dena Ancillary Services Study 2030.

Security and reliability of a power supply with a high percentage of renewable energy.

dena Ancillary Services Study 2030.

Security and reliability of a power supply with a high percentage of renewable energy.

Final report

Deutsche Energie-Agentur GmbH (dena) – German Energy Agency

Energy Systems and Energy Services

Chausseestrasse 128 a

10115 Berlin, Germany

Tel: +49 (0)30 72 61 65 – 600

Fax: +49 (0)30 72 61 65 – 699

E-mail: seidl@dena.de

Berlin, 11/02/2014

Legal Information.

Publisher.

Deutsche Energie-Agentur GmbH (dena) – German Energy Agency
Energy Systems and Energy Services
Chausseestrasse 128 a
10115 Berlin, Germany
Tel: +49 (0)30 72 61 65 – 600
Fax: +49 (0)30 72 61 65 – 699
E-mail: info@dena.de
Internet: www.dena.de

Last revised 02/14

Study title	**dena Ancillary Services Study 2030. Requirements for a secure and reliable power supply with a high percentage of renewable energy.**
Version	Final report
Date	11/02/2014
Author	**Deutsche Energie-Agentur GmbH (dena) – German Energy Agency** Energy Systems and Energy Services Annegret-Cl. Agricola Hannes Seidl Stefan Mischinger **Dortmund Technical University / ef.Ruhr GmbH** Prof. Christian Rehtanz, Marco Greve Dr. Ulf Häger Domenik Hilbrich Stefan Kippelt Andreas Kubis Volker Liebenau Theresa Noll Sven Rüberg Thorsten Schlüter Johannes Schwippe Christopher Spieker Jan Teuwsen
Commissioned by	50Hertz Transmission GmbH, ABB AG, Amprion GmbH, BELECTRIC GmbH, E.DIS AG, ENERCON GmbH, EWE Netz GmbH, Mitteldeutsche Netzgesellschaft Strom mbH, N-ERGIE Netz GmbH, Netze BW GmbH, SMA Solar Technology AG, TenneT TSO GmbH, TransnetBW GmbH, Westnetz GmbH, Younicos AG
Translation	TL Translationes GmbH

dena Ancillary Services Study 2030.

Summary of the key results of the study

"Security and reliability of a power supply with a high percentage of renewable energy"

by the project steering group.

Project management:

Deutsche Energie-Agentur GmbH (dena) – German Energy Agency

Project partners:

50Hertz Transmission GmbH, ABB AG, Amprion GmbH, BELECTRIC Solarkraftwerke GmbH, E.DIS AG, ENERCON GmbH, EWE Netz GmbH, Mitteldeutsche Netzgesellschaft Strom mbH, N-ERGIE Netz GmbH, Netze BW GmbH, SMA Solar Technology AG, TenneT TSO GmbH, TransnetBW GmbH, Westnetz GmbH, Younicos AG

Berlin, 03/07/2014

1 dena Ancillary Services Study 2030: Background and objectives.

With the 2010 energy concept and the decision to accelerate the Energiewende (energy turnaround) in Germany in 2011, the German Federal Government committed to the objective of expanding the percentage of the gross electricity consumption supplied from renewable energy sources to at least 80 percent by 2050. This objective is part of a far-reaching strategy to establish a secure, economical and sustainable energy supply, which takes into account the requirements of climate protection and the targeted reduction of Germany's dependence on fuel imports between now and 2050. The objectives chosen brought about a major change of the power supply structure in Germany, which requires new solutions to provide ancillary services in future. These new solutions are necessary to guarantee reliable and stable operation of power supply grids.

As part of the Energiewende (energy turnaround) in Germany, the electricity grids must be modified and expanded to facilitate the changes in the electricity generation structure, and to guarantee constant supply security in the future. The electricity transmission grid must be upgraded to transport large quantities of electrical energy from the main generation areas for onshore and offshore wind energy in the north and east of Germany to the main consumption areas in the south and west of Germany, and at the same time to permit increasing international transit as part of European electricity trading. Renewable energy systems are largely connected to the distribution grid, i.e. at high, medium and low-voltage levels. The energy generated is largely fed from the distribution grids into the transmission grids, and must often be transported over long distances. As a result, there is a significant need for expansion and innovation in the transmission and distribution grids in Germany to prevent overloading of the operating equipment and the permitted voltage limits being exceeded.

Against this background, a review is needed of how secure operation of the power supply system can be organised under the new conditions. Conventional power plants, which today still largely provide the ancillary service products for stable grid operation, will be on-grid for fewer and fewer hours in future. The question as to how the scope and type of these ancillary service products must change to provide the **ancillary services frequency control, voltage control, system restoration and system control**.

Relevance of ancillary services for the power supply system.
In order to guarantee a high quality, reliability and security of electricity transmission and distribution, the system operators continuously take measures to keep the frequency, voltage and load of the operating equipment within the permitted tolerances or to return them to the normal range after faults. **These services, which are essential to keep the supply of electricity functional, are called ancillary services. The products required for this are largely provided by power generation units or other technical systems. System operators use these products and provide ancillary services by deploying them appropriately.**

Frequency control is implemented by transmission system operators by maintaining a balance between electricity generation and consumption. Transmission system operators can use the instantaneous reserve and balancing energy to do so.

Voltage control refers to the responsibility of the transmission and distribution system operators to maintain the grid voltage in a permissible range for the voltage quality. The system operators must also ensure that voltage drops are limited if a short circuit occurs.

Re-establishing the power supply is used in the event of a widespread power failure. Then the transmission system operators, with the cooperation of the distribution system operators, must be in a position to restore the supply of electricity within a very short time.

As part of **system control**, the system operators are responsible for organising secure grid operations. Therefore, they continuously monitor and control the electricity grid including generation and (to a limited extent) load for threshold violations (e.g. current flow overloads), in order to guarantee secure operation of the entire power supply system.

To ensure the provision and availability of the ancillary services required for secure and stable operation of the electricity grids, the following options are used today:

- Intrinsic system properties of electricity generators or consumers or properties required via grid connection codes or legal specifications
- Flexible use of operating equipment of the system operators as part of system control
- Services procured by system operators from third parties based on bilateral agreements or market mechanisms

Table 1 provides an overview of the main ancillary service products and their providers.

The **transmission system operators have the superordinate responsibility for system stability**, and must also coordinate with the other transmission system operators involved in the European integrated grid.

System restoration is realised based on a specified process controlled by the transmission system operators in the event of a power failure. The respective distribution system operators are responsible for local grid faults which are restricted to the distribution grid. In the event of larger-scale failures which impact grids up to the extra high voltage grid, the transmission system operators are responsible for controlling the system restoration.

System control and **voltage control** are the responsibility of the respective system operator, which must take into consideration the required specifications of the upstream system operators.

Ancillary service	Frequency control	Voltage control	System restoration	System control
Objective	▪ Maintenance of the frequency in the permitted range	▪ Maintenance of the voltage in the permitted range ▪ Restriction of the voltage drop in the event of a short circuit	▪ System restoration after faults	▪ Coordination of the grid and system operations
Products/ Measures	▪ Instantaneous reserve ▪ Balancing energy ▪ Flexible loads ▪ Frequency-dependent load shedding ▪ Active power reduction on excessive/insufficient frequency (RE and CHP plants)	▪ Provision of reactive power ▪ Voltage-related redispatch ▪ Voltage-related load shedding ▪ Provision of short circuit power ▪ Voltage regulation	▪ Switching measures to restrict the fault ▪ Coordinated commissioning of feeders and sub-grids with loads ▪ Black start capability of generators	▪ Grid analysis, monitoring ▪ Congestion management ▪ Feed-in management of RES ▪ Coordination of the provision of ancillary services across grid levels
Current providers (selection)	▪ Conventional power plants ▪ Flexible controllable loads ▪ Balancing energy pools (including RE systems and large-scale batteries)	▪ Conventional power plants ▪ Operating equipment (e.g. reactive power compensator) ▪ RE systems	▪ Network control unit ▪ Black start capable conventional power plants ▪ Pumped-storage power plants	▪ Network control units in conjunction with operating equipment and conventional power plants

Table 1 - Classification of current ancillary service products.

Please note here that for supply security, irrespective of the provision of ancillary services, a sufficiently dimensioned secure generation capacity will have to be maintained in the future[1] to meet the electricity demand if there is a generation shortfall from renewable energy sources due to weather conditions.

Ancillary Services Study 2030: Objectives.

The objective of the present study is to identify the need for action to guarantee secure and reliable grid operation between now and 2030 in a power supply system with a high percentage of electricity generation from fluctuating renewable energy sources. The study focuses on the power supply system in Germany taking the European integrated grid and international electricity trading into consideration.

[1]The secure generation capacity for guideline scenario B2033 of the 2013 Network Development Plan is roughly 96,000 MW with an annual maximum load of 84,000 MW.

The following **key questions** were examined as part of the study:

- How will the requirements and the demand of ancillary services to be provided develop between now and 2030?
- What contribution can and should innovative technological solutions (in particular via renewable energy sources, inverters, grid technology, demand-side management and electricity storage units) make to the provision of ancillary services in future?
- To what extent can the minimum generation capacity from conventional power plants currently required to provide ancillary services be reduced?

Study design.
This dena Ancillary Services Study 2030 was produced by the Deutsche Energie-Agentur (dena) – the German Energy Agency in close interdisciplinary cooperation with transmission and distribution system operators, manufacturers and project developers for renewable energy and manufacturers of grid and system technology.

dena initiated and headed up the study project. The study was designed by dena and coordinated with the group of experts from the companies involved in the project steering group.

The following members were represented in the project steering group as sponsors of the study: **50Hertz Transmission GmbH, ABB AG, Amprion GmbH, BELECTRIC Solarkraftwerke GmbH, E.DIS AG, ENERCON GmbH, EWE NETZ GmbH, Mitteldeutsche Netzgesellschaft Strom mbH, N-ERGIE Netz GmbH, Netze BW GmbH, SMA Solar Technology AG, TenneT TSO GmbH, TransnetBW GmbH, Westnetz GmbH, Younicos AG**. In addition to this, RWE Deutschland AG and Statkraft Markets GmbH took part in the meetings of the project steering group as guests.

The **research partner** involved was **ef.Ruhr GmbH** under the **leadership of Prof. Dr.-Ing. Christian Rehtanz**. The ef.Ruhr GmbH performed the quantitative and qualitative analyses. The project steering group discussed and checked the methods used and the results.

2 Scenario assumptions for the power supply system in 2030.

For the investigations in this study, Scenario B from the 2013 Network Development Plan was assumed for the 2033 study year. Any time “Ancillary services in 2030” is mentioned in this study, this refers to the study year 2033.

The analyses in this study assume that the installed renewable energy capacity for electricity generation will almost triple between 2013 and 2033. Onshore wind with an installed capacity of 66.3 GW, photovoltaics with an installed capacity of 65.3 GW and offshore wind with an installed capacity of 25.3 GW are the dominant generation technologies in this scenario.

For the conventional power plant fleet, the 2013 Network Development Plan predicts that the nuclear power phase-out will be complete by 2022, and that many gas power plants will be built. Overall, an installed conventional generation capacity of approx. 76 GW is assumed for 2033.

Installed generation capacity in Germany in the study year (total: 259 GW)									
Lignite	Hard coal	Natural gas	Pumped-storage	Others	Onshore wind	Offshore wind	Photovoltaics	Hydroelectric power	Biomass and others
12 GW	20 GW	41 GW	11 GW	3 GW	66 GW	25 GW	65 GW	5 GW	11 GW

Table 2 - Installed generation capacity in the study scenario (Source: Scenario framework of the 2013 Network Development Plan).

Even if changing political stipulations result in deviating expansion and development targets, the trends and the need for action revealed will largely remain unchanged as the expansion of renewable energy progresses.

For other European countries, the assumptions of the Scenario Outlook & Adequacy Forecast (ENTSO-E 2013) published in 2013 were assumed for the composition of the electricity generation mix. This analysis predicts a moderate expansion of renewable energy sources for other European countries compared with Germany.

The renewable generation capacities were allocated to individual grid nodes or regions in the grid model based on a number of criteria. Among other factors, an increase of the installed renewable energy capacity at current locations (e.g. repowering of onshore wind) and the construction at new locations particularly suitable for generating electricity are incorporated. As part of the analyses, the power plant use is calculated with hourly precision using a market-based model.

The transmission grid model used for the analyses in the dena Ancillary Services Study 2030 incorporates the expansion of the extra high voltage grid with three-phase and alternating current connections in accordance with the 2013 Network Development Plan, and the measures in the ENTSO-E Ten-Year Network Development Plan 2012 (TYNDP) for the further grid upgrades in Europe.

As part of the Network Development Plan for the extra high voltage grids, state of the art technologies are to be implemented by the transmission system operators (e.g. reactive power compensators for voltage control) in accordance with the regulatory framework. Determining the need for expansion and modification of the electricity transmission grid in the Grid Development Plan, the need for reactive and short circuit power for static and dynamic voltage control was analysed in detail as part of grid planning.

Based on the results of the Network Development Plan, this study examines all ancillary services required for secure and stable grid operation across all grid levels, and evaluates the potential of all (i.e. even new) innovative technology solutions for their provision (e.g. provision of reactive power and emulation of instantaneous reserve with renewable energy). Accordingly, the dena Ancillary Services Study 2030 is an important and forward-looking addition to the existing Grid Development Plan. The economic forecasts made in the study permit an initial classification of the alternatives available for efficient provision of the ancillary services.

Ancillary service products (e.g. primary balancing energy for frequency control) are currently utilised jointly by the participating transmission system operators, and will continue to be in future. However, for physical reasons, there is automatic mutual support in the European integrated grid for other ancillary services (e.g. instantaneous reserve for frequency control).

As a boundary condition, the requirement for all analyses performed in this study was that the technical alternatives studied for future provision of ancillary services must be provided in a manner and volume to guarantee the current level of system stability in Germany and Europe in future, too.

All analyses of the dena Ancillary Services Study 2030 were also made under the boundary condition that Germany will continue to fulfil its share of the system responsibility in the European integrated grid at a constant level compared with the current situation, and that the system support responsibility is not to be transferred to European partners.

3 Frequency control in 2030.

For stable operation of the power supply system, the power fed must correspond with the electricity consumption in the grid at all times, taking the import/export balance into account. The balancing group managers should ideally ensure fully balanced planning and react in the event of deviations within their respective balancing group.

In the event of deviations between generation and consumption, the frequency increases or decreases. The transmission system operators must ensure that the balance is restored immediately so that the target frequency of 50 Hz is maintained again.

The instantaneous reserve and the balancing energy are particularly important and are analysed in detail in this study. To maintain the frequency, transmission system operators can use contractually agreed flexible loads, or demand further adjustments from electricity suppliers and consumers in emergencies. Frequency-dependent load shedding, i.e. automatic gradual disconnection of loads from the grid, is used as a final security measure in the event of insufficient frequency. In the event of excess frequencies, electricity feed-in is throttled.

3.1 Instantaneous reserve.

Before balancing energy is technically fully available to equalise generation and consumption due to the activation times, rapid frequency changes are attenuated in the short term due to the inertia of the rotating masses of generators in the conventional power plant fleet. The capability of counteracting frequency changes by absorbing or feeding kinetic energy is referred to as instantaneous reserve.

In order to check whether there is sufficient kinetic energy in the system as an instantaneous reserve, a load or generation step of 3,000 MW is assumed as the design case for the current European integrated grid. In such cases, the instantaneous reserves must attenuate the resulting frequency change sufficiently before primary regulation sets in, so that the permitted frequency range of 50 Hz +/- 0.8 Hz (short-term/dynamic) or 50 Hz +/- 0.2 Hz (stationary) is not exceeded.

Development of the need for instantaneous reserve until 2030.

In terms of the development of the demand for instantaneous reserve by 2030, it can be assumed that the currently standard design case for grid support with a capacity change of 3,000 MW (equivalent to the failure of a double power plant block) will remain adequate.

The introduction of more renewable energy systems with generally smaller system sizes will not reduce the design case of 3,000 MW by 2030. The design criterion applies in the entire synchronous integrated grid of ENTSO-E. In 2030, there will still be a sufficient number of large-scale power plants (which determine this design criterion) in operation – based on the assumed generation scenario for Germany and Europe. Even taking the connection of offshore wind farms, construction of HVDC lines in the integrated grid and the existence of electricity distribution grids with a high installed capacity from renewable energy sources, there will be no need to increase this design criterion. This is based on the assumption that the planning principle for grid design, i.e. that no capacity steps of over 3,000 MW can occur during failures, will be retained in future.

As the renewable energy systems which feed in via inverters cannot contribute to the instantaneous reserve without additional technical measures, Germany's contribution to system support in the integrated grid would be far lower in 2030 in situations with a high RE feed-in unless countermeasures are taken. Germany's involvement in the instantaneous reserve and the need for alternative provision of instantaneous reserve to keep the contribution constant until 2030 is summarised in Figure 1. For 2011, the model calculations in this study show a contribution of the German balancing zones to a capacity step of 3,000 MW with a braking power of 372 MW and a kinetic energy of 0.95 MWh. Without the provision of instantaneous reserves from alternative sources, this contribution would reduce to roughly one third by 2030 during certain hours of the year. Until the limit value of the maximum dynamic frequency deviation of 49.2 Hz, there remains a sufficient safety margin of 0.25 Hz. To operate the power supply system as stably as in 2011 in future, i.e. to keep Germany's contribution to the instantaneous reserve constant, in 2030 at times of high RE feed-in or low conventional generation, a capacity difference of roughly 254 MW and a kinetic energy of 0.68 MWh must be provided for the instantaneous reserve via suitable alternative technologies.

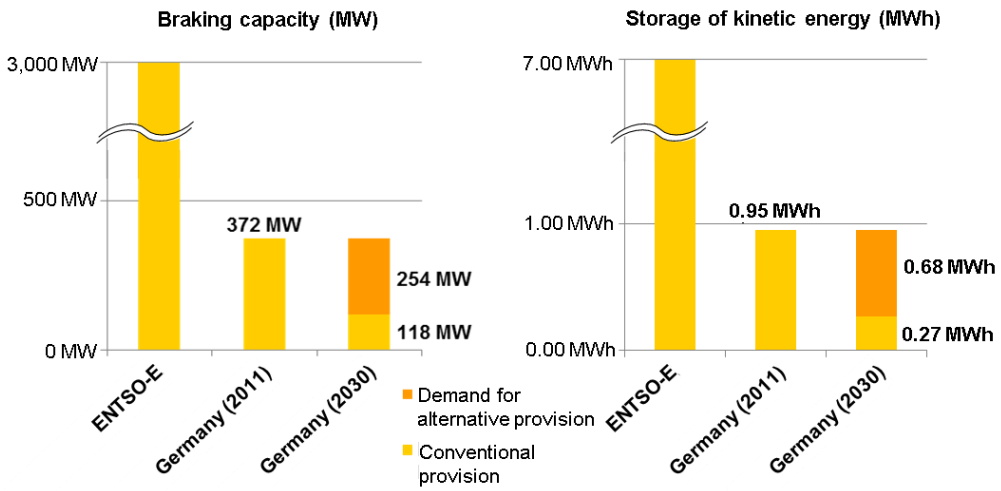

Figure 1 - Provision of the German share of instantaneous reserve.

Alternatives for provision of instantaneous reserve.

Renewable energy sources – especially wind turbines and large ground-mounted solar power plants – as well as battery storage capacities can already be technically equipped to contribute to the instantaneous reserve. In this case, the power electronics of the systems' feed-in inverters emulates the inertial properties of an electromechanical synchronous generator.

Inverters must be able to absorb and output energy in order to provide instantaneous reserve. The main technical solutions which could potentially be used for this are throttling wind turbines or photovoltaic systems, using battery storage capacities or the inertia of wind turbines (emulation of instantaneous reserve). As throttling fluctuating renewable energy would lead to a long-term loss of active power, and additional investments would be required to build battery storage for instantaneous reserve[2], using the inertia of wind turbines is the most efficient alternative. The studies assume that a wind turbine with an average system capacity of 2 MW can provide a braking capacity of up to 0.2 MW, and thus kinetic energy of up to 0.55 kWh by using the inertia of the wind turbine. In 93 percent of all hours studied in 2030, the instantaneous reserve provided in this way by wind turbines would be sufficient to keep Germany's contribution to the instantaneous reserve in the European integrated grid constant at the present level. In the remaining 7 percent of hours, there are sufficient power plants connected to the grid to provide the required braking capacity and kinetic energy for the stability of the electricity grids missing due to the lack of wind feed-in.

Recommended actions.

In order to enable Germany to fulfil its system responsibility in the European integrated grid reliably and fully in future, suitable alternative technological solutions are required to provide the instantaneous re-

[2] If battery storage are already available in the grid for other reasons (e.g. to provide primary balancing capacity), they can be incorporated for the instantaneous reserve.

serve in future in parallel to the further expansion of renewable energy. To implement this, the regulatory framework conditions must be adapted such that decentralised energy units can contribute to the provision of instantaneous reserve in future. In particular, in a first step, the conditions required for a provision of instantaneous reserve via large-scale wind turbines (emulation of instantaneous reserve) must be created. In the longer term, the extent to which the integration of other alternative providers (throttling decentralised energy units, battery storage) is necessary/economically viable and must be examined.

3.2 Balancing energy.

In order to compensate the excess generation or load which occurs over all balancing groups, the transmission system operators use positive or negative balancing energy. They purchase the balancing energy in the three product qualities – primary and secondary control and minute reserve[3] – via a regular market-based auction process. Potential providers on the balancing energy market are subjected to a pre-qualification process before participating to prove that the planned generation units or flexible loads have the required availability, reliability and controllability.

Development of the demand for balancing energy until 2030.
Assuming the generation scenario in the 2013 Network Development Plan, the assessment of the demand for balancing energy reveals a significant increase in the secondary balancing energy and minute reserve to be provided. In particular, the effect of generation forecasting errors which grows with the installed renewable energy capacity affects the demand for balancing energy. Assuming a constant forecast precision for RE feed-in, the demand for negative minute reserve capacity will increase approximately 70 percent and the demand for positive minute reserve capacity will increase by approximately 90 percent. The demand for secondary balancing energy will increase to a lesser extent (approx. 10 percent for negative and 40 percent for positive secondary balancing energy), however the increased occurrence of major wind flanks leads to the assumption of more frequent activation of the secondary balancing energy.

The dimensioning processes used today measures the demand for balancing energy on a quarterly basis. The increase of the average balancing energy demand required between now and 2030 can be restricted (see Figure 2) if in future an adaptive dimensioning process were used for balancing energy demand, e.g. for the previous day, and calculated based on the actual forecasts for load and feed-in of renewable energy. Note that even if the adaptive process is used, there will be individual days with high electricity feed-in from renewable energy sources with almost double the demand for minute reserve in 2030 compared with the present-day demand.

[3] Primary control is used to stabilise the system where there is only a brief power deficit or surplus. It is provided in a way of solidarity by all synchronously connected TSOs inside the UCTE area and has to be activated within 30 seconds. The time period of availability per single incident is up to 15 minutes.
If a longer disturbance occurs, secondary control is automatically activated within 5 minutes. The time period of availability per single incident is between 30 seconds and 15 minutes.
If the power flow deviation lasts for an extended period (more than 15 minutes) secondary control gives way to minute reserve. The latter is activated by a telephonic or schedule-based request of the affected TSO at the respective suppliers. In case of a telephonic request, the minute reserve has to be activated within 15 minutes after the phone call.

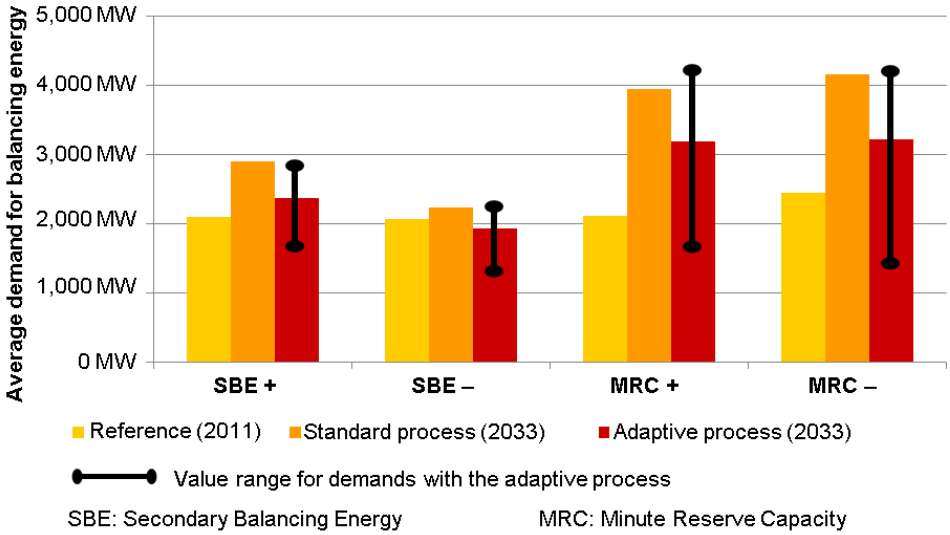

Figure 2 - Estimating the future demand for balancing energy.

Alternative providers of balancing energy.

In the present-day power supply system, balancing energy is largely provided by conventional power plants including pumped-storage plants. Alternative providers, some of which already market their capacity on the balancing energy market, include balancing energy pools comprising biogas plants, emergency electricity generators and large-scale batteries, as well as particularly energy-intensive industrial companies with flexible loads. Other alternative providers which have the fundamental capability to provide balancing energy include remote-controlled wind turbines or photovoltaic systems, and smaller generation systems (e.g. small-scale CHP plants) and loads (e.g. connection of flexible electricity loads).

In future, there will be more periods when the electricity feed-in from renewable energy sources will exceed the consumption in Germany. Then, there will be very few or no conventional thermal power plants on the German grid due to market signals. The study reveals that in 2030, market forces will dictate that during certain hours, there will not be enough conventional power plants to provide balancing energy. There are alternatives for the provision of all balancing energy products which can meet the demand, even in these hours.

Economic viability of alternative provision of balancing energy.

The study shows that there are technical options with sufficient potential. Compared with exclusive utilisation of conventional must-run capacity for balancing energy provision, using alternative providers is more economical. The study results indicate that large-scale batteries are the most economically viable alternative of those considered for primary balancing energy. There are a variety of possible alternatives for secondary balancing and minute reserve energy. The extent to which the respective alternatives can actually be developed and utilised to provide balancing energy must be derived from the supply and demand on the balancing energy market.

Recommended actions.
In order to avoid a conventional must-run capacity in order to provide balancing energy in the medium term, and thus also improve the system integration of renewable energy, the conditions for providing balancing energy from alternative sources should be improved. To do so, we must evaluate the extent to which product characteristics and pre-qualification requirements can be adapted to facilitate the market entry of new providers of balancing energy from e.g. renewable energy sources, flexible loads and electricity storage units, and meet the changing system requirements (e.g. steep flanks). In this context, a reduction of the tender periods for primary and secondary balancing energy must also be reviewed.

At the same time, technical and organisational solutions must be developed to permit coordination of increased provision of balancing energy via decentralised energy systems from the distribution grid, taking the local grid conditions into account.

In addition to this, the implementability of the adaptive assessment process must be reviewed, for example to determine and tender the probable balancing energy demand for the next day based on the previous day.

4 Voltage control in 2030.

With regard to the security and reliability of the electricity system, the stability and the level of the grid voltage must be guaranteed both in normal operation and in the event of failures. At the same time, to cope with voltage drops in the event of major failures, sufficient short circuit power must also be provided, among other things. In addition to this, stable system properties in normal operation and during failures also depend on suitable coordination of the voltage controllers in the electricity grid.

4.1 Provision of reactive power for static voltage control.

For stable grid operation and to protect people, operating equipment and end consumer devices, the voltage is kept in the permitted voltage range of +/- 10 percent of the nominal voltage at the end consumer via a variety of means. That is currently largely implemented via grid planning and operationally via provision of reactive power by conventional power plants and intentional stepping of transformers. In addition to this, reactive power compensators and voltage controllers are used in the electricity grid. Some of the redispatch measures in the transmission grid are taken for voltage control reasons.

Development of the demand until 2030.
Due to the increasing transport distances and international power transit, the demand for reactive power in the transmission grid will increase significantly by 2030. The reactive power range to be provided at the extra high voltage level, i.e. the range of reactive power demand at the respective grid nodes at different times, will increase overall.

With the increasing fluctuating feed-in of renewable energy and the increasing use of underground cables, the demand for regulating reactive power and thus voltage is growing to prevent violations of the permitted voltage range and restrict the grid expansion requirements.

Alternative provision of reactive power.

By 2030, an increasing number of alternative solutions to the current provision of reactive power in the power supply system via conventional power plants will be required. From a current perspective, the following alternatives are technical options to meet the demand for reactive power in the electricity grid:

- Installation of additional reactive power compensators (inductors, capacitors, SVCs and STATCOM[4])
- The inverter stations of the planned high voltage direct current (HVDC) transmission lines
- Reactive power provision from decentralised generation systems in the electricity distribution grids
- Modification of disused power plants for phase shift operation, equipping new power plants for decoupled phase shift operation and building standalone phase shifters

In addition to this, voltage problems can also be solved via redispatch, i.e. starting individual power plants which then regulate voltage, if the demand only arises in individual hours and corresponding generation systems are available.

The analyses show that in the studied sample electricity distribution grids, targeted controllable provision of reactive power from wind turbine and photovoltaic system inverters, which is possible irrespective of the active power feed-in, technically permits reactive power-neutral operation at all distribution grid levels. This reduces the strain on the transmission grid, which was previously used to exchange reactive power in the distribution grid. The available potential of the provision of reactive power by renewable energy sources in the high voltage grid (110 kV level) in 2030 can also be used to meet the reactive power demand of subordinate grid levels, in addition to its own demand. In addition to this, the grid regions examined in the study have the potential to provide reactive power from the high voltage grid for the superordinate extra high voltage grid.

However, results from studying individual grids cannot be extrapolated to indicate the availability and total calculated potential to provide reactive power. This must be calculated in individual cases for specific grid nodes taking the grid topology and the connected generation systems into account. A major influencing factor on the ability to provide reactive power from the electricity distribution grids for the transmission grid is the position of the grid connection points of the renewable electricity generation systems. The nearer these systems are to the transformer, the better they can be used to provide reactive power for the superordinate grid level, and the loads on the grids are reduced. For decentralised provision of reactive power, the incorporation of the tap changers from transformers to the upstream grid must be taken into account in the control concept.

Economic viability of alternative provision of voltage control

From an economic perspective, the converter stations of the planned HVDC lines are initially to be used to provide reactive power in the transmission grid. A redispatch can be implemented at grid nodes with remaining reactive power demand in individual hours only, if conventional power plants are available. For more frequent reactive power demand at grid nodes or if there is no local availability of suitable power

[4] SVC = Static Var Compensator, STATCOM = Static Synchronous Compensator.

plants for redispatch, the most economical and currently established technology available is to build reactive power compensators.

Further provision of reactive power for the extra high voltage grid via decentralised energy units from the distribution grid can be an alternative to building reactive power compensators. For this, the corresponding requirements must be available locally (presence of sufficient capacity from decentralised energy units, grid topology and capacities). In addition, an evaluation is required in individual cases as to whether the provision of reactive power via decentralised energy units is more economical than building and operating a compensation system. The study sees considerable potential for decentral provision of reactive power which also appears economically viable. This applies in particular for large ground-mounted solar power plants and wind farms. Taking the above mentioned requirements into consideration, continuous provision of minimum generation from conventional power plants is not necessary to meet the demand for reactive power.

Recommended actions.
With the increasing shift of electricity generation to the distribution grids[5], optimisation of voltage control by providing reactive power from decentralised generation systems at all distribution grid levels must be assessed under technological and economic aspects. Where it makes sense, a reduced transfer of reactive power between the grid levels should be the goal, to relieve the strain on the overlying grid levels and in particular the electricity transmission grid. The resulting costs must be economically acceptable both for the system operators and the operators of decentralised energy units.

The provision of reactive power via the inverter stations of the planned HVDC lines, should become a fixed component of coordination of voltage control in the transmission grid.

When planning the grid, the option of providing reactive power from the high voltage grid for the extra high voltage grid from RE systems is to be assessed as an alternative to building new reactive power compensators.

4.2 Provision of short circuit power for dynamic voltage control.

The provision of sufficient short circuit power is necessary to guarantee secure response to short circuit events by the corresponding protective devices. Further, short circuit power is needed to guarantee the transient stability of electric machines and to restrict the voltage drop to an area as small as possible if a failure does occur. However, the short circuit power may not be excessively high, as otherwise operating equipment could be damaged due to excessive short circuit currents and power switches may not be able to securely deactivate the high short circuit currents in the event of a failure.

[5] In 2012, 96 percent of all electricity generation systems based on renewable energy were installed in the electricity distribution grids.

Development of the availability between now and 2030.
The analyses of the short circuit power available in future show that by 2030, the range between the minimum and maximum short circuit power will hardly change from today's levels, taking the assumptions made into account. However, significant changes can be observed at individual grid nodes compared with today. The procurement of short circuit power from other countries will not increase significantly overall in spite of the changes in the power supply between now and 2030. However, the countries of origin could change.

Systems connected via inverters contribute to the short circuit power to the amount of their operating current. The short circuit power available in 2030 is therefore subject to major weather and time-dependent fluctuations. In individual cases, a review is required to assess whether the protection concept permits this bandwidth.

Provision of short circuit power can be homogenised regionally with renewable energy plants, by enabling the provision of short circuit power from inverters even without active power feed-in. This results in a decoupling from the weather and time-dependent availability of systems for short circuit power.

Recommended actions.
With regard to the regulatory framework of grid operation, conditions must be created to allow system operators to claim short circuit power from the renewable energy electricity generation plants even in times when there is no active power feed-in.

In addition to this, an analysis is also required of the effects the short circuit power changes have on the existing protection concepts and other operating aspects of the system operators.

5 System restoration in 2030.

According to the current regulations, in the event of a full or widespread power failure in the European integrated grid, the system restoration is implemented using a central concept by starting large-scale power plants with black start capabilities in the transmission grid. At the start of the grid re-establishment process, temporary standalone grids are established around these power plants with black start capabilities. Large-scale hydroelectric power plants (especially pumped-storage) and gas turbines are current examples of black start capable power plants, which can be started with batteries or emergency power systems even in the event of a blackout. Loads are added while connecting further generation capacity. Building on that, the standalone grids are gradually synchronised and connected as part of the re-establishment.

Development of the demand until 2030.

In order to guarantee the supply security, a sufficiently dimensioned secure generation capacity will still be required. In accordance with the scenario framework for the 2013 Network Development Plan, there

will still be sufficient pumped-storage and gas power plants to implement the current concept of central system restoration also in 2030.[6]

Before connecting further grid areas during the re-establishment of power supply, the extent to which electricity consumption or electricity generation are being supplemented must be known. Therefore, the weather situation and other generation-relevant forecasts must be incorporated in the power supply re-establishment concept. In addition to this, for a controlled re-establishment of the grid, the communication technology option of intentionally throttling the electricity generation from decentralised generation systems is necessary to avoid difficult to predict load changes when reconnecting grid lines or afterwards.

Alternative concepts for re-establishing the power supply.

As an alternative, the present study examines the options of decentralised concepts for re-establishing the grid. Following this concept, in the event of a widespread failure of the European integrated grid, individual electricity distribution grids autonomously permit the supply of the loads based on local generation. After elimination of the cause of the failure, the individual standalone grids are then connected and synchronised with each other in order to form the integrated grid again. As re-establishment of the grid is only needed extremely rarely, implementing a decentralised concept would mean to implement a highly complex and cost-intensive system is implemented in this case, which is only used in very rare cases. That is why a decentralised grid re-establishment concept is inefficient from a macroeconomic perspective.

Recommended actions.

Due to the extreme technical complexity and the associated investment costs, decentralised system restoration is not recommended for the future. Where corresponding options are planned by initiatives of industrial grids or individual municipal utility companies for standalone operation in subordinate grid levels, they should be incorporated in the superordinate supply re-establishment concept. Corresponding technical regulations must be issued for this.

In order to guarantee the supply security, it must be ensured that a sufficient amount of secured power plant capacity continues to be available in Germany. Centralised grid re-establishment should be implemented on the basis of these power plants, some of which need to be black start capable.

Technical solutions must be available to transmission and distribution system operators to control or limit decentralised energy systems after a grid collapse for a controlled re-establishment of the grid, even if public communication networks are not available at the time. Alternatively, the grid connection codes must ensure that generation units' responses after a blackout are suitable for a controlled system restoration.

[6] Note that the conventional power stations listed in the 2013 Network Development Plan are based on an exogenous assumption. Against the background of the decreasing economic viability of conventional power stations in today's electricity system, and the present uncertainty on the future energy law conditions, it is impossible to forecast the conventional power station capacities actually available in 2030.

6 System control in 2030.

As part of system control, system operators are responsible for monitoring and, where necessary, controlling the electricity grid and all connected generation units to guarantee safe operation of the overall system. The responsibilities of the transmission system operators include organising the use of balancing energy to maintain the frequency, voltage control and congestion management in the transmission grid as well as coordinate the grid re-establishment after failures. In their respective grids, the distribution system operators are responsible for voltage control, congestion management, elimination of local faults and the system restoration coordinated by the transmission system operators, and support the measures of upstream system operators.

Development of the system control requirements.

With the increasing integration of volatile renewable energy sources, primarily at the distribution grid level, the increased provision of ancillary service products in the distribution grid, the planned hybrid structure of the transmission grid comprising alternating current and direct current, and the increasingly multi-regional exchange of energy in the European electricity market, the requirements for system control of the electricity grids are growing at all voltage levels.

Due to the rising number of decentralised energy units, largely connected to the electricity distribution grids, the need for information and control in grid operation to guarantee system stability is also growing. It is expected that in future, an increasing number of innovative operating equipment (e.g. voltage regulated transformers in distribution grids or SVC in transmission grids) will be used to facilitate a cost-efficient expansion of the electricity distribution and transmission grids in Germany. There are also various technical options, e.g. overhead line monitoring and load flow control via FACTS[7], which can be used to guarantee optimised operation of the grid.

With a further dynamic expansion of the fluctuating renewable energy sources, it is expected that the need to control critical grid situations with congestion management, feed-in management of renewable electricity generators and switchable loads will increase in future. At the same time, these technical and organisational options will be implemented to an increasing extent to restrict the future grid expansion requirements, if the legal conditions are created to allow this.

Note also that the increasing shift of electricity generation into the distribution grids results in increasing need for coordination between the transmission system and distribution system operators. One example of this is the required coordination between the transmission system operators responsible for frequency control and the distribution system operators whose grid areas are to provide balancing energy for the respective balancing zone via decentralised energy units or flexible loads.

Solutions.

The analyses of this dena study show that grid stability via ancillary services in 2030 can be guaranteed on the basis of the operating equipment existing in the transmission grid or the additional operating equip-

[7] FACTS = Flexible AC Transmission Systems

ment planned in the 2013 Network Development Plan, in conjunction with utilisation of large-scale renewable generators, in particular at a high-voltage level, large-scale batteries and with larger flexible industrial loads. The conventional control technology available today is generally suitable for controlling these large units. If, in addition to this, a large number of decentralised units must be integrated at a medium and low-voltage level to provide ancillary service products for technical and organisational reasons, a broad-based standardised information and communication infrastructure must also be available. The costs and benefits of such a solution must be assessed in detail.

The increasing percentage of generation units in the electricity distribution grids and increasing provision of ancillary service products by these units require increasing coordination in system control between the transmission and distribution system operators and an expansion and standardisation of data and information transfer between the system operators involved.

Recommended actions.

Based on the fundamental need to expand the transmission and distribution grids to integrate renewable energy sources, the distribution system operators in particular must be allowed from a regulatory standpoint to make a technical and economic decision whether to invest in further grid expansion or optimise grid operation using stabilising interventions in generation and consumption.

For the necessary provision of ancillary service products from the distribution grid and the increasingly varying grid states, monitoring capabilities, in particular in the lower grid levels, must be expanded to guarantee secure and efficient system control operations management. This results in new responsibilities and tasks for data collection, evaluation, simulation and management of grid states. For this purpose, existing processes must be adapted and expanded, and new tools must be developed.

Implementation of the design and planning of the planned Energieinformationsnetz (energy information network) should be continued rapidly, to permit the transfer of information on the load, grid and generation situation between the system operators.

In order to make ancillary service products from the distribution grid useful for the transmission grid to the extent necessary and appropriate from an overall economic perspective, taking grid restrictions into account, the operative interaction between the transmission grid, distribution grid and plant operators should be developed further.

7 Summary.

The German Federal Government has decided to continue to expand renewable energy to reach 80 percent of the power supply in 2050. The path taken significantly changes the requirements and the technical and economic options available to provide ancillary services to guarantee a secure and stable operation of the electricity grids between now and 2030.

There are sufficient technical solutions for all kinds of system solutions now to guarantee the current level of system security, reliability and high quality of the power supply system in the future, too. Decentralised energy units and operating equipment can and must provide ancillary service products at a far higher

level, as conventional power plants, which primarily meet our need for ancillary services today, will have far shorter operating hours in future.

With regard to the lead time to implement the solutions and the goals set for further speedy expansion of electricity generated from renewable energy sources, the requirements for using economically appropriate technical alternatives to provide ancillary service products must be created at an early stage. The need to use the alternative products presented in the study to provide ancillary services must be implemented gradually via the solutions discussed as part of the Energiewende (energy turnaround), in order to guarantee system security continuously in the electricity system.

In order to guarantee the same level of system stability in 2030 as today, the members of the dena Ancillary Services Study 2030 project steering group recommended the following actions:

- The regulatory framework must be adapted to ensure that future renewable energy-based electricity generation systems, especially wind turbines and ground-mounted solar power plants, as well as large-scale batteries are equipped to provide instantaneous reserves, so that Germany can fully fulfil its system responsibility in the European integrated grid at all times. The exact scope of the systems to be involved and the need to retrofit the existing systems must be reviewed.
- With regard to the characteristics of the balancing energy market, the extent to which pre-qualification requirements, tender periods and lead times between the tender and provision period can be adapted to allow new providers of balancing energy from decentralised energy units and flexible electricity loads to enter the market, must be assessed. At the same time, solutions must be developed to permit coordination of increased provision of balancing energy via decentralised energy systems from the distribution grid, taking the local grid conditions into account. Further, the determination of the demand for balancing energy should be made more dynamic to allow a daily changing dimensioning of the balancing energy demand as it is increasingly influenced by the weather-dependent electricity feed from renewable energy sources.
- The grid connection codes and the technical capabilities of the systems must be refined to allow larger decentralised energy units in particular to provide reactive power whether they are feeding active power or not. The exact scope of the systems to be involved and the need to retrofit the existing systems must be reviewed. The option of coordinated reactive power provision from decentralised energy units can be used to optimise the demand for grid expansion in the electricity distribution grids. Furthermore, the option of demand-appropriate transfer of reactive power between the high and extra high voltage grid should be reviewed as an alternative to building reactive power compensators.
- The existing grid re-establishment concepts based on black start capable conventional power plants should be retained and developed in future. Suitable instruments must be created to enable system operators to control the fluctuating generation capacity from renewable energy sources appropriately during re-establishment of the grid.
- For increased use of ancillary service products from decentralised energy units in the electricity distribution grids, coordination and suitable exchanges of information between the system operators are required. For this purpose, the existing cascade principle of passing on requirements and information between upstream and downstream system operators must be upgraded. Every system operator remains

responsible for the security, reliability, system control and voltage control in its grid area. The transmission system operators will continue to bear the superordinate system responsibility for coordinating grid operation in the European integrated grid. In future, the distribution system operators will have additional responsibilities for data processing, simulation and management.

- The implementation of future-proof solutions to provide ancillary services in an electricity supply system with a high percentage of renewable energy must already start now to identify technically and economically optimised solutions today, and ensure that they are available reliably by 2030. Note in particular that required adaptations to the grid connection codes for various elements of the power supply system must be examined and implemented if necessary, to avoid potentially cost-intensive retrofitting measures at a later stage. Sufficient transition periods for design and pilot tests must also be incorporated when introducing new systems and processes.
- The costs for maintaining and providing ancillary service products must be economically bearable both for the system operators and the operators of decentralised energy units and flexible loads. Fundamental properties of generation systems and controllability must be required and ensured as part of the further development of grid connection codes. Further provision of ancillary service products and associated expenses must be made economically viable with a suitable compensation system. Investments and ongoing operating expenditures required on the part of the system operators for secure and stable grid operation in a power supply system with an increasing proportion of renewable energy sources (e.g. grid monitoring and development of system control tools) must be incorporated suitably in the regulatory framework.

8 Appendix

The changes until 2030 described in the previous sections and the optional and alternative measures for ancillary services are summarised in the following table.

	Frequency control Instantaneous reserve	Frequency control Provision of balancing energy	Voltage control Provision of reactive power	Voltage control Provision of short circuit power	System restoration	System control
Requirements for 2030	▪ Significantly lower contribution by conventional power plants ▪ Without alternative providers, support from the European integrated grid would be required	▪ Demand for secondary balancing energy and minute reserve increases ▪ At times, conventional power plants will not be able to meet this demand	▪ The demand for reactive power in the transmission and distribution grids increases ▪ Increased demand for reactive power control in the distribution grid	▪ Bandwidth of the short circuit power available in future will hardly change ▪ Major time-dependent fluctuation at all grid levels due to decentralised energy units	▪ There are sufficient black start capable power plants to retain the central power supply re-establishment concept	▪ Increasing complexity ▪ Increased need for congestion and feed-in management ▪ Increased need for coordination between transmission and distribution system operators
Alternative providers	▪ Wind turbines ▪ Large-scale ground-mounted solar power plants ▪ Storage capacities	▪ There are alternative providers for all types of balancing energy, which can cover the future demand	▪ Reactive power compensators ▪ HVDC inverter stations ▪ Phase shifters ▪ Power plants in phase shift operation ▪ Provision from decentralised energy plants in the distribution grid	▪ Retooling the inverters in renewable energy plants to allow them to provide short circuit power even without feeding active power	▪ Decentralised system restoration is technically feasible but not macroeconomically efficient	▪ Conventional control technology is sufficient initially to utilise ancillary service potential ▪ Broad-based standardised ICT is required to utilise smaller potential Costs/benefits must be evaluated
Recommended action	▪ Use of the inertia of wind turbines ▪ Long-term: Review of the use of potential from throttling decentralised energy plants and storage facilities	▪ Adaptation of product characteristics and prequalification requirements ▪ Check implementation of adaptive demand calculation for balancing energy	▪ Develop coordinated balancing energy provision from decentralised energy plants in the distribution grid ▪ Check alternative use of reactive power from high voltage for extra high voltage in individual cases	▪ Option for distribution system operators to request short circuit power from decentralised energy plants without active power ▪ Effect on protection concepts must be evaluated in individual cases	▪ Weather and other generation-relevant forecasts must be incorporated in the future concept ▪ It must be possible to control RE systems during system restoration	▪ Esp. distribution system operators must be able to choose between grid expansion and optimised system control ▪ Rapid implementation of the "energy information network"

Table 3 – Changed requirements and options for alternative provision of ancillary services.

Ancillary Services 2030 Report

The following report commissioned by dena was drawn up by

ef.Ruhr GmbH

Joseph-von-Fraunhofer-Strasse 20

44227 Dortmund, Germany

in cooperation with

Prof. Dr.-Ing. Christian Rehtanz

Dortmund Technical University

ie3 – Institute of Energy Systems, Energy Efficiency and Energy Economics

Emil-Figge-Strasse 70

44221 Dortmund, Germany

The report was drawn up independently and forms the basis for the dena Ancillary Services Study 2030 with quantitative and qualitative analyses. The individual statements made in the report therefore do not necessarily reflect the opinions of the project partners and dena.

Translation:

TL TRANSLATIONES GmbH

Engeldamm 14

10179 Berlin

Authors and publishing information

Authors

Prof. Dr.-Ing. C. Rehtanz,
Dipl.-Wirt.-Ing. M. Greve
Dr.-Ing. U. Häger
D. Hilbrich, M. Sc.
Dipl.-Wirt.-Ing. S. Kippelt
A. Kubis, M. Sc.
Dipl.-Wirt.-Ing. V. Liebenau
Dipl.-Wirt.-Ing. T. Noll
Dipl.-Ing. S. Rüberg
Dipl.-Wirt.-Ing. T. Schlüter
Dipl.-Ing. J. Schwippe
C. Spieker, M. Sc.
Dipl.-Wirt.-Ing. J. Teuwsen

Publishing information

Technical University of Dortmund
ie3 – Institute of Energy Systems,
Energy Efficiency and Energy Economics
Emil-Figge-Strasse 70
44227 Dortmund, Germany

ef.Ruhr GmbH
Joseph-von-Fraunhofer-Str. 20
44227 Dortmund, Germany

30 January, 2014

Table of contents

List of figures

List of tables

List of abbreviations

BMP	Biomass plant
BMU	German Federal Ministry for the Environment
BNetzA	Federal Network Agency
BP	Balancing power
CRM	Counter rate measurement (in Germany, the storage and, if required, transmission of counter readings in 15-minute intervals)
CR	Control Reserve
DECU	Decentralised energy conversion units
DSL	Digital subscriber line
DSM	Demand-side management
DSO	Distribution system operator
EHV	Extra-high voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	German Energy Industry Act
FACTS	Flexible AC transmission system
GCC	Grid control cooperation
GSM	Global System for Mobile Communications
HV	High voltage
HVDC	High-voltage direct current transmission
ICT	Information and communications technology
IGCC	International Grid Control Cooperation
LV	Low voltage
Micro-CHP	Micro-combined heat and power system
MR	Minute reserve

MV	Medium voltage
NEP	Network Development Plan
PBP / PRC	Primary balancing power / Primary control reserve
PCC	Point of common coupling
PGS	Power generation unit
PSP	Pumped-storage power plants
PSS	Power system stabiliser
PV	Photovoltaics
PV system	Photovoltaic system
RCM	Registered consumption metering
reBAP	uniform balancing energy price (in German: regelzonenübergreifender einheitlicher Bilanzausgleichsenergiepreis)
RES	Renewable energy sources
SBP / SCR	Secondary balancing power / Secondary control reserve
SNL	Quickly interruptible load
SO&AF	Scenario outlook & adequacy forecast
SOL	Immediately interruptible load
SVC	Static VAR Compensator
SY	Switchyard
TSO	Transmission system operator
UMTS	Universal Mobile Telecommunication System
WT	Wind turbine

1 Summary

1.1 Motivation

As part of the transformation of the energy supply system (energy turnaround), its share of renewable energy sources (RES) is increasing significantly. This trend is associated with a drastic restructuring of the entire energy supply system, since a large part of the renewable energy systems are locally connected to the grid, and differ from conventional large-scale power plants in terms of their technical characteristics. Due to the changed generation structure, the integration of renewable energy systems requires a significant expansion of the grid on the transmission and distribution level, and has been extensively investigated in studies such as [1] and [2].

For a technically functional energy system, additional ancillary services are required that span the four areas of voltage and frequency control, grid restoration after disturbances, and system control. For the larger part, the provision of these ancillary services is currently based on conventional large-scale power plants. Conventional large-scale power plants will be increasingly displaced by renewable energy systems. Times in which renewable energy systems nearly exclusively feed energy into the grid in Germany, and only very few or no conventional power plants, will become more frequent. Power electronics components for consumers and energy conversion systems are becoming increasingly common. This changes the requirements and the possibilities of their controllability. In addition, significant changes in the demand for ancillary services will result from an altered feed-in structure and the related temporary change or increase of electric power transmissions.

The impact of changes in the energy supply system on the level and nature of the required ancillary services, their consequences and possible alternative provision options are analysed in this study.

1.2 Objective

The aim of this study is an expert evaluation of change of ancillary services in the energy supply system caused by an accelerated integration of RES over the next two decades, and beyond the year 2030. The year 2013 is chosen as the base year of assessment, and the year under review is 2033.

It must be examined whether new concepts might need to be developed to guarantee stable and efficient system operation. The interaction between the different grid levels is of particular interest in this context. Responsibility for the ancillary services of voltage control, frequency control, grid restoration and system control lies with the relevant grid operators. Renewable energy systems are mainly incorporated on the distribution grid level and temporarily displace conventional power plants, which are today's definitive ancillary service providers. Therefore, the study will examine to what extent decentralised energy conversion plants (DECUs) and storage systems can be incorporated for the provision of ancillary services, and which interfaces between the respective grid operators are to be considered. The interplay between the transmission and the distribution grid levels is considered in particular.

The four separately examined ancillary service areas are assessed on the basis of indicative, quantitative or qualitative statements about the development of the ancillary service and the potential of possible alternatives.

In the following, changes in the energy supply system until 2033 will be described, and then the core findings of the study are summarised.

1.3 Changes in the energy supply system until 2033

The expected changes in the energy supply system affect both the generation structure as well as the consumers. Compared to conventional power plants, RES such as onshore wind turbines and photovoltaic systems (wind turbines/PV systems) are usually connected to the grid via the high, medium or low voltage levels; their specific nominal capacities are lower and their feed-in mostly depends on the availability of primary supply. PV systems are con-

nected to the grid at the converter exclusively, wind turbines only to a large extent. In the future, offshore wind turbines will mostly be connected to the transmission grid via direct current high voltage (HVDC) connections. The connected capacity of wind farms is in the multi-digit megawatt range.

The expected changes in the conventional power plant portfolio affect the installed capacities of the various power plant types as well as their locations. According to *Scenario B* of the Grid Development Plan 2013 (NEP 2013) [3], the total installed power plant capacity in Germany will only be slightly reduced in the future. Nuclear power plants will be phased out by 2022 in accordance with policy decisions. Given the adoption of *Scenario B* of the NEP 2013, the installed capacity of coal-fired power plants will decrease while the installed capacity of gas-fired power plants increases. The choice of power plant location is determined by many factors, of which access to the primary energy source is essential, while acceptance and environmental protection requirements constitute other important factors.

At the same time, the annual peak load as per NEP 2013 will change only slightly. New consumers such as electric cars, heat pumps and decentralised storage systems will be connected to the grid. These consumers also allow for the storage of electrical energy and thus, to a certain extent, a decoupling of energy production from consumption. In addition, the extent to which consumers can be controlled will increase towards full controllability, whereas the technical and economic potential is difficult to quantify.

Due to the high number of renewable energy sources which feed-in via converters and the accompanying displacement of conventional power plants, the stored energy constant currently necessary for frequency control and reactive and short circuit power as now provided by conventional power plants to support the static and dynamic voltage stability during these periods will be significantly reduced. These tasks must be carried out by alternative suppliers such as DECUs, storage systems or loads to maintain the current stability of the energy supply system.

The transmission grid will have to realise higher capacity transmissions because feed-in is becoming more distant from the points of consumption. At the same time, the volatility of power flows will increase. For an improved control over these new boundary condi-

tions, the transmission grid will be expanded and equipped with an increasing number of controllable components (high voltage direct current transmission (HVDC transmission), phase-shift-transformers and flexible AC transmission systems (FACTS)). Expansion, or reconstruction, of the distribution grid level is necessary to take into account changing operational requirements.

In summary, it is apparent that a significant change of the system will be the consequence, which will entail changes and an adaptation of ancillary services. The results of the study for individual aspects of these ancillary services are summarised below.

1.4 Frequency control results

Regarding frequency control, a distinction is made between instantaneous reserve and CR provision.

Instantaneous reserve

The development of renewable energy systems as outlined by the NEP 2013 for Germany is assumed for the year under review of 2033. For other European countries, however, a moderate expansion in accordance with *ENTSO-E* scenarios [71] is assumed. For this reason, there theoretically is no further need for action in the area of instantaneous reserve, because Europe has enough rotating masses to support the energy supply system after a generation outage of 3,000 MW, and to keep the frequency change within the specified limits.

To maintain the current share in the provision of Germany's instantaneous reserve, measures for this provision must to be taken. In this case, there are four alternatives to provide the instantaneous reserve: the use of rotational energy in wind turbines (wind inertia), throttling of DECUs, the construction of phase shifters and the employment of storage systems. Wind inertia is the most cost-effective alternative. The study of the future provision of instantaneous reserve shows that wind inertia, combined with conventional power plants, is sufficient to keep the future system on the same level of stability with respect to instantaneous reserve as today – in every hour of the year 2033.

Control reserve

If today's design practice regarding the dimensioning of CR is maintained, an increase in demand of both secondary balancing power (SBP) and minute reserve (MR) is expected. With flexible and time-dependent dimensioning, however, this effect can be somewhat compensated for. It is assumed that the dimensioning of primary balancing power (PBP) will be maintained in the future for the entire *ENTSO-E* grid area and that the proportion of transmission system operators (TSOs) does not change significantly.

PBP is currently provided by hydraulic and thermal power plants and individual large-scale batteries. As the results of Scenario 2033 demonstrate, there are many hours during which the demand for PBP cannot be fully covered by thermal power plants and pumped-storage power plants (PSP). The provision of the missing portion of PBP is most efficiently ensured by batteries. Alternatively, suitably regulated renewable energy systems and loads can also contribute towards this. If provision was ensured by systems coupled via power electronics components such as renewable energy and storage systems, they would be able to cover the demand for instantaneous reserve owing to their rapid controllability if appropriately designed. The provision of the required SBP and MR cannot be guaranteed by conventional plants in some hours of the scenario year 2033 with a low residual load.

In order to avoid a reservation of fossil-fuel must-run power plants for CR provision, other technical units must be included in the provision of all types of CR in the future. Some providers have already placed alternatives on the market, including emergency power systems, industrial loads or biomass plants (BMPs), as part of minute reserve pools. The market for SBP remains inaccessible to many of these providers, since the high availability, and the technical requirements to the output quality and the information and communication technology (ICT) involved, as well as the long time slices, represent too great a hurdle. A small proportion of PBP is already covered by large-scale batteries and run-of-the-river power plants. A shortening of the time slices would be a first step towards supporting the necessary development of further additional flexibility options.

1.5 Voltage control results

The topic of voltage control includes reactive power demand and its provision in the transmission and distribution grid. In addition, the change of the short circuit power is considered.

Reactive power demand and provision

The increased load on the transmission grid caused by energy supply that is becoming increasingly distant from load centres means that that in the future, reactive power demand on the EHV level will rise. It is necessary to overall increase the range of supplied reactive power, or the range of demanded reactive power, at the grid nodes since not only the provision of capacitive reactive power, but partly also the provision of inductive reactive power is required.

One way to meet the reactive power demand is to employ DECUs and electricity storage units on the distribution grid level. The analysis of the reactive power potential shows that reactive power neutral operation is possible at all voltage levels of the distribution grid. Prerequisite for a local compensation of the distribution grid is that DECUs make a reactive power contribution in the future without active power provisioning, which is what fully rated converters for example in PV systems, wind turbines and electricity storage units can already accomplish today. The investigations have shown that the inclusion of renewable energy systems in the high voltage level at many grid nodes is sufficient to operate this grid level in a reactive power neutral manner vis-à-vis the transmission grid. However, it cannot be ensured that there are enough renewable energy systems installed on the high voltage level throughout all grid regions in Germany to meet the reactive power demand. Therefore it will be partly and regionally necessary to include systems of the medium voltage (MV) and low voltage (LV) levels in the provision of reactive power.

In tapping the potential of the distribution grid level and involving active conventional power plants, existing reactive power compensators and HVDC transmission converters, the reactive power demand of the transmission grid can be largely covered.

The monetary valuation of reactive power provision from the distribution grid as based on the most cost-effective alternative in the transmission grid has shown that additional annuity costs of ap-

proximately € 1,500 to 2,000 per year and MW of installed wind turbine and PV capacity are acceptable in the high voltage level to leverage the potential of reactive power provision.

Short circuit power

The bandwidth between the minimum and maximum short circuit power in 2033 changes only slightly versus 2011. However, the short circuit power changes significantly at a number of nodes within the band. Despite a reduced installed capacity of conventional power plants, the available short circuit power will increase due to the expansion of the grid. According to the investigations, the German grid will not draw significantly larger amounts of short circuit power from abroad than it does today. However, there will be shifts in terms of the individual countries of origin.

The future available short circuit power is subject to the weather and daytime-dependent fluctuations because, as it currently stands, supply-dependent renewable energy systems disconnect from the grid in times without a RE supply, and therefore they are no longer available as short circuit current suppliers in case of a failure. To limit this change, converter-based DECUs and storage systems could remain consistently and actively connected to the grid to provide the ancillary service of short circuit power. In this context, the effect on the coordination of the protection systems is to be examined.

1.6 Grid restoration results

Generally, there will be no insurmountable barriers to grid restoration leading up to the year 2033. With gas turbines that are easily started from hot standby and with PSPs, it can be assumed that an emergency operation of the 380 kV grid is possible in order to gradually resupply further lower-level voltage levels, thereby integrating decentralised feed-in into the grid restoration concept.

In order to consider a large number of renewable energy systems in the future when restoring the grid, it is necessary to carry out slight throttling to reconnect the systems. In addition, frequency and voltage stability capability as well as instantaneous reserve provision are further prerequisites.

The approach of grid restoration on the basis of decentralised stand-alone/microgrids is not recommended due to the extreme

technical complexity and the associated installation costs, as this approach would only be pursued in addition to conventional grid restoration.

1.7 System control results

The future power system management for system control consist of the classical power system management architecture and an associated standard ICT-based architecture for smart market mechanisms. The smart market mechanisms serve the market-based balance between generation and consumption. At the same time, the ICT infrastructure must serve the development of area-based ancillary services and help avoid grid congestions, so that only one shared infrastructure will be implemented as a data platform. Initially, however, it will suffice to incorporate large renewable energy systems directly into the control systems for the provision of ancillary services. To this end, agreements must now be established for new systems so their potential can be fully leveraged by 2033.

ICT standards must be established at an early stage and intervention options must be defined in a legal and regulatory way to employ DECUs for area-based ancillary services. This includes, for example the design of ancillary service products in the area of frequency control up to the prequalification of providers, which also needs to be adjusted. For voltage stability, a cross-level coordination must be established that initially optimises reactive power and voltage control regulations involving DECUs, storage systems and grid controllers as ancillary services within the distribution grid, and which then provides any further potential to the transmission grid in the form of ancillary services.

At the interface between transmission and distribution grids, the distribution system operators (DSOs) are increasingly able to play an active role in the use of ancillary services in their own grids, and can therefore relieve or support the transmission system operator (TSO). DSOs also provide for mechanisms in the distribution grids to take account of grid restrictions when activating ancillary services.

Renewable energies are causing an expansion of the grid for reasons of rare feed-in peaks. Since grid expansion can hardly keep pace with the construction of new RES, and therefore the trans-

mission demand within the power grids, measures such as redispatch, DECU, storage system and load intervention in critical grid situations on all voltage levels are increasingly necessary. In contrast to market interventions, grid expansion must be weighed in an economic and carefully planned way for these rare critical events. In the future, temporary and economically viable intervention options should be regularly permissible to lower the demand for grid expansion. This approach must be fully clarified in terms of regulation so that the grids might be developed in an economically optimised way.

For this purpose, new methods of operational planning and system control must be designed that optimise and coordinate any stabilising interventions in generation and consumption on all grid levels, so that stability can be guaranteed despite scarce grid resources and a volatile operation. This planning must be probabilistic in nature in order to weigh rare circumstances and intervention options. Accordingly, grid management needs preventive and stabilising measures that can be activated for correction purposes where necessary.

1.8 Conclusion

In summary, it can be stated that the future development of the individual ancillary service aspects will pose specific challenges. In all areas, however, there are realistic solutions and potentials for solutions that make it possible to carry the current level of system stability into the future.

Wind turbines are able to support the instantaneous reserve. DECUs and battery storage systems can collectively contribute to PBP and fully cover the missing portion of thermal generation capacities at any time. SBP and MR must be dimensioned and contracted in shorter periods of time in order to be provided by DECUs.

DECUs can contribute to voltage stability, even across grid levels. Especially systems coupled via fully rated converters, such as ground-mounted solar power plants, PV systems, wind turbines and storage systems, can play a vital role.

The short circuit power in today's larger power plant locations will decline, while that of rural areas will increase. The changes are not

critical to grid operation and are technically manageable. Detailed analyses are required in the future to take into account regional grid-specific characteristics.

For the time being, today's grid restoration concepts can be continued if appropriate mechanisms for influencing DECUs are added.

System control is complex, but can be controlled by supplementing and dividing ancillary service tasks amongst transmission and distribution system operators. Optimised intervention options in generation and loads (smart grids vs. smart markets) help stabilise the grid and economically optimise its further development.

1.9 Structure of the study

In the following chapters, this study describes and analyses expected challenges in the area ofancillary services, and evaluates viable provision alternatives. To this end, the challenges for each ancillary service are first analysed qualitatively and with reference to sources, and a comprehensive list of all aspects is offered, thereby clearly outlining the problem area.

The most important ancillary service changes will be analysed in detail later in the study by means of indicative quantitative and qualitative statements on the development of ancillary services and the potential of possible alternatives made on the basis of example calculations of the German energy supply system. In this context, it is important to examine if the scope of ancillary services is changing significantly or fundamentally new solutions must be found to keep the changed system stable in the future. Where appropriate, the need for change from a political, regulatory or standardisation point of view are discussed in each section in addition to economic evaluations.

2 Frequency control

Secure operation of the power grid requires a stable frequency of 50 Hz. Frequency is the reference variable for the power balance between generation and consumption in the energy supply system. In combination with turbines, synchronous machines are rotating energy storage systems that are able to briefly compensate deviations of the active power balance before speed control or frequency control corrects power imbalance. This behaviour is called instantaneous reserve. A tolerance band of 20 mHz is granted to speed control to relieve the turbines of frequent and rapid valve movements. With very large deviations, vibrations of the generator turbine shaft can damage or destroy the shaft. For this reason, synchronous generators are turned off and disconnected from the grid at large frequency deviations. The task of frequency control is to keep the frequency at a stable level below these critical values.

The particular challenge of the future's frequency control is the increasing number of small DECUs connected to the grid via power electronics components. Due to their low feed-in capacity, these systems mainly feed electricity into the distribution grids. At short notice, these systems have only limited amounts of power available for frequency control.

Frequency control today is ensured with the three products of PBP, SBP and MRP, which each cover different time periods after a power imbalance. The required amount of these balancing reserves depends on forecast uncertainties, the underlying noise of the grid load as well as technical uncertainties such as power plant outages in the respective control area. Due to future changes in the German energy supply structure, it is to be expected that forecast uncertainties, in particular with regard to RES, will have a large influence on the required amount of balancing reserves.

In summary, Figure 2.1 presents the instantaneous reserve and various qualities of BP with regard to their activation time.

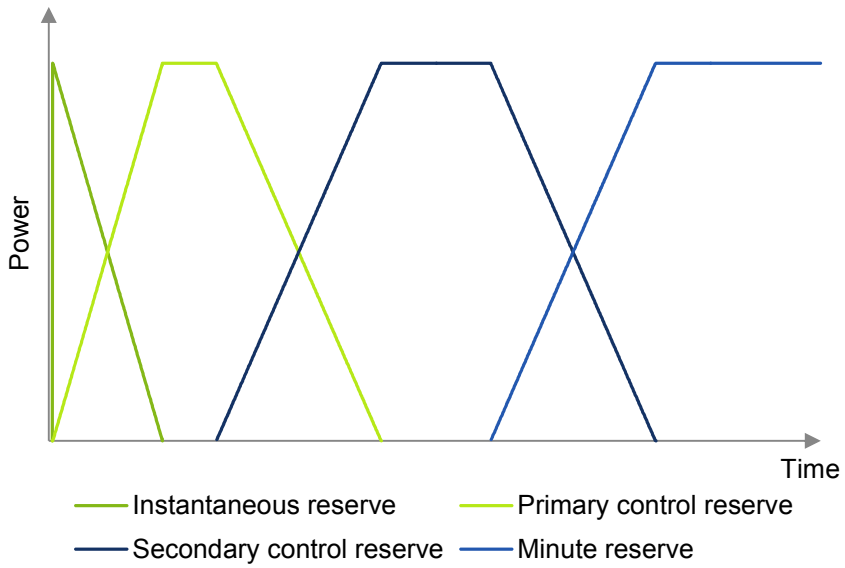

Figure 2.1 Time sequence of instantaneous reserve and CR provision (based on [4])

Instantaneous reserve, and therefore the rotating masses of conventional power plants, supports frequency control until balancing power, which is divided into three CR types according to their lead times, sets in. The automatically activated primary balancing power reserve must be fully available within 30 seconds and be maintained for at least 15 minutes. Activation of the secondary balancing power reserve is directly realised within the area affected by the outage. It takes place automatically and within a few minutes after the fault. In the German energy supply system, this reserve must theoretically last for a maximum period of one hour. In practice however, successive interferences regularly lead to longer activation times [101]. MR is a schedule-based activation by the TSO. Since July 2012, MR activation takes place in quarter-hour intervals based on automated processes [6].

Instantaneous reserve

Temporary substitution of conventional power plant capacity

Today's frequency control is ensured mainly by large power plant units that feed into the transmission grid level. However, since these (mainly fossil-fired) power plant units are increasingly being substituted by DECUs at the distribution grid level, this lowers the amount of rotating masses present in the grid, which serve as

short-term energy storage systems [4]. The overall system thus responds more sensitively to changes in the active power balance. Compliance with the required frequency limits (maximum dynamic frequency deviation of 800 mHz and quasi-steady-state deviation of 180 mHz or 200 mHz) may be at risk given a generation outage of 3,000 MW according to [9]. Compliance with these limits, especially with the lower threshold for the maximum dynamic frequency deviation, is regarded as one of the important criteria for stable grid operation. An extension of the permissible frequency band is not possible due to conventional power plants feeding in power at all times in Europe. The European energy supply system exhibits low-frequency oscillations that are damped by conventional power plants by means of PSSs (Power System Stabilisers). Due to the loss of conventional power suppliers, it may be possible that these oscillations cannot be attenuated this way in the future.

Contribution to the instantaneous reserve by European collaborative partners

It remains uncertain if contributions to the instantaneous reserve coming from abroad will always be sufficiently and systematically available to Germany, and if the transmission capacity of the interconnectors is sufficient for this purpose. In addition, this aspect has to be scrutinised against the background of acceptance by foreign countries. Moreover, the development of the power plant fleet and its utilisation, and therefore the quantity of rotating masses abroad, is fraught with uncertainty which is why the instantaneous reserve is not necessarily available with the required degree of reliability. This also has to be considered in the context of the provision of instantaneous reserve in case of failures. In case of a failure, the grid is divided into several sub-grids, so instantaneous reserve must be supplied to the individual sub-grids in order to maintain operation.

