SRU German Advisory Council on the Environment

Climate-friendly, reliable, affordable: 100% renewable electricity supply by 2050

Statement

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Foreword

In the fall of 2008 the German Advisory Council on the Environment (*Sachverständigenrat für Umweltfragen, SRU)* began work on a Special Report concerning the future of electricity generation in Germany for the period leading up to 2050. The main challenge the Council is facing is the transition to sustainable electricity production that largely avoids greenhouse gas emissions. For this Special Report, slated for publication in late 2010, the SRU is exploring, in an interdisciplinary manner, the technical, economic, legal and political challenges of transitioning to climate neutral and sustainable electricity.

In spring 2009 within the framework of this study, the SRU commissioned the German Aerospace Center (Deutsches Zentrum für Luft- und Raumfahrt, DLR) to investigate options for a reliable electricity supply completely based on renewable energy sources. Unfortunately, the head of this project, Dr. Wolfram Krewitt, died unexpectedly in October of that same year, which was a terrible loss. Yvonne Scholz completed the project in Dr. Krewitt's stead, and in so doing exhibited extraordinary commitment to it. The technical and economic scenarios developed by the SRU based on the REMix model have been finalized (DLR 2010). In addition the Council likewise commissioned the following expert reports that are discussed in the present document:

Dr. Gregor Czisch: Möglichkeiten des großräumigen (transeuropäischen) Ausgleichs von Schwankungen großer Teile intermittierender Elektrizitätseinspeisung aus erneuerbaren Energiequellen in Deutschland im Rahmen einer 100 % regenerativen Stromerzeugung mit Zeithorizont 2050, November 2009 ("Options for large scale (trans-European) compensation for fluctuations in largely intermittent electricity input from renewable energy sources in Germany within the framework of implementation of a wholly renewable electricity supply by 2050").

Prof. Dr. Heinrich Brakelmann and Prof. Dr. Istvan Erlich: Technische Möglichkeiten und Kosten transeuropäischer Elektrizitätsnetze als Basis einer 100 % regenerativen Stromerzeugung mit Zeithorizont 2050: Optionen der elektrischen Energieübertragung und des Netzausbaus, March 2010 ("Technical options for and the costs of a trans-European electricity networks based on 100 percent renewable electricity for implementation in 2050: electricity transmission and grid expansion options").

Fraunhofer Institut für Windenergie und Systemtechnik (Institutsteil Kassel): Systemkonflikt in der Transformation der Stromversorgung Berechnungen und graphische Darstellung auf der Datenbasis eines SRU Szenarios ("Project director: Dr. Michael Sterner; April 2010 ("System conflicts entailed by an electricity supply system transformation: calculations and graphics based on the data from an SRU scenario").

In view of recent events, the SRU has decided to publish the above mentioned technical and economic scenarios as a statement of position (hereinafter referred to as the "Statement") in the run-up to completion of the Special Report.

In the coalition agreement of October 2009, the governing parties (CDU, CSU and FDP) indicated their intention of "transitioning to a regenerative era" via an "energy policy that is non-ideological, embraces new technologies and is market oriented," and where nuclear energy plays a key role as a "transitional technology (...) until renewables can be deployed reliably." The German government plans to elaborate an energy concept in 2010 comprising scenario based guidelines for "a clean, reliable, and affordable energy supply" that will allow for implementation of the aforementioned goals. In August 2010, a consortium of research institutions will submit investigations on whose basis preliminary decisions concerning the guidelines are expected to be made. The scenarios reportedly center around various nuclear power plant life-span prolongation models that could potentially put the goal of "transitioning to a regenerative era" on the back burner and lack a scenario based on a wholly renewable electricity supply, as well as a scenario that would seriously investigate the issue of how the German government's climate protection goals for 2020 and 2050 can be reached without significantly extending the life span of nuclear power plants.

However, a non-ideological energy policy that embraces new technologies should also take account of these options in formulating an energy concept. By issuing the present Statement, we hope to close this gap – not by presenting our own energy concept, but rather with a view to contributing to the debate on the development of "a clean, reliable, and affordable energy supply" in presenting an option that – which we feel – should be given very serious consideration. However, our final Special Report will propose policy instruments and discuss the relevant statutory frameworks.

The present Statement is also based on the expert and dedicated work of the SRU's members and staff. Holger Höfling, Sönke Bohm and Anna Leipprand have made particularly valuable contributions to writing this document and developing its scientific material.

Scenarios concerning the distant future are invariably subject to uncertainty by virtue of being based on evolutions that are difficult to forecast. The plausibility of the assumptions on which the present report is based, as well as the consistency of the methodology used, have been externally reviewed by three independent experts, to whom we express our heartfelt gratitude for their critical and constructive feedback. However, the views expressed in the present document are solely those of the SRU.

1 Introduction

1. Germany will be facing key decisions in the coming years concerning the structure of its electricity generation, much of whose generation capacity will need to be replaced over the next two decades since many power plants will be reaching the end of their service lives by then. The investments that are made in the coming years will have a major impact on not only the structure but also the emissions associated with the electricity sector for decades (SRU 2009b). This situation presents an opportunity to set in motion a relatively low cost but far reaching infrastructure reorganization process.

Climate study findings indicate that Germany and other industrial nations will need to reduce their greenhouse gas emissions by 80 to 95 percent by 2050 (IPCC 2007) – a goal that was officially endorsed by the Council of the European Union in October 2009 (Council of the European Union 2009). Germany's ambitious environmental goals are backed by broad and nonpartisan support from all social actors. The present German government has endorsed the national goal of reducing greenhouse gases by 40 percent by 2010 (relative to 1990 levels) and has also recognized the need to further reduce these gases by at least 80 percent by 2050 (CDU et al. 2009).

Electricity generation is a key area of Germany's energy and climate policies in view of the fact that this sector currently accounts for roughly 40 percent of national carbon emissions (UBA 2010). However, it is also a sector where carbon emissions could be reduced at a relatively low cost – which means that reducing overall greenhouse gases by only 80 percent by 2050 will necessitate implementation of a completely carbon neutral electricity supply in Germany.

That being said, we can only reliably achieve a sustainable and climate friendly electricity supply system over the long term if it is based on renewables. Other low carbon technologies such as nuclear energy and carbon capture and storage (CCS) cannot be regarded as viable long term solutions for a sustainable energy supply, for the following reasons, among others: (1) carbon storage capacity is limited; (2) potential conflicts between CCS and other underground uses; (3) the still unresolved problem of nuclear waste disposal; (4) limited availability of worldwide uranium resources; (5) other costs and risks associated with nuclear power (see for example SRU 2009a; 2000).

The vast majority of Germans support the concept of an electricity generation that is mainly based on renewables; this goal has also been endorsed by the coalition government (CDU et al. 2009). Such a goal represents an opportunity for sustainable technological and infrastructure innovation here in Germany that will help ready our country to face future challenges in this sphere. However, there is considerable political controversy at present on the issue of how and when Germany should transition to a renewables-based energy supply, and the "bridging" role nuclear power plants and coal-fired power plants should play in this process (possibly in conjunction with carbon capture and storage (CCS)).

The German government is currently in the process of developing an energy concept that will form the basis for its future energy policies. In order for such a concept to define a viable roadmap, we need a solid basis of information that will allow for reliable estimates concerning the options and challenges entailed by the transition to renewables. To this end, we feel that the following issues need to be addressed:

– Is a fully renewables based electricity supply technically feasible for and in Germany? Would such a system allow for a security of supply that is on a par with today's?

– How much would a wholly renewable electricity supply and the transition thereto cost?

– What would be a realistic timeline for the transition to such an electricity supply and which measures would this transition entail? Which priorities should our current energy policies set in this regard?

– Which political measures and management instruments could be used to bring about this transformation smoothly and efficiently?

The SRU is currently elaborating a report on the future of Germany's electricity supply between now and 2050. This report will (a) take account of the option to transition to a sustainable and wholly renewable electricity supply in light of the relevant technical and economic factors; and (b) discuss the policy instruments that would be needed to implement such an option. The present Statement contains the initial findings (which are particularly relevant for the first three issues enumerated above) with a view to making these findings available for the government's elaboration of the aforementioned energy concept.

We thus hope that the present Statement will help to flesh out the option of implementing a wholly renewable electricity supply by 2050 so that all concerned can get a clear idea of what such a solution would actually look like. The concept of transitioning to renewables is supported by a number of very recent studies that show that an electricity system reorganization process involving a transition to a wholly or partially renewables based electricity supply is a viable option that is well within reach (PwC et al. 2010; ECF et al. 2010; EREC 2010; UBA 2009; Öko-Institut und Prognos AG 2009; NITSCH and WENZEL 2009; FOE and SEI 2009). Our work is based on various scenarios involving a wholly renewable electricity supply that were elaborated for us by the German Aerospace Centre (DLR).

The following background information is intended to make the content of the present report clearer:

– Key condition: a wholly renewable electricity supply. All of our scenarios presuppose that Germany can and will implement a wholly renewable electricity supply by 2050, albeit under varying conditions in respect to grid connections with other states and the electricity demand that will need to be met. The purpose of these scenarios is to show that a wholly renewable electricity supply could be implemented in various forms. Our scenarios exclude the energy policy option whereby in 2050 some electricity would still be generated using fossil fuels or nuclear power. Information concerning the differences between a wholly renewable electricity supply and one that still relies on the aforementioned non-renewable sources can be found in recent studies (e.g. ECF et al. 2010) or in the German government's energy concept scenarios.

– Decisions concerning the transition roadmap. According to our calculations, an expansion of renewable electricity generation capacity will conflict with conventional power plants in the medium term (SRU 2009b; also see section 4.5). Moreover, in our view extending the life span of nuclear power plants and constructing new coal fired power plants exceeding the scope of those currently under construction would be incompatible with the expansion of renewable electricity generation capacity we are proposing here.

– Policy implementation and instruments: The issue as to which economic incentives and statutory management and control instruments will be needed in order to implement the desired transformation of the electricity system does not fall within the scope of the present Statement. However, we will be addressing these issues in our Special Report, which is slated for publication late in 2010.

– The European and national perspective. Germany's energy policy must evolve within a European context and within the framework of the evolving EU-wide internal market for energy. That being said, our scenarios take account of the relevant factors in Germany only, and in so doing define restrictive conditions concerning cross-border electricity interchange. We opted for this approach in order to show that the lion's share of Germany's energy demand could be met using the currently available renewables potential within our borders, and that transitioning to a fully renewables based electricity supply would be well within the realm of possibility, even assuming the highly restrictive condition to the effect that Germany would need to supply virtually all of its own electricity. However, it would be an error to regard this scenario design as a call to turn away from the goal of pursuing a European energy policy and a single energy market. The SRU strongly advocates the development of a genuinely pan-European concept for the expansion of renewable electricity generation capacity. That being said, the impact that establishing one or more European energy supply networks could have on renewables might vary considerably: On the one hand, it could enhance European energy security and reduce the cost of generating renewables based electricity, but it would also allow for the stabilization of large amounts of electricity from nuclear and coal fired power plants. Our final report will discuss in depth, including legal aspects, the options for resolving this ambivalence in such a way that the expansion of renewable electricity generation capacity is prioritized and prevails

– Sectoral segmentation of the electricity grid. Our work currently centers around the energy supply since (a) this is the area where the most important decisions need to be made; and (b) expanding the scope of electrification in sectors such as transport and heat supply will probably promote climate protection. Hence we have included high energy demand scenarios with a view to taking account of extensive electrification in other sectors.

– Inter-regional energy supply networks – examples of numerous possible solutions. The scenarios in section 3 show how Germany could join forces with its neighbors in such a way as to fully meet its electricity demand using renewables in a relatively small scale network comprising Germany, Denmark and Norway and/or via a larger-scale European-North African network. These two constellations of scenarios (see section 2) are intended merely as representative examples of a series of other possible solutions. The rationale for the smaller network comprising Germany, Norway and Denmark is that Norway's substantial hydro power and pump storage system potential would allow for efficient equalization of fluctuating levels of input from renewable electricity. Current trends show that strengthened renewable energy cooperation between Germany and Norway is already on the horizon, in view of (a) a Swiss-Norwegian consortium's plan to implement the so called NorGer project involving installation of a power transmission cable extending from the Norwegian coast to Wesermarsch, Germany; and (b) the North Sea Countries' Offshore Grid (Seatec) project, which would allow for improved connections between offshore wind farms and onshore power grids, and would set the stage for integrating renewable energy into the electricity grids of the participating states. Moreover, pump storage system potential is available in countries such as Sweden, Switzerland and Austria.

Hence it goes without saying that other approaches to implementation of an inter-regional network and/or incorporating other countries into such a system are completely within the realm of possibility. The outcome in this regard will be determined by both technical and political factors. Needless to say, inter-regional networks would have to comply with European law.

Section 2 covers the following: the methodology used for our scenarios; our key scenario related assumptions concerning renewable electricity potential and the attendant costs; the structure of the scenarios; and the characteristics of the model used. Section 3 describes various possible ways in which a wholly renewable electricity supply could be implemented in Germany by 2050, as well as the results of our calculations via graphics and tables. Section 4 describes the putative timeline for the transformation of the electricity grid by 2050. This section also contains a cost estimate for renewable electricity during this period. Section 5 contains a summary of our findings, as well as our conclusions and recommendations.

2 Methodology

2.1 Introduction

2. The scenarios in the following sections describe the dynamics of a wholly renewable electricity supply in Germany and the steps that would need to be taken to implement it.

The energy policy debate in Germany revolves around and has engendered a number of scenarios that vary according to the frame of reference on which they are based. By scenario, we mean a description of a possible future that is characterized by various assumptions and conditions. Studies often compare various scenarios with a view to identifying the factors that give rise to the scenarios and shedding light on their potential design leeway. Thus scenarios are fundamentally different from projections, which aim to predict future trends as accurately as possible.

In comparing various studies involving the use of scenarios, allowance should be made for the fact that the consequent results and conclusions may differ greatly according to the methodology and frame of reference applied. Scenarios are not intended to be a substitute for hard decisions concerning priorities and goals; all scenarios can hope to do is identify the conditions that would allow specific evolutions to occur and render the impact of the relevant factors more transparent.

The scenarios presented here posit a possible future state of the German electricity supply system based on a predefined level of electricity demand in the year 2050 (see section 3), and in so doing demonstrate the following:

– that a wholly renewable electricity supply (a) is achievable in Germany on its own, or via an inter-regional electricity supply network encompassing North African and neighboring European states, based on technical potential; and (b) would provide a fully reliable electricity supply round the clock year round.

– the specific elements and their composition that such a system would comprise, assuming that (a) the attendant costs were optimized by 2050; and (b) these costs evolve in a manner that appears to be plausible based on today's knowledge.

– the probable order of magnitude of the costs of such a system

– how the makeup of the system components, as well as system costs, would vary according to the design of the different scenarios.

Scenario terminology and methodology

In this report, the term potential means the maximum amount of electricity that can be generated using various technologies within a specific region over the course of 12 months. Our estimates of such a potential of course take account of the relevant natural conditions, technical and economic factors such as the manner in which the relevant areas are used, weather data, and costs. We also distinguish between various types of potential. Physical potential is a hypothetical variable that factors in all energy available from natural sources and that remains virtually constant over time. The portion of this potential that is useable for electricity generation is referred to as technical potential, which can be ramped up by means of technological optimization that in turn optimizes efficiency. Economic potential refers to the financial cost of developing technical potential and should be regarded as merely a snapshot whose characteristics may be subject to considerable fluctuation over time owing to economic factors such as oil prices.

Scenario studies often use computer models that attempt to mathematically simulate the key structures and interactions of the complex real world. Such models can be evaluated and their results translated into graphics using computer supported numerical methods. The mathematical elements that fluctuate during a computer simulation owning to external factors are referred to as variables. Fixed parameters, or constants, characterize specific relationships and, as the term implies, remain constant over the course of a given computer simulation. A computer model can be used for various scenarios by running a series of simulations for which varying baseline conditions or parameter values are posited.

There are various possible approaches to scenario development. The findings in the present Statement are based on the backcasting approach, whereby the scenario takes as its starting point a specific target – the target here being a wholly renewable electricity supply. The modelling results then show how and under which conditions the target can be reached.

On the other hand, scenario simulations can also be used to investigate the impact of various circumstances such as energy policy measures on the evolution of a series of variables, relative to a reference case, which is referred to as an exploratory scenario. When applied to an activity such as a policy analysis, an exploratory scenario can potentially raise the issue as to how the system in question will evolve if specific events occur or if specific conditions change. The more closely such scenarios extrapolate from current structures and past evolutions, the more likely they are to underestimate the potential for change. By contrast, our target scenarios are based on the following questions: Can the system reach a defined target state, and if so how? Which circumstances will need to change in order for this target to be reached?

These findings were then used to determine how the available electricity generation, transmission and storage capacities would need to evolve in order to achieve the defined target state by 2050. Based on the characteristics of the existing power plant fleet, we show how conventional generation capacity could be replaced incrementally by renewable energy (section 4). Here we made a conscious decision to forego a putative optimization of the generation mix for each individual year, since the exact costs entailed by the various renewable and conventional electricity generation options will vary greatly over time and even a relatively minor change in the relative costs could greatly alter the results of any such optimization.

As with all scenarios, those presented here should not be read as projections that may or may not come true. Transitioning to a wholly renewable electricity supply, as is proposed here, should instead be regarded as an option – one we feel is well worth pursuing – whose implementation will necessitate targeted policymaking, strategic measures, careful planning, and considerable effort.

The scenarios presented here show (a) that such a transition is well within the realm of possibility; and (b) the form such a system would take, based on what currently appear to be plausible assumptions concerning technological and cost evolutions.

2.2 The German Aerospace Center's REMix model

3. Various wholly renewable electricity supply scenarios were simulated mathematically, at our behest, by the DLR's Department of Technical Thermodynamics using the REMix energy model. The DLR has extensive experience in the field of research into technology development and cost trends in the realm of renewable energy and thus participates regularly in studies concerning the future of Germany's energy supply system (see Nitsch 2008; Nitsch and Wenzel 2009). Although the REMix model can be regarded as the best available German model for simulations of hour-based optimized electricity supply scenarios for Germany and Europe, it should be borne in mind that the results presented here are based on a series of *assumptions*. We feel, however, that all of these assumptions are plausible and reasonably represent the best available knowledge, even if, for example, our cost and price estimates concerning conventional energy resources and technologies for the use of renewable energy resources extending over a four decade period are subject to significant uncertainty.

The basic characteristics and principles of the REMix model will now be described. Further information concerning this model and the attendant assumptions will be published separately (DLR 2010).

Having first analyzed the potential of renewable energy resources, the REMix model uses the results of this analysis to determine a cost optimized (i.e. lowest cost) constellation of energy resources for the defined conditions.

The potential analysis is based on a GIS database, which provides detailed information concerning the electricity generation potential for renewable energy resources in Germany, Europe and North Africa, via a high resolution grid (grid cell size 10 km x 10 km) (see Figure 2-1).

The REMix model takes account of the following ten renewable electricity options:

– Photovoltaic solar energy

– Onshore wind

– Offshore wind in the German portion of the North Sea and Baltic Sea

– Gaseous biomass with and without combined heat and power generation (cogeneration, CHP)

– Solid biomass with and without cogeneration

– Geothermal energy with and without CHP

– Run-of-river hydro power

– Storage hydroelectric power stations

– Pump storage systems

– Compressed air energy storage

The REMix model also takes account of concentrated solar power (CSP) potential. However this energy resource is available solely in regions with a greater amount of solar radiation such as North Africa and thus was only factored into the scenarios that included Southern European and North African states.

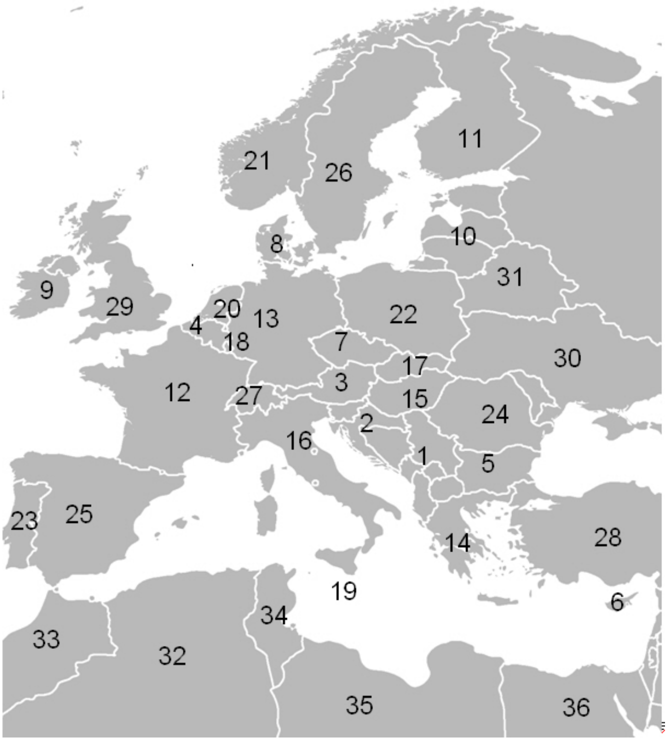
The REMix model's potential data for intermittent wind and solar energy resources were broken down by hours (DLR 2010).

The analysis of potential was based on coverage types for areas available as GIS maps. Various assumptions were made in this regard as to which areas are suitable for use of a specific technology and which portion of these areas are available for such use in light of the main area use restrictions such as inhabited areas, ecological considerations, or competing land use forms.

Table 2-1 summarizes, for the various energy resources, the underlying data and assumptions, as well as the areas that were excluded from consideration. Such exclusions were based on the presence of specific ecological or technical conditions that ruled out the area in question for use in connection with a specific energy technology. Thus for example all nature reserves are excluded, and solar energy (photovoltaic and concentrated solar power (CSP)) can only be used in gently sloping areas. Some areas are characterized by competing forms of use whose geographic boundaries cannot be clearly defined. Hence a maximum area utilisation rate was defined for the area in which each technology can mainly be used. These rates, which are based on the sustainability criteria defined by Germany's Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) (2004) and Quaschning (2000), normally yield conservative estimates of potential. The area utilisation rates were set in such a way that aggregate potential could be determined, including in the presence of competing use forms (i.e. not subject to multiple uses) (see Table 2-1). For example, non-cultivated desert areas could potentially be used for concentrated solar power (CSP), wind energy and photovoltaic energy, to each of which the REMix model allocated 33 percent of the available area as the maximum useable area.

Figure 2-1

REMix model countries



No.	Country (region)	Abbreviation	Area coverage	No.	Country (region)	Abbreviation	Area coverage
1	Albania	AL_CS_MK	1	17	Slovakia	EC	1
1	Serbia			18	Luxembourg	LU	1
1	Macedonia			19	Malta	MT	1
2	Bosnia	BA_HR_SI	1	20	The Netherlands	NL	1
2	Croatia			21	Norway	NO	1
2	Slovenia			22	Poland	PL	1
3	Austria	AT	1	23	Portugal	PT	1
4	Belgium	BE	1	24	Romania	RO	1
5	Bulgaria	BG	1	25	Spain	ES	1
6	Cyprus	CY	1	26	Sweden	SE	1
7	Czech Republic	CZ	1	27	Switzerland	CH_LI	1
8	Denmark	DK	1	27	Liechtenstein		
9	Ireland	IE		28	Turkey*	TR	0.80
10	Estonia	EE_LT_LV	1	29	Great Britain	UK	1
10	Lithuania			30	Ukraine	U_MD	1
10	Latvia			30	Moldavia		
11	Finland	FI	1	31	Belarus	BY	1
12	France	FR	1	32	Algeria*	DZ	0.31
13	Germany	DE	1	33	Morocco*	MA	0.73
14	Greece	GR	1	34	Tunisia*	TN	0.99
15	Hungary	HU	1	35	Libya*	LY	0.18
16	Italy	IT	1	36	Egypt*	EG	0.13

*A portion of this country/region is located outside of the area under investigation. Note: area coverage indicates the percentage of the region's surface area that lies within the area under investigation.

SRU/Stellungnahme Nr. 15–2010; Figure 2-1; data source: DLR 2010. pp. 2-3

The utilisation rates indicate the maximum potential for each area, whereby the REMix model simulations indicate the amount of each such area that is usable in the various scenarios.

