The in-house heating demand decreases to almost zero until 2050. The increased demand of cooling is limited by highly efficient technologies. As a principle, the best available technologies are used.

Prognos

Assumptions of the scenarios regarding the development of the transport sector Table 7-5

Transport	
BAU	Increasing substitution of fossil fuels by biofuels. Increasing importance of electromobility leads to increasing electricity consumption.
Reference	Increasing substitution of fossil fuels by biofuels. Increasing importance of electromobility leads to increasing electricity consumption. Avoiding trips without load, improved capacity utilisation. Specific promotion of electromobility.
Efficiency Plus	The efficiency in the transport sector does not show any further increase due to an efficiency commitment system. The assumptions of the Reference scenario apply.
Energy Concept	Increased efficiency development in comparison to the Reference scenario. Increasing use of fuel-saving engines. All instruments of the Reference scenario are intensified.
WWF	Goods are mainly transported by railway. The remaining road-bound goods transport exclusively uses sustainably produced biofuel until 2050. Private transport converts to electromobility to a large extent.

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7.2 Special consideration: Impact of a reduced electricity consumption on the expected wholesale prices

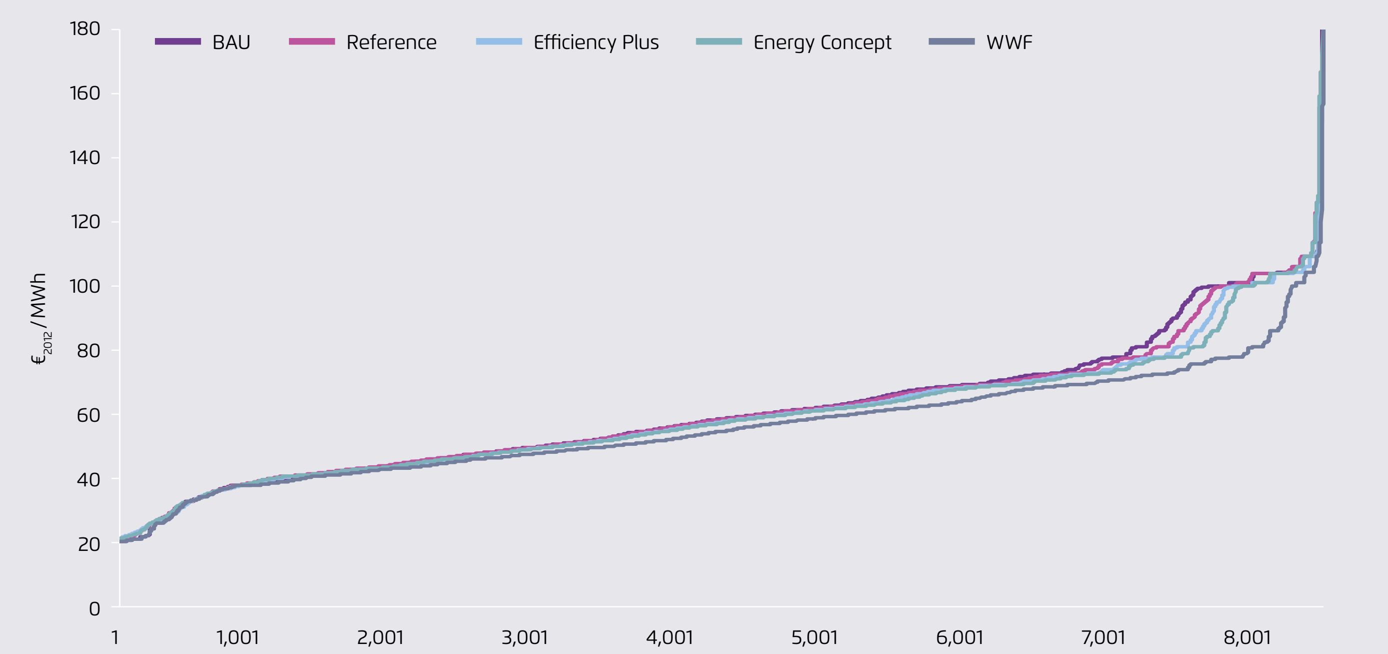
Here we will look at the effect that a reduced electricity consumption could have on the development of the hourly wholesale prices. However, different wholesale prices of the individual scenarios do not have a direct effect on the total costs (full costs) of electricity generation calculated in this study. The impact of a changed power station use on electricity generation costs was already represented by the hourly simulation for each individual plant of the power station fleet.

For a stable electricity supply, a reduced electricity demand tends to reduce prices at the exchange. If efficiency measures result in a sudden decrease of electricity consumption, electricity prices at the stock exchange may temporarily dip. In the medium and long term, the power station fleet will react to a changed consumption pattern or to lower exchange prices by shortening the supply and will decommission generation capacity at an earlier point or reduce new construction of power plants.