Contribution to the instantaneous reserve by DECU

The increasing supply of DECUs in the distribution grid level directly influences the instantaneous reserve. In times of high feed-in from renewable energy sources, mainly by wind turbines and PV systems, only few conventional power plants are connected to the grid. This results in a lower rotational energy of conventional power plants. Due to the lack of mass-carrying generators connected directly to the grid, DECUs as a rule do not contribute to the in-

stantaneous power reserve without additional technical measures [4].

Frequency control

Dimensioning the balancing power

It has already been shown by previous studies [20] that situations with a high share of renewable energy supply cause an increased demand for MR because forecast errors have to be balanced. Accordingly, the demand for MR heavily depends on the particular feed-in situation of RES. In the coming decades, it can be assumed that the increasing demand for MR will be counterbalanced by improved forecast accuracy and by more flexible marketing opportunities (for example, 15-minute-products on the intraday market). In keeping with today's calculation methods for BP dimensioning, no significant changes can be identified for the future demand of SBP. However, additional and very short-term power gradients should be considered (load and renewable energy system feed-in) for SBP dimensioning. In addition, the tender volumes for SBP and MR are additionally adjusted in times of predictable and high balancing uncertainties (for example, during the Christmas season of 2013 [101]). PBP dimensioning is based on the overall demand of the synchronous grid area of +/- 3,000 MW, and is adjusted annually according to the summed annual energy feed-in volume of the respective TSO. In the German Grid Control Cooperation (GCC), the tendered PBP volume has decreased slightly in recent years, namely from 623 MW in January 2010 to 576 MW in December 2013 [101].

Loss of conventional balancing power providers

Today, the providers of the three aforementioned BP products are often conventional power plants. In eliminating them, or by long-lasting high DECU feed-in, these systems no longer continuously supply power to the grid, and are therefore not available as BP providers. Even today, smaller plants are sometimes combined to form a pool of BP providers. However, the smaller the plants are and the greater their number, the greater the effort required for the additional communication infrastructure, and thus the costs of BP provision. In extreme cases, the provision of BP by DECUs in the distribution grids can lead to grid congestions due to the high degree of concurrency. At the MV and LV level, there is no guaran-

teed secure (n-1) plant connection, a fact that must be considered to ensure adequate availability.

Forecast errors with increasing feed-in from RE

The balance deviation caused by RE forecast errors is now offset mainly in the time domain of the MR, where the long-term balancing of large amounts of power takes place. Therefore, the influence of the increasing feed-in from RES is most apparent in the demand for MR. Despite the strong expansion of renewable energy systems, no direct correlation between increased RE feed-in and an increased demand for MR could be found in practice in recent years [20]. In times of low residual loads, the displacement of conventional suppliers leads to a shortage of the provision of BP. In the future, the required BP must be provided by new suppliers for times like these.

Remote-controllable renewable energy systems in direct marketing or battery storage systems are viable approaches. Therefore, pools of wind turbines or BMPs offer a negative balancing potential. Aggregated controllable loads or emergency power systems, however, are suitable for the provision of positive BP.

Frequency-dependent load shedding

Conventionally, protection relays are installed on the low-voltage side of a transformer station between the HV and MV grids. Load shedding is triggered when the grid frequency exceeds or falls below a predetermined value. This happens regardless of the load flow direction. Since DECUs are mostly connected to the distribution grid, underfrequency-dependent shutdowns can lead to a further increased power deficit, thus putting system stability at risk.

Geographical distribution of the balancing power providers

Despite nationwide tendering and activation of BP, these capacities are usually ignored in the management of grid congestions. In the event of impending grid congestion within the GCC, it is therefore necessary to ensure that the provision of BP does not violate the transmission capacity limits. This is realised by the designation of minimum core portions specific to the balancing zones. The designation of these core portions for SBP or MR is made at the request of the TSO at the Federal Network Agency (BNetzA) and is granted for a limited period. 425 MW of negative SBP in the balancing zone of the TSO 50Hertz were tendered as a core portion. Since August 2013, core portions have no longer been tendered in

the GCC [101]. The increasing future grid load caused by load-remote RES feed-in may have an impact on the requirement for the designation of new core portions, and in extreme cases it may cause an increased demand for BP due to a reduction of stochastic balancing effects. This also leads to a higher balancing power price due to the deviation from the merit order list.

Load flexibility

Analogous to BP, TSOs have the option of binding interruptible loads for the maintenance of grid and system security via a market since the amendment of the Energy Industry Act (EnWG) on 28 December, 2012 [75]. Due to the market-side implementation, flexibility on the demand side is created which counteracts the non-market-driven supply from RES. Remuneration for the contracted loads takes place according to a monthly service price of € 2,500 per MW and an energy price between € 100 and 400 per MWh. Technical requirements to the loads are extensive. The consumption unit must be connected to the HV and EHV grid and have a minimum capacity of 50 MW. A combination of up to five consumption appliances is possible, provided they are connected to the same grid node. The TSOs tender 3,000 MW every month, half of which each are immediately interruptible loads (SOL) and quickly interruptible loads (SNL). The interrupting power of the immediately interruptible loads must be provided by the TSO automatically and in a frequency-controlled way within one second, and instantaneously when remotely controlled. For SNL, no frequency-controlled activation is required and the BP is to be provided within 15 minutes [75].

Potential providers of interruptible loads are industrial furnaces or electrolysis cells owing to their almost constantly high consumption. For these highly energy-intensive industrial companies, an additional marketing option is being created on the basis of this regulation in addition to the established BP market. Currently, however, only seven framework agreements between TSOs and suppliers of disconnectable loads with a total capacity of 1,056 GW are concluded (as of: December 2013 [101]).

2.1 Research issues

In the future, there may be situations in which only few conventional power plants are connected to the grid that can contribute to

the instantaneous reserve and the three conventional BP products. Therefore, it must be investigated whether the requirements as per [9] regarding compliance with frequency limits are still fulfilled in the future, and which alternative BP providers are available in the future in times of high feed-in from RES and a low amount of rotating masses on the grid. The integration of a large number of renewable energy systems connected with power electronics components will change the system performance significantly. This must be taken into account for the newly determined requirements to the already existing and conceivable future BP products.

The following research questions are focal points of instantaneous reserve:

- How much instantaneous reserve is required for a stable grid operation?
- What is the upper limit of large-scale instantaneous reserve provision?
- To what extent can instantaneous reserve purchased from abroad be considered as secured, and may they be included in the stability analyses?
- Can the system continue to operate in a stable manner when the rotating mass decreases, but the frequency-dependent loads increase and/or the power plant dynamics are improved?
- To what extent can technologies such as DECUs and storage systems benefit from smart controlling in terms of contributing to the instantaneous reserve? Does the capacity of the distribution grid restrict provision?
- To what extent do technical measures have to be adapted in order to provide the hitherto mandatory provision of instantaneous reserve in the future?
- To what extent does the legal and technical framework have to be adapted to the future provision of instantaneous reserve?
- Can the system still operate in a stable manner with a high number of controlling components without any mutual negative effects on each other's control?

The following research questions are focal points of BP:

- To what extent do today's existing time intervals for the provision of BP, and the time slices for dimensioning in a

system with a high share of feed-in from RES, make sense?

- Does power generation in the future, predominantly by renewable energy plants, require new dimensioning methods?
- Can the future BP demand be provided by today's common suppliers or are new players called for on the BP markets (in particular renewable energy systems and storage systems)?
- For which products would power plant pooling be technically and economically viable for supply and provision in the future?
- How would it be possible to secure the tendered BP by third party plants whose performance does not meet the required degree of reliability in the provision of BP (wind turbines in direct marketing)?
- To what extent can little-used technologies, such as battery storage systems, make a contribution to frequency control and offer PBP as well as SBP independently or within a pool of plants?
- How can loads, storage systems and renewable energy systems contribute to the provision of BP?
- To what extent will there still be the traditional frequency response in an RES-driven energy supply system with the divisions into instantaneous reserve and BP products of differing quality levels?

2.2 Evaluation of current literature and studies

2.2.1 Instantaneous reserve

Calculations on the changing starting time constant in the integrated European grid at different penetration levels of RES feed-in were carried out and interpreted in [19] for selected hours of the years under review of 2011 and 2023. It is assumed that only conventional power plants with their rotating masses contribute to the instantaneous reserve. Together with other European countries, synchronous operation in Germany is possible even without rotating masses, according to approximate calculations based on the requirements in [9] as well as the current load and power generation units (PGS) [10]. Operational limits are not violated given de-

sign-compliant dimensioning [9]. [8] is based on the statement that despite the change of generation technology in Germany, enough conventional power plants continue to feed power into the integrated European grid, and that therefore the expected effects on frequency control are tolerable. Since a sufficient provision of instantaneous reserve is expected from foreign capacities, a market design change with concomitant remuneration is not expected until 2050 [7].

In addition to conventional power plants, alternative suppliers can also make a contribution to the instantaneous reserve. [7] shows that PSPs, as well as compressed air storages, are suitable to provide instantaneous reserve. Flywheel mass storages are already being tested used in pilot plants, showing that they are quite capable of offering feed-in capacities of around 10 MW, and the corresponding capacities for a charge and discharge time of 15 minutes. In addition, the possible contribution of other storage technologies such as batteries to instantaneous reserve is being analysed, along with which technologies are unsuitable and which technologies require further research. In [92], flywheel mass storages are also regarded as suppliers of instantaneous reserve. Another way to provide instantaneous reserve is by refitting existing conventional power plants to pure phase shifters. A corresponding project has already been implemented in Biblis [37]. The available rotating mass contributes to grid stabilisation but compared to a power plant, it has a lower starting time constant because the steam turbine has been partially dismantled.

In case of an inadmissible reduction of the rotating mass, plants that feed in via converters must provide instantaneous reserve by having artificial rotating mass imposed onto them from energy storage systems [8]. In [11], this is intended for larger PGS.

Concepts for regulating power electronics systems are currently being researched [12], [13]. The underlying idea is transferring the behaviour of a synchronous machine to an inverter. The control of the inverter then has properties of an electromechanical synchronous machine, and it therefore has a virtual rotating mass. Power electronics allow fast controllability, but can only provide instantaneous reserve if feed-in is secured via a storage system.

Furthermore, with an appropriate control of the rotor blades, wind turbines can provide rotational energy [93]. This short-term active

power increase reduces the frequency drop during an active power deficit. Due to the speed-dependent control of active power generation of wind turbines, it should be noted, that lowering the speed control leads to a reduced active power output [14], [15]. In Canada, technical requirements imposed on TSO wind farms with a rated capacity of over 10 MW mean that they must be able to provide instantaneous reserve through an implemented frequency control. As per this requirement, these plants approximate the behaviour of conventional synchronous machines with an inertia of 3.5 s [16]. It is necessary to examine whether the active power reduction can compromise system stability after providing instantaneous reserve, thus causing a backlog of PBP and SBP, or whether the additional stabilisation predominates at the time of the disturbance. Furthermore, it remains unanswered how a stable control can be implemented given a large number of plants and which overall system behaviour would result from this. In this context, it must be ensured that decentralised systems do not conflict in their control.

Besides a direct influence on the starting time constant of the grid-connected generators, there are two more indirect approaches to stabilising the system. The first approach involves the frequency dependence of loads. By increasing the frequency dependence of the loads, it is possible to compensate for the reduction of the instantaneous reserve. There is a study on demand-side response, in which loads were equipped with frequency chips and corresponding control methods in order to increase the frequency dependence of the load [17]. In [94], it is mentioned that loads can voluntarily participate in active power control. The acceptance of such a system and the actual usable potential of the loads must be examined.

The second approach concerns the power plant dynamics, and in particular the dynamics of primary control. In [9], referring to the prequalification of power plants, it is assumed that they are able to provide PBP within 30 seconds. Shortening this time period can counteract the lowered starting time constant caused by a decrease of rotating masses. However, the increased flexibility results in an increased lifetime consumption of conventional power plants [18], [19].

2.2.2 Balancing power

Demand for balancing power

From a technical point of view, the volume of RES represents a fluctuating feed-in capacity that is always subject to a forecast error. Up to 45 minutes prior to physical delivery, this forecast error can be balanced bilaterally, or on the intraday market, for example. The TSO then ensures a balance between supply and loads through the use of BP. If this deviation (for example, an opposing load forecasting error) is not offset by other effects, the TSO activates BP. Forecast deviations of wind turbines and PV systems are fundamentally long-term in nature, so for their compensation, MR is used after PBP and SBP. The amount of technically required SBP and MR is determined with a convolution-based method [95] carried out by the TSO, and which is then procured via the common tender platform regelleistung.net. The tendered BP volumes are currently adjusted quarterly. The PBP volume required for the energy supply system is prescribed by *ENTSO-E* and is determined annually for the TSOs.

With the further expansion of fluctuating power suppliers, the factors influencing demand for BP will be subject to constant changes. In the future, the absolute forecast error will increase due to the expansion of the volatile capacity provision of DECUs. As a result, a heavily fluctuating BP demand is to be expected. This effect has already been observed in the past. In the winter of 2012/2013, during a period of rapid wind speed changes (24.12.2012) and with an erroneous consideration of the snow cover on PV systems (02.10.2013), the maximum available BP was activated. In an analysis of time lines, a correlation between BP demand in the GCC and rapid changes in wind speed were observed (see Chapter 2.3). The current, quarterly change in the tender quantities can compensate for these high fluctuations only through a general increase in BP quantities for the entire quarter. Another measure to counteract this increase is a significant improvement in the accuracy of forecasts. A PV reference measuring system is currently under construction for this very purpose, similar to that for wind forecasts as requested by the TSOs [96].

The effect of an increasing volume of fluctuating feed-in on BP has often been studied in the past: for their analyses, both the dena Grid Study II [1] as well as the expert opinions [97] and [98] used a

convolution-based approach in combination with assumptions on future H-1 forecast errors. The outcome of the investigation for 2020 in [1] is a relatively low total balancing power demand (SBP + MR) of 4,180 MW in the positive and 3,317 MW in the negative balancing direction at a deficit level of 0.01%. A much higher demand, particularly for MR is reported in a study commissioned by the BMU [99]. According to this study, a nearly unchanged SBP demand of 2 GW is reported for the year 2033, whereas an increase in demand to 7 GW positive and 5 GW negative is expected for MR. To adapt the provision of BP to the expected RES feed-in volume, a modification of the market conditions is recommended.

Expansion of the Grid Control Cooperation

One approach to reduce the need for BP is the cooperation of control area as it is being implemented in Germany in the form of the GCC. The expansion of the GCC to the international IGCC has already led to savings of several hundred million euros by preventing counteracting activation of BP [100]. The exchange volume between foreign and German TSOs for every quarter hour, and further market information are published on an Internet platform for tendering the BP of German TSOs [101]. An extension of the IGCC is scheduled for 2014: as of January 2014, a portion of the PBP required in the Netherlands is procured (35 MW of 101 MW) via the common auction of the GCC. Previously, a study of the joint tendering of PBP between Germany and the Netherlands had been written [101]. Since March 2012, swissgrid partakes in this shared tendering of German TSOs with a portion of the PBP demand of Switzerland. In order to expand the international exchange of BP on the basis of a common merit order list, an international standard (Network Code on Electricity Balancing) is currently being developed [103]. As with the German nationwide merit order, the balancing code with a cross-border merit order allows for the purchase of cheap BP. For the technical provision of the BP, however, each TSO itself remains responsible, so the Electricity Balancing Code has no impact on technical considerations.

Alternative suppliers of balancing power

There are already some suppliers on the BP market that bundle decentralised units and market them as BP pools (cf. list of prequalified suppliers in [101]). These pools are comprised of dif-

ferent units such as biogas plants, emergency power systems, remote-controlled wind turbines or PV systems, smaller DECUs (e.g. µ-CHP) and loads (flexible industrial loads, heat pumps). This way, it was already possible to successfully prequalify all three types of balancing energy [104]. The provision of PBP by battery storage systems [105] and run-of-the-river power plants (composite of run-of-the-river power plants at the Lech river with ± 30 MW of prequalified PBP [106]) is being tested in pilot projects.

Just how great the future potential of technical units to provide the necessary flexibility is, is being discussed for the European electricity sector in [107], with a focus on loads in [109], and in terms of storage systems in [7]. The German nationwide technical potential and the respective hourly range of 20 different flexibility options is summarised in [110] and estimated quantitatively. In the future, balancing energy should be supplied by more flexible thermal power plants, load management through energy storage systems and renewable energy plants. In the following, these alternative providers of BP are discussed individually.

The concepts for the provision of BP by wind turbines were investigated with regard to economic, technical and regulatory aspects. In [111], the potential of wind turbines for the provision of BP is estimated. From July 2010 to December 2010, wind turbines have a theoretical potential of 4.7 TWh for the provision of positive and/or negative MR (4h product), with a certainty of 99.994% and a tender volume of 5 MW. Depending on the mode of operation - a distinction is made between throttling to a constant feed-in capacity per ¼ hour ("roadmap") and the difference to the feed-in capacity actually available ("possible feed-in") - slightly throttling the plants leads to higher or lower feed-in losses. Based on the year 2012 and all wind turbines in Germany, the throttled energy volume for the provision of negative MR is estimated at 760 MWh/h per offered hour [112]. The result of throttling is a constant feed-in capacity for four hours with a security level of 99.994%. An example also shows that a pool consisting of a wind farm and gas turbines can place a 30% higher offer on the balancing power market than the sum of the individual offers. With an analogous procedure in [113], the provision of BP by PV systems is evaluated and quantified for a 4h product with a potential of 0.66 TWh. This would make the participation in the BP market economically feasible both

for wind turbines as well as for PV systems and would amount to cost savings of up to 24% (MR by wind) or 6.5% (MR by PV).

Prerequisite for the leverage of this potential is the remote control capability of the plants and the adaptation of prequalification requirements in terms of certifying the provided BP and the required temporal availability of 100% for PBP and MR. In the course of the further development of the legal framework, the Federal Network Agency requests that claims of the market premium and green power privilege should be coupled to the existence of a direct control option from the very outset, and that it should not be optionally funded by a separate premium [96]. Individual direct marketers already have access to remotely controlled wind turbines and PV systems with over 4.4 GW [115]. The investment costs for connection depend heavily on the existing infrastructure and are estimated at up to € 40,000 per wind farm [116]. In terms of the typical installed capacity of wind farms (more than 12 turbines with a total connected output of 15 - 150 MW), the specific investments are on average € 60 - 800 per MW. For large ground-mounted PV systems, it is assumed that the connection costs are similar to those of wind farms. The exercise price is equal to the lost revenue from electricity marketing, resulting from the necessary throttling in the "roadmap" procedure. If negative BP is offered as a difference to the actually possible feed-in, prior throttling is not necessary. However, a prerequisite for the application of this method is the determination of the possible feed-in capacity based on wind data, taking into account plant-specific correction factors.

The use of decentralised battery storage systems is a technical and economical alternative to throttling PV systems and wind turbines for the provision of BP. PBP can be offered in combination with a battery management system, for example. An investment appraisal in [117] shows that the combination of a PV system and a storage system can be economically viable compared to throttling. In contrast to decentralised battery storage systems, large-scale battery concepts have already been technically implemented. A sodium-sulphur battery with a capacity of 1 MWh already offers a symmetric operating range of +/- 1 MW of PBP as of 2012 [104]. Another plant, consisting also of a lithium-ion storage system with an output and capacity of 5 MW, will be put into operation in September 2014 [119]. In particular, supply of PBP and SBP by battery storage systems will gain importance in the future due to

the decreased availability of thermal power plants (cf. Chapter 2.4). The energy installation costs of lithium-ion batteries for frequency control are estimated at € 150 - 300 per kWh for 2030 and the capacity installation costs at € 35 - 65 per kW [118].

Emergency power systems (EPS) offer a flexibility option, especially for MR, if they are connected by means of communication technology and have a way to feed into the grid. EPS ensure maintenance of power supply irrespective of the public power grid and are used, for example, in hospitals, airports and data centres. The positive potential of activating EPS in Germany is estimated to be 5 - 8 GW in 2020 [120]. The necessity of their existence in order to ensure security of supply, and their reliability, make emergency power systems particularly appealing to MR pool operators. The exercise costs correspond to the fuel price and depend on the efficiency of the EPS. An EPS with an electrical output of 1 MW and a consumption of 260 l/h incurs variable costs of € 360 per MWh at a fuel price of € 1.40 per litre.

Another potential, especially for MR, are consumers and PGS for the provision of thermal energy in the private sector, such as micro-CHP (µ-CHP), heat pumps and electric heating systems. The cumulative electric output of µ-CHPs is still very low at currently about 0.5 GW [121]. Their potential, however, is much higher, because with 17 million households, the majority of the flats in Germany are heated with natural gas [121]. Only very few of these systems provide electricity in addition to heat, but they could be a useful flexibility option through the increased use of µ-CHP in a current-controlled mode of operation. The flexibility of heat pumps is being discussed as a controllable load in private households. In Germany, only less than 300,000 flats use heat pumps to leverage geothermal, exhaust air and other environmental heat sources. Nevertheless, the further consideration of this flexibility option is worthwhile, because a strong expansion of this technology is expected [124]. Far more common are the electric heating systems installed in 1.4 million households [121]. With an electrical output of 7 - 19 kW per household, this leads to a theoretically usable positive balancing potential of about 10 GW. The availability of these units is affected by the heating demand of the residents and is therefore subject to pronounced seasonal and daily fluctuations. Moreover, the impact on the distribution grid given a marketing of these flexibility options is to be observed, as it leads to a high de-

gree of local simultaneity under certain circumstances. In [123], the revenue potential of providing MR is determined taking into account the work and capacity availability of the different units. The capital costs of the necessary communication infrastructure, meters and installation is estimated at € 200 - 250 per household [154] . In addition to the debt service for this investment, annual costs for operating the metering station, metering services and billing are incurred, resulting in fixed total costs of at least € 130 per year. This metering and billing method, suitable for making household loads and generation more flexible, is currently being designed and is called "Zählerstandsgangmessung (ZSG)" (counter rate measurement, CRM) [127]. The costs of CRM are below those of registered consumption metering (RCM), which is used for large-scale customers (€ 500 - 1,000 per year). The billing method via standard load profiles as currently used for household customers is relatively cheap with about € 30 per year, but inadequate in terms of flexibility. The major challenge in developing the potential flexibility of private households thus lies in the implementation of new supply, balancing and metering concepts (cf. [127]).

The BP potential in the cement industry, aluminium electrolysis, the paper industry and in chlorine electrolysis currently amounts to 0.5 - 1.5 GW and is already largely being offered in the form of positive MR [124], and of SBP in the case of zinc electrolysis (cf. list of prequalified suppliers in [101]). These participants compete with capacities on the production side, which leads to a very low revenue potential. The provision of positive BP is technically and organisationally possible in some industrial sectors, but carries the risk of increased grid fees should its activation result in an increase of the annual peak load. The leverage of the technical potential is largely still outstanding and requires a comprehensive consideration of individual cases. Due to the largely optimised process chain of the manufacturing industry it is likely, however, that the technical potential is far lower than the theoretical potential, especially since the economic incentive is very low given the current price level on the BP market. The effect of load shifting or load shedding on the production process is a higher price risk than the additional ICT costs for increased flexibility, since RCM is often already applied. A detailed analysis of the nationwide demand side management (DSM) potential in Germany, with a distinction between domestic, commercial and industrial potential can be found in [2].

The flexibility of BMP is already being marketed as SBP and MR (see supplier list on [101]). The challenges for the electricity and balancing power market-determined mode of operation are upgrading the plants by increasing their power generation capacity alongside lower full-load hours and, if necessary, adjusting the gas storage capacity. The flexibility premium pursuant to § 33 EEG promotes plant expansion and has led to the availability of nearly 100 MW of demand-based electricity generation in Germany [125]. Table 2-1 lists the future suppliers of BP.

Table 2.1 Overview of examined future suppliers of BP

Supplier	Note	Costs
Wind turbines	Possible, theor. pot.: 4.7 TWh (July to Dec. 2010)	ICT: € 60-800 / MW Var. c.: lost revenue from electricity marketing
PV systems	Possible, theor. pot.: 0.7 TWh (July to Dec. 2010)	
Emergency power systems	Already used, capacity in 2020: 5 - 8 GW	Var. c. (fuel): approx. € 360 / MWh
µ-CHPs	Current potential: Low	New supply concepts required, then ICT per household: approx. € 250 per year If necessary, costs for additional thermal storages
Heat pumps	Current potential: Low	
Electric heating systems	Theor. pot. >10 GW	
Industry sector	Part. already used, positive pot.: 0.5 - 1.5 GW; negative pot.: minimum	ICT: low, since RCM available Var. c.: heavily depend on production process
Battery storage systems	Individual large batteries already exist, decentralised concepts conceivable	Investment costs highly dependent on technology and application, Lithium-ion battery today: € 150 - 200 / kW and € 300 - 800 / kWh; in 2030: € 35 - 65 / kW and € 150 - 300 / kWh

The minimum requirements to the ICT of the supplier for the provision of SBP are higher than those for MR and are regulated by [129]. The connection of every technical unit must be carried out as part of an SBP pool and the connection of the supplier control system to the TSO has to take place via a separate grid. When using a public ICT (for example, DSL, GSM or UMTS), it must be ensured that it is only used by a restricted user group. Communication with connections outside of this restricted user group is

thereby prevented and a direct connection to the Internet or other user groups is not possible. The connection of the control centre of the pool operator to the TSO must be redundant. Depending on the TSO, the supplier receives a new setpoint value every 1 - 4 seconds that it then autonomously forwards to the technical units in its pool. For units with a low power capacity, this required control system connection is a significant effort and incurs high costs. The higher power gradient of SBP in the event of its activation is a major challenge for some of the alternative suppliers. In addition to these technical requirements, the market entry barriers for the provision of SBP are higher due to the longer time slices. A detailed consideration of individual suppliers of instantaneous reserve and BP is made in the following section.

2.3 Calculations for the instantaneous reserve

First, the method for determining the future demand of instantaneous reserve is explained using the Matlab/Simulink model. The results of the model yield the frequency response curves for the *ENTSO-E* area for selected hours of the calculated power plant utilisation in 2033, after a 3,000 MW generation outage. The share of the provision of instantaneous reserve is shown separately for Germany and the *ENTSO-E* area. Furthermore, the frequency response curves are examined that result if the generation outage is covered only by the rotating masses of foreign countries, and therefore when the energy supply system in Germany is powered solely by renewable feed-in. Finally, it is shown which alternative providers can contribute to the provision of instantaneous reserve and how a stable grid operation can be guaranteed by these providers in the year under review of 2033.

2.3.1 Method used to determine the instantaneous reserve

The examination of the frequency response after a generation outage is crucial to analyse the future demand for instantaneous reserve. A mathematical model derived from [130] is used in Matlab/Simulink to describe the response. Information and requirements from the *ENTSO-E Operation Handbook* are adopted as a reference and serve to validate the mathematical model. The

model takes into account the instantaneous reserve of the rotating masses of the synchronous machines, the frequency dependency of the load as well as the primary control of the conventional power plants. The frequency dependency of the load is assumed to be 1% / Hz (load droop of $S_L = 2$), and the droop of the primary control is assumed to be $S_P = 0.2$. For primary control, a linear increase in the reserve power after a generation outage is assumed, similar to the assumptions made in the *Operation Handbook*. The share of directly coupled electric machines will decrease in the future in favour of grid connection via fully rated converters. An explicit model of these grid components is therefore not provided.

The observed frequency response is a global phenomenon of the energy supply system, which is why the analytical framework is not restricted to the German power grid. Information on European collaborative partners and their feed-in structures must be included in the future. The analysis focuses on the frequency response of the system, so that an examination of power flows is not necessary. Under the premise that the integrated European grid is universally viewed as rigid in terms of frequency, its treatment as a point grid is permissible. Runtime effects and a possible overloading of cross-border transfer points are ignored in this consideration. By evaluating the grid calculations carried out in chapter 3, it can be generally assumed that cross-border transfer point cables are not bottlenecks in terms of the (n-1) criterion even in situations of high wind supply, and that there is enough available transmission capacity for the provision of instantaneous reserve (see Chapter 3.3).

To study these issues, market simulations (see Appendix A.2) for the generation and load structure of Germany as based on *Scenario B* of the NEP, and for other European countries as based on *Scenario Outlook & Adequacy Forecast (SO&AF)*, for the year under review of 2033 are conducted and evaluated. Hours of the year 2033 with, amongst others, a particularly high proportion of renewable energy suppliers are selected and modelled on the basis of the underlying single-node model. Regenerative energy suppliers are considered to be static suppliers, so they do not contribute neither to the instantaneous reserve nor to primary control.

The conventional generation required to cover the remaining residual load is determined according to the result of power plant

utilisation planning, and the involved conventional power plants are modelled according to their type using typical dynamic parameters.

In viewing the system as a single-node grid, the entire rotating mass in the grid can be combined into one single equivalent rotating mass. A uniform system frequency can thus be assumed for the entire grid. This is equivalent to the notion that all available rotating masses rotate synchronously to the grid's frequency. The determined scenario results in a corresponding starting time constant of the grid.

If this grid suffers a generation outage, the resulting frequency response of the *ENTSO-E* area can be determined using the mathematical model. In particular, the focus is on compliance with threshold values of the maximum and quasi-steady-state frequency deviation as per the *ENTSO-E Operation Handbook*. Compliance with these limits, especially with the lower threshold of the maximum dynamic frequency deviation, is regarded as one of the important criteria for stable grid operation.

For different extreme scenarios of the *ENTSO-E*, the frequency response is determined after a generation outage of 3,000 MW. This frequency response is then used to derive the fraction of the instantaneous reserve provision for Germany and the *ENTSO-E* area. If the threshold values in the selected scenario with a high level of feed-in from renewable energy sources and a lower conventional feed-in level are not observed, it is checked in the following how much additional instantaneous reserve is required so as not to fall below the limit values. Furthermore, the frequency response of *ENTSO-E* is reported that results if Germany has no rotating masses in the grid. The frequency response takes into account the provision of instantaneous reserve and primary control reserve from conventional power plants, as well as the frequency dependence of the loads.

In addition, it is qualitatively examined how many alternative provision options are needed to ensure stable grid operation in 2033.

2.3.2 Future development of the instantaneous reserve

In order to determine the future demand for instantaneous reserve, different hours of the year 2033 were selected with regard to high

(*Scenario I*), medium (*Scenario II* and *Scenario III*) and lower conventional generation (*Scenario IV*). In consideration of the respective conventional generation, the results are the current RES feed-in and the load ratio, which is evaluated using the Matlab/Simulink model.

In Table 2.2, the scenarios considered are summarised.

Table 2.2 Scenario definition instantaneous reserve - selected hours during the year under review of 2033

Scenario	Scenario definition
Scenario I Hour number 739	• Evening hour end of January • High level of conventional generation • Low RES feed-in
Scenario II Hour number 842	• Evening hour end of February • Medium level of conventional generation • High level of wind turbine feed-in
Scenario III Hour number 4071	• Noon middle of June • Medium level of conventional generation • High level of wind turbine and PV feed-in
Scenario IV Hour number 3053	• Morning hour beginning of May • Low level of conventional generation • High level of wind turbine feed-in, no PV feed-in

Explicit load and feed-in data of the selected hours for the German energy supply system are listed in Table A.6. The frequency response curves over time are shown in figure 2.2 for the selected hours for the *ENTSO-E* area. At time t = 0, there is a generation outage of 3,000 MW.

Shown for the respective hour in every scenario are the rated apparent power (S_N) of the grid-connected conventional power plants, the current RES feed-in and the total starting time constant (T_{AN}) of the energy supply system. It should be noted that the load is different in every hour. To ensure comparability of results, par-

ticularly in relation to the starting time constant of the grid, the load is relative to 300 GW in all scenarios.

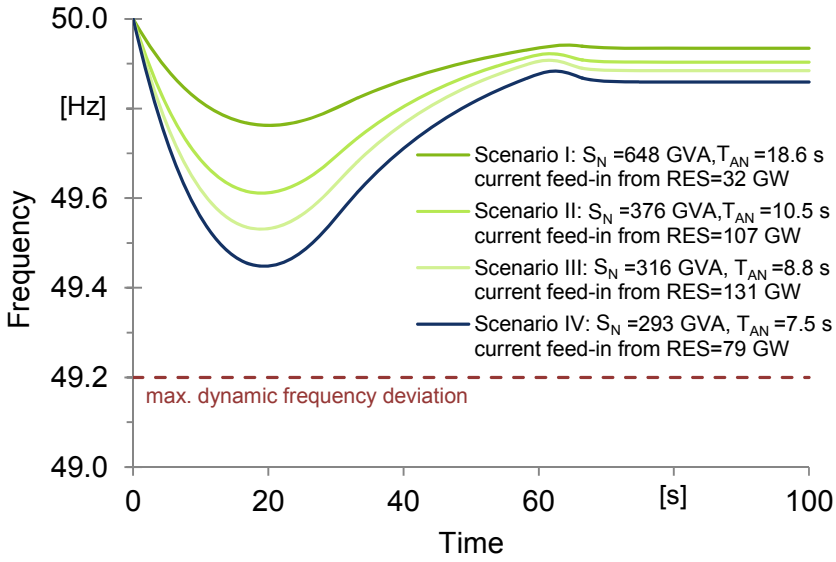

Figure 2.2 Frequency response curves of selected hours for the *ENTSO-E* area in the year under review of 2033

The results show that there are sufficient rotating masses on the grid for every selected scenario of 2033, which is compliant with the limits as per *Operation Handbook*.

For *Scenario I* and as an example, Germany's share and the overall share of *ENTSO-E* in the provision of instantaneous reserve as caused by the generation outage are shown in Figure 2.3 for 2033. The share of Germany in 2011 for the same hours is shown for purposes of comparison.

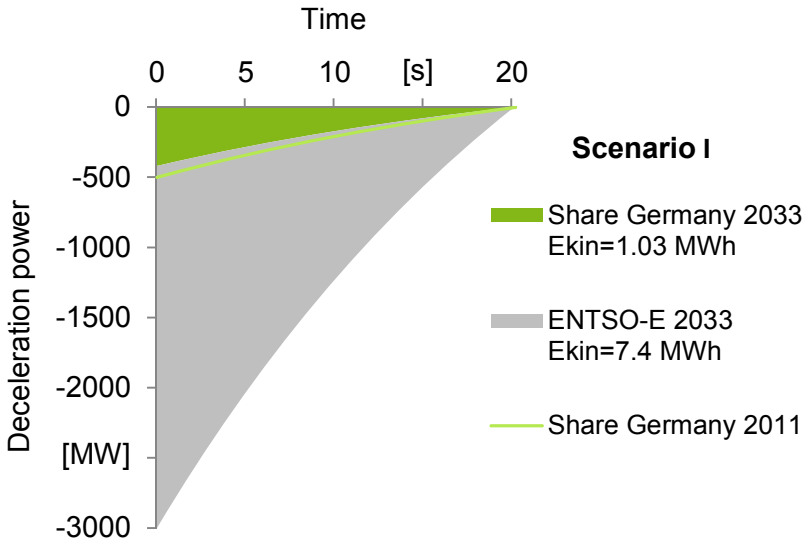

Figure 2.3 *Scenario I*: Contribution to the provision of instantaneous reserve made by Germany and the *ENTSO-E area*

In *Scenario I*, the entire *ENTSO-E* area including Germany covers the occurring generation outage with a braking power of 3 GW and by reduction of 7.4 MWh of kinetic energy. In this case, Germany contributes with a capacity of approximately 420 MW and with kinetic energy amounting to 1.03 MWh.

Figure 2.4 shows that at a system frequency of 50 Hz, the entire European energy supply system has a total available kinetic energy of 773.6 MWh in *Scenario I*. In addition to the resulting frequency response after a generation outage of 3 GW at time t = 0 s, the resulting kinetic energy is shown at the time of the frequency minimum. 7.4 MWh (cf. Figure 2.3) is withdrawn from the system as a result of the generation outage.

In addition, the frequency response curve is shown that would result after a fictitious power generation outage in order to reach the maximum limit of 49.2 Hz [9]. To reach this limit, 24.6 MWh of kinetic energy would have to be withdrawn from the system.

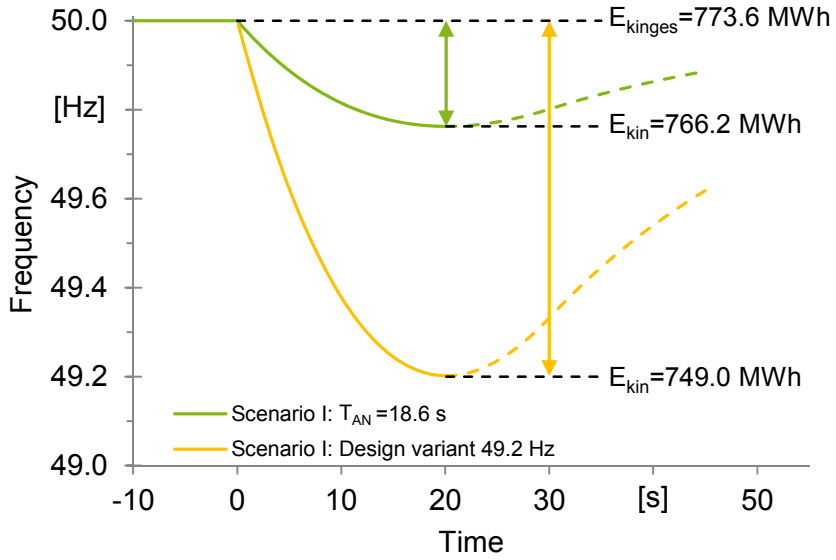

Figure 2.4 *Scenario I*: Frequency response curves for the selected hour and the design variant plus designation of the kinetic energy

For *Scenario IV*, the results regarding the share of Germany and the overall share of *ENTSO-E* in the provision of instantaneous reserve as triggered by the generation outage are shown in Figure 2.5.

In this case, Germany contributes to the generation outage with a power of approximately 120 MW and kinetic energy amounting to 0.27 MWh. The kinetic energy withdrawn from the entire *ENTSO-E* area amounts to approximately 7 MWh.

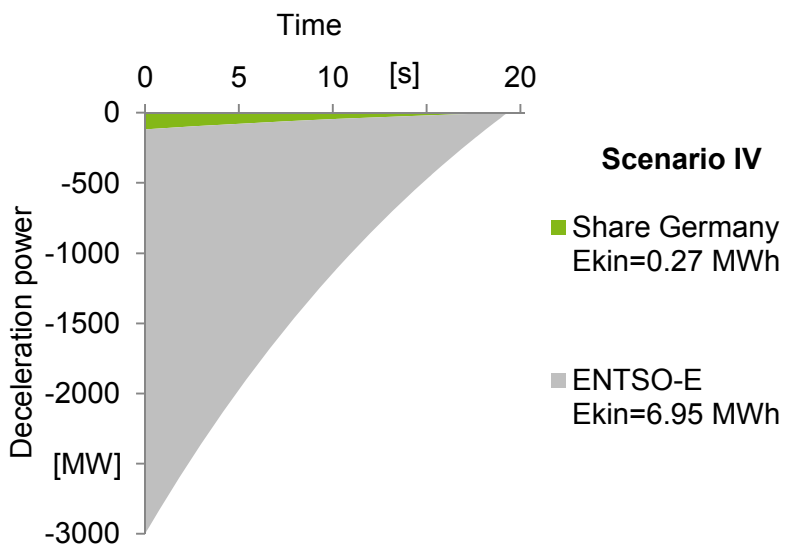

Figure 2.5 *Scenario IV*: Contribution to the provision of instantaneous reserve by Germany and the *ENTSO-E*

Figure 2.6 shows that at a system frequency of 50 Hz, the entire European energy supply system has a total available kinetic energy of 314.7 MWh.

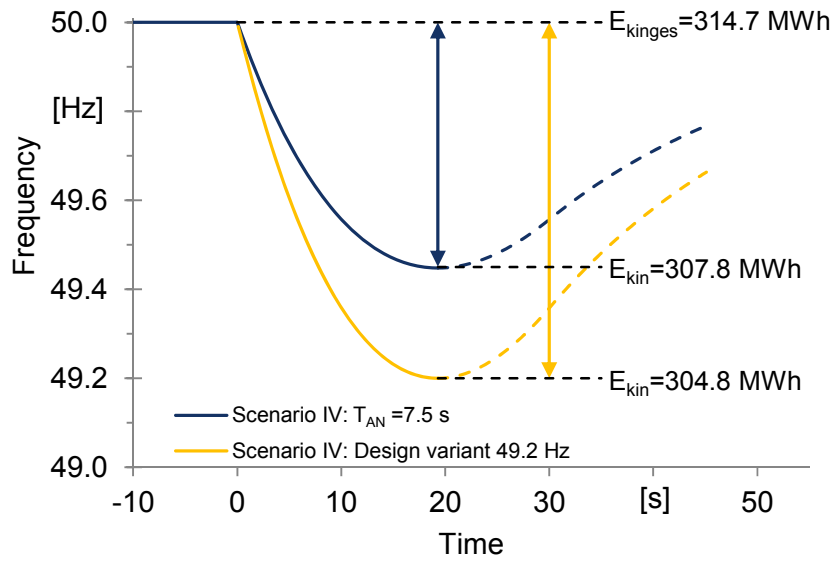

Figure 2.6 *Scenario IV*: Frequency response curves for the selected hour and the design variant plus designation of the kinetic energy

In addition to the resulting frequency response after a power shortage of 3 GW at time t = 0 s, the resulting kinetic energy is shown at the time of the frequency minimum. 6.95 MWh (cf. Figure 2.5) is withdrawn from the system as a result of the generation outage.

In addition, the frequency response curve is shown that would result after a fictitious generation outage in order to reach the maximum limit of 49.2 Hz. To reach this limit, approximately 10 MWh of kinetic energy would have to be withdrawn from the system.

By withdrawing almost the same share of kinetic energy from the rotating masses in *Scenario I* and *Scenario IV* (cf. Figure 2.3 and Figure 2.5), a lower minimum frequency (cf. Figure 2.4 and Figure 2.6) results in *Scenario IV*. This is due to the different kinetic energy of the system at 50 Hz. In *Scenario IV*, the starting capacity is less than half at 50 Hz. The system therefore has a lower system stability from the very outset. *Scenarios II* and *III* are not shown because they lie between the two *Extreme Scenarios I* and *IV.*

In the following, the frequency responses are examined for *Scenarios I* to *IV* from Figure 2.2, which result if the grid-connected

conventional power plants with their rotating masses are fully replaced by RES feed-in in Germany.

The frequency response curves shown in Figure 2.7 are the result.

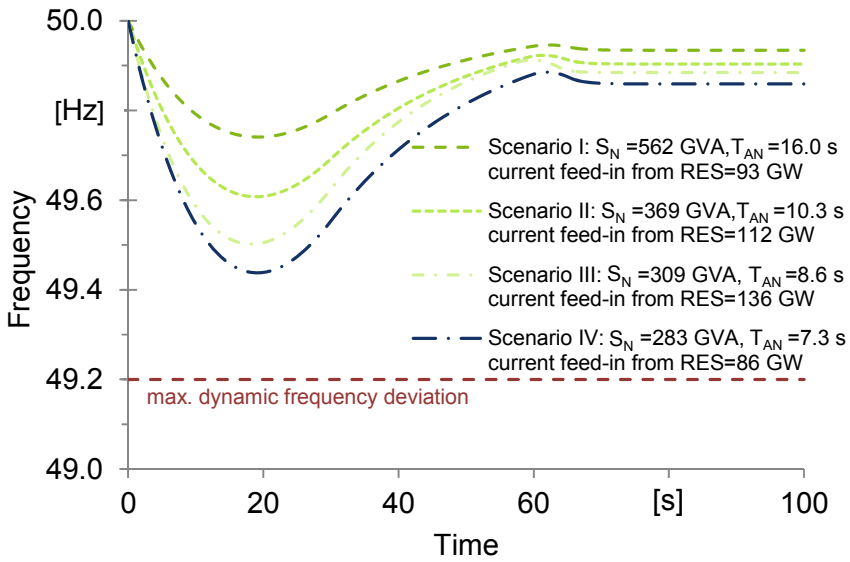

Figure 2.7 Frequency response curves for the *ENTSO-E* area in the year under review of 2033 for selected hours without rotating masses in Germany

It is apparent that even if Germany has no rotating masses during the selected hours and the remaining *ENTSO-E* countries respond to the generation outage of 3,000 MW, that no limits are violated. There is a sufficient safety margin in all scenarios up to the limit of the maximum frequency deviation of 49.2 Hz. In [10], comparable conclusions are drawn according to approximate calculations based on the current load and generation information and the specifications of the *Operation Handbook.*

The results for all scenarios are summarised in Table 2.3.

Table 2.3 Overview of results for Scenarios I-IV: Starting time constant (T_{AN}) and maximum dynamic frequency deviation ($f_{dyn.max}$)

		Scenarios			
		I	II	III	IV
T_{AN} [s] relative to 300 GW	ENTSO-E	18.6	10.5	8.8	7.5
	DE	2.6	0.2	0.2	0.2
$f_{dyn.max.}$ [mHz]	ENTSO-E area	238	389	469	552
	Assumption D 100% reg.	259	392	498	562

Since the energy supply system can be operated in a stable manner in all selected hours of 2033, and there are no limit violations, a variation with an increased frequency dependency of the load and/or increased dynamics of the primary control in the existing model is forgone.

2.3.3 Possible alternative suppliers of instantaneous reserve

Measures must be taken if Germany wants to maintain the status quo with respect to stability of the provision of instantaneous reserve, and if Germany does not want to fully rely on provision from abroad in the future. In this case, the following alternatives are available to provide instantaneous reserve:

- Wind inertia from wind turbines: implementation of frequency control using the energy of the rotor required.
- Use of energy storage systems: use/construction of a storage unit and associated converter with frequency control required.
- Throttling renewable energy plants: slight throttling of renewable energy systems and thus no exploitation of the full potential of RES.
- Rotating phase shifters: conversion of disused power plants is very expensive. Contribution to instantaneous reserve provision is low since the turbine shaft is separated.
- Must-run power plants: reservation of conventional power plants to provide the required instantaneous reserve.

As already mentioned in the evaluation of current studies, there currently is no market mechanism for instantaneous reserve. Conventional power plants are currently not compensated for the provision of instantaneous reserve. The phenomenon of instantaneous reserve is based solely on the physical properties of the rotating generator masses when a generation outage occurs in the grid. Currently, static suppliers are not involved in the provision of instantaneous reserve. With an appropriate control of wind turbines, throttling of renewable energy systems, the use of rotating phase shifters, storage systems, or must-run power plants, instantaneous reserve can be provided. By implementing a frequency control in wind turbines, they would be able to provide instantaneous reserve by dumping rotational energy. Initially, this can be equated to the provision of kinetic energy of the rotating masses of conventional power plants. If a power imbalance occurs, the rotating masses of generators participate directly in the required coverage. This provision form incurs low costs. Instantaneous reserve can also be provided with an appropriate slight throttling of renewable energy units. However, the throttled operating mode of the units has a direct influence on the volume of energy fed into the grid and thus on the degree of exploitation of the renewable energy potential. In addition, rotating phase shifters, storage systems with an appropriate control and must-run power plants can make a contribution to instantaneous reserve. A possible future compensation model could be modelled after the already existing remuneration schemes for the provision of BP.

Due to the small necessary technical changes to wind turbines to enable them to provide instantaneous reserves and the great technical potential, wind inertia is prioritised in the investigation of the preservation of the status quo in Germany.

Development and coverage of instantaneous reserve in Germany

In the course of this analysis, it is shown to what extent Germany must utilise alternative suppliers to operate the system in 2033 with the same stability level of 2011, thus without having to rely on foreign support.

For 2011, the hour with the least conventional generation is determined, likewise for 2033. Due to the same starting points, both hours can then be compared. The results of Germany's provision of instantaneous reserve for 2011 and 2033 are shown in Figure 2.8.

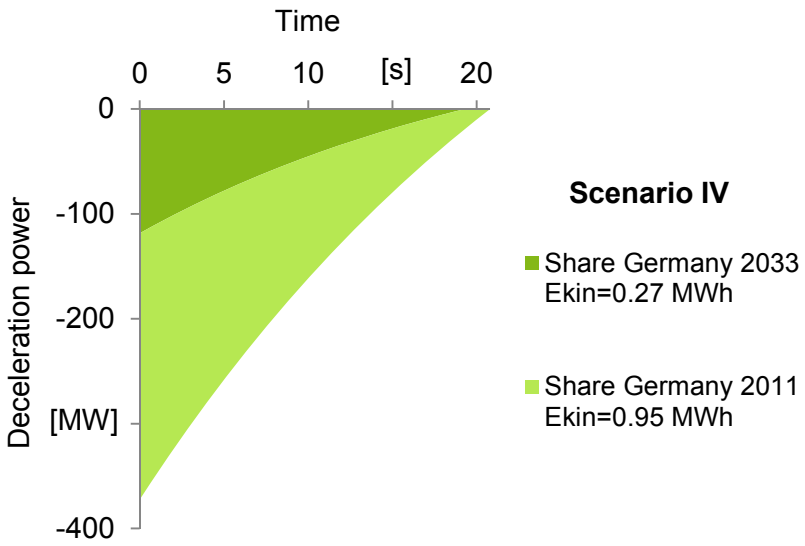

Figure 2.8 *Scenario IV*: Share in the provision of instantaneous reserve by Germany for one selected hour in 2033 and 2011

In 2011, Germany proportionately covers the load step of 3,000 MW with a braking power of 372 MW and a kinetic energy of 0.95 MWh. In 2033, the available braking power is three times smaller, just like the available kinetic energy. To operate the energy supply system in 2033 with the same stability as in 2011, an additional capacity difference of around 254 MW and a kinetic energy of 0.68 MWh must be provided by appropriate alternative instantaneous reserve providers in 2033. Assuming a 100% utilisa-

tion of wind turbines, *Scenario IV* has a grid-connected capacity of 34 GW in Germany. With a plant capacity of 2 MW, this corresponds to a total of 17,000 plants that can contribute to the provision of the capacity and energy difference. If all of these plants contribute to the generation outage while subject to a corresponding control, they will be able to supply a capacity of 3.4 GW and a kinetic energy of 9.4 MWh to the instantaneous reserve. In view of the required capacity and energy difference, this is several times the amount required. To provide only the required capacity difference of 254 MW, a minimum of 1,270 plants is necessary. It is evident that the capacity and energy difference can be provided only through the use of wind inertia in order to operate the energy supply system of 2033 with the same level of stability as in 2011.

In order to make a statement as to whether the potential of wind inertia in the remaining hours of the year under review of 2033 can contribute to the provision of instantaneous reserve, a time series analysis of wind turbine feed-in is carried out. Using the wind turbine feed-in time series, the available potential of wind inertia is determined for each hour of the year. Then the time series is ordered by decreasing wind turbine feed-in to yield the power duration curve (cf. Figure 2.9).

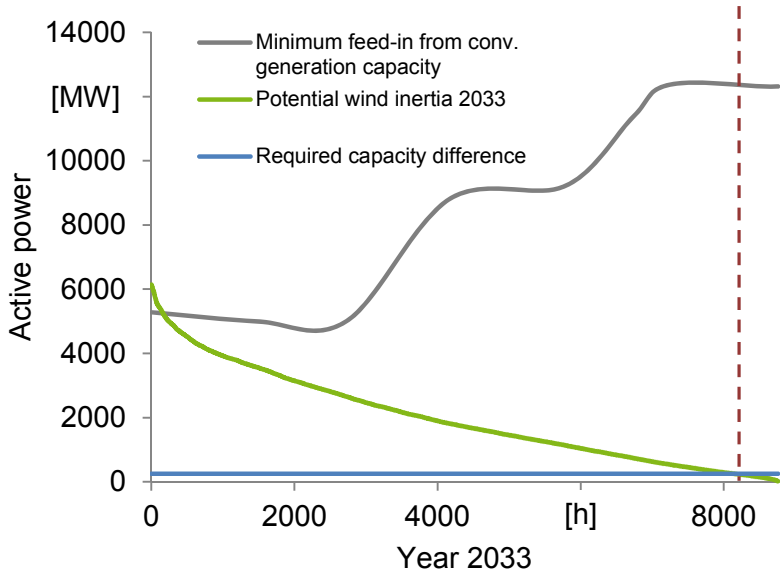

Figure 2.9 The power duration curve of the potential of wind inertia in 2033 relative to the required capacity difference in 2011, and the minimum feed-in from the conventional generation capacity.

In addition to the power duration curve, the additionally required capacity difference of 254 MW is shown. It is evident that the out-

put, by taking advantage of wind inertia in well over 8,000 hours of the year 2033, is higher than the required capacity difference. In about 93% of the cases, it is sufficient to use wind inertia for the additional provision of instantaneous reserve in order to ensure the same energy supply system stability in 2033 as in 2011. An evaluation of the remaining 7% of hours indicates that there is a portion wind inertia that contributes to covering the capacity difference. Even in the last sorted hour, the share is 20 MW. Figure 2.9 additionally shows the minimum feed-in from conventional power generation. It becomes clear that these hours have a conventional power generation capacity of at least 12 GW and thus contribute to covering the instantaneous reserve, because the conventional generation capacity is about three times greater than in the critical hour of the observation year of 2033.

When activating wind inertia, it should be noted that it must have a development similar to that of conventionally generated instantaneous reserve. The control of wind turbines must be implemented accordingly. The provision of instantaneous reserve has the consequence that it provides the required output at time t = 0 for conventional power plants as well as for wind inertia. The rotor is initially slowed down after providing instantaneous reserve. If the generation of PBP and the frequency dependence of the system exceeds the load, the power generation units are accelerated again and returned to their rated speeds. Due to a constant dimensioning of the PBP and the frequency dependence of the loads in the energy supply system in 2011 and 2033, the throttled power generation units can be accelerated up to their rated speeds in the future once the instantaneous reserve has been supplied.

Additional provision of power is therefore not required. It should be noted that the consideration of the potential of wind inertia took place without dynamic calculations.

Technical and legal framework

Currently, alternative suppliers cannot and may not participate in the provision of instantaneous reserve. In order to call upon an active participation of alternative suppliers in the provision of instantaneous reserve in the future, the technical guidelines must be adapted early enough, so that enough wind turbines are equipped with wind inertia by 2033. Since there are no stringent requirements to the regional distribution of instantaneous reserve suppli-

ers and no technical upper limit of instantaneous reserve provision, no further adjustments to the framework are required. What an appropriate remuneration scheme would look like is not the topic of the present study and is therefore not looked at in detail.

2.3.4 Relationship between instantaneous reserve and primary balancing power

For the future development of the instantaneous reserve, it is necessary that the entire *ENTSO-E* grid area with all its grid-connected rotating masses of conventional power plants is taken into account, since the considered frequency response is a global phenomenon of the energy supply system. The instantaneous reserve is a purely mechanical factor. In all scenarios of 2033, conventional power plants are connected to the grid and contribute to the instantaneous reserve. As the largest assumable error, the failure of a double busbar with a connected power plant output of 3,000 MW is to be mastered. The 3,000 MW of PBP to be reserved in the *ENTSO-E* area is to be activated at a quasi-steady state frequency deviation of 200 mHz, which is consistent with the first stage of the 5-stage plan.

The further steps depend on the requirements of the *Operation Handbook Policy 5* [31]. It is assumed that in 2033, all wind energy utilisation systems have been upgraded or replaced according to the guidelines in force today. This would prevent a shutdown at 49.7 Hz or 49.5 Hz [73]. Starting at a limit value of 49.0 Hz, selective automatic load adjustments take place to stabilise the grid frequency [72]. The current dimensioning of PBP of 3,000 MW will not change by 2033. Even if only a low power plant capacity is feeding into the grid at certain times, France for example would still have large generating units connected to the grid.

Due to the Europe-wide coordinated planning principles, output from conventional power plants will feed no more than 3,000 MW into the grid via one common busbar. According to [4], the planned HVDC transmission connections in 2033 do not have higher transmission capacities than the design variant. In addition, the current and future connection capacities of a secondary 380 kV node do not exceed a generation output of 3,000 MW and thus have no impact on the design variant. A risk to stability would result after an outage of over 3,000 MW. The additional power flow

may thus lead to overloads and line shutdowns, which would not be ruled by the formation of partial grids, or an impermissible grid oscillation could be the result, compromising grid operation. [73] A current and future planning principle must therefore take into account a shortage of 3,000 MW for operational planning (cf. Chapter 5).

The relationship between the provision of the instantaneous reserve and the provision of the PBP is illustrated for *Scenario IV* in Figure 2.10.

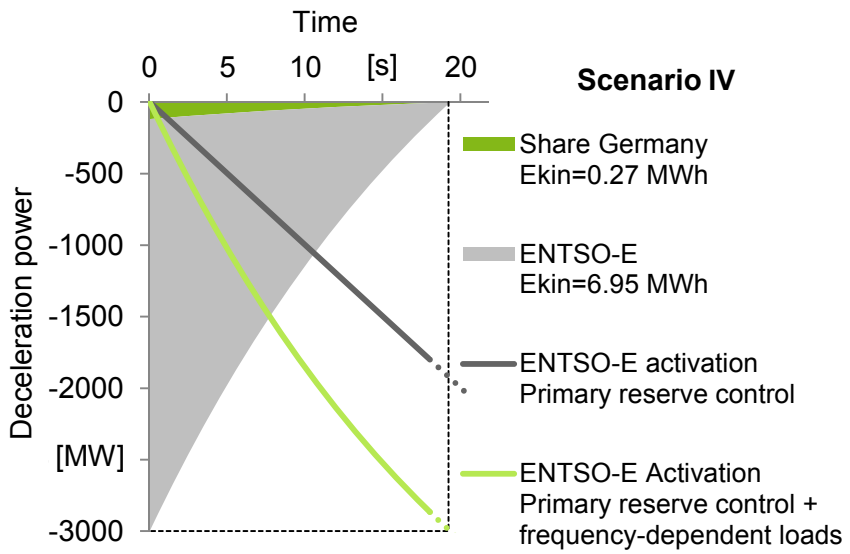

Figure 2.10 The relationship between the provision of instantaneous reserve and PBP

The largest error to be controlled is an outage of 3,000 MW that is covered only by the instantaneous reserve at time t = 0, i.e. by the rotating masses of conventional power plants. A constant PBP of 3,000 MW is assumed for the whole *ENTSO-E* grid area in the year 2033. The PBP (grey line) successively replaces the provision of instantaneous reserve. At time t = 30 s, the maximum PBP is activated. Its activation has the characteristics of proportional control. With the reserved PBP of 3,000 MW and a quasi-steady state frequency deviation of 200 mHz, the result on power plant side is a power-frequency characteristic of 15,000 MW/Hz. Taking into account the grid self-regulating effect of 1%/Hz, a share of 1,500 MW/Hz would result when assuming an low load case with a high DECU feed-in of 150 GW. [9] The resulting grid characteristic is 16,500 MW/Hz in this case. It should be noted that the outage of 3,000 MW must be covered at all times. After about 8 seconds, the

outage of 3,000 MW is covered on the one hand by the instantaneous reserve of 1,500 MW and on the other by the PBP and the frequency-dependent loads.

2.4 Calculations on primary balancing power

The demand for PBP in the *ENTSO-E* area is divided proportionately amongst the individual TSOs based on the annual total feed-in volume. In the future scenario of this study, an approximately constant load is assumed, and according to the results of the market simulation, the German export balance is not (see also Appendix A.2) altered significantly. In the following analysis, therefore, the current German PBP share of 551 MW is assumed for the year 2033.

PBP today is provided both by thermal and by hydraulic power plants, whereas the proportion of hydraulic power plants with a prequalified capacity of 60% predominates [136]. According to the German Transmission Code [39], generating units over 100 MW are obligated to provide PBP amounting to ±2% of their nominal capacities. Since a sufficient number of thermal power plants are always active in today's generation, sufficient PBP can be provided from active thermal and hydraulic power plants.

Due to the reduced residual load in the 2033 scenario, a greatly reduced contribution from thermal power plants compared to today is the result. Power plant utilisation models for 2033, for example, show that large-scale thermal power plants are needed no longer than 100 hours to cover the load. Consequently, there is a reduced participation in the provision of PBP. To quantify this effect, the power plant utilisation simulation is employed (see Appendix A.2) and supplemented by the ability of individual types of power plants to provide PBP. The power gradients in Table 2.4 are used. Until 2033, a more volatile generation situation is to be expected along with an adapted power plant design, so the more flexible published values are chosen for this study.

Table 2.4 Power gradients of thermal and hydraulic power plants [137] [138].

Type of power plant	Power gradient P_N/min		Tech. Minimum output	
	Literature	Selected	Literature	Selected
Lignite	2% - 8%	6%	40% - 60%	40%
Hard coal	3% - 8%	8%	30% - 40%	30%
Gas	8% - 12%	12%	20% - 40%	20%
CCGT	5% - 12%	10%	20% - 40%	20%
PSP	100%	100%	0% - 25%	25%

The maximum hourly PBP that can be provided by the active generation mix can now be calculated using the annual overview. According to the parameters selected in Table 2.4, the thermal power plants in operation provide PBP within the required 30 seconds and with 3% to 6% of their nominal capacity. PSPs provide PBP through a coordinated fine-tuned control of the water supply during turbine and pump operation. Due to their high power gradient, modern PSPs are taken into account for PBP provision with 50% of their nominal capacity [139]. Since the storage capacities of German PSPs exceed the provision time required for PBP several times over, the storage capacity of a PSP is not a restriction here [4] [158].

The results of the simulation for the provision of PBP in 2033 are compared with the amount required, identifying the uncovered PBP demand. Figure 2.11 shows the allocated demand for PBP that cannot be covered by active conventional power plants and PSPs in 2033. The dashed line shows the result assuming the selected power plant gradient for a full activation of the PBP available in Germany within 30 s. In 30% of the annual hours, there is a non-covered PBP demand in Germany. The requirements of the applicable time slices for the PBP tender of one week are neglected here. When considering the weekly reservation, demand for PBP cannot be met by conventional suppliers at any time.

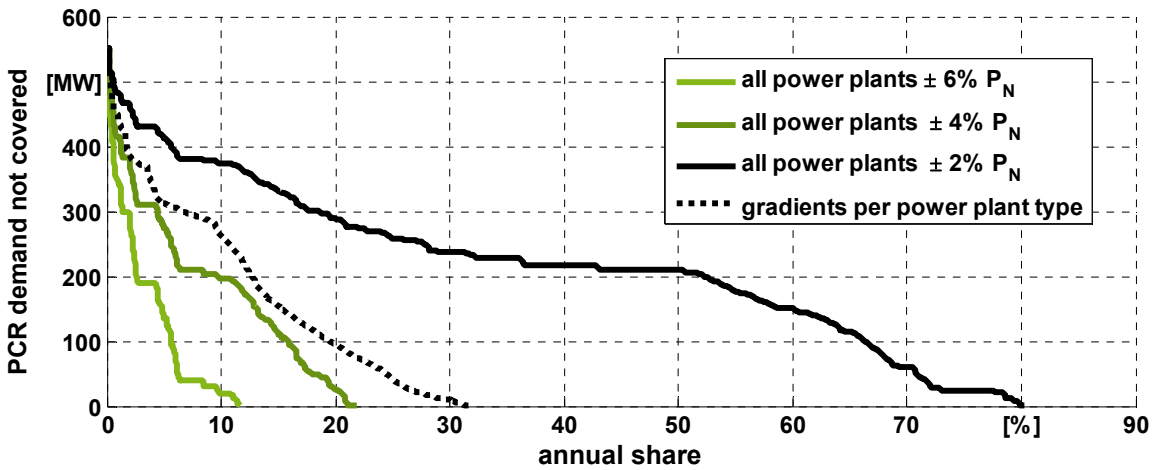

Figure 2.11 Allocated demand for PBP that cannot be covered by thermal and hydraulic power plants in 2033. The various curves illustrate the influence of the nominal capacity share that power plants can provide as PBP.

Since the actually achievable gradients are highly dependent on the individual design of the power plant as well as the current operating point, further sensitivity analyses are being carried out: if thermal and hydraulic power plants provide only the ±2% of their nominal capacity as PBP as defined by the transmission code's minimum requirements, then the required PBP cannot be provided in 80% of the annual hours. With a theoretical minimum requirement of ±6%, however, about 10% of the annual hours remained without sufficient PBP. In the following considerations, the individual gradients in Table 2.4 are taken as a basis.

It is possible to reserve thermal power plants as so-called must-run plants for the provision of the unmet demand for PBP. If flexible gas-fired power plants with a power gradient of 12%/min. and a minimum output of 20% are used, according to Table 2.4, the result of the ratio of provided PBP to electric power generation is approximately 4.3 MW_{el}/MW_{PBP}. This means that the provision of one MW of PBP from one gas-fired power plant causes 4.3 MW of must-run output. The unmet demand for PBP is approximately 490 GWh when using the individual power plant gradient. To provide this demand through gas-fired power plants, approximately 2.1 TWh of electrical energy must be generated that is not required to cover loads. With assumed future electricity generation costs of € 95 - 125 per MWh [140], this corresponds to additional reservation costs of € 200 - 317 million per year. (For comparison: In

2011, the costs of providing the entire PBP amounted to € 112 million [141].)

In addition to the conventional provision of PBP by large power plants, there are several innovative concepts to use new suppliers. These include battery storage systems, wind turbines, PV systems, BMP, run-of-the-river power plants and loads. In principle, supply-dependent generators have the problem that providing a positive balancing potential is usually associated with energy yield losses. Since positive and negative balancing directions in PBP pools can be provided by individual plants [142], these plants would lend themselves to pooling with suppliers of negative balancing potential. Positive and negative balancing potential can therefore be considered separately.

The hours of the year 2033 in which there is an unmet demand for PBP are known from the analysis of the deficit hours in Figure 2.11. In a further step, these hours are compared with the feed-in time series of feasible new suppliers of PBP. Figure 2.12 shows the results of this analysis. For example, if the current wind turbine feed-in capacity can be throttled by 2% at any time of the year and thus be offered as negative PBP, then the need for negative PBP would be secured for 99% of the annual hours. Likewise, a reservation of 2% of the current wind turbine feed-in capacity can cover the demand for PBP 99% of the time.

The analysis shows that PV systems can only make a small contribution to the provision of PBP in addition to conventionally generated PBP. The reason is the low temporal coincidence between increasing PBP demand and PV system feed-in capacity. Run-of-the-river power plants and BMP are in principle technically suitable. To fully deliver the additional required PBP, however, a wide operating range or a high proportion of power plants upgraded for PBP provision are required. If this flexibility is brought about by hydropeaking in run-of-the-river power plants (cf. [106]) and by storage systems in BMP (cf. [125]), then hydropower and biomass energy does not remain unused.

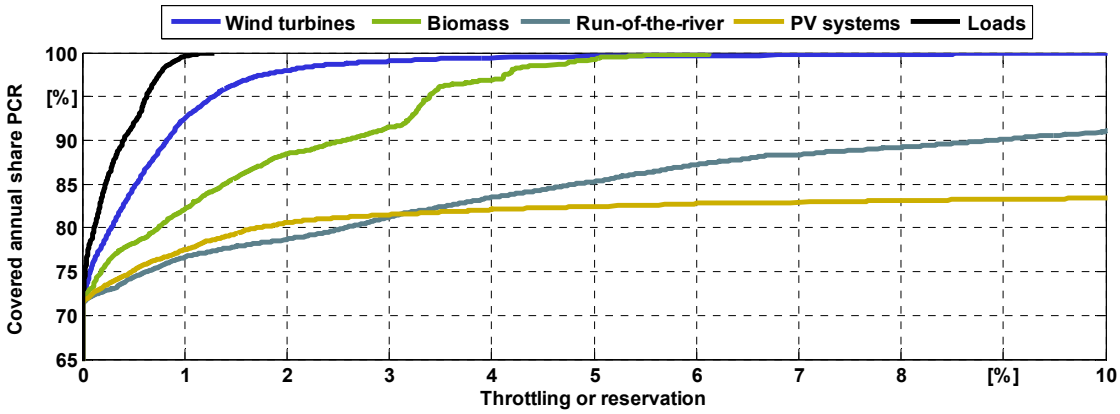

Figure 2.12 Provision of PBP by new suppliers. The figure shows the achievable supply rate with PBP with reservation (pos. PBP) and the possibility of throttling (neg. PBP) of the active capacity of the respective supplier.

Wind turbines exhibit a high feed-in potential up to throttling or reservation of 1.5% of their qualified feed-in capacity. With an increasing capacity of qualified wind turbines, the marginal utility decreases due to a lacking temporal coincidence of wind supply levels and demand for PBP. For the provision of the total uncovered PBP demand, an operating range of approximately 40% is necessary, so a combination with battery storage systems or BMPs would be beneficial. Field tests have shown that the provision of PBP currently poses technical challenges in addition to the requirements of the tender (symmetric tenders, long lead time) [112]. If a wind farm is to produce PBP, it must be ensured that the individual turbines respond synchronously in order to prevent oscillatory behaviour. In Ireland, a mandatory participation of wind farms is currently being implemented regarding frequency control [113].

The provision of positive PBP by reducing the load leads to full coverage starting with a share of about 1.3%. In terms of load flexibility, both the large number of domestic loads that be switched on or off in short intervals [107], as well as industrial loads (cf. SOL in [75]) can be considered as providers of PBP. They are technically able to contribute to PBP. The same applies to biomass plants. The term comprises various types of technologies used to generate electricity from bioenergy. Gas motors are often used for electricity generation and their power gradient in principle allows for the provision of PBP. Hydroelectric power plants are convenient because they have a high number of full load hours in comparison

with other alternatives. As part of a project, a composite consisting of ten run-of-the-river power plants was prequalified for 30 MW PBP and supplied 20 MW consistently throughout the year by means of hydropeaking [106]. Battery storage systems can be used as another alternative, or to provide PBP [104], [119]. To fully cover the additional demand, 551 MW of prequalified PBP is required, but this is necessary only in a few hours per year (cf. Figure 2.11).