Based on the cost assumptions for the various technologies, the REMix model was used to determine the share that these technologies would have in a generation mix and which transmission and storage capacities would have to be installed. The estimated electricity generation costs for the various technologies are based on installable capacity and electricity generation potential in conjunction with specific investment costs, fixed and variable operating costs, and the lifecycles of the reference power plants. Future costs were estimated by projecting current costs into the future via learning curves. The DLR's assumptions concerning the timelines for specific electricity generation costs were based on Nitsch et al. (2004) and Krewitt et al. (2005) and have been subject to continuous updating ever since in light of new findings. These putative costs, which are consistent with those posited by a 2009 Federal Environment Ministry (BMU) study (Nitsch and Wenzel 2009), are based on a presumed 6 percent interest rate and are summarized in Figure 2-2. These costs are also based on so called learning rates, according to which doubling the production of a given technology (e.g. the number of wind turbines manufactured annually) will yield a cost reduction amounting to X percent. Such cost curves, which can be observed for numerous technologies, are primarily based on improvements in the technology per se (e.g. higher efficiency for a facility, reduced material use) and cost reductions resulting from higher production (efficiencies of scale). Although the existence of such effects has been scientifically proven and is undisputed, experts often disagree on the extent to which costs can be reduced in the future. The cost reduction potential posited by the DLR is subject to significant uncertainty since the attendant calculations relate to the next four decades. However, technology based cost reduction potential is subject to less uncertainty than are the prices of oil, coal, or natural gas over the same period.

Table 2-1

Regions and renewable energy source potential in German, Europe and North Africa taken into account by the German Aerospace Center's REMix model

	Resource data	Excluded areas	Area distribution parameter	Area utilisation rate	Comments
Photovoltaic energy in inhabited areas	Global horizontal incidence solar radiation and direct normal incidence (DNI) solar radiation[2]		Inhabited areas[3, 4]	Roofs: 0.775%; building facades: 0.48%; miscellaneous: 1.17%[1]	Orientation distribution in accordance with[1]
Photovoltaic energy in non-inhabited area	Global horizontal incidence solar radiationand DNI[2]	Protected areas with a slope exceeding 2.1%	Farmland[3, 4]	0.03%[1]	Southern orientation without solar tracking
			Pastureland[3, 4]	0.03%[1]	
			Uncultivated and sparsely covered areas[3, 4]	33% (NA)/ 0.03% (EU)	
Concentrated solar power (CSP)	DNI[2]	Protected areas with a slope exceeding 2.1%	Uncultivated and sparsely covered areas[3, 4]	33%	North-south orientation with east-west solar tracking and DNI exceeding 1,800 kWh/(m^2*a)
Onshore wind	Wind velocity 116 meters above sea level[6]	Protected areas[5]	Uncultivated and sparsely covered areas[3, 4]	33%	
			Pastureland[3, 4]	3%	
			Bush[3, 4]	3%	
			Mosaic areas (grass, bush, trees)	3%	
			Farmland[3, 4]	3%	
			Forests[3, 4]	0%	
Offshore wind	Wind velocity 116 meters above sea level[6]	Protected areas[5]	Entire exclusive economic zone, 5 km from the coast at a depth of less than 300 meters	16%	
Geothermal energy, only for electricity generation	Temperatures at a depth of 2, 3, 4, and 5 km[7, 8]	Protected areas[5]	All areas	100%, minus geothermal and CHP potential	
Geothermal power-CHP	Temperatures at a depth of 2, 3, 4, and 5 km[7, 8]	Protected areas[5]	Required heat demand more than 0-4 GWh/square km	Limited by absolute heat demand	European heat demand map; proprietary source
Run-of-river hydro	Installed capacity;[9] annual electricity generation potential; full load hours[10]		Installed capacity;[9] hypothetical hydro power potential[11]	100%	Top down approach
Hydro reservoirs	Installed capacity;[9] annual electricity generation potential; full load hours[10]		Installed capacity[9]	100%	Top down approach
Biomass	National biomass potentials[12, 13, 14]	Protected areas[5] with a slope exceeding 60%	Forest, farmland, pastureland, inhabited areas[3, 4]; population density[15]		Top down approach

1 Quaschning, V., Systemtechnik einer umweltverträglichen Elektrizitätsversorgung in Deutschland für das 21. Jahrhundert. 2000. Düsseldorf: VDI Verlag GmbH. 0-188.

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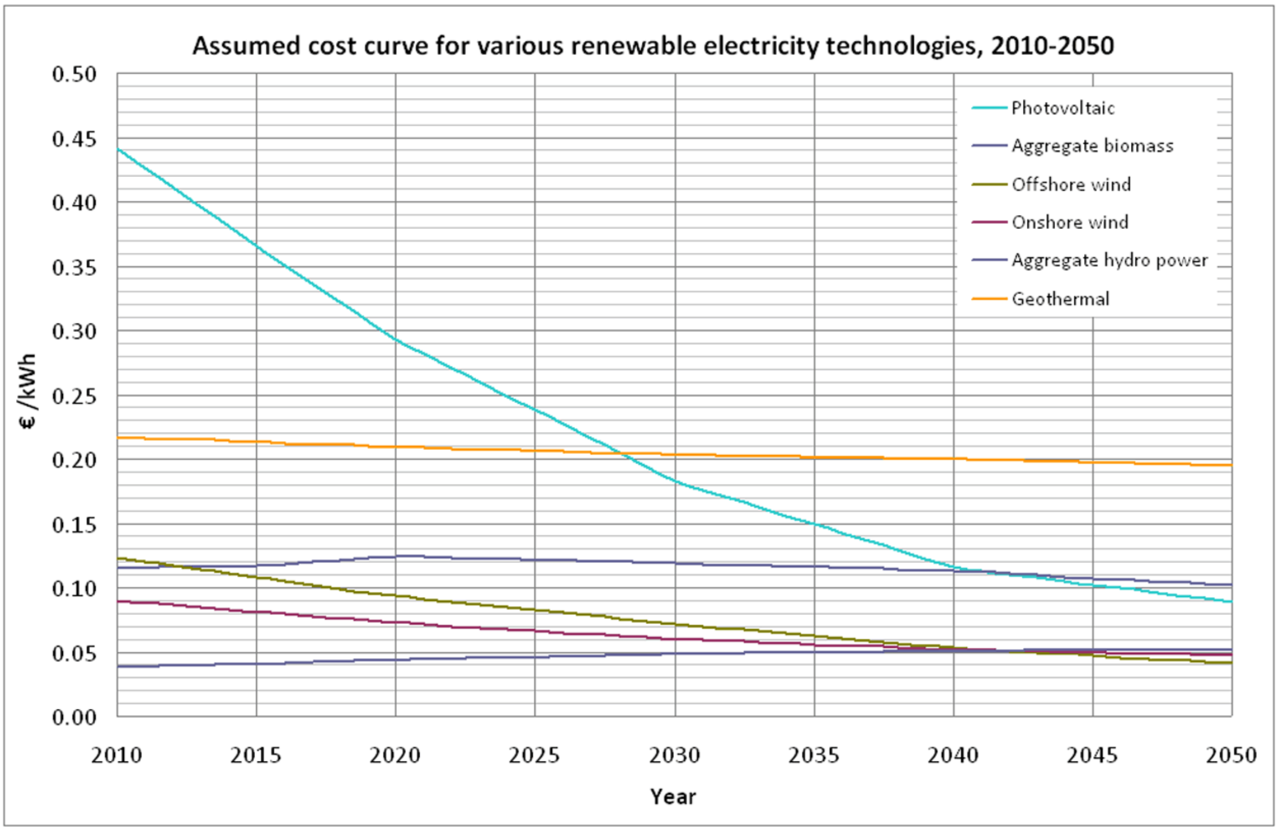
Source: DLR 2010, p. 6

Figure 2-2

Projected cost curve for the various renewable electricity generation technologies until 2050



SRU/Stellungnahme Nr. 15–2010; Figure 2-2; data source: DLR 2010, p. 41 ff.

Changes in the costs of renewable and conventional electricity technologies may have a substantial effect on the portion of each technology simulated in the model, as well as on overall system costs. In our view, the DLR's assumptions are plausible and not unduly optimistic in light of other studies involving similar timelines, particularly in view of the interim results of the Intergovernmental Panel on Climate Change (IPCC) concerning the potential role of renewable electricity in fighting climate change. This study reviewed the results of all key international studies to date concerning the use of renewables. The learning rates indicated in the literature range from 4 to 32 percent, whereby Lemming et al. (2009, p. 35) cite Neij (1997; 1999; 2008) as the most reliable source for wind energy learning rates, which according to Lemming et al. (2009, p. 35) range from 9 to 17 percent based on the aforementioned publications by Neij. Neij's latest findings (Neij 2008, p. 2209) prognosticate a range of 10 to 20 percent. Based on the renewable electricity expansion defined for Germany in our scenarios, a backward projection of the presumed costs indicates that the DLR learning rates are 11.5 percent for onshore wind farms and 18.6 percent for offshore wind farms. According to one author, the historical learning rate for photovoltaic energy is 20 percent (Surek 2005, p. 294). However this author also assumes that such high learning rates for crystalline silicon photovoltaic modules cannot be maintained over the long term (Surek 2005, p. 303). Neij (2008, p. 2209) predicts that photovoltaic costs will decrease by 15 to 25 percent by 2050. Backward projection of the costs indicated by the DLR reveals a putative learning rate of 26 percent, which would appear to be highly optimistic. The putative learning rate of 2.2 percent for biomass can be regarded as relatively conservative in view of the 0 to 10 percent range for this parameter indicated by Neij (2008, p. 2209). Geothermal energy may be a special case in this context. The latest DLR figures (not included in the present findings) indicate that geothermal energy costs could be subject to a far greater decrease than that prognosticated by the DLR calculations. If this is the case, geothermal energy could potentially play a larger role than that indicated in the scenarios presented here.

Even if the cost reduction potential posited in the present report would prove to be unduly optimistic, this would not alter the results of our calculations indicating that wholly renewable electricity supply is achievable; but it would equate to higher climate protection costs than those indicated by the scenarios. For further information concerning the posited costs, see section 4.5, which goes into greater depth on this matter in light of the specific scenario results.

The REMix model includes Europe and North Africa, where our scenarios allow for electricity interchange across specific national borders as well as for specific maximum interchange levels. This approach allowed for the analysis of country groups of varying sizes, as well as individual countries.

The REMix model calculated total system costs as well as mean per kWh cost for each scenario, and in so doing determined the necessary transmission capacities between the states concerned and the attendant total transmission costs. However, the incidental costs arising from electricity transmission via a grid expansion within an individual country were handled differently. Although technical potential was determined using a high spatial resolution during the simulations, some geographical information was lost in this process since it was necessary to aggregate technical potential for specific regions for reasons of limited computing capacity. Hence the total renewable electricity potential of each country was treated as aggregated. The REMix model did not take account of the grid expansion needed in Germany and elsewhere, particularly in terms of integrating offshore wind farm capacity and transporting it to the consumption centres – a process that also drives up electricity supply system costs. In view of this fact, we estimated the costs of the grid expansion in Germany separately (see section 4.5).

Inasmuch as the model uses one hour time intervals, it can correlate annual electricity generation with electricity demand down to the hour. A condition was defined whereby each scenario must allow for a completely reliable and secure electricity supply, which means that the technologies deployed must have the capacity to satisfy fluctuating electricity demand at all times via concurrent generation of renewable electricity or the use of stored electricity. The optimal makeup of a electricity generation mix was determined by extrapolating the load curve for a past year to the posited target year (2050) demand level of 509 or 700 TWh/a, whereby it was presumed that the demand curve during that year will be similar to the annual curve in Germany to date. We are well aware of the fact that, in the absence of a better estimate of electricity demand in 2050, the prognostication arrived at here is only an initial rough estimate. However this method very probably posits higher requirements for installed capacity and speed of changes in generation than what will actually be the case in 2050. Moreover, many of the efficiency optimization technologies such as dispatchable loads and smart devices that may well be implemented between now and 2050 for climate protection reasons will allow for grid load balancing and reduced demand peaks.

Inasmuch as the model also takes account of fluctuating availability over time down to one hour intervals, it was also possible to determine the hourly requirements for production capacity and equalization solutions using storage systems. This in turn allowed for computation of the costs associated with each of the various scenarios based on the calculations for the relevant generation and storage technologies, as well as the posited cost functions, and in such a way as to take account of all of the inherent imponderables.

The model takes account of three key storage modalities, namely pump storage systems, compressed air energy storage, and the use of hydrogen as an electrical energy storage medium (see section 4.3 for a description of the model related assumptions in respect to storage technologies and the potential thereof). None of the optimized solutions yielded by the REMix model call for the use of hydrogen as an electricity storage medium due to the relatively high system loss and consequent elevated costs associated with this technology, although the model allows for its use. All of the calculations factored in the relevant conversion and line losses for long distance transport, but disregarded the distribution losses that occur in the current German electricity grid. However, such losses will continue to occur if conventional electricity generation remains in use.

2.3 Scenarios

4. The SRU used the German Aerospace Center’s REMix model to analyze various scenarios for a wholly renewable electricity supply for Germany, whereby various conditions were posited in respect to German energy demand in 2050 and the possibility of cross-border electricity interchange. A total of eight scenarios were modelled so that a relatively broad range of requirements and options could be taken into account. These scenarios fall into three different scenario groups, whose main characteristics are shown in Table 2-2.

All of the scenario groups differentiate between a variant with stabilized electricity demand and one with substantially increased demand (see section 2.4). The paradigm entailing national (i.e. German) electricity self sufficiency, a relatively small regional network and a far larger scale Europe-North African network were compared with each other. This approach took account of a broad range of solutions for a wholly renewable electricity supply, while at the same time shedding light on the impact of various strategy options on costs, the constellation of renewable energy sources used, and storage capacity requirements.

The DE 100 % SV scenario group assumes for Germany to develop a wholly self-sufficient renewable electricity supply – meaning that Germany's entire electricity demand would be satisfied via domestic renewables and there would be no cross-border electricity interchange. And in keeping with the exigencies of such a scenario, all electricity storage would also have to be realized on German territory. Although such a scenario would appear to be neither necessary nor desirable in view of (a) the fact that Germany currently imports roughly 60 percent of its resources required for domestic electricity generation and (b) European market integration, the technical and economic feasibility of such a solution was assessed nonetheless for purposes of cost and technology comparisons with other scenarios. Section 3 solely presents the key results of the assessment of this scenario group.

In the DE–DK–NO scenario group, Germany was modeled as part of a network structure comprising Germany, Norway and Denmark. These scenarios investigated the impact of Norwegian pump storage system potential use on renewable electricity in Germany. Denmark would act as a transit country to Norway in this network and also offer considerable wind power potential for the system as a whole.

Four scenarios were analyzed for this network. The first, DE–DK–NO 100 % SV, presupposes that on the average Germany can achieve complete self sufficiency for its domestic electricity demand, i.e. the amount of electricity generated will satisfy 100 percent of domestic demand. However, unlike the DE 100 % SV scenario, the DE–DK–NO 100 % SV scenario allows for up to 15 percent of annual output to be interchanged between Germany and its network partners. This would notably give Germany access to Norway's pump storage system capacity to compensate for temporary discrepancies between electricity demand and generation. A second scenario (DE–DK–NO 85 % SV) allows Germany to import 15 percent of its net electricity from Sweden and Denmark, thus reducing Germany's self sufficiency rate to 85 percent. This straightforward tripartite cooperation yielded extremely clear analyses, unlike pan-European electricity exchanges, where some changes are difficult to classify owing to overlapping effects; moreover, the role of Germany and certain other states is far more difficult to assess.

The DE–DK–NO 100% SV scenario can be regarded as a relatively close approximation of a complex but realistic evolution of Germany's electricity supply system, since (a) considerable electricity is already interchanged between Germany and other European countries; and (b) Germany is a net electricity exporter. This scenario is the main focus of the discussion (in section 3.2) of a possible transition from our current electricity system to the putative 2050 system.

A network comprising Sweden and Germany and involving the use of Swedish hydro power for electricity storage purposes is also an option. However, Norway, with its roughly 84 TWh of capacity, has Europe's largest storage potential, which is far larger than Sweden's roughly 36 TWh (see Nord Pool ASA 2010). These two countries, along with Switzerland, Austria, France and Italy will undoubtedly be offering considerable pump storage system capacity at some point down the road. All of the calculations described below presuppose that Germany and Norway will form an electricity storage partnership in view of Norway's substantially higher storage potential and the relatively rudimentary power transmission lines between the large wind energy potential in the German North Sea and the storage potential in southwest Norway.

Table 2-2

Wholly renewable electricity supply scenarios

Scenario group	**Characterization**	**Demand in 2050: 500 TWh/a**	**Demand in 2050: 700 TWh/a**
1	Complete self-sufficiency in Germany	Scenario 1.a DE 100% SV-500	Scenario 1.b DE 100% SV-700
2	Complete self-sufficiency in Germany in terms of annual production Interchanging of up to 15 percent of annual output with Denmark and Norway	Scenario 2.1.a DE–DK–NO 100% SV-500	Scenario 2.1.b DE–DK–NO 100% SV-700
	Up to 15 percent net import of electricity from Denmark and Norway (plus interchanging of up to 15 percent of annual output)	Scenario 2.2.a DE–DK–NO 85% SV-500	Scenario 2.2.b DE–DK–NO 85% SV-700
3	Up to 15 percent net import from Europe-North Africa (EUNA) allowed (plus interchanging of up to 15 percent of annual output)	Scenario 3.a DE–EUNA 85% SV-500	Scenario 3.b DE–EUNA 85% SV-700

SRU/Stellungnahme Nr. 15–2010; Table 2-2

The third scenario group, DE-EUNA, describes an expanded network structure comprising North Africa and all of Europe. In these scenarios, as in the aforementioned ones, each of the member states could import up to 15 percent of its annual output so as to achieve an optimally reliable electricity supply. This larger-scale network would allow access to far greater renewable energy potential and would more efficiently offset regional output fluctuations, particularly in terms of wind power.

For all of the aforementioned scenario groups, total German demand (gross electricity demand) was set at 500-700 TWh (more precisely: 509-700; see section 3.2). Moreover, all of the scenarios were subject to the requirement that all electricity in all participating states must be generated from renewables.

2.4 Electricity demand

5. Based on our analysis of various studies, it is safe to say that annual (net) electricity demand in Germany can be stabilized at around 500 TWh (e.g. Öko-Institut and Prognos AG 2009; UBA 2009; Barthel et al. 2006; Enquete-Kommission Nachhaltige Energieversorgung unter den Bedingungen der Globalisierung und Liberalisierung 2002; Nitsch 2008). This would (a) require stringent energy saving and efficiency optimization measures are implemented for classic electricity uses, and (b) allow roughly half of Germany's auto fleet to go electric. Using this assumption as a starting point, 2050 electricity demand in Germany amounting to 500 TWh was initially defined for all of the scenario groups based on the scaled hourly-interval annual load curve.

A second variant involving 2050 electricity demand amounting to 700 TWh in Germany was analyzed. Demand could potentially rise to this level if we fail to implement ambitious efficiency measures and if most of Germany's auto fleet goes electric; demand would increase by an additional 100 TWh/a (see Wietschel and Dallinger 2008) if the entire fleet goes electric. On the other hand, such a 700 TWh/a scenario where energy efficiency measures have been successfully implemented would enable electrical power cover (a) a large portion of heating energy demand in 2050; and (b) a more substantial proportion of industrial process heat demand, in addition to auto electrification.

Our comparison of the 500 and 700 TWh/a scenarios sheds light on how total electricity demand affects system costs and energy resource constellations in a cost optimized electricity mix.

Although we feel that electricity demand stabilization at the lowest possible level should be an avowed government policy goal with a view to keeping electricity costs as low as possible, the 700 TWh/a scenarios reveal that considerably higher demand could be satisfied using renewable energy – which of course means that demand ranging from 500 to 700 TWh/a could also be met. For example, if all possible energy efficiency and savings potential were used in a scenario where Germany's entire auto fleet goes electric, aggregate electricity demand would amount to roughly 550 TWh.

2.5 The transition process

6. In section 4 we propose, for scenarios 2.1.a and 2.1.b (see Table 2.2) a timeline for the transition from Germany's current electricity system to a wholly renewable electricity supply as per the REMix model

This proposed solution presupposes only very minor expansion of the conventional power plant fleet and in so doing calculates, based initially on conservative assumptions concerning average conventional power plant lifecycles, the phase-out timelines for such power plants.

We then extrapolated from these phase-out timelines the scope of expansion of renewable electricity generation capacity that would be necessary by 2050 to satisfy residual demand. The scope of annual expansion of installed capacity for the various technologies was defined in such a way that a cost optimized energy mix would be achieved for the scenario simulations by 2050 (see section 2.1). However, the posited annual expansion was not itself based on optimization calculations. Thus in periods when an unusually large number of conventional power plants is being phased out for age related reasons, safety margins for the expansion of renewable electricity generation capacity were factored in to a limited degree. The transition process described in section 4 comprises only one possible strategy that would allow Germany to achieve its goal of a wholly renewable electricity supply by 2050, without jeopardizing supply reliability during any phase of the transition. Moreover, in section 4.3 we explain why it would be essential for the expansion of renewable electricity generation capacity in Germany to go hand in hand with incremental development of electricity storage potential in Germany and Norway and the requisite grid expansion.

3 Wholly renewable electricity supply options

3.1 Renewable electricity potential

3.1.1 Potential in Germany

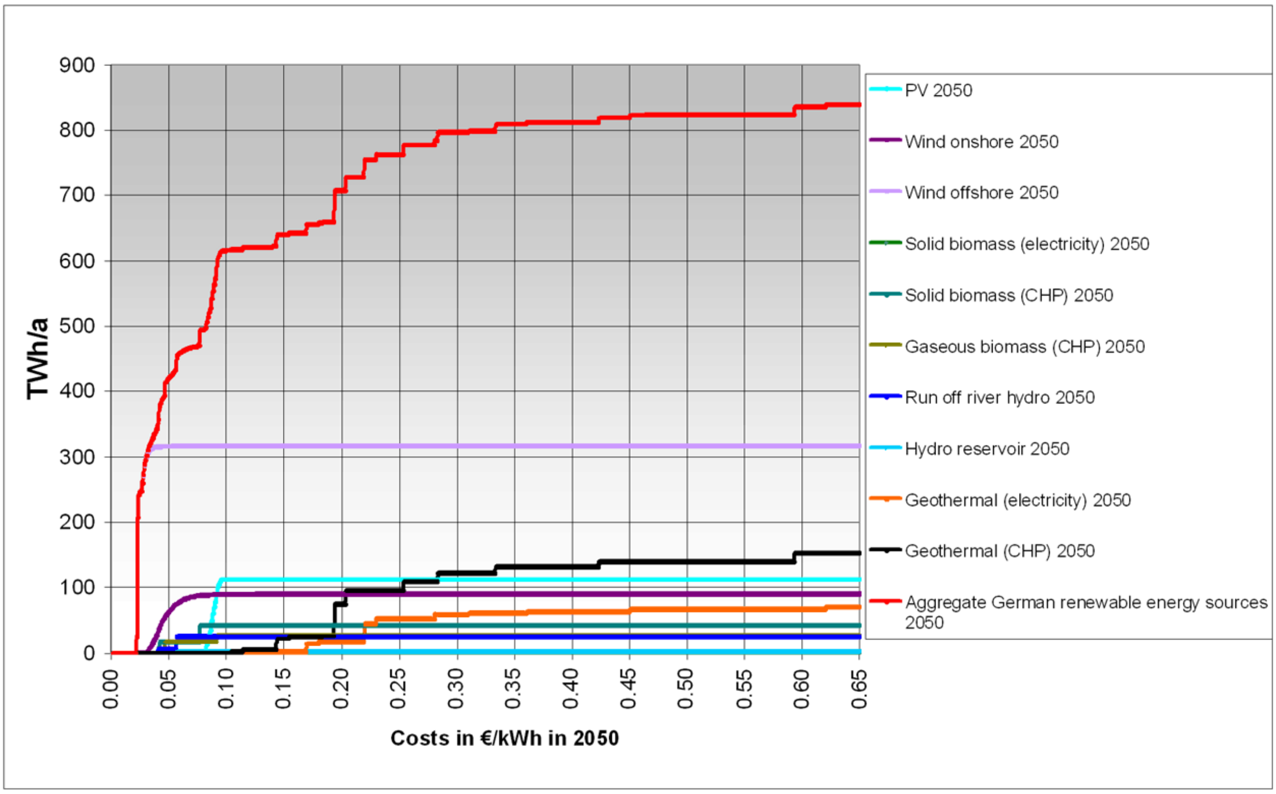
7. Renewable electricity potential in Germany was determined using the REMix model as per the methodology described in section 2.2. An average wind year equates to renewable electricity generation potential in Germany amounting to 839 TWh/a, roughly 612 TWh of which can be generated at the cost entailed by peak price kilowatt hours amounting to 0.096 euros per kWh (see Figure 3-1).