Whether a reduced electricity consumption will result in decreasing or increasing exchange prices in comparison to the reference development cannot be reliably predicted, as a number of different, partially contradicting factors will impact the result (e.g. age and cost structure of the existing power station fleet, development of CHP electricity generation, activation of demand-side management potentials, assumptions regarding capacity components).

With the assumptions of this study, the model calculations did not show any significant correlation between reduced consumption in the scenarios and the development of wholesale prices. The following figures show that average exchanges prices – also across most hours of the year – are very similar in all scenarios.

Sorted price curve (based on marginal costs) of the scenarios in 2030 — Figure 7-1



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In the most expensive hour range of the scenario WWF 2030, prices are lower than those in the other scenarios (see figure 7-1). Here due to the larger reduction of the consumption and the assumed comparatively large power station fleet, there are less capacity shortages that drive market prices.

In the scenario WWF 2030, marginal costs of electricity generation thus are on average 0.7 to 1.3 euros/MWh lower than in the other calculated scenarios.

For 2050, the evaluation does not show any significant impact of consumption on exchange prices (see figure 7-2). The reason is the long-term dynamic adjustment of the fossil-thermal power station fleet on the corresponding electricity demand in all scenarios. The average marginal costs are very similar in all scenarios.

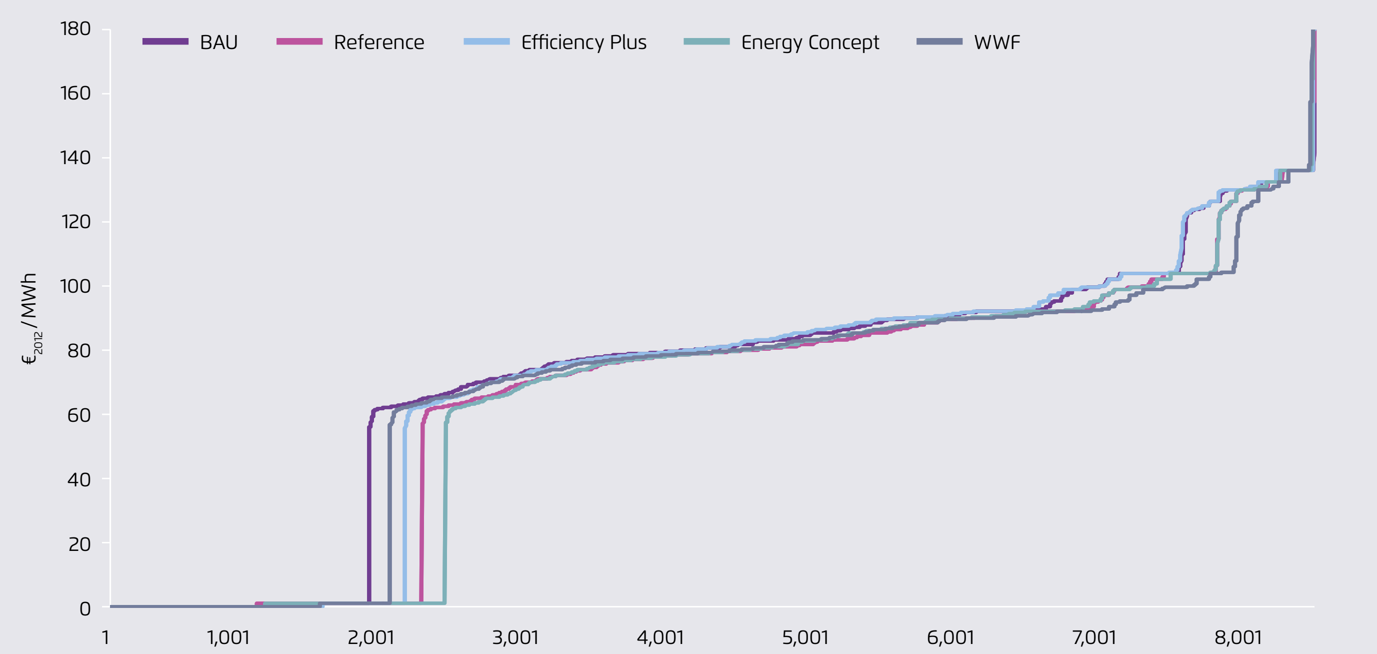
For the very subject of this study, i.e. total costs (full costs) of electricity generation and distribution, actual wholesale prices as well as retail prices are not relevant. Market prices only affect how costs are spread and are not the focus of this study.