A cost comparison of combinations of alternative suppliers of PBP in 2033 is listed in Table 2.5. In this consideration, the missing PBP is provided by additional thermal power plants (must-run), throttling of wind turbines by 1% or 2% and throttling of BMP by 2% in combination with wind turbines by 2%. The cost required to achieve the generation mix's expansion state listed in the Grid Development Plan [5] are not taken into account. Since a very high prequalified power capacity is required for a complete coverage of the PBP demand (cf. Figure 2.12) by wind turbines or biomass plants alone, it is assumed that these suppliers will be combined with battery storage systems. These storage systems cover the missing PBP volume. As another alternative, PBP provision alone by battery storages is being considered. For thermal power plants to achieve the gradient required for PBP, they must have a minimum capacity. This surplus is 2,100 GWh in the considered scenario, and is referred to as "Δ production" in Table 2.5. Accordingly, the throttling of turbines leads to a generation deficit. Employing BMPs for the provision of PBP does not incur a generation deficit since it only shifts the generation capacity by means of intermediate storage. The indicated energy costs result from the specified energy volume and the actual electricity generation costs as an opportunity of supplier. Electricity generation costs are taken from [140] and amount to € 96 - 151 per MWh for wind turbines. These volume differences must be covered by a generation mix utilisation that deviates from the cost optimum allocation. The resulting costs are not taken into account.. The investment costs for a battery park are taken as a basis for the missing capacity required to cover the PBP demand. Energy installation costs of € 35 - 65 per kW for lithium-ion batteries with the main application of frequency control, and capacity installation costs of € 150 - 300 per kWh and a service life of 10 to 30 calendar years are assumed for the calculation [118]. Based on existing PBP batteries [104], it is assumed that

power and capacity will be implemented 1:1. Storage losses are neglected in the cost comparison due to the high overall efficiency of 85 - 90% [118]. Based on this information, the capital-value-neutral costs are determined using the net present value method. Interest on capital is 7% p.a. for this calculation. The various suppliers and their combinations (e.g. wind turbines + BS) differ greatly in the medium-cost segments. Providing the PBP through battery storage systems appears to be economically feasible based on the assumptions made. Regarding the costs of battery storage, however, it must be considered that there will be a pronounced degression of the investment costs. Construction at current system costs would incur annual costs of € 20.0 - 78.5 million. For a single battery park with 5 MW / 5 MWh, this would equate to investments of € 2.3 - 5.0 million. Since the regulation of PBP is decentralised, ICT costs can be considered very low. The costs of technically upgrading the respective system are heavily dependent on the type of plant and possibly all required components already exist. Therefore, these two cost pools were not taken into account when determining the total costs of providing the missing PBP.

Table 2.5 Provision of missing PBP in 2033. All information refers to (possibly annualised) yearly values.

Provider	Δ production [GWh]	Energy costs [million €]	Missing capacity [MW]	Storage installation costs [million €]	Average costs [million €]
Therm. must-run power plant	+ 2,100	200 - 317	-	-	258.5
Wind turbines 1% + BS	- 362	34.8 - 54.7	308 MW	4.6 - 16.0	54.1
Wind turbines 2% + BS	- 415	39.8 - 62.7	285 MW	4.2 - 14.8	60.0
Biomass 2% + wind turbines 2% + BS	- 135	13.0 - 20.4	105 MW	1.6 - 5.5	19.9
Battery storage systems (BS)	-	-	551 MW	8.2 - 28.6	16.9

Assuming the existence of a generation mix as described in the scenario framework (cf. A.1), cost-optimal power plant operation (cf. A.2) as well as the power gradient used in (cf. Table 2.4), bat-

tery storage systems prove to be the most cost-effective alternative to cover the missing PBP demand.

2.5 Calculations on secondary balancing power and minute reserve

The study of the future demand for SBP and MR is based on a model which draws upon currently existing, convolution-based methods. The results demonstrate the demand of the Scenario 2033 using the existing method and the expanded approach. Furthermore, the influence of the wind and PV forecast error on the demand for MR is indicated. Subsequently, an investigation of demand for BP as based on the SBP set-point signal and the impact of rapid wind speed changes and the management of balancing groups follows. Based on the scenario for 2033, it is shown to what extent potential providers of BP are available at low residual loads. Finally, there is an economic evaluation of alternative providers based on the potential revenue on the MR market.

2.5.1 Future demand

Previous studies on the future demand for reserves for capacity-frequency control show a large range of results. A direct comparison of the individual study results, however, is difficult due to the large number of different assumptions made, in particular regarding development scenarios, forecast errors and distribution functions as well as deficit levels. However, a common trend is reflected in a moderate to strong increase in demand for MR and small changes in the demand for SBP.

The main factor influencing the future demand for MR is the expected improvement of forecasts. Figure 2.13 shows the sensitivity of the demand for positive MR with variations in the errors of the wind power forecasts, PV forecasts and joint variations of both factors. Basis of the calculation is the currently used convolution-based approach. As reference values, a forecast error of $\sigma_N = 0{,}85\ \%$ is assumed as based on [1] both for wind power and for PV forecasts. Further assumptions used for the calculations can be found in Appendix C.

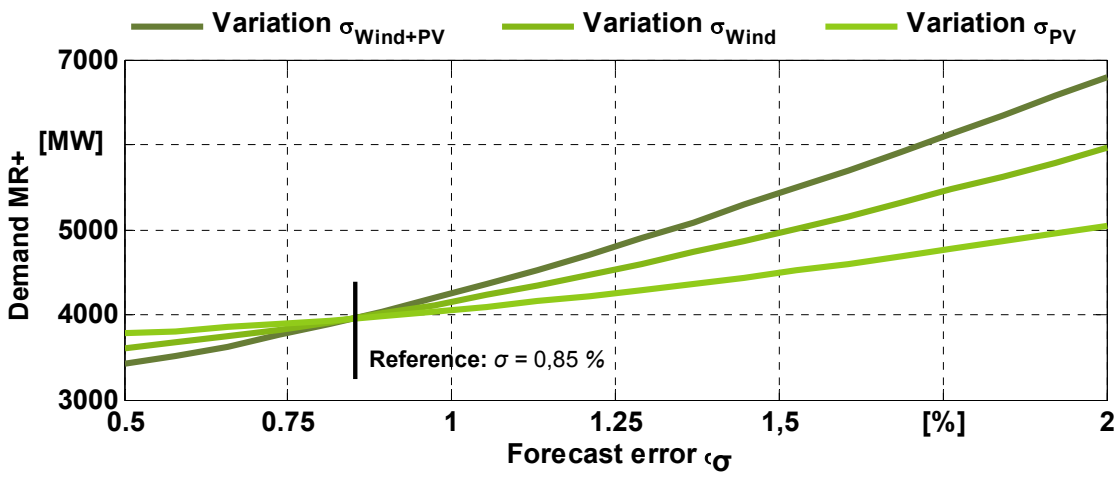

Figure 2.13 Demand for positive MR in 2033 with an individual and joint variation of (h-1) forecast errors for wind power and PV.

Due to the uncertainty regarding the future forecast error (for comparison: in 2007, the (h -1) wind power forecast error was approximately $\sigma_N = 1{,}5\ \%$ [1]), the forecasts of the future demand for MR are also subject to high levels of inaccuracy. At the same time, when using the (h -1) forecast error, it must be taken into account that the difference between the day-ahead and intraday forecast is offset by the intraday market. Part of the forecast uncertainty is thus shifted onto the energy market. In case of insufficient market liquidity, there may be larger balances for BP to compensate for despite highly accurate forecasts.

Due to the forward projection of the current dimensioning procedure, there is a systematic problem resulting for an energy system with a high share of fluctuating generation: a calculation of the CR requirements based on installed RES capacities leads to increased CR quantities, even in times of low uncertainties of the system balance. An increased CR reservation by PV feed-in is necessary only given a sufficiently high level of solar irradiation. Similarly, a lower absolute forecast error can be expected during periods of low wind supply.

In order to cope with the increasing volatility of technically necessary future CR quantities, their dimensioning should be adapted to their respective balancing uncertainties. In the following, therefore, an adaptive method for CR dimensioning is presented that adapts the tender volume for SBP and MR to the day-before feed-in forecasts. Instead of quarterly dimensioning, the tender volumes are

calculated daily for the day ahead with an hourly resolution and are subsequently adapted to the designated time slices of the respective CR type. The adaptive dimensioning thus represents an extension of the convolution-based method currently in use [97], which uses forecast performance values for the day ahead (day-ahead forecast) instead of the installed RES capacity. At the same time, the installed capacity forecast error for wind power or PV feed-in σ_N can be replaced by performance-based forecast errors $\sigma_m(P_{EE})$.

This would accommodate for the non-linear relationship between RES feed-in and specific forecast errors (cf. [1]). An overview of the differences between the conventional dimensioning method and the adaptive approach can be found in Table 2.6.

Table 2.6 Comparison of the input variables of today's convolution-based method with the adaptive approach based on the day-ahead RES forecast

Balancing uncertainty	Today's approach	Adaptive approach
Power plants	Tot. generation mix	Only running power plants
Load noise	Annual peak load	Load forecast
Load forecast error	Annual peak load	Load forecast
RES feed-in	Inst. RES capacity	Forecast RES capacity
RES forecast error	Forecast error relative to installed capacity, σ_N	performance-based forecast error, $\sigma_m(P_{EE})$

With adaptive CR dimensioning, the CR volume can be reduced during periods of low balancing uncertainties. Large volumes are tendered only (high wind supply and PV feed-in) in times of high uncertainty. Compared with the conventional dimensioning method, the average CR volume can be significantly reduced. Figure 2.14 shows the average CR volumes required for the year 2033 as per the current method (static) in comparison with adaptive dimensioning (adaptive). In order to classify the results, the volumes actually tendered in 2011 are given. In the adaptive approach, the value range in which the tender volumes fluctuate throughout the year is also specified.

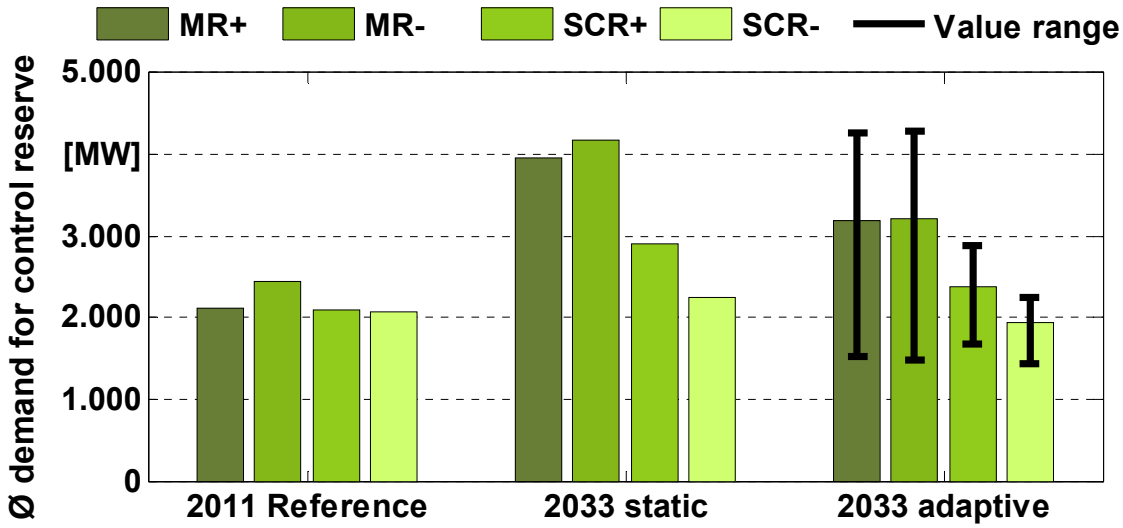

Figure 2.14 Annual average of current and future CR demand as per the current method (static) and the adaptive method.

Compared with the static approach, the additional demand for MR in 2033 can be reduced by about 40% (MR+) and 55% (MR-) versus the annual average by applying the adaptive method. However, there still is an increased demand for MR compared with 2011, both on average and during peaks, when using the adaptive approach. The difference for SBP is less pronounced. A detailed description of the adaptive dimensioning method is given in [20]. The detailed assumptions of the results presented here can be found in Appendix C. A further reduction in the average volume of required MR is possible by adjusting the time slices for the CR tenders. In [20] however, it was shown that even an introduction of hourly time slices would yield a relatively small reduction in the required MR volume.

2.5.2 Influence of rapid wind speed changes on the balancing energy demand

As early as 2010, hourly jumps of the CR demand during times of significant rises of the consumption load were reported [97]. According to this, especially hours with a high load increase or decline exhibited imbalances in the control area. The reason given is that management of the balancing groups often takes place in one-hour intervals, and sharp rises of the load curve can be reacted to only insufficiently. During the hours in question, an control area

imbalance is observed that manifests itself in a demand for positive CR during the first half-hour and for negative CR during the second half-hour (sawtooth wave). This behaviour is exemplified in figure 2.15, which shows the mean CR demand in a four-second resolution for the entire GCC after the IGCC optimisation for the month of March in 2013. The figure shows that the CR demand exhibits the typical sawtooth profile with sharp rises in several hours.

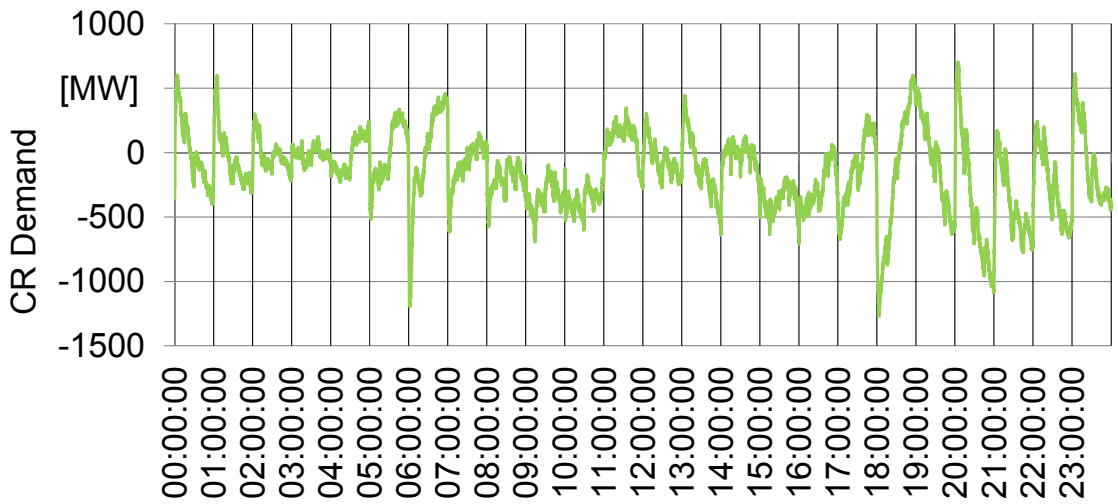

Figure 2.15 Average CR demand in the GCC using the example of March 2013 in the course of the day, data provided by: 50Hertz Transmission GmbH.

In October 2012, measures for the adaptation of the method for calculating the uniform balancing energy price (reBAP) were decided [150]. The coupling of the reBAP to the spot market price and the markup for a high CR activation volume set the incentive to stabilise the balancing groups and to respond to the quarter-hour-resolution load curves. The presented results of the demand for CR in figure 2.15 show that despite the additional incentive, there still are numerous hourly jumps. Many of those responsible for balancing groups therefore do not meet their legal obligation of a quarter-hour compensation, or they lack technical or market-side resources. According to an example evaluation of BNetzA [96] for a few days in the winter of 2012/2013, the problem of hourly jumps in times of rapid wind speed changes or PV forecast errors is only reinforced. This relationship can be demonstrated throughout the year. To this end, the 5-minute average of the GCC balance is compared with the rate of change of wind power feed-in during the

quarter hour (cf. Figure 2.16). An increased average balance deviation given high rates of change of wind power feed-in is evident. Marked changes in wind speed more frequently occur during periods of high wind supply levels; the influence of these speed changes on the demand for SBP is considerably more pronounced than the influence of the absolute wind supply. Another striking feature is an asymmetrical effect that promotes a negative balance deviation. If, for example, feed-in from wind turbines increases to 715 MW or more within a quarter of an hour, the total average deviation is about -720 MW. In these quarter hour intervals, the GCC tends to be oversupplied and the annual average of about -70 MW is significantly exceeded. These values are of a magnitude relevant to the dimensioning of SBP (average of about ± 2,100 MW in 2012). Accordingly, this effect should be monitored and, if required, considered in the future dimensioning of SBP.

The results of the market and grid model also allow a detailed analysis of the relationship between the expansion of installed wind capacity and the occurrence of rapid changes in wind speed for the year 2033. The maximum feed-in deviation of wind turbines within one hour is 3.4 GW in 2011, and 10.2 GW in 2033. However, typical wind speed changes lead to an elevated feed-in capacity for several hours (cf. [96]). Where the maximum feed-in difference is 7.3 GW for a period of eight hours in 2011, this difference will increase to 21.4 GW in 2033. These figures illustrate the importance of forecast accuracy and the need for a quarter-hour management of balancing groups for the demand for CR.

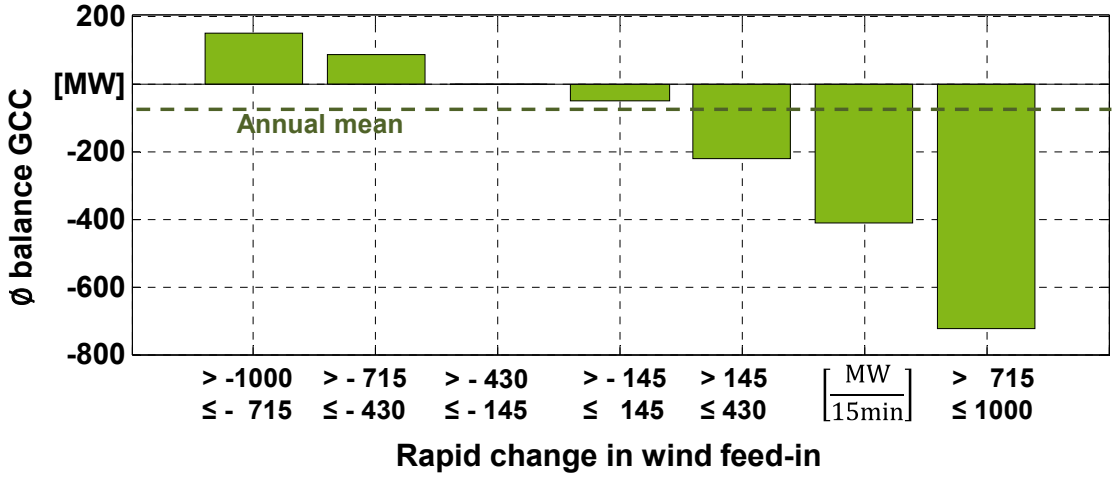

Figure 2.16 Average CR demand in the GCC as a function of rapid changes in wind speed for the year 2012, data provided by: EEX Transparency, 50Hertz Transmission GmbH.

In addition to rapid changes in wind speed, an influence of the gradient of the residual load on the balance deviations in the GCC is apparent. Here, too, there is a pronounced asymmetric behaviour: a sharp decline of the residual load promotes the use of negative CR although even highly positive gradients exert only a minor influence.

2.5.3 Provision of secondary balancing power and minute reserve

Analogous to the considerations of PBP provision, the cost-optimised power plant use model for 2033 (see Appendix A.2) can be combined with the power gradient and minimum capacity of the individual types of power plants in Table 2.4. The quantity of SBP and MR that can be provided by power plants required for load coverage can now be analysed with this. To this end, the one-minute power gradients from Table 2.4 are compared with the gradients required for a load-dependent mode of operation, therefore calculating the available power gradient required for the provision of CR. Taking into account the minimum capacity of the power plants, the capacity that the individual power plants can provide as SBP and MR can then be determined.

According to the prequalification conditions, the available power gradient for a full provision of capacity for SBP is considered within

5 minutes, and for MR within 15 minutes. While thermal power plants can offer balancing reserves only in their active state, PSPs can provide SBP and MR from a standstill [139]. The provision of SBP is prioritised due to the higher potential revenues on the SBP market. MR is only provided by PSPs when the demand for SBP is fully covered in the hour in question. Afterwards, the technically possible provision of different types of CR can be compared with the previously calculated demand. A basis for comparison is the previously determined demand for SBP and MR as per the adaptive process. Two further comparative calculations are carried out to analyse the influence of the SBP and MR time slices. The underlying calculation is based on hourly time slices while the second variant uses the time slices available today (SBP: 12 h, MR: 4 h). Within one time slice, the entire generation mix can only offer the minimum balancing power potential of the individual hours.

The analysis shows that the demand for CR in 2033 cannot be met throughout the whole year from the generation mix that is active for load coverage. This applies, under the assumption of today's time slices, to both balancing directions of SBP and MR (Figure 2.17). Regarding MR, there is an uncovered demand of up to 3,700 MW in 204 h (pos. MR) and 648 h (neg. MR). By prioritising the provision of SBP, there is a deficit of SBP in only 60 h (pos. SBP) and 96 h (neg. SBP).

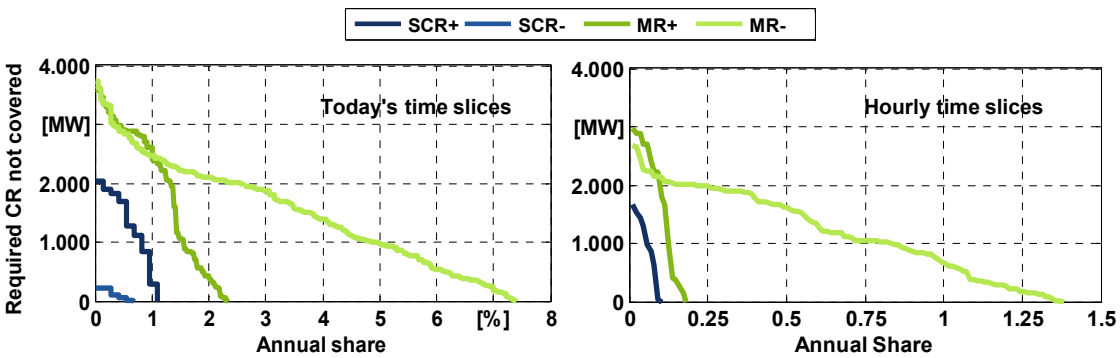

Figure 2.17 Allocated uncovered demand for BP CR in 2033. Left: while maintaining today's time slices. Right: for hourly time slices.

If hourly time slots were used as a basis instead of the currently used time slices, then the CR deficit would be reduced significantly: for MR, there would only be 15 (pos. MR) and 120 (neg. MR)

deficit hours, for SBP, there would only be a deficit of 8 h in the positive balancing direction. Negative SBP, however, can be fully provided in all hours of the year.

Due to the low number of full-load hours of conventional power plants in the future, a rising share of CR will be provided by PSPs. The pump operation of PSPs plays a special role. During these hours of low residual load, they can prevent throttling or the export of supply-dependent feed-in, and they allow for the operation of base load power plants, in particular during the midday PV peak. However, pump operation is a restriction for CR provision, because there is only a positive balancing potential at full pump capacity. Particularly in the case of SBP, the CR that can be offered during one time slice will be reduced by brief pumping phases.

To illustrate a production situation that can lead to a significant deficit in CR, the following section analyses the hour with the highest uncovered demand for negative SBP and MR. This hour is examined in detail in the following section in terms of the generation situation and potential new suppliers of MR.

2.5.4 Provision of balancing power at a low residual load

The energy market-oriented power plant utilisation model does not provide for the utilisation of large-scale fossil power plants during several hours of the year. Without the explicit designation of must-run units, the entire CR volume during these hours must be provided by PSPs, other storage technologies, fluctuating generation or other innovative CR suppliers. Even in hours with a low volume of fossil generation, the flexibility of the active power plants is not sufficient to fully cover the identified demand for SBP and MR. The absolute level of demand is not decisive for the volume of the uncovered demand, instead the deficit is determined by the volume of the residual load.

Figure 2.18 shows the generation situation in 2033, in which the previous analysis identified the highest deficit of negative CR. It is at noon, during a particularly windy and sunny day in April of the scenario year. The analysis of the deficit of positive CR takes place in Chapter 2.5.5 as part of an annual overview.

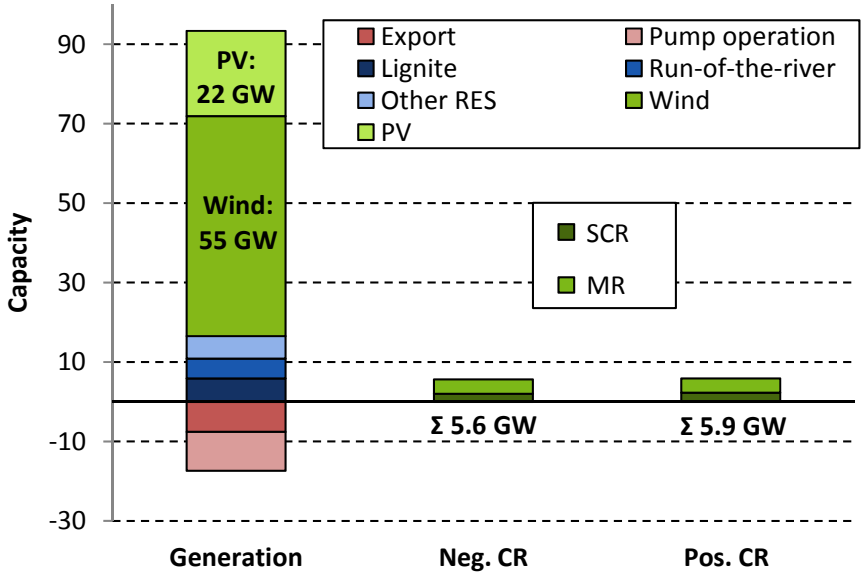

Figure 2.18 Generation situation and CR demand at the time of the highest uncovered negative CR demand in 2033 (noon in April).

The total balancing potential in this generation situation can be inferred from the minimum capacities, the gradients of the thermal power plants and the balancing potential of the PSPs. The capacity of the active lignite power plants is already reduced by about 30% at this time, so they have a limited balancing potential. Most PSPs are already in pump operation mode, so they have a positive balancing potential exclusively. Only the capacity of the inactive PSPs (600 MW) can be used for negative capacity reservation. At this time, therefore, there is a deficit of about 3,600 MW of negative balancing reserve (SBP + MR), while the demand for positive balancing reserve can be fully covered (see Figure 2.19). To supply this uncovered demand, further PSPs may be drawn upon by forgoing pump operation. With the now reduced grid load, however, excess feed-in volumes must be limited or exported.

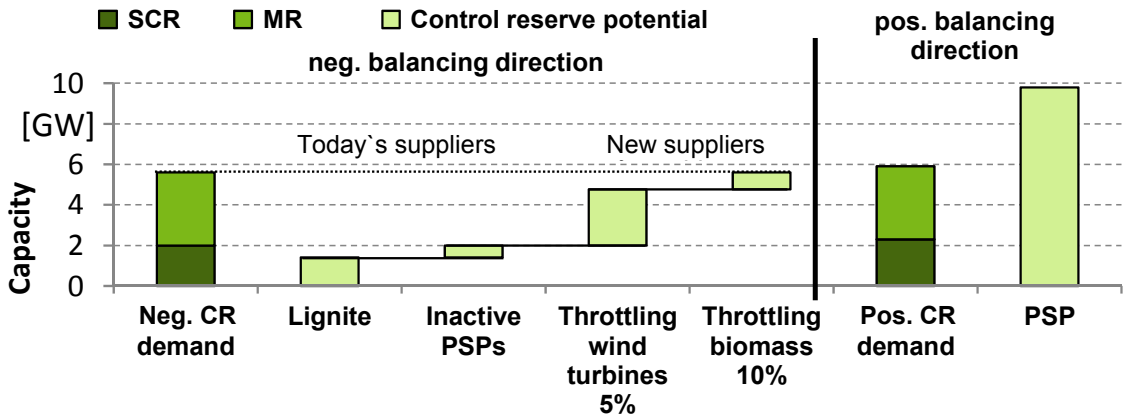

Figure 2.19 CR demand (SBP + MR) as well as potential providers at the time of the greatest deficit of negative CR in the 2033 scenario.

Besides PSPs, storage systems (for example, battery storage systems), flexible loads, biomass plants and the provision of negative CR by wind turbines come into consideration. The potentials of CHP plants and heat pumps are neglected due to the low thermal energy demand for that point in time. The required additional volume of negative MR can be provided, for example, by throttling wind turbine feed-in capacity by about 7%. With the additional inclusion of PV systems, an average reduction of the feed-in capacity by 5% would suffice. With a combination of biomass and wind turbines, a reduction of 5% or 10% is sufficient. However, the actual nominal capacity of wind turbines and PV systems to be qualified for the provision of CR may be higher for the following reasons:

- to reach the required level of security, the entire forecast feed-in capacity cannot be sold as CR [111], [112].
- The operating range of a wind turbine does not necessarily extend across its total nominal capacity range. To provide 1 MW of CR with an operating range of 10%, 10 MW of wind turbines must be qualified.
- A number of turbines is possibly already involved in the provision of other ancillary services (e.g. PBP).
- The geographical distribution of the CR volumes may possibly need to cover existing core portions and take potential grid bottlenecks into account.

These limitations strongly depend on the composition of the pool, the forecast accuracy and the prequalification conditions and are

therefore not taken into account in calculations in the further course of this study. For the 2033 scenario, it is assumed that approximately 80% of the wind turbines' nominal capacity in larger wind farms is connected to the high-voltage level (HV) (cf. Table 3.1). Since only a portion of the wind power must be throttled, it will likely be enough to qualify these wind farms to guarantee a sufficient negative CR volume. As an alternative to the provision of SBP by lignite power plants and PSPs, the use of battery storage systems also comes into consideration. However, a high storage capacity is required for the usually longer activation times of SBP compared with the provision of PBP. A review of these and other alternatives follows in the next chapter and in an annual overview.

2.5.5 Annual overview of the provision of balancing power

Combined with the capacity gradients of the power plant types in Table 2.4, the power plant utilisation model allows for an analysis of the undersupply of the balancing reserve for the year 2033. In addition to the consideration of individual hours, the identified remaining demand for SBP and MR (see Figure 2.17) are also determined over the course of the year. The remaining demand refers to the demand for CR that cannot be covered by thermal and hydraulic power plants that are used for load coverage.

A residual demand in the positive balancing direction occurs mainly when PSPs cover short peak loads at low residual loads, thereby avoiding the short-term operation of large-scale thermal power plants. A conventional supply with positive balancing reserve could be achieved by starting flexible thermal power plants in these hours, thus liberating the available PSPs for the provision of reserve power. However, the actual operating performance of the PSPs also heavily depends on the price level on the CR markets and may have a greater tendency for the provision of CR than considered in the model.

The reduced capacity operation of wind turbines and PV systems will not be considered as an alternative for the provision of positive balancing potential. Relatively low opportunity costs arise from potentially low market prices for energy at that time, the lost energy volumes however are significant (cf. [111] [112]).

Switchable loads are more suitable for the provision of MR due to the high technical requirements and the more complex ICT connectivity. As an alternative for SBP, switchable loads are therefore suitable only for pooling with power generation units or storage systems. The only prequalified load for SBP is offered by the electrolysis process in a zinc smelter [101]. Another marketing option for large consumption units is offered by the market for interruptible loads, which would also make a contribution to grid and system security.

In addition to thermal power plants and PSPs, other suppliers of positive and negative capacity are discussed separately for SBP and MR below. For each of these suppliers, the impact of provision and, if necessary, the resulting costs are stated.

The model yields a residual demand for positive SBP in 96 h (eight 12-hour time slices) of the year 2033 with a maximum of 2,024 MW. During the course of the year, the residual demand is 132 GW*h. Here, the unit GW*h does not indicate energy, but the provision of a capacity potential over time. There is the option of reserving flexible must-run units to use thermal power plants to cover demand. Analogous to the determination of overproduction by must-run units for primary balancing (Chapter 2.4), an overproduction of about 0.3 MW_{el}/MW_{SBP+} is determined for a gas-fired power plant. This value is derived from the minimum capacity of 20%, the capacity gradient of 12%/min, and the activation time of SBP of 5 min. Over the year, there is an overproduction of 39.6 GWh that incurs annual costs of € 3.8 - 5.0 million at electricity generation costs as per Chapter 2.4.

Provision by PSPs requires forgoing generator operation in the corresponding hours. This leads to the loss of profits through arbitrage dealings in the energy market. On the other hand, load coverage in this case takes place by additional generators, which results in an overproduction of about 11 GWh by other, possibly thermal, generators. However, the resulting additional costs arise from the average actual electricity generation costs in 2033 and thus fall short of the expenses of a thermal must-run power plant.

Provision by biomass plants requires the option to store the used primary energy source as well as the possibility to upgrade plant capacity. However, generally applicable provision costs are not yet known. It should be noted that the total installed capacity of 9 GW

is low relative to the SBP demand of approximately 2 GW. Either a broad operating range is required or other providers must be included.

Another way to provide a positive SBP is offered by storage systems, of which the battery type is considered here. A capacity of 4 MWh/MW_{SBP} is necessary for the provision of SBP [7]. To cover the residual demand, a storage system with 2,024 MW and 8.1 GWh is required. The annualised investment costs (see Chapter 2.4) amount to € 104 - 364 million per year. However, the battery storage system is available for other application purposes in 98.9% of the annual hours. If the storage system can achieve a constant contribution to coverage throughout the year, the hours required incur proportional investment costs of € 1.1 - 4 million.

For negative SBP, the model yields a remaining demand in 60 h (five 12-hour time slices) of the year 2033. The missing capacity is 229 MW at most. In total, the residual demand throughout the year amounts to about 7 GW*h. To cover the demand with thermal power plants, a high generation capacity is required that can be reduced if necessary, in contrast to a positive balancing direction. The resulting overproduction of a flexible gas-fired power plant is approx. 1.3 MW_{el}/MW_{SBP}, analogous to Chapter 2.4. This value is derived from a gas-fired power plant that can reduce its capacity to 20% P_N at a generating capacity of 80% P_N. Throughout the year, this results in an overproduction of 9.7 GWh and an additional generation cost of € 0.9 - 1.2 million per year.

Provision by PSPs requires forgoing pump operation of some PSP in the corresponding hours. This reduced load can necessitate the throttling of renewable energy systems in hours with a low residual load. The avoided storage system loading also leads to an overproduction of 0.6 GWh from other generators. The additional costs of electricity generation are low compared to the use of must-run power plants.

Wind turbines can also be considered for the provision of negative SBP. However, today's time slices, lead times and the process for determining the actually provided SBP represent a major obstacle. The requirements to ICT connectivity are high for SBP, and can constitute a significant cost item (cf. Chapter 2.2.2). Under favourable conditions, however, the variable costs are low.

In principle, the same conditions apply to the provision of negative SBP by biomass plants as to the provision of positive SBP. Differences are possible with the required plant and storage system dimensions. Due to the lower residual demand of negative SBP, full demand coverage by biomass plants is possible with a comparatively narrow operating range.

Battery storage systems can provide positive and negative SBP at the same time. A storage system installed to meet the residual demand of positive SBP can thus simultaneously provide the required residual negative SBP. A storage system installed solely to cover residual demand for negative SBP would have annualised investment costs of € 12 - 41 million per year, of which € 0.1 - 0.3 million per year would be for the hours with a residual demand.

Table 2.7 Provision of the uncovered demand for SBP in 2033 by current and future suppliers.

CR type	Provider	Effects and costs
SBP+ Max. residual demand: 2024 MW Duration of demand: 96 h Annual volume: 132 GW*h	Th. power plants	• Flexible power plants as a must-run unit • For gas-fired power plants: 0.3 MW_{el}/MW SBP+ • Overproduction 39.6 GWh • Additional production costs: € 3.8 – 5.0 million/year
	PSP	• Abandonment of energy market-oriented generator operation in the demand hours • Substitution of generator operation with other (thermal) generators at relatively low costs
	Biomass	• Costs for storage system and plant expansion, and ICT connectivity • Installed capacity (9 GW) is low compared with demand
	Battery storage systems	• Required capacity approx. 5 MWh with an offer of a symmetric SBP product of ±1 MW • Annualised investment costs: € 104 - 364 million per year, relative to demand hours: € 1.4 - 4.9 million per year
SBP- Max. residual demand: 229 MW Duration of demand: 60 h Annual volume: 7.3 GW*h	Th. power plants	• Flexible power plants as a must-run unit • For gas-fired power plants: 1.3 MW_{el}/MW_{SBP-} o Overproduction 9.5 GWh o Additional production costs: € 0.9 – 1.2 million/year
	PSP	• Forgoing energy market-oriented pump operation in the demand hours • Throttling of RES plants possibly required due to missing pump operation o Low additional generation costs due to RES throttling
	Wind turbines	• Obstacles caused by prequalification conditions and lead times • Installation costs due to ICT connection up to approx. € 40,000 per wind farm • Max. 0.6% of the wind power feed-in capacity must be throttled to fully cover the residual demand
	Biomass	• See SBP+
	Battery storage system	• For symmetric design, see SBP+ • For dimensioning as per SBP-: o Annualised investment costs: € 12 - 41 million per year

With a maximum of 3,590 MW, the residual demand model for positive MR significantly exceeds the deficit for SBP. The demand duration (204 h) and annual quantity (GW*h) to be covered have a more pronounced deficit of positive flexibility. In contrast to the provision of SBP, this deficit can be covered by thermal power plants from a standstill, for example by using gas turbines, at low standby costs.

Alternatively, this residual demand can be provided by forgoing energy market-oriented generator operation in PSPs. This means that other producers are activated for load coverage during these demand hours, and possibly do so at higher electricity generation costs. Overproduction in this case is about 29 GWh.

The provision of MR by emergency power systems (EPS) is tried and technically tested, and is possible with their inclusion in MR pools. Although the installed capacity of EPS is far higher in Germany, the usable potential of these units is 5 - 8 GW. EPS are available at their nominal capacity within a few minutes, but have high variable costs due to their relatively low degree of efficiency. Investment costs for the control system are considered low since the required system technology is readily available (cf. [120]).

As flexible distributed generation units, biomass plants are able to provide SBP and MR. Prerequisites for this flexibility are sufficient available storage system and plant capacities, which incur costs when retrofitted. The installed capacity of 9 GW expected for 2033 is low compared with the MR demand, because the entire operating range is not available.

Some interruptible industrial loads are already used for MR. The costs of developing this flexibility heavily depend on a possibly already existing energy management system and the respective production process.

For negative MR, the model yields a residual demand for a duration of 648 h with a maximum volume of 3,740 MW. Throughout the entire year, the residual demand for capacity amounts to approximately 977 GW*h.

To cover the negative demand with thermal power plants, a high generation capacity is required that can be reduced if necessary, in contrast to the positive balancing direction. When using a gas-fired power plant with a generation capacity of 100% P_N, which can

be lowered to 20% P_N if necessary, the resulting overproduction is approximately 1.25 MW_{el}/MW_{MRP-}. Throughout the year, this results in an overproduction of 1.22 TWh and additional production costs of € 116 - 152 million per year.

Provision by PSPs requires to temporarily forgo pump operation. This reduced load can necessitate the throttling of renewable energy systems in hours with a low residual load. The prevented storage loading leads to an overproduction of 194 GWh by other producers. However, the resulting additional costs of electricity generation are low compared to the use of must-run power plants.

In principle, the same conditions for negative MR provision by biomass plants apply as for the positive balancing direction.

If wind turbines are able to keep up with the scheduled power output, they will have a high potential for providing negative MR. However, economic feasibility heavily depends on the qualification conditions and the existing ICT infrastructure. A maximum of 11% wind turbine feed-in capacity needs to be throttled throughout the entire year for a full coverage of the residual demand.

The potential of switchable loads in the industrial sector is estimated to be low and is currently inadequately evaluated due to the dependence on the production process (cf. Bibliography in 2.2.2). The flexibility of thermal applications has a seasonal potential in the industrial, commercial and household sector. The ratio of adjustable output and the costs of developing the individual plant is determined by economic efficiency. An estimate of the potential revenue for the private sector is given in Chapter 2.5.6.

In Table 2.8, the parameters of the missing MR and the effects of various alternatives to cover the residual demand for the year 2033 are summarised.

Table 2.8 Provision of uncovered MR in 2033 by current and future suppliers.

CR type	Provider	Effects and costs
MR+ Max. residual demand: 3,590 MW Duration of demand: 204 h Annual volume: 386 GW*h	Th. power plants	• Use of gas turbines from a standstill • Low reservation costs
	PSP	• Abandonment of energy market-oriented generator operating in the demand hours • Replacement of generator operation by other (thermal) producers at comparatively low costs
	Emergency power systems	• Partially in use today • Installed capacity (5 - 8 GW) low in comparison with demand
	Biomass	• Costs for storage system and plant expansion and ICT connectivity • Installed capacity (9 GW) is low compared with demand
	Interruptible loads	• Partially in use today • Costs heavily depend on production process
MR- Max. residual demand: 3,740 MW Duration of demand: 648 h Annual volume: 977 GW*h	Th. power plants	• Flexible power plants as a must-run unit • For gas-fired power plants: 1.25 MW_{el}/MW_{MRP-} o Overproduction: 1.22 TWh • Additional production costs: € 116 – 152 million/year
	PSP	• Forgoing energy market-oriented pump operation in the demand hours • Throttling of RES plants possibly required due to missing pump operation o Additional generation costs due to RES throttling
	Biomass	• See MR+
	Wind turbines	• Potential and cost-effectiveness depend on qualification conditions • For full coverage of the residual demand, a max. of 11% of the wind turbine feed-in capacity must be throttled
	Connectible loads	• Low potential in the industrial sector • Season-dependent potential of thermal applications in the residential sector

The need for SBP and MR in 2033 as determined in Chapter 2.5.1 cannot be met by the available hydraulic and thermal suppliers in some few hours. It is shown, however, that currently existing and new suppliers offer enough alternatives on the CR markets to cover demand. They also have the potential to meet the CR demand of cost-effective thermal must-run power plants.

With the currently used time slices, the positive and negative residual SBP demand can provided by PSPs in a CR-oriented opera-

tion mode and by innovative CR suppliers (e.g. battery storage systems, biomass plants, wind turbines). For wind turbines in particular, an adaptation of the SBP time slices eliminates market entry barriers and allows the increased use of innovative suppliers. Shorter time slices reduce the residual demand for SBP and thus lead to lower reservation costs. Large-scale batteries are another competitive alternative for the provision of SBP, because they can offer symmetric operating ranges at any time and prequalification is not a technical hurdle. Switchable loads can supplement innovative CR pools; the overall potential for exclusive provision, however, is considered to be low.

In addition to the duration of the SBP time slices, the duration of the lead times for supply-dependent suppliers is crucial. For these RES systems, the shortest possible lead time between award and delivery obligation is recommended due to the improved capacity forecast. TSOs, however, need room for manoeuvre, for example for the option of a second SBP tender after an unsuccessful initial attempt. The tendering process has to ensure that CR is sufficiently available to TSOs at any time. This includes the procurement process and a sufficiently long lead time between the award notification and delivery date, in order to give the TSO room for manoeuvre. The deadline for offers for the current weekly tender of SBP is usually on Wednesday of the week before, so up to eleven days lie between submission of the offer and the obligation to deliver. For CR suppliers with supply-dependent renewable energy systems, the available capacity during this period is difficult to predict accurately. Battery storage systems, however, do not directly depend on forecasts and do not require shortened lead times.

A number of alternative suppliers are already qualified for the MR market. In the positive balancing direction, this includes emergency power systems and biomass plants, as well as flexible loads. Flexible fossil fuel power plants can also be used from a standstill for the positive balancing direction, avoiding overproduction as must-run units. The identified residual demand for positive MR can therefore be provided without the reservation of must-run units in the future.

Innovative suppliers such as biomass and wind power plants as well as switchable loads with an energy market-oriented operation come into consideration to cover the negative MR demand, in ad-

dition to PSPs and thermal power plants. To cover the residual demand of negative MR, thermal must-run power plants lead to high system costs. PSPs and alternative suppliers are, however, sufficiently available and are so at lower costs. For some, especially fluctuating, suppliers, the adjustments of the qualification conditions lead to further potential gains and possibly to lowered costs.

2.5.6 Potential revenues on the balancing power market

TSOs procure the required CR quantities by auction on the CR market. The reservation costs correspond to the service price paid to the suppliers and are published in an annual monitoring report by the Federal Network Agency [141], [142]. In Figure 2.20, the balanced costs of CR provision for a symmetric operating range are shown relative to average tender volumes. There is a trend towards cost savings in all CR types. The reservation costs of MR are significantly lower than for PBP and SBP.

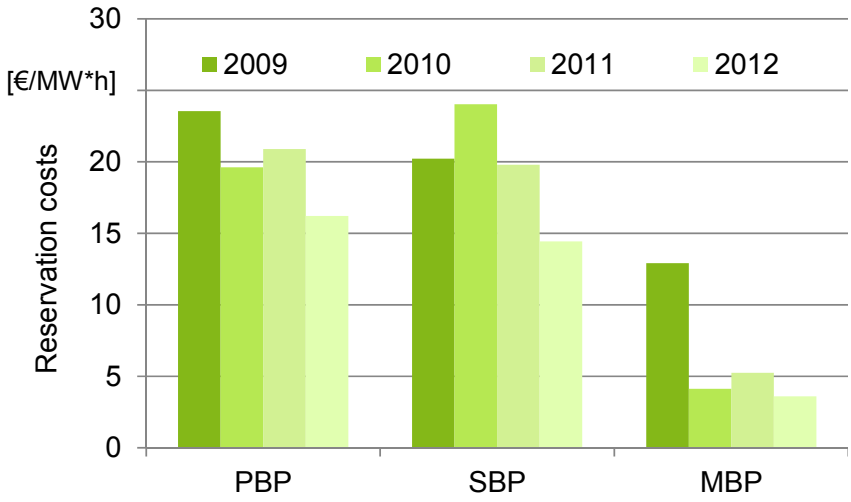

Figure 2.20 Annual balanced costs of CR provision

In the analysis of the annual costs, however, it was not considered that the prices on the CR market are also subject to seasonal fluctuations. Both the energy prices and the service prices of the different CR products vary throughout the year, and in the case of MR even throughout one day. Figure 2.21 shows the energy price development for negative Figure 2.22 and positive MR as mean values per month. For both balancing directions, a fluctuation of the maximum energy price (marginal energy price) over several

years can be seen. Negative MR also shows a significant increase of the average marginal energy price. Positive MR does not share this energy price trend. The difference between the average energy price of all awarded offers and that of the activated offers is rarely due to the activation of high volumes of MR. The even more significant difference between the maximum and the average energy price shows that only small volumes of MR are offered at a relatively high price. A presentation of the historical development of the volume-weighted energy and service prices of MR from 2009 to 2013 per time slice is given in [123]. It clearly demonstrates the highly volatile development of the both prices over the years.

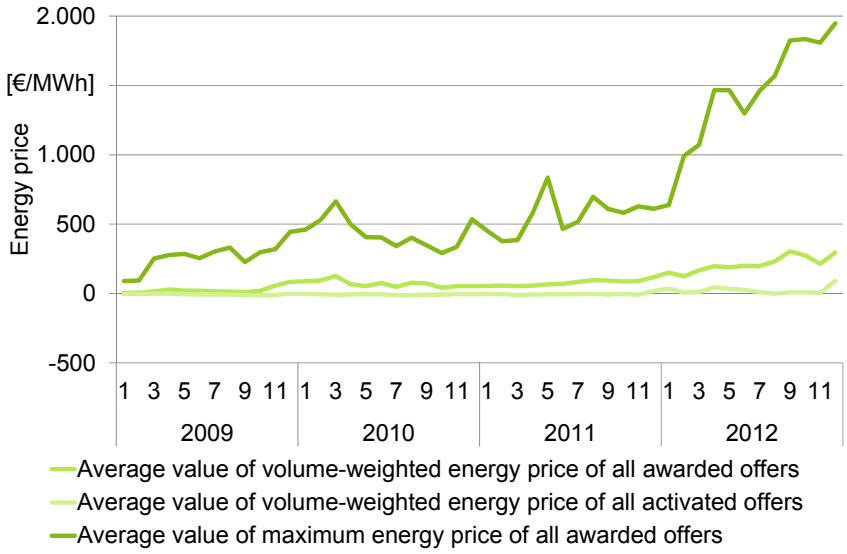

Figure 2.21 Development of the energy prices for negative MR

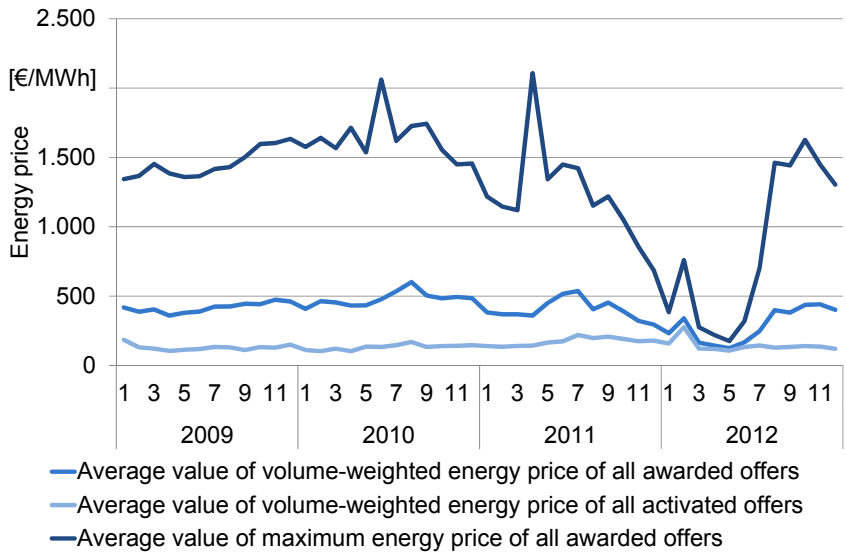

Figure 2.22 Development of the energy prices for positive MR

The price fluctuations are due to the opportunity prices of the providers, such as power suppliers on the spot market, increasing competition in the market and changing tender conditions (e.g. daily auction). In addition, the current auction as a pay-as-bid auction leads to strategically motivated bidding behaviour [132]. This applies equally to SBP, as an analysis in [133] shows. A statement about the future development of prices for CR cannot be made against this background. Based on the price history, however, the annual revenue potential for alternative suppliers can be determined.

Figure 2.23 shows the revenue for the provision of MR by heat pumps, micro-CHPs and electric heating systems in single and multi-family homes. The revenue for each of the three heating technologies is determined for 7 different types of buildings (year of construction, living space, spec. heating requirements, number of residents and housing units) in 15 climate zones for the years of 2009 to 2012. Annual revenues are distinguished according to revenues on the basis of the mean (E_{average}) and the maximum (E_{max}) energy and service prices. A detailed explanation of the method and the assumptions made is offered in [123].

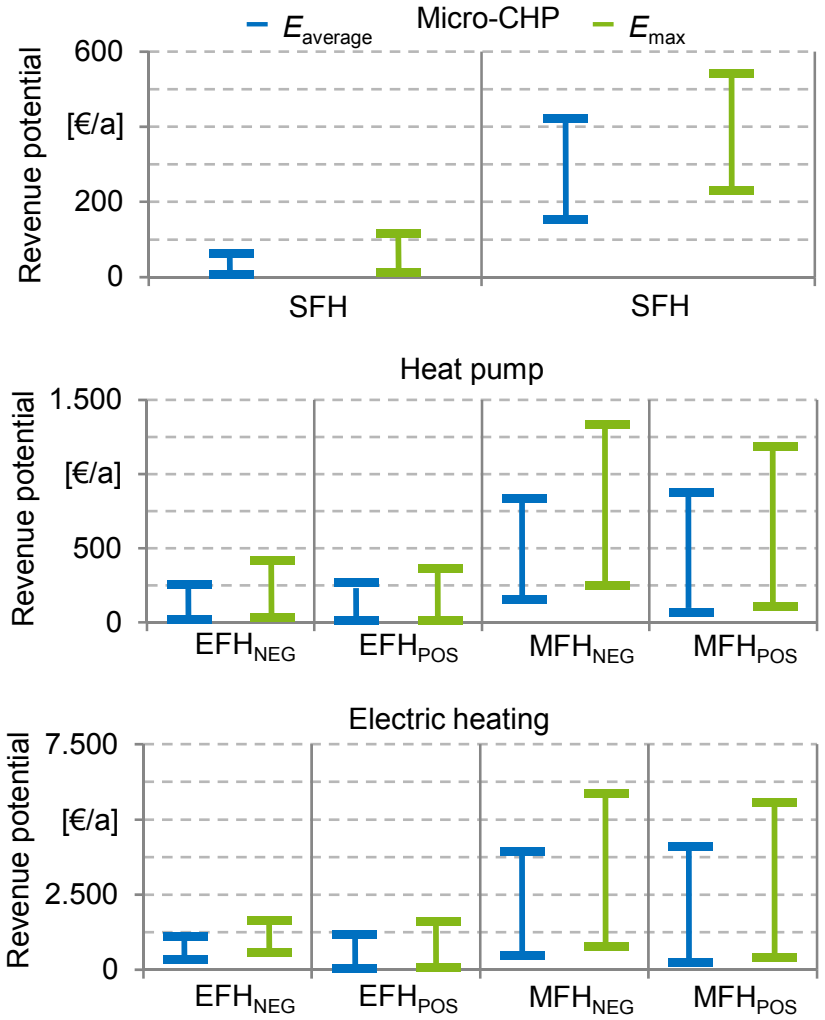

Figure 2.23 Annual revenue potential for marketing different heating technologies in single and multi-family homes on the MR market from 2009 to 2012.

The results show that revenues vary greatly even within the individual technology and type of building. This illustrates the dependence of revenue on meteorological conditions and CR prices during the four years under review. In the year with the lowest revenue, it is expected that no plant generated revenue of over € 46.16 per kW of installed capacity, even assuming maximum prices. Assuming average, volume-weighted prices, this figure is only € 30.44/kW. Given the low installed capacities in single-family homes, an economic operation of the system is therefore highly unlikely. The annual costs of installing a smart meter, including ICT and billing are estimated at about € 130 per household (see data on prices in Chapter 2.2). Revenues listed are system-specific and cannot be transferred to other alternative suppliers. Instead, the

average energy and service prices may serve as an orientation for potential revenues.

2.6 Conclusion for frequency stability

Instantaneous reserve

The results show that in the period under review in 2033, there is enough available instantaneous reserve to support the system after a generation outage of 3,000 MW. Regarding instantaneous reserve, no additional action is required. In the scenarios considered, the magnitude of the maximum frequency deviation is 200 to 600 mHz. Even assuming that the energy supply system in Germany will no longer have any rotating masses and that they have been replaced by renewable energy systems, there will still be no limit violations. In this particular case, the instantaneous reserve would have to be provided exclusively from abroad. The provision of instantaneous reserve from abroad, however, is only possible if their local systems evolve according to the assumptions. Currently, instantaneous reserve from abroad can be considered as secured. The question, however, is whether there might be a need for action arising from future political decisions.

In addition to conventional power plants, alternative providers such as wind turbines can make a contribution to the provision of instantaneous reserve in the future. There are different measures to support and additionally stabilise the system. Throttling DECUs, the use of the rotational energy of wind turbines, increasing the frequency dependence of loads, increasing power plant dynamics, the use of storage systems, the use of rotating phase shifters and possibly the use of must-run power plants can all make a contribution. To ensure that the German energy supply system does not have to rely on the provision of instantaneous reserve from abroad in the future, the mentioned alternative providers are required in Germany to operate the German energy supply system in 2033 with the same stability as in 2011.

The investigation shows that the capacity difference can be covered by wind inertia in 93% of the hours of the year 2033. In the remaining hours of the year, conventional power plants and a certain remaining level of wind inertia help cover the instantaneous reserve and maintain system stability. The actual provision of the capacity difference by wind inertia with correspondingly

implemented controls must yet be verified using a dynamic model. If future alternative suppliers are to be involved in the provision of instantaneous reserve, then the technical requirements must be met.

Finally, Table 2.9 summarises the recommendations for action in the area of instantaneous reserve. The short-term recommendations for action are considered as necessary within the next ten years, and the long-term recommendations as necessary until the end of the review period 2033.

Table 2.9 Recommendations for action for the future provision of instantaneous reserve

	Recommendation for action	Motivation	Legal / technical / regulatory aspects	Economic aspects
Short-term	Inclusion of wind turbines for wind inertia		Creating the necessary framework conditions	Wind inertia cost-effective alternative
Long-term	Inclusion of wind turbines for wind inertia	Maintaining the status quo of Germany's share	Use of wind inertia to provide instantaneous reserve	Wind inertia cost-effective alternative

Primary balancing power

The results of the power plant utilisation model show that in 2033, the exclusive generation with wind turbines will exceed the load in Germany in over 70 hours. CR provision by thermal power plants is accordingly low during these hours and can not be provided by today's typical CR suppliers without a reservation of must-run power plants. Accordingly, the provision of the required CR is not possible with the current setup. Without the designation of mandatory conventional power plants in these times, the CR demand must be covered by renewable energy systems and alternative providers. In these hours, therefore, is must be economically and ecologically considered whether the additional operation of conventional power plants is preferable to the use of innovative CR

providers. This is especially true for PBP and the positive balancing direction of SBP.

The analysis of the dimensioning procedure for PBP indicates that there will be no significant change in demand in the future. Due to changes in the generation situation of thermal and hydraulic power plants, the provision of PBP while maintaining today's weekly time slots is not secured at any time of the year under review. Even if one assumes hourly PBP products, sufficient PBP can be provided by thermal and hydraulic power plants in only about 70% of the annual hours.

Innovative providers of PBP are required in particular during hours with a low residual load. Otherwise, thermal must-run units will incur high generation costs. Wind turbines, BMP, loads, run-of-the-river power plants, battery storage systems and PV systems are being investigated as alternative providers. Due to their high temporal availability, wind turbines, run-of-the-river and biomass plants are viable future providers of PBP. Battery storage systems combined with renewable energy systems benefit from synergistic effects. On the other hand, an exclusive PBP provision by battery storage systems may be a viable alternative in the future due to declining battery costs. Today, a number of large-scale battery storage systems have already demonstrated that it can be economically feasible to provide PBP.

Secondary balancing power and minute reserve

With respect to SBP, the model does not indicate any significant change of the required balancing power reserve. However, increasingly frequent and rapid wind speed changes and residual load changes may lead to an increased demand for SBP. Current model approaches, however, do not reflect this possibility. The analysis of the future demand for MR shows that a significant increase in fluctuating feed-in and the maintenance of today's billing practice will demand a significant increase of the reserve volumes. However, since balancing uncertainties largely depend on the respective feed-in situation of fluctuating RES, a day-before adjustment of tender volumes is recommended. As a result, the average increase in demand for MR can be greatly reduced by 2033 in comparison with the current billing practice.

A market-oriented power plant utilisation approach is used to determine to what extent the calculated demand for SBP and MR is

covered. Taking into account the present time slices, this approach shows that there is a need for CR that cannot be covered by thermal and hydraulic power plants in up to 7% of the annual hours. Assuming hourly time slices, the deficit is reduced to about 1.5% of the annual hours. Negative MR is affected in particular. The operating mode of PSPs has a strong influence on the model results. It becomes clear that sufficient alternatives for the provision of the CR demand are indeed available. These alternatives turn out to be potentially more cost-effective than thermal must-run power plants, so their use for frequency control is not required. The cost structure of future CR providers, particularly of wind turbines, however, depends greatly on the prequalification conditions, the duration of the time slices and the frequency of tenders. Shorter time slices and more frequent tenders have the potential both to reduce the CR demand and to encourage the market entry of new suppliers.

An analysis of the theoretical potential of alternative flexibility options has been carried out in numerous studies. The technical potential of the flexibility options and the cost-effectiveness of their utilisation has been identified for some sub-areas. The prices on the balancing power market vary greatly, and in the area of MR they lead to a potential revenue that can only insufficiently cover the costs for improved flexibility in private households. The potentially higher revenue from the provision of SBP is blocked by market entry barriers, such as longer time slices and high technical requirements, for example to ICT.

Alternative providers of CR with technical units, such as emergency power systems or larger industrial loads, have a higher installed capacity and are already active on the market as part of CR pools. The installation of locally distributed batteries as intermediate storages for wind and solar power prevent the throttling of these DECUs, which includes the provision of CR. Without storage systems, the availability of these flexibility options fluctuates throughout the year, including the load shift potential in the industrial sector, so further research is needed for a detailed consideration of these potentials.

The provision of MR from the distribution grid is already possible through local decentralised technical units such as storage systems, industrial loads, biomass and emergency power systems. To this end, they are fitted with a smart control and are connected to a

pool control centre via communication technology. Research is needed to clarify how the DSO should accompany the prequalification of technical units in the distribution grid in order for an aggregator to offer this capacity as CR without overloading the grid when it is activated.

Recommendations

For all CR types, the adaptation of the CR tendering time slices, the tender frequency and prequalification conditions supports the market entry of new suppliers and can thus contribute significantly to demand coverage in the future. A revision of the prequalification conditions regarding proof of the CR provided and the required temporal availability of 100% for PBP and MR is recommended to facilitate the leverage of the potential of renewable energy systems or loads.
At the same time, a shorter lead time facilitates CR provision in RES-dominated feed-in situations. The introduction of daily auctions for PBP and SBP would also aid the market entry of new suppliers. It can also be shown that the demand for MR will fluctuate heavily in the future. A day-before adaptation of the MR volume to RES feed-in can greatly reduce any additional CR demand caused by RES forecast errors. To tap the potential of flexible household loads in the future in addition to industrial loads, the introduction of alternative metering and balancing methods will be necessary. The cost-effectiveness of CR provision by household loads can so far not be verified.

Finally, summarised in Table 2.10 are the recommendations for action in the area of CR. The short-term recommendations for action are considered as necessary within the next ten years, and the long-term recommendations as necessary until the end of the observation horizon in 2033. Among the long-term recommendations for action, measures are listed that will make no substantial contribution to the provision of CR in 2033 from today's perspective, and therefore entail no urgent need for action, and their technical development should be waited for.

Table 2.10 Recommendations for the future CR

	Recommendation for action	Motivation	Legal / technical / regulatory aspects	Economic aspects
Short-term	Allow supply-dependent renewable energy systems for CR provision	Cost-effective provision of CR by renewable energy systems	Allow limitation of RES and adjust prequalification	CR by DECUs, loads or storage systems as cost-effective alternatives
	Shorten the tendering and lead times	Units that are available during limited periods offer increased performance (DECUs, loads)	Adjust tendering practice in terms of time slices and lead times	More potential suppliers, increased price pressure, but more effort involved in processing
	Adapt the dimensioning procedure for SBP and MR	Adapt demand to the generation situation	-	Low reservation costs
Long-term	Introduce alternative metering and balancing methods (e.g. CRM)	Allow utilisation of flexibility options in private households	Amend the procedure specifications (GPKE, MaBiS, etc.)	Potential economic value added through more suppliers on the balancing energy market minus higher costs for metering and balancing methods

3 Static voltage control

For voltage control, a distinction is made between static and dynamic voltage stability. Static stability is given when the system returns to its steady-state default condition after a minor fault. Static voltage stability primarily requires a locally balanced reactive power balance. Transient and dynamic balancing measures take place after larger disturbances. The return to a stable operating point largely depends on the behaviour of the suppliers during a disturbance, amongst others. In the following, the impacts of changes within the energy system are considered separately according to the two aspects of static voltage control and behaviour in case of a fault. In general, the issue of voltage control is associated with the provision of locally adequate reactive power. In addition, however, all voltage controllers must be coordinated to ensure a stable system behaviour both in the static and in the dynamic range.

Intermittent lack of conventional power plant capacity in the transmission grid

Voltage control in the transmission grid is mainly realised by controlling larger power plants by means of reactive power supply. In contrast to frequency control, in which all generators of balancing power plants participate in the balancing process, the reactive power demand of a grid section must be supplied by local points of feed-in. A lack of larger power plants leads to a local deficit of reactive power sources on the transmission grid level. In addition, the reactive power demand of the transmission grid increases along with longer power transits, as it is the case with wind turbines that feed into the grid over longer geographical distances [4], [10]. To find a balance between demand for reactive power and reactive power generation, TSOs dispose of the following measures on the transmission grid level in addition to the utilisation of active, conventional power plants [39]:

- Installation of additional reactive power compensators (inductors, capacitor banks, static VAR compensators, STATCOM)

- Upgrading disused power plants for phase shifter operation
- Use of HVDC transmission converters
- Voltage-related redispatch (use of power plants not used due to market-related circumstances with the technically lowest possible active power feed-in)
- Transformer tapping
- Changes to the grid topology (e.g., line shutdowns)
- Load shedding as an emergency measure

Reactive power feed-in of DECUs in the distribution grid

With active power feed-in from DECUs on the distribution grid level, the voltage of the distribution grid is raised locally. A reactive power contribution by DECUs is currently being demanded to counteract this effect. Existing requirements to DECUs with respect to the exact volume of their reactive power supply depend on plant size and the point of common coupling (PCC) in the respective voltage level. One way to provide capacitive and inductive reactive power, for example, is the use of a Q(U) characteristic. Operating behaviour is adjusted in response to the voltage at the grid node by using the droop characteristic of the DECUs. The option of providing capacitive and inductive reactive power to the transmission grid level is currently not taken advantage of.

To increase the potential of reactive power supply by DECUs, there is also the possibility of adapting inverter designs to a higher maximum apparent output in order to feed in additional reactive power during maximum active power feed-in. It must be noted, however, that over-dimensioning the inverters affects the profitability of the plant. This is especially true when reactive power supply is not remunerated at lower voltage levels of the distribution grid. Current grid connection codes require a provision of reactive power by DECUs only in the case of simultaneous active power feed-in. A contribution to voltage control on the distribution grid level, e.g. at night by PV systems, is currently not intended. However, there may be demand for reactive power even in times of low supply from RES.

Concepts for voltage control on the distribution grid level

In addition to the previously described requirements for reactive power provision by DECUs, DSOs dispose of other concepts to

maintain voltage control. Measures such as wide-area voltage control or the use of variable local grid transformers mostly serve an improved exploitation of the available voltage range [21]. Currently, all measures are generally only used for voltage control on the distribution grid level [2]. A coordination of reactive power provision from the distribution grid for the transmission grid has not yet been considered in detail. In this context, it is to be examined whether a control scheme for reactive power provision on the distribution grid level is stable. For this purpose, the entire reactive power chain has to be considered taking transformer tapping into account.

Distribution grid design in planning and operation

The high share of renewables already leads to high loads on the distribution grid level. The inhomogeneous line distribution of DECUs leads to voltage threshold violations mainly on the MV level.

In addition to planning grid expansion measures, operational measures are available to increase the grid capacity for RES. Load and RES-dominated lines can be operated on separate busbars. This has the advantage that the tap selection can be controlled independently for each respective line. Prerequisite is the availability of a transformer in parallel. This is problematic, however, when maintenance work, for example on a transformer, has to be carried out. In this case, the voltage range limits can be violated, especially in marginally configured distribution grids.

Another aspect regarding the management of distribution grids is the blockage of tap selections to avoid a wide-area voltage collapse. In case of imminent voltage collapses, a load reduction takes place by specific voltage drops in the distribution grid and hence the tap selections on the MV and HV level must be blocked, which is then exploited. However, the voltage-supporting effect of DECUs prevents the targeted voltage reduction on the distribution grid level. Consequently, blocking the tap selections is ineffective. This effect can be enhanced by the increased use of DECU Q(U) droops.

Simultaneous contribution to voltage and frequency control

If the provision of ancillary services for the transmission grid is mostly ensured from within the distribution grids in the future, it would be useful to consider frequency control and voltage control simultaneously. For example, an altered active power flow in the

transmission grid due to CR provision has a direct influence on the voltage level and thus on the reactive power demand of the transmission grid node.

If supply is to be realised via the distribution grid level in the future, it should be considered that this not only has an impact on the active and reactive power flows for voltage and frequency control of the transmission grid, but that effects on the distribution grid level need to be considered as well.

Voltage-related redispatch

As part of system control, redispatch measures are carried out to relieve certain lines of the transmission grid and thus resolve bottlenecks by means of shifting feed-in from power plants. Today, redispatch measures are no longer used solely for congestion resolution during certain hours of the year, but also to maintain voltage in the transmission grid. With a targeted intervention in power plant dispatch, conventional suppliers are used in locations with an increased reactive power demand in order to meet this demand locally. This aspect should be examined particularly against the background of an increasing replacement of conventional suppliers, and is discussed in Appendix B System coordination.

3.1 Research questions

Due to the lack of large generation units in the transmission grid, there will be a future shortfall with respect to possible sources of reactive power for voltage control in the transmission grid. Therefore, it must be examined how exactly the reactive power demand of the transmission grid in Germany is developing. Further alternatives to meet demand must also be identified. One of these alternatives is the provision of reactive power from the distribution grid. Here, several aspects of voltage control are to be observed on the distribution grid level. This leads to the following research questions:

- How is the reactive power demand of the transmission grid and the distribution grid developing?
- How can the future demand of the transmission grid be covered?
- Can distribution grids make a contribution to voltage control on the transmission grid level?

- To what extent can decentralised voltage control that simultaneously balances the local voltage level and that of the higher-level grid level be realised?
- What impact does the provision of reactive power have on the operation of distribution grids?
- To what extent it is sensible to demand a provision of reactive power by DECUs without active power feed-in?
- Is it economic to overdimension DECU inverters to increase the provision of reactive power?
- To what extent does a combination of various voltage control concepts make sense?
- What would a complex Q(U) control look like versus Q(U) droop on the distribution grid level?

3.2 Evaluation of current literature and studies

Today, voltage control on the transmission grid level is realised through the provision of reactive power from conventional large-scale power plants. An increasing shortage of generation units will thus result in a coverage gap in the provision of reactive power. This problem has already been discussed, for example in the NEP 2012 [4] and in the second amendment of the NEP in 2013 [8]. As part of the NEP, the reactive power demand of the transmission grid is initially covered by conventional power plants as well as through the use of HVDC transmission converters. To cover the total reactive power demand in a selected grid use case of *Scenario B 2023*, reactive power compensators at 75 locations are provided for with a reactive power generation capacity of about 27,000 Mvar. However, provision of reactive power from the distribution grid remains unaccounted for in the NEP and is only listed as an alternative [4], [8]. In [37], the use of a Q(U) characteristic for DECUs is mentioned, but not explicated, as an alternative to the use of phase shifters and reactive power compensators. Analyses in terms of efficient voltage support in LV grids are provided in [23]. The use of a Q(U) droop is recommended here. Any potential stability problems of such a control can only be expected in the case of an incorrect parametrisation of the controllers.