As noted in section 2, the German Aerospace Center determined the costs for the various technologies based on quantity dependent cost reduction functions for the target year in terms of 2009 prices (see DLR 2010, p. 13 ff.). The lowest cost potential here is offered by onshore and offshore wind energy (roughly 407 TWh/a) and hydro power. However, hydro power potential for electricity generation in Germany is limited to about 28 TWh/a for orographic reasons. The use of biomass, which compared to geothermal energy is relatively inexpensive at 0.081 euros/kWh, is likewise limited (to approximately 71 TWh/a). Biomass electricity use may also be further restricted by competing demand for biomass from the fuel and heating sectors. The SRU presumes that biomass could be used optimally in power plants that generate both heat and power. In the scenarios presented below which assume a moderate electricity demand in Germany (509 TWh in 2050) and cross-border electricity interchange, only about half the total amount of biomass is used for electricity generation and in this constellation would be used almost exclusively in cogeneration (CHP) systems. Only in the hypothetical scenario that cross-border electricity interchange is ruled out (see scenarios 1.a and 1.b) would the entire potential be used for electricity generation – and in such a case mostly in peak demand periods without CHP. Although the potential for photovoltaics is greater (about 110 TWh/a), its use would increase the marginal costs to 0.096 euros per kWh. Although geothermal electricity generation potential is high (an additional 220 TWh), the cost of developing this potential is high as well, ranging up to 0.062 euros per kWh. However, according to recent findings that only became available after the modeling was completed, the long term costs for geothermal electricity would be substantially below those indicated by our calculations. However, these possibly lower costs would only be relevant in the those scenarios where a high demand (700 TWh) is largely met using domestic resources (scenarios 1.b and 2.1.b).

All renewables can be used round the clock except for run-of-river stations, wind turbines and photovoltaic plants. The potential of the latter two energy resources is subject to substantial fluctuation secondary to variations in wind speed and insolation respectively. This fluctuation translates into wind and solar power generation capacity potential in Germany amounting to approximately 190 GW under favorable conditions (see Figure 3-2) and only about 39 GW under unfavorable conditions, which should be viewed against the backdrop of peak demand of 81 GW, minimum load of 35 GW, and annual demand of about 500 TWh. However, minimum grid load and minimum generation potential periods do not always coincide, as can be seen in Figure 3-2, which shows that most of the time renewable electricity potential substantially exceeds annual demand (i.e. the load curve) amounting to 500 TWh.

Figure 3-1

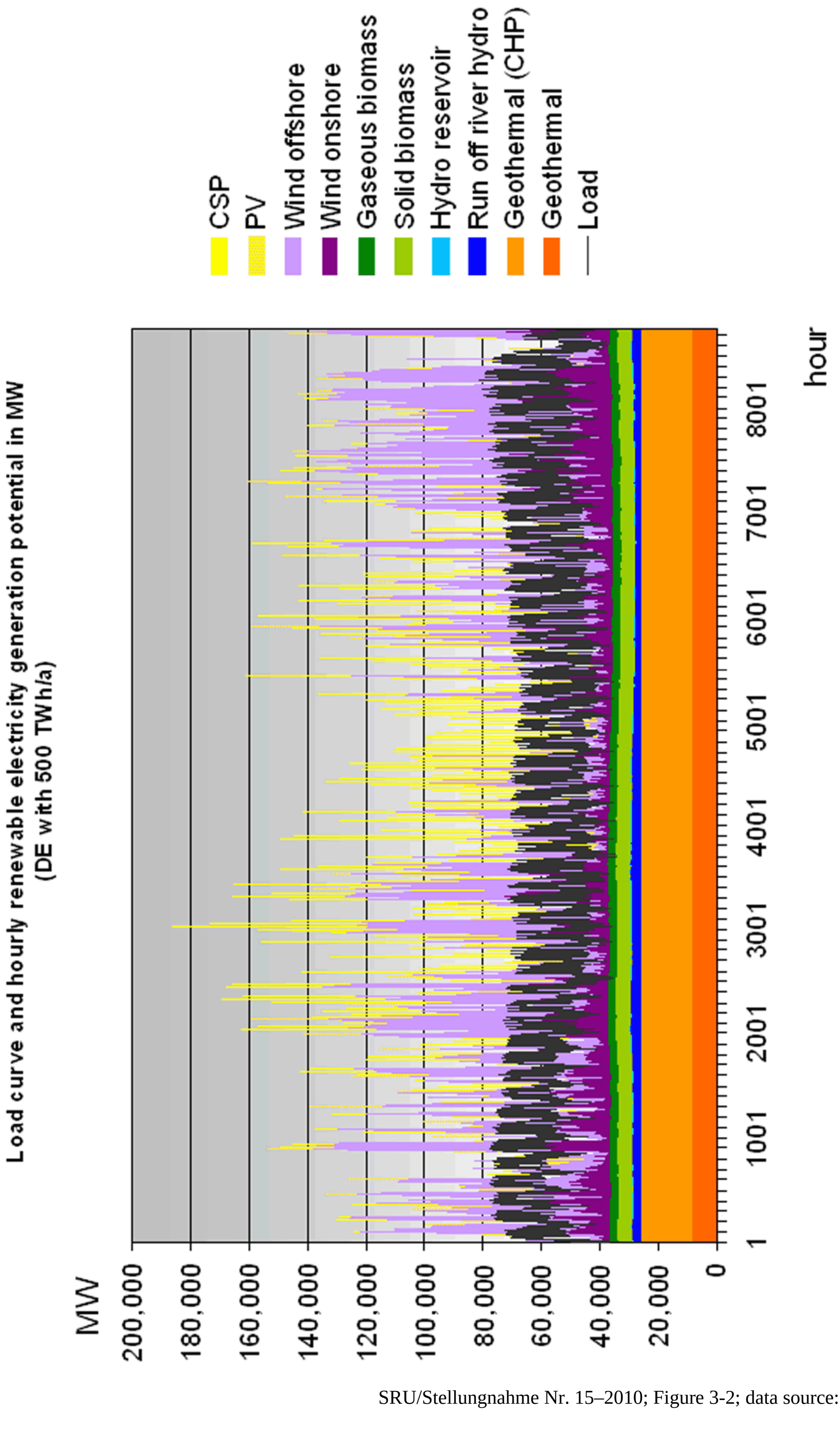
Renewable electricity potential in Germany, in TWh/a as a function of per kWh costs



SRU/Stellungnahme Nr. 15–2010; Figure 3-1; data source: DLR 2010

Figure 3-2

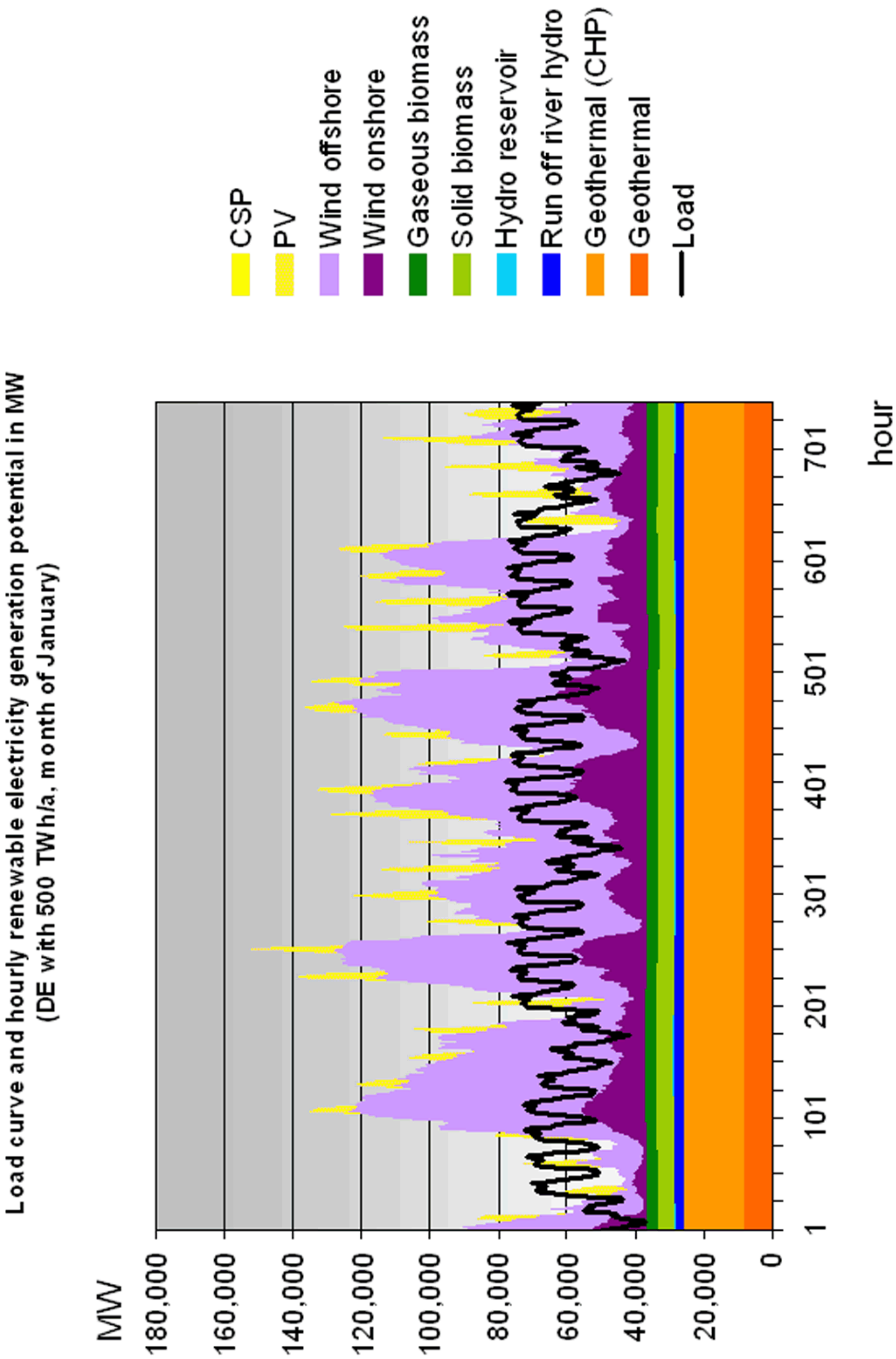
Load curve and hourly renewable electricity generation potential in MW (DE with 500 TWh/a)



SRU/Stellungnahme Nr. 15–2010; Figure 3-2; data source: DLR 2010

Figure 3-3.a

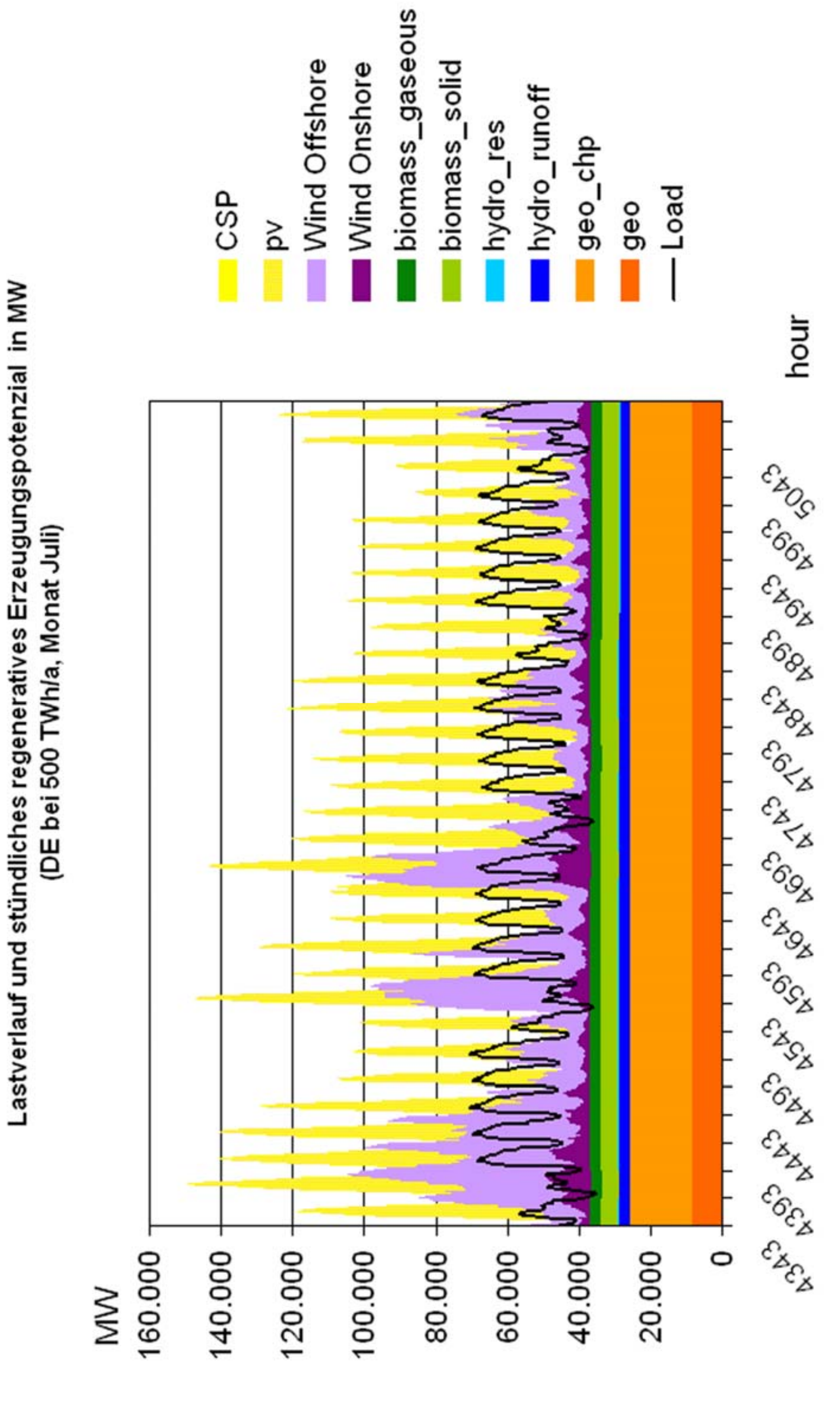
Load curve and hourly renewable electricity generation potential in MW (DE with 500 TWh/a, month of January)



SRU/Stellungnahme Nr. 15–2010; Figure 3-3.a; data source: DLR 2010

Figure 3-3.b

Load curve and hourly renewable electricity generation potential in MW (DE with 500 TWh/a, month of July)



SRU/Stellungnahme Nr. 15–2010; Figure 3-3.b; data source: Data source: DLR 2010

If the fluctuations in putative electricity production are analyzed in a higher (hourly) resolution (see Figures 3.3a and 3.3.b, where the months of January and July are used as examples), shortfall periods appear to be a relatively rare occurrence. These graphics also show the load curve (500 TWh/a) relative to hourly electricity potential. In both months, brief generation shortfalls occur infrequently, whereas potential surplus production occurs far more frequently. From the perspective of this higher resolution, it becomes readily apparent that annual renewable electricity generation would amount to about 840 TWh for an anticipated annual demand of 500 TWh. Annual demand amounting to 700 TWh (which would arise from a combination of relatively minor efficiency optimization and Germany's auto fleet going electric) would constitute a far less favourable scenario necessitating considerable storage capacity if Germany supplies all of its own electricity.

The analyses of the various scenarios based on hourly values (see section 3.2) provide precise comparisons of generation potential and electricity demand.

As these scenarios show, the extent to which satisfying hourly electricity demand would entail the use of relatively cost intensive generation potential such as geothermal and biomass energy would largely depend on the scope of total demand, storage capacity and cross-border electricity interchange.

3.1.2 Renewable electricity potential in the Europe-North Africa region

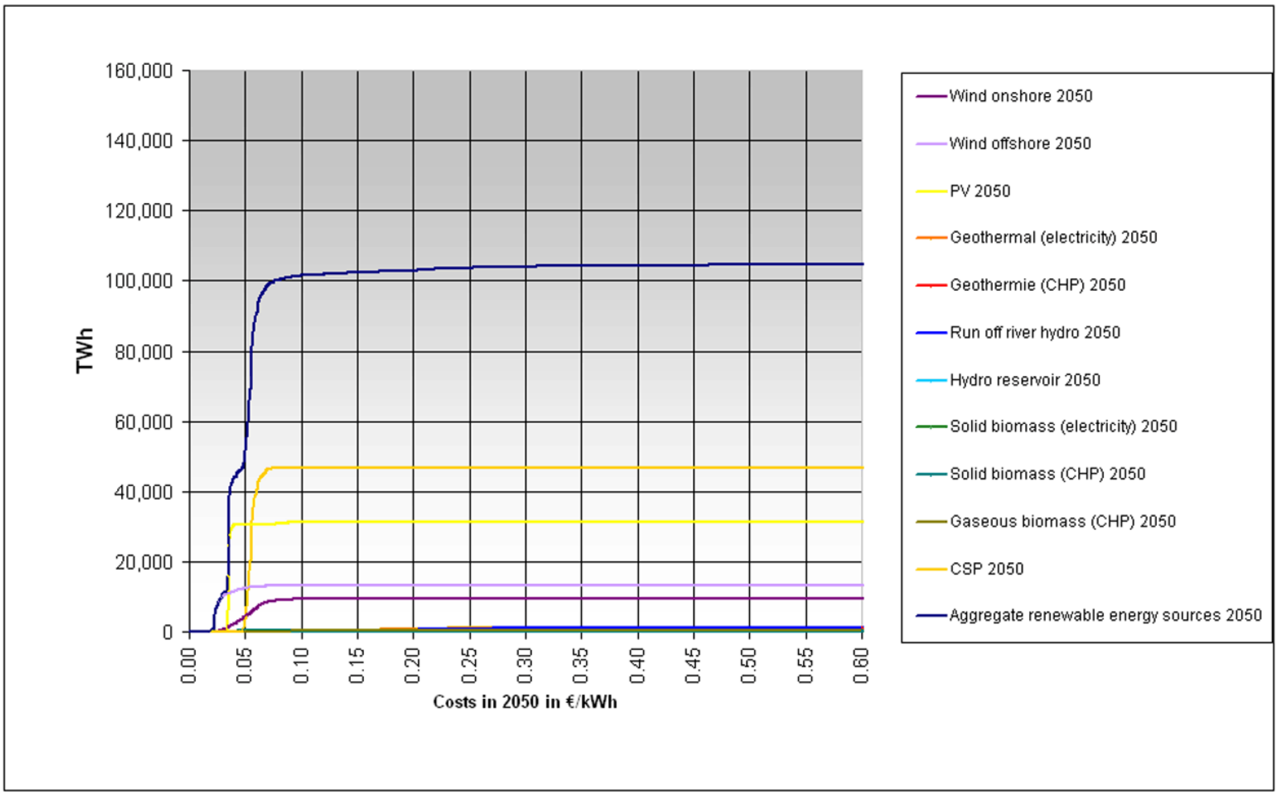
8. The renewable electricity potential of the Europe-North Africa region (as territorially defined in the DLR REMix model (see Figure 2-1)) would amount to approximately 105,000 TWh/a, which surpasses German generation potential by a factor of more than 100. This would allow for the generation of more than 47,000 TWh/a at a cost (in 2050) of 5 euro-cents per kWh. The least expensive electricity would come from offshore wind farms, as well as photovoltaic plants in sunnier regions (see Figure 3-4).

If Europe and North Africa are regarded as a potential energy supply network, a maximum grid load (demand) there would amount to approximately 840 GW (peak load in the entire region for a scenario that equates to German electricity demand amounting to 500 TWh/a and German peak load amounting to just over 80 GW), whereas renewable electricity potential would be in the neighborhood of 39,800 GW.

Even on the day with the lowest wind turbine output of the year, the 1,609 GW available in the middle of the night far exceeds peak annual load. A full-fledged network in this region would theoretically require no

Figure 3-4

Renewable electricity potential in the Europe-North Africa region as a function of per kWh costs



SRU/Stellungnahme Nr. 15–2010; Figure 3-4; data source: DLR 2010

electricity storage capacity at all, although it is doubtful that this would be an economically viable solution. How optimal resource use should be arranged, however, cannot be determined without more precise computation, as described in section 3.2. The fact that renewable electricity potential greatly exceeds demand in the Europe-North Africa region is clearly shown in Figure 3-5 whose scale ranging up to 50 million MW indicates total renewable electricity potential; whereby the annual load (demand) ranging from 420,000 to 840,000 MW (only 1-2 percent of renewable electricity potential) is so low as to be almost indiscernible.

Moreover, as Figure 3-5 shows, solar energy (33,800 GW) offers far and away the greatest renewable electricity potential, whereby a more detailed analysis of the German Aerospace Center calculations reveals that the lion's share of this capacity is accounted for by maximum concentrated solar power (CSP) capacity amounting to 20,000 GW, with photovoltaic solar energy providing an additional 13,800 GW of capacity. However this tremendous capacity could only be used during daylight hours unless storage systems are also installed.

The resource that provides the second highest renewable electricity potential is wind, whose maximum potential is around 5,500 GW, which is about evenly divided between offshore and onshore wind farms (2,700 and approximately 2,800 GW respectively). The advantage of wind power is that it provides minimum capacity of around 700 GW even during low wind periods.

Geothermal energy is in third place in terms of renewable electricity potential. Unlike solar and wind energy, geothermal energy is available without interruption, but is also relatively expensive. Geothermal electricity potential in the Europe-North Africa region amounts to roughly 275 GW.

The fourth highest renewable electricity potential in this region is hydro power, whose putative capacity ranges from 109 to 224 GW, depending on the season. The Europe-North Africa region's hydro power, which would chiefly come from run-of-river stations, would make a significant contribution to enabling renewable electricity to satisfy overall electricity demand. Hydro power also has a special role to play in terms of short and medium term storage in pump storage systems.

Biogas and solid biomass in accordance with nature conservation and environmental protection requirements would play a relatively minor role since the potential factored into the DLR calculations defined severe restrictions in terms of biomass crop cultivation. Thus the lion's share of this potential would necessitate the use of residual agricultural and forest materials. Biomass potential amounts to approximately 71 GW, assuming usage distributed evenly across the entire year. Inasmuch as solid biomass such as forestry smallwood ideally lends itself to storage, and since large amounts of biogas and natural gas can be stored seasonally in depleted gas fields, these renewables will mainly be used during periods when solar and wind power is at a low ebb.

It can be concluded that supplying the Europe-North Africa region with electricity from renewable sources could be achieved there using a mere 2 percent of renewable electricity potential.

In the hypothetical scenario under which Germany is fully self-sufficient in terms of electricity supply, the supply from renewable sources can – in the very unlikely case of demand exceeding 800 TWh/a and given the rather restrictive modeling assumptions imposed by the DLR - reach its limits. However, Germany's integration into an international renewable electricity supply network – a project that is already in the works – would satisfy German electricity demand in any imaginable scenario. It seems unlikely that this would require the use of North Africa's solar energy potential, but the integration of this potential would probably decrease mean electricity generation costs.