7.3 Sensitivity: Larger RE share due to more energy efficiency

All five scenarios assume a uniform share of renewables for supplying the electricity demand. A decreased electricity consumption will therefore always result in an absolute reduction of conventional and renewable electricity generations. The following sensitivity calculations will analyse the effect of a reduced electricity consumption with the development path of renewables remaining unchanged. Here we combine the assumptions from two analysed scenarios:

→ the electricity consumption path of the Energy Concept scenario and
→ the development path of renewables from the Reference scenario.

Sorted price curve (based on marginal costs) of the scenarios in 2050 Figure 7-2



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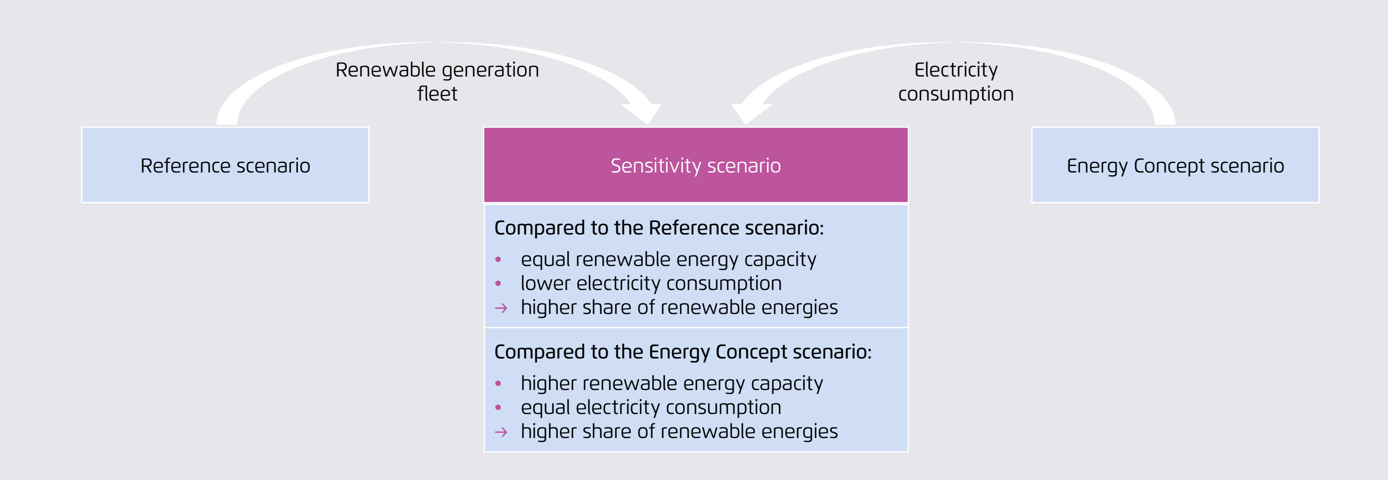
Concept of the sensitivity scenario — Figure 7-3



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For this sensitivity, the share of renewables increases faster than in the Reference scenario and the Energy Concept scenario. Instead of 2050, here renewables reach the target value of 81 percent already in 2042 – the value that the other scenarios were assumed to reach in 2050.

The sensitivity analysis shows that an increased energy efficiency in combination with an ambitious expansion path of renewables results in a larger RE share in the electricity system.

Due to a lower conventional electricity generation in relation to the here selected Reference scenario (Energy Concept), CO_2 emissions will decrease. In the sensitivity case, CO_2 emissions for the year 2042 are with 42 million tonnes substantially lower than the values of the Energy Concept scenario and the Reference scenario.

Also the costs of the conventional generation in the sensitivity case lie below the costs of the Energy Concept scenario. However, the larger RE plant fleet according to the Reference scenario assumptions is more costly than the corresponding fleet in the Energy Concept scenario.

In the sensitivity case, total additional electricity generation costs for the year 2042 amount to 3.3 billion euro_{2012} in comparison to the Energy Concept scenario. Compared to the Reference scenario, the sensitivity case results in cost savings of 4.7 billion euro_{2012}. Due to a lower electricity consumption in the sensitivity case, the costs of conventional electricity generation decrease in comparison to the Reference scenario.

Within the framework of this study it was not possible to model the necessary grid expansion for the sensitivity case and its related costs.

Assumptions and results of the sensitivity calculation for the year 2042 — Table 7-6

		Reference	Sensitivity	Energy Concept
Electricity consumption path		Reference	Energy Concept	Energy Concept
Renewables generation fleet		Reference	Reference	Energy Concept
Renewables share in 2042	%	72	81	72
CO_2 emissions of electricity generation	million tonnes	89	42	76
Costs of renewable electricity generation	billion $€_{2012}$	40.4	40.4	34.4
Costs of conventional electricity generation	billion $€_{2012}$	12.5	7.8	10.5
Total costs of electricity generation	billion $€_{2012}$	52.9	48.2	44.9

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