If DECUs are considered in grid planning in the future to help control voltage, it would be sensible to demand reactive power supply without simultaneously demanding active power supply. This possibility is currently not considered by the applicable guidelines

[25], [35]. The ability of wind turbines connected to the grid via a converter to provide reactive power during downtimes is discussed in [1]. The same applies to the consideration of PV systems.

3.3 Own calculations

In addition to researching relevant literature, this chapter presents the results of own calculations for the analysis of voltage control in the transmission grid level, as well as the underlying research methods applied.

The simulations are characterised in particular by a consideration of the mutual support of coupled voltage levels, i.e. the provision of reactive power as an ancillary service across grid levels.

3.3.1 Method for determining the reactive power demand in the transmission grid and the most cost-effective way to cover demand

A simulation model was developed as composite of several elements for the analysis of the demand for reactive power for voltage control in the transmission grid. Based on the node-accurate grid entries and exits as determined in the market simulation, and the grid data from the aggregate grid model, AC load flows were calculated in a first step. In addition to the line loads in the base case, the power transfer distribution factors (PTDF) are determined, which represent a linear transformation of the node capacity into active power flows. Since the market simulation takes into account the static, bilateral transfer capacities (net transfer capacity values) between Germany and its neighbouring countries, the determined power plant utilisation can cause bottlenecks within Germany that must be resolved by redispatch measures. In order to determine measures necessary during grid congestions, a so-called redispatch model was developed. In this optimisation problem, the physical power flows in the cross-border lines and domestic lines are taken into account as network constraints. This is done by using the PTDF matrices determined in the load flow calculations, and the grid load base case. Due to the underlying linearisation of the load flow equations, the overall optimisation problem is also linear. Only conventional power plants that are already in operation in the respective hour, as well as peak load power plants that can

be operated for short periods of time due to short startup times and low minimum times for standstill and operation, can take part in redispatch measures. As a result, the redispatch model provides for a congestion-free power plant utilisation and a utilisation of HVDC transmission lines that relieves the three-phase supply network. In a third step and based on the results of the other model elements and including additional data such as reactive power limits of conventional power plants and voltage limits at the grid nodes, an optimal power flow (OPF) is carried out and the demand for reactive power in the transmission grid is determined, accurate to a resolution of individual nodes and for the entire year under review. Based on these results, relevant grid load scenarios, i.e. periods with an increased reactive power demand, are identified and the cost-optimal reactive power provision from various sources is determined taking into account various specific costs.

Feasible reactive power sources include active conventional power plants, power plants that are idle due to market conditions, phase shifters, HVDC transmission converters, existing as well as yet to be built conventional reactive power compensators and in particular DECUs from lower-level distribution grids, and their potential for reactive power provision is determined as part of a distribution grid model. The interaction of the individual model elements is presented in Figure 3.1 in the form of a flowchart.

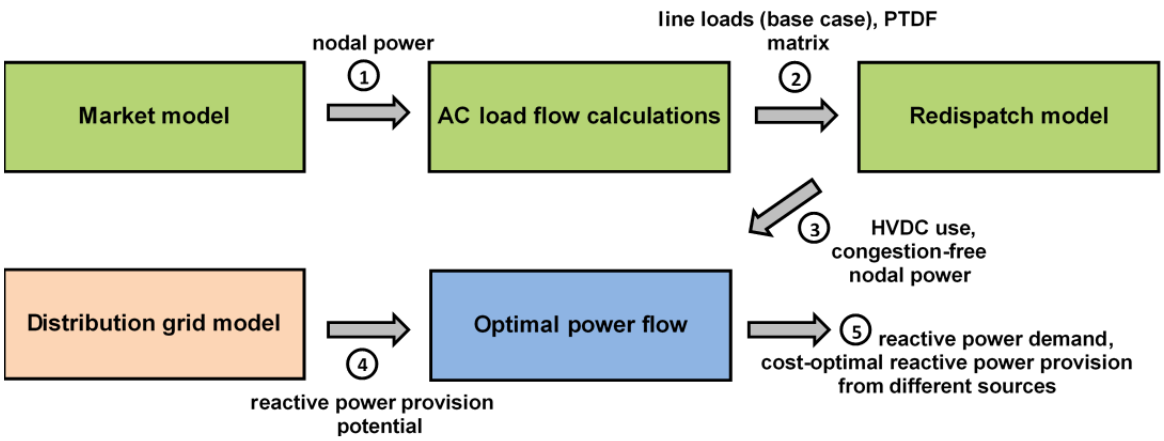

Figure 3.1 Flowchart of the analysis of the demand for reactive power for voltage control in the transmission grid

3.3.2 Description of the optimal power flow

Based on the results of the market simulation and the redispatch model, and for the identified design-relevant grid load scenarios, an optimal power flow was carried out to calculate the reactive power demand and the cost-optimal provision of reactive power in the German transmission grid both for the grid's ground state (n-0) and for the steady-state (n-1) case.

Possible reactive power sources are incorporated in the model with a node-accurate resolution, and with a ranking of their specific costs. Sources considered are active, idle and shut down power plants (phase shifters), existing and planned HVDC transmission converters, conventional reactive power compensators and lower-level distribution grids whose potential for reactive power supply is calculated in the chapter "Method for determining the reactive power potential of the distribution grid".

The developed OPF optimises the provision of reactive power in the sense of minimising overall generation costs sequentially for every time step. Active power provision, determined in a cost-optimal way in the market simulation, is kept constant so that the time-coupling constraints of the market simulation, which result from the consideration of minimum up- and downtimes, ramping limits and PSP, are not subsequently violated by the OPF. Constraints of the OPF are the power balance between generation and consumption, the reactive power limits of conventional power plants and other sources of reactive power, the voltage band at the grid nodes and the maximum transmission capacity of the lines. Viable voltage support for adjacent regions is incorporated by considering a permissible voltage range.

The method for determining the reactive power demand and the cost-optimal reactive power supply is shown in Figure 3.2.

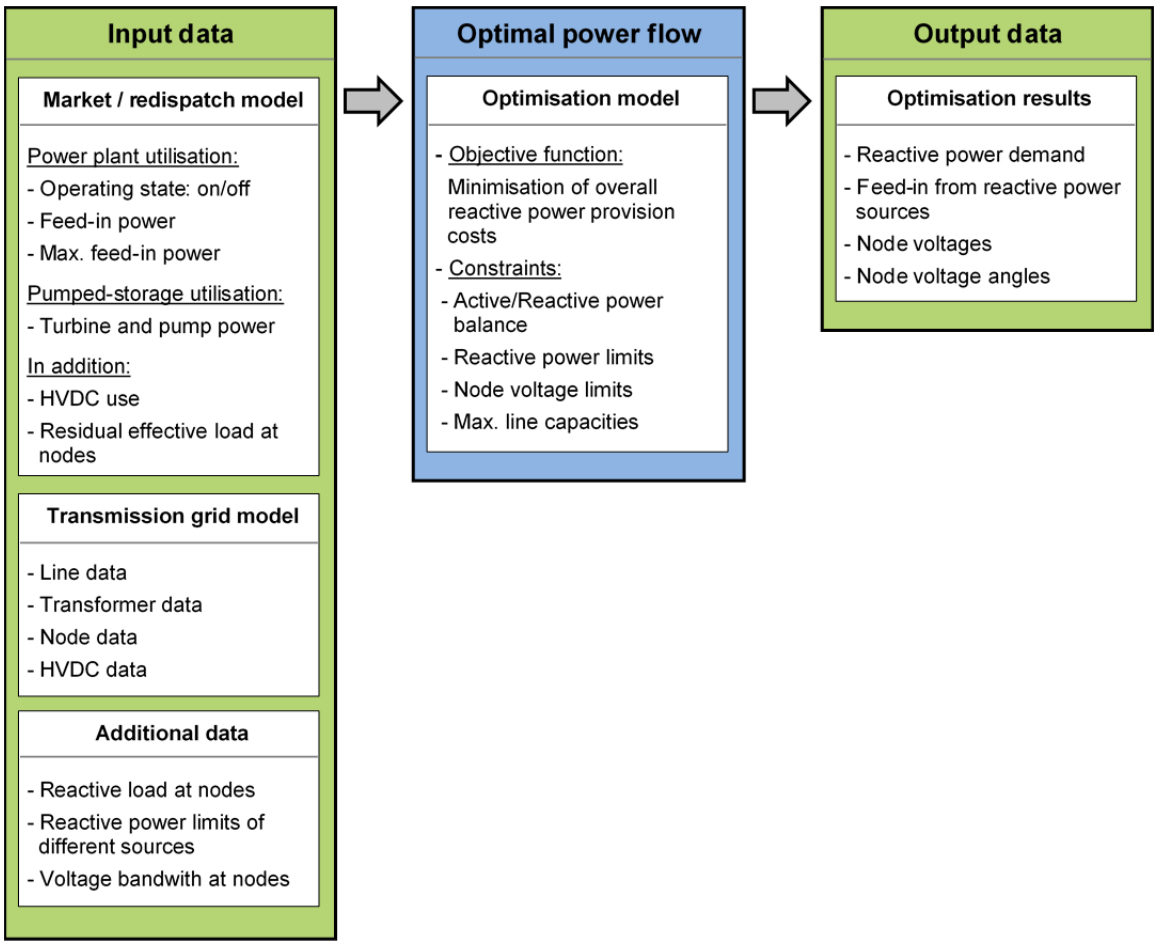

Figure 3.2 Method for determining the reactive power demand and the cost-optimal provision of reactive power

3.3.3 Reactive power demand in the transmission grid

The calculation of the reactive power demand, or the reactive power generation required at each grid node, is undertaken for all 8,760 grid use cases of the year under review and makes use of the optimal power flow presented in the previous section.

The calculation is based on the following assumptions:

- The selected node-accurate reactive load results from the effective node load for a $\cos\varphi = 0.95_{ind}$
- The maximum and minimum node voltages are 1.1 and 0.9 p.u.

The calculation is carried out initially without a consideration of reactive power sources and it therefore represents demand. In a second step, definitely available sources are considered in the

analysis, and the additional demand to be covered by alternative sources is identified.

In Figure 3.3, the range of the node-accurate reactive power demand, that is the required maximum and minimum capacitive or inductive reactive power generation at each grid node during the year 2033, is shown for the grid's ground state ((n-0) case). The maximum capacitive reactive power demand of 2,859 Mvar occurs at node 20 (Rhine-Ruhr region). The maximum inductive demand occurs at node 23 (border Thuringia and Saxony) and is 1,467 Mvar. It should be noted that the determined maximum and minimum values generally occur at different times of the year.

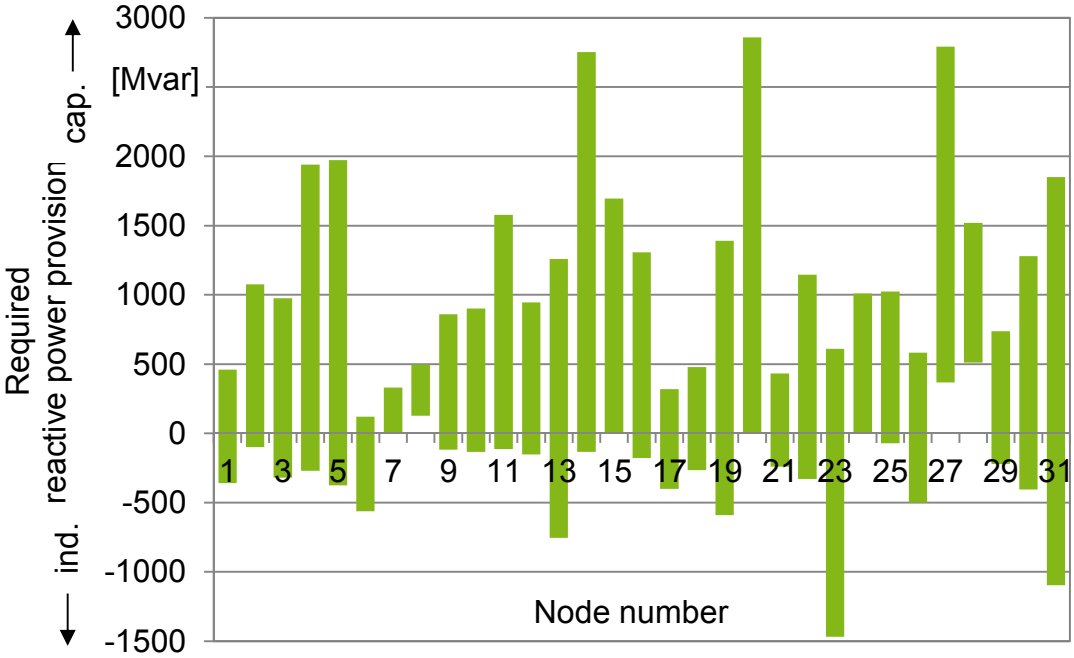

Figure 3.3 Range of the reactive power demand in the year under review 2033

The determination of the relevant grid load scenarios is not only based on the reactive power demand, but also on the additional demand for reactive power. OPF was used to calculate the share of demand that can be covered by available reactive power sources.

The following sources were included in the calculation:

- Existing reactive power compensators and those planned for the next few years
- Active conventional power plants

As a result of the annual simulation, Figure 3.4 shows the node-accurate range of the additional reactive power demand.

While the highest additional capacitive demand of 2,753 Mvar occurs at node 14 (Rhine-Ruhr region), the highest additional inductive demand of 562 Mvar occurs at node 6 (Greater Bremen).

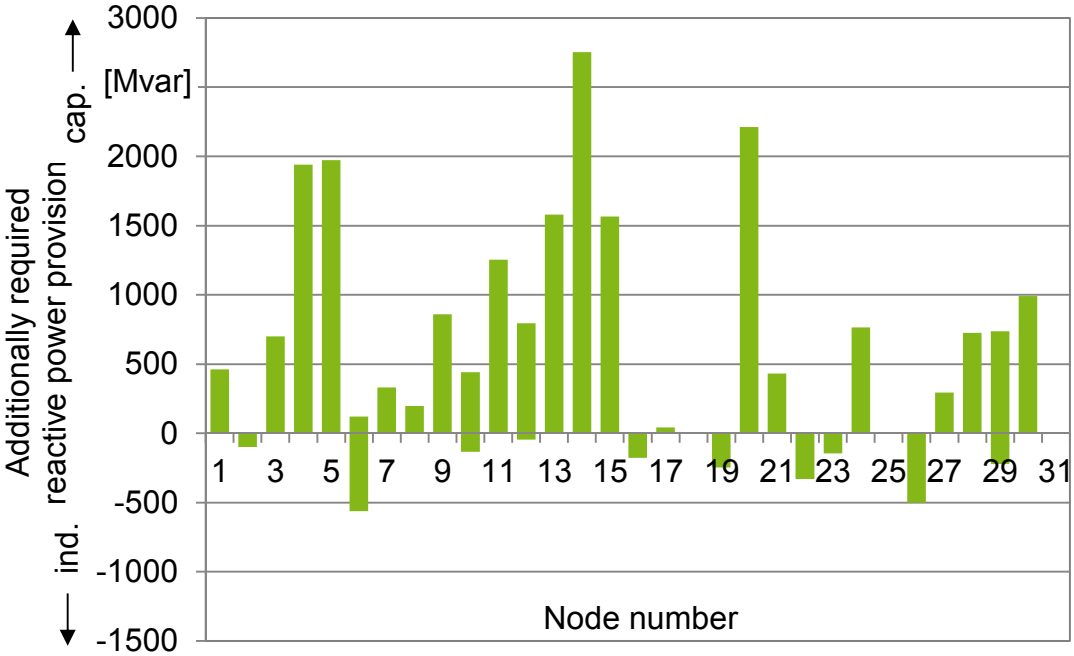

Figure 3.4 Range of additional reactive power demand in the year under review 2033

3.3.4 Identification of grid load scenarios relevant to assessment

Two relevant grid load scenarios were identified with the help of the simulation results. The criterion for the selection of the first relevant scenario was the presence of a high capacitive demand with a simultaneous maximum additional capacitive demand for one grid node in the year under review (relevant hour capacitive). The selected hour is characterised by high wind power feed-in and high PV feed-in with a simultaneous high load volume (hour 5,964, see Appendix A.3). The total wind power feed-in on all grid levels is 44.5 GW (annual maximum 61.4 GW), feed-in from PV is 27.4 GW (annual maximum 36.3 GW). With 76.1 GW, the load is only slightly lower than the annual peak load of 84 GW. Figure 3.5 shows the relevant hour's demand for reactive power for steady-state voltage control in the German transmission grid.

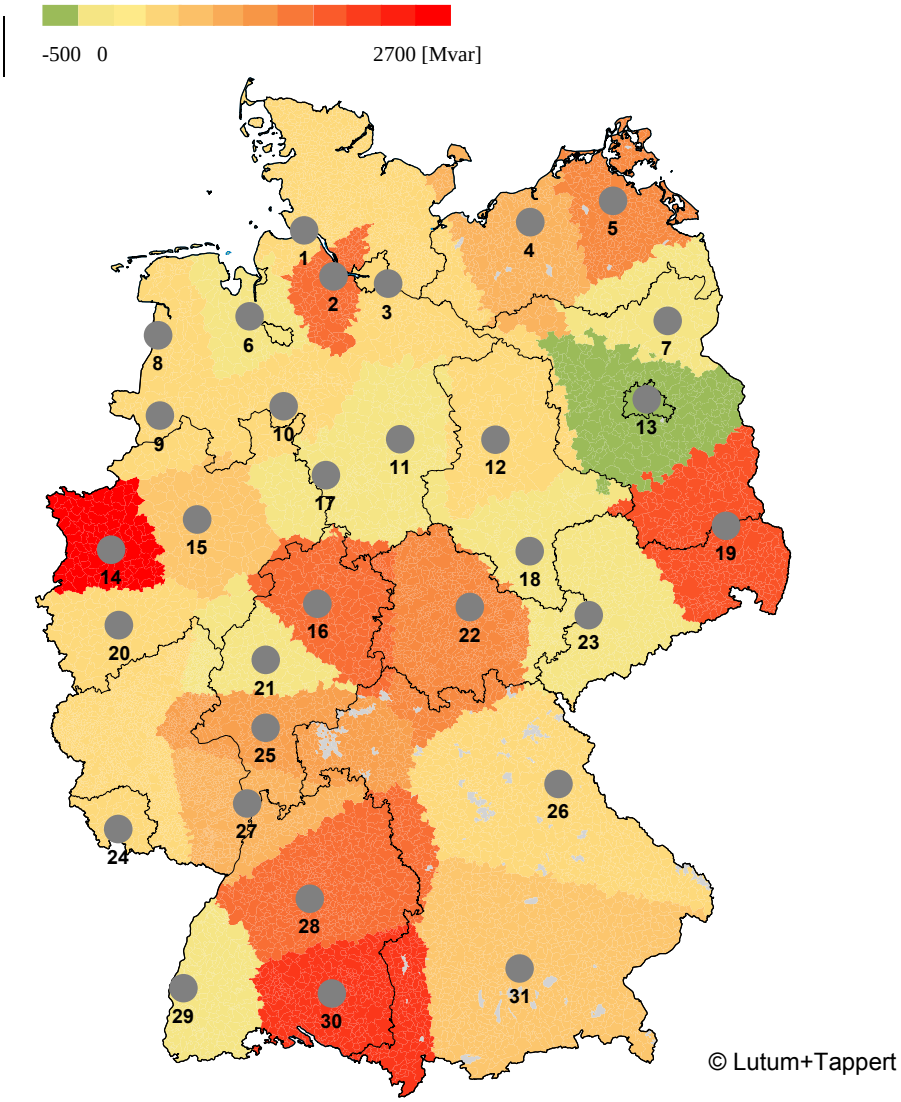

Figure 3.5 Reactive power demand for the design-relevant capacitive hour in the (n-0) case

In the selected scenario, it is mainly required to provide capacitive reactive power to cover the inductive vertical reactive load and the predominantly inductive demand of the grid. In particular in the Rhine-Ruhr region, the Main-Neckar region and in the region of Rostock, there is an increased demand for reactive power. Only greater Berlin requires a provision of inductive reactive power. Due to the low load, the lines in the greater Berlin area are below normal operating conditions and therefore exhibit capacitive behaviour.

The reactive power demand of the German transmission grid is approximately 5,800 Mvar for the load scenario in the (n-0) case.

The criterion for the selection of the second relevant grid load scenario is analogous to the first selected scenario: the occurrence of a high inductive reactive power demand with a simultaneous maximum additional inductive demand occurring at one grid node (design-relevant inductive hour). The selected scenario is characterised by an average wind power feed-in at low loads (hour 8,263, see Appendix A.3). The total feed-in from wind power on all grid levels is 29.1 GW. Since the selected hour is before sunrise, there is no PV feed-in. The load volume of 42.4 GW is about half as high as the annual peak load. The reactive power demand in the selected grid load scenario is shown in Figure 3.6.

In this hour, an increased provision of inductive reactive power to cover the demand of the predominantly capacitive grid is required. The lines in eastern Germany and in the region south of Bremen are lightly loaded, so they are under subnormal operating conditions and exhibit a capacitive behaviour. Only the region of Rostock requires a high volume of capacitive reactive power. Due to increased wind power feed-in in combination with a low load situation in northeastern Germany, the transmission lines are heavily loaded there.

The reactive power demand of the German transmission grid is approximately 5,500 Mvar in the load scenario case of (n-0).

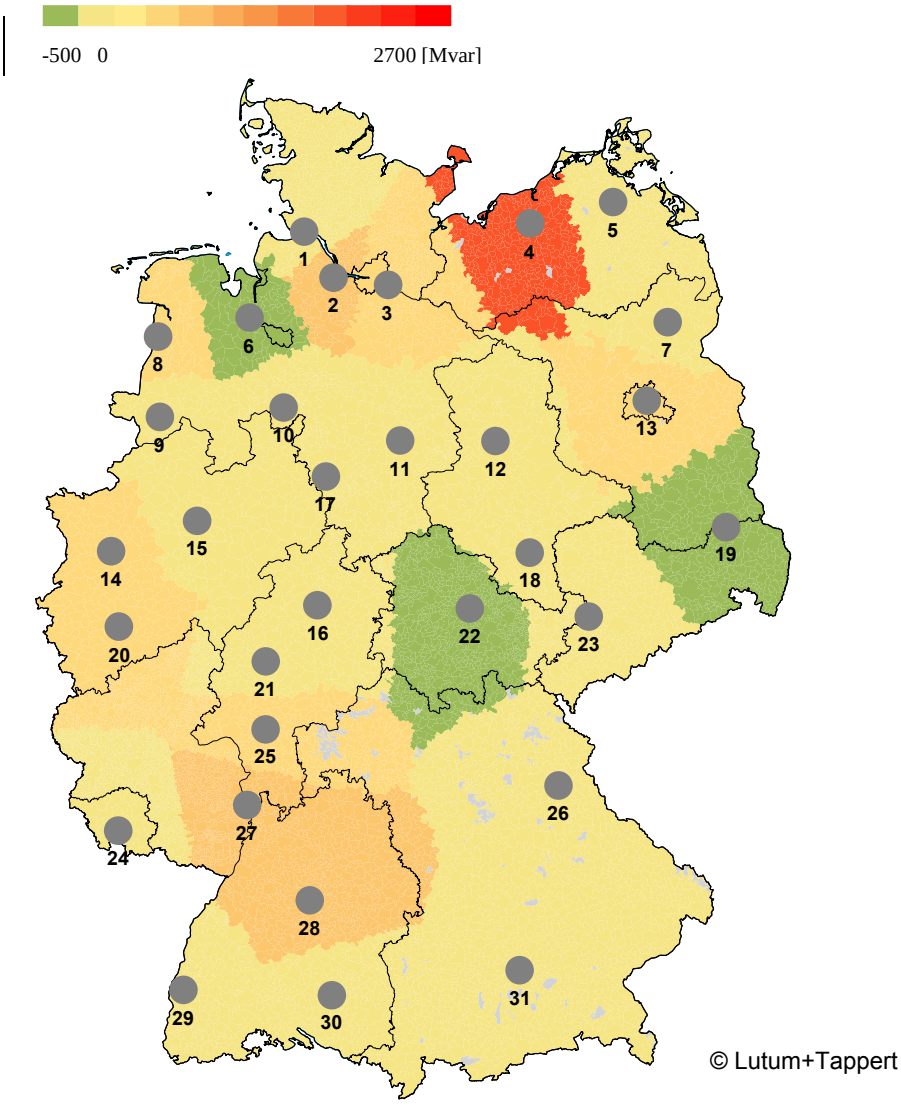

Figure 3.6 Reactive power demand for the design-relevant capacitive hour in the (n-0) case

3.3.5 (n-1) failure analyses for grid load scenarios relevant to assessment

(n-1) failure situations were analysed to calculate the reactive power demand in the disturbed system states for the identified relevant grid load scenarios. As part of the (n-1) failure analysis, both the impact of the failure of 380 kV circuits as well as HVDC transmission connections are investigated. Analogous to the NEP in 2012, an (n-1) failure situation of HVDC transmission connections is defined as a failure of an entire channel (an entire connection) within a corridor.

Figure 3.7 shows the reactive power demand that occurs at every grid node (n-0), and the maximum and minimum capacitive and inductive demand of all (n-1) cases in the relevant capacitive hour.

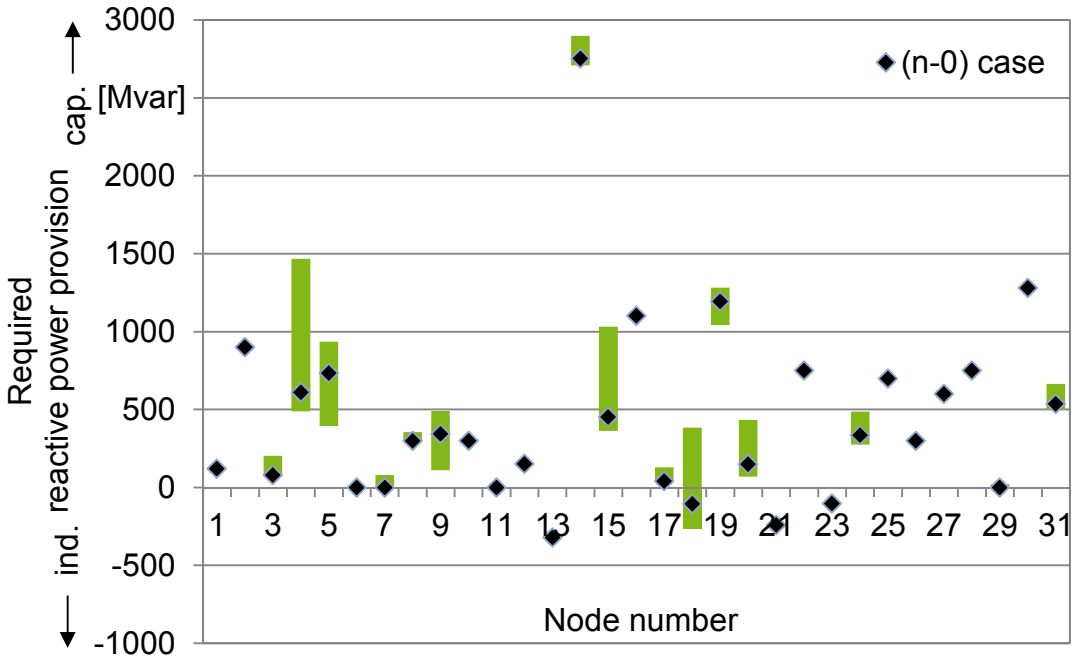

Figure 3.7 Range of the reactive power demand of the design-relevant capacitive hour in the (n-0) case, and in all (n-1) cases

The (n-1) failure simulation of the relevant capacitive hour has shown that the impact of the failure of an HVDC transmission connection on the reactive power demand is greater than the failure of any 380 kV circuit. Upon failure of the HVDC transmission connection between node 4 (Rostock/Guestrow) and node 31 (Munich) (corresponds to Güstrow-Meitingen, corridor D), the selected scenario's highest additional demand for reactive power in all (n-1) cases occurs at a grid node (node 4). In this case, the reactive power demand of the grid rises from 5,800 Mvar (n-0) to 6,900 Mvar. The reason for the increased reactive power demand is the additional long-distance transfer in the three-phase supply network that has to be ensured in case of a HVDC transmission connection failure. Figure 3.8 shows the reactive power demand for the relevant capacitive hour in the selected (n-1) case.

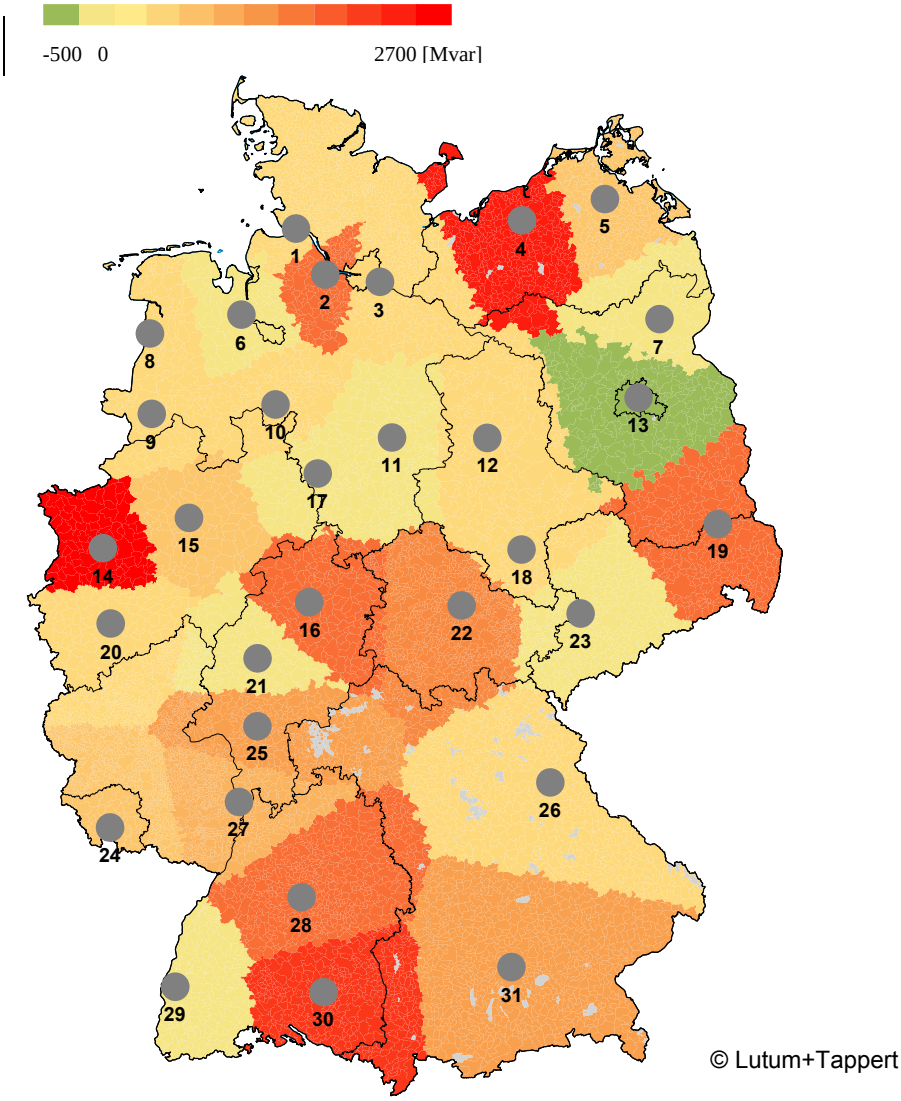

Figure 3.8 Reactive power demand for the relevant capacitive hour in the selected (n-1) case

It is evident that the reactive power demand increases significantly in particular in the region around Rostock in comparison with the (n-0) case (see Figure 3.5).

Analogous to the relevant capacitive hour, an (n-1) failure analysis was carried out for the relevant inductive hour. Figure 3.9 shows the reactive power demand for the (n-0) case and the range of the reactive power demand at each grid node for all (n-1) cases in the relevant hour.

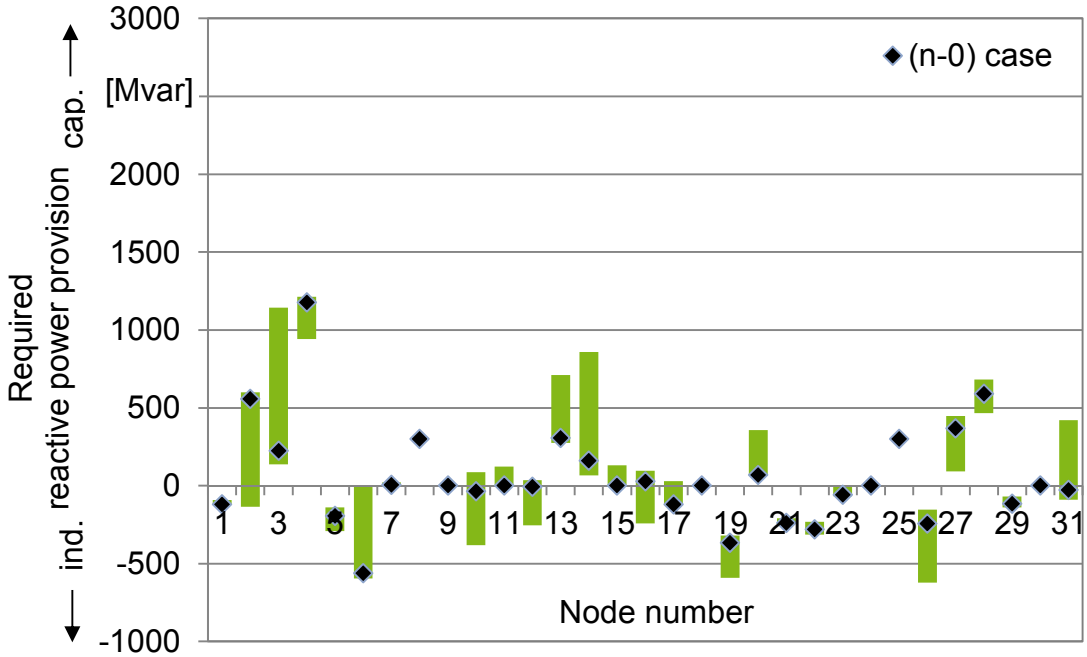

Figure 3.9 Range of the reactive power demand for the inductive relevant hour across all (n-1) cases

Upon failure of the HVDC transmission connection between node 3 and node 25, the highest additional demand results at one grid node (node 3). Figure 3.10 shows this (n-1) case.

Both in the Rhine-Ruhr region and in the region of Rostock, the demand for capacitive reactive power has increased significantly (see Figure 3.6). Due to the failure of the HVDC transmission line, the AC lines of the region are more heavily loaded, so the reactive power demand of the grid rises in these regions. In the region around Bremen and eastern Germany, however, an increased provision of inductive reactive power is required to meet the capacitive demand of the grid, because these lines are less heavily loaded.

On the basis of the additional reactive power demand in the grid's ground state and in each respective critical (n-1) case, the provision of reactive power by various sources is determined taking into account their specific costs for the identified relevant grid load scenarios. The additional reactive power demand corresponds to the difference between demand and supply by active conventional power plants and existing compensation systems.

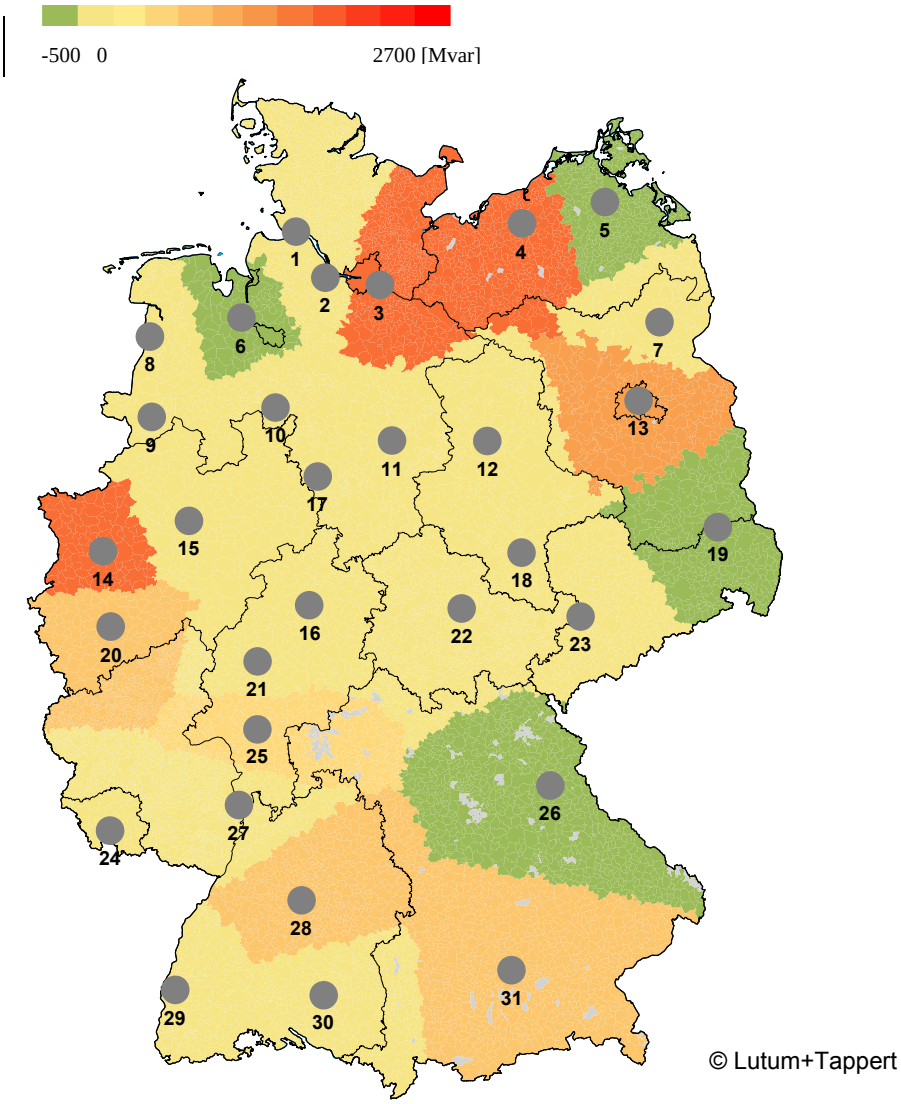

Figure 3.10 Reactive power demand of the relevant inductive hour of the selected (n-1) case

As possible sources to cover the additional reactive power demand, idle power plants, phase shifters, HVDC transmission converters, yet to be constructed reactive power compensators (inductors, capacitor banks, SVC, STATCOM) and especially DECUs from lower-level distribution grids are drawn upon, whose potential for reactive power supply is analysed in the following.

3.3.6 Method for determining the reactive power potential of the distribution grid

The calculations for determining the reactive power potential on the different voltage levels of the distribution grid are based on real network data. The reactive power potentials to be identified for the LV, MV and HV level are determined separately and then consid-

ered in the assessment of the overlayed grid levels. In doing so, the entire reactive power chain from the LV level up to the EHV/HV transformer is assessed.

In the following, the research method is described that is used to determine the reactive power potential in accordance with Figure 3.11 by means of the LV level, and the transfer of results to the MV level is described. An analogous procedure to determine the potential of the MV and HV levels is carried out.

The forecasts are first assigned to the selected grid areas to determine the reactive power potential from the distribution grid of the year 2033. As part of the research method, wind turbines and PV systems are considered as well. However, analogous to the examined supply-dependent renewable energy systems, all power plants connected by converters, such as CHP plants, can contribute to the provision of reactive power regardless of the energy source used. Therefore, the reactive power potential refers to all DECUs.

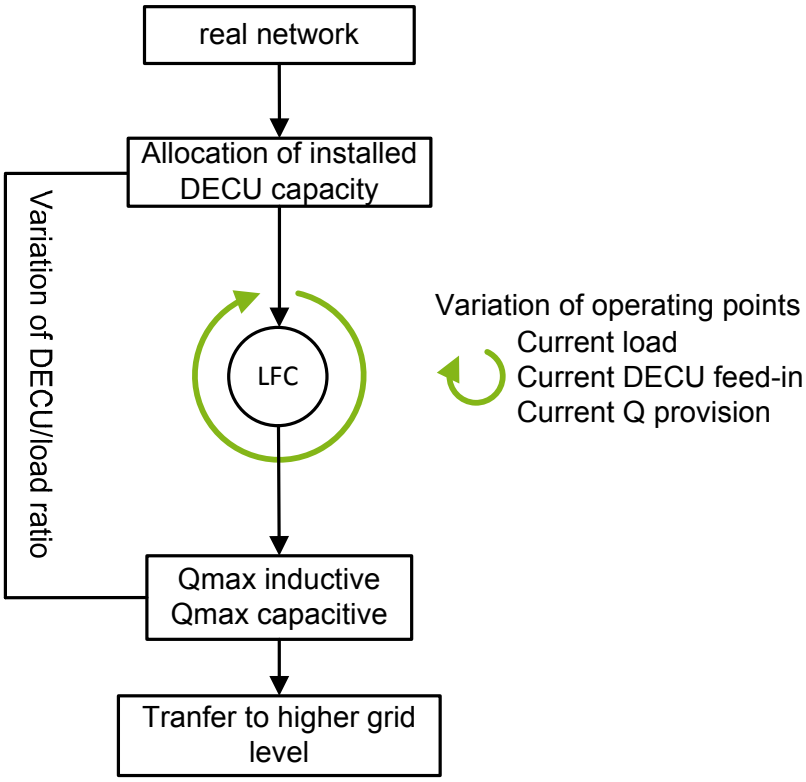

Figure 3.11 Method for determining the reactive power potential on the distribution grid level

For each energy source, the forecasts must be differentiated depending on voltage levels in the distribution and transmission grids. In the regionalisation of wind turbine forecasts, a distribution grid share of 95.3% is assumed, and for PV forecasts of 100.0%, as based on [2]. The allocation of distribution grid forecasts on the HV, MV and LV levels is specific to the energy source as per table 3.1.

Table 3.1 Share of energy source forecasts sorted by voltage levels of the distribution grid

Energy sources	HV level	MV level	LV level
Wind energy	80%	20%	0%
PV	10%	30%	60%

Within the examined grid regions, the allocated forecasts are transferred to discrete plant sizes as per [2], and are randomly distributed amongst the existing grid nodes. It is ensured that extreme concentrations at individual nodes are avoided, and that distribution is largely even amongst the existing load nodes.

Regarding installed DECUs, it is assumed as per Figure 3.12 that all plants can make a contribution to voltage stability by means of reactive power supply without active power feed-in. This kind of reactive power supply is not required by currently applicable guidelines and is an extension of the technical grid connection codes. Today's solar power plants, PV systems and most wind turbine types are technically capable of this, however. In addition, communication between all DECUs and a higher-level voltage-reactive power controller and the grid control centre is required. In all operating conditions, the maximum contribution of an individual plant is specified by the dimensioning of the inverter. It is designed for maximum active power feed-in with a simultaneous provision of reactive power with $\cos\varphi=0.95_{ind}$. In the resulting operation diagram, the impermissible operating areas are shaded green.

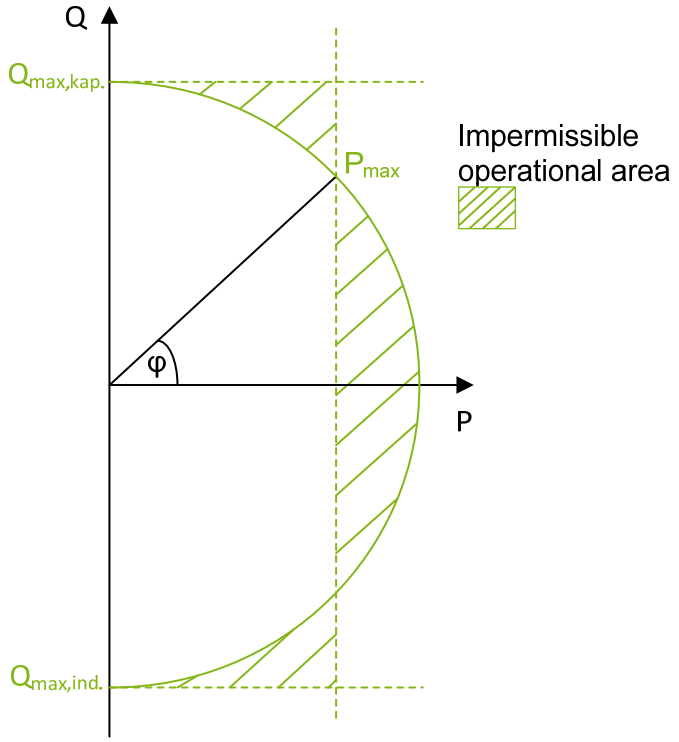

Figure 3.12 PQ operation diagram with a DECU connected via a converter.

After the assignment of the installed DECU and load capacity, a grid expansion is carried out for both the peak load and a low load case with a high DECU feed-in capacity. The assumptions used regarding planning and operating principles are based on [2], and are detailed in Appendix B. Grid expansion takes the (n-1) planning criterion into account, with the exception of the LV level.

After determining necessary grid reinforcements and network expensions, a variation of operating points takes place which includes the current load and the current active and reactive power feed-in from DECUs. Load, DECU feed-in and the provision of reactive power is increased from 0 p.u. to 1 p.u. in discrete steps. There is a separate load flow calculation (LFC) for each of these variations. This way, a pair of values for the inductive maximum and capacitive maximum possible reactive power contribution at a MV/LV-substation can be determined for each operating point. The determined limits consider possible violations of the voltage band and thermal capacity limits. The resulting reactive power contributions are determined for the examined grid area and apply only to the locally installed DECU capacity. In order to map a variety of LV grids with differing DECU penetration levels, there is a variation of the DECU/load ratio by varying the DECU capacity while keeping

the load constant. Thus, a maximum of inductive and capacitive reactive power volume is determined and passed on to the MV level for every DECU/load ratio and every operating point.

Analogous to the LV level, DECU forecasts are allocated to the actual grid area as part of the MV analysis. The distribution of forecasts takes place as per table 3.1. The resulting distribution amongst the LV and MV level is shown schematically in Figure 3.13. The allocation of DECU forecasts is green on the LV level, and the forecasts on the MV level are blue.

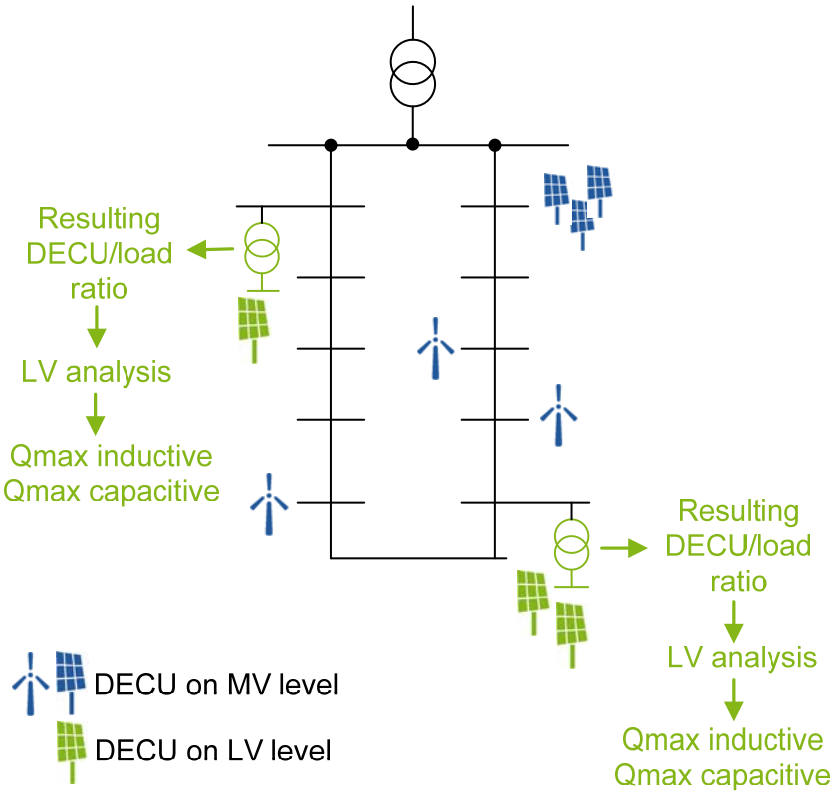

Figure 3.13 Schematic diagram of the forecast distribution

To consider the determined reactive power potential in the LV level, the resulting DECU/load ratio is first determined for each MV/LV-substation. Based on this, a maximum inductive and capacitive reactive power volume for every MV/LV-substation can be determined depending on the operating points. When transferring the results from the lower-level voltage levels, violations of the voltage band in every grid level are ruled out by subdividing the voltage band in accordance with Appendix B. The transfer of results from the MV analysis to the HV level is analogous.

In Figure 3.14, there is a schematically presentation of the results for the determination of the reactive power potential on the distribution grid level.

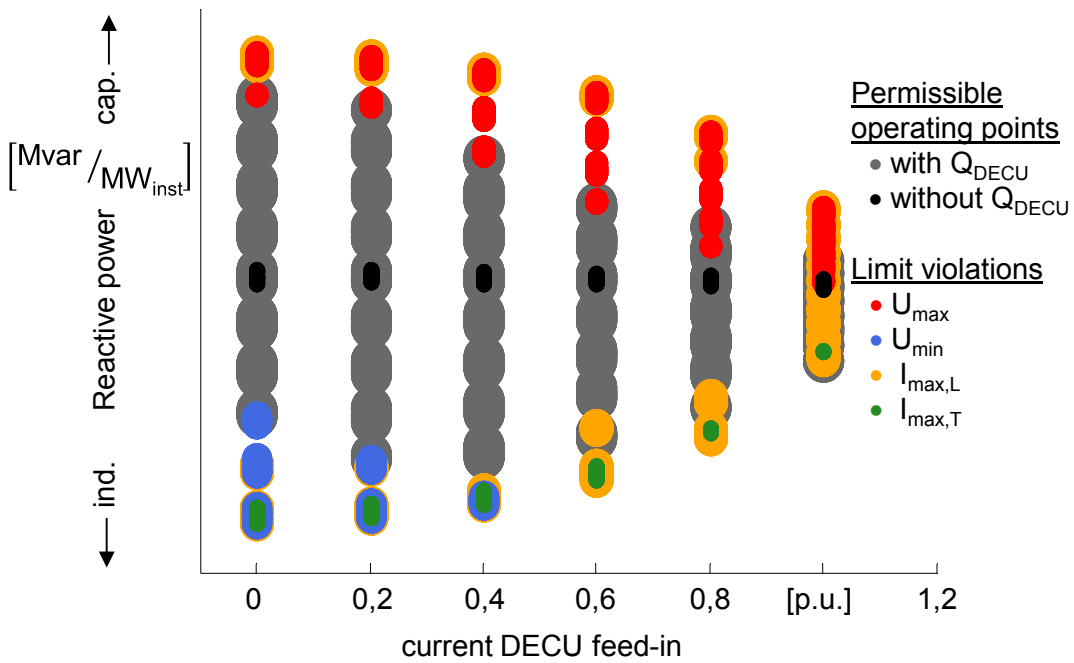

Figure 3.14 Schematically presentation of the reactive power potential on the distribution grid level.

In this context, a positive reactive power supply is a capacitive behaviour of the examined distribution grid area. Consequently, a negative reactive power supply is an inductive behaviour of the distribution grid. For comparability purposes, the reactive power range shown is based on the installed capacity. Operating points that lead neither to thermal nor to voltage range violations are coloured grey. Violations of the upper voltage limit are coloured red, violations of the lower voltage limits blue. Operating points, in which violations of the thermal limits of a line occur are highlighted in orange. Green operating points indicate a violation of the thermal limits of a transformer. Where DECUs provide no reactive power, the corresponding operating points are black.

Since the variation of the three dimensions of load, DECU capacity and reactive power supply is pictured in a two-dimensional representation, an overlap in the display of the operating points can be seen.

Regarding the analysis in the LV level, a constant transformer tapping is assumed. This tapping is determined according to the peak

load and low load cases relevant to the grid's design, and it is used in the following for all variations of operating points. In contrast to the evaluation of the LV level, an adaptation of the tap selection is taken into account for the HV and MV analysis. This applies to the differing tap selections for the peak load and low load case, as well as for the investigated operating points. Since there can be no clear distinction between peak load and low load cases regarding the variation of load and feed-in from DECUs, a tap is selected that leads to a voltage magnitude of approximatly 1 p.u. on the low-voltage side of the transformer station. A voltage dead band of ± 1.5% is taken into account here.

3.3.7 Results of the reactive power potential from the distribution grid

The presented method is used to determine the reactive power potential in the LV, MV and HV levels for selected grid areas.

Reactive power potential in the LV level

To determine the reactive power potential in the LV level, two different grid areas are examined. One is a grid area in a PV-dominated region in southern Germany. The other region is not characterised by PV systems and lies in northern Germany.

In Figure 3.15, the reactive power potential of a MV/LV-substation is illustrated for a DECU/load ratio of one. The installed DECU capacity is 546.4 kW as per the municipality forecast for the year 2033. The installed transformer capacity in the investigated area amounts to 3,780 kVA.

Without a provision of reactive power from DECUs, the investigated grid exhibits an inductive behaviour due to the inductive loads. In addition, it can be seen that U_{min} voltage band violations are to be expected in cases of lower feed-in from DECUs. These are operating conditions with a low load, a low active power feed-in from DECUs, and an inductive operation of DECUs. In all other operating conditions, the reactive power potential is limited only by the nominal apparent power of the inverter. Since, according to the planning principles, the grid is designed for 85% of the PV feed-in volume in the case of a low load, reactive power supply must be guaranteed only for this range. The result is a secured range for reactive power provision of -0.7 p.u. to 0.7 p.u. In terms of the in-

stalled capacity of 546.4 kW, this corresponds to a range of -382 kvar to 382 kvar.

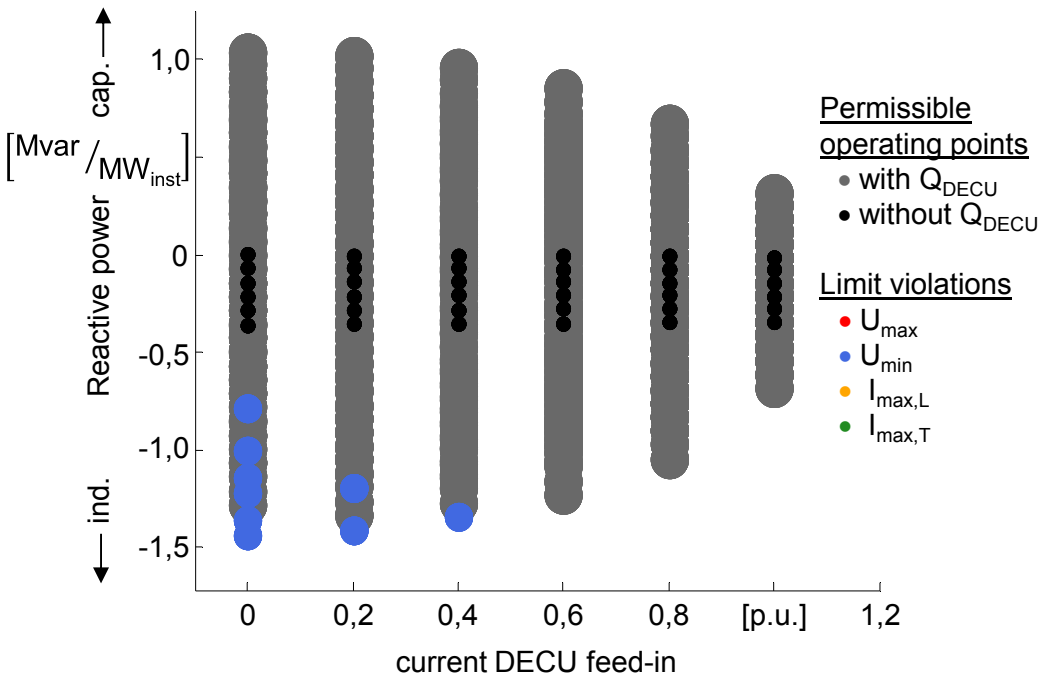

Figure 3.15 Reactive power behaviour of an LV grid area with a DECU/load ratio of 1 ($DECU_{inst.}$ = 546.4 kW)

If the installed DECU capacity is increased threefold, i.e. to 1,639.2 kW, the maximum permissible voltage band U_{max} is violated in cases of low loads, high PV feed-in, and a capacitive behaviour of the DECUs (cf Figure 3.16). The secure range for the provision of reactive power is limited by the additionally installed DECU capacity. The result is a range of approximately -0.7 p.u. to 0.1 p.u. With an installed capacity of 1,639.2 kW, this is equivalent to a range of -1,147 kvar to 164 kvar. With a higher installed capacity, the inductive range for reactive power increases. In contrast, the capacitive range decreases.

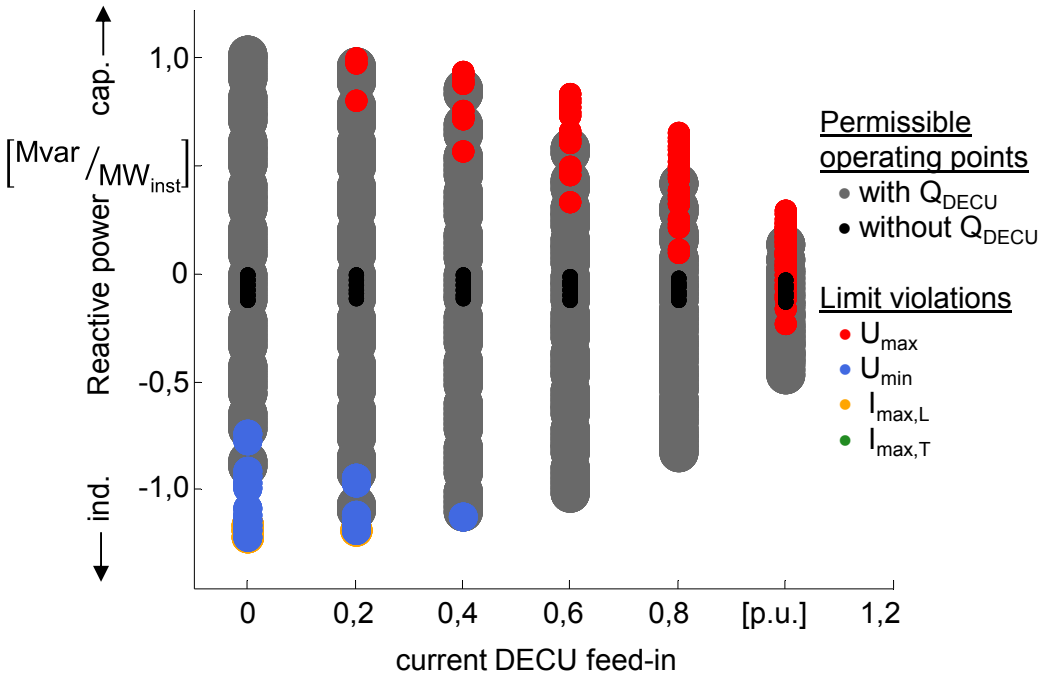

Figure 3.16 Reactive power behaviour of an LV grid area with a DECU/load ratio of 3 ($DECU_{inst.}$ = 1,639.2 kW)

The investigation of both LV grid areas is carried out up to a DECU/load ratio of ten and leads to a comparable range in terms of inductive and capacitive provision of reactive power. The secure range of reactive power provision does not change after an analysis of the second grid area.

In summary, it can be seen that a reactive power neutral range occurs in both considered LV grid areas. Local compensation of LV grid level is therefore possible. Furthermore, it is apparent that even in cases of a high DECU/load ratio, a large range for the provision of reactive power is possible from the LV level. This applies to both an inductive and a capacitive reactive power behaviour of the grid. The occurrence of limit violations mostly depends on the DECU/load ratio.

Reactive power potential in the MV level

The determination of the reactive power potential in the MV level takes place in two selected grid regions. The installed DECU capacity is 12.2 MW, and the installed transformer capacity is 25 MVA. The reactive power potential of a transformer station for a DECU/load ratio of one is illustrated in Figure 3.17.

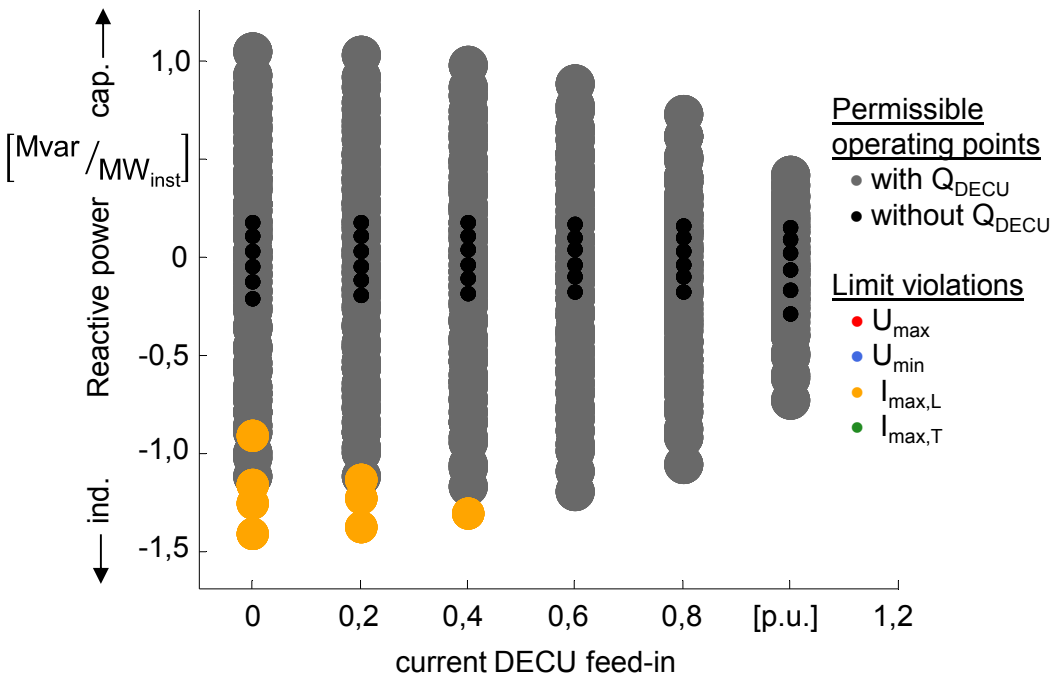

Figure 3.17 Reactive power behaviour of the MV grid area at a DECU/load ratio of 1 ($DECU_{inst.}$ = 12.2 MW)

The examination of the MV grid area shows that the maximum permissible inductive operating point of the DECUs, especially in times of low DECU feed-in, is limited by thermal overloading of lines. Analogous to the LV level, a secured reactive power range of approximately -0.9 p.u. to 0.9 p.u. can be offered. This corresponds to a range of -11 Mvar to 11 Mvar.

However, if the DECU/load ratio is increased, then violations of the upper voltage limit occur especially in times of high DECU feed-in (cf. Figure 3.18).

The range for provision of reactive power at a DECU feed-in capacity of 0.8 p.u. is limited by a few violations of U_{max}. This leads to a reduction of the secured capacitive range from 0.4 p.u. to 0.1 p.u. The resulting secured range for reactive power provision is -0.4 p.u. to 0.1 p.u. This corresponds to a range of -16.6 Mvar to 3.7 Mvar.

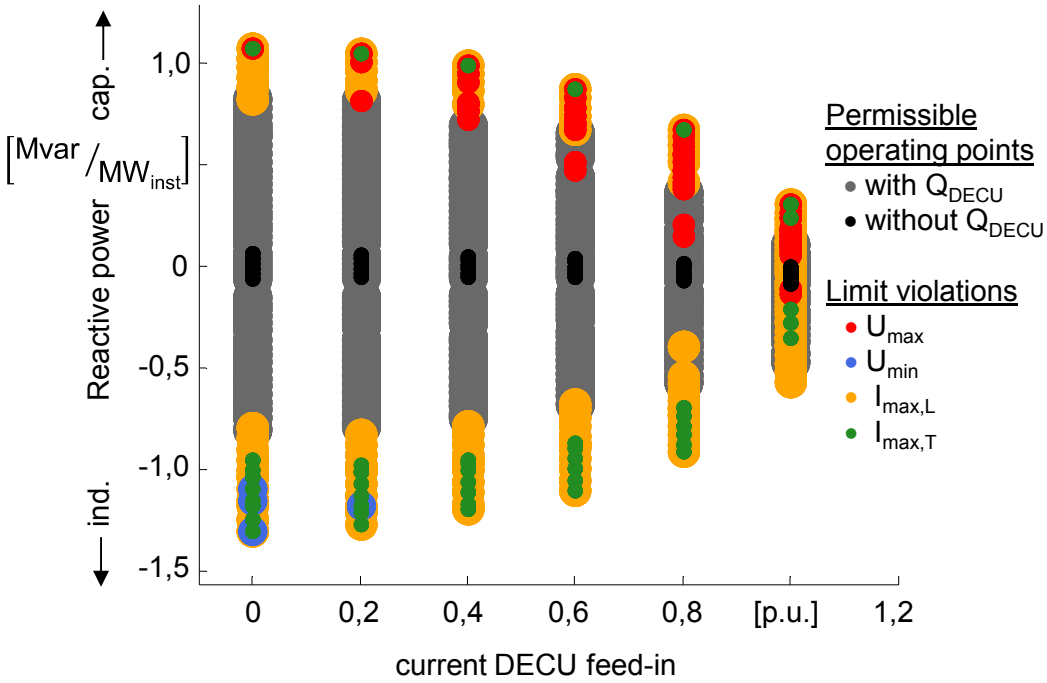

Figure 3.18 Reactive power behaviour of the MV grid area at a DECU/load ratio of 3 ($DECU_{inst.}$ = 36.6 MW)

The reactive power range is analysed up to a DECU/load ratio of ten for both considered MV grid areas. The secure range of reactive power provision does not change after an analysis of the second MV grid area.

In summary, it is evident that reactive power neutral operation is also possible in the MV level, which leads to local compensation. Furthermore, it is apparent that even in cases of a high DECU/load ratio, a large range for the provision of reactive power is possible from the MV level. This applies to both an inductive and a capacitive reactive power behaviour of the grid. The occurrence of limit violations mainly depends on the DECU/load ratio.

Reactive power potential in the HV level

As for the MV and LV levels, the determination of the reactive power potential in the HV level is carried out in two selected grid regions. The installed DECU capacity is 655 MW.

Figure 3.19 shows the available reactive power potential for a 110 kV grid group at a DECU/load ratio of one. The sum of the reactive power potential of all 380/110 kV transformers in the grid group is shown. The transformer capacity installed in the grid area is 2,100 MVA.

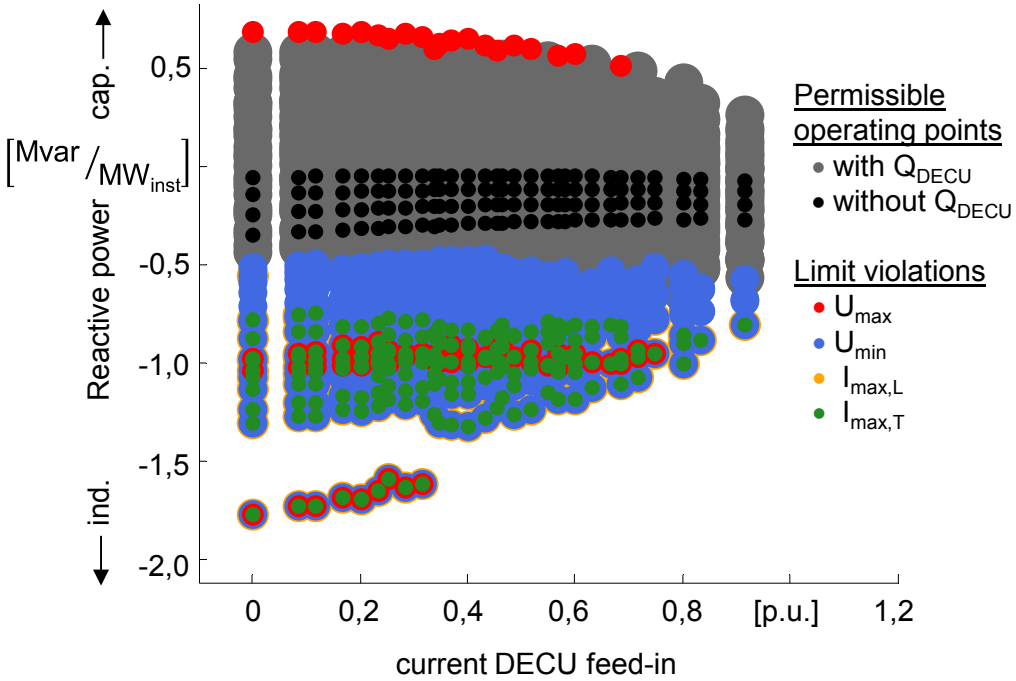

Figure 3.19 Reactive power behaviour of a HV grid at a DECU/load ratio of 1 ($DECU_{inst.}$ = 655 MW)

The analysis of the reactive power potential in the considered grid area shows that from the transmission grid's point of view, the investigated HV grid generally works as a reactive power sink. This is illustrated by the black operating points that do not consider reactive power feed-in from DECUs. An inductive operating mode of the 110 kV grid as well as a shift into the capacitive range is possible. Operating points not shown at a highly inductive operating mode of DECUs with a simultaneously low active power feed-in can be explained in the presentation by a non-converging load flow.

The result is a secured range for reactive power provision of -0.5 p.u. to 0.4 p.u. In terms of the installed capacity of 655 MW, this corresponds to a range of -327.5 Mvar to 262 Mvar.

In order to evaluate the effects of a high installed DECU capacity in a 110 kV grid area on the reactive power potential, this potential is illustrated in Figure 3.20 for a DECU/load ratio of three. The transformer capacity installed in the grid area is 4,500 MVA.