3.2 Three scenario groups involving a wholly renewable electricity supply

9. As shown by our analysis of renewable electricity potential in section 3.1, a wholly renewable electricity supply would be achievable in Germany even if Germany's renewable electricity potential were the sole renewable energy resource. However, this would be relatively cost intensive and would entail extensive use of various storage systems to balance the severe fluctuations in electricity generation. As noted, supplying the Europe-North Africa region with renewable electricity would necessitate the use of only 2 percent of the region's usable electricity generation potential and thus would not come anywhere near exhausting such potential. But as likewise previously pointed out, use of the entire region's potential would entail the integration of some politically unstable Eastern European and North African states. A simpler solution – one that would obviate the problems entailed by the exclusive use of German electricity generation resources, as well as the problems that could potentially arise from an inter-regional Europe-North Africa network – would be a trilateral German-Danish-Norwegian cooperation, which would be endowed with (a) considerable additional low cost renewable electricity potential in terms of wind power; and (b) thanks to Norway, the best electricity storage potential in Europe. Against this backdrop, we feel that it would be worthwhile to shed light on the options entailed by a wholly renewable electricity supply, via the following three scenarios groups (see section 2.3):

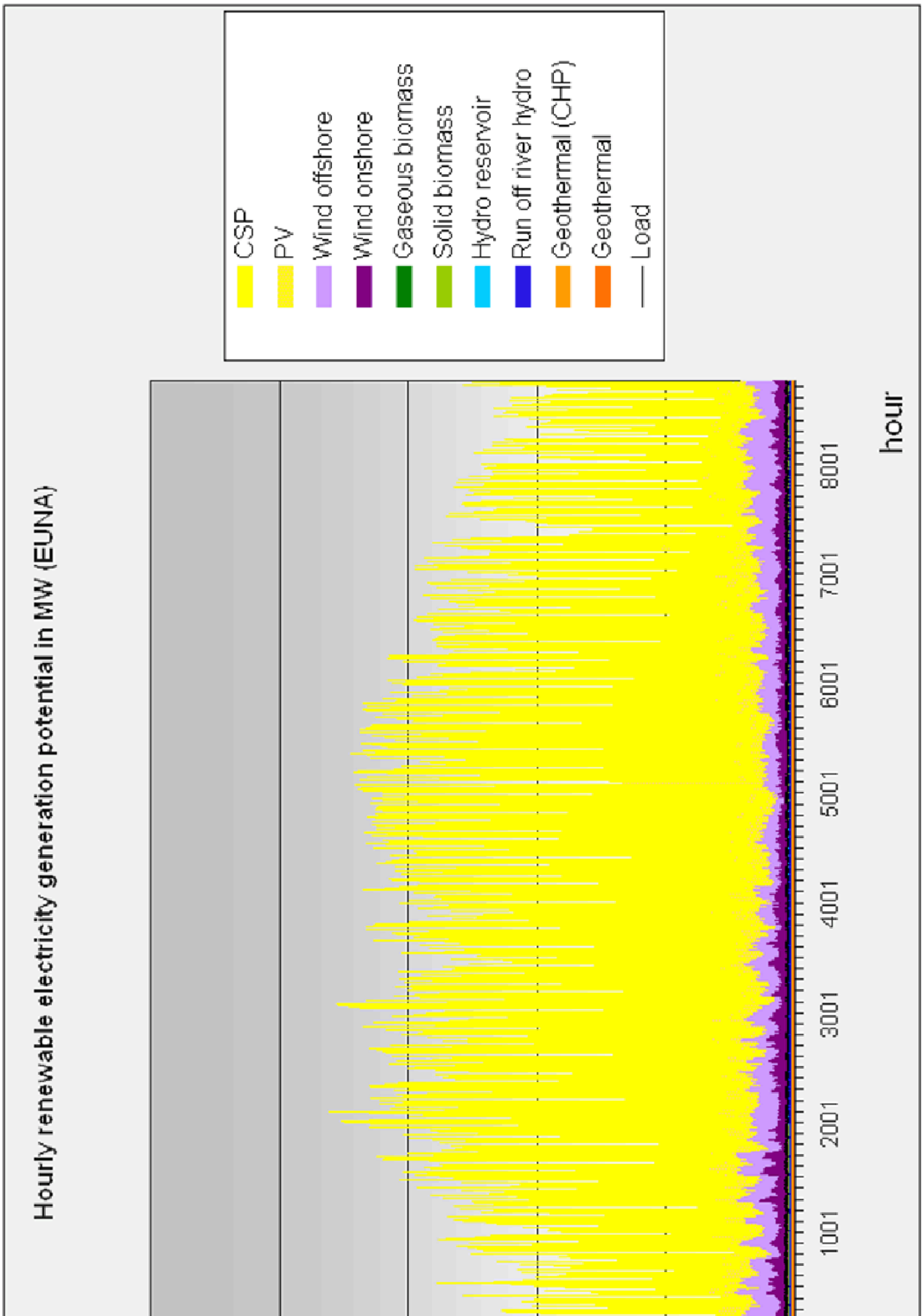
– A wholly renewable electricity supply based solely on German potential (scenarios 1.a and 1.b).

– A wholly renewable electricity supply involving a German-Danish-Norwegian network (scenarios 2.1.a, 2.1.b, 2.2.a and 2.2.b).

– A wholly renewable electricity supply via a large-scale network comprising the Europe-North Africa region (as territorially defined by the DLR) (scenarios 3.a and 3.b).

Figure 3-5

Hourly renewable electricity generation potential in MW (EUNA)



SRU/Stellungnahme Nr. 15–2010; Figure 3-5; data source: DLR 2010

The specifications for each of the various sub-scenarios can be found in Table 2-1 and section 2.3. As we see it, the German-Danish-Norwegian solution is a particularly promising option inasmuch as, relative to the 100 percent German self sufficiency of scenarios 1.a and 1.b, it would allow for substantial cost reductions by avoiding surplus capacity and its implementation would entail relatively little political or technical effort. Moreover, such a cooperative network structure could potentially set the stage for incremental integration of additional states without the need for a large number of states to reach a pre-implementation agreement and/or consensus. The scenarios described in the following only take technical and economic factors into consideration, to the exclusion of legal considerations, which will be addressed in a subsequent report.

3.2.1 The least likely solution: a wholly renewable electricity supply based solely on German renewables

10. Unlikely though the prospect of Germany going it alone by implementing a wholly renewable electricity supply involving absolutely no international electricity interchange may be, this admittedly hypothetical scenario would entail the highest requirements in terms of achieving a wholly renewable electricity supply and thus constitutes the toughest test for our assumption that Germany could achieve a wholly renewable electricity supply by 2050. If it can be shown that such an electricity supply is achievable in Germany using the renewables available solely within our borders, then it stands to reason that any scenario that includes other states and posits the same restrictions would be easier to implement since a larger region entails additional generation and storage potential as was shown in our discussion of the available potential in the Europe-North Africa region (see section 3.1.2). Since, as noted, the German energy self sufficiency scenario is more of a thought experiment than a plausible option – and one whose legal issues have yet to be analyzed – the results of scenarios 1.a (DE 100% SV-500) and 1.b (DE 100% SV-700) will be described only briefly here. Moreover, in view of the fact that many of the assumptions we made apply to all of the scenarios, they will be described in our discussions of scenarios 1.a and 1.b.

The basic scenario for a wholly renewable electricity supply in Germany defines a reference demand amounting to 509 TWh/a in 2050. Based on DLR documentation for other target 2050 scenarios, in the interest of keeping the computing resources needed for the simulations within reasonable bounds we presupposed that German electricity demand will reach 509 TWh/a by 2050. Electricity demand was modelled for all of the scenario simulations based on the characteristic historical annual load curve in all of its hourly segments. Using the DLR's REMix model, and factoring in storage capacity and the cost assumptions in section 2, an optimal electricity mix was determined for the satisfaction of hourly demand. In terms of storage capacity, we assumed that in Germany compressed air energy storage capacity equating to an electrical storage volume of up to 3.5 TWh could be provisioned. This assumption, which was based on the work of Ehlers (2005) who analyzed the availability of salt formations for the creation of storage caverns, needs further confirmation via additional investigations.

Only 1 GW of Germany's 7 GW of pump storage system capacity was folded into the storage of intermittent inputs as it was assumed that most of this capacity will be used for grid functions such as minute reserves and frequency stabilization. This assumption can be regarded as being extremely conservative in view of the practice, already in place today, whereby pump storage systems are used for peak load provisioning.

As Figure 3-6 shows, German electricity demand can be satisfied at all times using the renewable electricity potential within our borders combined with compressed air energy storage systems, and without importing a single kWh of electricity. This could be accomplished via the following combination of technologies: 33 GW of installed offshore wind power, which would generate 76 TWh/a of electricity; 73 GW of installed onshore wind power, which would generate approximately 317 TWh/a of electricity; 86 GW of installed photovoltaic capacity, which would generate approximately 88 TWh/a of electricity; and biomass whose installed capacity of 33 GW would equate to 71 TWh/a of electricity. This "thought experiment" scenario involving German energy independence uses all available biomass potential for electricity generation purposes. Here, solid biomass, which exhibits high capacity but relatively few operating hours (1,660 equivalent full load hours (EFLH) per year), would be used for peak load situations (see Figure 3-6), owing to the fact that while biomass lends itself to storage, additional storage facilities are in short supply. Hydro power, for which virtually no expansion is currently in the works, accounts for just under 25 TWh/a via approximately 4.5 GW of installed capacity. A summary of the scenario 1.a (509 TWh/a) and 1.b (700 TWh/a) results can be found in table 3-1.

Scenario 1.a entails the generation of 580 TWh/a in Germany for demand amounting to 509 TWh/a. Of this output, approximately 51 TWh/a would be kept in compressed air energy storage facilities; and after allowing for storage and conversion loss, 34 TWh/a would be available to satisfy demand on a deferred basis. Pump storage systems, which would also be used here, would allow for the storage of approximately 1.2 TWh/a and for reclaiming of an additional 1 TWh/a. This scenario results in surplus production amounting to more than 53 TWh/a, which can normally be avoided by shutting down wind turbines. Peak load amounts to approximately 81 GW during peak demand periods, whereas total primary installed capacity is 230 GW, with 32 GW of secondary capacity from hydro reservoirs. The electricity supply cost in this scenario, including annual capital costs, amounts to € 45.9 billion annually in 2009 prices – which equates to a mean annual generation cost of 0.09 euros per kWh or € 90 per MWh. An overview of all scenario 1.a and 1.b assumptions concerning capacity, generation, annual costs, and specific costs can be found in Table 3-1.

The most exacting scenario that was analyzed on the basis of these assumptions – scenario 1.b – was obtained by increasing gross electricity demand to 700 TWh/a and scaling up the load curve accordingly. However, such elevated electricity demand would occur in 2050 only if current energy saving efforts achieve only limited success, if Germany's individual motor car fleet will be completely electrified (see Wietschel and Dallinger 2008) and if the electricity needed for this evolution is derived from domestic renewable energy only.

The potential cost curve in Figure 3-1 for renewable electricity in Germany indicates that electricity demand amounting to around 700 TWh/a would also entail more expensive options such as the use of geothermal electricity. This is confirmed by the analysis based on hourly optimization (Figure 3-7). Geothermal energy would be used nearly year round to ramp up power generation, and would generate 147.1 TWh/a via 18.3 GW of installed capacity. At € 202 per MWh, this far exceeds the mean generation costs in the 509 TWh/a scenario. As a result, overall capacity would rise from 230 GW in the 509 TWh/a scenario to 283 GW in the 700 TWh/a variant, in order to meet the considerably higher demand with a peak load of more than 112 GW. Apart from the new geothermal capacity needed to satisfy this increased demand, the following other technologies would be similarly affected: photovoltaic capacity would rise from around 86 to around 110 GW; wind onshore turbine capacity would rise from around 33 to around 39 GW; and biomass capacity would rise from around 33 to around 38 GW. The biomass capacity increase would not, however, translate into a rise in production owing to the fact that the biomass capacity limit amounting to 71 TWh/a was already reached in scenario 1.a. This additional (solid) biomass would solely be used for relatively high peak loads. In scenario 1.b, usage would decline from approximately 1,660 equivalent full load hours (EFLH) to approximately 1,450 hours per year, with compressed air energy storage capacity increasing from 32 to 37 GW. As a new major electricity generation resource, geothermal energy generation is considerably higher in scenario 1.b than in scenario 1.a (509 TWh/a) (see Figure 3-7). However, despite this substantial generation capacity increase, surplus production decreases from 53 TWh/a in scenario 1.a to 45 TWh/a in scenario 1.b.

Total annual costs increase from just over € 46 billion to just under € 81 billion, with geothermal electricity generation accounting for the lion's share of the increase (€ 30 billion) and per kWh costs rising from 0.09 to 0.115 euros due to the necessity of including very cost intensive electricity.

3.2.2 A wholly renewable electricity supply in a German-Danish-Norwegian network

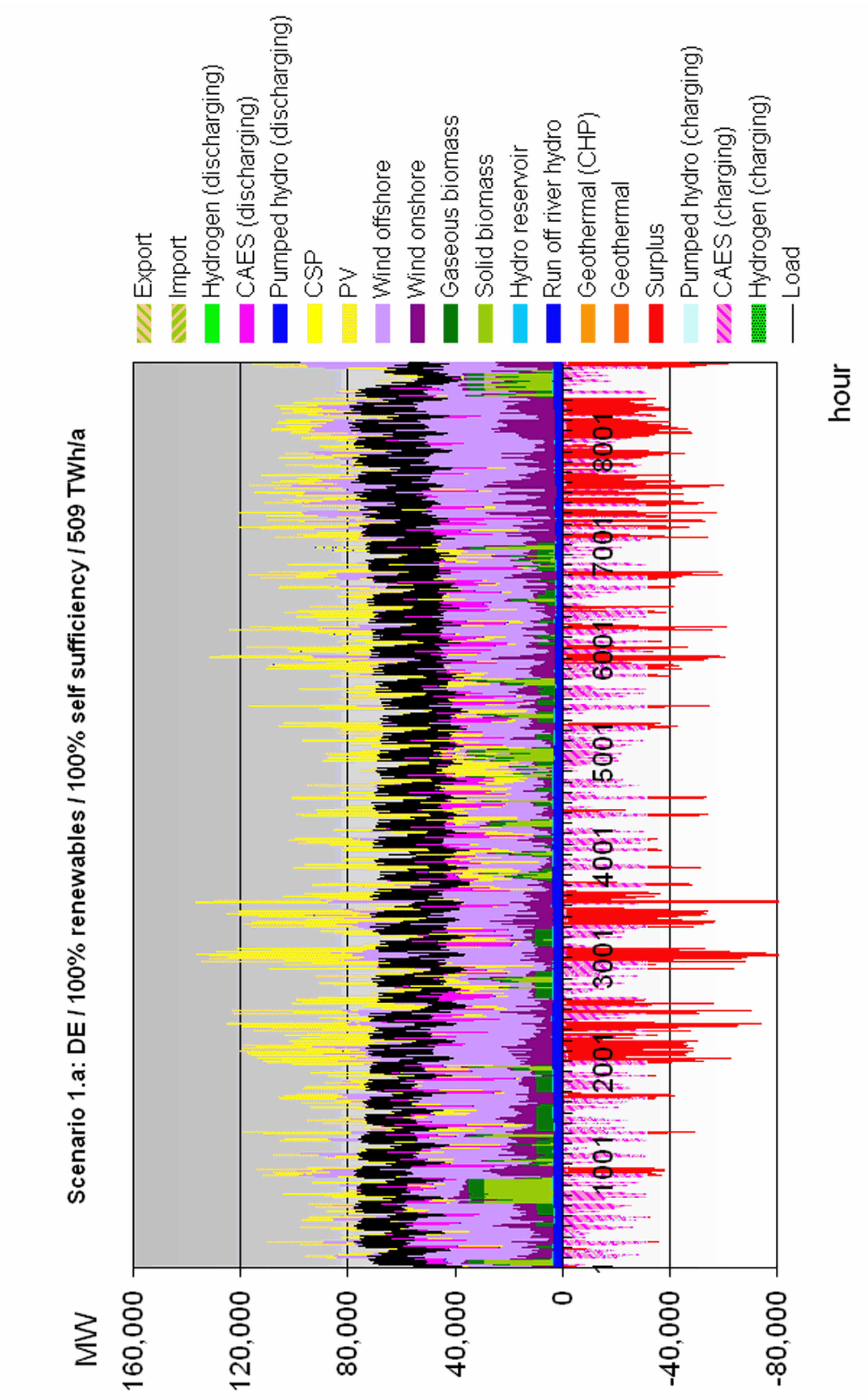
3.2.1.1 A wholly renewable electricity supply in Germany with cross-border load balancing in a German-Danish-Norwegian network

11. In view of the international cooperation in the European electricity generation sector already achieved today, scenarios that would allow for a wholly renewable electricity supply for and produced within Germany appear to far exceed the necessary goal of energy security. Hence scenarios 1.a and 1.b suggest that even extremely ambitious energy security objectives can be reached if solely renewables are used. However, it appears to be far more likely that Germany will continue to interchange electricity with its neighbors. A simple model for such cooperation is an energy supply network comprising Germany, Denmark, and Norway (or Sweden), whose interchange and reciprocal dependency even the most hardened skeptics would have to admit will entail little or no risk in terms of ensuring a reliable electricity supply. Hence the scenario group 2 scenarios were analyzed as an initial phase in the relaxation of the regional restrictions entailed by scenario group 1, for a wholly renewable electricity supply in a German-Danish-Norwegian system. In so doing, we assumed for scenarios 2.1.a and 2.1.b (a) that each of the three states in this network will produce all of its own electricity over the course of any given year; but (b) that these states will be permitted to interchange up to 15 percent of their total output so as to avoid a situation where each state is required to produce all of its own electricity round the clock. This set of circumstances was in turn analyzed for total German demand amounting to 509 TWh/a (scenario 2.1.a) and 700 TWh/a (scenario 2.1.b), which equates to approximately 650 TWh/a (scenario 2.1.a) and approximately 895 TWh/a (scenario 2.1.b) of the aggregate demand of the three participating states. A complete overview of all of the scenarios we investigated can be found in Table 2-1.

In scenario 2.1.a (509 TWh/a in Germany), electricity generation costs in Germany are reduced from 0.09 to 0.07 euros per kWh by virtue of the fact that electricity interchange and particularly the use of Norwegian pump storage system capacity equates to the following reductions in Germany: generation capacity from 230 to 163 GW; surplus production from 53 TWh/a to approximately 0.8 TWh/a; compressed air energy storage capacity from 32 to 18 GW. A noteworthy evolution here is that the installed capacity of cost intensive power technologies would be reduced (biomass and photovoltaic 27 and 47 GW lower respectively), but at the same time German onshore wind capacity would rise 6.4 GW to the maximum potential posited by the model amounting to 39.5 GW, by virtue of the Norwegian pump storage system capacity that would be used for equalization purposes within the framework of the German-Danish-Norwegian network. However, German use of installed compressed air energy storage capacity would decline relative to the counterpart scenario 1.a, resulting in an increase in specific storage costs from 0.109 to 0.276 euros per kWh. The lower degree of capacity utilization in Germany is due to competition from cheaper Norwegian pump storage systems. This also means that biomass does not have to be used for storage purposes as was the case in the German self sufficiency scenarios 1.a. and 1.b. In scenario 2.1.a, solid biomass is used solely for cogeneration plants, whose equivalent full load hours (EFLH) increase to 6,840.

Figure 3-6

Scenario 1.a: DE/100% renewables/100% self sufficiency/509 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-6; data source: DLR 2010

Table 3-1

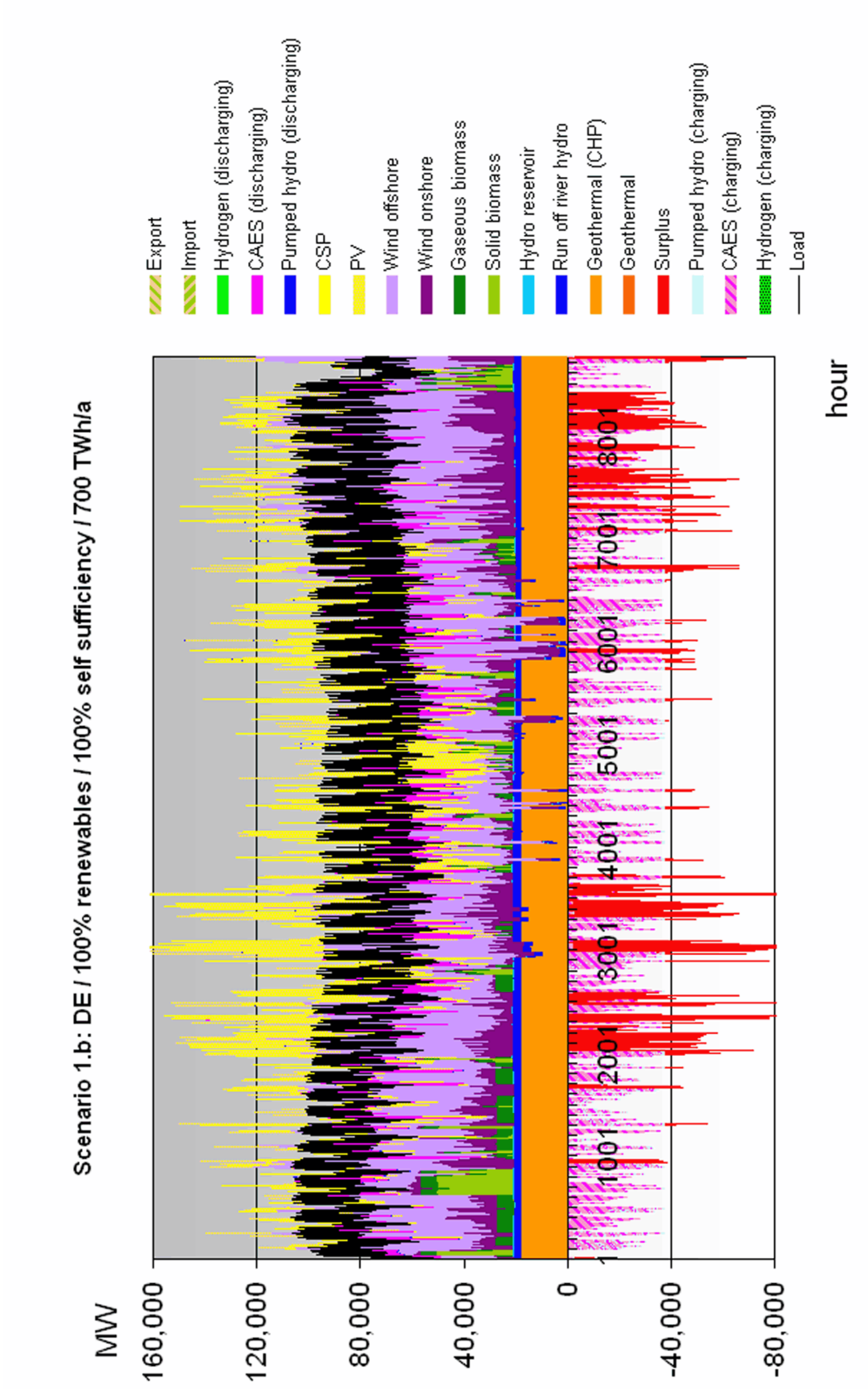
Capacity, electricity generation, and annual and specific cost assumptions used for scenarios 1.a and 1.b

	Capacity used		Electricity produced		Costs			
	Max. GW		TWh/a		Millions of euros per year		Euro-cents per kWh	
Energy source/technology used for scenario...	1.a	1.b	1.a	1.b	1.a	1.b	1.a	1.b
Photovoltaics	85.9	109.6	87.9	112.2	7,798	9,957	8.9	8.9
Solar thermal								
Onshore wind	33.1	39.5	76.0	90.6	3,578	4,267	4.7	4.7
Offshore wind	73.2	73.2	316.9	316.9	13,056	13,057	4.1	4.1
Geothermal								
Geothermal with CHP	0.0	18.3	0.0	147.1	0	29,696	0.0	20.2
Solid biomass	26.8	30.8	44.5	44.5	11,664	12,734	26.2	28.6
Solid biomass with CHP	0.0		0.0					
Biogas	0.0		0.0					
Biogas with CHP	6.6	6.7	26.6	26.6	4,687	4,745	17.6	17.8
Run-of-river hydro	4.1	4.1	25.3	25.3	1,337	1,337	5.3	5.3
Hydro reservoir storage	0.4	0.4	2.3	2.3	119	119	5.3	5.3
Totals/average (gross)	**230**	**283**	**579.5**	**766**	**42,239**	**75,911**	**7.3**	**9.9**
Electricity imports	0	0	0.0	0	0			
Electricity exports	0	0	0.0	0	0			
Electricity storage								
Pump storage (storage)	0.5	0.6	1.2	1.4				
Pump storage (generation)	0.5	0.6	1.0	1.1	68	85	7.1	7.7
Compressed air (storage)	32	37	50.5	60.3				
Compressed air (generation)	32	37	33.5	39.7	3,654	4,660	10.9	11.7
Hydrogen (storage)	0	0.0	0.0	0.0				
Hydrogen (generation)	0	0.0	0.0	0.0				
Storage loss			17.2	21				
Total demand/costs	**81**	**112**	**509.0**	**700**	**45,960**	**80,656**	**9.0**	**11.5**
Surplus capacity/production	181	209	53.3	**45**				

SRU/Stellungnahme Nr. 15–2010; Table 3-1; Data source: DLR 2010

Figure 3-7

Scenario 1.b: DE/100% renewables/100% self sufficiency/700 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-7; data source: DLR 2010

A summary of the results of scenarios 2.1.a and 2.1.b can be found in Table 3-2. It should be noted here that the losses attributable to cross-border transport and storing electricity outside of Germany for reimport purposes was computed in such a way that these losses were offset by additional electricity generation outside of Germany. The posited reimport costs include international cross-border transport in both directions, the cost of storing electricity in Norwegian pump storage systems, and the cost of generating electricity (via Norwegian wind farms) to compensate for the losses.

Figure 3-8 shows the dynamics of electricity generation in the German-Danish-Norwegian network structure in 2050. Noteworthy here are is high proportion of electricity generation accounted for by pump storage systems and the oftentimes high storage capacity of such systems, virtually all of which comes from Norway. Wind energy is the predominant primary electricity generation modality.

As can be seen in Figure 3-9, scenario 2.1.a entails extensive short-term electricity interchange, and high wind turbine capacity translates into higher generation peaks than in scenario 1.a, thus substantially reducing biomass and photovoltaic capacity. Figure 3-9 also reveals that electricity is exported during peak production periods and is reimported a short time later, as soon as wind power generation falls off substantially. German compressed air energy storage capacity is used far less than is the case in scenario 1.a.