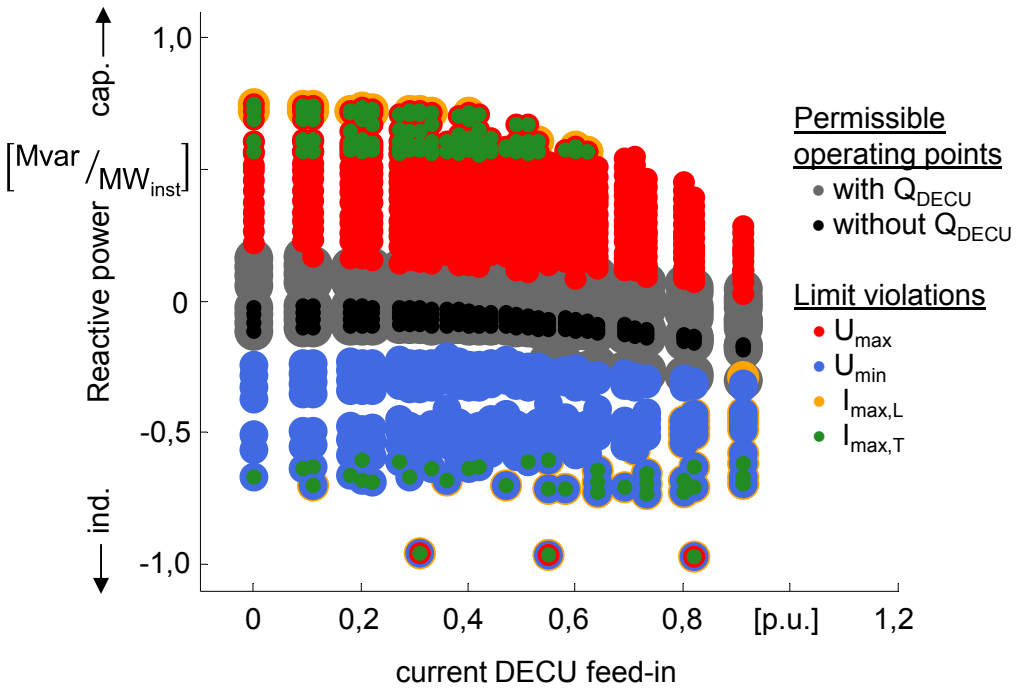

Figure 3.20 Reactive power behaviour of a HV grid at a DECU/load ratio of 3 ($DECU_{inst.}$ = 1,965 MW)

The result is a secured range for reactive power provision of -0.2 p.u. to 0.05 p.u. In terms of the installed capacity of 1,955 MW, this corresponds to a range of -391 Mvar to 98 Mvar.

The investigation of a further HV grid area leads to a comparable range in terms of the inductive and capacitive provision of reactive power from a 110 kV grid area. A change to the secured range of provision of reactive power does not result.

In summary, it is evident that a reactive power neutral operating mode is also possible in the HV level, which leads to local compensation. Furthermore, it is apparent that even in cases of a high DECU/load ratio, a large range for the provision of reactive power is possible from the LV level. If the DECU/load ratio increases,

then so does the absolute inductive range for reactive power; the capacitive tap selection range decreases, however.

The maximum inductive and capacitive reactive power potential for various DECU/load ratios of the distribution grid is summarised in Table 3.2.

Table 3.2 Reactive power provision potential from the 110 kV distribution grid

DECU/load ratio	Q_{max} inductive [p.u.]	Q_{max} capacitive [p.u.]
1	-0.50	0.40
2	-0.25	0.20
3	-0.20	0.05
4	-0.20	0.00
5	-0.20	0.00

This is a secured tap selection range that is applicable in the transmission grid as a reactive power source and sink. In this context, it should be noted that for certain hours, a higher reactive power potential from the distribution grid would be available, but it cannot be regarded as secured.

The following section will examine the contribution to reactive power provision that can be made by HV plants exclusively. It is assumed that all plants in the MV and LV levels do not make any reactive power contribution. Figure 3.21 shows the resulting reactive power potential of a 110 kV grid at a DECU/load ratio of one. It should be noted that within the examined grid region, about 50% of the installed DECU capacity is connected within the HV level.

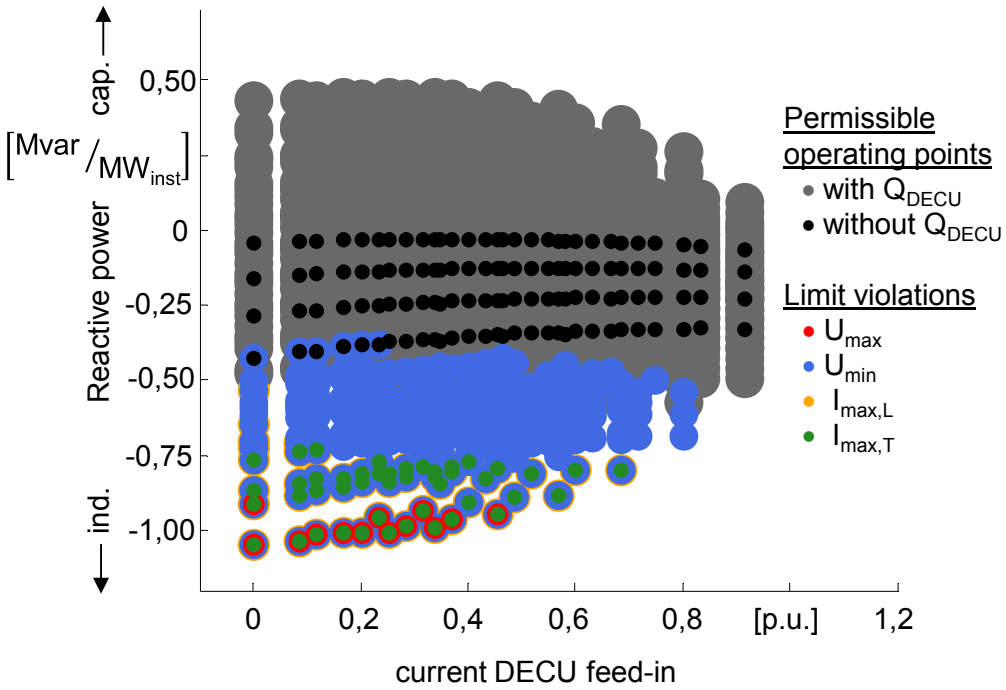

Figure 3.21 Reactive power behaviour of a HV grid without any contribution from the MV and LV levels at a DECU/load ratio of one ($DECU_{inst.}$ = 655 MW)

If only HV plants are included in the provision of reactive power, a secured range of -0.4 p.u. to 0.2 p.u. is the result. In terms of the installed capacity of 655 MW, this corresponds to a range of -262 Mvar to 131 Mvar.

The available reactive power range is reduced with regard to Figure 3.19. However, the inclusion of HV plants is sufficient to allow for an inductive and capacitive distribution grid operation. This statement is not generally valid because it cannot be ensured for all grid regions in Germany that an appropriate number of HV plants is installed.

Effect of reactive power provision from the distribution grid on grid losses

In the analysis of the reactive power potential from the distribution grid, grid losses were not yet considered. However, they must be considered in terms of the cost-efficiency of reactive power provision from the distribution grid.

Figure 3.22 shows the losses resulting from an analysis of the reactive power potential of a LV grid as per Figure 3.16.

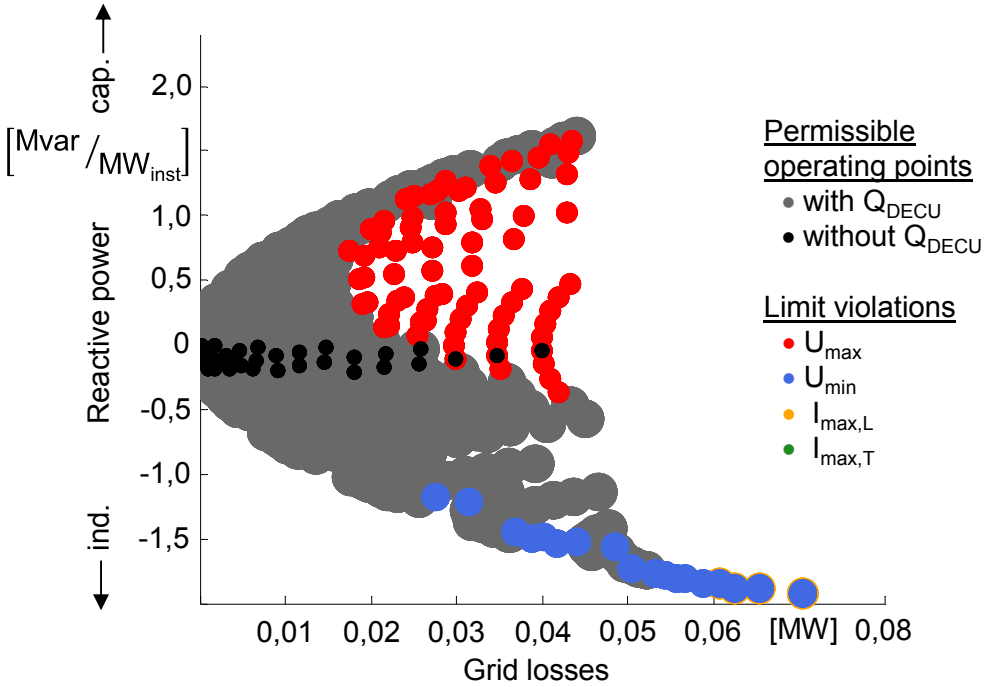

Figure 3.22 Grid losses of a LV grid area at a DECU/load ratio of 3

It can be seen that with an increasing provision of reactive power, grid losses increase both in the inductive and capacitive directions. It should be noted that today's predominantly inductive operating mode of DECUs also results in increased losses. The operating points shown in black do not represent today's reference case, but cases in which DECUs do not provide reactive power. Thus, the operation of DECUs already leads to an increase in grid losses under the currently applicable grid connection codes. If there is a future regulation of the reactive power of DECUs for voltage support of the higher-level transmission grid, it must therefore not necessarily lead to an increase in grid losses. On the contrary, a compensation of reactive power within a grid level can even lead to a reduction of grid losses.

The fundamental impact of reactive power provision on grid losses on the MV and HV levels are comparable to the results of the LV level, even if the absolute losses are greater.

Influence of grid topology and the point of common coupling of DECU on the reactive power potential

Both the grid topology, as well as the position of the PCC of DECUs have an impact on the possibility of providing reactive power to meet local reactive power demands in a given grid level, or to provide it for higher grid levels.

Methodologically, the effects of a changed grid topology are largely accounted for by the standard grid expansion measures. Grid expansion based only on the design-relevant peak load case and low load case with a high DECU feed-in does not lead to a significant increase or reduction of the reactive power potential from the distribution grid. Exceptions are an increase of the line capacities with existing undersized cross-sections, or the grid expansion of long feeders. In this case, only minor grid expansion measures can prevent limit violations within a grid area when determining the reactive power potential, and therefore the potential is increased. However, this does not lead to characteristic curves of limit violations different from those shown in the images, since more than just one line leads to limit violations in most operating conditions.

Another important factor influencing the ability to provide reactive power from the distribution grid is the location of the PCC of DECU. If DECUs are connected close to the transformer, they can provide more reactive power without voltage range or thermal violations. In operating distribution grids, it is therefore preferable to use plants located near the transformer station for the higher-level grid level for reactive power provision. The use of plants in critical lines, however, should be avoided as they can cause limit violations in particular in times of high feed-in.

Only HV overhead transmission grids were studied as part of the investigations. Generally, the operating range of HV grids shifts more heavily into the capacitive reactive power range with the use of cables, since cables are always operated in a subnatural manner due to their high characteristic wave impedance. This must be considered when planning new cable routes. When operating pure cable grids, on the other hand, a purely inductive operating mode of the HV grid may no longer be possible.

Increase of the reactive power potential from the distribution grid by a smart control of DECUs

The method for determining the reactive power potential from the distribution grid assumes that all DECUs equally contribute to voltage control. As previously described, this leads to the fact that individual plants cause limit violations and therefore lower the potential of the distribution grid. A smart DECU control, which utilises plants near a transformer, can raise the potential for reactive power provision of the distribution grid. This is especially true in grid

regions without a sufficient installed capacity in the 110 kV grid. In such cases, a large number of smaller generation units as reactive power sources are required. These are mainly installed in the MV and LV level. Particularly in rural regions, DECUs are located at the end of long feeders or lines, and especially in times of high active power feed-in, they limit the available potential for reactive power provision. The implementation of a smart control system, which initially utilises plants on higher voltage levels and then plants near transformers and on the lower voltage level, requires exact knowledge of the current grid situation. Only this way can DSOs specifically use plants as reactive power sources without violating grid limits. However, such a metrological measurement of the grid state is currently not given in the LV grid (see Chapter 6).

3.3.8 Requirements for reactive power provision from the distribution grid

To utilise the identified potential for reactive power provision from the distribution grid, essential implementation requirements must be met, which are discussed below:

- Direct controllability of plants on the distribution grid level
- Integration of DECUs in power system management
- Reactive power provision without active power feed-in
- Coordination of the provision of reactive power

To use DECUs for reactive power provision, it must be ensured that the corresponding DSO can demand a reactive power contribution at every operating point of the DECU. To this end, it is necessary that DECUs have a corresponding communication link. With the currently applicable grid connection codes and legal framework, a corresponding direct control option by the grid operator is not yet given, at least for DECUs in the LV level [68]. According to the EEG[1], plants with an installed capacity of 30 kW or less initially have the choice of installing a remote control system, or of

[1] § 6 EEG; Renewable Energy Sources Act of 25 October, 2008 (German Civil Code 1. I p. 2074), last amended by Article 1 of the law dated 17 August, 2012 (German Civil Code 1. I p. 1754).

generally throttling to 70% of the installed capacity. It is therefore not guaranteed that all smaller DECUs can be included in a targeted control of reactive power. Controllability as permitted by the EEG is limited only to remote-controlled feed-in reduction during grid congestions and the respective actual feed-in. If the currently possible controllability be expanded to include the provision of reactive power, no further costs would arise for the integration of DECUs at this point. Otherwise, a corresponding expansion with € 60 - 800 per MW_{inst} has already been quantified in Chapter 2. For DECUs with a grid connection point in the HV and MV levels, however, a corresponding remote control system for the provision of reactive power may already be required in accordance with currently applicable grid connection codes [25], [39]. Additional costs would therefore not arise.

To utilise the reactive power potential from the distribution grid, an inclusion of DECUs in the existing power system management of the relevant system operator must take place. In [154], the necessary investments for the integration of smart measurement systems and smart meters is estimated to be € 100,000 - 1,000,000 depending on the size of the system operator. If these necessary investments are also set for the integration of DECUs in the power system management of a system operator, significant investments can be expected in this context.

With regard to the operation of distribution grids, the different control times for tap-changing transformers and the control of DECUs are to be observed. For this purpose, appropriate balancing strategies are to be developed that take into account that changing the tap position of a EHV/HV transformer is slower than a possible regulation of DECUs. Concepts for higher-level voltage regulation and the corresponding control or coordination mechanisms are to be implemented in the power system control.

It must also be ensured that the provision of reactive power from the distribution grid is available at any time. Therefore, it must be considered that converter-based suppliers are able to make a reactive power contribution even without active power feed-in. The resulting converter losses, assumed to be about 1-2% of the capacity, are generally covered by the active power feed-in of the DECU. In the case of non-existent active power feed-in, losses are

inevitably covered by the grid. At this point, it must be ensured that billing is cause-fair.

It should also be noted that system operators are responsible for their respective grid areas in terms of securing voltage control. Reactive power provision is only possible after ensuring reactive power neutrality of a distribution grid relative to the transmission grid. In this context, a coordination of all voltage levels for reactive power provision is required. Initially, it is the responsibility of the DSO to draw upon concepts for the integration of DECUs, electricity storage units, and voltage controllers. While guaranteeing compliance with the distribution grid limits, ancillary services can also be provided to the TSO (cf. Chapter 6). This requires a communication interface between TSOs and DSOs, which for example allows the specification of a fixed reactive power value between the two.

3.3.9 Reactive power provision for design-relevant grid load scenarios in the transmission grid

In the following, the provision of reactive power to cover the additional reactive power demand on the transmission grid level, i.e. the difference between demand and provision of reactive power from existing reactive power compensators and active conventional power plants, is determined for the design-relevant grid load scenarios.

The following alternative sources are considered to cover the additional demand:

- Use of HVDC transmission converters
- Installation of additional reactive power compensators
- Upgrading of disused power plants for phase shifter operation
- Use of power plants not used due to market-related circumstances with the technically lowest possible active power feed-in (voltage-related redispatch)
- Reactive power provision from the distribution grid

The assumed specific costs of each alternative reactive power source are specified in Table 3.3.

Table 3.3 Model costs of the various reactive power sources

Reactive power source	Cost components	Costs
Inductor (100 Mvar incl. SY)	Investment: € 4 million [1] Operating costs: 2% invest. p.a. Service life: 35 years Interest: 8%	€ 420,000 per year
Capacitor (100 Mvar incl. SY)	Investment: € 3.3 million [1] Operating costs: 2% invest. p.a. Service life: 35 years Interest: 8%	€ 350,000 per year
HVDC transmission converter	-	-
SVC (100 Mvar incl. SY)	Investment: € 5.2 million [1] Operating costs: 2% invest. p.a. Service life: 35 years Interest: 8%	€ 550,000 per year
STATCOM (100 Mvar incl. SY)	Investment: € 6.8 million Operating costs: 2% invest. p.a. Service life: 35 years Interest: 8%	€ 720,000 per year
Phase shifters	Investment: € 7 million Operating costs: 3.5% invest. p.a. Service life: 30 years Interest: 8%	€ 870,000 per year
Voltage-related redispatch	Marginal costs: € 50…180 per MW Minimum active power generation: 0…20 MW Annual utilisation hours: n	€ 0…3,600 · n
Distribution grid	-	-

The specified annuities per alternative were calculated taking into account the investments, operating costs, service lives and calculated interest rates listed. Costs for possibly necessary switchyards (SY) were included in the investment.

For existing reactive power generators, such as conventional power plants and HVDC transmission converters, whose construction is required for other reasons or whose planning has already been

completed, no additional costs are added. The costs of a voltage-induced redispatch are determined by the remuneration of the minimum active power that most conventional power plants in operation are required to provide. Under the assumption that the provision of reactive power will not be remunerated, the costs of voltage-induced redispatch are recognised similarly to the costs of a congestion-induced redispatch. However, the payments for savings in fuel costs that the TSO receives from the power plant operators in case of power plant throttling are neglected. The range of minimum active power feed-in listed in the table results from the assumption that only those power plants participate in voltage-induced redispatch that have short startup times, and that can be started and shut down quickly due to short minimum up- and downtimes. These are primarily gas-fired power plants with a low minimum active power provision.

To cover the additional reactive power demand in the design-relevant hours, the freely available HVDC transmission converters are used first. For the HVDC transmission converters, it is assumed that their apparent power is 105% of their nominal active power capacity. For a HVDC transmission line with a maximum active power transfer of 2 GW, this results in a reactive power provision potential of -640 to 640 Mvar. In Figure 3.23, the remaining maximum and minimum capacitive and inductive reactive power generation required after the use of HVDC transmission converters is shown in the design-relevant grid load scenarios. The grid's ground state and each critical (n-1) case is considered. It can be seen that the yet to be covered, additional reactive power demand is significantly reduced through the use of HVDC transmission converters during the design-relevant hours.

To meet the remaining demand for both the (n-0) as well as for the critical (n-1) case in the design-relevant hours, reactive power is drawn from the distribution grid. Until now, the assumption was made that the reactive load at every node results from an active node load for cosφ of 0.95. In Table 3.2, the listed and secured tap selection range of reactive power provision from the distribution grid at nodes with a residual reactive power demand is now defined as relative to the locally installed DECU/load ratio.

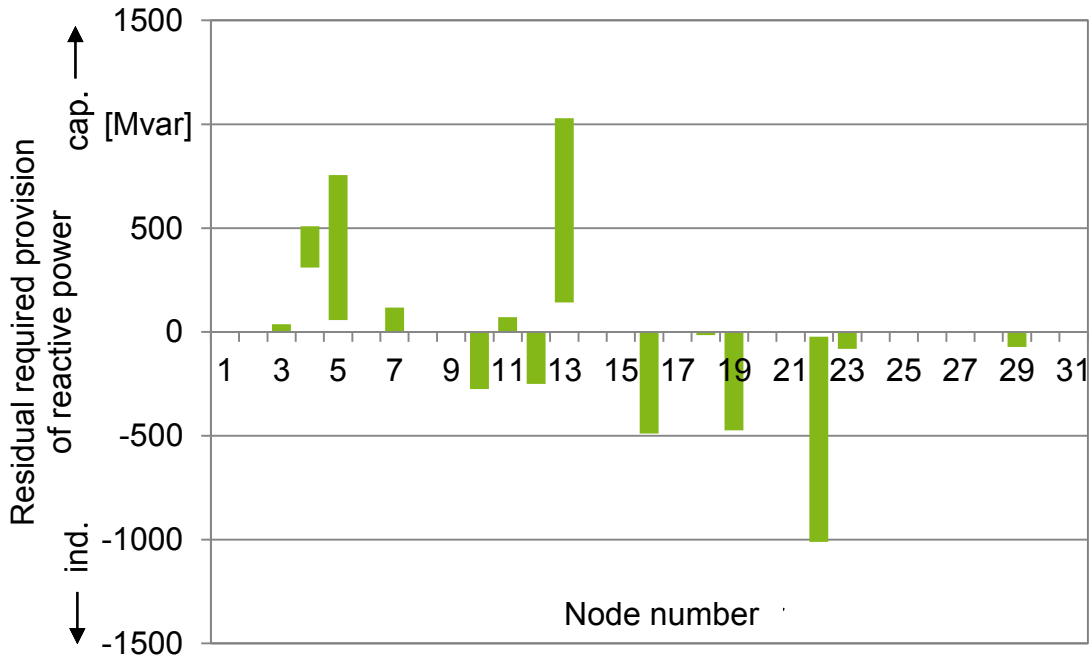

Figure 3.23 Range of the remaining reactive power demand for the design-relevant hours after the use of HVDC transmission converters

To cover the remaining demand for both the (n-0) as well as for the critical (n-1) case in the design-relevant hours, reactive power is drawn from the distribution grid. Until now, the assumption was made that the reactive load at every node results from an active node load for cosφ of 0.95. In Table 3.2, the listed and secured tap selection range ofreactive power provision from the distribution grid at nodes with a residual reactive power demand is now defined as relative to the locally installed DECU/load ratio.

A new application of the OPF taking into account that the reactive power provision potential from the distribution grid for the design-relevant hours demonstrates that there is no further demand in the critical hour (capacitive) both in the grid's ground state, and in the (n-1) case. An additional provision of capacitive reactive power of 300 Mvar is only required in the design-relevant hour (inductive) at node 4.

In summary, it can be stated that the additional reactive power demand can, to a large extent, be met in the identified design-relevant grid load scenarios through the use of HVDC transmission converters and the provision of reactive power from the distribution grid.

3.3.10 Monetary valuation of the provision of reactive power from the distribution grid

Since the costs of reactive power provision from the distribution grid are difficult to quantify, the monetary valuation of reactive power provision from the distribution grid will be based on an estimate. For this purpose, the costs of the cheapest alternative in the transmission grid are calculated that are needed to cover the remaining demand while neglecting the distribution grid potential at individual grid nodes. The costs of the cheapest alternative correspond to the maximum costs that are acceptable to leverage the reactive power provision potential from the distribution grid, so that the distribution grid would become preferable to its alternatives and therefore used as a reactive power source for the transmission grid.

Their utilisation hours, i.e. the number of hours in a year during which a remaining demand must be covered, are decisive for assessing the economic efficiency of alternatives. To determine the utilisation hours, the OPF is performed for all 8,760 hours of the year taking into account the provision of reactive power by HVDC transmission converters. The annual assessment is carried out exclusively on the basis of the (n-0) case, owing to the complexity of the optimisation problem. The result of the simulation listed in Figure 3.24 shows the remaining demand in the year under review, as well as its minimum and maximum value for the grid's ground state.

It can be seen that at most nodes in the (n-0) case, an additional provision of reactive power is needed only in few hours. For these hours and nodes, voltage-induced redispatch is the most cost-effective alternative to meet the demand. Due to the low costs of voltage-induced redispatch, investments to bring about the technical conditions for the provision of reactive power from the distribution grid are not justified at these nodes.

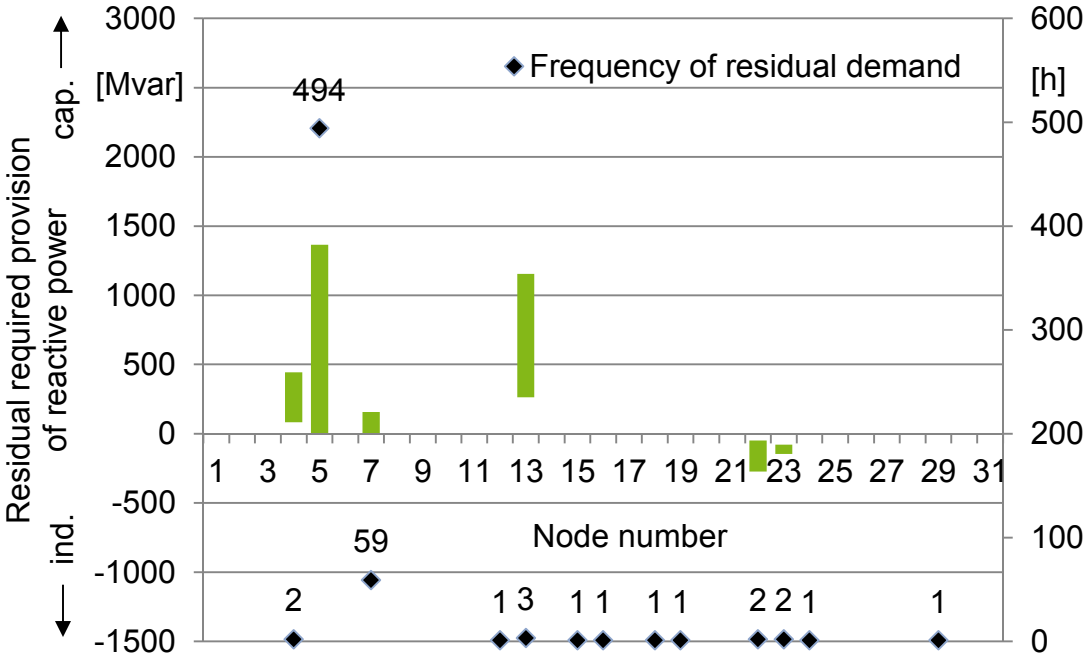

Figure 3.24 Frequency of the remaining reactive power demand in the entire year under review after the use of HVDC transmission converters

In several hours of the year, there is a remaining demand for reactive power only at nodes 5 and 7 in northeastern Germany. In view of the cost range specified in Table 3.3, voltage-induced redispatch measures are not necessarily the best alternative due to the frequency of occurrence of the remaining demand. According to the underlying Platts power plant database, there are only few power plants available at nodes 5 and 7, so that voltage-induced redispatch is not a sufficient alternative, for reasons of limited availability alone. The most cost-effective alternative to reactive power provision from the distribution grid as a controllable compensation is at nodes 5 and 7 of the SVC on the transmission grid level. In sum, approximately 1,600 Mvar in compensation capacity are needed here, leading to annuity costs of approximately € 8.8 million per year. This corresponds to the value of reactive power provision from the distribution grid, which is subordinate to nodes 5 and 7. When applied to the installed wind turbine and PV system capacity in the connected HV level, costs result of approximately € 1,500 to 2,000 per year and MW of installed capacity that are acceptable to leverage the reactive power provision potential.

It should be noted that the values above were determined for the grid's ground state. Since the remaining reactive power demand to be covered increases in the (n-k) case, therefore requiring the pro-

vision of more compensation capacity, the annuity values to leverage the reactive power provision potential from the distribution grid until the technical upper limit of reactive power provision is reached also rise. In this study, it was shown that the distribution grid can supply a sufficient quantity of reactive power in the selected design-relevant grid load scenarios at least in the (n-1) case.

3.4 Conclusion for voltage control

The analysis of the reactive power potential from the distribution grid shows that a reactive power neutral operation of the distribution grid is possible on all examined voltage levels. A secured reactive power range is possible in the inductive and capacitive direction in grid areas with low DECU/load ratios. With increased DECU/load ratios in a given distribution grid area, the capacitive range of reactive power provision becomes increasingly limited. The absolute, inductive reactive power potential, however, increases along with the installed capacity.

HV networks can provide a significant contribution to the provision of reactive power, even without consideration of plants on the MV and LV levels. However, the statement is not generally valid because it cannot be ensured for all grid regions in Germany that an appropriate number of HV plants is installed. Therefore, it is necessary that plants on the MV and LV levels are able to contribute in the future. Plants with a lower installed capacity currently do not have an option for direct control by the relevant system operator, accordingly they cannot be used specifically for the provision of reactive power. An extension of the control options is estimated at € 60 - 800 per MW_{inst}. Electricity storage units coupled via an inverter can contribute to reactive power support, analogous to the considered DECUs. To utilise the identified potential for the provision of reactive power from the distribution grid, not only the possibility of DECU controllability is to be ensured, but also the involvement of DECUs in a regulation concept or power system control by the responsible DSO. In this context it should be noted that the necessary integration of DECUs in the power system control of the responsible grid operator is associated with significant costs in the range of € 100,000 - 1,000,000. If DECUs are to be used in the distribution grid for the provision of reactive power for the transmission grid, this will require a defined interface between DSOs

and TSOs, which for example would allow for the specification of a fixed reactive power value between TSOs and DSOs.

Due to the increasing, load-remote power generation and the associated higher utilisation of lines, reactive power demand in the transmission grid will increase in the future. As part of the analysis, the Rhine-Ruhr region, the Main-Neckar region and the region around Rostock have been identified as areas with an increased demand for the provision of capacitive reactive power. Since there is an increased demand for the provision of inductive reactive power in times of low demand in particular in eastern Germany, the reactive power range, or the range of reactive power demand at the grid nodes will be higher overall.

The simulations have shown that the reactive power demand can be largely covered by the active conventional power plants, the existing reactive power compensators, HVDC transmission converters and DECUs from lower-level distribution grids. The value of reactive power provision from the distribution grid is determined by the most cost-effective alternative in the transmission grid. Taking into account the results of the determination of the potential of the distribution grid, additional annuity costs of approximately € 1,500 to 2,000 per year and MW of installed wind turbine and PV system capacity in the HV level are justifiable to leverage the potential of reactive power provision. On an individual basis and from an overall systemic perspective, every grid operator must determine whether the savings achieved by economically utilising the distribution grid justify the above-mentioned necessary investments for the integration of DECUs in power system management. This largely depends on the voltage level and the size of the grid, the installed DECU capacity, available storage systems and the local demand for reactive power. In conclusion, Table 3.4 summarises the recommendations for action in the area of voltage control. The short-term recommendations for action are considered as necessary within the next ten years, and the long-term recommendations as necessary until 2033.

Table 3.4 Recommendations for action for future voltage control

	Recommendation for action	Motivation	Legal / technical / regulatory aspects	Economic aspects
Short-term	Inclusion of HVDC transmission converters and DECUs in the HV level	Coverage of demand in the transmission grid Local compensation of the distribution grid and reactive power contribution for the transmission grid	Creation of the framework for the provision of reactive power by plants connected to the transmission grid, even without savings in active power feed-in	Forgoing of reactive power compensators
Long-term	Additional inclusion of MV and LV plants	Local compensation of the distribution grid and reactive power contribution for the transmission grid	Integration of plants in the LV level via ICT	Forgoing of reactive power compensators

4 Short circuit power

Short circuit power is a calculation parameter used to quantify the load applied to an electrical system, the switching capacity of the circuit breakers and the system perturbation of connected electrical equipment. It is a fictitious parameter because parameters are combined that never occur simultaneously. The nominal voltage of the faulty appliance is used to calculate the short circuit power, even though the voltage in the event of a fault is practically 0 V.

TSOs are obliged to maintain a sufficiently high short circuit power in the grid to allow for the reliable detection of short circuit events, to ensure the transient stability of electric machines [24], and to ensure a potential gradient as narrow as possible in case of a fault, i.e. to confine the voltage drop as far as possible. In contrast, they are also obliged to ensure that the short circuit power is not too high, so that appliances are not damaged due to high short circuit currents, and that circuit breakers can safely interrupt the short circuit currents. The short circuit power of a given grid also serves as an indication of voltage and power quality, and is thus a relevant parameter for the assessment of additional DECU grid connections.

The volume of the available short circuit power still mostly depends on the number and the apparent power of the grid-connected synchronous generators, as well as their electrical distance to the fault location. A change to the generation structure, such as a reduction in the share of synchronous generators within the grid or a shift of generating capacity from the transmission into the distribution grid, can entail a significant change of the short circuit power, as will be explained below using an example.

It is assumed that the installation of decentralised renewable energy systems, in particular of PV systems and wind turbines, will at least temporarily lead to an altered distribution of short circuit power sources. In the following consideration, the consequences of this development are discussed and key drivers are identified that contribute to a change of the available short circuit power. Additionally explained are the currently applicable specifications in Germany regarding the response to short circuits, laying the foun-

dation for a consideration of the development of short circuit currents and the corresponding short circuit power. An examination of current related studies serves to identify unanswered research questions, which are then prioritised and answered.

Displacement of conventional generation by DECUs

It is expected that the cumulative connected capacity of all synchronous generators in the transmission grid will decrease due to market-driven displacement effects exerted by DECUs connected in the distribution grid. Therefore, it is expected that the secured short circuit power as provided by conventional suppliers with synchronous machines will decrease. Against this background, the development trend of short circuit power must be analysed taking into account short circuit current contributions from DECUs.

Closely connected with this development is the question as to whether Germany will be able to provide industrial customers with strict requirements to the short circuit power available from CPs with enough CPs in the future. This would affect, for example, industrial customers operating electric arc or induction furnaces.

Tighter coupling between the voltage levels

It can be observed that the construction of new generation units in the distribution grids is associated with an increase in transfer capacity demand at the grid interconnections between the transmission and the distribution grid, which in turn requires the construction of additional transformers or grid interconnections [2]. The result is that the electrical distance between the respective grid levels decreases while the degree of coupling increases, and therefore there will likely be a trend towards greater short circuit current contributions from the transmission grid in case of faults in the distribution grid.

The effect of this more pronounced grid coupling, however, can be counteracted by changing planning principles and operating modes of the lower-level grids.

Weather-dependent availability of short circuit power

The weather-dependent, volatile nature of supply-dependent renewable energy systems such as PV systems or wind turbines will also affect the provision of short circuit power assuming today's standard grid codes. So it can be assumed that supply-dependent renewable energy systems cannot contribute to the short circuit

power as soon as their primary energy source, e.g. the sun or wind, is no longer available, because these systems disconnect from the grid in times without any supply. Therefore, it is expected that a certain level of volatility of the available short circuit power will be the result. Here, however, it should be noted that fully rated self-commutating converters (optionally after a software update of the system controller) would be technically capable of four-quadrant operation, thus supplying reactive current without primary energy provision and consequently providing short circuit power [153]. Since there is no active power exchange between the three-phase supply network and the direct current intermediate circuit of the converter, only the active power losses caused by the converter valves and by the capacity of the direct current intermediate circuit need to be compensated by active power supply from the three-phase supply network.

Impact on the grid codes

Short circuit power is currently used to calculate whether or not a newly installed plant may be connected to a considered grid CP [25] [26]. It serves as an indicator to estimate both the impact on voltage stability and the maximum load caused by harmonic currents. In the case of heavily modified or even volatile short circuit power, these principles must be reviewed and adjusted where necessary.

Coverage of short circuit power demand by European collaborative partners

The discussed possibility of potential displacement effects of conventional generation by DECU assumes a market-driven process. It is known that a special market situation is given in Germany due to currently applicable support conditions for renewable energy sources. This means that it cannot be assumed that displacement effects, such as expected in Germany, will apply to the same extent to all of Europe. Regardless, it must be investigated to what extent short circuit power can be provided by the plants of the collaborative partners in cases of faults. It should be noted that this is not only a technical but also a political and regulatory issue. It is therefore necessary to consider to what extent the German transmission grid would be able to meet its short circuit power demand regardless of collaborative partners.

Voltage quality

Apart from pure voltage stability, voltage quality is a growing challenge. Volatile supply from plants with power electronics connections can lead to flicker noise and harmonic components. With a large number of these plants, unwanted grid perturbations may arise.

4.1 Research questions

It is expected that there will be a , temporal and weather-dependent distribution of short circuit power sources. Therefore, it must be investigated whether the minimum and maximum requirements to short circuit power are met in every situation in the future. The following research questions are derived from this:

- How will the short circuit power in the German transmission grid and in the 110 kV distribution grids develop in the future?
- How weather-dependent will the available short circuit power be?
- To what extent does the German energy supply system depend on the provision of short circuit power by European collaborative partners?
- What possible solutions are available to alleviate situations in which there is not enough, or too much, available short circuit power?
- What is the impact of a changed volume of available short circuit power on the grid connection requirements of PGS?

4.2 Evaluation of current literature and studies

Short circuit behaviour of power generation units

Short circuit current, which is fed into the grid by an electric machine in case of a grid-side failure, depends on the reactance of the machine and the electrical distance to the fault. A distinction is made between short circuits near to and far from a generator. In short circuits close to a generator, there is a high initial short circuit current, which then decays to a steady-state value. In short circuits far from a generator, there is a nearly time-independent, steady-state short circuit current from the beginning. In both cases, the resulting short circuit current largely depends on

the reactance of the equipment. Details on the calculation of the relevant reactances for the short circuit current calculation can be found in DIN EN 60909 (DIN VDE 0102) [33], which are used in the calculations carried out as part of the present considerations.

In the event of a grid-side fault, the technical behaviour of DECUs connected to the grid via electronic power converters depends on the power generation technology and on used converters. So far, there are no applicable standard for the short circuit current calculation of DECU-based power converters in the event of grid-side faults [33]. However, specifications of the behaviour of DECUs are defined by the grid codes for grid-side short circuits [25]. These so-called fault-ride-through requirements define the power supply by DECUs in the event of short circuits based on the prevailing voltage levels at the grid connection point as a function of time.

A distinction is made between faults occurring near to and far from CPs. In faults near to a CP, the half-wave root mean square value of the line-to-line voltage at the CP is lower than 70% of the nominal voltage. Cases with a higher voltage at the CP are by definition far from the CP. Plants may not disconnect from the grid in case of a fault occurring far from a CP and must support the voltage by remaining online. CP-related errors are distinguished between PGS with high and low short circuit current contributions. A PGS with a high short circuit current share must be able to feed in a short circuit current for 150 ms which must be at least twice as high as its rated current. Then it must be able to feed in a third of its rated current for a duration of several seconds. Given a fault clarification time of 150 ms, such a PGS may not lead to instability throughout the whole operating range, or disconnect from the grid. If the voltage drops below a time-dependent setpoint, PGS with a high short circuit current share may disconnect from the grid. Analogue requirements also apply to PGS with a low short circuit current contribution. Conventional PGS are usually equipped with a synchronous or asynchronous generator and belong to the group of PGS with a high short circuit current contribution, while DECUs are generally driven by converters and belong to the group of PGS with a low short circuit current contribution.

In case of a grid-side fault, all PGS must support the voltage by injecting reactive current that must be provided in addition to the reactive power injected prior to the fault. Due to their design, syn-

chronous generators provide reactive currents without further adjustments. For all other PGS, the current value of the reactive current depends on the half-wave root mean square value of the line-to-line voltage and is 2% of the rated current of the PGS per 1% voltage drop. At a voltage drop to 50% of the rated voltage, these PGS are therefore obliged to inject their nominal current in the form of an inductive reactive current. Such a participation in dynamic grid support is not required for plants in the MV grid, but they have to be generally technically capable of doing so. Detailed information about the relevant requirements can be found in [25].

4.2.1 Present plant behaviour in fault case

Studies have shown that the above-mentioned requirements must be observed in order to maintain the system stability of the integrated European grid even during serious faults such as busbar short circuits [76]. Wind turbines installed prior to 2003 and that have not been modernised or upgraded since do not meet these requirements. These units will likely lead to larger potential gradients due to a lack of voltage support. This means that further PGS will disconnect from the grid and will therefore not be able to support it. The lowered generation capacity may exceed the design case of PCR of 3,000 MW and pose a serious challenge to system security [76]. PGS, particularly wind turbines connected after 2003, comply with these requirements and contribute actively to voltage support in case of a fault. Analyses have shown that this reduces any widening of potential gradients, and that it has a positive effect overall. Nevertheless, the behaviour of old plants is a problem for system security, because until today, generating capacity in the order of several gigawatts disconnects from the grid rather than supporting voltage in fault case. This is particularly the case with faults in the wind power generation areas in northern Germany.

Key findings of the dynamic investigations carried out as part of the dena I study [76] are summarised below. Wind turbines hardly contribute to limiting the potential gradient in the event of short circuits. It is expected that voltage gradients will expand due to the displacement and the associated shutdowns of conventional power plants, and that this will result in even more outages of old wind turbines. Compared to conventional power plants directly connected to the EHV grid, wind turbines only make an insignificant contri-

bution to the short circuit current. The voltage-supportive properties of wind turbines connected in voltage levels subordinate to the EHV grid have a negligible effect on the voltage of the transmission grid. Synchronous generators are able to support voltage significantly, and could be converted to phase shifters in the course of displacement processes to help reduce the expansion of potential gradients and to contribute to dynamic voltage stability. Upgrading power plants to phase shifters, however, is technically possible possible but associated with high retrofit costs [37].

Old wind turbines located at the end of the fault-induced potential gradient remain connected to the grid for reasons of frequency control, but they do not contribute to voltage support in the EHV grid. On the contrary – since most of the considered old wind turbines are asynchronous machines, they consume a high amount of reactive power in a very short time due to their design, and counteract any effort made to correct the voltage drop [76]. Furthermore, it was shown that grid support by active compensation systems did not lower the potential gradient during the fault. However, they can make a valuable contribution to grid support after the fault has been corrected.

Threat to system stability

An uncontrolled disconnection of old plants can have far-reaching consequences for the stability of the integrated European grid. The loss of significant generation capacity in the order of several gigawatts can exceed the design case of primary balancing power and may have implications on frequency control. Furthermore, the sudden, spatially concentrated loss of generating capacity - depending on the preloading of interconnectors - can lead to safety cut-offs of cross-border tie lines, and of tie lines close to the border. This would entail a separation of the integrated European grid. The occurrence of expansive potential gradients, the lowered voltage stability and the loss of generation capacity associated with the shutdown of older plants would tend to increase the risk of a transient instability of conventional PGS.

4.2.2 Comparable studies

The following section compares the results of selected studies on the development of the short circuit power.

A study on the development of the short circuit power in the Dutch transmission grid came to the conclusion that the short circuit power increased significantly during 2003 and 2013, and that a further rise is expected [76]. The increase is attributed to the permanent installation of new equipment in the transmission and distribution grids. So far, there is no trend in the Dutch grid regarding the dismantling of equipment, especially PGS. On the contrary – further installations are increasing the available short circuit power. The study describes the consequences of too high short circuit currents and short circuit capacities and makes recommendations on how to cope with this. A detailed description of the results and research methods of this study, however, was not published, and therefore a fundamental examination of the interactions of the circumstances described above remains a research question.

A study commissioned by German TSOs [10] came to the conclusion that in terms of short circuit power, a reservation of a minimum generation capacity would not be necessary. This is due to the fact that there is always a certain minimum amount of conventional generation capacity connected to the grid to maintain voltage stability. In addition, reference was made to a high import potential of short circuit power from the integrated European grid. As long as the partners in the European energy system do not curtail their conventional generation mix, no adverse effects in terms of a reduced short circuit power level in Germany need to be expected. This study differs in its posed question, i.e. the quantification of a necessary minimum generation from conventional power plants, from the study in which the development of the short circuit power was calculated taking into account clearly defined grid and generation expansion measures.

A study elaborated by the Fraunhofer IWES in 2012 compared the development of the short circuit power in an energy supply system with a generation mix as per NEP 2012 with today's generation mix [145]. The installed generation capacity was initially and methodically distributed amongst all relevant voltage levels from 380 kV to 0.4 kV, and then a characteristic grid connection type was assigned to each power supplier type and power plant taking into account the generator system. Then the short circuit power contribution of the generator system was taken as independent of the fault location and therefore as maximum, which was then used to calculate the theoretical maximum.

The magazine *ew - Magazin für die Energiewirtschaft* (magazine for the energy industry) reported on this study, noting that the estimates show that the planned changes to Germany's generation mix by the year 2032 will have a direct impact on the volume of available short circuit power. By the year 2032, however, a joint reduction of the short circuit power up to 20% compared to the reference year 2010 is expected. [145].

The study is thematically congruent with the research question examined here, but it identifies the trends in the development of short circuit power while ignoring the influence of the electrical grid, grid expansion and the regional distribution of short circuit power sources. Furthermore, the study refers exclusively to Germany, which is why the interdependencies with the neighbouring European countries could not be examined. Therefore, a calculation of the short circuit power is carried out in the following to determine its change in the integrated grid and lower-level distribution grids.

4.3 Modelling

The calculation of the developmental trend of the short circuit power in the German transmission grid is based on an aggregated European transmission grid model (see Appendix B.1) and a showcase 110 kV distribution grid. First, short circuit currents are calculated on the 380 kV grid level without taking into account lower-level grids to determine the minimum and maximum short circuit power in the 380 kV grid. Correspondingly, short circuit current analyses are carried out in a showcase 110 kV distribution grid to identify the minimum and maximum short circuit power. Once the isolated contributions from the respective grid levels are known, they are then mathematically combined. The showcase 110 kV distribution grid is connected to selected 380 kV busbars to observe the resulting short circuit capacities once combined. The share of short circuit power provided from abroad is accounted for separately. With the method described in detail below, it is possible to observe trends in the development of the short circuit power of the 380 kV and 110 kV grid levels in an isolated and combined manner.

A study of multiple grid levels requires a suitable estimation of the load and generation distribution in the considered simulation mod-

els. In this analysis, two representative situations were considered that were identified using an annual simulation with the market and grid model (see Chapter A.2) for the years under review of 2011 and 2033 (see Chapter A.3). In the following two situations, any renewable energy sources are considered independent from their primary energy supply with their minimum and maximum short circuit power contribution possibilities. The situation is one of maximum conventional generation that takes place around 7 pm on a winter evening in both observation years at the same annual hour. In this scenario, the highest short circuit power is to be expected by trend, therefore this scenario is referred to as "maximum case". On the other hand, there is a situation with minimum conventional generation on a summer morning at 5 am. By trend, the lowest short circuit power is to be expected in this scenario, therefore this scenario is referred to as "minimum case". Both the maximum and the minimum case share the fact that they are based on the context of Germany plus neighbouring states and Italy.

In an annual simulation of the electricity market, the conventional power plant utilisation is calculated in accordance with technical constraints, including the preferred supply of electricity from renewable energy sources, and delivered as the aggregated total capacity for every node of the aggregated transmission model, as it is described in Chapter A.2. This total capacity is divided into regions depending on the considered generation technologies. For the representative calculation of short circuit current contributions and maximum short circuit currents, it is necessary to divide this total capacity amongst the relevant voltage levels as per [2]. The factors used serve the distribution of the installed generation capacity and the definition of the operating points and are listed in Chapter A.1. The installed generation capacity does not change during the course of one annual simulation.

30% of the load on which the market model is based is allocated to the 220 kV and 380 kV grid level, 30% to the 110 kV grid level and 40% to the MV and LV levels. The total load on the 380 kV nodes aggregated in the grid and market model correspond to a merging of several real 380 kV nodes, which can each be connected to more than one lower-level 110 kV grid. In order to make a representative calculation using a 110 kV grid, a scaling factor for generation and load is chosen. This scaling factor relates the 380 kV grid load $P_{i,\mathrm{Load,380kV}}$ at node i to the reference load of the consid-

ered 110 kV grid $P_{\mathrm{Load,110kV}}$ in high load case. Using this factor, the total load and generation in the 110 kV grid is scaled. The voltage and frequency dependency of loads is not relevant to the calculation of short circuit currents and is ignored in this study.

The generation capacity is calculated using the same scaling and distribution factors. The generation capacities per energy source are relative to the total power generation in the considered grid. The total power generation from PGS is distributed in the grid area using typical nominal values.

The newly constructed transformer substations and operationally relevant switching measures can have a significant impact on the level of the short circuit power. In this study, a representative grid expansion state with a defined switching state is assumed to ensure comparability. A detailed examination of different expansion variants and switching states is not provided in this study.

Conventional generation

It is assumed that all conventional PGS use a synchronous machine connected to the grid via a step-up transformer. Therefore, the reactance of these operating resources is the relevant driver to determine the short circuit current contribution of conventional generation technologies. The physical value of the reactances X_{d}, X'_{d} and X''_{d} are taken from an internal database depending on the generator's rated apparent power.

Renewable energy systems

RES are generalised and considered as connected to the grid via a converter. This means that the short circuit current contribution depends on the voltage at the grid connection point when a short circuit occurs (see also section "Short circuit behaviour of PGS"), since these PGS have a low short circuit current contribution. For a consideration of the short circuit power trend, it is sufficient to assume that all plants participate in voltage support of the affected grid level, while all PGS of higher and lower-level grids do not due to their longer electrical distances. This ensures that the maximum possible short circuit power can be accounted for in the considered grid level. Furthermore, it is assumed that all plants connected via converters can provide short circuit current equal to the nominal current rating of their converters, and that they inject this into the grid as a purely inductive reactive current in the event of a fault.

Short circuit current calculation

The calculation of short circuit currents is carried out in accordance with DIN EN 60909 (DIN VDE 0102) [33], which is an accepted method for the determination of maximum and minimum short circuit currents for grid planning analyses. In the following analyses, a distinction is made between minimum and maximum short circuit current calculations. In determining the maximum short circuit currents, the voltage factor is assumed to be $c_{\max} = 1{,}1$ and impedance correction factors are taken into account. Regardless of their operating points, DECUs contribute to short circuit power with the full amount of their rated apparent power. The calculation of minimum short circuit currents is carried out with the voltage factor $c_{\min} = 1{,}0$. In addition, impedance correction factors and electronic power converters are neglected as stated in the standard. In this case, DECUs connected to the grid via converters do not contribute to the short circuit power. In deviation from the standard, the short circuit current contributions of motors and the associated future load behaviour are neglected. This was deliberate, in order to better highlight the short circuit power trend with respect to a changed grid expansion and power plant utilisation.

4.4 Calculations in the transmission grid

The aim is to determine the existing short circuit power injected by operating resources and PGS in the transmission grid exclusively. For this purpose, an isolated consideration of the 380 kV grid level is carried out neglecting lower-level voltage levels. Subsequently, selected representative areas of the grid are analysed in detail, and a cross-grid analysis including contributions from the 110 kV distribution grid is carried out. For each scenario, three-phase short circuits on all 380 kV busbars are simulated and the minimum and maximum short circuit currents as determined according to DIN VDE 0102. In order to analyse development trends more accurately, variant calculations are carried out in conclusion.

4.4.1 Development of the maximum short circuit power

It is assumed that the maximum short circuit power has a trend of being available in the annual hour with the maximum conventional

generation. In this scenario, node 20 in the year 2011 was revealed as the node with the highest amount of available short circuit power. It is therefore used as a reference for the other observation points. An overview of the relationship between the short circuit power level at all other nodes in Germany relative to this reference node is provided in Figure 4.1. It is evident that in industrial centres, such as at nodes 14, 20 and 27, significantly more short circuit power is available than in less industrial or more rural regions in eastern Germany, such as at nodes 4, 5 and 7. This is due to the fact that a large number of conventional generation plants are installed near industrial regions. In 2033, node 20 continues to be the node with the highest short circuit power, see Figure 4.2.

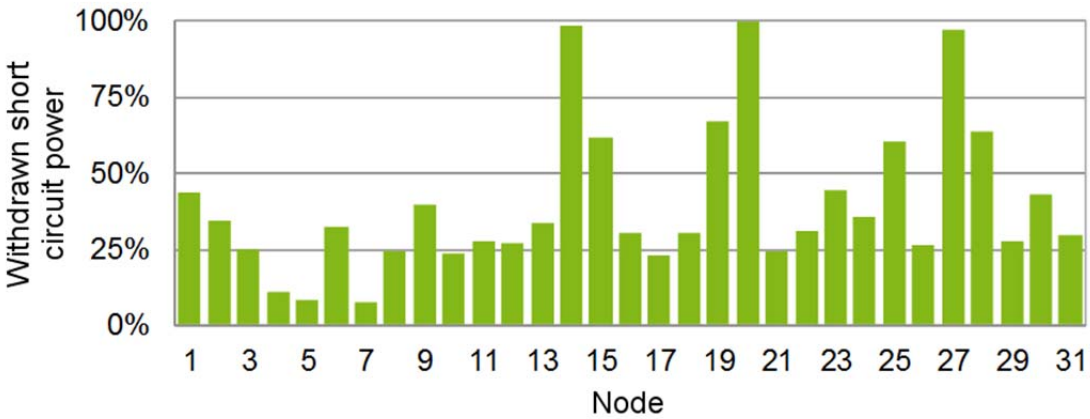

Figure 4.1 Representation of the short circuit power in 2011 based on the node with the highest short circuit power (node 20) in 2011

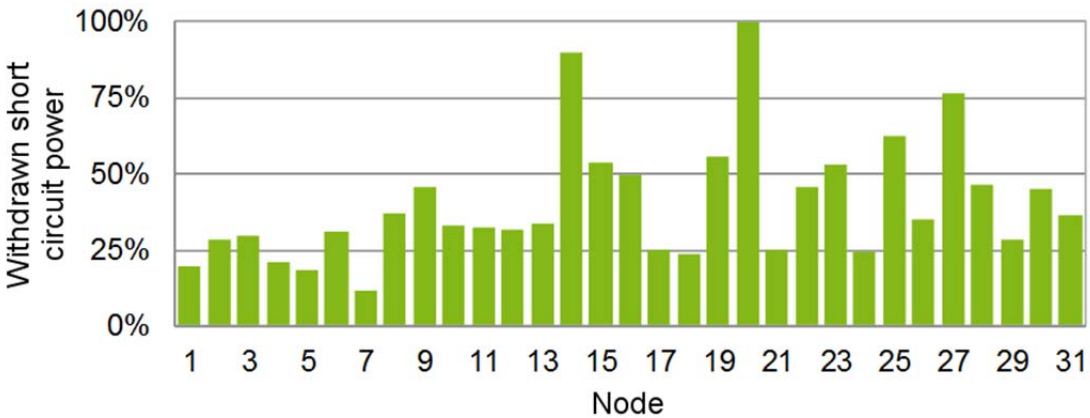

Figure 4.2 Representation of the short circuit power in 2033 based on the node with the highest short circuit power (node 20) in 2033

It can also be seen that higher short circuit power levels exist in industrial regions than in rural areas. However, the second and

third strongest nodes have moved away from the reference. The nodes with the lowest short circuit power in 2011 will still have the lowest short circuit power, but here the distance to the reference node is shorter.

Figure 4.3 shows the relative change of short circuit power in 2033 compared to the year 2011. The graph should be interpreted such that positive values indicate an increase and negative values a decrease in short circuit power. It is noticeable in some cases that the short circuit power at the nodes can change by over 100% and that both decreased and increased short circuit capacities can be expected. Nodes at which a high short circuit power was already available in 2011 experienced only moderate changes. Nodes 3, 4 and 5 exhibit a trend to low short circuit capacities in comparison to the reference node. However, there are significant increases here.

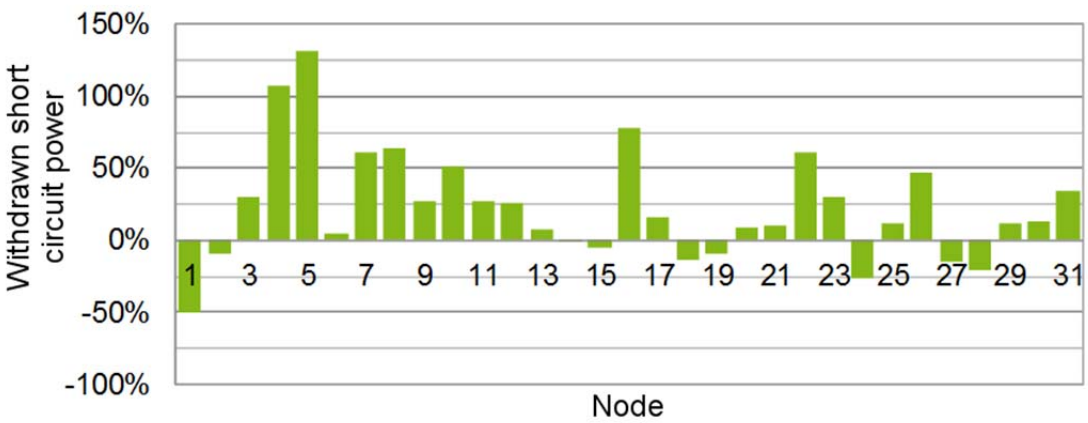

Figure 4.3 Relative changes in the short circuit power in the maximum case at each node in 2033 relative to 2011

4.4.2 Development of the minimum short circuit power

It is assumed that the maximum short circuit power has a trend of being available in the annual hour with the maximum conventional generation. In this analysis, node 7 exhibits the lowest available short circuit power. In order to ensure comparability with the previous results, node 20 will continue to serve as the reference node with the maximum short circuit power. An overview of the relationship between the short circuit capacities at all other nodes in Germany relative to this reference node is provided in Figure 4.4. In

general, it can be observed that at nodes with a relatively low short circuit power in 2011, there will be more short circuit power available in 2033, even though the construction of new DECUs has not yet been considered in this isolated approach.

The minimum short circuit power for three-phase busbar short circuits in the aggregate grid model in 2033 can be both significantly lower and higher than in 2011, as it is shown in Figure 4.5.

In order to explain all the changes discussed above, detailed analyses are necessary. To this end, nodes selected in the following are analysed as examples. The selected nodes represent the highest (node 20) and the lowest (node 1) calculated short circuit power and the node with the largest reduction of available short circuit power (node 7).

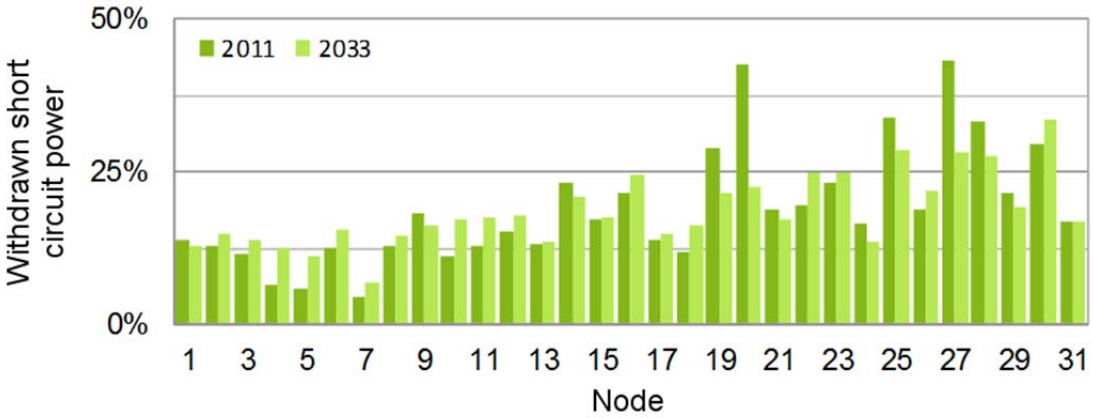

Figure 4.4 Representation of the short circuit power in 2033 based on the node with the highest short circuit power (node 20) in 2011

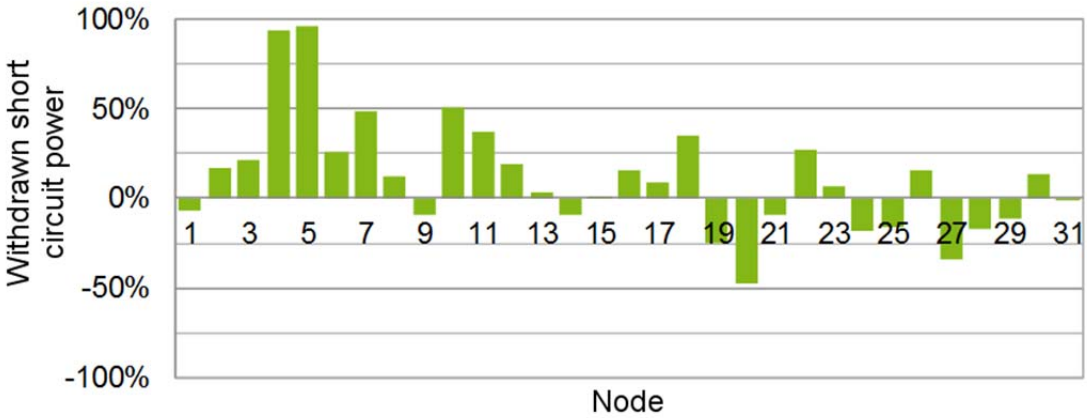

Figure 4.5 Relative changes in the short circuit power in the maximum case at each node in 2033 relative to 2011

4.4.3 Detailed analysis

Detailed analyses of node 20

Figure 4.6 represents the relative contributions of all grid regions given a three-phase busbar short circuit at node 20 based on the highest occurring short circuit power in 2011, which was also calculated at node 20. The term "node 20" means short circuit power provided at node 20 by PGS. D represents the share of the short circuit power that is provided by further generators in Germany. The regions West (NL, B, L and F), South (A, CH, I), East (P, CZ) and North (DK) are representing the neighbouring countries of Germany. The total short circuit power is composed of these six regions. It is evident that in the maximum case, the main part of the short circuit power, over 80%, is provided by German power plants and this will change only insignificantly by 2033. However, by trend the share that is provided locally in the region of node 20 will be halved. With 50%, this share of the total available short circuit power of Germany in 2011 is very high. In total, the calculated available short circuit power increases by about 10% at this node, from which it can be concluded that more absolute short circuit power is provided from nearby locations in Germany and abroad.

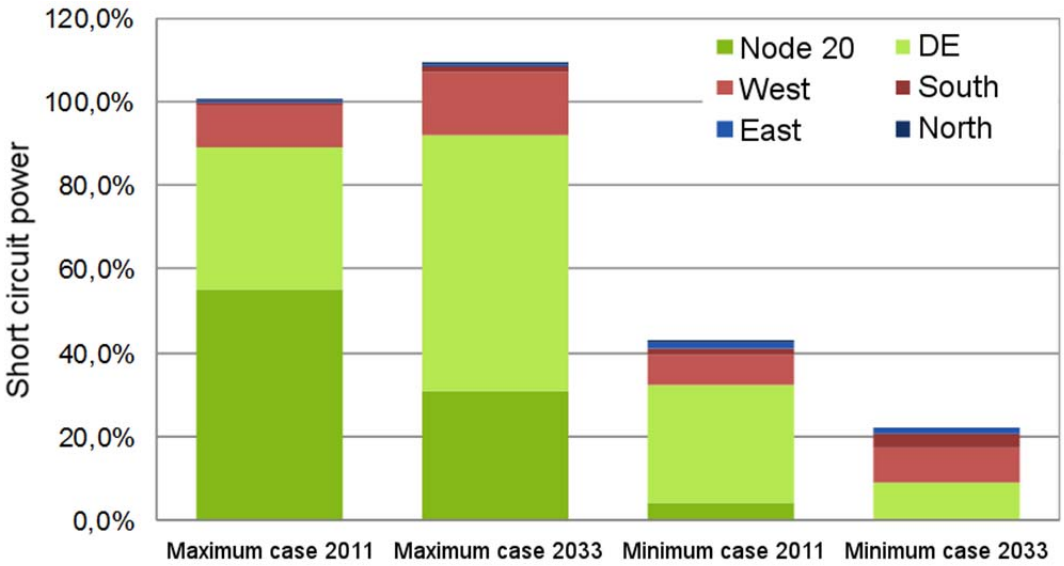

Figure 4.6 Relative contributions to the short circuit power sorted by grid regions at node 20, based on the highest available short circuit power in the maximum case of 2011

In case of a short circuit at node 20, the voltage drops at all bus bars tend to be higher. This means that the resulting potential gradient will tend to be flatter and that possibly more generators will

be involved in the supply of short circuit current. The largest relative changes were calculated for the Ruhr area. The changes here are up to -37%. The arithmetic mean of the voltage drop changes is below -5%, which shows that the potential gradient does flatten but is still relatively steep due to the tight coupling to neighbouring nodes.

In 2011 and 2033, node 20 belongs to the nodes at which a relatively high short circuit power is available compared with the rest of Germany, even in the minimum case. However, a clear difference between the minimum scenario of the year 2011 and that of the year 2033 can be observed. The minimum short circuit power drops by almost 50%. Figure 4.6 shows that in 2011, about 76% of this available short circuit power comes from Germany, while this number drops to only 40.3% in 2033. The foreign share of the relative and absolute short circuit power has risen. The share of the available short circuit power from West European countries in the minimum case in 2033 has more than doubled. In the minimum scenario, short circuit power is not provided by generators in the area around node 20 due to market-related reasons. This is one of the key drivers behind the lower short circuit power at this observation point. Nevertheless, the bottom line is that the absolute level of the available short circuit power at node 20 significantly exceeds the absolute minimum volume in 2011 at node 7. When considering the voltage drops, it has to be noted that the drops are generally less pronounced. On a nationwide average, there are changes amounting to -21%, with a maximum change of -48%. This reveals that a cutback of the conventional generation mix in a market previously dominated by conventional power generation leads to a drastic change in the expected potential gradients.

Detailed analyses of node 7

At node 7 in the maximum case in 2033, an increase in short circuit power by about 62% compared with 2011 is expected. Figure 4.3 shows the relative contributions of defined grid regions to the available short circuit power given a three-phase busbar short circuit at node 7. It is evident that generators at node 7 do not provide short circuit power from conventional power plants - both in 2011 nor in 2033. The contributions in 2011 are made to approx. 56% from the East area, and to 44% from Germany. In 2033, the share from Germany will increase to about 57% and that of the East area will drop to about 42% relative to the total short circuit

power. However, the short circuit power increases overall, which is due to a share of 77% from German generators, and 19% from generators in Eastern Europe. Since the conventional generation mix has halved in the considered area between 2011 and 2033, and there is no conventional generation at the nodes under review in 2011 and in 2033, it seems likely that grid expansion is the key driver of the changed short circuit power amount. At node 7, it can further be observed that the voltage drops will change by trend. These results in changes

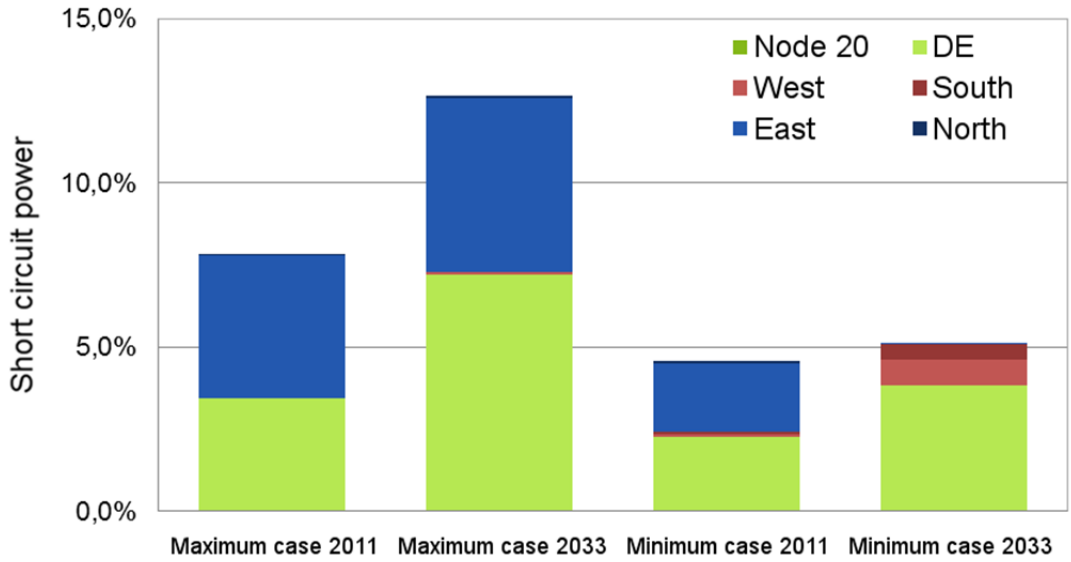

Figure 4.7 Relative contributions to the short circuit power sorted by grid regions at node 7, based on the highest available short circuit power in the maximum case of 2011

of around -12% to 2%. On average, the voltage drops change by -1.3%.

In the minimum case in 2033, node 7 was also identified as the node with the lowest short circuit power in all examined cases, although the short circuit power increases slightly compared to 2011. It is suspected that the causes of the additional short circuit power are market-driven spatial shifts of power plant sites in the East area. However, this could not be confirmed. The share of the short circuit power supplied from the area East significantly decreases in the minimum case 2033 compared with 2011, whereas more short circuit power is provided from the area West. The share of short circuit power supplied from Germany increases. German plants have a share of 70% in the difference occurring between 2011 and 2033. The contribution from Western Europe increases significantly from 2% in 2011 to 11.3% in 2033. It is therefore evi-

dent that grid expansion is a key driver that leads to an increase in the minimum short circuit power at this location.

Voltage drops are more pronounced compared with 2011. In the German average, approx. -7.8% lower voltage drops are the result. The highest change is -27%.

Detailed analysis of node 1

Node 1 has been chosen for a detailed analysis, since it can provide clearly less short circuit power in 2033 than in 2011 when calculating the maximum short circuit power. The calculation reveals that the short circuit power available in the maximum case with its high level of conventional generation is halved. The share of short circuit power supplied from Germany relative to the total short circuit power is about 82.5% in 2011 and about 76% in 2033, as shown in Figure 4.8. However, in terms of the absolute contributions to the short circuit power, there is a resulting reduction of the German contribution of -89%. In 2011, about 56% of the German short circuit current contribution was provided at node 1. In 2033, there will be a reduction of almost 98%. The contribution from the node itself is marginal. This is due to the reduction of conventional generation mix at this point.