Table 3-2

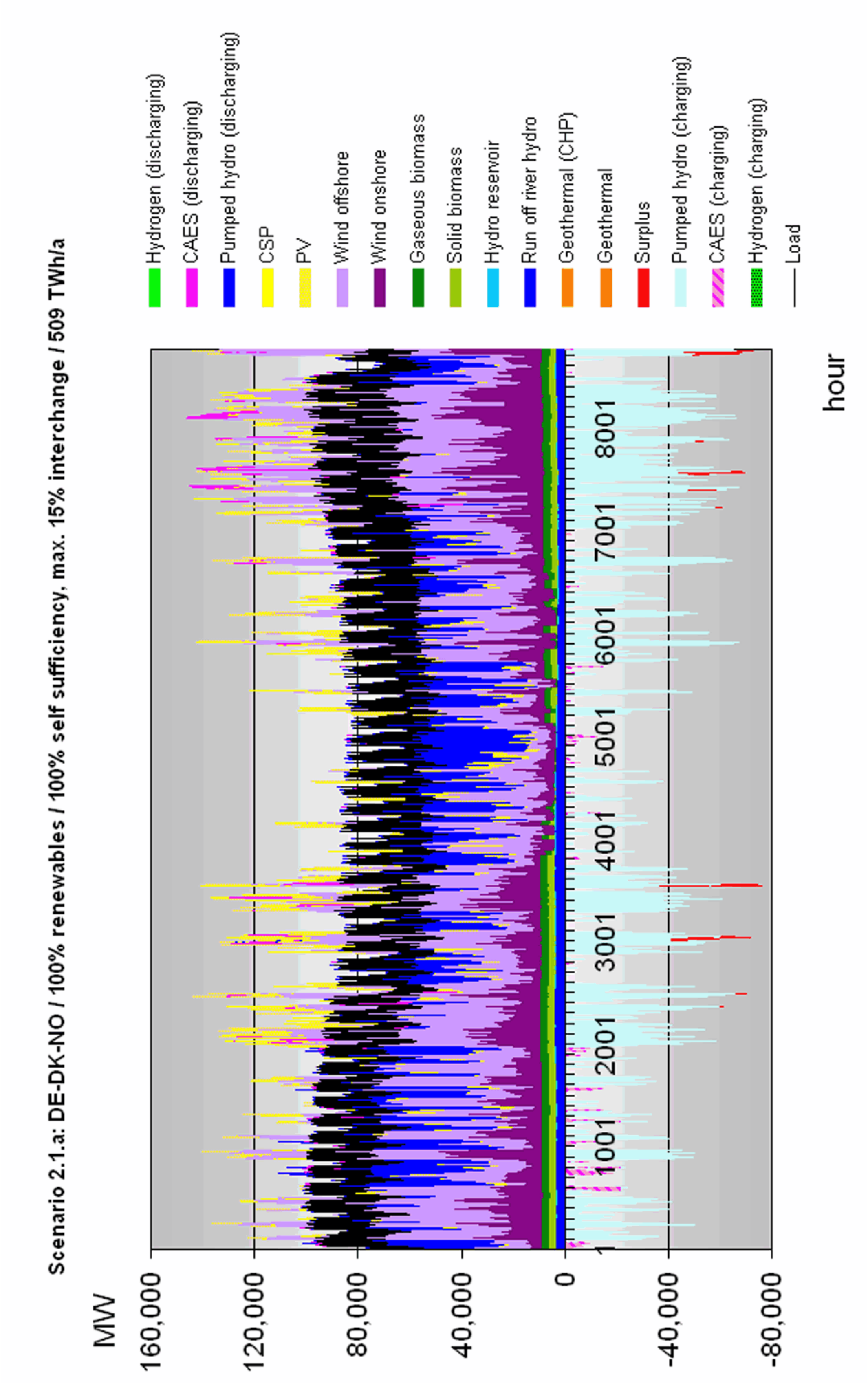
Overview of capacities used, electricity generated, and annual and specific costs in scenarios 2.1.a and 2.1.b

	Capacity used		**Electricity produced**		**Costs**			
	Max. GW		TWh/a		Millions of euros per year		Euro-cents per kWh	
Scenario	2.1.a	2.1.b	2.1.a	2.1.b	2.1.a	2.1.b	2.1.a	2.1.b
Energy source used								
Photovoltaics	40.9	109.6	41.9	112.2	3,714	9,957	8.9	8.9
Solar thermal		0.0		0.0		0		
Onshore wind	39.5	39.5	90.6	90.6	4,267	4,267	4.7	4.7
Offshore wind	73.2	73.2	316.9	316.9	13.057	13.057	4.1	4.1
Geothermal		0.0		0.0		0		
Geothermal with CHP		14.4		119.8		23.314		19.5
Solid biomass		0.0		0.0		0		
Solid biomass with CHP	2.5	3.0	17.1	17.1	1,983	2.249	11.6	13.2
Biogas		0.0		0.0		0		
Biogas with CHP	2.4	2.9	17.1	17.1	1,495	1,741	8.7	10.2
Run-of-river hydro	4.1	4.1	25.3	25.3	1,337	1,337	5.3	5.3
hydro reservoir	0.3	0.3	2.3	2.3	92	92	4.0	4.0
Totals/average (gross)	**162.9**	**247.0**	**511.2**	**701.3**	**25.944**	**56.013**	**5.1**	**8.0**
Electricity reimporting	0.0	0.0	76.4	103.1	8.406	11.304	11.0	11.0
Electricity storage								
Pump storage (storage)	1.2	1.2	1.0	0.8				
Pump storage (generation)	1.2	1.2	0.8	0.6	171	170	21.4	28.3
Compressed air (storage)	18.1	23.5	5.7	4.0				
Compressed air (generation)	18.1	23.5	4.3	3.0	1189	1466	27.6	48.9
Hydrogen (storage)	0.0	0.0	0.0	0.0				
Hydrogen (generation)	0.0	0.0	0.0	0.0				
Storage loss			1.6	1.2				
Total demand/costs	**81**	**111**	**509.4**	**700.1**	**35.709**	**68.953**	**7.0**	**9.8**
Surplus capacity/production	101.2	160.7	0.2	0.0				

SRU/Stellungnahme Nr. 15–2010; Table 3-2; Data source: DLR 2010

Figure 3-8

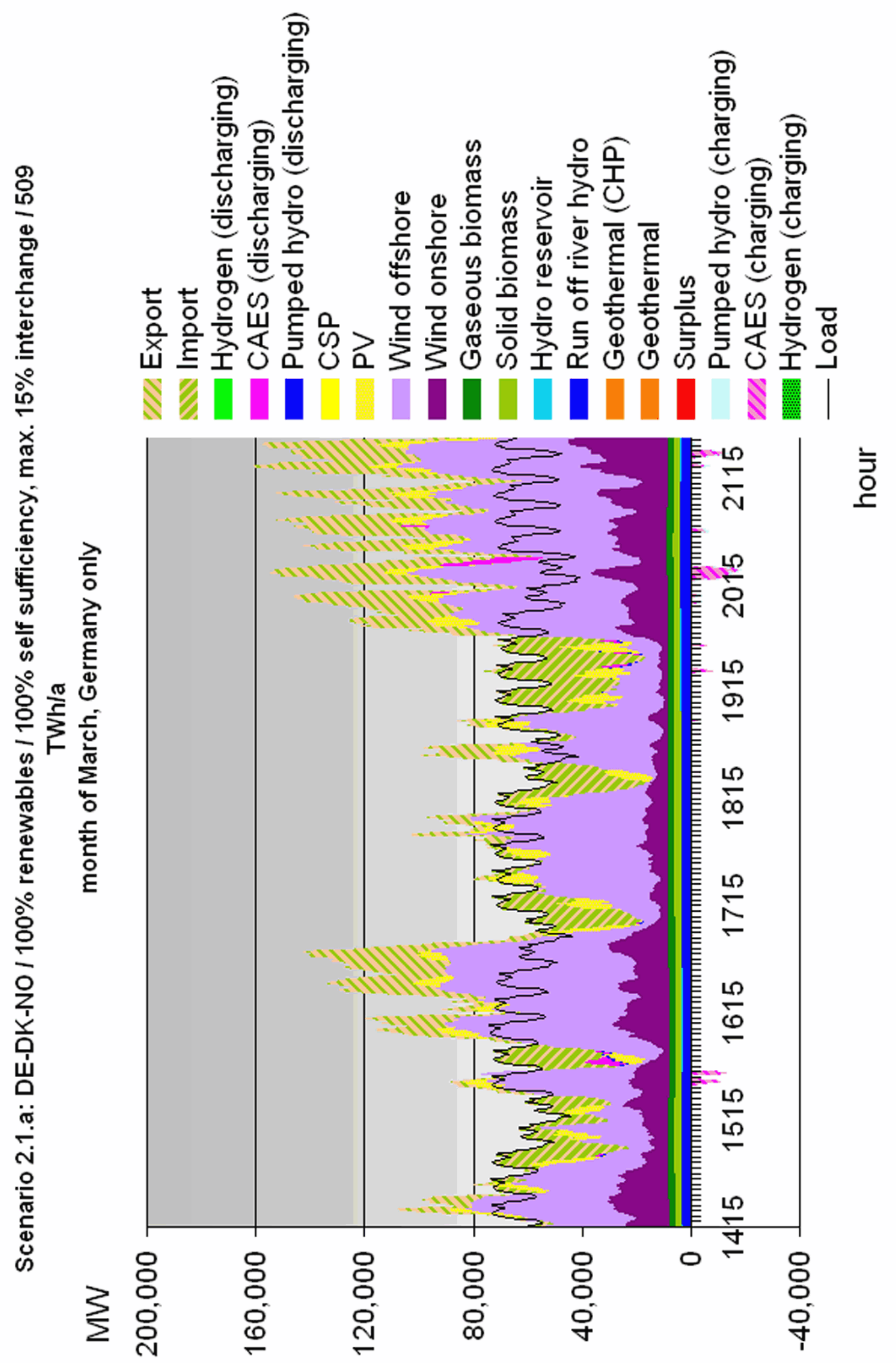
Scenario 2.1.a: DE–DK–NO /
100% renewables/100% self sufficiency, max. 15% interchange/509 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-8; data source: DLR 2010

Figure 3-9

**Scenario 2.1.a: DE–DK–NO /
100% renewables / 100% self sufficiency, max. 15% interchange / 509 TWh/a,
month of March, Germany only**



SRU/Stellungnahme Nr. 15–2010; Figure 3-9; data source: DLR 2010

In scenario 2.1.b, as in scenario 1.b, electricity demand in Germany increases to 700 TWh/a, whereby electricity interchange for only up to 15 percent of demand is allowable for the three participating states, each of which must produce 100 percent of the electricity for its annual demand. An increase in German electricity demand to 700 TWh/a equates to an increase in aggregate demand amounting to approximately 895 TWh/a in these three states, which results in an increase in average electricity costs to 0.098 euros per kWh. However, electricity costs are 0.017 euro per kWh lower than in scenario 1.b (German electricity generation self sufficiency with demand amounting to 700 TWh/a). The cost increase relative to scenario 2.1.a (509 TWh/a) is primarily attributable to the following: (a) the fact German geothermal capacity amounting to approximately 14.4 GW is included to allow for the generation of additional electricity; and (b) the necessity of ramping up photovoltaic generation capacity from 41 to 110 GW. It is also necessary to increase German compressed air energy storage capacity from 18.1 to 23.5 GW, although this leads to a less efficient use of this capacity. The data concerning capacity use, electricity generation, and total and specific costs can be found in Table 2-3.

3.2.2.1 German electricity supply with allowable net electricity import amounting to 15 percent

12. Scenarios 2.2.a and 2.2.b eliminate the restriction on the German-Danish-Norwegian network requiring that 100 percent of each member state's electricity must be produced within its borders, whereby each state is permitted to import 15 percent of total output from either of the other two partners. Scenario 2.2.a assumes again a German electricity demand of 509 TWh/a (and a demand of 650 TWh/a in all three countries), whereas scenario 2.2.b investigates a German electricity demand amounting to 700 TWh/a (895 TWh/a in the tripartite system).

As can be seen in Table 3-3, the scenario 2.2.a costs decrease from 0.07 euros per kWh only slightly to 0.065 euros per kWh as compared to scenario 2.1.a (net import barred, interchange allowed), although installed generation capacity in Germany decreases from 163 to 107 GW. This is mainly attributable to the elimination of photovoltaic generation capacity (41 GW) and the reduction of installed onshore wind energy capacity to 25 GW. However, since imported renewable electricity, including all storage expenses, is relatively expensive (0.148 euros per kWh), the avoided investment costs in Germany barely reduce overall costs.

A comparison of Figure 3.11, which shows aggregate generation in the German-Danish-Norwegian network, and Figure 3-8 (scenario 2.1.a) shows that no solar energy is needed to satisfy electricity demand, and that relatively expensive photovoltaics are replaced by additional wind energy and storage.

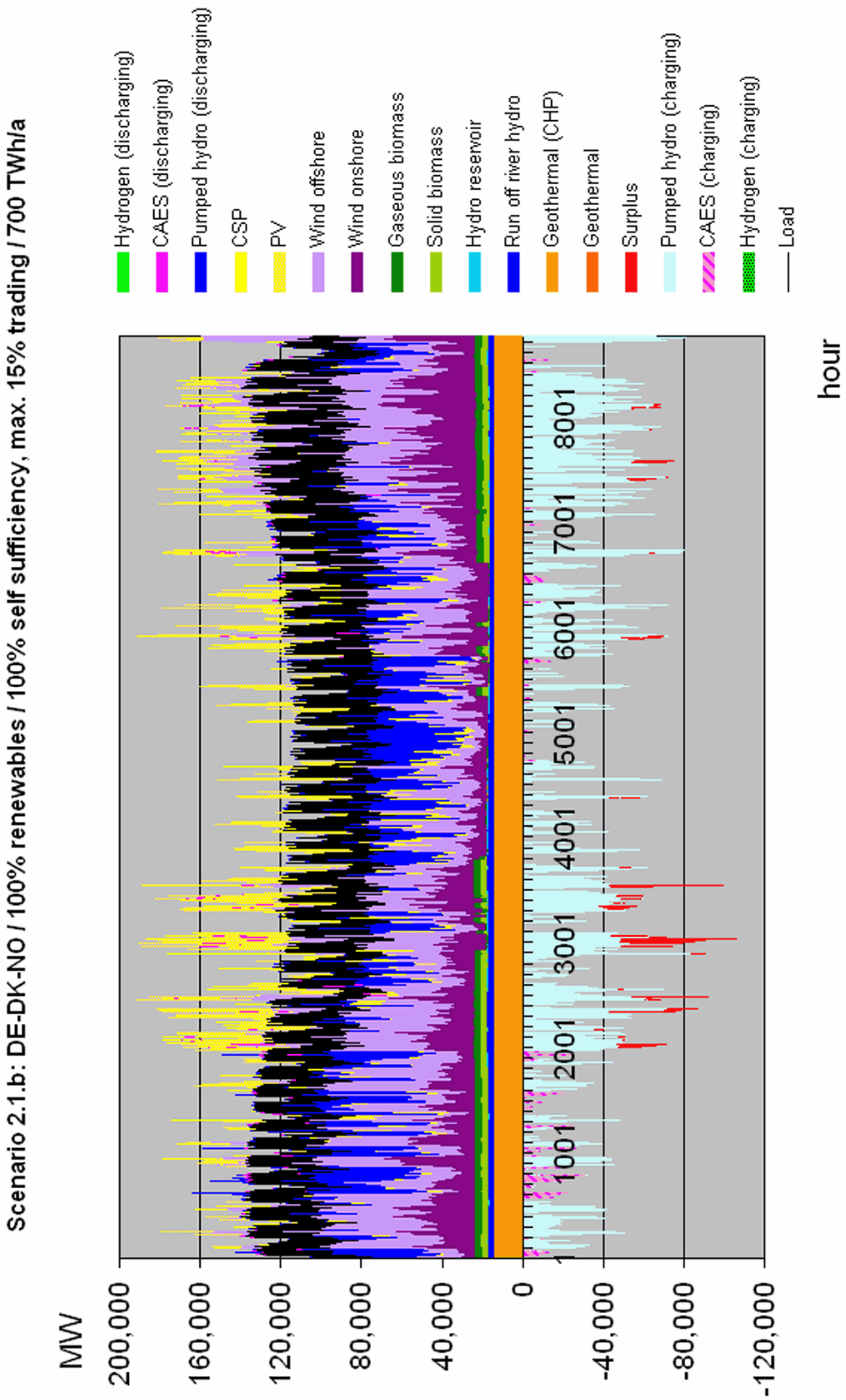
If the assumed demand is increased to 700 TWh/a under these same conditions (i.e. Germany importing 15 percent of its electricity from the two other cooperating states), the conditions for scenario 2.2.b are obtained. As is shown in Table 3-3, in order to provide 85 percent of this electricity output (595 TWh/a) in Germany, generation capacity would have to be raised to 234 GW, which is more than twice the 107 GW in scenario 2.2.a. However, German electricity production would only have to be increased by 161 TWh/a, from 435 to 596 TWh/a. This capacity increase would be realized by expanding photovoltaic capacity to 110 GW (up 110 GW), expanding onshore wind capacity to 39.5 GW (up 15 GW) and by geothermal capacity amounting to 1.8 GW. This would translate into an aggregate cost increase from 0.065 euros per kWh in scenario 2.2.a to 0.072 euros per kWh.

However, relative to scenario 2.1.b, which disallows electricity import and only allows electricity interchange, scenario 2.2.b costs decrease substantially, from 0.098 to 0.072 euros per kWh, mainly due to substantially lower geothermal energy transmission capacity (down 12.6 GW), which in scenario 2.2.b is replaced by imports. As can be seen by comparing Figures 3-12 (scenario 2.2.b) and 3-10 (scenario 2.1.b), geothermal energy is no longer a mainstay of electricity generation.

In the four Table 3-4 scenarios, electricity transmission between the three cooperating states would necessitate a substantial increase in line capacity, which was factored into the electricity supply costs. The transmission capacities in the present report presuppose that all electricity transmission between Germany and Norway would transit through Denmark. However, in reality these transmission lines would traverse the Danish exclusive economic zone in the North Sea, whereby only a minute portion of these lines would be installed onshore in Denmark. This arrangement would necessitate line capacity ranging from 42 to 69 GW (see Table 3-4). These figures show that electricity interchange amounting to 15 percent of annual electricity production (but excluding net imports) (scenario 2.1) would also necessitate up to 54 GW of transmission capacity between Denmark and Norway (scenario 2.1.b), 48 GW of which, however, would be accounted for by electricity transit between Germany and Norway. Raising the allowable amount of imports would necessitate increased transmission capacity, but only 10 percent more than in the scenarios that exclude net imports.

Figure 3-10

Scenario 2.1.b: DE–DK–NO /
100% renewables/100% self suffiency, max. 15% interchange/700 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-10; data source: DLR 2010

Table 3-3

Overview of capacities used, electricity generated, and annual and specific costs in scenarios 2.2.a and 2.2.b

	Capacity used		**Electricity produced**		**Costs**			
	Max. GW		TWh/a		Millions of euros per year		Euro-cents per kWh	
Energy source used for scenario...	2.2.a	2.2.b	2.2.a	2.2.b	2.2.a	2.2.b	2.2.a	2.2.b
Photovoltaics		109.6		112.2		9,957		8.9
Solar thermal								
Onshore wind	24.6	39.5	56.5	90.6	2,663	4,267	4.7	4.7
Offshore wind	73.2	73.2	316.9	316.9	13,057	13,057	4.1	4.1
Geothermal								
Geothermal with CHP		1.8		14.6		2,842		19.5
Solid biomass								
Solid biomass with CHP	2.5	2.6	17.1	17.1	1,960	2,035	11.5	11.9
Biogas								
Biogas with CHP	2.3	2.5	17.1	17.1	1,471	1,545	8.6	9.0
Run-of-river hydro	4.1	4.1	25.3	25.3	1.37	1,337	5.3	5.3
Hydro reservoir	0.3	0.3	2.3	2.3	89	89	3.9	3.9
Totals/average (gross)	**107.0**	**233.6**	**435.2**	**596.1**	**20.576**	**35.128**	**4.7**	**5.9**
Net electricity imports			76.4	105.0	11,298	14,091	14.8	13.4
Electricity storage								
Pump storage (storage)	0.5	0.9	1.1	0.4				
Pump storage (generation)	0.5	0.9	0.9	0.3	76	125	8.4	41.7
Compressed air (storage)	18.7	23.1	7.0	3.5				
Compressed air (generation)	18.7	23.1	5.2	2.6	1,228	1,352	23.6	52.0
Hydrogen (storage)								
Hydrogen (generation)								
Storage loss	0.0		2.0	1.0				
Total demand/costs	**81.0**	**111.4**	**509.4**	**700.0**	**33,178**	**50,697**	**6.5**	**7.2**
Surplus capacity/production	45.2	146.2	0.5	0.1				

SRU/Stellungnahme Nr. 15–2010; Table 3-3; Data source: DLR 2010

Table 3-4

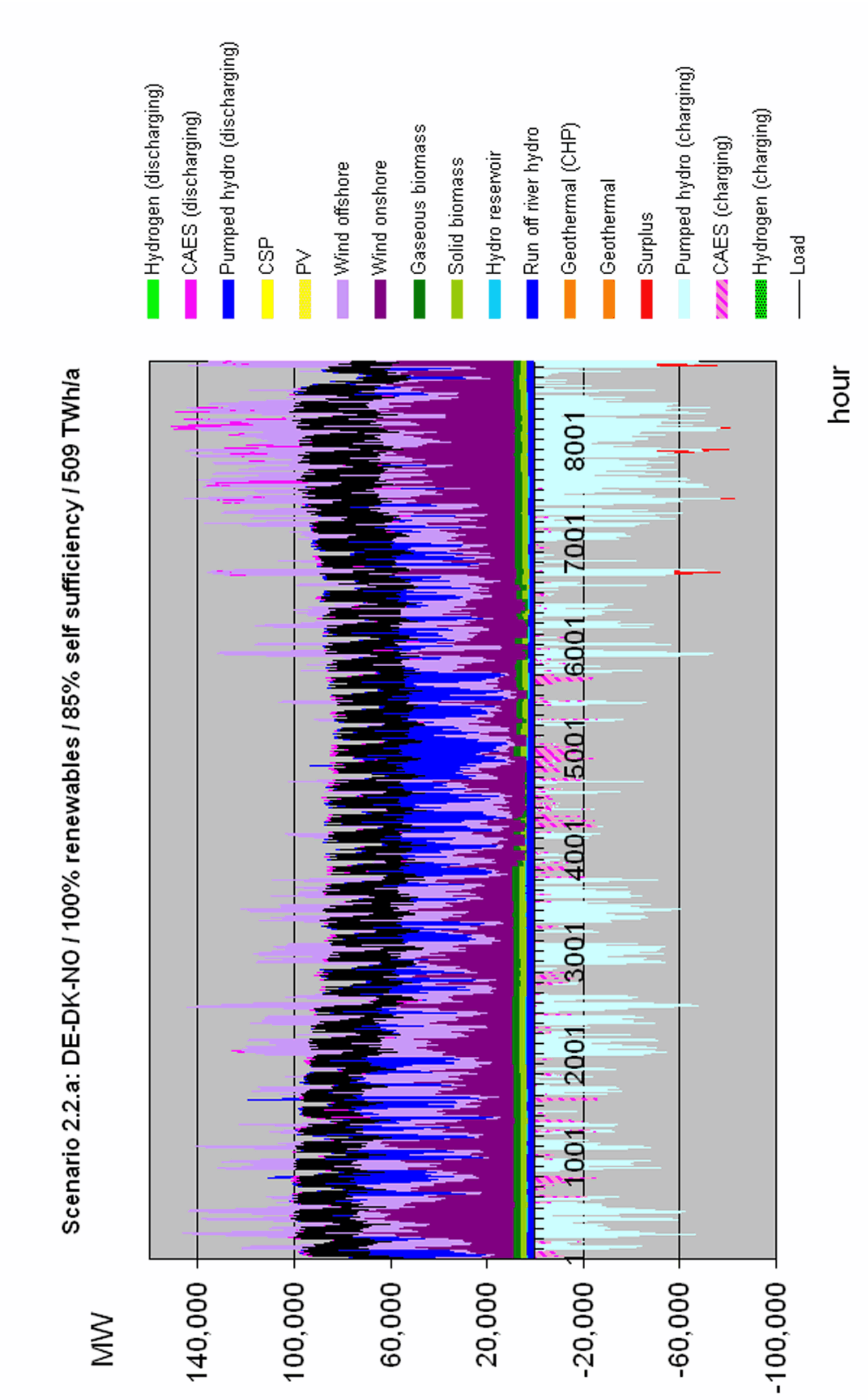
Electricity transmission capacities (in GW) within the German-Danish-Norwegian energy supply network for the various scenarios

Network states	**Scenario**			
	2.1.a	**2.1.b**	**2.2.a**	**2.2.b**
	100% self sufficiency/509 TWh	100% self sufficiency/700 TWh	85% self sufficiency/509 TWh	85% self sufficiency/700 TWh
DE–DK	41.9	48.5	47.1	61.6
DK–NO	46.0	54.2	50.0	68.8

SRU/Stellungnahme Nr. 15–2010; Table 3-4; Data source: DLR 2010

Figure 3-11

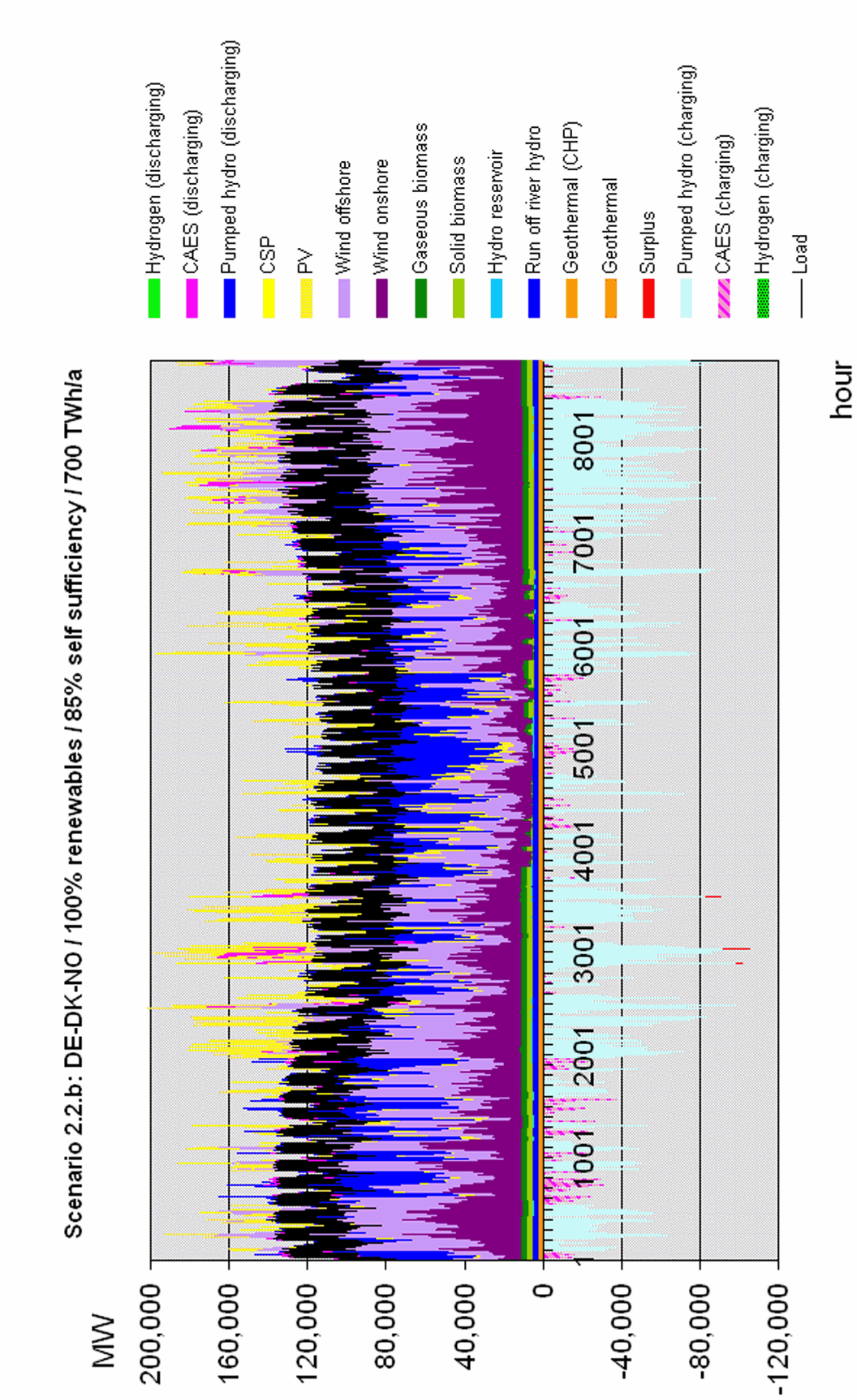
Scenario 2.2.a: DE–DK–NO /
100% renewables/85% self sufficiency/509 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-11; data source: DLR 2010

Figure 3-12

Scenario 2.2.b: DE–DK–NO /
100% renewables/85% self sufficiency/700 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-12; data source: DLR 2010

3.2.3 A wholly renewable electricity supply in an inter-regional Europe-North Africa network

13. Inasmuch as the exploitable renewable energy potential for a Europe-North Africa network exceeds foreseeable demand by a factor of 20 (see section 3.1.2), in scenario group 3 we investigated the impact such an inter-regional network would have on German electricity supply in 2050. Here again, it was assumed that each network state will cover at least 85 percent of its electricity demand via renewables over the course of a year and that maximum net imports of 15 percent are allowable. These scenarios also admit electricity interchange (export and reimport) for electricity storage purposes abroad. Scenario 3.a assumes a German electricity demand in 2050 amounting to 509 TWh/a, which corresponds to an aggregate demand in the network zone amounting to approximately 5,400 TWh/a, whereas scenario 3.b. assumes a German demand amounting to 700 TWh/a in this same year.

In view of the fact that modelling an optimization solution for a 36 state/region network for the 8,760 hours comprising a year would entail a monumental amount of computing resources, the scenario 3.a and 3.b simulations were run for every other hour over the course of a year and for five intervals of equal length, so as to keep the requisite computing resources within reasonable bounds. Despite these measures, each simulation took days or even weeks to run. In view of the fact that, as at the April 2010 cutoff date for the present report, the scenario 3.b simulation results were available for only three of the five aforementioned intervals, this scenario will not be discussed in depth here.

In the enlarged network entailed by scenario 3.1, the costs for a wholly renewable electricity supply in Germany are the same as for scenario 2.2.a (0.065 euros per kWh). As Table 3-5 shows, relative to scenario 2.2.a installed German generation capacity increases by 3 GW to 110 GW due to the increase in installed onshore wind power from 24.6 to 28 GW, whereas offshore wind power amounting to 73.2 GW remains unchanged. Installed capacity and electricity generation from biomass and hydro power differ little relative to scenario 2.2.a. Noteworthy here is that installed German compressed air energy storage capacity increases from 18.7 to 20.7 GW, which equates to the generation of 11.8 TWh/a from 15.7 TWh/a of stored electricity over the course of a year. Owing to the multiplicity of transmission lines in a complex network comprising 36 states, it cannot be determined exactly which state produces or stores electricity for which other state. Nonetheless, it is noteworthy that the maximum Norwegian pump storage system capacity used (in TWh) in the Europe-North Africa network is lower than in the German-Danish-Norwegian system. Expanded Norwegian pump storage system capacity, the use of new compressed air energy storage facilities, and the equalization effect of such a large scale network structure (without any pump storage system capacity increase in any other participating state) allow for a wholly renewable electricity supply in Europe on a 24/7/365 basis. It is also safe to assume that an analogous expansion of the already considerable capacity of hydro reservoirs will occur, certainly in Sweden, but also in France, Italy, Switzerland and Austria. The present report did not allow for this possibility, since many such expansion projects necessitate the prior construction of lower lakes, which experience has shown can provoke considerable opposition.

As in the German-Danish-Norwegian network, wind power is the predominant energy source in here, accounting for more than 3,400 TWh/a (63 percent) of the more than 5,400 TWh/a of demand. However, the presence of southern Europe and North Africa in this grid also yields relatively low cost solar power potential, amounting to 1,080 TWh/a for concentrated solar power and 575 TWh/a for photovoltaic energy, or 31 percent of this network's aggregate electricity generation – a substantial contribution, particularly during the summer months. Figure 3-13 shows how hourly demand is satisfied via electricity generation in the inter-regional Europe-North Africa network, where primary generation capacity amounting to just under 1,380 GW is installed for an annual peak load amounting to 840 GW. Apart from this, compressed air energy storage capacity amounting to more than 230 GW and pump storage capacity amounting to more than 100 GW would be needed for a fully reliable round the clock electricity supply in this wholly renewables based system.

As can be seen in Table 3-5, the basic supply situation in Germany would change very little in the Europe-North Africa network relative to scenario 2.2.a (DE–DK–NO 85% SV). And in terms of satisfying hourly demand, as is shown in Figure 3-14, wind energy and imports of stored surplus electricity would account for a substantial portion of Germany's electricity supply.

In view of the fact that the Europe-North Africa network is only marginally more advantageous than the German-Danish-Norwegian network and would take considerably longer to implement owing to the large transmission line distances involved, Germany should move quickly to establish a cooperation with Denmark, Norway and possibly Sweden. For even if Austria and Switzerland have substantial storage hydroelectric power station capacity amounting to just under 30 TWh/a at present, the Scandinavian potential amounting to more than 120 TWh/a is four times as large. Moreover, this potential is utilized by far fewer states than is the case with Austria and Switzerland on account of Scandinavia's far greater distance from centers of electricity demand.

Table 3-5

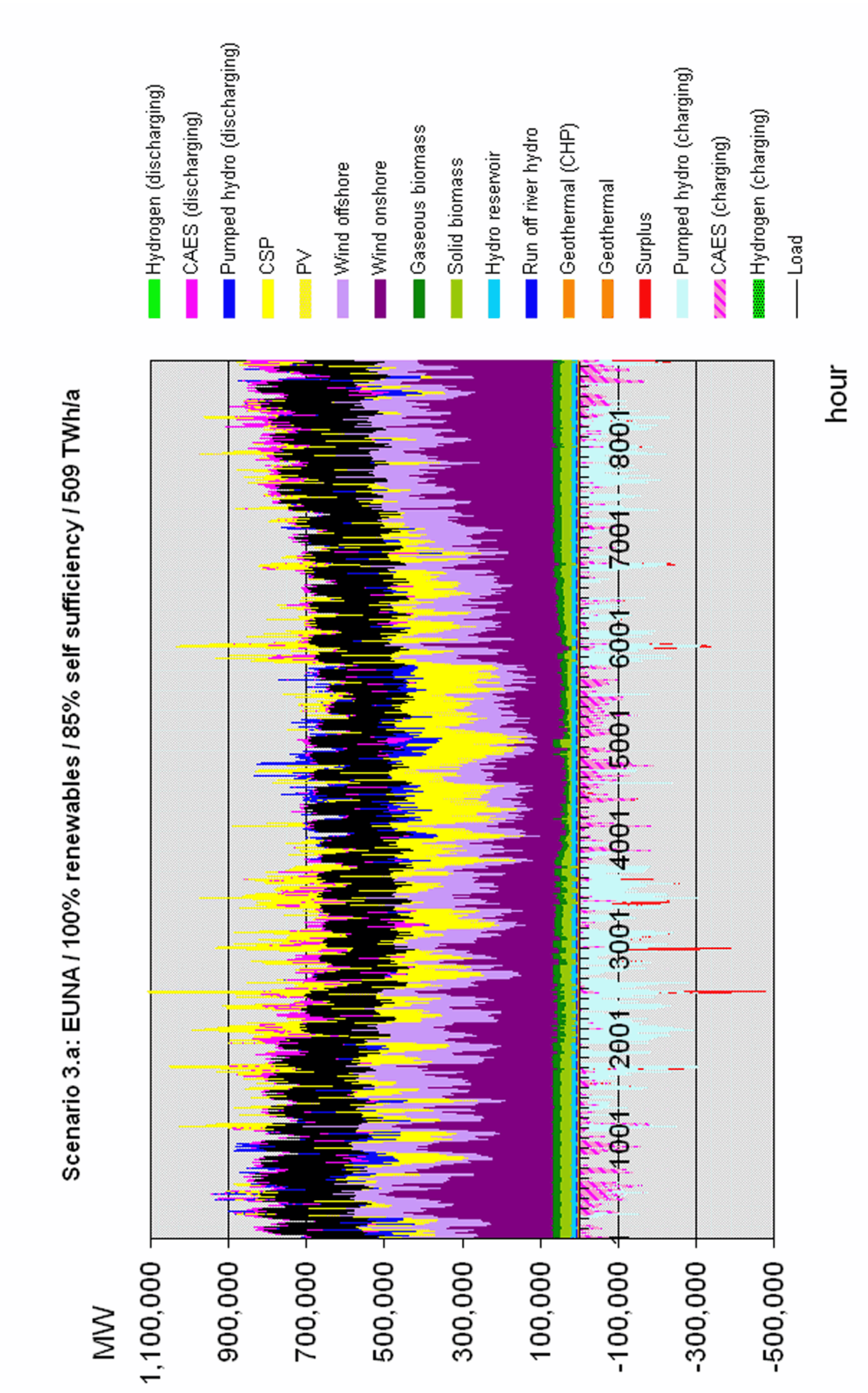
Overview of capacities used, electricity generated, and annual and specific costs in scenario 3.a

Scenario	**3.a**	**Germany 509 TWh/a, 85% self sufficiency, German interchange with the Europe-North Africa region**		
	Capacity used	Electricity produced	Costs	
	Max. GW	TWh/a	Millions of euros per year	Euro-cents per kWh
Energy source used				
Photovoltaic				
Solar thermal				
Onshore wind	38.3	63.7	4,142	6.5
Offshore wind	73.2	316.9	13,057	4.1
Geothermal				
Geothermal with CHP				
Solid biomass				
Solid biomass with CHP	2.6	17.1	1,986	11.6
Biogas				
Biogas with CHP	2.4	17.1	1,489	8.7
Run-of-river hydro	4.1	20.2	1,337	6.6
Hydro reservoirs	0.3	2.3	107	4.7
Totals/average (gross)	**120.9**	**437.2**	**22,117**	**5.1**
Electricity imports		76.4	11.298	14.8
Electricity storage				
Pump storage (storage)	0.8	1.5		
Pump storage (generation)	0.8	1.2	115	9.3
Compressed air storage)	30.6	15.7		
Compressed air (generation)	30.6	11.8	1.474	12.4
Hydrogen (storage)				
Hydrogen (generation)				
Storage loss		4.7		
Total demand/costs	**81.0**	**509.4**	**35,004**	**6.9**
Surplus capacity/production	71.3	0.1		

SRU/Stellungnahme Nr. 15–2010; Table 3-5; Data source: DLR simulations (2010)

Figure 3-13

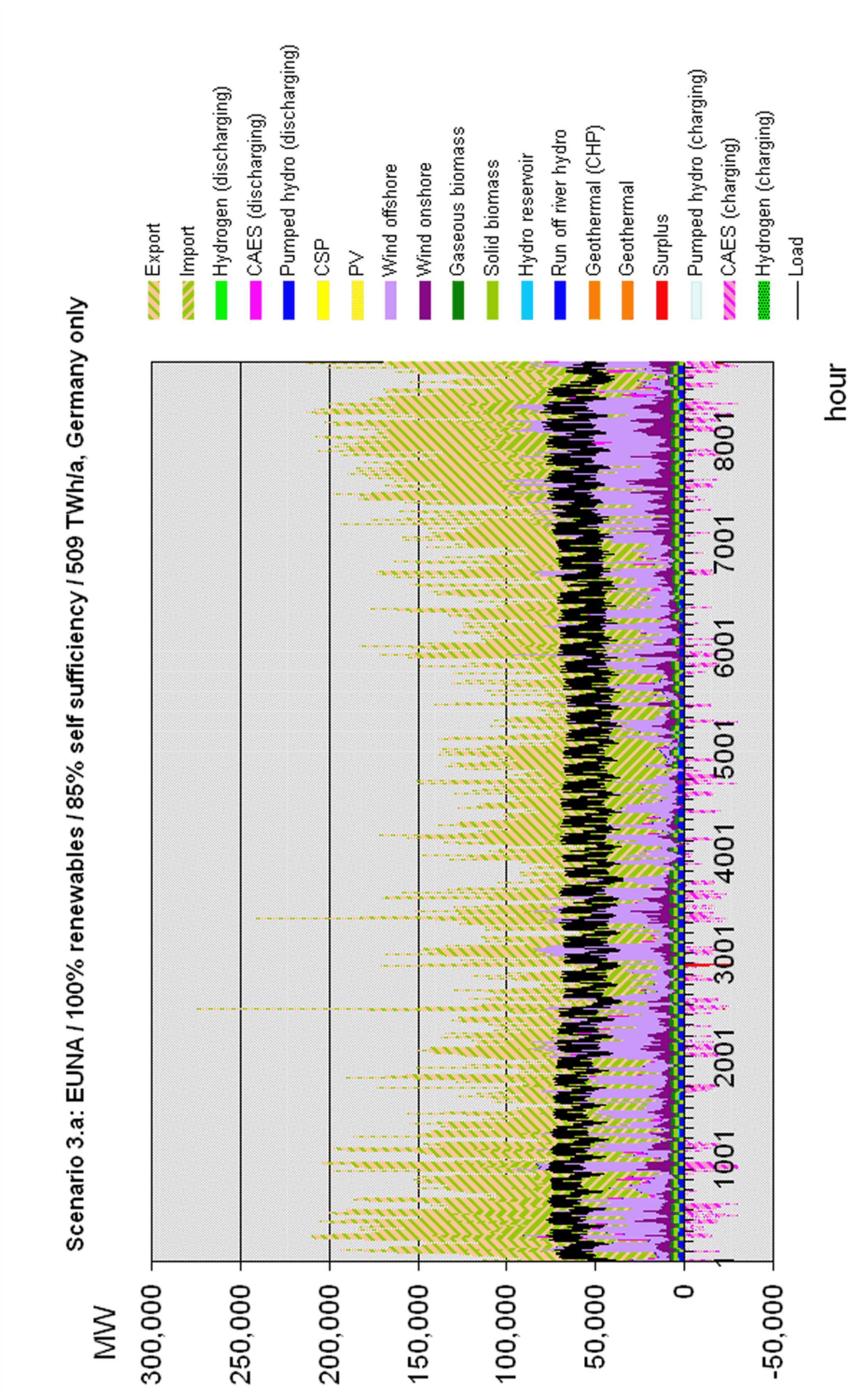
Scenario 3.a: EUNA / 100% renewable / 85% self sufficiency / 509 TWh/a



SRU/Stellungnahme Nr. 15–2010; Figure 3-13; data source: DLR 2010

Figure 3-14

Scenario 3.a: EUNA/100% renewables/85% self sufficiency/509 TWh/a, Germany only



SRU/Stellungnahme Nr. 15–2010; Figure 3-14; data source: DLR 2010

4 The technical development roadmap and the decisions needed for it

4.1 Capital-stock timeline

14. Section 3 aimed to show that a wholly renewables-based sustainable electricity supply is achievable by 2050. The question nonetheless arises as to which roadmap would allow for realization of such a scenario in light of Germany's current electricity supply situation. Our aim here is not to predict how the current electricity supply situation will evolve in light of current conditions, but rather to show which pathway can ensure that the objectives are reached.

This roadmap takes as its starting point Germany's current power plant fleet and the evolution this fleet is slated to undergo as the result of various German power plants being decommissioned at the end of their technical or economic life time. Each year between now and 2050 will be characterized by a specific residual power plant fleet, the attendant aggregate capacity resulting from the age of the power plants involved and their projected mean service life thereof, and can be represented graphically. Inasmuch as a power plant's life cycle can extend over 50 years, these graphics of these cycles extend a number of decades into the future. Multiplying the capacity of the current power plant fleet for each year by a posited mean annual service life, which is expressed as equivalent full load hours (EFLH), yielded the amount of electricity that can be generated annually with the existing power plant fleet. This production potential was then compared with the assumed future electricity demand for each year. It should be noted in this regard that conventional power plants are prone to considerable internal consumption and that transmission of their electricity to customers entails a certain amount of power loss. In cases where electricity generation potential would undercut future demand, it is necessary to ramp up generation capacity or import electricity in order to avoid supply shortfalls.

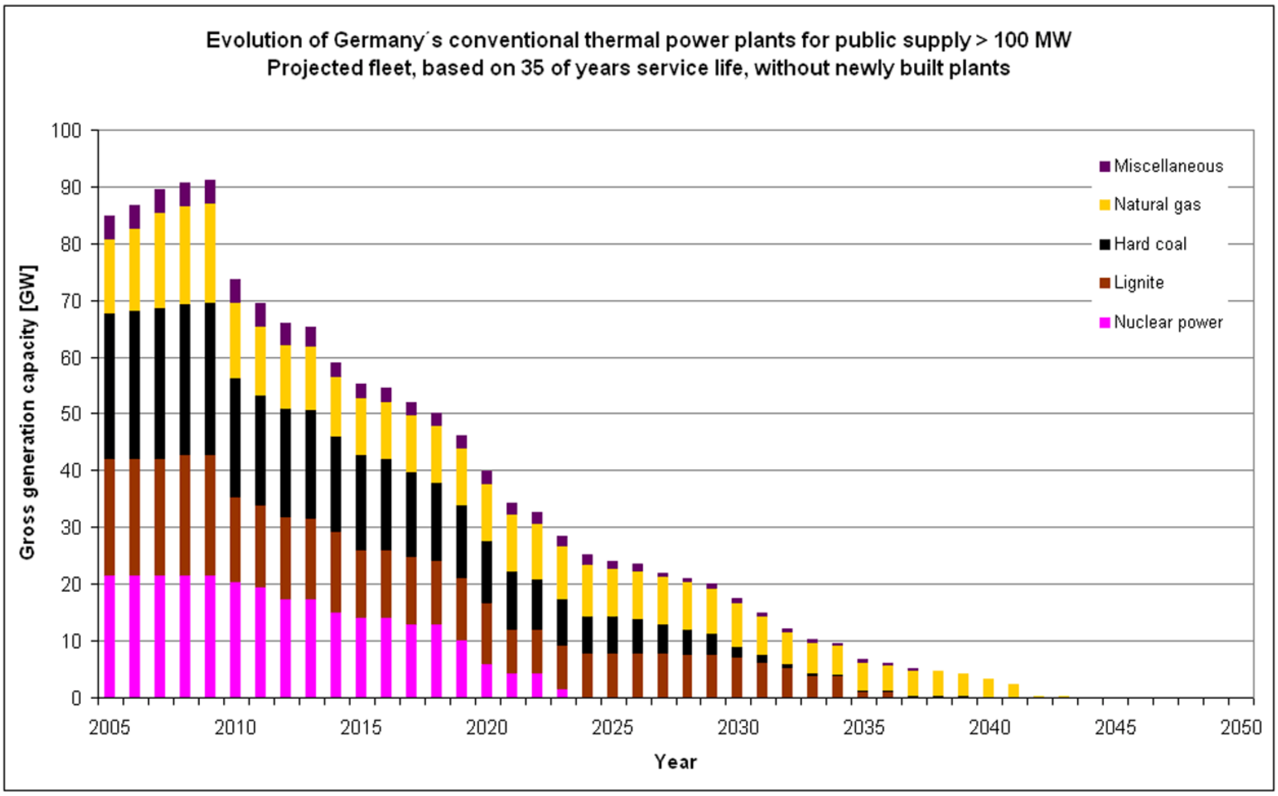
Life spans ranging from 30 to 50 years were assumed for conventional thermal power plants. However, the actual life spans of German power plants tend to be longer than the nominal service life indicated by the manufacturer, and can be extended by an additional 20 to 25 years if they are overhauled. Life spans ranging from 35 to 45 years were assumed for coal fired power plants (Loreck 2008, p. 4; Marketwitz et al. 1998, p. 40), and life spans ranging from 30 to 35 years were posited for gas power plants, which, however, oftentimes remain in operation for up to 50 years (Dena 2010, p. 9).

The equivalent full load hours (EFLH) per year indicated in the literature for various types of power plants differ greatly, depending on how they are used. Moreover, power plant operating hours vary considerably over time according to annual load and power plant fleet availability. For example, fewer operating hours for nuclear power plants can substantially ramp up the operating hours for coal fired power plants. Moreover, the extent to which wind energy is fed into the grid can have a major impact on the number of full load hours for a conventional power plant, particularly in the medium load range.

Relatively short life spans amounting to 35 years for all available and under construction thermal power stations were defined for the 2010-2050 road map simulation of our target scenario, as was also done in a published basic scenario (Marketwitz et al. 1998, p. 40). The term conventional thermal power plant refers to virtually all fossil fuel powered power plants and nuclear power plants to the exclusion of hydro power plants. The assumption that conventional power plants have a relatively short life span means that the scope of renewable energy sources will have to be expanded with all due speed and makes the transition to a wholly renewable electricity supply particularly challenging. The evolution of the German power plant fleet in terms of capacity, assuming a power plant life span of 35 years, is shown in Figure 4-1. No assumptions have been made concerning the political climate surrounding nuclear power plant operation in Germany. Hence a 35 year life cycle was likewise defined for these facilities. This mean s that the last conventional thermal power plant currently in operation would be decommissioned in 2041 (see Figure 4-1.a).