In contrast to other previously studied locations, there are complementary voltage drops at the nodes in the vicinity. While the voltage drop is lowered by 37% at node 3, the voltage drop at node 4 is more severe with -12%. On average and relative to the whole of Germany, there are hardly any changes.

In terms of the examination of the minimum short circuit power, only a marginal change is likely as illustrated in Figure 4.5. Figure 4.8 shows that the share from Western Europe increased by about 10% and the share from Northern Europe falls from 23% to about 4%. In 2011, six times more short circuit power was provided by the area North relative to the absolute difference between 2011 and 2033. Likewise, nearly six times more than the difference itself is provided the areas West, South and East in total. This is almost offset by the total amount of available short circuit power and serves as an indication that grid expansion has a very large impact on the future distribution of short circuit power. On average, the voltage drops change by -6.4%.

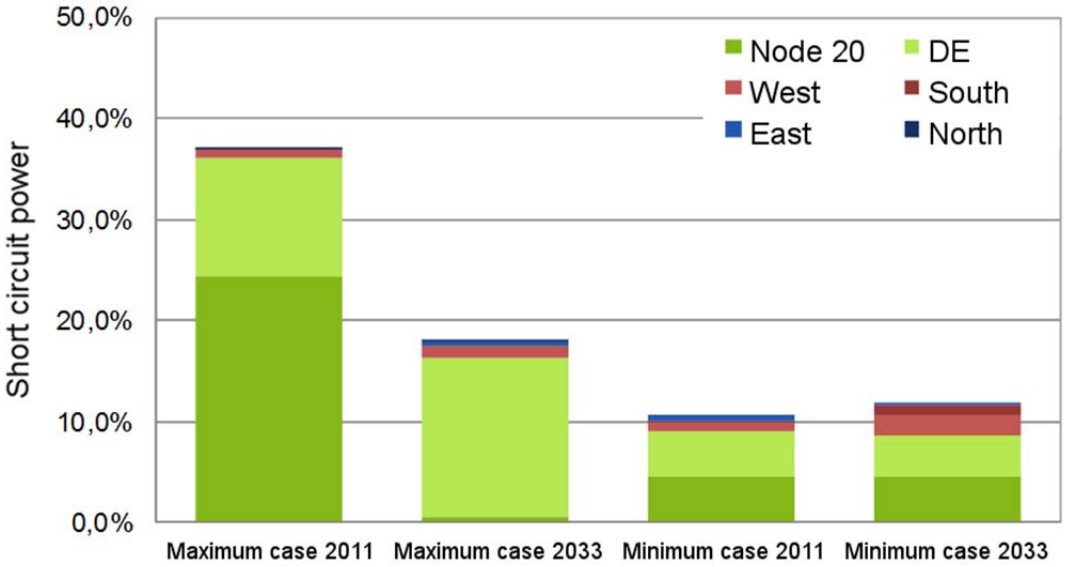

Figure 4.8 Relative contributions to the short circuit power sorted by grid regions at node 1, based on the highest available short circuit power in the maximum case of 2011

4.4.4 Cross-grid level consideration

In the following, the shares of the total available short circuit power are presented for a three-phase busbar short circuit in the transmission grid. A distinction is made between shares from the distribution grid, the transmission grid and shares from supply-dependent renewable energy systems in the distribution grid. The calculation of the distribution grid contributions is discussed in detail in Chapter 4.5 and is carried out as an example for the industrial and the rural region in this section. Table 4.1 shows the available short circuit power with a combined consideration of the transmission and distribution grid level compared with the isolated consideration of the transmission grid based on the respective scenarios. In any case, the additional consideration of the lower-level distribution grid has led to an increase in the available short circuit power. Significant contributions from the distribution grid occur at rural nodes. The short circuit power increases by about 10% in the maximum and by approximately 16% in the minimum case, which is due to a contribution from renewable energy systems.

Table 4.1 Relative short circuit power for a 380 kV busbar short circuit taking into account the short circuit power contribution from the 110 kV level based on the short circuit power of the isolated 380 kV consideration

Year	Node 7		Node 20	
	Minimum case	Maximum case	Minimum case	Maximum case
2011	116.0%	110.8%	101.5%	101.8%
2033	115.2%	109.5%	101.7%	102.7%

In the more industrial grid, the results are slightly higher short circuit capacities; increases, however, are marginal with about 2%. Table 4.2 shows the contributions to the rural node 7, grouped by grid level. In the minimum case, the contribution from the distribution grid in 2011 and 2033 is slightly over 13%, and in the maximum case just under 10%. Since there is no conventional power plant capacity installed in the distribution grid in any of the considered scenarios, the contributions are madesolely by renewable energy systems.

Table 4.2 Short circuit power contributions per grid level for node 7

Year	Operating condition	Contribution from TG	Contribution from DG	RES	SG
2011	Minimum	86.1%	13.9%	100.0%	0.0%
	Maximum	90.2%	9.8%	100.0%	0.0%
2033	Minimum	86.8%	13.2%	100.0%	0.0%
	Maximum	91.3%	8.7%	100.0%	0.0%

The results for an industrial distribution grid at node 20 are listed in Table 4.3. In 2011 and in 2033, there are existing conventional power plants that make a short circuit current contribution. This contribution is 0% in the minimum case, because the power plants here are not connected to the grid, and 64.2% in 2011 and 73.3% in 2033 relative to the share provided in the transmission grid from the distribution grid for busbar short circuits. By trend, almost the entire short circuit power (> 95%) is provided by conventional suppliers at node 20 in all considered situations.

Table 4.3 Short circuit power contributions per grid level for node 20

Year	Operating condition	Contribution from TG	Contribution from DG	RES	SG
2011	Minimum	98.5%	1.5%	100.0%	0.0%
	Maximum	98.3%	1.7%	35.8%	64.2%
2033	Minimum	95.8%	4.2%	100.0%	0.0%
	Maximum	97.4%	2.6%	26.7%	73.3%

4.4.5 Variant calculation

In the following variant calculation, the influence of grid expansion on the development of short circuit power is investigated. The power plant utilisation of the years 2011 and 2033 is calculated without grid expansion with the grid of 2011, and with a grid expansion as per NEP for 2033. Figure 4.9 shows the relationships of the respective scenarios in terms of grid expansion relative to the variants without grid expansion. It is apparent that all values are over 100%, which means that more short circuit power is provided due to grid expansion in the generation situations in 2011 and 2033. At selected nodes, grid expansion even leads to an increase in short circuit power, for example by nearly 100% at node 7. Analogous to the results above, Figure 4.10 shows the calculations for the minimum case. Again, there is a significant influence of grid expansion on the volume of the expected short circuit power. An increase in short circuit power is expected at every examined point.

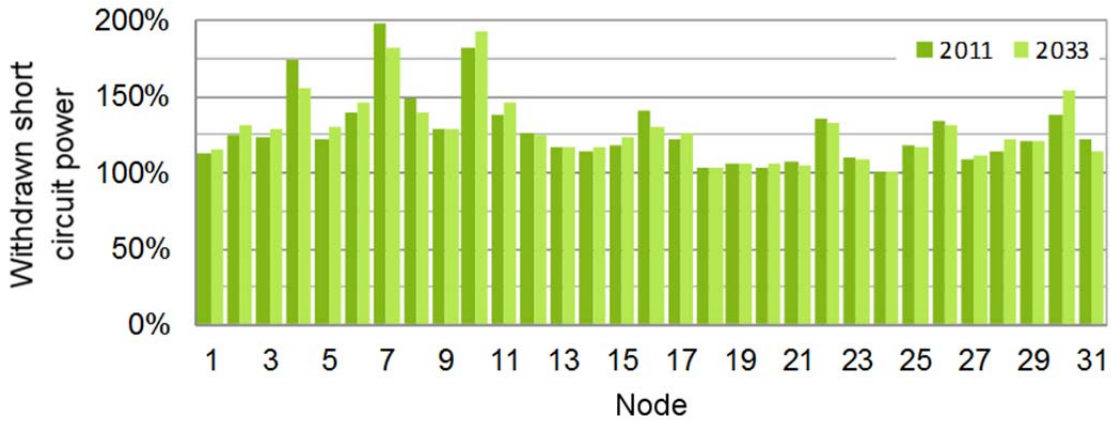

Figure 4.9 Relative short circuit power of the maximum cases in 2011 and 2033 as calculated taking into account grid expansion by the year 2033 (with NEP) relative to the maximum cases with the grid from 2011 (without NEP)

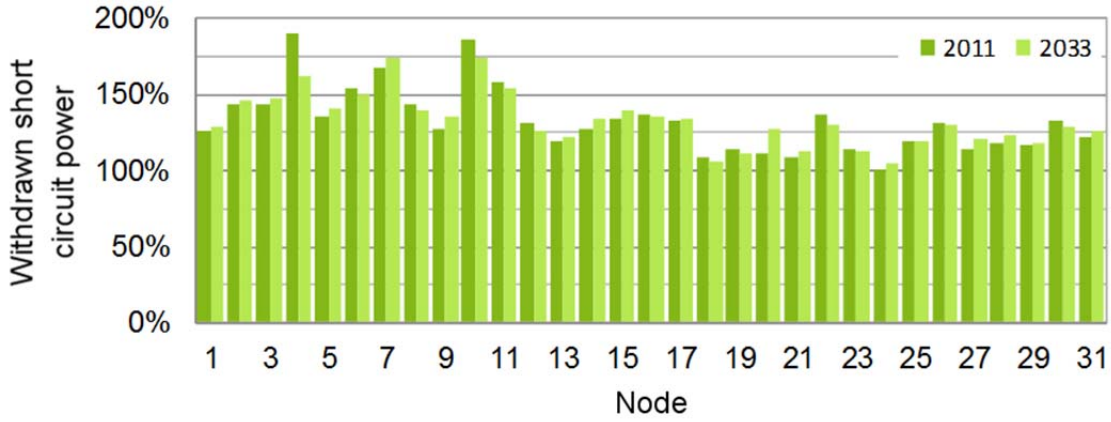

Figure 4.10 Relative short circuit power of the maximum cases in 2011 and 2033 as calculated taking into account grid expansion by the year 2033 (with NEP) relative to the maximum cases with the grid from 2011 (without NEP)

As a further variant, the influence of the changed generation mix on the volume of the expected short circuit power is examined. To this end, the grid of the study scenarios is assumed to be constant and generation to be variable. This means there is a comparison between the feed-in situation of 2011 and 2033 using the same grid expansion variant. Figure 4.11 shows this for the maximum case. It can be seen that the proportion of the short circuit power change that is caused by the changed generation mix over the period under review tends to be only slightly dependent on the grid expansion situation. Analogously, Figure 4.12 shows this for the minimum case.

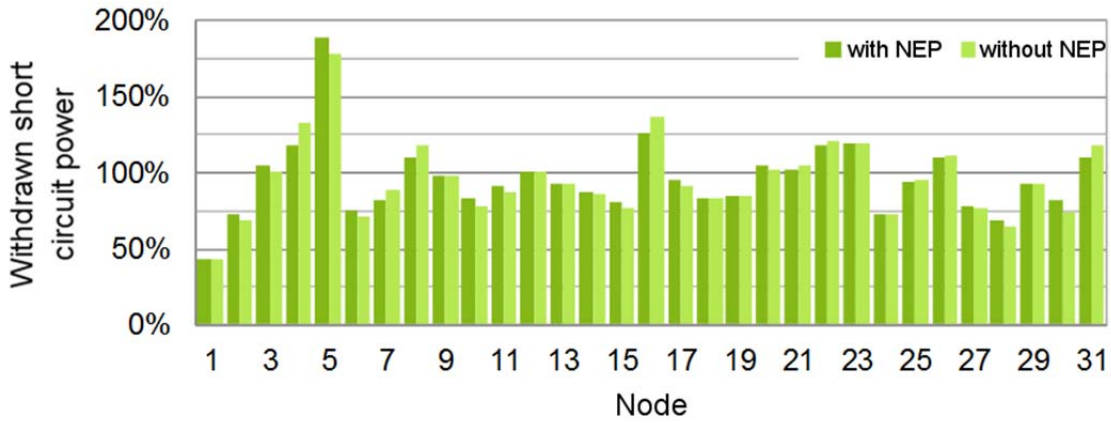

Figure 4.11 Relative short circuit power in the maximum cases given a variation of the generation situation in 2011 and 2033, each based on the grid of 2011 (without NEP) and the grid of 2033 (with NEP)

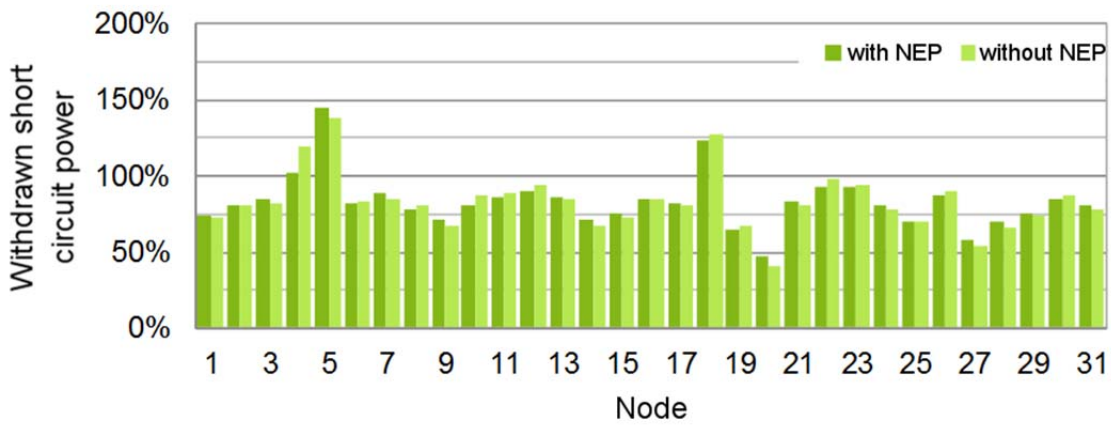

Figure 4.12 Relative short circuit power in the maximum cases given a variation of the generation situation in 2011 and 2033, each based on the grid of 2011 (without NEP) and the grid of 2033 (with NEP)

4.5 Consideration of the distribution grid level

In this step, the minimum and maximum sub-transient short circuit capacities are calculated in a representative 110 kV example grid. Like with the isolated consideration of the 380 kV grid level, the distribution keys from Chapter A.1 are adopted to representatively map and appropriately scale the generation and load situation. This way, both an industrial and a rural 110 kV distribution grid can be represented. The industrial grid was scaled according to the power plant utilisation at node 20, thus representing a very industrial grid area close to a city. The rural grid was scaled according to the power plant utilisation at node 7, and it thus represents a rural

grid area with a relatively low load and a high proportion of renewable energy systems.

4.5.1 Development of the maximum short circuit power

Figure 4.13 shows the result of the determination of the maximum sub-transient short circuit power in a rural 110 kV distribution grid. The shown short circuit capacities in the year 2033 are based on the short circuit power of the respective node of the year 2011 in the maximum case.

It can be seen that the resulting changes in this grid area do not vary very strongly. With few exceptions, the available maximum short circuit power increases from 2011 to 2033 by an average amount of about 25%. Only three nodes (38, 39 and 46) are an exception: the maximum short circuit power available at the respective nodes in 2033 is marginally lower than the 2011 value.

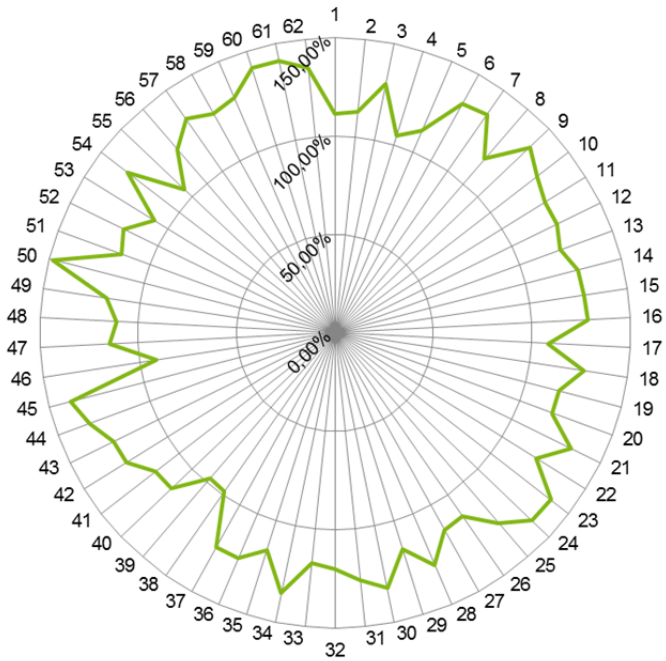

Figure 4.13 Maximum short circuit power in a rural 110 kV distribution grid in 2033, based on the respective short circuit power of the node in 2011

The development of the maximum short circuit power of the highly industrialised grid in the same observation period of 2011 to 2033 in the maximum case is shown in Figure 4.14; here too, the short

circuit capacities shown are based on the short circuit power of the respective node in 2011.

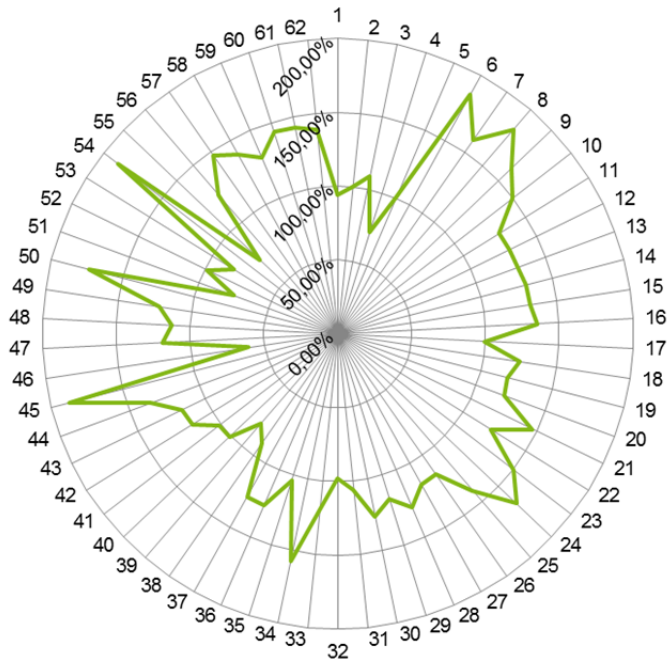

Figure 4.14 Maximum short circuit power in a rural 110 kV distribution grid in 2033, based on the respective short circuit power of the node in 2011

The shown changes in the short circuit power vary over the entire grid area, whereas most nodes in this industrial distribution grid exhibit an increase in the maximum short circuit power. The largest changes are experienced by nodes 6, 8, 45, 50 and 54, where the available maximum short circuit power rises on average to about 180% (compared to the respective value from 2011).

At some nodes (4, 39, 46 and 55) there even is a decrease in the local short circuit power. Nodes 46 and 55 are most affected by this with a short circuit power decrease to about 40% (based on the current value of 2011). The main reason for this is, that at these nodes, and in their vicinity, renewable power generation does not increase to the same extent that local conventional generation is taken from the grid.

Figure 4.15 summarises these relative changes in the short circuit power of the two considered grids of 2011 and 2033.

It can be seen that - as already described - rural distribution grids are likely to experience an increase in short circuit power, but changes are limited to a maximum of +50%. In characteristically

industrial distribution grids, a clear trend cannot be identified, since the new construction of renewable energy systems does not keep pace with that of rural regions, and because conventional generation has to be considered as no longer connected to the grid due to displacement effects. Change rates of of more than +80%, but occasionally also declinations of -40%, can be identified that lead to a more uneven geographical distribution of short circuit power.

4.5.2 Development of the minimum short circuit power

According to DIN VDE 0102, the determination of the minimum short circuit power of a grid node must neglect any short circuit current contributions from renewable energy systems connected via converters. The conclusion is that in the isolated consideration of the 110 kV sample grid, the available minimum short circuit power is 0 MVA, because no conventional generation capacity exists in the considered grid section in any of 2011 and 2033 scenarios relevant to the determination of the minimum short circuit power.

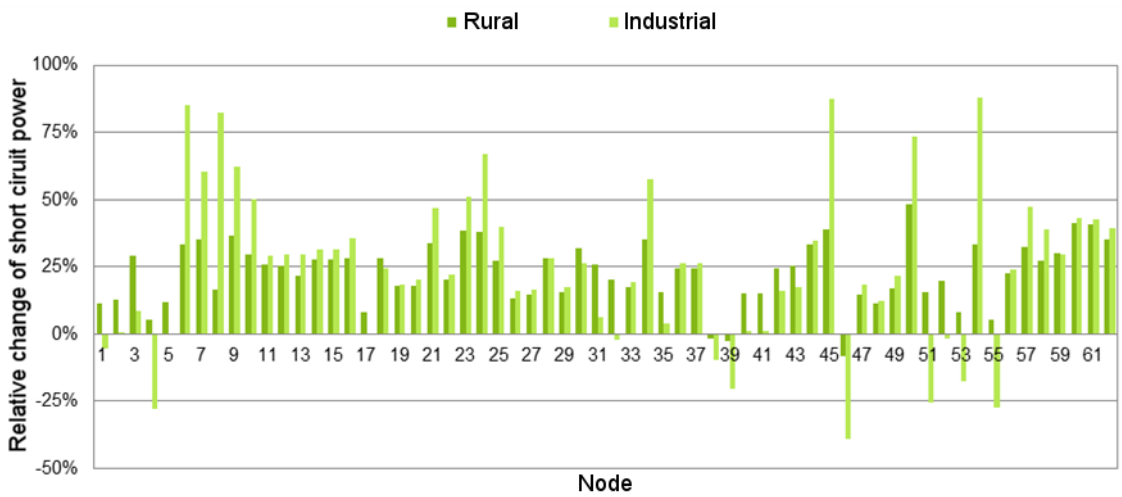

Figure 4.15 Relative change of the maximum short circuit power from 2011 to 2033 for both a rural and an industrial 110 kV sample grid

4.5.3 Cross-grid level consideration

In the following combined considerations, the 110 kV grid is considered in combination with the 380 kV transmission grid to assess the short circuit power development in the 110 kV grid and its interaction with the 380 kV grid level. In addition, one can thereby

estimate the share of short circuit power contributions from the 110 kV grid for three-phase bus bar faults on the 380 kV grid level. The development trend of short circuit power in the 110 kV grid is analysed by simulating three-phase bus bar short circuits at all 110 kV nodes in different generation situations with a constant topology. The generation situations are based on the minimum and maximum cases, and the regionalised generation mix of the 380 kV nodes with the minimum (node 7) and maximum (node 20) short circuit capacities.

The results for the predominantly rural 110 kV grid in combination with the 380 kV grid model at CP 7 are shown in Figure 4.16 for the minimum and maximum cases. The diagram shows the changes between 2011 and 2033. The largest short circuit power change is 124% in the maximum case and 121% in the minimum case relative to the respective values 2011. The highest absolute short circuit power value in the entire grid of the year 2033 will increase by 23.8% compared with 2011. The smallest absolute short circuit power remains approximately the same and is equivalent to 102% of the short circuit power in 2011. The minimum values of short circuit power of 2011 are therefore not undershot. Figure 4.17 compares the short circuit power in the minimum case both with the maximum contributions of all installed renewable energy systems, and without these systems for the years 2011 and 2033. It can be seen that the systems installed in the 110 kV grid further increases the available short circuit power. In the observed section, this increase is on average +35% in the minimum case in 2011, and +30% in the minimum case in 2033. Under current conditions, this means that the available short circuit power is supply-dependent, and is therefore to be assumed as volatile.

The results for the lower-level and predominantly industrial 110 kV grid are shown in Figure 4.18 for the minimum and maximum cases. The largest short circuit power increase is 154% in the maximum case. In the minimum case, the short circuit power drops to 61% relative to the value of 2011. The highest absolute short circuit power value throughout the entire grid in 2033 will decrease by 84% compared with the value of 2011. The smallest absolute short circuit power remains approximately the same and is equivalent to 99% of the short circuit power in 2011. The minimum values of short circuit power of 2011 are therefore not undershot.

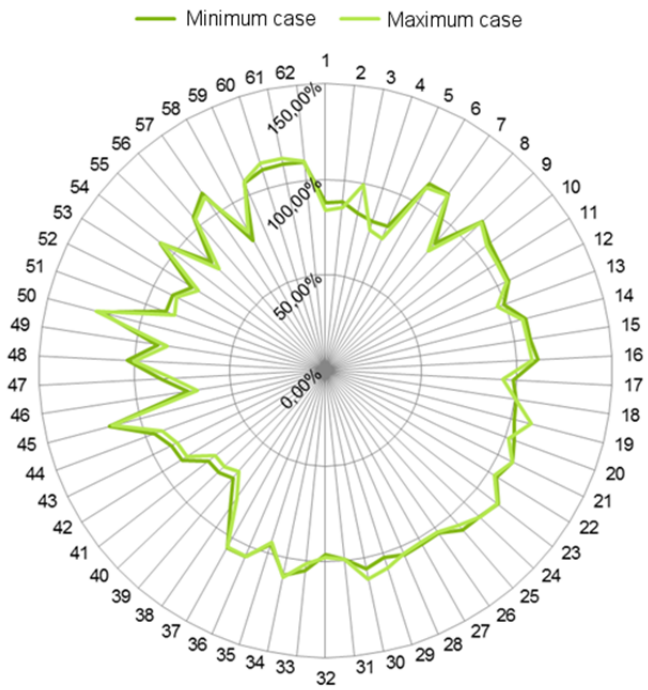

Figure 4.16 Relative changes of the short circuit power between 2011 and 2033 in the minimum and maximum case at node 7

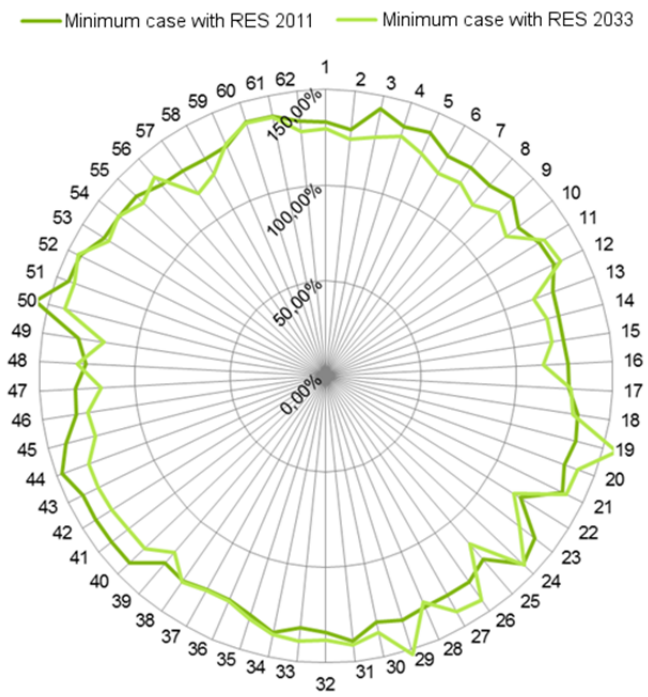

Figure 4.17 Minimum case with RES contribution, each based on the minimum case without RES for the years 2011 and 2033 at node 7

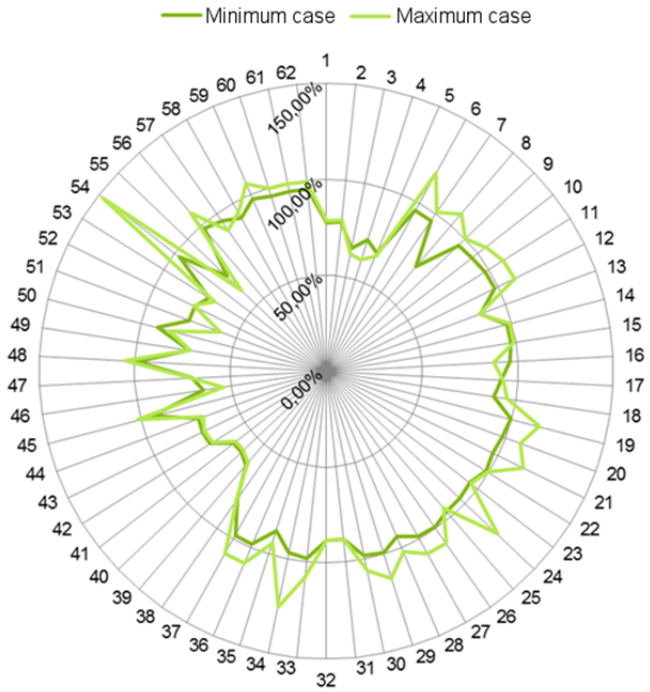

Figure 4.18 Relative changes of the short circuit power between 2011 and 2033 in the minimum and maximum case at node 20

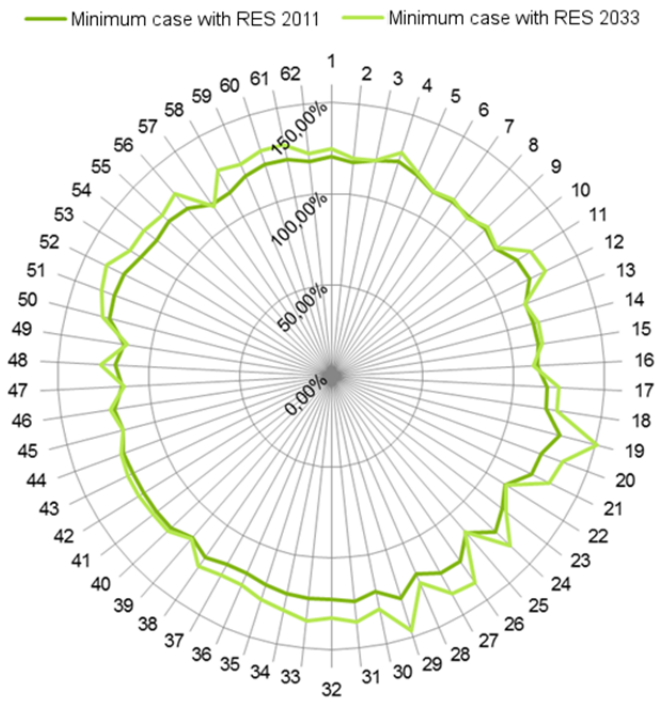

Figure 4.19 Minimum case with RES contribution, each based on the minimum case without RES for the years 2011 and 2033 at node 20

Figure 4.19 compares the short circuit power in the minimum case both with the maximum contributions of all installed renewable energy systems and without these systems for the years 2011 and 2033. It can be seen that the systems installed in the 110 kV grid further increases the available short circuit power.

4.6 Conclusion on short circuit power

The study analyses the qualitative development of the short circuit power in Germany using the specified assumptions about the development of the German and European energy system. Therefore the study cannot be used to assess isolated cases in detail, however, the tendency of changes in the short circuit power based on the current grid are correctly reproduced.

The analysis has shown that today's nodes with a very high short circuit power will retain that capacity in 2033. The short circuit power of industrial regions will continue to be far higher than that of rural areas. The weakest nodes in terms of short circuit power will continue to be the weakest in terms of available short circuit power, but will experience significant growths, by over 100% in some cases, relative to the reference year 2011. The bandwidth between the minimum and maximum short circuit power in 2033 changes only slightly versus 2011. However, significant changes are to be expected regarding the medium range of the available short circuit power bandwidth. On average, the short circuit power in Germany will tend to increase by about 20%. Overall, it should be noted that the minimum and maximum short circuit capacities already achieved in 2011 will be neither over- nor undershot in 2033.

It is striking that the available short circuit power increases in some regions, despite a reduced installed capacity. This increase cannot be explained solely by a slight increase in the short circuit power supplied from abroad. Rather, the increase originates mainly from German plants. It has been shown that this increase is plausible despite a smaller generation mix. The reduced power plant capacity in the vicinity of the fault location entails a reduction of the short circuit power immediately available for voltage support. In turn, the absence of this short circuit power entails a flattening of the grid-side potential gradient, so geographically more distant generators must make a higher short circuit power contribution. This effect is

further aggravated by grid expansion, which causes a closer grid coupling between the remaining generators, thereby shortening their electrical distance from the fault.

In sum, it could not be observed that significantly more short circuit power in Germany was provided from abroad. However, the countries of origin could change. In terms of the provision of short circuit power, this is established for 2011 and 2033. However, it remains unclear whether more or less foreign generators will be involved in the future. Due to the inadequate data regarding the regional grid and generation development of the collaborative partners, it was not possible to analyse this in the context of the present study.

The largest share of renewable energy systems is and will be installed in the 110 kV distribution grid, and not the 380 kV transmission grid. Our analysis shows that the available short circuit power is subject to heavy weather and daytime-dependent fluctuations. In an isolated calculated (without short circuit power share from the transmission grid) distribution grid variant, it was determined that market-driven situations are conceivable, in which neither conventional power plants nor generation from wind or PV were connected to the observed 110 kV distribution grid. This may be the case, for example, on a windless night. As a result, no short circuit power is reserved in the 110 kV grid level. However, in combination with the transmission grid, acceptable short circuit capacities did develop in the 110 kV distribution grids. However, an increase in short circuit power of 30-40% in 2033 was identified compared with the situation in which wind and PV systems were also in operation. The conclusion is that the short circuit power can be subject to heavy daily fluctuations and that these fluctuations depend on the installed DECU capacity. In order to control this volatility, one must consider the extent to which DECUs with converters, especially supply-dependent renewable energy systems, should stay connected to the grid at any time to provide the ancillary service of short circuit power. This study has previously shown that this would be technically possible. However, so far there is no (tariff) model of and how DECU operators should be compensated monetarily for the provision of such a ancillary service.

States in which the short-circuit power exceeds technical feasible short-circuit power capacities of primary equipment are not ex-

pected. Nevertheless, it is recommended to carry out further analyses with detailed data to adapt asset management strategies to the changing conditions, and also to examine the feedback between all voltage levels in one combined analysis. Furthermore, the impact of the change to the potential short-circuit power gradients on the protection coordination strategy of conventional protection systems must be analysed. Therefore, it must be investigated whether protection system concepts based on communication infrastructures, as presented in [146], [147], [148], [149] can continue to ensure the protection of operating resources and the stability of the energy supply system, and whether or not they provide an economic added value. Only after this investigation, it would be possible to estimate investment costs for eventual upgrading measures in the area of future protection and control systems. As discussed in the preliminary analysis, consumers such as heavy industry have special requirements to the short circuit power at their grid CP. The consideration of sites suitable for the grid connection of heavy industry facilities, or whether future restrictions might result, was not the focus of this study. A detailed analysis of this question based on selected locations is another separate research question.

In conclusion, the main recommendations for action are summarised in Table 4.4. The short-term recommendations for action are considered as necessary within the next ten years, and the long-term recommendations as necessary until the end of the review period 2033.

Table 4.4 Recommendation for action

	Recommendation for action	Motivation	Legal / technical / regulatory aspects	Economic aspects
Short-term	DECUs should consistently remain connected to the grid in order to provide short circuit power	Reduction of weather-dependent fluctuations of the short circuit power	Clarification of responsibilities and establishment of the necessary framework conditions	Financial compensation for converter losses incurred due to standby mode
	Investigation of the effects of a changed short circuit power distribution on the protection coordination strategy	Analysis of the selectivity and reliability of the employed protection concepts	Maintenance of reliable system operation	-
Long-term	Potential analysis of adaptive protection concepts and evaluation of possible expansion costs	Adaptation to frequently changing system conditions, especially volatile short circuit currents	Clarification of data protection aspects regarding data exchange	Studies must be carried out and necessary investments must be quantified

5 Grid restoration

Currently, grid restoration after a complete or large-scale black out is realised following a central concept, namely by starting black start capable large-scale power plants in the transmission grid, with these plants then forming individual stand-alone grids at the start of the grid restoration process. The transmission grid lines are gradually reconnected upon startup of the power plants. In case of partial failures, the transmission grid is restored by a gradual reconnection of transmission grid lines in the affected grid areas [31], [39]. Then an alternating incorporation of lower-level voltage levels, loads and further power plants takes place. Today's concept is based on the constant availability of black start capable power plants with a connection to the transmission grid level. Large hydroelectric power plants (especially PSPs) and gas turbines are suitable for this purpose, since startup is possible with batteries and emergency power systems.

The last large-scale system disturbance in Europe took place in November 2006 when the former UCTE grid had split into three asynchronous zones after a fault [86]. The formation of the stand-alone grids resulted from a random process after cascaded line failures due to protection tripping. Black starting power plants, however, was not required since all grid operators were able to maintain operating power plants on the transmission grid level.

5.1 Research questions

In the future, the structure of the conventional generation mix will further change. In times of high feed-in from RES, only few conventional power plants will be connected to the grid, or certain regions up to the whole of Germany might even be operated completely without conventional power plants. For these reasons, today's central grid restoration concepts have to be checked as to their applicability. As alternatives, decentralised approaches including renewable energy and storage systems are viable. Here, grid restoration would be initiated starting at the lower-level voltage levels. It is also conceivable that sub-grids decouple from the integrated grid upon an incipient blackout and recover in stand-alone

grid operation should the higher-level grid fail. Such concepts are currently only in their research phase. The problem here is the timely detection of a propagating large-scale fault up to a transmission grid failure. This results in the following research questions for the subject area of grid restoration:

- How many gas turbines are required for grid restoration?
- To what extent is grid restoration hindered or delayed by a small number of gas turbines?
- How would grid restoration take place with RES connected to the grid in these situations?
- Which technical boundary conditions are necessary, and how fast can this method ensure the re-establishment of supply?
- What effect does the geographical distribution of power plants have on grid restoration concepts?
- Can lower-level grid groups (for example, 110 kV grid group) recover in a stand-alone grid after a failure of the transmission grid? What are the technical boundary conditions in these cases?
- How can a resynchronisation of many stand-alone grids be carried out efficiently?
- How can RES participate in the regulation of stand-alone grids?
- How must the existing protection systems for stand-alone grid operation be modified?

5.2 Evaluation of current literature and studies

The current approach to grid restoration as based on centralised large-scale power plants is described in [87].

The possibilities and side constraints for the implementation of possible future decentralised approaches to grid restoration are analysed in the literature from several points of view. The VDE study "Aktive Netze im Kontext der Energiewende" (Active grids in the context of the energy transition), February 2013 [26], points to a necessary transformation of protection concepts regarding the implementation of stand-alone grid operation on the distribution grid level. In addition, solutions for grid automation in the LV and MV level are being discussed.

In Denmark, a distribution grid area (consisting of LV, MV and HV) was equipped and field-tested with mixed feed-in from wind turbines and CHP plants with stand-alone grid capability and a resynchronisation unit as part of the Cell Controller pilot project [136]. To this end, decentralised frequency and voltage stability mechanisms were established. Amongst other things, short-term stand-alone grid operation was tested with feed-in from wind turbines exclusively. Long-term stable operation with supply from wind turbines is not possible with this implementation.

In the E-Energy project called Model City of Mannheim, a virtual power plant was realised with the involvement of PV systems and micro-CHP systems. The primary focus of this project is on the development and investigation of new business models and incentives for a local balancing of loads and suppliers. An application of the system in combination with a possible stand-alone grid operation is not considered [88].

The BDEW discussion paper [89] discusses a possible partition of the central grid management concept into a number of decentralised systems in Chapter 9. This would serve to better optimise the many decentralised suppliers. However, the document highlights the fact that the decentralised systems should continue to balance via the transmission grid, and that they should not enter stand-alone grid operation mode during normal operation.

As part of the DEZENT project [90], a load and feed-in management system for lower-level voltage levels has been developed. The aim was to compensate the active power balance from the lowest voltage level and to compensate for a possible imbalance versus the overlying hierarchy level.

In the project FOR1511 (www.for1511.tu-dortmund.de), the targeted formation of stand-alone grids on the transmission grid level was pursued to avoid blackouts after fault situations, thereby preventing a more rapid propagation of the fault. Decentralised stand-alone grid formations were not considered in this project.

In summary, it can be assumed that there are very few publications on the formation of stand-alone grids in the distribution grid or on black starts with the participation of decentralised suppliers or storage systems. Rather, most publications explore decentralised compensation mechanisms on the distribution grid level, which do not provide for a separation from the transmission grid and which

were not primarily designed for grid restoration. For this reason, the research questions above are discussed as part of our own research that follows below.

5.3 Own research

5.3.1 The central concept

In this section, the applicability of the current central concept for grid restoration in 2033 is discussed.

Number of black start capable power plants

It is assumed that until 2033, there will be no significant decrease of the installed conventional power plant capacity [4], in particular gas turbines and PSPs will remain available. It is therefore likely that there will be a sufficient number of conventional power plants available for the black start capability of the entire grid. However, in situations with a long-lasting and high feed-in from renewable energy sources, conventional power plants are turned off and enter hot standby mode. The consequence is that given a grid failure, this would lead to less available conventional power plants that could recover in a potential auxiliary power stand-alone grid. Thus, the grid's black start capability will become more important in the future.

Since a black start of the grid is carried out primarily with PSPs [87], black starts will remain possible even in situations with long-lasting supply from renewable energy sources due to their availability at short notice. In addition, it can be assumed that PSPs are not in turbine operation mode in these situations, and one can therefore expect an adequate storage reservoir level. Gas turbines also involved in black starts, and partly also combined cycle power plants, have a startup time from hot standby mode of under 10 minutes [91], and can therefore also be used. Other large-scale power plants, especially coal-fired power plants, cannot be configured for black starts due to technical limitations.

The total number of required black start capable power plants will probably not change compared to today, since they depend on the grid size that is to be supplied with voltage (see geographic distribution below), and not on the lower-level feed-in or load structure. This means that the voltage-reactive power controllability must be

given first, and then the capacity must be quickly available in an adjustable manner to cover the load in the stand-alone grid that is ready to be started. Furthermore, redundancy is an important criterion in determining the minimum number of black start capable power plants. Since power plants may not be available for reasons such as maintenance work or faults, several power plants in each control area must be black start capable. In 2008 for example, four power plants were black start capable in the control area of Vattenfall Europe (now 50Hertz Transmission) [87].

Geographical distribution of power plants

Area-wide grid restoration requires an adequate geographical distribution of a sufficient number of reactive power sources. Reactive power sources from the lower-level voltage levels cannot be used for centralised grid restoration. Since it is not expected that the demand for reactive power of the idling transmission grid will change significantly by 2033, the current distribution of the necessary black start capable power plants will remain.

Inclusion of renewable energy systems in grid restoration

RES are largely connected to the distribution grids, which is why a black start with the central concept is initially carried out with conventional power plants. With the gradual addition of lower-level voltage levels when restoring the grid, it must be observed that depending on the design of the balancing measure, a large part of the suppliers in these levels will inject their currently available capacity into the grid when the grid voltage and frequency returns, and thus, depending on the weather conditions, make high demands on the compensation of the active power balance by controllable power plants. This might jeopardise grid stability during the critical grid restoration process. So far, no concept takes account of renewable energy systems for grid restoration.

To estimate the residual load, such a concept must take the current weather situation into account when selecting the grid areas to be added, because the last known feed-in status could have changed since grid disconnection. It must be checked whether the maximum feed-in of wind farms or ground-mounted solar power plants during grid restoration should be fundamentally limited, or if this value should be specified by the grid operator via a communication interface.

This leads to technical boundary conditions for RES installations in stand-alone grid operation:

- Option of throttling supply-dependent suppliers
- Participation in frequency and voltage stability, and instantaneous reserve (see Chapters 2 and 3)

Not all RES must meet these boundary conditions. The required share results from the size of the grid area to be restored and the proportion of conventional power plants and RES in this area.

Black starts with renewable energy systems

If RES are to be used for black starts, they must be generally online and specified as black start capable in the control centre of the TSO. Should these plants concern the grid of a DSO, this DSO must be considered in the information chain.

Dynamic stability studies must be conducted prior to a black start with the participation of RES. A sufficient controllability of these plants must be verified first. If it is given, detailed transient tests must be carried out to validate balancing behaviour and stability.

Grid management training

Regular training measures are necessary in order to master the complex coordination processes between the transmission grid and the distribution grids in fault situations. In particular the interaction between the grid operators must be taught.

5.3.2 Decentralised concepts for stand-alone grid operation

In this section, the future possibilities for stand-alone grid formation on the distribution grid level will be discussed. According to [26], the cellular approach is when a 110 kV grid group recovers itself in fault situations. The injected capacity is mainly provided by DECUs, provided that a sufficient feed-in capacity is available. In addition, a load and storage management system is required to ensure the power balance. The decentralised stand-alone grid can be operated more easily if it is disconnected before the blackout, thereby recovering in a stable condition.

For a decentralised stand-alone grid formation, new methods of balancing loads, storage systems, and suppliers are required due to the high number of grid areas and operating resources. In this context, there is the issue of implementing frequency and voltage control with a large number of decentralised weather-dependent

suppliers. Load intervention is required in many cases, since it is expected that the available capacity of RES will be lower than the load in many cases throughout the year, and that the storage system share will not be high enough to ensure that all loads are accommodated.

Minimum stand-alone grid size

Possible grid sizes could be sections of electrically isolated grid areas of a single or multiple voltage levels interconnected by transformers. The active power balance must be ensured in order to ensure a reliable stand-alone grid operation. The smaller the stand-alone grid area, the lower the compensation effects of stochastic suppliers/loads. This results in higher demands on active power control. Moreover, it is not possible to separate suppliers from loads in the MV and LV level, at least not with reasonable effort. At first, only suppliers provide for grid voltage and only then are the loads gradually connected. This behaviour must be taken into account in grid restoration concepts of these voltage levels.

Stand-alone grid size versus cost-benefit ratio

A significant amount of effort (installations, remote control technology, personnel, synchroniser equipment, emergency power systems) is necessary to enable decentralised stand-alone grid operation. The smaller the stand-alone grid, the higher the specific effort. In particular, the resynchronisations of many smaller grid areas is very time and labour-consuming, or would require a yet to be developed automated synchronisation method. To lower this effort to an acceptable level, it would be conceivable to operate individual HV grid areas or HV grid groups as stand-alone grids and to carry out resynchronisations via the transmission grid level. If there are multiple CPs between HV and EHV, resynchronisation is gradual. Decentralised stand-alone grids on the MV and LV level are generally not recommended.

In the past, stand-alone grids of the size of a city have proven to be technically manageable. In Germany, especially the former grid of West Berlin can be highlighted as an example. It is to be noted, however, that feed-in in the case of the West Berlin grid was based mainly on quickly controllable conventional power plants.

Technical boundary conditions for decentralised stand-alone grid operation

It must be ensured that a sufficient number of DECUs or storage systems are available for voltage stability and frequency control in the decentralised stand-alone grids. Not all existing plants are technically capable of participating in voltage and frequency control. The smaller the grid area of the stand-alone grid, the greater the necessary involvement of decentralised suppliers or storage systems for stand-alone grid control (see Chapter 2 and 3).

Interaction with protection

In stand-alone grid operation, there are different boundary conditions with respect to the short circuit power that the protection system must be designed for, in order for it to safely detect and react to faults while being in stand-alone grid operation mode. In reducing the short circuit power in stand-alone grid operation, more complex protection systems must be installed, for example differential protection systems. At the same time, the protection system may not overreact to highly volatile processes during restoration or stand-alone grid operation.

Power gradients

The geographic size of the stand-alone grid area that must be supplied has an impact on the load and supply behaviour of the grid area. The smaller the area that is to be operated as a stand-alone grid, the lower the stochastic compensation effects of load and feed-in fluctuations, and the greater the occurring power gradients [30]. The frequency control equipment of the stand-alone grid must be able to cope with the corresponding power gradients.

Active load and feed-in management

The suppliers of a stand-alone grid can consist of supply-dependent RES to a significant proportion. In order to stay within the permissible frequency band during supply fluctuations, an active load, storage system and feed-in management system must be introduced, otherwise a very coarsely graduated response to the loads by means of frequency-dependent load shedding would be the result. It would also lead to a simultaneous drop of suppliers, which in turn would result in a reduction of the maximally coverable load [49]. Relevant literature offers solutions, but they were designed for fault-free operation. [90] describes a coordination method based on decentralised marketplaces that utilises the de-

grees of freedom of controllable loads and suppliers to reach a real-time, i.e. in the order of seconds, balance between load and suppliers at the lowest possible grid level. If this succeeds only in part, an attempt is made to gradually compensate for the residual power imbalance in the superordinate grid level. The compensation of power fluctuations takes place while keeping to grid restrictions, so that a higher utilisation of the existing grid structure can be achieved.

Automated resynchronisation

In order to keep the specific effort for stand-alone grid operation, given relatively small stand-alone grids, within reasonable limits (see topic of "Stand-alone grid size versus cost-benefit ratio"), automatic synchronisation devices are required for grid restoration [30]. As soon as several small grid areas merge to form a larger grid area, load and feed-in management must be adjusted accordingly to exploit the synergistic effects resulting from the larger grid area. For this purpose, a communication infrastructure is required that is not currently common in the MV and LV levels.

Stand-alone grid detection

Decentralised suppliers must be able to distinguish between a desired stand-alone grid operation and maintenance-related shutdowns [26], [32]. Otherwise, maintenance work could result in decentralised suppliers accidentally impressing a voltage. The occupational safety of the technical staff cannot be guaranteed in this case.

5.3.3 Decentralised concepts for black starts

Where decentralised concepts for stand-alone grid formation are available (see previous section), an optional black start capability can also be implemented. This system would be designed to complement black starts from within the transmission grid level to allow for a faster resupply of loads in fault situations. However, considerable technical effort is expected, particularly with setting up the black start capability on the lower voltage levels. In addition, due to the rare need for black starts, no gain in efficiency by employing DECUs rather than centralised gas-fired power plants is expected.

Required retrofitting in the HV level

A black start in the HV level would be implemented by retrofitting existing gas turbines or large wind farms with the appropriate batteries and emergency power systems. In addition, an adjustment of the wind turbines' converter programming is required to impress a voltage. Depending on the grid area, only a small number of black start capable suppliers are required. The additional effort to set up the black start capability is manageable given an existing stand-alone grid operation.

Required retrofitting in the MV level

In the MV level, black starts would be implemented especially via wind turbines, or locally connected ground-mounted solar power systems, and with storage systems where present. This is only possible in situations with sufficient wind or sunlight. A portion of the existing wind turbines must be equipped with batteries to allow for rotation of the nacelle or pitching of the rotor blades for black starts, and to provide exciting voltage for the rotor if not permanently excited. In addition, these wind turbines require a reprogramming of their converters, analogous to the HV level. With these turbines, it would be possible to apply a voltage to the surrounding grid area. The necessary share of black start capable plants is determined by the local grid topology. All other decentralised suppliers must then be restarted after grid voltage returns. The load management system (see Stand-alone grids) must disconnect all loads from the grid in the event of a blackout, and gradually reconnect the suppliers along with a successive reconnection of loads. With a sole reliance on regenerative systems, a further failure of the grid due to low or no feed-in from RES is possible. Biomass and hydroelectric plants have the ability to store

power and are therefore suitable for controllable active power feed-in.

Required retrofitting in the LV level

In the LV level, mostly PV systems and loads are connected that cannot be separated circuitry-wise. Load and feed-in management should thus start with each individual household and supplier, in order to ensure a correct active power balance in advance. In addition to PV systems, storage systems would have to be installed in the LV level to prevent a new blackout due to a reduction in PV feed-in in the evening hours.

Compensating currents when connecting DECUs

After starting a supplier, high compensating currents can occur when switching to a de-energised grid area. For this reason, individual simulations must be carried out in advance for review purposes. Due to the high number of required black start capable decentralised suppliers, this is a considerable effort. For the future, it will be important to examine to what extent certain recurrent grid situations can be summarised and how characteristics for a rapid assessment of compensating currents after switching operations can be derived along with behaviour of the protective devices.

5.4 Conclusion for grid restoration

The generation mix of 2033 is expected to have a relatively high share of gas-fired power plants [4]. It is assumed that gas-turbines that can be rapidly started from hot standby mode will be part of this share. With these power plants and the PSPs, an emergency operation of the 380 kV grid is possible in order to resupply lower-level voltage levels, thus including centralised feed-in in the grid restoration concept.

Generally, there will be no insurmountable barriers to grid restoration leading up to the year 2033. In order to consider a large number of RES in the future when restoring the grid, it is necessary to carry out slight throttling based on the weather situation to reconnect the plants, as to avoid uncontrollable frequency jumps during reconnection. In addition, further requirements for grid restoration with RES are the participation of these systems in frequency and voltage control, and in the provision of instantaneous reserve. Compared with today, a more elaborate coordination process be-

tween TSOs and DSOs will be required, which must be implemented soon by creating suitable interface definitions in the short term. Training for grid restoration must include the DSO in addition to the TSO. New methods are also soon required to estimate the condition of the decentralised suppliers at the time of reconnection. In addition, due to the constant changes to the number, capacity and location of the decentralised suppliers, a regular verification of black start capability is required taking into account the above-mentioned boundary conditions.

The introduction of grid restoration on the basis of decentralised stand-alone/micro-grids is not recommended due to the extreme technical complexity and the associated installation costs, as this approach would only be pursued in addition to conventional grid restoration. Since a black start is rarely carried out, the gain in efficiency through the use of supply-dependent suppliers instead of gas-fired power plants is negligible.

In conclusion, the main recommendations for action are summarised in Table 5.1. The short-term recommendations for action are considered as necessary within the next ten years, and the long-term recommendations as necessary until the end of the review period 2033.

Table 5.1 Recommendations for action for future grid restoration

	Recommended action	Motivation	Legal / technical / regulatory aspects	Economic aspects
Short-term	Improvement of current state detection of RES Improvement of cooperation between TSO and DSO	Prevention of instabilities during grid restoration with decentralised suppliers	Creation of the necessary framework conditions Interface definition between TSO and DSO required	
Long-term	Participation of RES in frequency and voltage control as well as instantaneous reserve	Supportive effect of RES required for grid restoration	See chapters on frequency control and voltage stability	Micro-grids not economic

6 System control

As part of system control, which is another ancillary service, the grid operators have to continuously monitor and control the grid and all connected loads and generation units to limit the impact of faults as well as to ensure operational safety during maintenance activities, conversions or new constructions. Tasks of the TSOs include the organisation of CR deployment for frequency control, the control of reactive power use for voltage stability in the transmission grid, the introduction of congestion management measures in their grids, and grid restoration after faults [39]. Today, DSOs are responsible, amongst other things, for voltage stability and grid restoration of their grids, and are obliged to support the activities of the TSOs [38].

With the increasing integration of volatile RES, primarily at the distribution grid level, and the planned hybrid structure of the transmission grid comprising alternating current and direct current, and the increasingly multi-regional exchange of energy in the European electricity market, the requirements to future system control are growing. Primarily, the complexity must be controlled - from a technical viewpoint, and under German as well as European market conditions - that results from a large number of DECUs with their high total capacity and mostly uncertain supply-dependent generation, increasing DSM-capable controllable consumption and new storage technologies. This requires a further development of today's existing concepts, methods and analytical tools of system control [40]. The altered interaction between the distribution grids, in which the major part of the DECUs, loads, and future storage systems are connected, and the transmission system must be considered in particular. Beyond that, the transnational European dimension especially of congestion management is of great importance in order to avoid market restrictions and to allow for a large-scale compensation of renewable energy systems. Otherwise, the economic potential in the European electricity market and the potential of renewable energy systems would not be fully exploited, since throttling renewable energy suppliers due to congestions would require a more expensive power plant deployment than in the uncongested case.

The following sections discuss the changing problem areas of system control.

Adapting operational concepts

Due to the changing demands on system control an adaption of operational concepts, organisational responsibilities and operational tasks is required, in particular between grid levels, and rearranged where necessary. Although the assignment of responsibilities for ancillary services to grid operators of given grid levels is unambiguous, e.g. TSOs for frequency regulation, or TSOs and DSOs for voltage stability in their respective grid levels, the mutual support and provision of ancillary services between grids of the same level, or lower-level grids, will increase. To manage this complexity, care should be taken to ensure that processes are distributed, but mutually coordinated [48]. This has to be considered for mechanisms between TSOs, but also between TSOs and DSOs. The use of central processes (e.g. optimisation of the overall system) can exploit additional potential of operational planning [49]. For online system control, distributed processes offer the advantages of shorter reaction times [50][51], more robustness regarding missing data, and a rapid adaptation to unforeseen grid conditions [51].

In some areas, regional security service centres such as CORESO, TSC and SSC already act as service providers supporting coordinated operational planning processes [52][53]. This raises the question as to whether the regional security centres proposed in [26], which must carry out system control tasks in addition to the grid operators, should actually carry out tasks that might as well be distributed within the existing structure.

Furthermore, it is important to analyse the extent to which large-scale fault and grid restoration concepts must be adapted to new conditions (see Chapter 5).

Further development of existing grid analysis functions

Grid models and grid analysis programs are used to assess grid conditions in control systems to ensure the continuous monitoring of grid security and grid stability. Existing grid models must be advanced and expanded by newly planned system components in the EHV level, such as HVDC transmission, capacitor banks, FACTS devices and reactive power supply from the distribution grid, and in the HV and MV levels by DECUs, storage systems and

FACTS devices [42][40]. To check frequency and voltage stability during online operation, it may be necessary in the future to employ dynamic models of the grid (for example, controllability of grid components), and of generation, load and storage units [40][46]. Further details go beyond the scope of the present study and should be examined separately.

In particular, an increase in the forecast accuracy of loads and renewable energy systems is useful and necessary in order to identify grid congestions and to evaluate redispatch measures at an early stage in the framework of load flow forecasts [40][53]. One goal here is to identify deviations from day-ahead forecast in time by means of short-term forecasts in the intraday range. Measurement data from reference plants are to be included as important additional information.

Given closer knowledge of the uncertainties and with mutual correlations, probabilistic calculations and risk analyses in the operational planning process can help assess the robustness of the admissibility of a certain grid state and the impact of uncertainties on grid security [45].

Coordination between grid operation and feed-in

With an increasing grid load on all levels, measures for intervening in feed-in, DECUs, storage systems and possibly also loads are required to stabilise the grid and resolve congestions [43][47][52]. Due to the disentanglement of generation, loads and grids, grid operators can intervene only indirectly via special redispatch products or market interventions in accordance with § 13 of the Energy Industry Act (EnWG). In addition to interventions in the conventional generation mix via redispatch measures, interventions in renewable energy systems are also provided for. Load interventions in accordance with § 14a EnWG represent a new way to stabilise the operation of the grid. These measures are now largely regarded as emergency measures for exceptional circumstances and do not relieve the grid operator from its duty to expand the grid in a way that would make these measures obsolete in the long term.

It turns out, however, that feed-in peaks, as rarely caused by RES, entail extensive grid expansion measures [2]. In the future, therefore, this will raise the question as to whether time-limited intervention options which are economically sensible must be regularly

admissible in order to reduce the demand for grid expansion [43]. These measures would have to be established as "normal processes" by appropriate amendments to the legal and regulatory framework.

Overall, intervention options must be integrated into system control so that stabilisation measures via feed-in and load interventions during overload and fault situations can take place quickly, without discrimination and in a technically and economically efficient way.

Active grid control in the transmission grid

In addition to intervention on the feed-in and load sides, additional control options are being introduced into the grids. In the integrated European grid, phase angle regulating transformers are used to shift load flows. In addition, HVDC transmission lines with a controllable active power transmission and reactive power provision, as well as controlled reactive power sources for voltage control that is independent of power plants are set up. All these controllable elements, some of which operate in the grid by means of power electronics (FACTS devices), must be coordinated [52]. Depending on the impact of balancing interventions across balancing zones, this coordination should not only be automated in operational planning, but also in short-term intervals during operation, especially after system changes or faults. The benefits can be optimised if the automated control options are already considered in operational planning and grid security calculations [44][54]. Given an increasingly automated active grid control, it is of particular importance to determine the dynamic system behaviour in fault cases, including component protection and system protection concepts (Dynamic Security Assessment, DSA; Special Protection Schemes, SPS) [46].

In particular fast grid controls are able to respond differently to different grid situations. Appropriate automated mechanisms and modes of action must be designed and are a topic of current research [51][55]. Especially the robustness of measures and controller interventions across balancing zones and national borders must be guaranteed to avoid human error that could put the system at risk [48]. With the increasing number of cross regulators, and no later than with the integration of HVDC transmission, these automated coordination mechanisms are necessary.

Monitoring of the distribution grid

Due to the increasing number of DECUs and storage systems mainly connected to the distribution grids, demand for ICT to manage these grids increases. Grid state detection is required to identify critical situations, which is currently hindered by an inadequate coverage of the distribution grids by measurement technology. Therefore, it must be analysed whether a comprehensive measurement infrastructure in the MV and LV grid must be established to gather information on operating resource loads, suppliers, loads and voltage conditions, thus being able to detect bottlenecks and limit violations [29]. It must be examined to what extent and to which degree such an infrastructure is a prerequisite for the provision of ancillary services, particularly for voltage and frequency control (Chapter 3 and Chapter 2), and where applicable also for black starts, stand-alone grid operation and grid restoration (Chapter 5) in connection with the distribution grid.

Inclusion of the distribution grid in active grid control

On the basis of comprehensive monitoring in the distribution grid, it must be investigated whether and to what extent the HV, MV and LV grids are to be included in active grid control in the sense of providing ancillary services or for redispatch. By controlling variable transformers, power electronic grid controllers and compensation equipment (FACTS devices) and by providing control information for storage systems, controllable loads and suppliers, critical system states are mitigated or eliminated in the distribution grid levels and in the transmission grid.

In this context, the interface between the smart grid and smart market mechanisms must be taken into account [78]. The mechanisms of data and control access to customer facilities such as DECUs, storage systems and loads must be clearly defined for grid control purposes. Legal and regulatory amendments are required depending on how far such interventions go beyond the current regulatory requirements for interventions by grid operators in fault situations.

Data and information exchange between grid operators

To carry out system control tasks that will become more complicated in the future, it is necessary to expand on and standardise the data and information exchange between grid operators. In addition to the vertical exchange between TSOs and DSOs, and low-

er and higher-level DSOs, an increased horizontal exchange between neighbouring TSOs must take place to ensure grid security even across regions. Cooperation of European TSOs is essential and is already being improved by an increasingly large-scale exchange of system data and measurement values between the central control rooms [53].

In addition, a Europe-wide real-time information system (Awareness System [79]) was constructed, which offers an overview of the current system state of the entire European grid area. This type of information provision does not necessarily imply a central decision-making body or central responsibility, but only that appropriate higher-level system information is provided in real-time [48]. It is necessary to examine which further technical and organisational measures must be implemented for extensive data and information exchange between the grid operators of one grid level, and between grid levels.

Information and communications infrastructure

The technical measures for a vertical exchange of information between TSOs and DSOs, and for a horizontal exchange between TSOs, includes an appropriate ICT infrastructure. Specific ICT solutions such as found in the control systems of the TSOs and in the HV level of the DSOs meet the requirements to safety and reliability. Cost-effective standard solutions must be designed for ICT solutions reaching into the areas of the DSOs and customer facilities such as DECUs and storage systems. To what extent they can be derived from standard ICT and automation technology must first be examined. Dependencies between critical infrastructures such as energy supply and ICT systems are always to be considered and checked. Security of data and information are relevant aspects that must be assessed as well.

Impact on the protection technology

The distributed integration of DECUs and storage systems inevitably also affects the configuration of the protection technology of the grids. The conventional vertical load flow structure (top-down) has already often been replaced by a direction-variable structure. Accordingly, adjustments to direction-dependent protection relays, as they are often used in distribution grids, are necessary. Furthermore, volatility of the available short circuit power it is to be expected, which also has implications for the reliability of the excita-

tion of protection relays (see Chapter 4). In addition, the probability of operating resource overloads increases due to the higher demand for the transmission of electric power, which is caused by the often increased distance between load and generation.

The higher load on operating resources and the increasing transmission distance between feed-in and consumption increases the risk of cascading failures. The more frequent necessary interventions on the part of grid management [27] also increase the likelihood of unfavourable manual interventions and of the resulting unforeseeable disturbances. For this reason, system protection concepts are required that detect overloads at an early stage and correct them automatically or assist the grid operators in doing so. Progress in the field of wide-area measurement technology and communication allow for the use of wide-area monitoring, control and protection applications, taking into account delays in data transmission and data loss [28].

It must be examined in detail to what extent the provision of ancillary services by DECUs or storage systems has an effect on component and system protection in electrical grids, and to what extent these ancillary services must be integrated into a coordinated system protection concept to maintain or improve system stability.

Earthing concepts or neutral point treatments are related to the issue of protection concepts. Decentralised suppliers and their behaviour in the grid, as well as systems for reactive power compensation, make it increasingly difficult to operate compensated grids. The phase-symmetrising properties of power electronics components in DECUs or storage systems, or FACTS devices used for compensation and grid control, require customised protection concepts.

6.1 Research questions

The demands on future system control are rising due to the enormous structural changes in the entire energy supply system. The individual problem areas were identified during the preliminary analysis. The following research questions are derived from this analysis:

- What would a system architecture from the perspective of the system control of individual grid levels look like that in-

tegrates ancillary services provided by DECUs or storage systems taking into account the communication and measurement infrastructure and the sequence of operations? How do prequalification, activation and offered products for ancillary service provision change in this context?

- To what extent do organisational responsibilities and operational functions have to be reorganised between grid levels? Do new facilities/organisational units have to be created that take over (cross-) regional system control?
- Do dynamic models of grids and of generation, load and storage units have to be used in future control systems in order to monitor the frequency and voltage stability during online operation, and to allow for offline dynamic security analyses of fault situations, including the characteristics of protection systems?
- How must intervention options be integrated into system control, so that stabilisation measures via feed-in and load interventions during overload and fault situations can take place quickly, without discrimination and in a technically and economically efficient way? What is the nature of the interaction and the interface between smart grid and smart market mechanisms?
- Is a comprehensive measurement infrastructure in the MV and LV grids required for the provision of ancillary services from the distribution grid, and which ICT technologies are suitable? Which distribution grid levels are to be involved in active grid control?
- Which technical and organisational measures for an extensive vertical and horizontal data and information exchange need to be implemented?
- What impact does the provision of ancillary services by DECUs and storage systems have on component and system protection, and earthing concepts in electrical grids?
- To what extent must DECUs and storage systems be integrated into a coordinated system protection concept?

6.2 Evaluation of current literature and studies

As of today after the liberalisation of the energy market, system operators normally do control loads and generation, but intervene indirectly via grid-related or market-related measures in accordance with § 13 (1) of the Energy Industry Act. Recently, load inter-

ventions in LV grids have become permissible in accordance with § 14 EnWG. As determined by today's body of regulations, TSO/DSO interventions are limited to situations that pose a risk to system security and must never serve economic or technical system optimisation purposes. For future ancillary services, the interplay between grid, loads, suppliers and storage systems will become more important to normal operation as well.

In the course of this study, smart grids and smart markets are distinguished as per [78]. Technologies used in the grid can be considered as belonging to smart grids, and the leverage of feed-in and load shifting flexibility options for the balancing of RES as belonging to the area of smart markets. The utilisation of market actors such as DECUs, storage systems and loads for the provision of ancillary services, including grid relief, stands between smart grids and smart markets and links the two areas.

Acatech summarise their recommendations for future grids in [80]. Here, smart grids are primarily for the control of DECUs, storage systems and loads for the compensation of fluctuations of renewable energy systems, since the provision of reserve capacity is considered the primary unsolved problem. Thus, the mechanisms described here largely correspond to those used to provide flexibility options and ancillary services from the distribution grids. The following is stated: "A successful energy transition requires that the operators of electrical distribution grids play an active, creative and innovative role in the introduction of the smart grid." The necessary ICT-related aspects through to data protection and information security are mentioned. Acatech's view shows that smart market and smart grid applications are merging, and will be closely linked in the future.

Further details on future ICT can be found in [81]. For the system architecture, a closed system level, an ICT infrastructure level and an open system level are defined. The closed system level corresponds to the classical central energy supply, including the conventional control system. The open system level with DECUs, storage systems and customers, i.e. smart market actors, are linked via the ICT level and interact through this level with the control system. This ICT level serves smart market and smart grid applications and is the core of future developments. The study [82] includes many details on the development paths of this necessary

ICT infrastructure. The developments of control systems, grid automation and grid controls that will determine future system control are outlined. Overall, it is evident that development is not characterised by a universal control system architecture down to the lower distribution grid levels, but that standardised ICT solutions enable the smart market functions regardless of the conventional control system.

The BDEW roadmap [83] specifies how the infrastructure should develop with respect to sensor technology, smart metering systems, grid automation and the energy information grid. In particular, an energy information system between the market and the grid is required with the end customer as a shared infrastructure. The interface between smart grids and smart markets is again required in order for the system control of the grid to provide ancillary services together with smart market actors, or to purchase these services from them. Since this interface lies almost exclusively within the distribution grid, the DSO has the responsibility for coordination, activation or application. Again, it is clear that the specifications for the energy information system must be based on standard ICT solutions in order to find cost-effective and large-scale application.

The traffic light model outlined in the roadmap assumes that future grids will not be designed for any rare condition possible, but that grid operators regularly have the option to intervene in the market area (smart market), thus helping reduce grid investments while maintaining operational security. During the "amber light phase", interventions are implemented through market incentives, and during the "red light phase" by immediate emergency measures. The implementation of these mechanisms requires clear rules and must be largely automated. The system control of distribution grids will change fundamentally as a result.

Based on the ICT in this environment, the Fraunhofer ESK [84] study confirms a medium to high availability, Internet/IP technologies and client-server architectures as the technological foundation. This points to a clear trend towards standard IC technologies.

General trends were already identified in 2010 by the DKE standardisation roadmap [85], in which the fields of action were specified, followed by a closer look at communication down to the household level and electromobility. It is made clear that the ICT

must range from the grid to the end customer, in order to achieve the future goals of the overall system.

In addition to the points just mentioned, the current VDE study [26] states: "With the formation of self-balancing and ancillary service-generating smart supply cells, the cellular approach is suitable to reduce the complexity of system control." Partitioning the energy supply system into individually balanced cells would dramatically change system control. This would open the opportunity to retrieve ancillary services for the grid from specific areas, and to avoid grid restrictions in certain areas. This balanced organisation must not be confused with self-sufficient cells, however, since this would require more extensive control mechanisms to stabilise the individual cells. The potential for renewable energy supply is also spatially distributed in a way that there are always cells with a balance excess and deficit, so large-scale exchanges between the cells are required. Possibly, the cells can locally compensate for a certain level of volatility, so a more even and predictable behaviour would result vis-à-vis the higher-level grid levels, thereby facilitating the operation of the higher grid levels.