Figure 4-1.a

Evolution of Germany's conventional power plant fleet (thermal power plants) as at 2009 for the years 2009-2050



SRU/Stellungnahme Nr. 15–2010; Figure 4-1.a; data source: UBA 2009

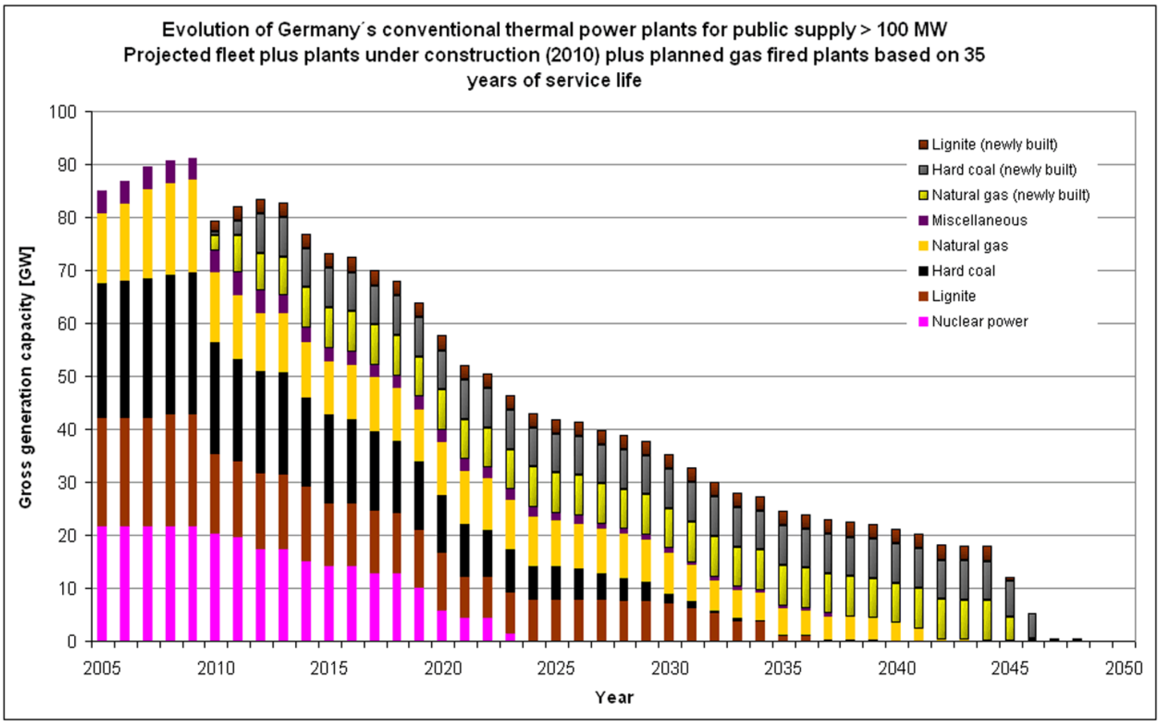
The severe capacity reduction from 2009 to 2010 is attributable to the fact that in 2009 a series of power plants were in operation that were more than 35 years old at that time were eliminated from the simulations as at 31 December 2009. However, actual power plant life cycles are considerably longer, which means that the capacity reduction indicated in Figure 4-1.a for 2010 would in fact be distributed across a number of years.

Factoring in coal fired power plants that are currently under construction as well as gas fired plants that are in planning or under construction equates to a considerable increase in the scope of Germany's installed power plant capacity amounting to around 15 GW (see Figure 4.1.b). In view of the fact that gas power plants lend themselves to particularly flexible supplementation of large portions of fluctuating input from renewables and exhibit the lowest carbon emission levels of all fossil fuel fired power plants, we presumed that all gas power plants that are currently under construction will be completed and that all such facilities that were in the planning stages as at January 2010 will be built. On the other hand, in view of the high carbon emissions of coal fired power plants, we presumed that only those facilities that were under construction as at January 2010 will be completed. Based on these assumptions, the last of the newly rolled out thermal power plants will be decommissioned in 2048.

If, however, a 45 year life cycle is posited for coal fired power plants, such facilities that are currently under construction will not be decommissioned until 2055-2077. For these conventional power plants, this 45 year life cycle would mean that approximately 10 KW of power plant capacity would still be in operation in 2050 (see Figure 4-2). If all coal fired power plants plans whose construction had been announced as at February 2010 are included, a 45 year life cycle would translate into additional capacity amounting to more than 20 GW, excluding the suspended planning process for the coal fired power plants in Kiel (800 MW), Dörpen (900 MW), Lubin (1,600 MW) and Mainz (760 MW). This in turn would mean that the last conventional thermal power plant would not be decommissioned until 2059. Figure 4-3 shows the evolution of Germany's fleet of conventional thermal power plants from 2005-2050, including coal fired power plants that are in the planning stages.

Figure 4-1.b

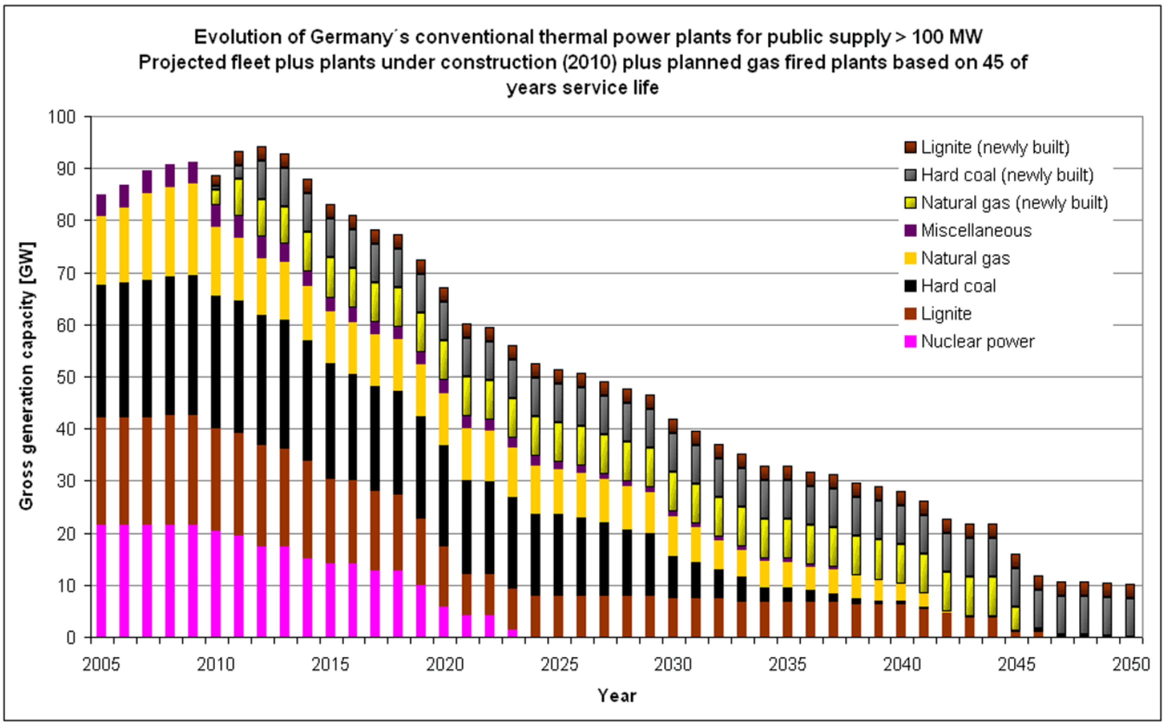
Evolution of Germany's conventional thermal power plant fleet, including coal fired power plants that are under construction and gas power plants that are in the planning stages, and assuming a 35 year life span for all power plants



SRU/Stellungnahme Nr. 15–2010; Figure 4-1.b; data source: UBA 2009; BDEW 2008

Figure 4-2

Evolution of Germany's conventional thermal power plant fleet, including coal fired power plants that are under construction and gas power plants that are in the planning stages (assuming a 45 year life span for coal fired power plants and a 35 year life span for all other types of power plants)



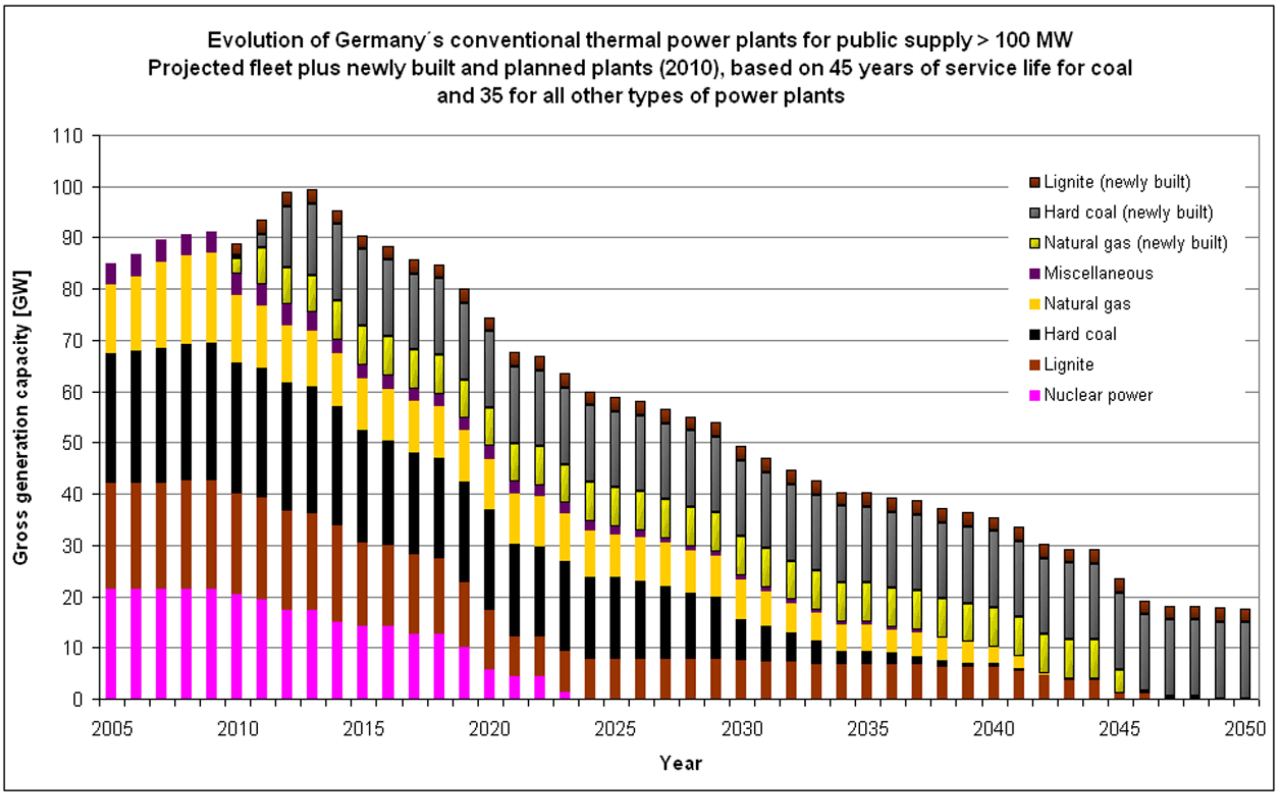
SRU/Stellungnahme Nr. 15–2010; Figure 4-2; data source: UBA 2009; BDEW 2008

Carbon emissions in 2050 would amount to roughly 100 megatons/year, assuming that all coal fired power plants that are in the planning phase are built and remain in operation for 45 years. However, the 80 percent greenhouse gas reduction goal for 2050 allows for only around 65 megatons/year of power plant carbon emissions by this date. If farther reaching reduction objectives of up to 95 percent were achieved, power plant carbon emissions could be reduced to just over 16 megatons per year. Thus even just the coal fired power plants that are currently in the pipeline (under construction or in the planning stages) would far exceed these emission limits, but would only satisfy some 25 percent of electricity demand. A large portion of coal fired power plants that are currently in the pipeline would – if run for a period of 45 years – have to be retrofitted with carbon capture and storage (CCS) systems which experts unanimously agree will be far more cost intensive than installing this same technology in new power plants (see IPCC 2005, p. 152). Moreover, CCS technology requires an infrastructure for transporting the captured carbon and storing extremely large quantities of it safely. Efforts to find underground carbon storage sites were met with firm opposition in 2009 on the part of the populations living near such sites. In our view, CCS is a possible, but not a sustainable and not a necessary strategy for the reduction of power plant greenhouse gas emissions and has a very limited overall capacity (SRU 2009, p. 9). The systematic expansion of the scope of renewable energy sources will obviate the need to keep conventional power plants in operation for 45 years and to use CCS technology for such facilities. However, if the coal fired power plants currently under construction are still in operation in 2050 and have not been retrofitted with CCS systems, the roughly 10 GW of coal fired power plant capacity they represent would equate to approximately 50 megatons of carbon emissions annually. Hence only a small proportion of these power plants could still be operated if an ambitious carbon reduction goal amounting to 15 megatons per year were promulgated.

All of our other simulations were based on the 35 year life span scenario shown in Figure 4-1.b. The assumption of such a relatively short conventional power plant life span translates into the most challenging scenario in the shorter term, both in terms of capacity (GW) and annual generation (TWh/a). If it can be shown that it is possible to moveto a wholly renewable electricity supply under these conditions, this will also prove that such a transition is feasible for longer conventional power plant life spans as well.

Figure 4-3

Evolution of Germany's conventional thermal power plant fleet, including power plants that are in the pipeline (assuming a life span of 45 years for coal fired power plants and of 35 years for all other types of power plants)



SRU/Stellungnahme Nr. 15–2010; Figure 4-3; Data source: UBA 2009; BDEW 2008

Even if the simulations described below are based on a strict life span of 35 years for all types of power plants in the interest of rendering the transition scenario calculations unequivocal and readily understandable, the real world scenarios will offer far greater flexibility. For example, if renewable energy sources come into greater use at a more rapid pace than that posited by our simulations, it may well be possible to decommission conventional power plants sooner, as has in fact sometimes been the case in recent decades (Markewitz et al. 1998, p. 40). But if the process of implementing renewable energy is delayed (for example offshore wind farm installation and commissioning can easily be delayed by six to nine months by early autumn storms; or electricity transmission line installation can be delayed by protests from local residents), normally the life cycle of conventional power plants can be extended beyond 35 years without undue additional expense. Hence the transitional scenarios discussed below that presuppose a 35 year life span for all types of power plants in fact allow for considerable generation capacity flexibility for the process of transitioning to renewable energy.

In view of the fact that annual hours of use for the various renewable energy resource technologies vary greatly, in addition to replacing conventional generation capacity it is also necessary to ensure that the generation capacity needed to meet electricity demand is available at all times in an electricity system that relies heavily on renewables. This in turn necessitates the installation of considerable storage capacity in conjunction with the envisaged generation infrastructure (see sections 3.2 (infrastructure) and 4.3 (storage capacities)). To this end, it is crucial to determine beforehand how much electricity (a) is likely to be generated each year by the remaining conventional power plant fleet; and (b) will need to be generated in connection with increased use of renewables to generate electricity.

Our conventional power plant calculations in this regard were based on 2008 annual full load hours for conventional power plants in the public grid (according to BDEW 2009; see Table 4-1). Multiplying the power plant fleet for each year by the presumed number of full load hours yields electricity generation by conventional thermal power plants.

Table 4-1

Posited annual full load hours for conventional power plants

Fuel	Annual full load hours
Lignite	6,710
Hard coal	4,320
Natural gas	3,430
Nuclear energy	7,690

Mean annual full load hours in 2008 for conventional power plants for public supply with more than 100 MW of electrical capacity.

Source: BDEW 2009

Our simulations were based on the assumption that (a) the level of hydro power use in Germany will remain relatively stable for the foreseeable future since most of the available environmentally compatible potential has already been developed; and (b) all necessary investments will be made to keep available hydro power capacity operational.

4.2 Renewable electricity generation: the way forward to 2050

15. It is safe to assume that, as various studies have shown (see section 2.4), if energy saving efforts are implemented successfully, German electricity demand in 2050 will amount to around 500 TWh/a, which will be satisfied by the necessary gross electricity generation. However, in our estimation if such efforts fail and but Germany's auto fleet goes electric in the meantime, gross electricity generation may be as high as 700 TWh/a by 2050. The simulations described below for the process of transitioning from our current electricity system to the putative 2050 structure were based on (a) our scenario simulations for 2050 (see section 3.2); and (b) presumed electricity demand amounting to 509 and 700 TWh, depending on the scenario.

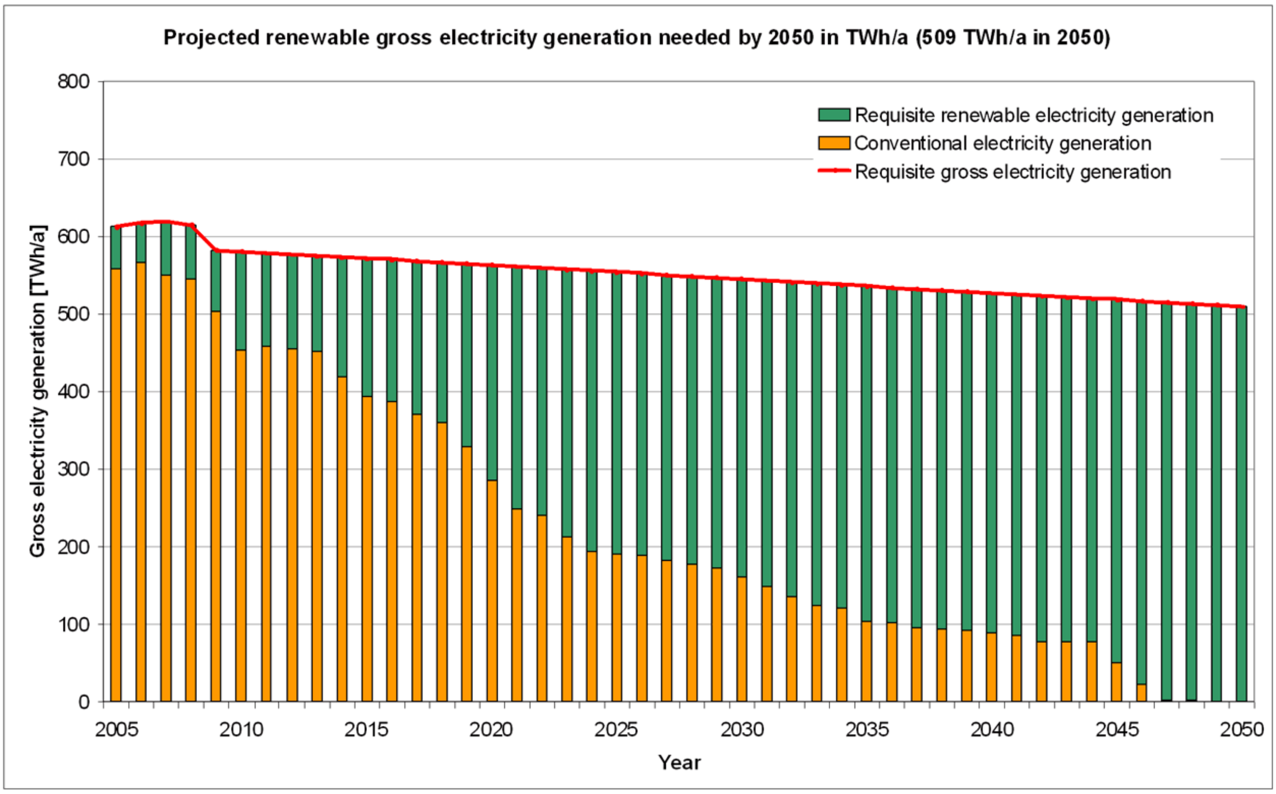
The transition scenarios for the 2010-2050 period were based on the generation structures posited for scenarios 2.1.a and 2.1.b (see section 3.2.2), which allow for electricity interchange within a German-Danish-Norwegian network, but are based on an equitable electricity export balance of "trade" and require that total annual German electricity demand be satisfied using domestically generated electricity. However, the electricity interchange in these scenarios allows for equalization during low electricity output phases in Germany (i.e. in low wind periods) via electricity imports and via exports during particularly high domestic production phases. The underlying structure of these scenarios is largely consonant with the evolution of German electricity generation in the past in that while Germany in general has always generated sufficient electricity to satisfy demand, we use our connections with the European power grid to compensate for short term domestic production shortfalls and surpluses.

If, congruent with 2009 gross electricity generation in Germany amounting to around 582 TWh, gross electricity generation declines to a posited 580 TWh in 2010 and to approximately 510 TWh by 2050, annual demand for renewable electricity can be determined by factoring in the electricity generated by existing conventional thermal power plants and presupposing that demand will decrease in a linear fashion until 2050. Greater use of renewable energy sources will virtually close the gap between gross electricity generation and demand by 2050, since renewable electricity obviates the internal electricity consumption that is associated with conventional power plants. The amount of renewable gross electricity generation equates to the difference between future annual gross electricity generation and the electricity generated by conventional power plants (see section 4.1 and Figure 4.1.a).

Figure 4-4 shows the evolution of gross electricity generation in this context and the amount of renewable electricity needed to fill the gap left by conventional power plants that are decommissioned, assuming gross electricity generation amounting to 509 TWh/a by 2050 (in accordance with scenarios 1.a, 2.1.a, 2.2.a and 3.a). As from 2021, the requisite proportion of renewable electricity generation amounting to 310 TWh/a will account for more than 50 percent of gross output. It will be necessary to transition to a wholly renewable electricity supply by 2049.

Figure 4-4

Renewable gross electricity generation needed by 2050 in TWh/a (509 TWh/a in 2050)



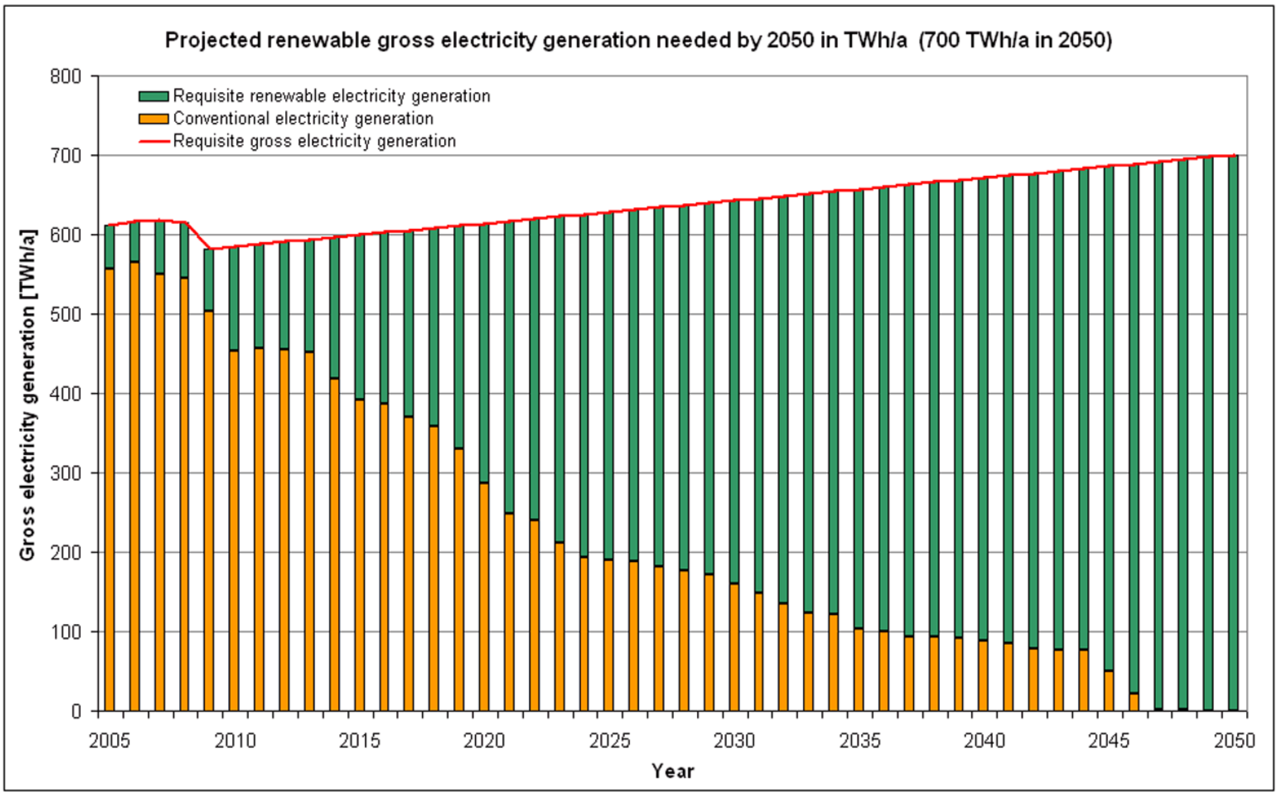
SRU/Stellungnahme Nr. 15–2010; Figure 4-4; data source: UBA 2009; BDEW 2008

Assuming that electricity demand increases steadily to approximately 700 TWh/a by 2050 in accordance with scenarios 1.b, 2.1.b, 2.2.b and 3.b, the amount of renewable electricity needed will rise accordingly (see Figure 4-5). Development of the requisite renewable energy sources will evolve in essentially the same manner as for 509 TWh/a demand (in 2050), except that overall generation capacity will rise more rapidly. This means that the goal of generating 50 percent of all electricity using renewables (just under 330 TWh/a) will have to be reached in 2020 rather than 2021.