In the area of coordinated system control between TSOs in continent-wide integrated systems, there have been two EU projects with conflicting approaches. The ICOEUR (www.icoeur.eu) project explored distributed state monitoring concepts in the steady-state dynamic area, and system protection and power control methods [48]. In contrast, the PEGASE (www.fp7-pegase.eu) project explored new methods for state monitoring and operational planning of transcontinental grids, with predominantly central approaches being investigated. As a result of the projects, it is shown that an increased exchange of information between TSOs is essential, however, distributed approaches and responsibilities are still possible and lead to similarly good results as with central approaches if a sufficient amount of clearly defined information is exchanged between the balancing zones.

In summary, it can be assumed that according to the evaluated literature, expanded smart market mechanisms, i.e. targeted interventions in DECUs, storage systems and loads, can be used to provide and activate ancillary services down to the distribution grid level in the future via standardised ICT. In addition, market interventions and redispatch will also be accepted to a certain extent to

design grids more efficiently. To this end, grid monitoring and controllability are increasing on all grid levels to ensure system security even in a grid infrastructure with lower reserves.

6.3 Own research

Based on the analysis of the relevant literature and according to the experience gained from our own studies and projects, future system control, as shown below, can be outlined.

6.3.1 System control and ancillary services in and from the distribution grid

Starting at the lowest level, there are DECUs, controllable loads and future storage systems acting in the market (smart market), and they are subject to ICT-based management supplemented by billing functions (smart metering). The ICT architecture used here is based on standard mechanisms of the ICT sector such as the Internet or cloud technologies to achieve cost-effective solutions. The DSO accesses existing data in these systems, determines grid states with that data and creates and provides control signals for the activation of ancillary services by the active components. The DSO may even be a service provider for the operation of this data exchange platform, or possibly act as a service provider supporting the provision of these ancillary services.

In particular with activation from distributed systems of the MV and LV level, it must be assumed that only a limited reaction probability is given, since it is not possible for all systems or grid customers to be contacted or to respond due to the simplified ICT. This means that the probability of activation must be considered in the methodology of the ancillary services, since it cannot be expected that all potentially addressable grid customers will react to control signals.

For future system control, the grid state at the lower distribution grid levels is estimated using various data. One part of that data is the above-mentioned system data that is linked together with other information such as plant master data, weather data, etc., but also individual measured values, to form overall information on the grid's state. Given a limit violation risk that is detected early enough, market-based incentive signals are sent to the customers

to change their behaviour in a targeted manner (see "amber light phase", BDEW roadmap [83]). The incentive signals mean that remuneration for the grid-induced up- or downregulation of customer facilities (DECUs, load, storage systems) is offered. Since these mechanisms are subject to certain market cycles and times, preventive action is required, or at least the preventive provision of required flexibility options must be agreed upon.

Given acute limit violations (see "red light phase"), control signals are mandatory in order to up- or downregulate plants in individual grid areas. Due to the diversification of the distribution grids, this mechanism must be automatic, and take place in a coordinated manner for the respective grid areas. Logics and intervention mechanisms must be defined preventively to then be activated to correct limit violations.

Figure 6.1 outlines the contexts of future coordination between grid and decentralised systems such as DECUs, storage systems and loads.

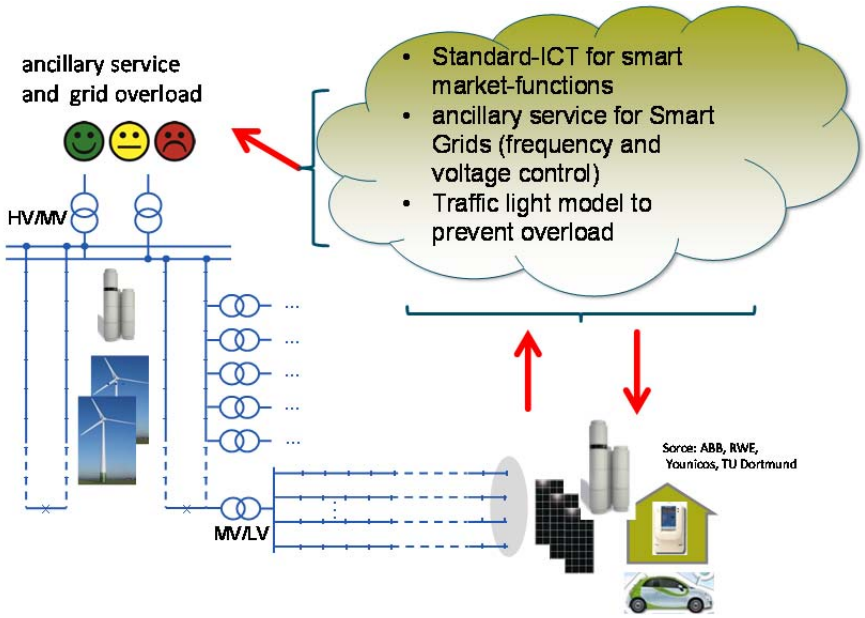

Figure 6.1 Draft of the coordination between decentralised plants and the grid for the provision of ancillary services

Such mechanisms are currently in the research and development phase, and will be implemented by way of example in individual projects. The exact design of the ICT infrastructure is not yet decided, which is a hindrance to the further spread of these mechanisms.

The described ICT access paths and mechanisms are a prerequisite for the provision of ancillary services for frequency and voltage stability from lower grid levels as described in the previous chapters, but also for grid restoration as described later. Due to limited reaction times, only voltage and reactive power target values, and the activation of MR can be transmitted. Today's requirements for the SBP would require faster response times than can be guaranteed by such an ICT system today. To what extent this is reliably possible in the future depends on the further technological development.

When activating ancillary services for voltage and frequency control, probabilistic behaviour as described above is expected, and respective default settings, for example of voltage target values, should be provided in case of ICT pathway failures.

Faster mechanisms such as the provision of primary control reserve and instantaneous reserve must be provided and implemented in a decentralised manner in the plants regardless of the described concept.

Based on knowledge of the estimated system state of the LV and MV grids, the DSO can predict the behaviour and forecast the ability to provide ancillary services in these grids. Information on lower-level control potentials and any limit violations during operation are processed in the HV level control systems of the distribution grid. The DSO coordinates the control potential for the provision of ancillary services taking into account the grid state for its own grid area and vis-à-vis the TSO. From the perspective of the TSO, a state defined within certain limits and a potential for the provision of ancillary services can be achieved in a transfer point to the distribution grid.

It must be noted that the specification of ICT systems for smart market mechanisms must take the conditions for coordination with system control and the provision of ancillary services into account. Ultimately, it is only efficient to implement a shared ICT system for the control of DECUs, storage systems and loads that meets the shared requirements for smart market mechanisms and for the provision of ancillary services. It can be assumed that such systems will be developed and standardised over the coming years, and that they will be available for the provision of ancillary services by 2033. The connection of larger DECUs such as wind farms or

solar power plants can take place via conventional control systems. To connect smaller plants distributed in a given area, however, the mechanisms described are necessary to exploit their potential for the provision of ancillary services.

The role of DSOs in this context may be that of service providers for the aggregation of data and information, or the operation of a data hub that then comprises the interface to the TSO.

6.3.2 System control with probabilistic grid expansion planning

The described system control mechanisms in the sense of the traffic light model assume that, to a certain degree, grid restrictions also occur during normal operation. It is therefore assumed that not all DECU feed-in and (controllable) load and storage situations can be covered without grid restrictions. For certain - especially unlikely - power flow situations, the occurrence of grid restrictions can be tolerated provided response options exist for these situations. This approach is relevant for grid expansion planning, operational planning and system control. In terms of grid expansion, for example, grid expansion costs can be reduced if intervention in generation and load is permissible for the rare (n-1) cases. A national economic optimum must be found between grid expansion and market interventions. Analogously, power flow situations can be permitted in operational planning that would temporarily result in grid restrictions if an improbable state of the system occurs, provided that there are sufficient fast response options available. This allows for cost-effective generation configurations or configurations with a higher share of RES, for example [44]. In this context, it is important that the described control mechanisms of system control are available in a timely manner and in sufficient quantities to stabilise critical grid conditions. It must therefore be ensured during operational planning, and afterwards continuously and preventively, that these measures can be activated reliably and that they are available to ensure a reliable operation of the grids. This type of grid planning design and a correspondingly adapted grid operation must be carefully matched; only combined do they lead to the desired grid optimisation along with the simultaneous operational security.

In considering such intervention or redispatch mechanisms, grid levels must be clearly distinguished. While the grids are not (n-1)-secure in the MV and LV levels regarding DECU feed-in, measures such as downregulating DECUs must be taken during grid faults either way to secure operation. The optimised grid design in accordance with the occurrence probabilities of critical states would only expand on these mechanisms, but not fundamentally change them. However, more DECUs could then be connected to existing grids.

Even in the HV level, grids that experience extensive expansion by means of DECUs [2] are partly not operated in an (n-1)-secure manner in terms of DECU feed-in. Rare (n-1) cases in which rare and extreme weather conditions cause major load peaks do automatically entail grid expansion if system control disposes of appropriate intervention mechanisms to stabilise the grid in these very rare extreme situations. The grid situation of all (n-1) cases must be automatically analysed from the perspective of the system control of a 110 kV grid group, so that the optimal up- and downregulation of feed-in can be preventively calculated for each (n-1) case. If such an (n-1) case occurs, it is possible to specifically intervene in lower-level feed-in via the described mechanism. Owing to the fact that there are mostly thermal restrictions in the 110 kV level, relatively long periods of tens of seconds to several minutes may pass until countermeasures are taken. Accordingly, the reaction of the protection systems must be adapted to avoid sequential tripping. Under certain circumstances, such an intervention in feed-in triggers a control reserve activation, which the affected grid area cannot offer at the same time. Such measures are established manually in system control due to the extensive addition of DECUs in some of today's HV grids. Table 6.1 schematically summarises this mechanism.

Table 6.1 Mechanism for preventive / corrective avoidance of grid overloads

Cases	Preventively plan measures	Activate measures
n-0		
1. (n-1) case 2. (n-1) case ...	Optimise and preventively reserve measures for each case: - RES throttling - Redispatch - Power flow control	activate **preventively** or **correctively**, activate fast enough upon fault/overload
n-2		Reserve leeway for emergency

The tasks in the coming years are the implementation of automated calculation mechanisms in the control rooms as well as the determination of the economic optimum between grid expansion and market interventions as a basis for planning. For the latter, however, the legal and regulatory framework needs to be adapted.

During congestions in the transmission grids, distribution grids can be used to a certain extent for redispatch measures. A sufficient degree of balancing flexibility must be ensured preventively, and the (n-1) security of the transmission grid must be guaranteed at all times.

However, the latest Network Code on Operational Security of the *ENTSO-E* [152] goes even further and defines the following in chapter 12, article 12, paragraph 5: "*In the (n-1)-Situation in Normal State each TSO shall keep power flows within the Transitory Admissible Overloads, preparing and executing Remedial Actions including Redispatching, to be applied within the time allowed for Transitory Admissible Overloads*". What this means is that corrective actions such as power flow control and redispatch measures may be taken for individual (n-1) cases if they comply with the thermal overload characteristics of the lines [44]. During their implementation, however, it must be ensured that the measures are preventively defined and sufficient, that activation is fast enough and reliable, and that protection systems are not triggered.

Under these conditions, possible rare overload situations can be mitigated, so that a lower degree of grid extension or a more fa-

vourable feed-in situation may be tolerated in operational planning. Here, however, one must also consider that further interventions for other critical and unexpected grid situations should also be made available to remain capable of operational action.

6.3.3 Vertical coordination between DSO and TSO

The defined responsibilities must be considered for the individual modes of ancillary service provision. Grid operators are initially responsible for voltage-reactive power control in their respective areas. For example, the ancillary service of voltage stability must first be provided in the distribution grid and for the distribution grid itself. A further coordinated provision of reactive power can only be achieved in excess of reactive power neutrality vis-à-vis the transmission grid. Sufficient short circuit power must be available in each grid area, which is the responsibility of the grid operator. The responsibility for frequency control lies solely with the TSO. This means that although the DSO coordinates provision in its grid area and ensures that grid overloads are avoided with suitable prequalification measures, activation itself is initiated by the TSO and lies with the TSO. The TSO coordinates the overall process of grid restoration, the DSO however is responsible for its own area.

Viewing the future system control from the perspective of the transmission grid level, it becomes clear that several mechanisms for the activation of ancillary services from the distribution grid level must be designed. The activation of ancillary services must be coordinated such that the most economically advantageous mode of provision is prioritised. Naturally, the provision of reactive power must be locally adapted. Given CR activation with a simultaneous congestion of the transmission grid, regional activation might be necessary as well.

Specifically, the following aspects can be noted for each ancillary service:

- For voltage stability, cross-grid level coordinated concepts for DECUs and storage systems for reactive power provision and other voltage regulators, e.g. step-up and –down transformers, must be designed that access larger systems by means of control technology, and smaller systems by means of the described ICT mechanisms. Coordination lies with the DSO, who first balances his own grid and then provides reactive power to

the TSO as an ancillary service, in compliance with the distribution grid limits.

- The provision of instantaneous reserve and primary control reserve must be automated and is done by the systems themselves. The DSO must consider this simultaneity in grid and operational planning and possibly restrict or prohibit the provision option during prequalification.
- MR can be provided by the described ICT mechanisms. Whether the DSO organises the activation or coordinates it with the grid, or whether or not new actors such as aggregators come into play, must be determined for the future.
- This also applies to SBP, but the prequalification requirements need to be adjusted. As part of the prequalification, the DSO respects activation restrictions. Activation is carried out by the controller of the TSO. Whether future ICT systems will meet requirements throughout the country remains to be examined.
- The DSO is responsible for grid restoration in the distribution grid. Using the described mechanisms, the DSO must initially ensure that the DECUs, storage systems and loads exhibit deterministic behaviour during grid restoration, i.e. that the volatility of renewable energy systems does not hinder restoration.

Redispatch measures will be increasingly required for the operation of marginally or probabilistically designed grids. The demand for redispatch measures is to be preventively determined for operationally occurring situations, and must be used for compliance with the (n-1) criterion.

In order to use this mechanism, computation and activation mechanisms must be available in the control rooms of the respective grid levels that calculate the optimal type and scope of measures and activate them at least partially automatically. Knowledge of available and usable redispatch potentials is important in this context. Redispatch options must be directly taken into account in grid and operational planning, so that they are available during critical grid situations. With a reduced number of conventional power plants, the redispatch options include in particular the throttling of renewable energy systems and counteraction by other DECUs, storage systems and load controllers. It is apparent that this ancillary service must be provided more frequently from out of the distribution grids.

Conventional redispatch measures are increasingly being preventively coordinated in operational planning. Even large wind farms or solar power plants can be considered directly or via the distribution grids if the reduction potentials have been exhausted in conventional suppliers. However, the consideration of further smaller plants in the distribution grids depends on the implementation of the described ICT infrastructure, so that the activation can be realised via efficient and automated mechanisms by, or with the participation of, the respective grid operator. Except for prequalified plants serving the provision of frequency control reserve, the activation of ancillary services must always take place via the relevant grid operator so he can fulfil his responsibilities.

6.3.4 Models in system control

Important aspects of future system control are the model assumptions of the methods employed. Temporal trends play an important role, which means that demand and reservation of CR fluctuate during the course of a day, as examined in Chapter 2. Operational planning and operation must be adapted to appropriately reflect the fact that the volatility of RES can be suitably forecasted. Probabilistic considerations must take scatter bands into account for the planning process to ensure both sufficient room for manoeuvre and available reserve for stability limits. The implementation of such methods is taking place successively.

Moreover, operational planning considerations must reflect dynamic models and temporal changes such as gradients and grid controller responses. The employment of such models in operational grid management has not yet reached the state of the art, and still requires some research and development work.

Another temporal aspect is that thermal limits of assets do not represent rigid performance limits, but may be subject to large fluctuations over time. Thus, the maximum line load is determined by conductor temperature monitoring as a function of the ambient temperature, wind speed and solar irradiation. The consideration of thermal behaviour and conductor monitoring are already implemented in many places and help increase operational flexibility. In fault situations, this technology can help identify the remaining time for stabilising actions that allow for a coordination across multiple grid levels [52]. In addition, the coordinated and robust activation

of reactive power via cascades of controlled lower-level suppliers, as discussed in Chapter 3, must be carefully designed in terms of control engineering. There is a need for research of suitable models and control concepts.

6.3.5 Horizontal coordination in the grid

The horizontal coordination between TSOs in Europe is necessary because of transnational market mechanisms and the expansion of RES in a growing number of regions. For an optimal utilisation of the grid infrastructure, power flow controls are employed by phase shifting transformers, or in the future by power electronic grid controllers (FACTS devices). HVDC transmissions also represent flow-controlling elements that will be introduced into the integrated European grid in the coming years. Due to these technologies, large-scale power flow changes will result that need to be coordinated across balancing zones. An exchange of operational grid data via *ENTSO-E* mechanisms is sufficient for today's preventive operational planning of controller settings. In the future, this planning must also comprise probabilistic and dynamic considerations, as described in the previous section, to take account of the volatility of generation.

If the controllers are supposed to reactively respond to unexpected grid situations, there needs to be a fast coordination across national borders. Today, adjustments are realised through consultations over the phone, and through manual interventions. The advantages of quickly responding components can only come to fruition if action mechanisms are preventively defined and agreed upon across balancing zones. Approaches to distributed optimal balancing and coordination strategies for a large-scale power flow control are still in their research stages [51][55][56].

To obtain shared information on large-scale grid situations in real time and to use this information to implement system protection mechanisms, wide area measurement systems (WAMS) are suitable to provide time-synchronised measurements in real time to the TSOs. This can be used to derive the dynamic system behaviour and identify fault events. Based on this, the system stabilisation measures between the TSOs need to be designed so that the system protection mechanisms as far as possible automatically take effect in fault situations. WAMS are already employed worldwide

[57]. The wide area control and system protection mechanisms based on this need to be carefully designed on a case by case basis. To ensure an efficient use of large-scale power flow controllers, including HVDC lines, a higher-level coordination especially in fault situations is essential. The development of mechanisms required for this must be expedited.

With a reduced number of power plants, the oscillation and damping characteristics of the integrated European grid can change. Based on WAMS, wide area damping controllers for HVDC transmissions and FACTS can be designed to attenuate large-scale oscillations between grid areas (so-called inter-area oscillations). To what extent and when this will be necessary in the integrated European grid system must be investigated.

6.3.6 Legal and regulatory demand for adaptation

With the liberalisation and unbundling of market and grid, the option was removed to optimise the entire energy supply system from one source in terms of technology and cost-efficiency. For the provision of ancillary services, it is necessary to allow grid operators to intervene in active systems on the market (DECUs, storage systems and loads). Future smart market mechanisms must be coordinated with the smart grid. Essentially, two main aspects have to be considered, with one allowing the introduction of ancillary services and the other leading to an efficient grid expansion.

When implementing smart market mechanisms and the associated design and development of ICT systems, they must be defined and standardised in such a way that the provision of ancillary services is enabled, and the DSOs have intervention options for the market and for grid users via a shared ICT system or a common data exchange platform. While the ancillary services must be designed as products and services, rapid interventions must be clearly defined for fault situations. The interface between smart grid and smart market including the ICT infrastructure must be established as quickly as possible by the government and through regulation, as this is what allows for the provision of ancillary services.

The second relevant aspect is the economic optimisation between grid expansion, permitted feed-in configurations and operational interventions. RES lead to rare and extreme grid situations, for which grid expansion might be inefficient. Planning criteria allowing

for a reduced grid expansion and a simultaneous intervention in the market and throttling of renewable energy systems are to be designed and established by corresponding regulations. The employment of such intervention options must be approved by the government and by regulation, and must be accordingly implemented in system control.

6.4 Conclusion for system control

The previous description of future system control is certainly not exhaustive. It would be possible to discuss and explore many further aspects in greater detail. However, the present study serves to present the essential aspects for the future development of system control. System control as an ancillary service has, amongst others, the task of coordinating and activating other ancillary services. Overall coordination and system responsibility remains with the TSOs. The distribution grids are facing new tasks with ancillary services in conjunction with DECUs, storage systems and load management that must be managed both for their own grids as well as for the TSOs. Joint working groups of TSOs and DSOs have already been founded to investigate the changed tasks and the associated interfaces.

In addition to these aspects, system control will also change due to an economically optimised and therefore more marginal grid expansion. This requires additional methods in system control or in the control centres for a coordinated, optimised and increasingly automated access to suppliers, storage systems and loads.

In summary, and as a preliminary conclusion, it can be stated that power system management for system control will split into a conventional control system architecture and an associated standard ICT-based architecture for the control of smaller DECUs, storage systems and widespread loads for smart market mechanisms. This ICT architecture simultaneously provides functions for the provision of ancillary services, but the reliability and the deterministic behaviour of conventional control systems must and should not be achieved. Standardisations and regulatory definitions must be established for the ICT architecture for ancillary service provision together with smart market mechanisms. Since, according to the previous studies, the provision of ancillary services from large renewable energy systems on the HV level is largely sufficient, it

would be sensible to control them via conventional control system connections. Only with nationwide ancillary service provision, and with provision from the underlying grid levels, is ICT shared with smart market mechanisms imperative.

The DSOs ensure voltage stability and grid restoration in their grid areas and thereby take over some of the duties related to the coordination and provision of ancillary services to the TSOs. They provide for appropriate mechanisms in the distribution grids taking into account grid restrictions. For this reactive power and voltage control spanning several distribution grid levels, a suitable data acquisition system and control structures must be designed to tap the potentials (see 3).

For frequency control, the DSO supports prequalification and takes into account any grid restrictions for a later activation. The activation of the secondary balancing power and minute reserve is carried out by the TSO, and the control system or the ICT system is used in the DSO's area. To what extent the DSO's area acts as an aggregator and service provider here must be determined in the future.

Today's task assignment remains untouched for grid restoration, but the DSO must ensure defined states for supply-dependent DECUs, so his area will face an increased complexity. Coordination effort between TSOs and DSOs increases as a result of nationwide suppliers that must be started in a targeted manner during grid restoration.

As mentioned above, all grid levels are designed with lower reserves, so that measures such as redispatch, DECUs, storage systems and load interventions are required for critical and rare grid situations, and which therefore must be supported by appropriate methods in system control. These interventions must be economically weighed against grid investments, with a focus on grid security in the transmission grids while tapping the economic potential of distribution grids. This approach must be fully clarified in terms of regulation so that the grids can be developed and operated in an economically optimised fashion.

Grids designed in this manner require new methods for operational planning and management, so that probability-based optimised, preventive intervention and control options can be calculated, determined and activated automatically. Coordination between grid

and market activities must be implemented on all levels (smart grids vs. smart markets).

The closer the grids are operated at the limits of stability, the more necessary are automated security mechanisms for stabilisation in critical situations.

Overall, it can be stated that the development of ICT and process control applications represent no principal obstacle to the future development of system control as an ancillary service. It must be ensured that the ICT standards are adopted and implemented, so that supportive applications can also activate the appropriate stabilisation measures. Ancillary service activation essentially follows economic and technical optimisation criteria.

A much bigger step would be the implementation of autonomous distributed systems for transnational coordination, since an extremely high level of robustness must be achieved in terms of human error. Cellular approaches for individual areas of the grid are only easy to implement while these cells provide services to a higher level grid without self-sufficiently decoupling from it. Should decoupling take place as a reserve or fallback measure during fault situations, then all control mechanisms, for example for full frequency control, must be provided in these cells as well. Further considerations of this can be found in chapter 5.

In conclusion, the main recommendations for action are summarised in Table 6.2. The short-term recommendations for action are considered as necessary within the next ten years, and the long-term recommendations as necessary until the end of the review period 2033.

Table 6.2 Recommendations for action for future system control

	Recommended action	Motivation	Legal / technical / regulatory aspects	Economic aspects
Short-term	Mechanisms for preventive / corrective stabilising measures	Mastering extreme operational situations by means of redispatch / RES throttling Cost-effective ancillary service provision by large DECUs	Allow limitation of RES and redispatch for grid optimisation Adapt ancillary service products and prequalification	Ancillary services by DECUs, loads or storage systems as cost-effective alternatives
	Coordination between DSOs and TSOs			
	Control of large DECUs (wind farms, solar power plants) for ancillary services			
Long-term	Automation of preventive / corrective stabilising measures	Economically optimised grid operation / probabilistic grid and operational planning with market interventions Cost-effective ancillary service provision by nationwide DECUs	Permit probabilistic grid and operational planning as a principle Determine smart market interventions for ancillary service provision and grid optimisation	Optimised grid expansion through market/DECU/storage system/load interventions
	Grid analysis functions (forecasts, dynamics, optimised ancillary service activation)			
	Ancillary services together with smart market from DECUs and storage systems			

Bibliography

[1] Deutsche Energie Agentur GmbH: *dena Netzstudie II - Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 – 2020 mit Ausblick 2025,* study, Berlin, November 2011

[2] Deutsche Energie Agentur GmbH: *dena-Verteilnetzstudie: Ausbau und Innovationsbedarf der Stromverteilnetze in Deutschland bis 2030*, Berlin, 2012

[3] Federal Network Agency, *Genehmigung des Szenariorahmens für die Netzentwicklungsplanung*, Bonn, 30 November 2012

[4] ENTSO-Operation Handbook, Policy 1, *Load-Frequency Control and Performance*, 2009

[5] 50Hertz Transmission GmbH; Amprion GmbH; TenneT TSO GmbH; TransnetBW GmbH; *Netzentwicklungsplan Strom 2013 – 2. überarbeiteter Entwurf der Übertragungsnetzbetreiber*; July 2013

[6] Speckmann, C.: *Bundesweit einheitliches Management von Minutenreserveleistung*, published in: ew - Magazin für die Energiewirtschaft, magazine volume 22, October 2012

[7] Energie-Forschungszentrum Niedersachsen (efzn): *Eignung von Speichertechnologien zum Erhalt der Systemsicherheit*, study, Goslar, March 2013

[8] 50Hertz Transmission GmbH; Amprion GmbH; TenneT TSO GmbH; TransnetBW GmbH; *Netzentwicklungsplan Strom 2012 – 2. überarbeiteter Entwurf der Übertragungsnetzbetreiber*, August 2012

[9] ENTSO-Operation Handbook, Appendix 1, *Load-Frequency Control and Performance*, 2004

[10] Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft e. V.(FGH), *Studie zur Ermittlung der technischen Mindesterzeugung des konventionellen*

Kraftwerksparks zur Gewährleistung der Systemstabilität in den deutschen Übertragungsnetzen bei hoher Einspeisung aus erneuerbaren Energien, January 2012, Aachen

[11] ENTSO-E, Draft Network Code, *Requirements for Generators*, Chapter 3, Article 16-2

[12] Beck, H; Hesse, R.;Turschner, D.; Chen, Y.; *Improving the grid power quality using virtual synchronous machines,* Proceedings of the International Conference on Power Engineering, Energy and Electrical Drives, May 2011; Torremolinos

[13] Visscher, K.; de Haan, S.W.H.; *Virtual synchronous machines for frequency stabilisation in future grids with a significant share of decentralised generation*, Proceedings of the CIRED SmartGrids conference; June 2008; Germany

[14] Erlich, I; Rensch, K; Shewarega, F.; *Impact of Large Wind Power Generation on Frequency Stability,* IEEE Power Engineering Society General Meeting; 2006; Montreal

[15] Miller, M.W.; Clark, K.; Shao, M.; *Impact of Frequency Responsive Wind Plant Controls on Grid Performance; GE Energy,* IEEE Power and Energy Society General Meeting; 2011; San Diego

[16] Hydro-Québec TransÉnergie: *Transmission Provider Technical Requirements For The Connection Of Power Plants To The Hydro-Québec Transmission System*, February, 2009

[17] Xu, Z.; Togeby, M.; Østergaard, J.; *Demand as Frequency Controlled Reserve,* Ørsted DTU; Research Project; September 2008; Kongens Lyngby

[18] Ziema, Ch.; Meinke, S.; Nocke, J.; Weber, H.; Hassel, E.; *Kraftwerksbetrieb bei Einspeisung von Windparks und Photovoltaikanlagen*; final report; May 2012; Rostock

[19] Weber, H. Ziems, Ch.; Nassar: I., *Versorgungssicherheit und Systemstabilität beim Übergang zur Regenerativen Elektrischen Energieversorgung,* 11. ETG

Fachtagung Netzregelung und Systemführung; June 2013; Munich

[20] S. Kippelt, T. Schlüter and C. Rehtanz: *Flexible Dimensioning of Control Reserve for Future Energy Scenarios*, IEEE Powertech Conference, Grenoble, France, 2013

[21] Gwisdorf, B.; Borchard, T.; Hammerschmidt, T.; Rehtanz, C.*: Praxisgerechte Anwendung innovativer Netzkonzepte mittels Grenzkurvenanalyse zur Unterstützung von Netzplanungsvorgängen*, VDE ETG-Kongress 2011, Würzburg, 08.-09.11.2011

[22] Heinz Stigler: *Gutachten zur Ermittlung des erforderlichen Netzausbaus im deutschen Übertragungsnetz*, TU Graz, December 2012

[23] P. Esslinger, R. Witzmann: *Evaluation of reactive power control concepts for PV inverters in low-voltage grids*, Lisbon, CIRED 2012

[24] Weidner; J.,Hoffman; L.: *Statische und transiente Stabilität von Erzeugungsanlagen in Verteilnetzen*, ETG Kongress 2011, Würzburg

[25] BDEW: *Erzeugungsanlagen am Mittelspannungsnetz*, June 2008

[26] VDE: *Aktive Energienetze im Kontext der Energiewende*, Frankfurt am Main, February 2013

[27] Golletz, F.: *Übertragungsnetzausbau – Die Voraussetzung fur zuverlassige Stromversorgung in der Zukunft*, 11. ETG/GMA-Fachtagung "Netzregelung und Systemführung", Munich, 11 - 12 June, 2013

[28] S. C. Müller, A. Kubis, S. Brato, C. Rehtanz, J. Götze: *Innovative Schutz- und Leitsysteme zur zuverlässigen und sicheren elektrischen Energieübertragung*, VDE Kongress 2012, Stuttgart, Germany, November 2012

[29] BDEW e.V. – German Association of Energy and Water Industries: *Smart Grids – auf dem Weg zu einem zukunftsfähigen Markt- und Regulierungsdesign*, Berlin, March 2011

[30] J. Haubrock: *Netzwiederaufbau nach einem Black-Out durch dezentrale Energieerzeugungssysteme unterstützt durch eine Frequenzüberwachung*, 2010

[31] ENTSO-E: *UCTE Operation Handbook Policy5: Emergency Operations*, 2012

[32] VDE; Forum Netztechnik/Netzbetrieb im VDE: *Technische Herausforderungen beim Umbau der Netze - Lösungsansätze*, Berlin, June 2012

[33] VDE, DIN EN 60909-0 / VDE 0102: *Kurzschlussströme in Drehstromnetzen*, VDE-Verlag, 2012.

[34] Ahmad-Rami Khalil Al-Awaad: *Beitrag von Windenergieanlagen zu den Systemdienstleistungen in Hoch- und Höchstspannungsnetzen*, Dissertation der Bergischen Universität Wuppertal, Wuppertal, April 2009

[35] VDE: *E VDEAR-N 4120 - Technische Bedingungen für den Anschluss und Betrieb von Kundenanlagen an das Hochspannungsnetz (TAB Hochspannung) – Entwurf*, November 2012

[36] VDE: *Sicherheit in der Stromversorgung*, Berlin, November 2011

[37] D. Kamenschikow, M. Lösing, K. Vennemann: *Spannungshaltung und Blindleistungsbereitstellung in hochausgelasteten 380-kV-Netzen*, Munich, ETG conference 2013

[38] Verband der Netzbetreiber VDN e.V.: *DistributionCode 2007*, Berlin, August 2007

[39] Verband der Netzbetreiber VDN e.V.: *Transmission Code 2007*, Berlin, August 2007

[40] Panciatici, P.; Bareux, G.; Wehenkel, L.: *Operating in the fog – Security Management under Uncertainties*. IEEE PES Power & Energy Magazine, vol. 10, iss. 5, 2012

[41] Dobschinski, J.; Baier, A.; Wessel, A.: *Vorhersage von Windstromeinspeisung in das elektrische Netz*, BWE Fachtagung Direktvermarktung Windenergie, 27 - 28 March 2012, Hamburg

[42] Zhang, X.-P., Rehtanz, C., Pal, B.: *Flexible AC Transmission Systems: Modelling and Control*, Springer-Verlag, 2nd Edition, February 2012

[43] Wieben, E.: *Netzstudie zur Steigerbarkeit der Netzanschlusskapazität ländlicher Verteilnetze durch ein intelligentes Erzeugungsmanagment*, EWE Netz GmbH, May 2012

[44] Müller, S.C.; Osthues, M.; Rekowski, C.; Rehtanz, C.: *Techno-economic evaluation of corrective actions for efficient attainment of (N-1)-security in operation and planning*, IEEE PES General Meeting, Vancouver, Canada, 21 - 25 July, 2013

[45] Liebenau, V.; Schwippe, J.; Kuch, S.; Rehtanz, C.: *Network Extension Planning Considering the Uncertainty of Feed-in from Renewable Energies*, IEEE Powertech, Grenoble, France, June 16-20, 2013

[46] Pourbeik, P. (Editor): *New Technologies to Improve Power System Dynamic Performance*, IEEE PES, Task Force on Blackout Experience, Mitigation and Role of New Technologies, Chapter 3 of Final Report "Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies", IEEE, July 2007

[47] Kunz, F.; Zerrahn, A.: *Koordinierung von Engpassmanagment in Deutschland: Welche Synergieeffekte sind zu erwarten?*, lecture, workshop, DIW Berlin, 5 April 2013

[48] Häger, U.; Rehtanz, C.; Voropai, N.: *ICOEUR Project Results on Improving Observability and Flexibility of Large Scale Transmission Systems*, IEEE PES General Meeting, San Diego, USA, 22 - 26 July 2012

[49] Capitanescu, F.; Martinez Ramos, J.L; Panciatici, P.; Kirschen, D.; Marano Marcolini, A.; Platbrood, L.; Wehenkel, L.: *State-of-the-art, challenges, and future trends in security constrained optimal power flow,* Electric Power Systems Research 81 (8), p. 1731–1741, 2011

[50] Leclerc, S.: *Discrete variables in power systems optimization problems*. IEEE PES ISGT Europe 2011

[51] Häger, U.: *Agent-based real-time coordination of power flow controllers*. Dissertation, TU Dortmund, 2012

[52] Arrivé, O.; Boulet, F.; Moran-Pena, C.; Johnson, P.; Van Roost, J.; Schuster, N.; Ziemann, O.; Ziesemann, H.-D.; Heinz, M.; Pierchalla, M.; Klaar, D.: *Improved TSO coordination in the Central West European region*. CIGRE C2-204, 2012

[53] Baumann, R. et. al.: *TSC Cooperation Platform (CTDS) – The Daily Operational Planning Tool of the TSC TSOs,* CIGRE Paper 1.4.145, Lisbon, 2013

[54] Hug, G.: *Generation Cost and System Risk Trade-Off with Corrective Power Flow Control,* 15th Annual Allerton Conference, Illinois, USA, 2012

[55] Müller, S. C.; Häger, U.; Rehtanz, C.: *Integrated Coordination of AC Power Flow Controllers and HVDC Transmission by a Multi-Agent System*, IEEE IES MSCPES 2013, Berkeley, USA, May 2013

[56] Hug-Glanzmann, G.: *Coordinated Power Flow Control to Enhance Steady-State Security in Power Systems,* Dissertation, ETH Zurich, 2008

[57] Phadke, A. G.: *The Wide World of Wide-area Measurement,*. IEEE Power and Energy Magazine, vol. 6, iss. 5, 2008

[58] Kubis, A.: *Introduction of a response based system protection scheme against line overload cascades*, accepted for IET DPSP 2014, Copenhagen, 2014.

[59] Math J.J. Bollen, F. Hassan: *Integration of Distributed generation in the Power System*, A. John Wiley & Sons, inc, Publication, New Jersey 2011

[60] V. Liebenau, J. Teuwsen, C. Rehtanz: *Impact of Regionalization Methods on Network Development Planning*, IEEE Energytech 2013, Cleveland, Ohio, 21 - 23 May 2013

[61] 50Hertz Transmission GmbH, Amprion GmbH, TenneT TSO GmbH, TransnetBW GmbH: *Einflussgrößen auf die Netzentwicklung*, 1 July 2013

[62] Deutsche Gesellschaft für Sonnenenergie e.V. (DGS): *EEG-Anlagenregister*“, online: http://www.energymap.info/; as of: February 2013

[63] Deutscher Wetterdienst: *Regional Model COSMO-EU*, online: www.dwd.de, 2013

[64] ENTSO-E - European Network of Transmission System Operators for Electricity: *Consumption Data*, online: www.entsoe.eu/data/data-portal/consumption/, January 2013

[65] German Association of Energy and Water Industries: *Nettostromverbrauch in Deutschland nach Verbrauchergruppen*, http://www.bdew.de/internet.nsf/id/DE_Energiedaten, 16.05.2013

[66] Consentec GmbH: *Regionalisierung eines nationalen energiewirtschaftlichen Szenariorahmens zur Entwicklung eines Netzmodell (NEM), Untersuchung im Auftrag der Bundesnetzagentur*, April 2012

[67] KERBER, G. : *Aufnahmefähigkeit von Niederspannungsverteilnetzen für die Einspeisung aus Photovoltaikanlagen,* Munich, TU Munich, dissertation, 2011

[68] VDE (pub.): *VDE-Anwendungsregel; VDE-AR-N 4105:2011-08; Erzeugungsanlagen am Niederspannungsnetz - Technische Mindestanforderungen für Anschluss und Parallelbetrieb von Erzeugungsanlagen am Niederspannungsnetz,* August 2011

[69] Bundesverband der Energie- und Wasserwirtschaft e.V. (pub.) : *Technische Richtlinie Erzeugungsanlagen am Mittelspannungsnetz - Richtlinie für Anschluss und Parallelbetrieb von Erzeugungsanlagen am Mittelspannungsnetz*. June 2008

[70] PARDATSCHER, R. ; et al. : *Untersuchung zu den Auswirkungen von Photovoltaikeinspeisung auf das Nieder- und Mittelspannungsnetz*; VDE ETG-Kongress 2011, Würzburg, 08. - 09.11.2011

[71] ENTSO-E: *Scenario Outlook and Adequacy Forecast 2013/2030*, Brussels, April 2013

[72] Forum Netztechnik / Netzbetrieb im VDE (FNN): *Technische Anforderungen an die automatische Frequenzentlastung*, Technical Note, June 2012

[73] Weber, H.; Madsen, B.; Asal, H.; Grebe, E.: *Kennzahlen der Primärregelung im UCPTE-Netz und künftige Anforderungen*, Elektrizitätswirtschaft, Jg. 96 (1997), mag. volume 4

[74] European Network of Transmission System Operators for Electricity (ENTSO-E): *Dispersed Generation Impact on CE Region Security, Dynamic Study Final Report*, 22.03.2013

[75] *Verordnung über Vereinbarungen zu abschaltbaren Lasten vom 28. Dezember 2012*, Bundesgesetzblatt Jahrgang 2012 Teil I Nr. 63, issued in Bonn on 31 December 2012

[76] Deutsche Energie Agentur GmbH: *dena Netzstudie I - Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020,* study, Berlin, February 2005

[77] Janssen, A.L.J.; Riet, M.v.; Smeets, R.P.P.; Kanters, J. Akker, W.F. v.d.; Aanhaanen, G.L.P: *Prospective Single and Multi-Phase Short-Cirquit Current Levels in the Dutch Transmission, Sup-Transmission and Distributions Grids*, CIGRE 2012 – A3 103

[78] Federal Network Agency: *Smart Grid und Smart Market - Eckpunktepapier der Bundesnetzagentur zu den Aspekten des sich verändernden Energieversorgungssystems*, Bonn, Dec. 2011

[79] ENTSO-E, https://www.entsoe.eu/news-events/announcements/newssingleview/article/entso-e-members-launch-the-european-awareness-system-to-help-keep-europe-switched-on, as viewed in October 2013)

[80] Appelrath, H.-J.; Mayer, C.; e.a.: *Deutschlands Energiewende kann nur mit Smart Grids gelingen - Vorläu-*

fige Empfehlungen aus dem acatech Projekt Future Energy Grid, acatech, 2012

[81] acatech (pub.): *Future Energy Grid - Informations- und Kommunikationstechnologien für den Weg in ein nachhaltiges und wirtschaftliches Energiesystem*, 2011

[82] Appelrath, H.J.; Kagermann, H.; Mayer, C. (pub.): *Future Energy Grid - Migrationspfade ins Internet der Energie*, acatech study, February 2012

[83] BDEW: *BDEW-Roadmap - Realistische Schritte zur Umsetzung von Smart Grids in Deutschland*, Berlin, February 2013

[84] Höfer-Zygan, R; Oswald, E.; Heidrich, M.: *Smart Grid Communications 2020 - Fokus Deutschland*, FhG ESK, Munich 2011

[85] DKE: *Die deutsche Normungsroadmap E-Energy / Smart Grid*, Deutsche Kommission Elektrotechnik, Elektronik, Informationstechnik (DKE) im DIN und VDE, publisher: VDE, April 2010

[86] UCTE: *Final Report System Disturbance on 4 November 2006*, 2007

[87] Krüger, M.; Weber, H.; Franke, W.; Kirsch, R.: *Wiederaufbau von Übertragungsnetzen nach Großstörungen*, ETG conference, Munich, March 2008

[88] E-Energy: *Modellstadt Mannheim, Abschlussbericht*, 2013

[89] BDEW: *Smart Grids: Das Zusammenwirken von Netz und Markt*, Berlin, March 2012

[90] Lehnhoff, S.; Krause, O.; Rehtanz, Ch.; Wedde, H.F.: *Dezentrales autonomes Energiemanagement*, Automatisierungstechnik, March 2011

[91] Feldmüller, A.: *Wie flexibel ist der heutige Kraftwerkspark aus Herstellersicht?*, slide presentation, workshop BMWi – dena, Berlin January 2013

[92] Brockmann, L.; Franz, P.; *Standpunkt, Stromspeicher – Einsatzbedingungen und Entwicklungsstand, Nr. 12*, KFW Bankengruppe, September 2011

[93] Wachtel, S.; Beekmann, A.; *Contribution of Wind Energy Converters with Inertia Emulation to frequency control and frequency stability in power systems,* 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems; October 2009; Bremen

[94] ENTSO-E : *Draft Network Code on Demand Connection*, Chapter 1, Article 21

[95] Consentec/Haubrich, *Gutachten zur Höhe des Regelenergiebedarfs*, Gutachten im Auftrag der Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen, Bonn 2008

[96] Federal Network Agency: *Bericht zum Zustand der leitungsgebundenen Energieversorgung im Winter 2012/13*, Bonn, June 2013

[97] Consentec GmbH: *Gutachten zur Dimensionierung des Regelleistungsbedarfs unter dem NRV*, Bonn, December 2010

[98] TU Dortmund, e-Bridge: *Optimierung der Ausregelung von Leistungsungleichgewichten*, expert opionion for BNetzA, 2009

[99] DLR, IWES, IFNE: *Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global*, final report, March 2012

[100] Press Release: *Dutch consumers save hundreds of millions of euros thanks to TenneT's acquisition of transpower*, published on: 14 January 2013

[101] Internet platform for the tendering of balancing power of the German transmission system operators, https://www.regelleistung.net/ip/action/index

[102] Consentec, *Market Study on a Common Market for Primary Control Reserve in the Netherlands and Germany*, market study for TenneT TSO B.V., 29. October 2012

[103] ENTSO-E: *Draft Network Code on Electricity Balancing*, Version 1.30, 16 October 2013,

[104] Energy2market GmbH, *Langfristige Zusatzerlöse*, pess release, online: http://www.pressebox.de/pressemitteilung/energy2market-gmbh/Langfristige-Zusatzerloese/boxid/649952

[105] Younicos: *Bahn frei für Wind und Sonne*, press release dated 6 February 2013

[106] Michael Brucker: *Wasserkraft als Netzdienstleister*, E.ON Wasserkraft GmbH, Trier, 15 September 2011

[107] Benjamin Biegel, Lars Henrik Hansen, Palle Andersen, Jakob Stoustrup: *Primary Control by ON/OFF Demand-Side Devices*, IEEE Transactions on Smart Grid, Vol. 4, No. 4, December 2013

[108] Energiewirtschaftliches Institut an der Universität zu Köln (EWI), *Flexibility options in European electricity markets in high RES-E scenarios*, Cologne, October 2012

[109] ETG-Task Force Demand Side Management, *Demand Side Integration, Lastverschiebungspotentiale in Deutschland*, Verband der Elektrotechnik Elektronik Informationstechnik (VDE), Frankfurt, 2012

[110] Plattform Erneuerbare Energien AG, interaction, appendix: Potentiale und Hemmnisse der Flexibilitätsoptionen, dated: 15.10.2012

[111] Malte Jansen, Markus Speckmann; Wind turbine participation on Control Reserve Markets; Fraunhofer Institute for Wind Energy and Energy System Technology, Kassel, Germany, 2013

[112] Fraunhofer-Institut für Windenergie und Energiesystemtechnik (IWES), *Regelenergie durch Windkraftanlagen*, final report, Kassel, December 2013

[113] EirGrid, System Operator for Northern Ireland (SONI): *Frequency Control Workstream*, 2013

[114] Malte Jansen, Markus Speckmann: *Participation of photovoltaic systems in Control Reserve Markets*, CIRED2013 Session 6. Paper No 0245

[115] Statkraft, *Deutschlands größtes Kraftwerk ist grün*, press release, online:

http://www.statkraft.de/presse/pressemtteilungen/Deutschlands-groesstes-kraftwerk-ist-gruen.aspx

[116] Fraunhofer-Institut für Windenergie und Energiesystemtechnik (IWES), *Wind Energie Report Deutschland 2012*, Kassel 2013, http://windmonitor.iwes.fraunhofer.de

[117] Daniel Unger, Bernd Engel: *Beteiligung von PV-Anlagen und Speichern an der PRL*, Technische Universität Braunschweig, January 2013 (published in 2014)

[118] Institut für Stromrichtertechnik und Elektrische Antriebe (ISEA): *Technologischer Überblick zur Speicherung von Elektrizität*, study on behalf of Smart Energy for Europe Platform GmbH (SEFEP), September 2012, Aachen

[119] WEMAG: *Richtfest für Schweriner Batteriepark*, press release dated 03.09.2013

[120] N. Krzikalla, S. Achner, S. Brühl, Büro für Energiewirtschaft und technische Planung GmbH, *Möglichkeiten zum Ausgleich fluktuierender Einspeisungen aus Erneuerbaren Energien*, Aachen, Germany, 2013

[121] Deutsche Energie Agentur GmbH: *Kurzanalyse der Kraftwerksplanung in Deutschland bis 2020 – Aktualisierung*, February 2010, Berlin

[122] Statistisches Bundesamt, *Ergebnisse der Mikrozensus-Zusatzerhebung 2010*, online: https://www.destatis.de/DE/ZahlenFakten/GesellschaftStaat/EinkommenKonsumLebensbedingungen/Wohnen/Tabellen/WohneinheitenWohngebaeudenBeheizung.html

[123] T. Schlüter, V. Liebenau, C. Rehtanz: *Technical Potential and Revenue Chances of Flexible Electricity Generation and Load Devices*, IEEE PES ISGT Europe Conference, Copenhagen, October 2013

[124] Franke, E.: *Markt- und Regulierungsdesign, Preisbildung & Vermarktung – Mengen und Preisentwicklungen auf den Regelenergiemärkten in Deutschland*, Proceedings Euroforum Konferenz, Berlin, 2012

[125] Holzhammer, U.: *Flexibilisierung von Biogasanlagen als Beitrag zur erneuerbaren Versorgungssicherheit, Fraunhofer-Institut für Windenergie und Energiesystemtechnik (IWES)*, lecture, 24 July 2013, Stuttgart

[126] H.-J. Belitz, S. Winter, C. Müller, N. Langhammer, R. Kays, C. Wietfeld, C. Rehtanz: *Technical and Economic Analysis of Future Smart Grid Applications in the E-DeMa Project*; IEEE PES ISGT Europe Conference 2012, Berlin, October 2012

[127] Federal Network Agency: *Wettbewerbliche Entwicklungen und Handlungsoptionen im Bereich Zähl- und Messwesen und bei variablen Tarifen*; Bonn, March 2013

[128] ETG-Task Force Demand Side Management, *Demand Side Integration, Lastverschiebungspotentiale in Deutschland*, Verband der Elektrotechnik Elektronik Informationstechnik (VDE), Frankfurt, 2012

[129] 50Hertz Transmission GmbH, Amprion GmbH, TenneT TSO GmbH, TransnetBW GmbH: *Mindestanforderungen an die Informationstechnik des Anbieters für die Erbringung von Sekundärregelleistung*, version dated 28 May 2013

[130] Welfonder, E.: *Regeldynamisches Zusammenwirken von Kraftwerken und Verbrauchern im Netzverbundbetrieb,* Elektrizitätswirtschaft 79 (1980), pp. 730-741

[131] Wachtel, S.; Beekmann, A.; *Contribution of Wind Energy Converters with Inertia Emulation to frequency control and frequency stability in power systems*; 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems; October 2009; Bremen

[132] Sven Heim, Georg Goetz: *Do pay-as-bid auctions favor collusion? - Evidence from Germany's market for reserve power*, Joint Discussion Paper Series in Economics, ISSN 1867-3678

[133] Flinkerbusch, Kai (2011): *Der Markt für Sekundärregelenergie – Eine Bewertung des Regelenergieeinsatzes im Rahmen des Netzregelverbundes,* In: *Zeitschrift*

für Energiewirtschaft. Available online at http://www.springerlink.com/content/NLP14293461M4644/fulltext.pdf

[134] Fraunhofer-Institut für System- und Innovationforschung (Fraunhofer ISI) ,*Nutzenwirkung der Marktprämie*, Working Paper Sustainability and Innovation, Karlsruhe 2013

[135] Schulz: *Strategien zur effizienten Integration der Windenergie in den deutschen Elektrizitätsmarkt,* Dortmund, Technical University of Dortmund, dissertation, 2007

[136] German Bundestag, 17th legislative period, Drucksache 17/3284, *Primärregelleistung in Deutschland*, 2010

[137] Haase, T.: *Netzseitige Anforderungen an Erzeugungseinheiten zur Gewährleistung eines sicheren Systembetriebes in der Regelzone 50hertz*, lecture, 3rd SoS conference – 26.08.2010, Rostock

[138] Roggenbaum, M.: *Kooperation der Übertragungsnetzbetreiber zur Minutenreservehaltung in elektrischen Verbundsystemen*, dissertation, Rheinisch-Westfälische Technische Hochschule Aachen, 1999

[139] Giesecke, J., Mosonyi, E.: *Wasserkraftanlagen, Planung, Bau und Betrieb*, Springer-Verlag, Berlin Heidelberg 2005

[140] Fraunhofer Institute for Solar Energy System (ISE): *Stromgestehungskosten Erneuerbare Energien*, Studie, November 2013

[141] Federal Network Agency: *Monitoringbericht 2012*, Bonn

[142] Federal Network Agency: *Monitoringbericht 2013*, Bonn

[143] Federal Network Agency: *Festlegung zu Verfahren zur Ausschreibung von Regelenergie in Gestalt der Primärregelung*, Beschluss BK6-10-097, 2011, Bonn

[144] Energinet.dk: *Cell Controller Pilot Project*, Fredericia, Denmark, 2011. Available online at http://www.energinet.dk

[145] Valov, Boris (2013): *Änderung der Kurzschlussleistung – Künftiges Energieversorgungssystem gemäß NEP 2012*, EW 14/2013.

[146] *S. C. Müller; A. Kubis, S. Brato, C. Rehtanz, J. Götze: Schutz- und Leitsysteme zur zuverlässigen und sicheren elektrischen Energieübertragung – Interdisziplinäre Forschung im Rahmen der DFG-Forschergruppe 1511*, ETG Mitgliederinformation Nr.2, June 2013

[147] *H. Georg, S. C. Müller, N. Dorsch, C. Rehtanz and C. Wietfeld:* INSPIRE: *Integrated Co-Simulation of Power and ICT Systems for Real-Time Evaluation, IEEE International Conference on Smart Grid Communications (SmartGridComm) 2013*, Vancouver, Canada, Oct. 2013

[148] T. Bopp, R. Krebs, J. Jäger (2013): *Capabilities and Prospects of State-Of-The-Art-Protection Security Audit and Assessment Tools*, Internationaler ETG Kongress 2013, 05-06.11.2013, Berlin.

[149] U. Kerin, R. Krebs, E. Lerch (2013): *Power System Application Tool for On-Line Security Investigations*, Internationaler ETG Kongress 2013, 05.06.11.2013, Berlin.

[150] Federal Network Agency, *Beschlusskammer 6, Az: BK6-12-024*, October 2012, Bonn

[151] European Patent Office, patent application 07018624.2: *Verfahren zur Primärregelung für ein Verbundstromnetz*, Patentblatt 2011/33, applicant: E.ON Wasserkraft GmbH, inventor: Keil, S.

[152] ENTSO-E: *Network Code on Operational Security*, 24 Sept. 2013

[153] D. Schröder: *Leistungselektronische Schaltungen,* 2. Auflage, Springer, 2008.

[154] Ernst & Young: *Kosten-Nutzen-Analyse für einen flächendeckenden Einsatz intelligenter Zähler*, July 2013

[155] Statistische Ämter des Bundes und der Länder (pub.): *Bodenfläche nach Art der tatsächlichen Nutzung regionale Tiefe*, Gemeinden, Samt-/Verbandsgemeinden

(449-01-5), dated: 31.12.2011; https://www. regional-statistik.de

[156] Arbeitskreis "Volkswirtschaftliche Gesamtrechnungen der Länder im Auftrag der Statistischen Ämter der 16 Bundesländer, des Statistischen Bundesamtes und des Bürgeramtes, Statistik und Wahlen, Frankfurt a. M. (pub.): *Bruttoinlandsprodukt, Bruttowertschöpfung in den kreisfreien Städten und Landkreisen der Bundesrepublik Deutschland 2008 bis 2010*, Reihe 2, Band 1. August 2011

[157] European Energy Exchange AG: EEX Transparency Platform, online, http://www.transparency.eex.com, as viewed on: 15.02.2013

[158] Trianel GmbH: *Pumpspeicherkraftwerke in Deutschland*, website, http://www.trianel-rur.de/de/wasserkraftwerk/pumpspeicherkraftwerke-in-deutschland.html, as viewed on 10.12.2013

A. Scenario framework

In this section, the necessary assumptions for the calculations are presented.

A.1. Installed capacities

Within the framework of this study, the development scenario for the year under review of 2033 as per NEP 2013 is taken as a basis and shown in Figure A.2.

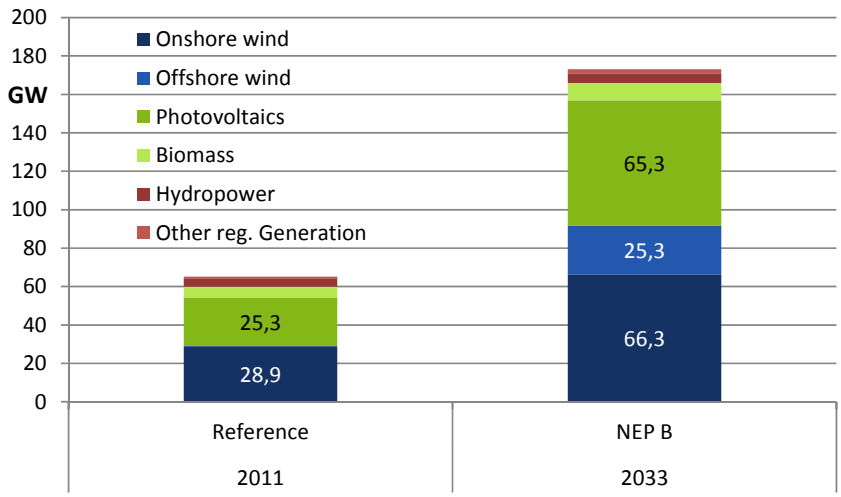

Figure A.2 Installed RES capacities

The installed capacities of the conventional power plants are shown in Figure A.3. In this scenario, gas-fired power plants exhibit the largest increase in comparison to 2011. The installed capacity of lignite-fired power plants is almost halved and the share of hard coal-fired power plants is reduced by about 1/5. The total installed capacity is reduced only slightly.

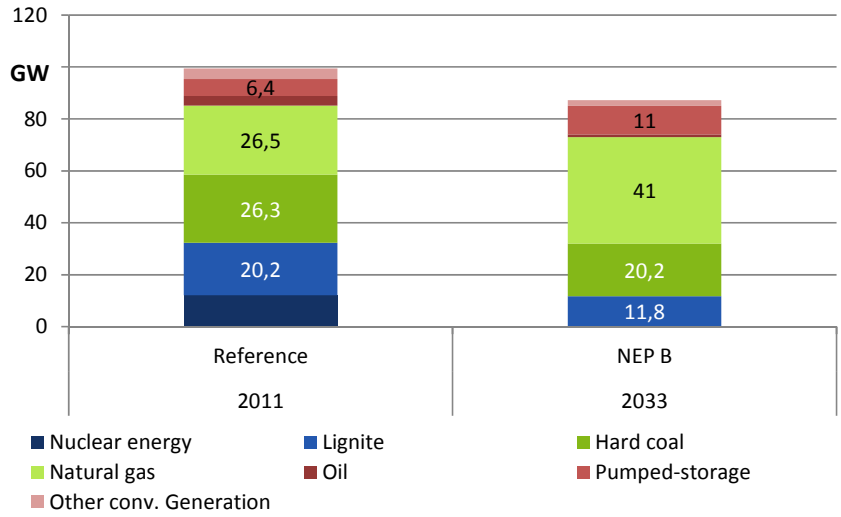

Figure A.3 Installed conventional power plant capacities

The installed capacities of renewable energy systems and conventional power plants in other European countries are taken from the Scenario Outlook & Adequacy Forecast (SO&AF) [71], analogous to the corresponding NEP scenarios.

Regionalisation

The regional distribution of power demand and supply (regionalisation) has a decisive influence on the necessity and efficiency of grid expansion measures in the electrical transmission grid [60]. Similarly, impacts on local reactive power demand can be expected [61].

Regionalisation is performed based on a region model at the municipal level. The municipal level is the lowest structural level at which data allocation is reasonably possible. Statistical, structural and meteorological data for each municipality in Germany are compiled in the data basis of the region model, which is mainly data from the Federal and Regional Statistical Offices and the German Weather Service. An overview of the most important structural data is offered in Figure A.4.

Wind turbines	Photovoltaic systems	Household load	Commercial load
- Energy yield potential based on wind speed - Arable land - Woodland - Currently installed capacity (also for repowering)	- Energy yield potential based on solar irradiation - Buildings and open areas in residential areas - Currently installed capacity (also for repowering)	- Residents - Size of household - Household income - Living space - Buildings and open areas in residential areas	- Gross domestic product - Gross value added per economic sector - Buildings and open areas in commercial areas

Figure A.4 Overview of the available structural parameters of the German municipalities on the regional distribution of the predicted capacity of loads and energy conversion systems

The distribution of the predicted capacities of the loads and renewable energy systems is carried out using so-called regionalisation factors. A regionalisation factor generally describes the share of the total capacity assigned to each municipality. A one-dimensional regionalisation factor is formed only on the basis of an input data set. One-dimensional regionalisation factors result, for example, from the distribution of wind turbines in relation to arable land, of PV systems in relation to buildings and land, or of the electrical load in relation to the population of the German municipalities. Multidimensional regionalisation factors provide the opportunity to consider multiple sets of data. For wind turbines, the distribution can be implemented in relation to arable land, forestry land and the energy yield potential as based on meteorological data and other influencing variables.

In the context of the present study, an investigation of various regionalisation methods is not feasible. Therefore, the regionalisation used in the present study is explained at this point, so that a qualitative assessment of the selected scenario is possible.

The scenarios of the scenario framework 2012 are used for grid development planning and regionalisation, upon which the sensitivity analysis of NEP 2013 is based [61]. Scenario C of the scenario framework 2012 is based on the implementation of the environmental policy objectives of the individual German states, insofar as the nationwide expansion of energy conversion plants corresponds to the sum of the federal state targets. The interrelation of the target valuesof the German states is also transferred to the other scenarios, so policy objectives are reflected there as well. During the approval of the scenario framework, it was criticised

that regionalisation was ultimately based on the reported target values of the federal states exclusively. However, the present study uses the scenario upon which NEP is based, with consideration of the federal state weighting.

A respective multidimensional regionalisation factor is used for the regionalisation of capacity from wind turbines and PV systems. A one-dimensional regionalisation factor is applied to distribute power from BMP. These factors are applied to the projected federal state values.

In the approved scenario framework 2012, regionalisation factors are described as follows [3]:

Regionalisation of wind turbines

- 50% of the new installations vis-à-vis 2011 are to be locally distributed in proportion to the previously installed onshore wind power capacity. The regional distribution of previously installed onshore wind power capacity is to be taken from the plant master data of the TSOs.
- 50% of the new installations vis-à-vis 2011 are to be distributed amongst locations suitable for wind power.
    - 15% of the new installations are to be evenly distributed amongst locations whose annual average wind speed is greater than 7.3 m/s.
    - 12.5% of the new installations are to be evenly distributed amongst locations whose annual average wind speed is greater than 6.4 m/s and less than or equal to 7.3 m/s.
    - 10% of the new installations are to be evenly distributed amongst locations whose annual average wind speed is greater than 5.5 m/s and less than or equal to 6.4 m/s.
    - 7.5% of the new installations are to be evenly distributed amongst locations whose annual average wind speed is greater than 4.6 m/s and less than or equal to 5.5 m/s.
    - 5% of the new installations are to be evenly distributed amongst locations whose annual average wind speed is less than or equal to 4.6 m/s.

Regionalisation of photovoltaic systems

- 50% of the new installations vis-à-vis 2011 are to be locally distributed in proportion to the previously installed PV capacity. The regional distribution of PV capacity installed between 1 January 2009 and 30 September 2012 is to be taken from the published figures in the PV reporting procedures of the Federal Network Agency. The regional distribution of the installed onshore wind power capacity prior to 1 January 2009 is to be taken from the plant master data of the TSOs.
- 50% of the new installations vis-à-vis 2011 are to be distributed evenly amongst "buildings and open spaces". The regional distribution of "buildings and open spaces" is to be taken from the data [155] published by the Federal and Regional Statistical Offices.

Regionalisation of biomass plants

- 100% of the new installations vis-à-vis 2011 are to be distributed evenly among "arable land". The regional distribution of "arable land" is to be taken from the data [155] published by the Federal and Regional Statistical Offices.

The following deviations are made from the described procedure:

Wind turbines

- The corrected plant master database of Deutsche Gesellschaft für nachhaltiges Bauen e.V. (German Sustainable Building Council, DGNB) [62] is used.
- The average wind speed in 2011 is taken from the DWD model COSMO-EU [63]. The closest true origin coordinates are identified in the model and used for each municipality.

Photovoltaic systems

- The corrected plant master database of Deutsche Gesellschaft für nachhaltiges Bauen e.V. (German Sustainable Building Council, DGNB) [62] is used.
- Buildings and land dated 31.12.2011 are taken from the statistics published by the Federal and Regional Statistical Offices [155].

Biomass plants

- Arable land dated 31.12.2011 is taken from the statistics published by the Federal and Regional Statistical Offices [155].

In addition to the regionalisation of the service offered by renewable energy systems, the demand for electric power has to be regionalised. The study is based on the profile of the load time series for Germany as published by *ENTSO-E* [64]. Regionalisation distinguishes between demand from households and the commercial sector. For every point in time, a fixed ratio of household to commercial load is assumed that corresponds to the ratio of the annual energy demand of both sectors [65]. Regionalisation is implemented as follows:

Regionalisation of the electrical load

- 26.6% of the load is distributed in proportion to the population figures of all German municipalities. The population figures are drawn from the municipality directory of the Federal Statistical Office, which was updated after the 2011 census.
- 73.4% of the load is distributed in proportion to the gross value added of all German municipalities. Gross value added is taken from the publications of the Regional Statistical Offices [156].

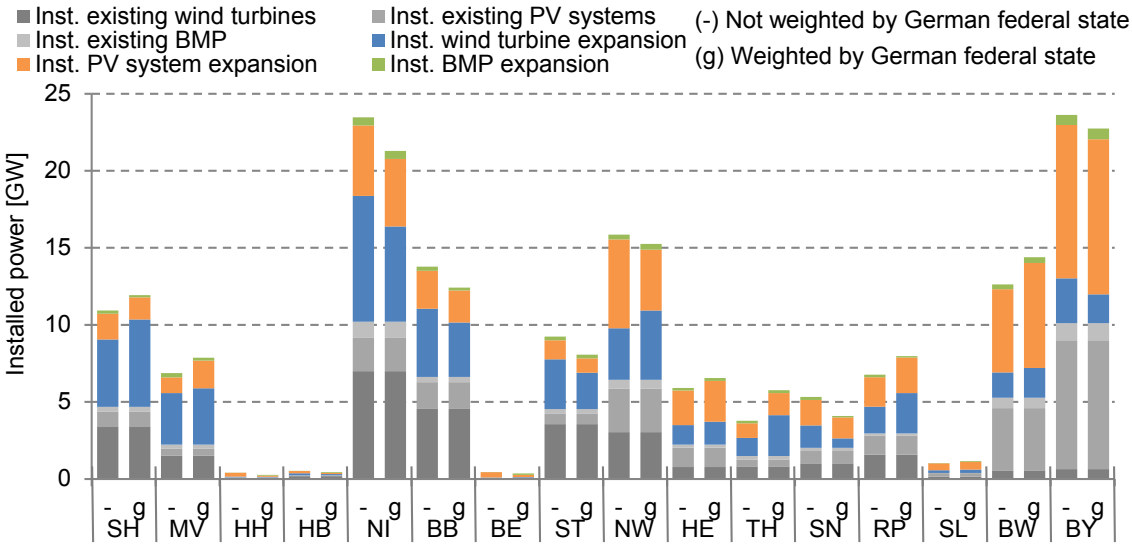

Figure A.5 shows the installed capacity of wind turbines, PV systems and BMP per German state with and without state weighting. Figure A.6 to Figure A.12 show the power density of the installed

capacity of wind turbines, PV systems, BMP and the electrical load in the heavy-load case per municipality relative to the average value of the year 2011.

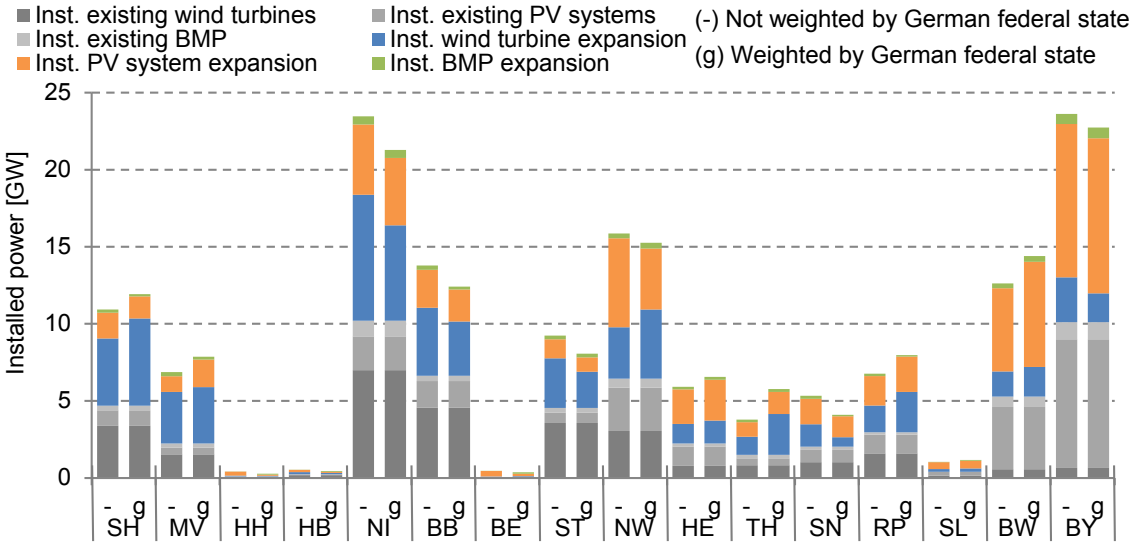

Figure A.5 Installed capacity of wind turbines, PV systems and BMP in each German state with regionalisation with and without weighting by state in 2033

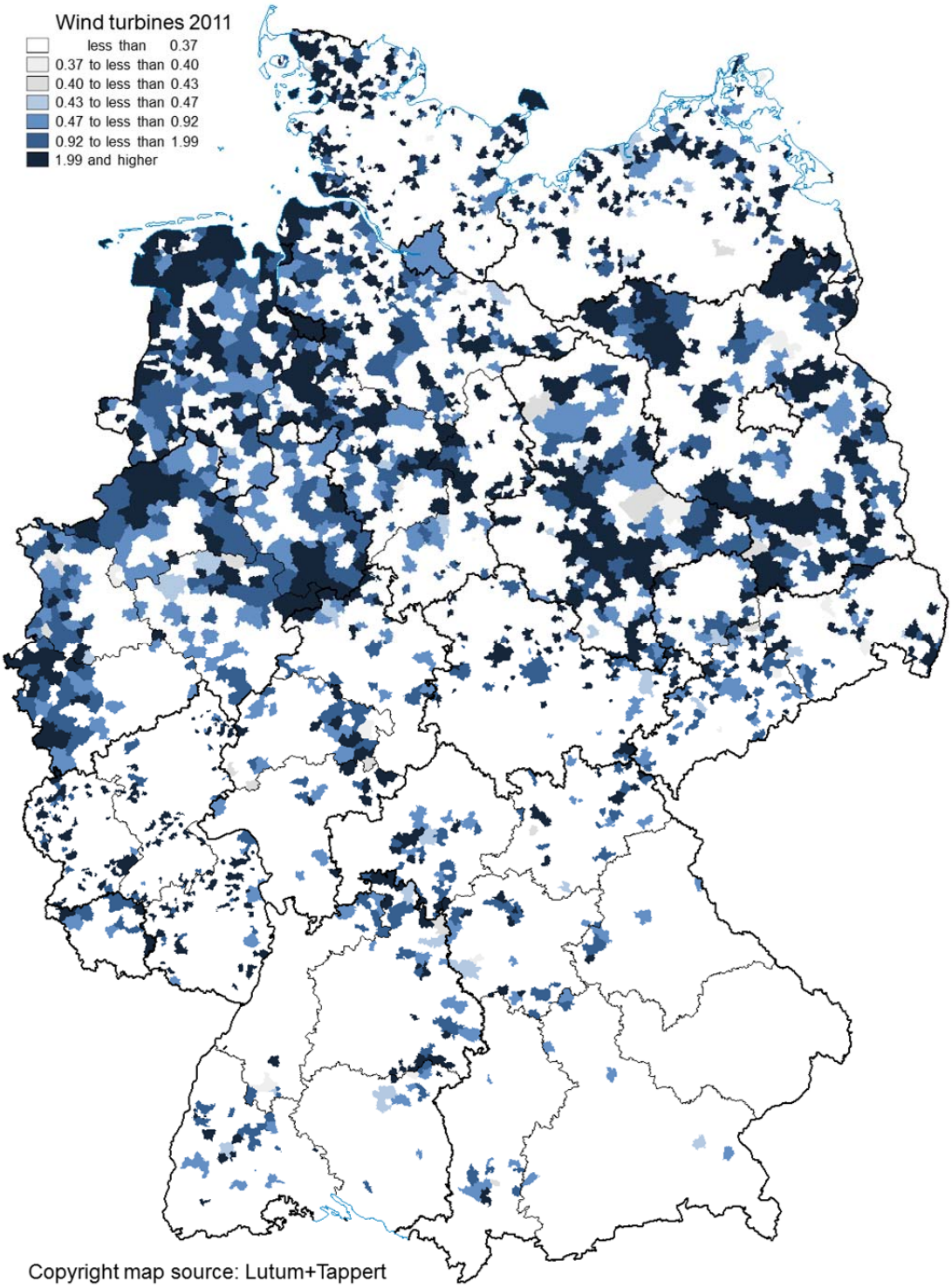

Figure A.6 Relative power density of the installed capacity of wind turbines per municipality in the year 2011

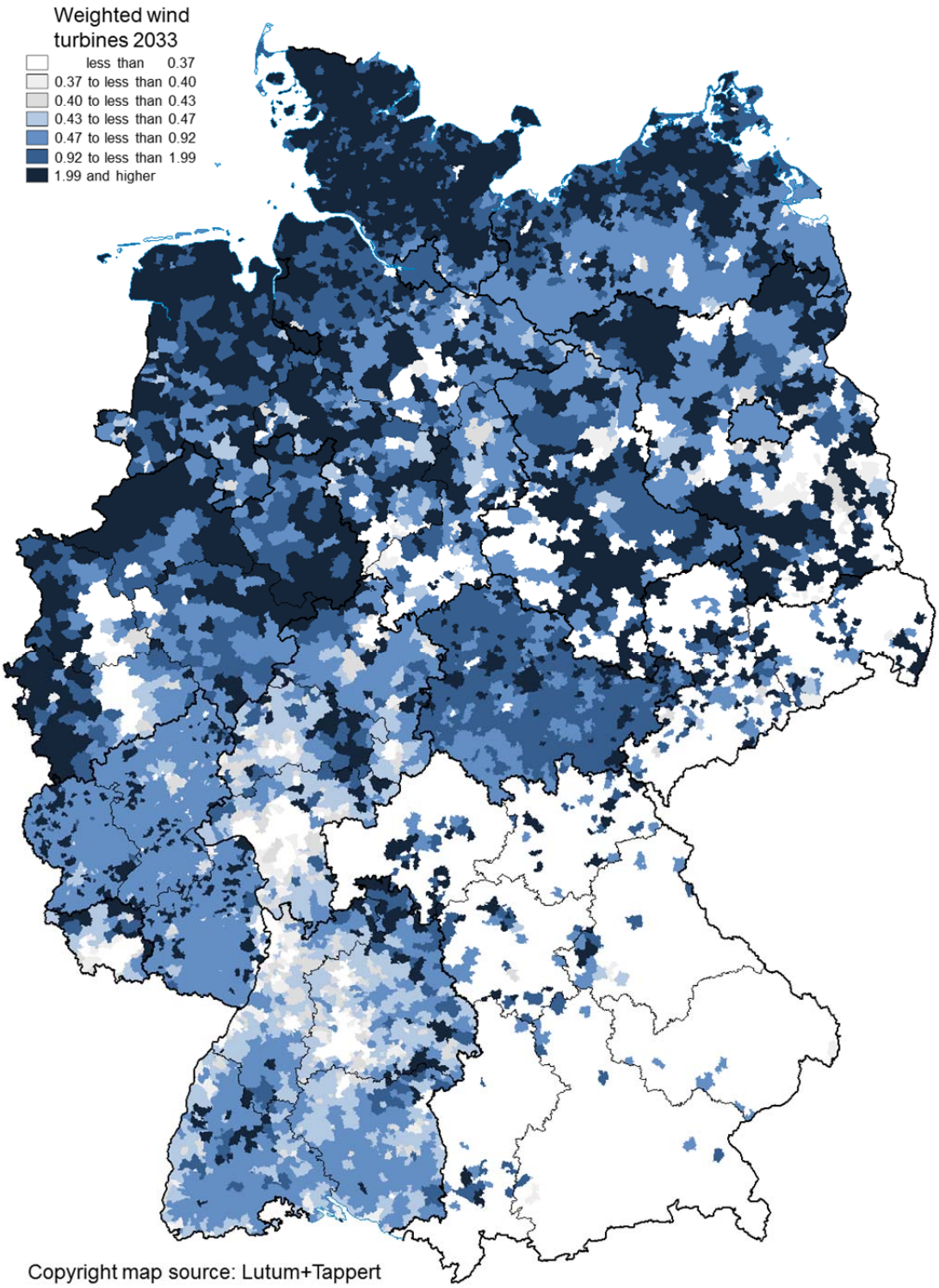

Figure A.7 Relative power density of the installed capacity of wind turbines per municipality in the year 2033, with federal state weighting

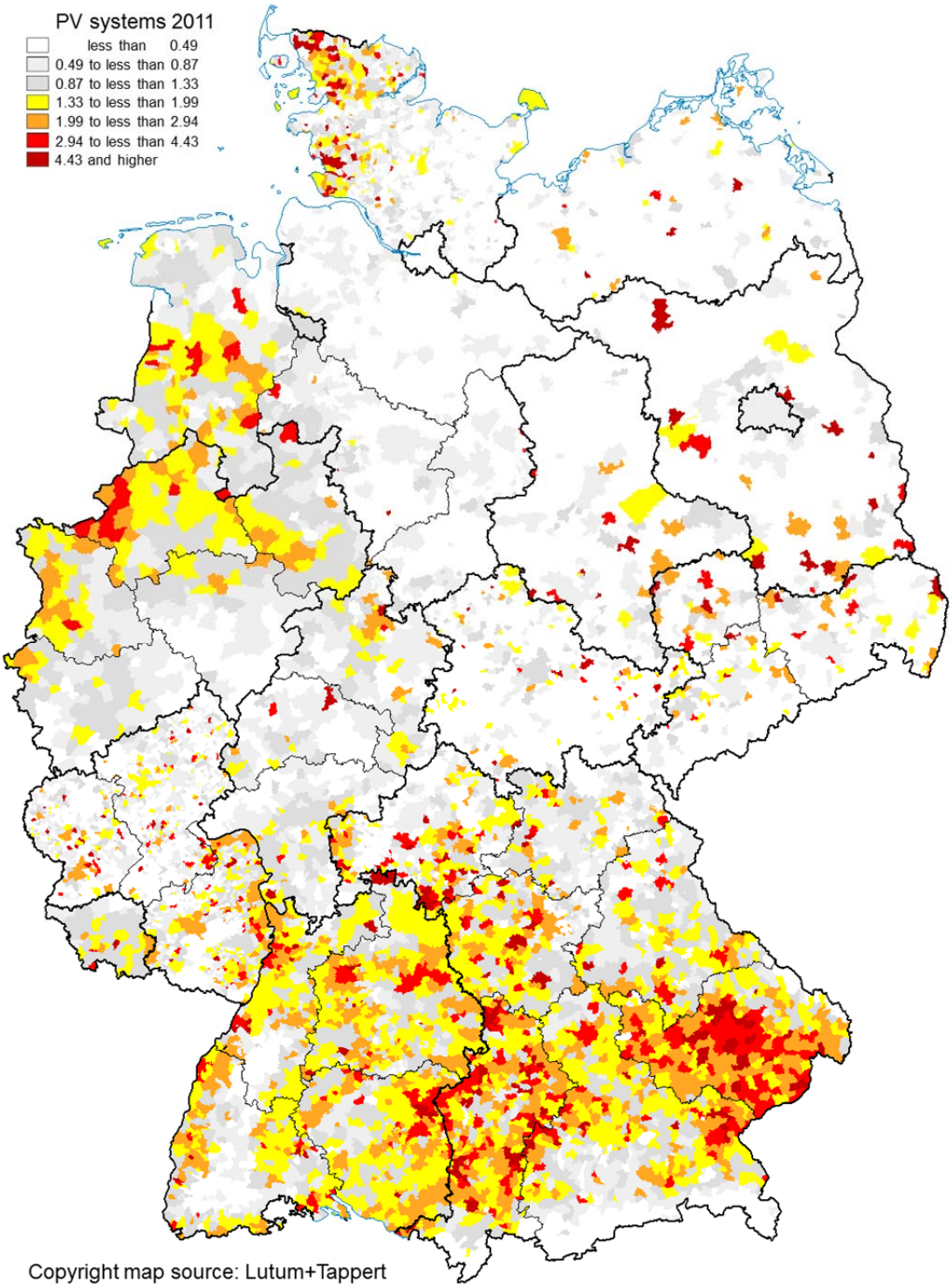

Figure A.8 Relative power density of the installed capacity of PV systems per municipality in the year 2011

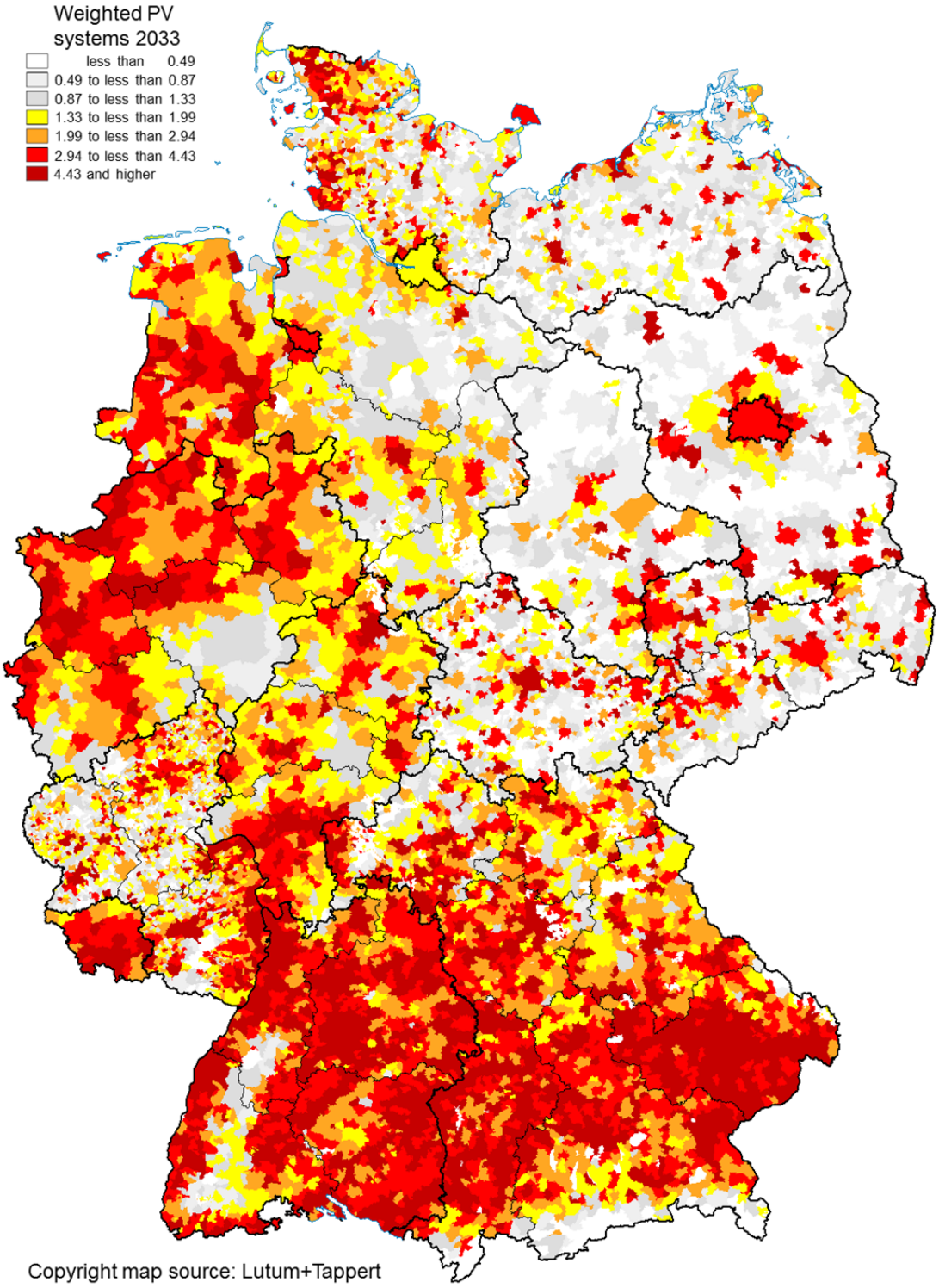

Figure A.9 Relative power density of the installed capacity of PV systems per municipality in the year 2033, with federal state weighting

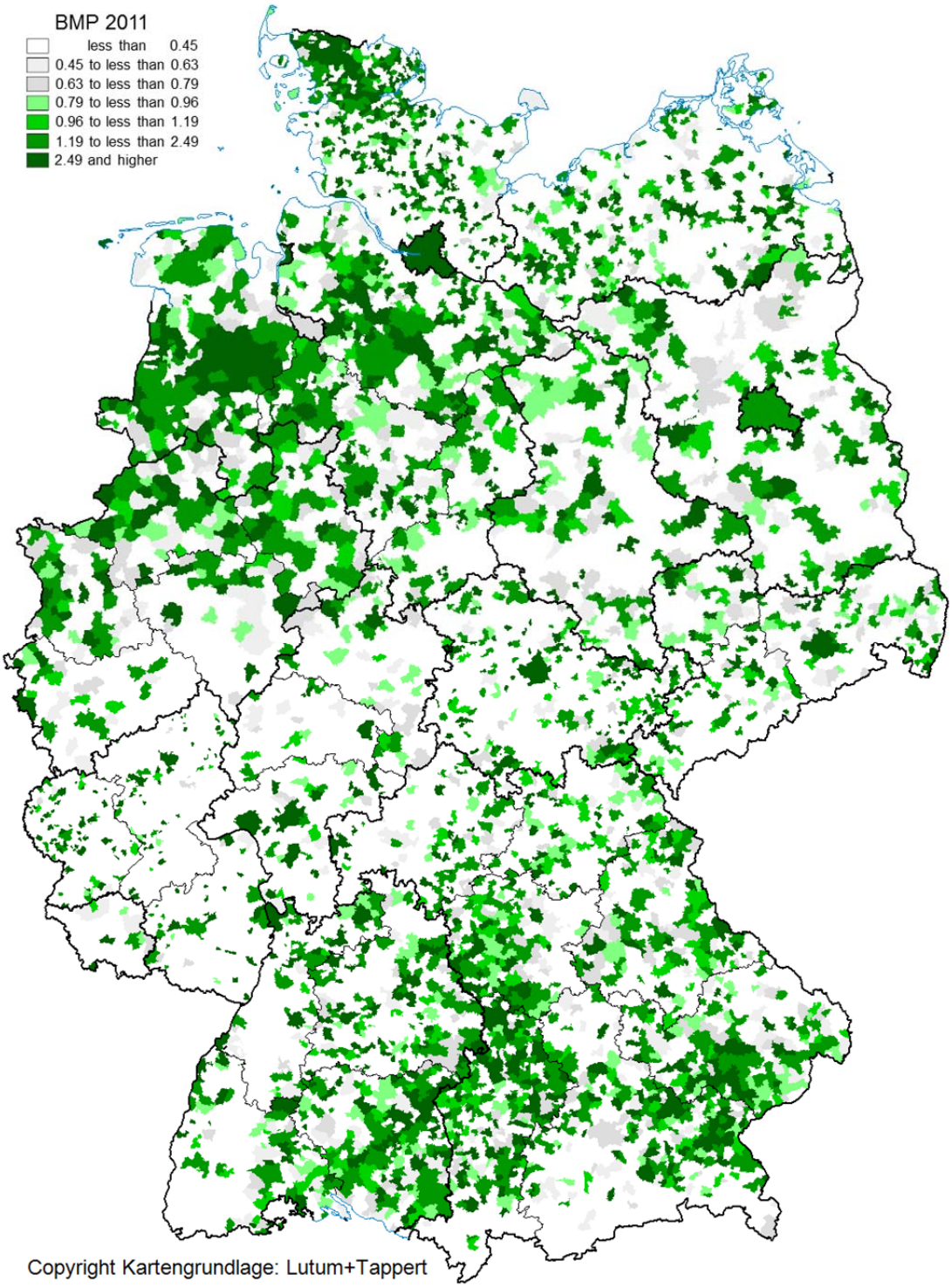

Figure A.10 Relative power density of the installed capacity of BMP per municipality in the year 2011

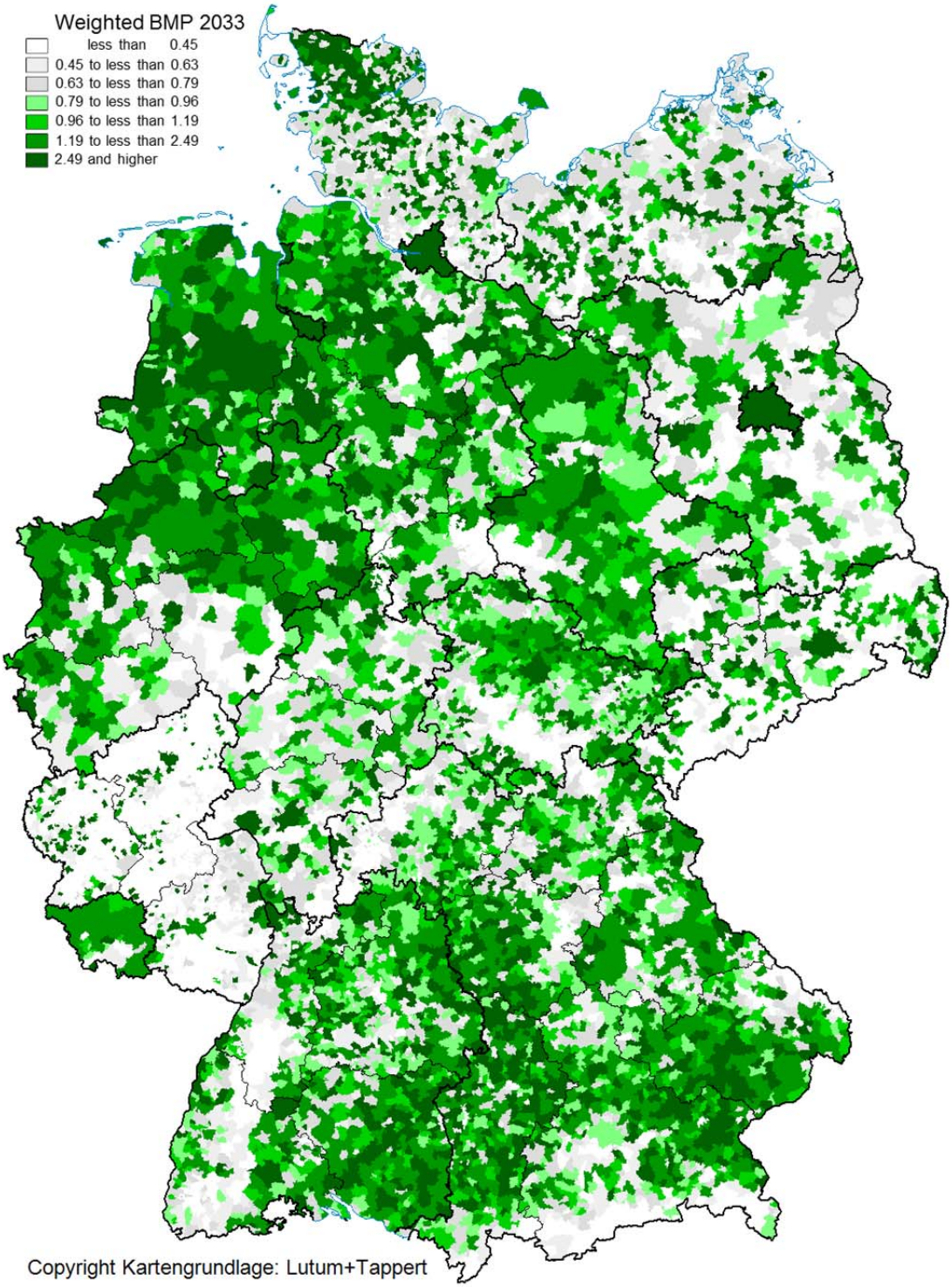

Figure A.11 Relative power density of the installed capacity of BMP per municipality in the year 2033, with federal state weighting

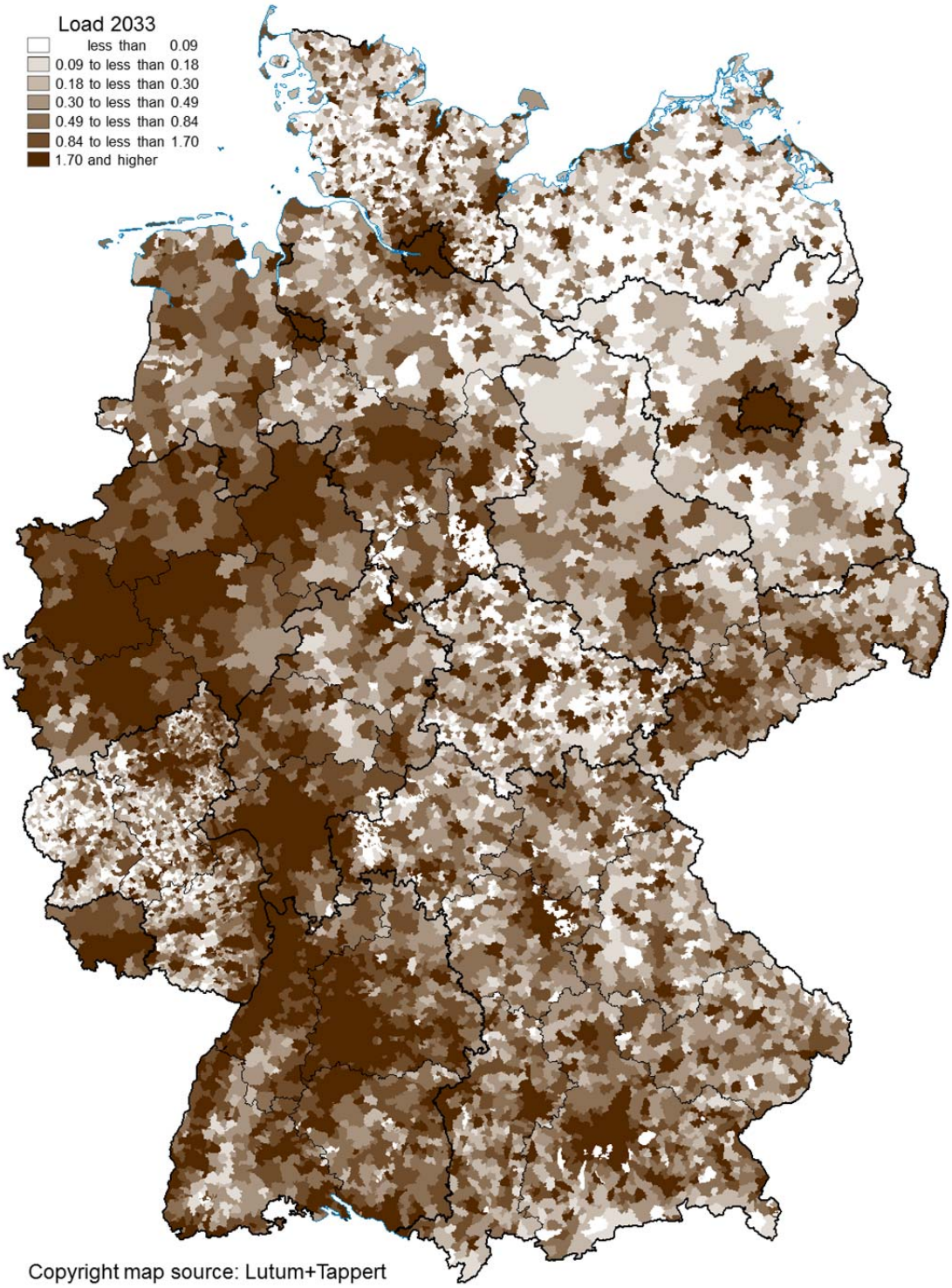

Figure A.12 Relative power density in the heavy-load case per municipality in 2033

Allocation to the voltage levels

The forecasts of the individual renewable energy systems are allocated to the different voltage levels according to Table A.3.

Table A.3 Allocation of forecasts to the voltage levels

Figures in %	Wind turbines	PV systems	BMP
LV level		60	
MV/LV level			
MV level	20	30	80
HV/MV level			
HV level	80	10	20

The nominal capacities of the individual plants or large-scale plants are determined as specified in Table A.4.

Table A.4 Nominal capacity of DECUs

Installed capacity small/large plants	LV	MV	HV
Wind turbines		3 MW	30 MW
PV systems	5 / 200 kW	400 kW	30 MW
BMP	50 / 200 kW	400 kW	

Regionalisation of the generation mix

The generation mix of 2033 is estimated using the plant list in the Platts database of 2011, and the expected installed capacity of the respective types of power plants in the federal states under consideration in accordance with the agreed scenario framework.

The regionalisation of yet to be constructed conventional power plants is preferably carried out at grid nodes where power plants of each respective type had to be shut down due to having reached their service life expectancy. Which plants had to be shut down and dismantled was determined by the year of construction data in the data base and the assumed service life of the respective type of power plant (cf. Table A.5). If no plants have to be dismantled,

new plants are mainly built in locations with good access to the respective primary energy source.

Table A.5 Service lives of the various types of power plants

Type of power plant	Technical service life [a]
Run-of- river	unlimited
Nuclear energy	50
Lignite	50
Hard coal	50
Gas and steam	45
Gas	45
Gas turbine	45
Heating oil	45
PSP	unlimited

A.2. Market model

Based on regionalisation and the resulting residual load curve, the use of the conventional European generation mix is determined under application of a market model for one year. The most cost-efficient utilisation of the generation mix required to cover the electrical load under review of the technical restrictions of the power plants and the grid is determined with an hourly resolution on the basis of fundamental input data such as primary energy prices, residual demand and transmission capacities between federal states. Technical constraints of the generation mix utilisation included minimum and maximum power output, minimum up- and downtimes, ramping limits (in operation and during startup and shutdown), and technical restrictions of PSPs such as maximum turbine and pump power. The result of the market simulation reflects the schedules of conventional power plants and storage systems, as well as the cross-border flows between the considered market areas. Moreover, prices within the market areas and the overall cost of electricity generation can be stated.

The optimisation problem formulated in the context of the market simulation is a mixed integer linear programming problem (mixed integer linear programming, MILP). This formulation allows for a direct consideration of the intertemporal, technical restrictions of

the power plants, such as minimum up- and downtimes and of ramping limits. Solving the MILP problem yields an optimal global solution for the utilisation of the generation mix, which cannot be guaranteed for Lagrangian relaxation frequently used in alternative approaches. The maximum permissible trade capacities are taken from the values published in [66] for the year under review of 2033.

A.3. Investigated hours

Figure A.13 to

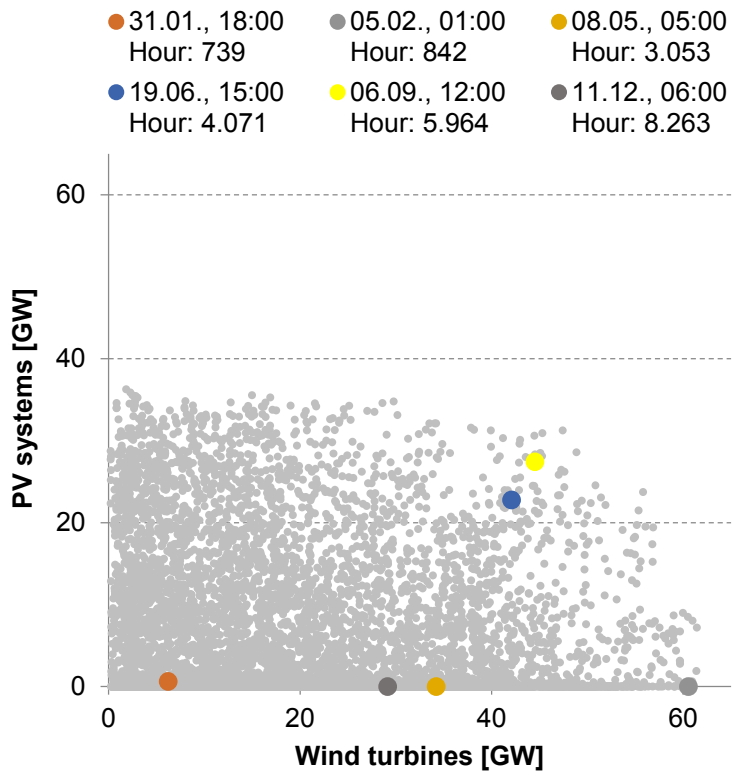

Figure A.16 compare the hours in 2011 and 2033 that are considered in the context of the investigations of this study. First, the load and supply-dependent share of RES feed-in (wind turbines and PV systems) are compared. In addition, RES feed-in is shown separately for wind turbines and PV systems.

In 2011, hours 739 and 4,901 are examined. In hour 739, a high load faces very low feed-in from RES. In this hour, conventional generation in Germany is at its peak. In hour 4901, the load is close to its minimum. At 5 pm, PV systems have not yet started injecting power into the grid. With 12.2 GW, wind turbine feed-in reaches 62% of the maximum feed-in reached in 2011. In this hour, conventional generation in Germany is at its minimum. The

selection of hours for 2033 follows similar criteria. Hours 842, 4,071 and 5,964 exhibit a new characteristic. In hour 842, wind turbine feed-in is near its maximum value in 2033, while PV systems are not feeding any power into the grid. In hours 4,071 and 5,964, there is a low load with a relatively high feed-in from both PV systems and wind turbines.

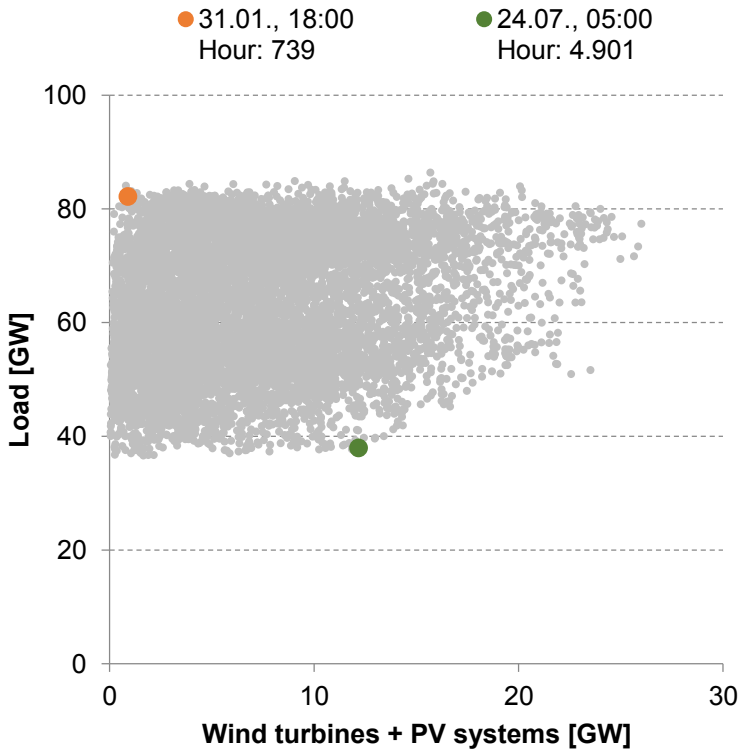

Figure A.13 Load and RES feed-in during the observed hours (2011)

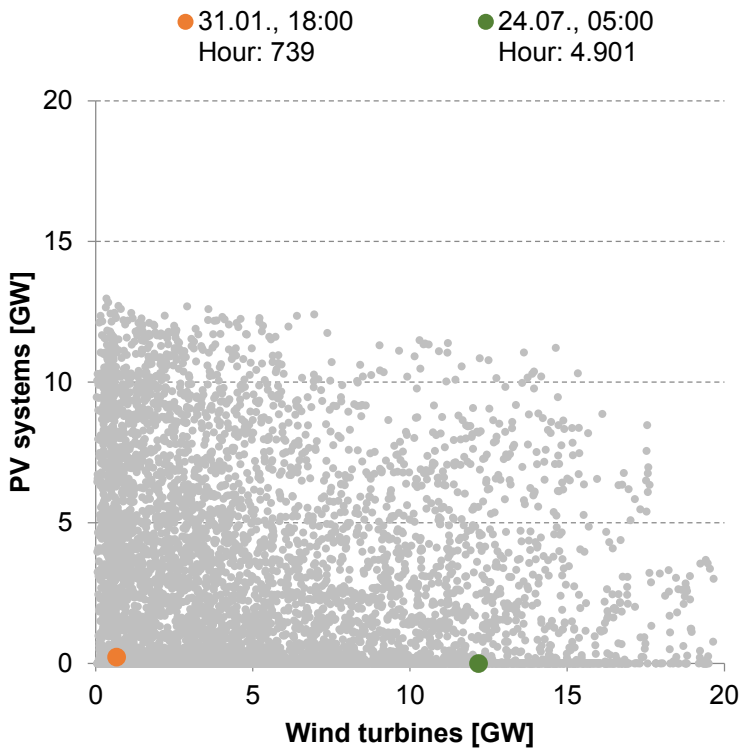

Figure A.14 PV system and wind turbine feed-in during the observed hours (2011)

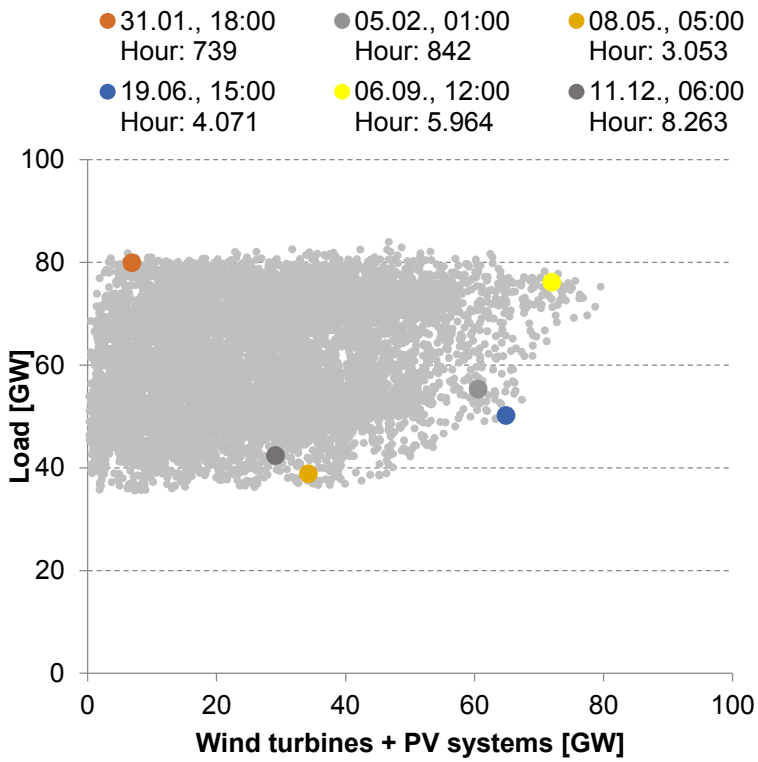

Figure A.15 Load and RES feed-in during the observed hours (2033)

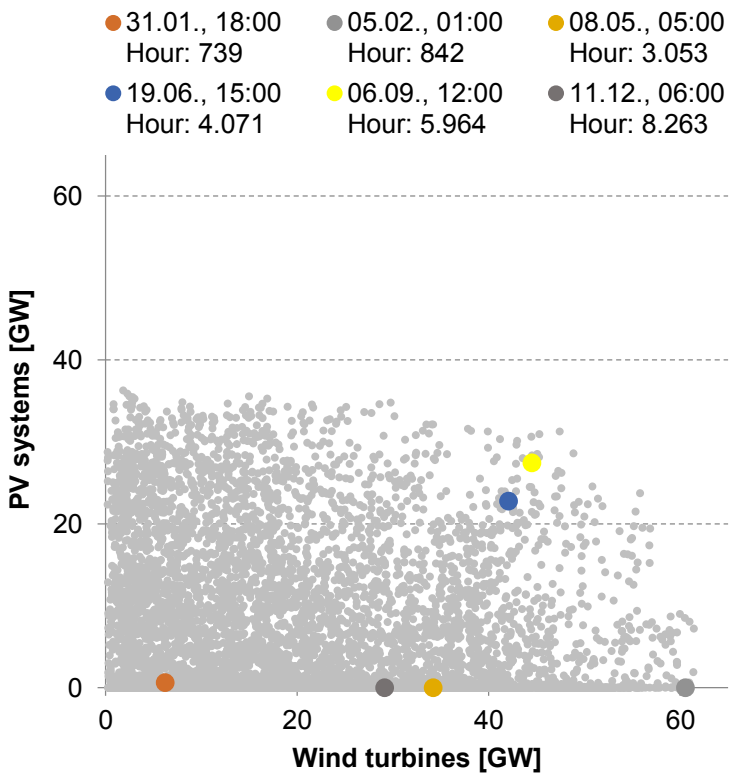

Figure A.16 PV system and wind turbine feed-in during the observed hours (2033)

Table A.6 summarises the load and feed-in data for Germany of the examined hours 739 and 4,901 in 2011, and of hours 739, 842, 3,053, 4,071, 5,964 and 8,263 in 2033. The indicated power requirement comprises the areas of load, PSP pump operation, exports and grid losses. On the feed-in side, a distinction is made between wind turbines, PV systems, other RES, conventional generation including run-of-the-river, PSP turbine operation and imports.

Table A.6 Load and feed-in data of the studied hours

	Output [GW]							
Year	2011		2033					
Date	31.01	24.07.	31.01.	05.02.	08.05.	19.06.	06.09.	11.12.
Time	18:00	05:00	18:00	01:00	05:00	15:00	12:00	06:00
Hour number	739	4,901	739	842	3,053	4,071	5,964	8,263
Load	82.20	37.97	79.91	55.36	38.85	50.21	76.14	42.42
PSP pump operation	0.00	3.94	0.00	8.97	8.8	12.13	4.37	0.00

Exports	0.00	0.00	0.00	4.60	0.00	11.10	5.35	0.72
Grid losses	3.29	1.52	3.20	2.21	1.55	2.01	3.05	1.70
Wind turbines	0.66	12.17	6.21	60.54	34.21	42.07	44.5	29.12
PV systems	0.23	0.00	0.64	0.00	0.00	22.78	27.44	0.00
other RES	3.29	3.29	5.60	5.60	5.60	5.60	5.60	5.60
conv. generation + run-of-river power plant	72.62	24.27	53.32	5.00	6.78	5.00	11.37	10.11
PSP turbine operation	3.94	0.00	7.94	0.00	0.00	0.00	0.00	0.00
Imports	4.75	3.70	9.41	0.00	2.62	0.00	0.00	0.00

Figure A.17 compares the modelled PV systems and wind turbine feed-in with the data from 2011 published in [155]. The comparison for the period around hour 4,901 in 2011 (24.07., 5 am) is shown. It is evident that the profiles of the published data of the EEX model are depicted realistically.

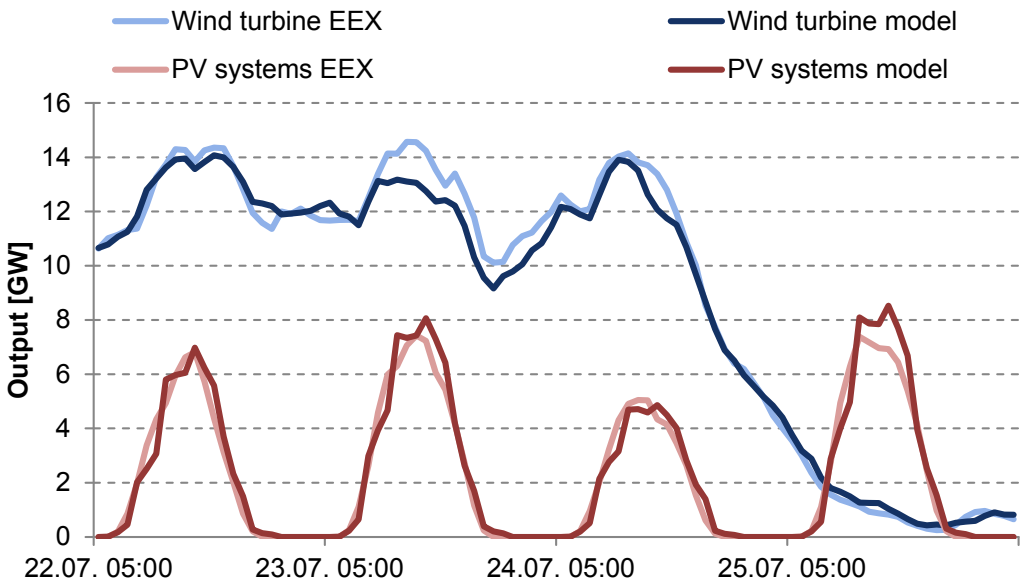

Figure A.17 Comparison of EEX and model data in July 2011 [157]

B. Planning and operational principles

B.1. Transmission grid model

To determine the reactive power demand of the transmission grid, the aggregate grid model of the Institute of Energy Systems, Energy Efficiency and Energy Economics (ie³) is used. Grid expansion measures of NEP 2012 [4] are taken into account.

The grid model comprises the entire *ENTSO-E* area. The real grid is reduced to about 300 nodes, of which 31 are in Germany. This aggregation process allows a more easy identification of factors that cause congestions or that endanger stability. The characteristics and properties of the real grid are retained, so the informational value of the model is comparable with that of the actual grid. The direct identifiability of individual real nodes and lines is hampered in the model, the electrical properties are, however, reproduced in good approximation.

Since accurate data on the transmission grid is not public available, a simulation of the transmission grid using public available data and grid maps[2]. In the development of the reduced grid, real grid nodes that are close together were aggregated, so that, for example, the concentrated generation in the Rhine-Ruhr metropolitan region is represented by two nodes. The line lengths were estimated using grid maps in order to present a qualitative and representative picture of the transmission grid. The line parameters used are those of typical overhead lines. Similar lines are used throughout Europe.

Grid conditions of possible future scenarios can be considered with different grid variants. To this end, already known expansion measures [1] were considered. Figure B.18 and Figure B.19 show the grid model used in its ground state 2011.

---

[2] *ENTSO-E* grid map 2007-2011 https://www.entsoe.eu/resources/grid-map/

Figure B.18 Section of the aggregate transmission grid model of Europe

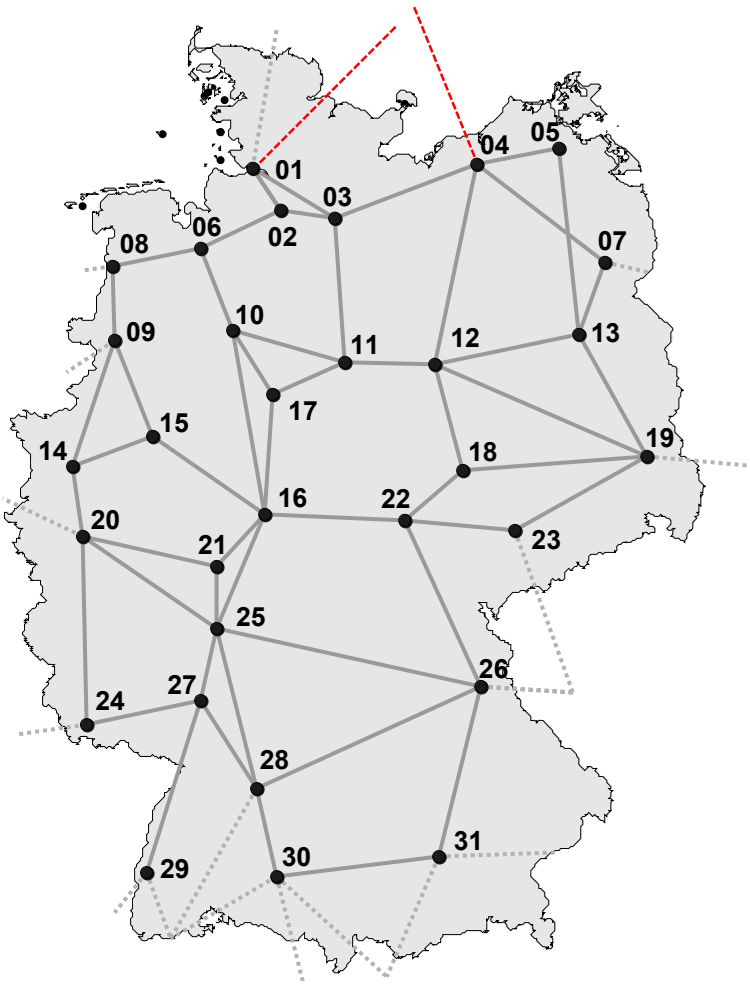

Figure B.19 Aggregate transmission grid model in Germany

There may be domestic grid congestions in extreme scenarios caused by regionalisations deviating from TYNDP/NEP 2013, and by a deviating generation mix utilisation or a different scenario framework.

B.2. Planning and operational principles in the low, medium and high voltage level

Prior to a determination of the potential of reactive power provision for higher-level grid levels, the distribution grids must be expanded to fulfil the task of supply in the respective scenario. This section describes the assumptions made regarding the applicable operating limits and the standard grid expansion measures, which mostly correspond to the dena distribution grid study [2].

EN 50160 describes the minimum requirements on voltage quality at the consumers. As required by EN 50160, the permissible voltage change at the LV end consumer is ± 10% of the nominal voltage. The voltage band of U_N ± 10% is split between the LV and MV level by the DSO..

In this study, the following distribution of the voltage band is defined:

- ± 4% for the LV level
- ± 2% for the MV/LV level
- ± 4% for the MV level

Voltage compounding by HV/MV transformers and the static adjustment of the tapping of MV/LV transformers are represented implicitly in the present study by idealised voltage value requirements made by higher voltage levels.

The (n-1)-secure supply of consumers in the MV level is an applied planning principle. This is why a sufficient reserve must be kept for the (n-1) case. For this purpose, a short-term load of 100% of the rated apparent power under load (load factor m = 0.7) is permitted for HV/MV transformers, MV cables and MV overhead lines in the (n-1) case. A maximum permissible load in the (n-1) case implies a maximum load of 50% for normal operation. The (n-1) criterion described here is also used in the HV level. Table B.7 summarises the permissible loadings of the equipment in the LV, MV and HV level.

Table B.7 Permissible loadings of the equipment in the LV, MV and HV level

Operating resource type	Permissible loads
EHV/HV transformer	50%
HV lines	50%
HV/MV transformer	50%
MV lines	50%
MV/LV transformer	100%
LV lines	100%

In addition to thermal loadings, voltage change is the second significant design parameter. The 3% and 2% voltage criterion of the grid connection codes for DECUs in the LV and MV grid is often

referred to as a technical limit of the line receptivity for DECUs [67]. In [68], the following formulation is used in this context:

"During normal operation of the grid, the voltage change caused by all DECU *(with a point of common coupling in the LV level) shall not exceed a value of 3% compared with the voltage without* DECU *at any point of common coupling in a LV grid."*

The guideline for DECU in the MV grid as written by BDEW in 2008 uses an identical expression, however, it permits a voltage change of only 2% in the MV level [69].

The 2% or 3% voltage criterion is **not** considered in this study, since a consideration would greatly limit the grid connection capacity of decentralised plants although no operating limits are violated [2].

Standard LV/MV grid expansion variants

As part of the standard expansion variants of the study, a critical line loading is avoided by a parallel line across one half of the line's length. In critical voltage conditions, a parallel line along two thirds of the line length is used.

Standard HV grid expansion variants

The planning principles are limited to a demand-appropriate construction of new lines, but do not make any structural grid optimisation measures. Overloaded lines are replaced with the standard equipment in use. If these measures are not sufficient, the overload must be corrected by additional overhead lines, which increase the intermeshing of the grid, or by new 380 kV connection points.

Underground cables have a significantly lower impedance than overhead lines. Therefore, the use of cable systems in parallel to existing overhead lines leads to a significant relief of the transmission line when the new cable system is high loaded. For this reason, new cable routes are not considered in the present study.

Primary technical equipment

To incorporate grid enhancement measures in the analysis of the LV and MV levels, equipment are uniformly used as per Table B.8. In comparison with the construction of overhead lines, the use of underground cables finds greater acceptance, so grid enhance-

ment measures in the LV and MV level are implemented exclusively with underground cables.

Table B.8 Standard operating resources in the LV and MV levels

Equipment type	Equipment
LV cable	NAYY 4x150
MV/LV transformer	Rated power 630 kVA
MV cable	NA2XS2Y, 3x1x185
HV/MV transformer	Rated power 40 MVA

The equipment used in the HV level are listed in Table B.9. For cables, the ampacity is set to 80% of the nominal value due to the laying procedure and possibly occurring multiple bundles and a reduced thermal conductivity of the ground.

Table B.9 Standard equipment used for grid expansion planning in the HV level

Figures in kA	$I_{Nominal}$	$I_{permissible}$
HV overhead line 265/35 Al/St twin conductor	1.36	1.36
HV cable N2XS(FL)2Y 3x1x800RM/50	0.89	0.712

Operating conditions for grid planning

In terms of the quality of supply, electrical distribution grids must meet the qualitative minimum requirements both in the peak load case and in the low load case with a high DECU feed-in. The scaling factors in Table B.10 are used to dimension the LV, MV and HV grids for the design-relevant peak load case and the low load case with a high DECU feed-in. The listed factors refer to the installed capacities and forecasts for the energy source in the respective study region.

Table B.10 Scaling factors in the LV, MV and HV levels for feed-in and load, relative to the installed capacity

Figures in %	LV		MV		HV	
	Peak load case	low load case with high DECU feed-in	peak load case	low load case with high DECU feed-in	peak load case	low load case with high DECU feed-in
Load	1	0.10	1	0.15	1	0.35
Wind turbines	-	-	0	1	0	1
PV systems	0	0.85	0	0.85	0	0.85
BMP	0	1	0	1	0	1

According to [70], existing PV units can be set at a maximum of 85% of the module capacity for grid calculations. This is supported by studies on the maximum global irradiation, inverter dimensioning and the evaluation of measured data.

In higher voltage levels, there is a stronger mixing of the stochastic behaviour of the consumers. Therefore, a higher share of the load is taken into account in the case of low load and a high DECU feed-in in the MV and HV levels than in the LV level. A $\cos \varphi = 0.95_{ind.}$ is assumed for all loads.

C. Assumptions on balancing power dimensioning

C.1. Static method (today's convolution-based approach)

To determine the required CR quantities, the following assumptions are made for the static method. All forecast errors and the load noise are assumed to be normal distributed.

Table C.11 Input parameters of the static method for CR determination in Chapter 2

Influencing values		Value	Source
System values 2033			
Annual peak load	P_N	84.0 GW	[4]
Inst. capacity wind (on- and offshore)	P_W	91.6 GW	[4]
Inst. capacity PV	P_{PV}	65.3 GW	[4]
Generation mix	As per appendix A.2		[4]
Forecast errors 2033			
Load noise	σ_{LR} μ_{LR}	0.41% 0.00%	[135]
Load forecast error	σ_{LP} μ_{LP}	1.67% 0.00%	[135]
Forecast error wind energy	σ_W μ_W	0.85%[3] 0.11%[7]	[1]
Forecast error PV	σ_{PV} μ_{PV}	0.85%[7] 0.00%[7]	[1]

[3] Relative to the nominal capacity

C.2. Adaptive method

The input parameters from Table C.12 are used for the adaptive method of determining the demand for CR. The time series used for grid load, wind and PV feed-in correspond to the generated time series for 2033 in Chapter 2. To calculate the demand for CR caused by possible power plant outages, only the hourly active portion of the generation mix is considered. Information on the generation mix utilisation in this case correspond to the model results in Appendix A.2.

Table C.12 Input parameters of the static method for CR determination in Chapter 2

Influencing values		Value	Source
Time series for: grid load, wind power, PV	as listed in appendix A		
Hourly generation mix utilisation	as listed in appendix A		
Forecast errors 2033			
Load noise	σ_{LR} μ_{LR}	0.41 0.00%	[135]
Load forecast error	σ_{LR} μ_{LR}	0.41% 0.00%	[135]
Forecast error wind energy	$\sigma_{W,m}(P_W)$ μ_W	1.1% - 8.4%[4] 0.11%[8]	own analyses, similar [1]
Forecast error PV	$\sigma_{W,m}(P_{PV})$ μ_{PV}	2.2% - 8.4%[4] 0.00%[8]	own analyses, similar [1]

Unlike the static method, the adaptive method can account for the capacity-dependence of the wind and PV forecast error. Large wind forecast errors occur due to the non-linear capacity curves of wind turbines, for example, they are larger at intermediate feed-in capacities. High wind power feed-in volumes, however, exhibit lower forecast errors. Similar to the approach in [1], the power de-

[4] Relative to the respective feed-in capacity

pendence of the forecast error for wind and PV feed-in is taken into account in this approach.

D. Provision of instantaneous reserve in Europe

In the following, a Europe-wide analysis is carried out in which the entire instantaneous reserve is to be provided from DECUs or storage systems. This is only a theoretical estimation of the potential using alternative suppliers to reveal how many plants are required, and to identify the corresponding magnitude.

For scenarios I and IV, the following is examined:

- The contribution to instantaneous reserve that wind turbines and PV systems can theoretically afford by throttling,
- How many plants are needed to provide instantaneous reserve from the rotational energy of wind turbines when they are provided with an appropriate control (cf [131]),
- And the performance and capacity of storage systems required in order to provide instantaneous reserves.

It should be noted that for all considerations, the current feed-in capacity of wind turbines and photovoltaic systems is assumed, which is used to estimate the theoretical potential for provision.

Wind turbines and PV systems can make a contribution to instantaneous reserve by appropriate throttling measures. In this case, the plants are no longer operated at their optimum operating point and therefore do not supply the maximum possible active power. In Figure D.20, the current wind turbine capacity is exemplarily throttled by 30% in order to fully and initially provide the required power and kinetic energy required to cover the generation outage of 3 GW in Scenario I with wind turbines.

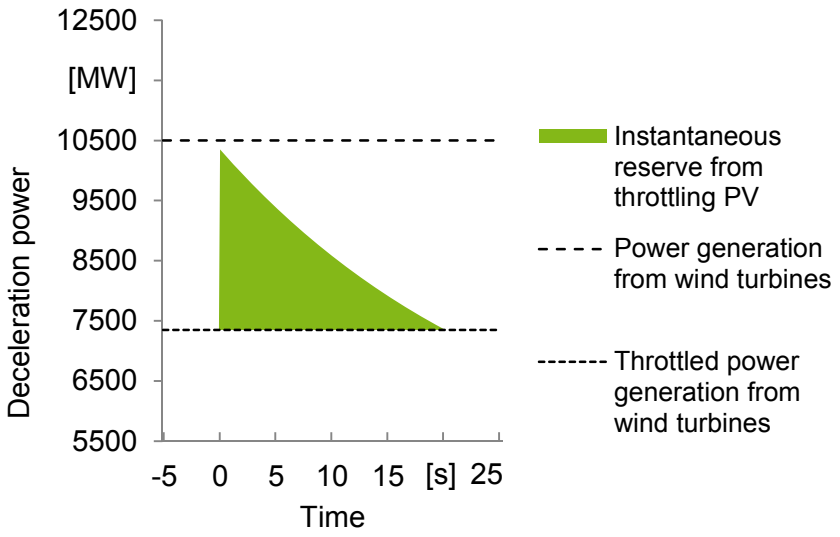

Figure D.20 Scenario I: Instantaneous reserve gained by throttling wind turbines

The generating capacity is reduced from 10.5 GW to 7.4 GW. The capacity difference of 3.1 GW can be used to provide the required power and kinetic energy of 7.4 MWh in case of a generation outage. To achieve this, the plant is controlled in a way that the generating capacity is increased during throttling in the event of a frequency dip. In this case, the generating capacity of the wind turbine is sufficient, given suitably heavy throttling, to replace the generating capacity of the instantaneous reserve. Whether or not the generating capacity of wind turbines can be increased fast enough remains to be verified. Throttling the plants also means that a part of the available capacity and energy is no longer available.

Assuming that PV units connected to the grid at that moment participate in the provision of instantaneous reserve on a percentage basis in addition to wind turbines, the capacity development shown in Figure D.21 is the result.

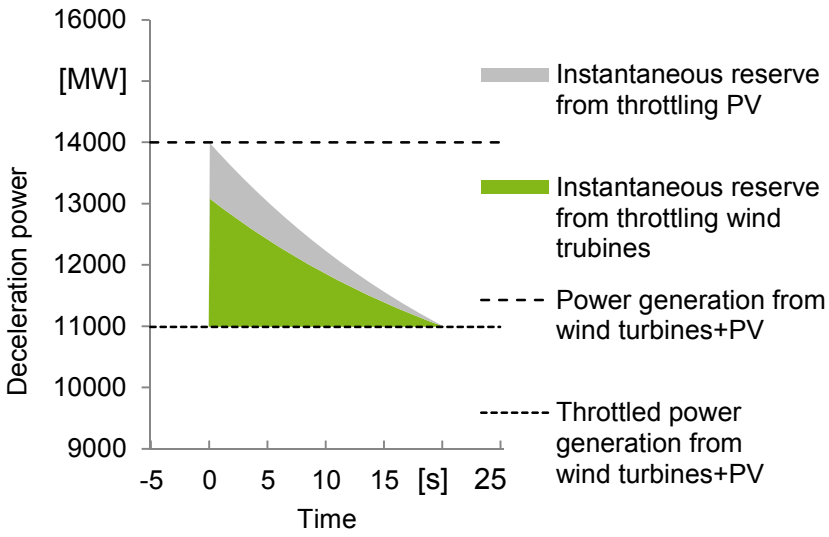

Figure D.21 Scenario I: Instantaneous reserve from the combined throttling of wind turbines and PV units

The generating capacity of wind turbines and PV units is 14 GW while unthrottled. With the additional throttling of PV units by 26%, the extent to which wind turbines need to be throttled is reduced to 20%. This amounts to a capacity difference of 3 GW. It should be noted that the generating capacity of wind turbines and PV units is low during this hour. In Scenario IV, the generating capacity of wind turbines is larger by a factor of six compared with Scenario I. This lowers the necessary throttling to 5% if only wind turbines are throttled.

In addition to throttling plants, wind turbines can provide instantaneous reserve by dumping kinetic energy from the rotor if they are provided with an appropriate control. Based on [131], it is estimated how many wind turbines would have to be available to contribute to the instantaneous reserve.

In order to muster the required kinetic energy of about 7 MWh in Scenarios I and IV using the rotational energy of wind turbines, 12,600 plants are required with an appropriate control. It is assumed that all wind turbines have a nominal capacity of 2 MW, and that they can increase their current generating capacity by 10% of their nominal capacity for 10s in the event of a generation outage. Taking into account the necessary compensation capacity of 3,000 MW, a number of 15,000 required plants is the result considering a wind turbine capacity of 2 MW. It turns out that wind turbine energy dumps are design-relevant. For this number of tur-

bines, the result is a kinetic energy of 8.3 MWh. According to the scenario principles, an installed wind turbine capacity of 263 GW can be assumed for 2033. Assuming that the turbines are 2 MW turbines exclusively, a number of 131,500 would be the result. It is important to note that only those turbines that are connected to the grid can contribute to frequency control. Depending on the wind supply, therefore, the actual number of turbines that can contribute to frequency control may be lower. As a worst-case estimate in Scenario I, a minimum of 5,250 turbines will be grid-connected and supply power, assuming a 100% wind turbine load with a wind power feed-in of 10.5 GW and a turbine capacity of 2 MW. It is evident that only about one third of the required 15,000 wind turbines are available to provide instantaneous reserve.

It must be examined whether a direct participation in the generation outage by means of rotational energy dumping in all wind turbines would lead to a lack of so much power in the grid that this would lower the frequency.

Analogous to the design of wind turbines for the provision of instantaneous reserve, storage systems can also be used. In this case, the storage system capacity required is also 3,000 MW. In order to provide the minimum required storage capacity of 7 MWh, the storage system must be able to store the power for a duration of 8.4 s.

Finally, Figure D.22 and Figure D.23 show the results of the provision options of alternative instantaneous reserve suppliers for Scenario I and Scenario IV respectively.

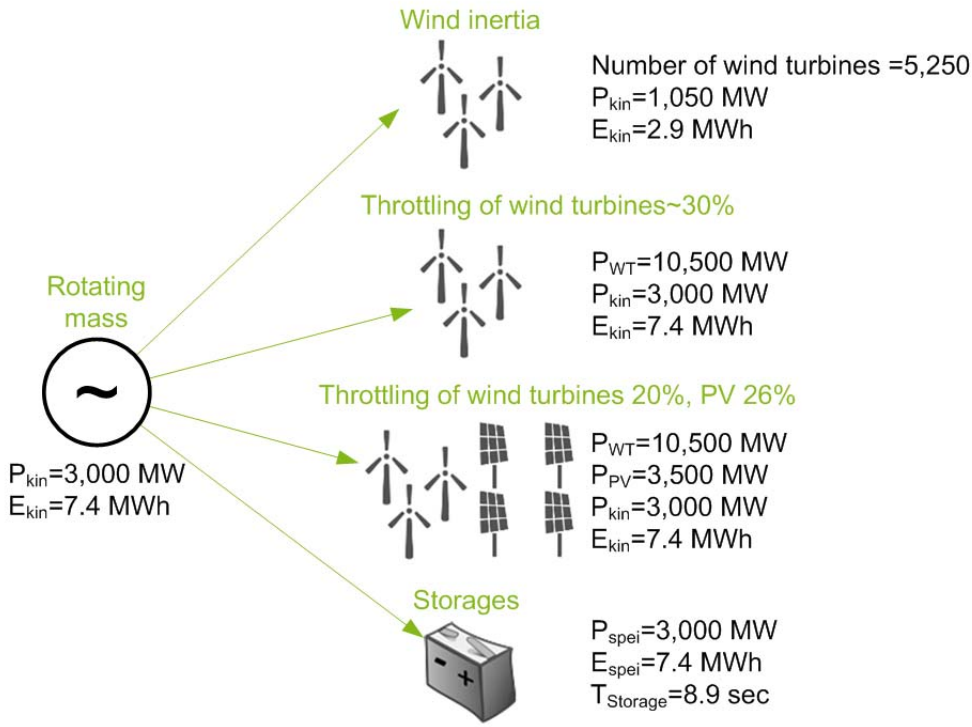

Figure D.22 Scenario I: Results overview of alternative suppliers for the provision of instantaneous reserve

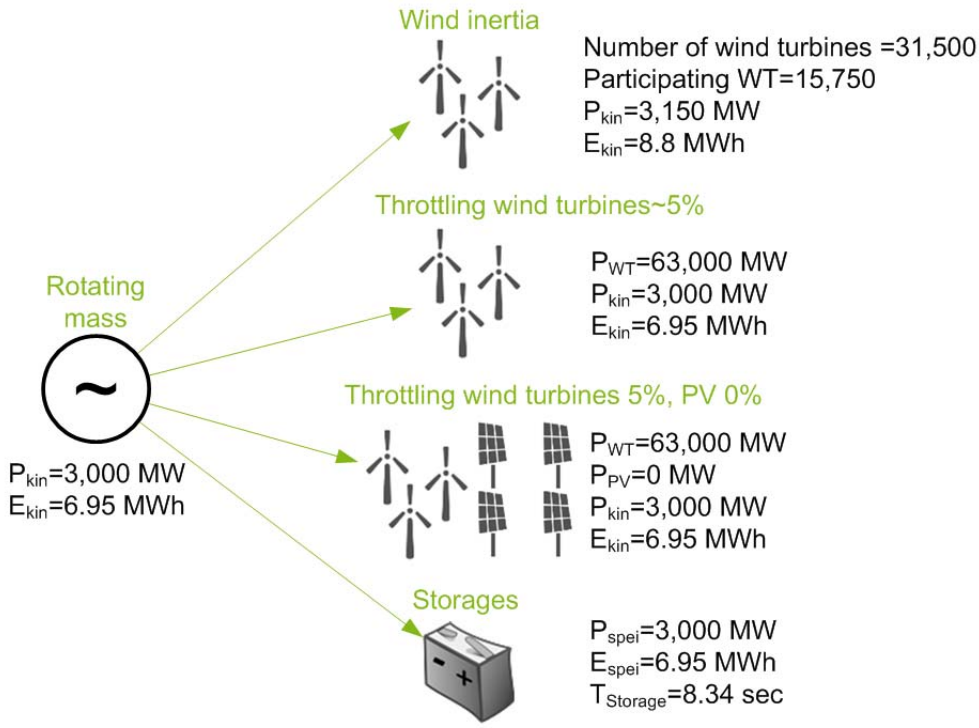

Figure D.23 Scenario IV: Results overview of alternative suppliers for the provision of instantaneous reserve

It should be noted that any alternative supplier separately contributes to the provision of instantaneous reserve, i.e every supplier makes a contribution regardless of the other. A combination of all suppliers for the provision of instantaneous reserve is conceivable, in particular due to the fact that in Scenario I, wind inertia alone is insufficient to generate both the required capacity of 3,000 MW and the kinetic energy of 7.4 MWh. In contrast, it is not necessary for all wind turbines to contribute to wind inertia in Scenario IV. Comparing the scenarios shows that given a high wind turbine feed-in capacity, the plant must only be slightly throttled for it to make a contribution to instantaneous reserve. When considering storage systems, a minimum storage system capacity of 3,000 MW is required. The necessary energy dump duration is calculated specific to the scenario and the required kinetic energy.

The considerations of alternative suppliers for the provision of instantaneous reserve assume that all wind turbines, PV units, and storage units in the entire *ENTSO-E* grid area contribute to provision.

E. Definitions

Instantaneous reserve

In the first few milliseconds, an active power imbalance leads to a change in the kinetic energy of the rotating masses in conventional large-scale power plants. The inertia of the rotating masses of the generators supports frequency control until the control reserve, which is divided into three types according to its CR lead time, sets in.

Primary control reserve

PCR is automatically activated and the operator must be able to supply it within 30 seconds for a duration of at least 15 minutes. PCR is tendered symmetrically, the tender period is currently one week. Its provision is based on the principle of solidarity and is afforded by all TSOs that are synchronously connected within the *ENTSO-E* grid area.

Secondary control reserve

The affected TSO immediately and automatically activates SCR after a controlled and specific energy exchange between the balancing zones of the GCC has taken place. Full provision has to occur within a maximum of 5 minutes. The tender duration of SCR is one week, and the products distinguished by high-rate tariff and low-rate tariff are traded separately for the positive and negative balancing directions.

Minute reserve

MR is a schedule-based activation by the TSO. MR activation takes place in quarter-hour intervals, and is fully automatic since July 2012. MR is tendered separately for the positive and negative balancing directions, each with six time slices over a period of 4 hours.

Interruptible loads

Following the intent of the "Regulation on agreements on interruptible loads" (AbLaV) from 28.12.2012, interruptible loads are regarded as large consumption units that are connected to the HV and EHV grids, and that draw large amounts of power nearly constantly. Upon activation by the TSO, these loads must be able to

lower or terminate their consumption at short notice for a defined minimum duration.

Static voltage stability

Static voltage stability is to be understood as voltage stability in the energy supply system in normal operating conditions, in which the slow voltage changes in the grid are kept within acceptable limits, thus maintaining security of supply. The relevant grid operator is responsible for voltage stability in the respective transmission and distribution grid.

Decentralised energy conversion plants (DECUs)

The term DECU describes distributed systems that are connected to the electrical grid on a variety of voltage levels. The feed-in capacity of this type of plant is determined primarily by the quantity of the primary energy source used, or other boundary conditions such as the required heat demand. The term DECU includes, amongst others, all decentralised suppliers such as renewable energy systems or fossil-fired CHP plants.

Renewable energy systems

The term renewable energy system applies to all systems that use energy from the sun, wind, water and renewable biomass. Explicitly, these are PV systems, wind turbines, BMP and run-of-the-river power plants. Larger power plants such as wind farms and ground-mounted solar power plants are also included.

Power generation unit (PGS)

System with one or more generating units for electrical energy (including the connection facility) and all electrical equipment required for operation.

Supply-dependent renewable energy systems

The term supply-dependent renewable energy system describe a system whose feed-in capacity is primarily determined by the presence of a primary energy source. Explicitly, these are PV systems, wind turbines, and run-of-the-river power plants.

Wind farm

The term wind farm describes a spatial accumulation of several wind turbines, all connected to the grid via a common grid CP. It is further assumed that wind farms have a communication link to the

grid operator, through which the operating point vis-à-vis the grid can be specified.

Ground-mounted solar power plant

The term ground-mounted solar power plant describes a PV system whose individual modules are placed in an open area and at ground level. It is further assumed that ground-mounted PV systems have a communication link to the grid operator, through which the operating point vis-à-vis the grid can be specified. The term ground-mounted solar power plant applies to larger PV systems.