The two roadmaps for transitioning from the electricity system of 2010 to that of 2050 described in the following (and referred to below as transition scenarios) show how the requisite expansion of renewable electricity generation capacity can be achieved by 2050 for both the 509 and 700 TWh/a gross electricity generation scenarios. A deliberate decision was made to forego economic optimization of the expanded electricity generation technologies, except in the 2050 target scenarios, since our main aim here was to show how the requisite amounts of electricity can be generated by expanding the capacity of various renewables without requiring that the extent to which the specific technologies are used be drastically increased. This approach allows for continuous expansion of production and construction capacity for the various technologies and is expected to minimize obstacles to technical realization. The scenarios presuppose that the necessary storage and transmission capacities (see section 4.3) will be expanded in concert with renewable electricity generation capacities.

Figure 4-5

Renewable gross electricity generation needed by 2050 in TWh/a (700 TWh/a in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-5; data source: UBA 2009; BDEW 2008

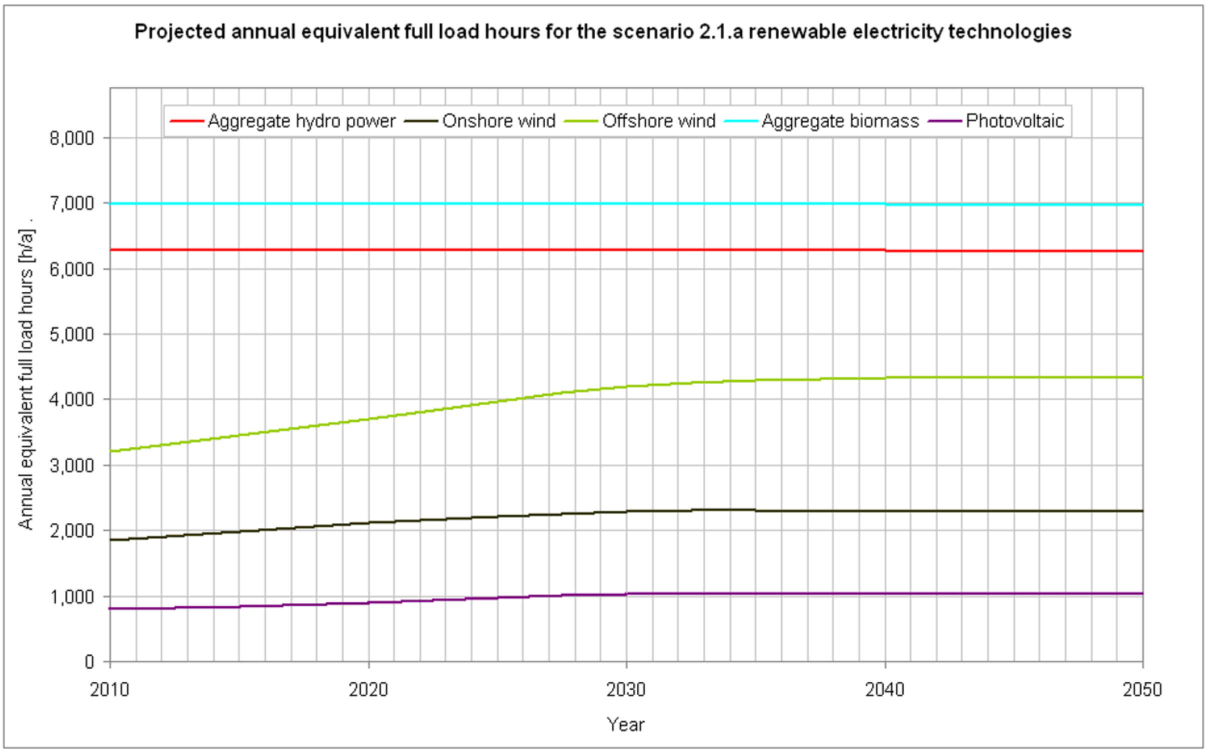
4.2.1 Transition scenario 2.1.a (509 TWh/a in 2050)

16. Transition scenarios 2.1.a (509 TWh/a in 2050) and 2.1.b (700 TWh/a in 2050) allow for a maximally smooth transition from today's energy generation system to the generation structures of target scenarios 2.1.a and 2.1.b for 2050. In this context, it should be borne in mind that the efficiency of, as well as the number of annual full load hours for, the various technologies involved, will improve over time. The assumed curve for annual full load hours is shown in Figure 4-6, whose baseline values constitute currently realizable annual equivalent full load hours (EFLH) and whose end point values constitute the DLR suppositions for the target scenario simulations that was carried out by the DLR. If the suppositions that form the basis for these scenarios are unduly optimistic (a possibility that cannot be excluded), higher capacities than indicated may be needed to satisfy electricity demand, particularly as the curve nears 2050. This evolution would mainly have a cost intensifying effect.

The scenario simulations attempted to provide for expansion of the various renewable energy technologies via an annual installation expansion rate that seems plausible from a technical and production standpoint against the backdrop of current evolutions. Figure 4-7 shows the consequent gross electricity generation curve for 2005-2050, during which period in some years it is necessary to compensate for the widely varying decommissioning rate of conventional power plants on account of their heterogeneous age structure. Hence the scope of renewable energy source use is expanded in the years leading up to each year where this compensation is deficient owing to a particularly high decommissioning rate, so as to prevent expansion "clumping" during individual years. This in turn can temporarily result in the generation of minor amounts of surplus electricity, which can be used for export purposes. However, a reliable electricity supply in terms of both quantity and demand is achieved via the year in and year out interplay between the capacity expansion timeline discussed in section 4.3 and the transmission grid build-out. Cooperative arrangements and electricity interchange in the German-Danish-Norwegian network structure will allow for a fail-safe supply reliability with only moderate capacity expansion.

Figure 4-6

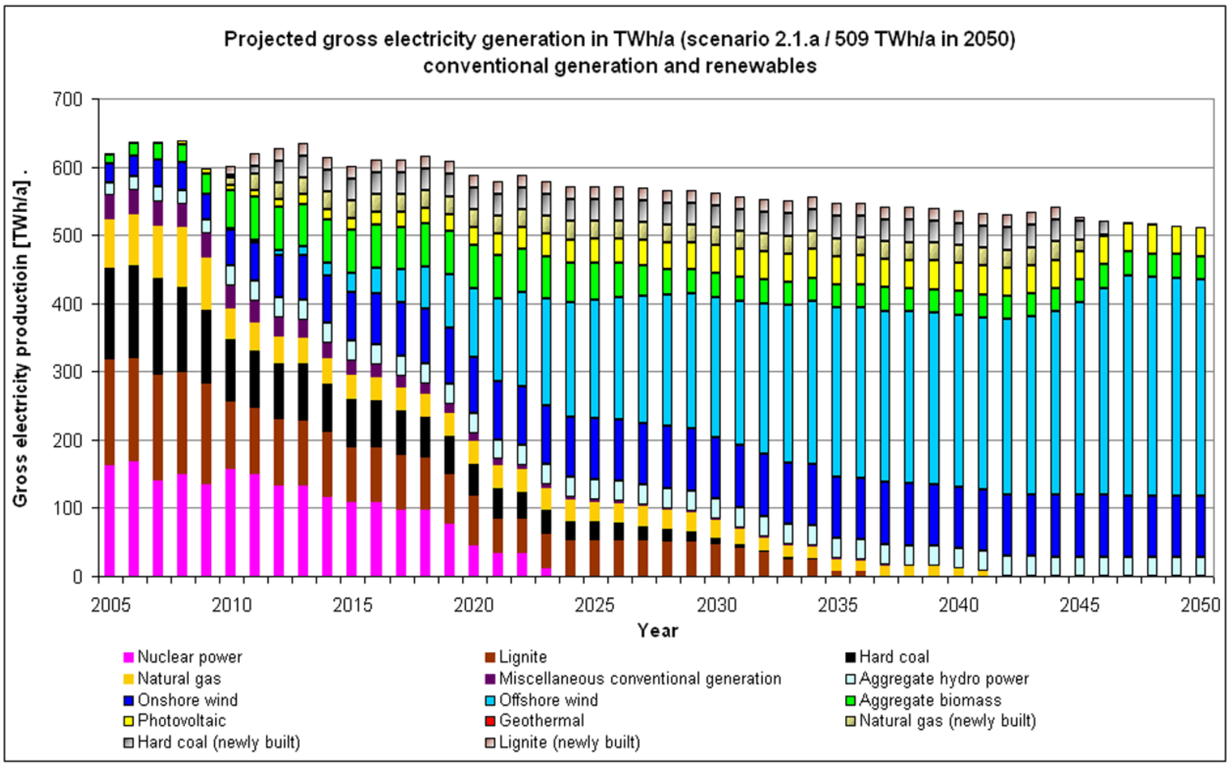
Projected annual electricity demand equivalent for the scenario 2.1.a renewable electricity technologies (EFLH)



SRU/Stellungnahme Nr. 15–2010; Figure 4-6

Figure 4-7

Projected gross electricity generation in TWh/a (scenario 2.1.a/509 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-7; data source: UBA 2009; BDEW 2008

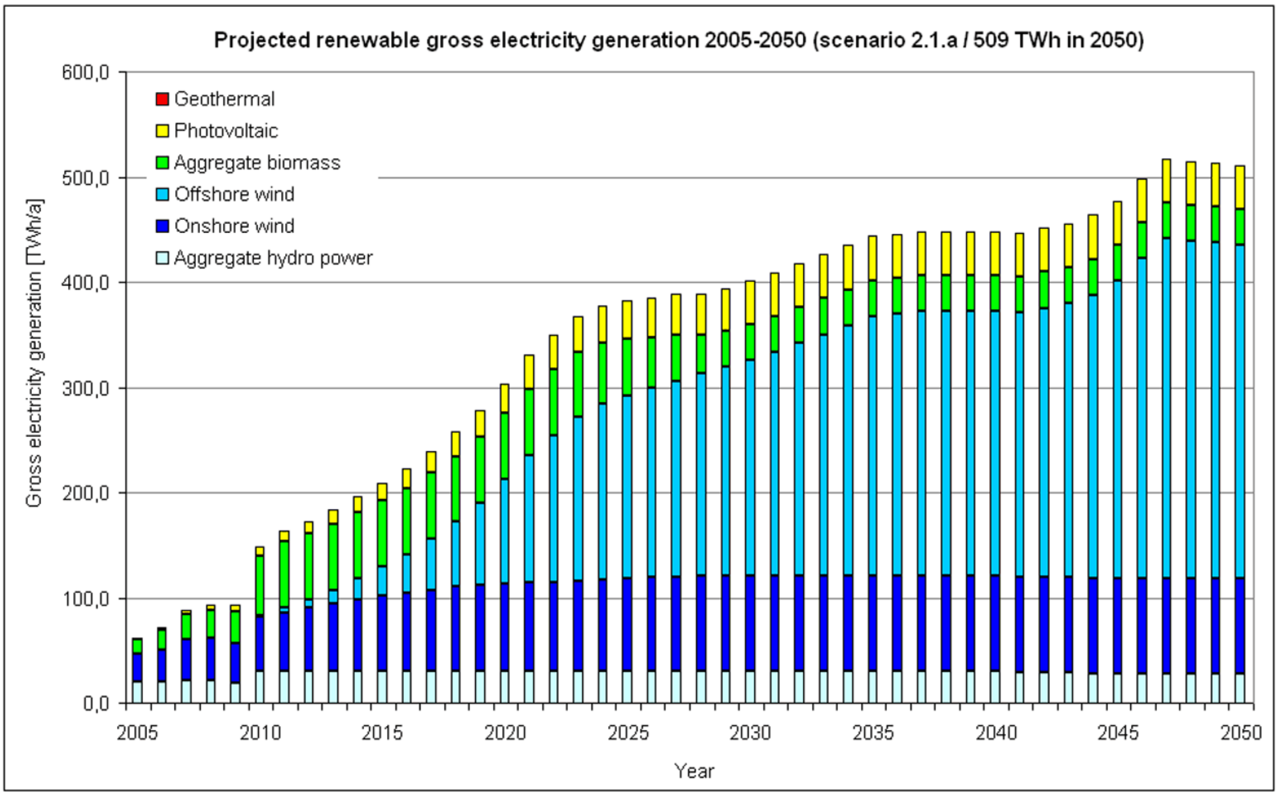
The expanded scope of renewable electricity generation capacity as from 2010 will allow for a steady increase in renewable gross electricity generation to roughly 390 TWh/a by 2024 (see Figure 4-8). The expansion rates needed in this context are comparable to those that were observed from 2005-2008. Despite a steady capacity increase prior to 2009 (see Figure 4-9), electricity generation in that year was considerably lower than would have otherwise been the case, on account of reduced hydro and wind power generation resulting from extreme weather conditions. Our scenarios for 2010 and thereafter presuppose that average weather conditions will prevail. This explains the sharp rise in electricity generation in 2010 relative to the prior year. A considerable increase in renewable electricity generation from 2010-2024 is followed by an only minor rise over the succeeding five years (2025-2029) due to a reduced conventional power plant decommissioning rate. However, biomass use for electricity generation, which is a significant driver of the short term rise in renewable electricity generation between 2010 and 2020, falls off sharply from 2025-2029 due to non-replacement of decommissioned conventional power plants and is replaced by expanded use of offshore wind energy. Rates of biomass use level off between 2030 and 2035, whereas renewable electricity generation rises to approximately 425 TWh/a secondary to further expansion of offshore wind farm use, remaining at virtually this same level until 2041. Following decommissioning of the last conventional power plants in 2042, in 2047 renewable gross electricity generation increases to roughly 515 TWh/a, declining to 509 TWh/a by 2050 secondary to decreased demand. The proportional share of onshore wind turbine generation rises relatively quickly, reaching its definitive level in 2025. Offshore wind energy production increases steadily until 2036, reaching its full potential in 2047.

The generation capacities for the gross electricity generation shown in Figure 4-8 vary greatly due to the fact that the various renewable electricity technologies require widely varying capacities to generate a terrawatt hour. This explains why biomass and geothermal electricity can exhibit extremely high annual operating hours (full load hours). Offshore wind farms can currently achieve full load hours ranging from 3,500-4,500 per year, whereas the figure for German onshore wind farms is only 1,500-2,500 and for photovoltaic electricity generation less than 1,000. The projected annual EFLH for the various renewable electricity technologies is shown in Figure 4-6. Figure 4-9 shows the renewable electricity capacities that will be needed. Figure 4-10 shows the consequent evolution of aggregate electricity generation capacities for transition scenario 2.1.a, including conventional power plant capacity.

The increase in photovoltaic energy generation, which is highly disproportionate to gross electricity generation, is accompanied by steady expansion of renewable electricity generation capacity until 2023 at a rate slightly

Figure 4-8

Projected renewable gross electricity generation in TWh/a (scenario 2.1.a/509 TWh in 2050)



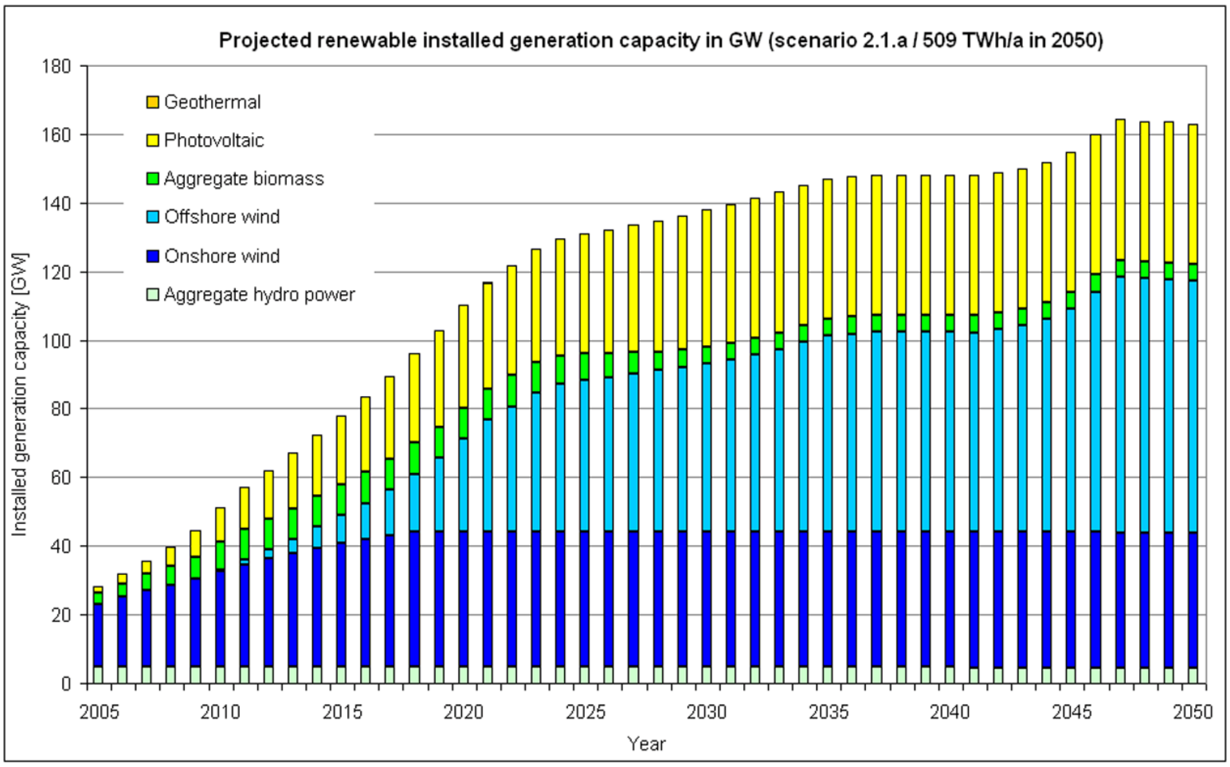
SRU/Stellungnahme Nr. 15–2010; Figure 4-8

higher than for 2005-2009 (see Figure 4-10). The expansion of renewable electricity generation capacity necessitates no rise in the requisite expansion rate, even if expansion from just over 40 GW in 2009 to just over 120 GW in 2023 entails mean expansion amounting to 6 GW per year. To all intents and purposes, this expansion rate is not unusual for the industries concerned. For example, in the run-up to 2008 the highest annual wind power expansion rate in Germany was 3.2 GW (in 2002); the figure for photovoltaic facilities was 1.9 GW (in 2008); and for biomass electricity 0.9 GW (in 2007) (BMU 2009, p. 12). In fact, German potential for manufacturing and installing such facilities already exceeds the annual installation rate of 6 GW. Inasmuch as a production capacity expansion amounting to more than 25 percent per year is, as noted, not unusual for the industries concerned, appreciably ramping up such capacity over the next decade would pose little or no problem. Solar cell manufacturing output is currently undergoing a great leap forward. Until recently standard production volumes equated to 0.03 GW of capacity, whereas thin layer solar cells are now being made at a rate of 1 GW per facility and year.

On the other hand, multiple GW wind power expansion in the North Sea poses a new challenge for the German parties involved. Nonetheless in January 2010 the Crown Estate, Britain's authorizing body in this domain, concluded exclusive development agreements with various consortiums for the construction of offshore wind farms with roughly 30 GW of capacity (The Crown Estate 2010). Although Germany only has one North Sea offshore wind farm, according to government information (Deutscher Bundestag 2010) licenses have been granted for 1,894 offshore wind farms, and the authorization procedures for an additional 5,178 are in the pipeline. This means that as of March 2010, assuming wind turbine capacity ranging from 3-5 MW, offshore wind farm capacity ranging from 5.7 to 9.5 GW has been given the go ahead and authorization for an additional 15.5 to 25.9 GW is in the pipeline. This equates to approximately 35 GW of offshore wind capacity (since 5 MW turbines are normally used for such facilities), which would be achieved in transition scenario 2.1.a, in 2022. Although offshore wind farms are in their infancy in Germany, the leading vendors in this domain such as Siemens and Vestas have up to 18 years of experience in wind turbine development and manufacture. It is unlikely that the expansion volume suppositions posited for transition scenario 2.1.a will pose any major unsolved problem for the wind turbine industry. Moreover, the takeover of small wind turbine vendors by major players such as General Electric, Siemens, Suslon and Areva (which have respectively acquired Tacke, Bonus, Repower and Multibrid) ensures that (a) these vendors will have the capital needed for rapid production capacity expansion and to cover the difficult to predict guarantee risks entailed by the initial phases of massive investments in offshore wind farms; and (b) the extremely dynamic evolution that is necessary in this domain will not be subject to delays or resource shortfalls.

Figure 4-9

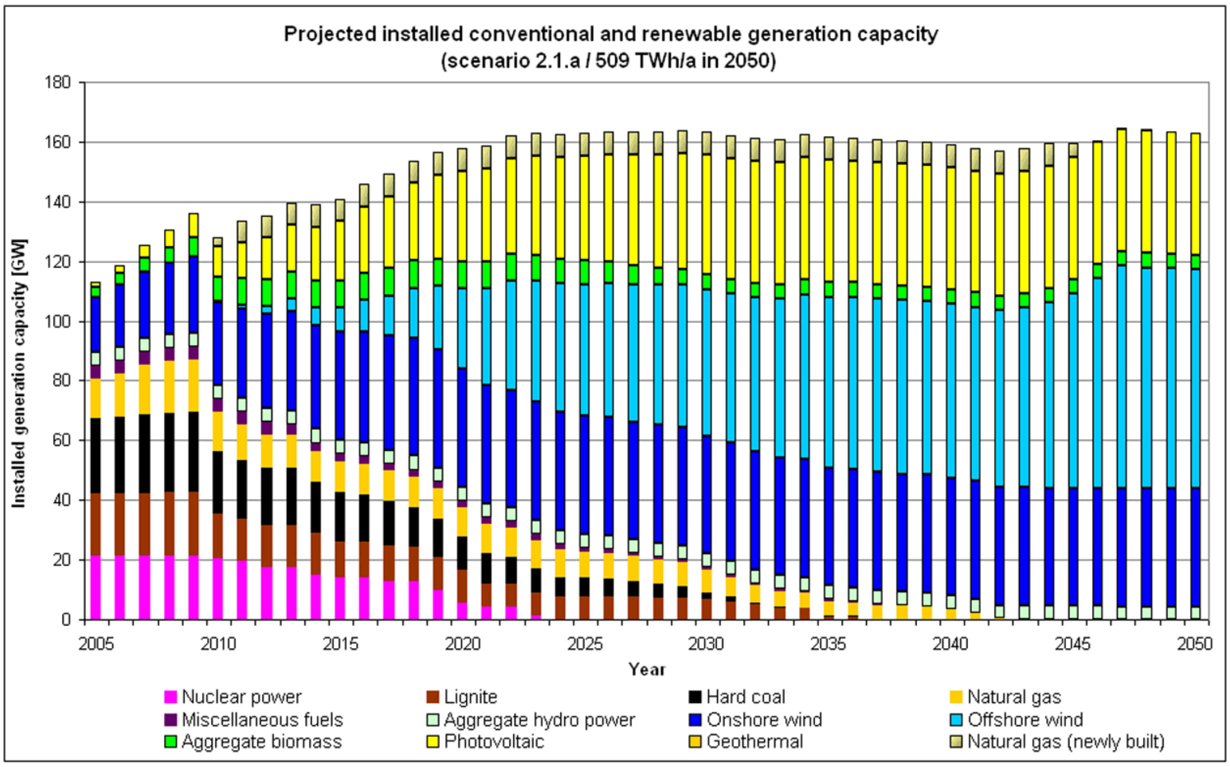
Projected renewable electricity generation capacity in GW (scenario 2.1.a/509 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-9

Figure 4-10

Projected aggregate electricity generation capacity in GW (scenario 2.1.a/509 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-10; data source: UBA 2009; BDEW 2008

Aggregate installed generation capacity for conventional power plants and renewable energy will increase from just under 140 GW in 2009 to roughly 174 GW in 2026, tapering off to just over 160 GW by 2050. This is an amazingly small increase in installed capacity in view of the unavoidable fluctuations in wind and solar energy output, which will in any case have to be supplemented by a substantial expansion of energy storage capacity (pump storage mainly in Norway, and advanced adiabatic compressed air energy storage (AA-CAES) in Germany) in order to satisfy demand round the clock (see section 4.3).

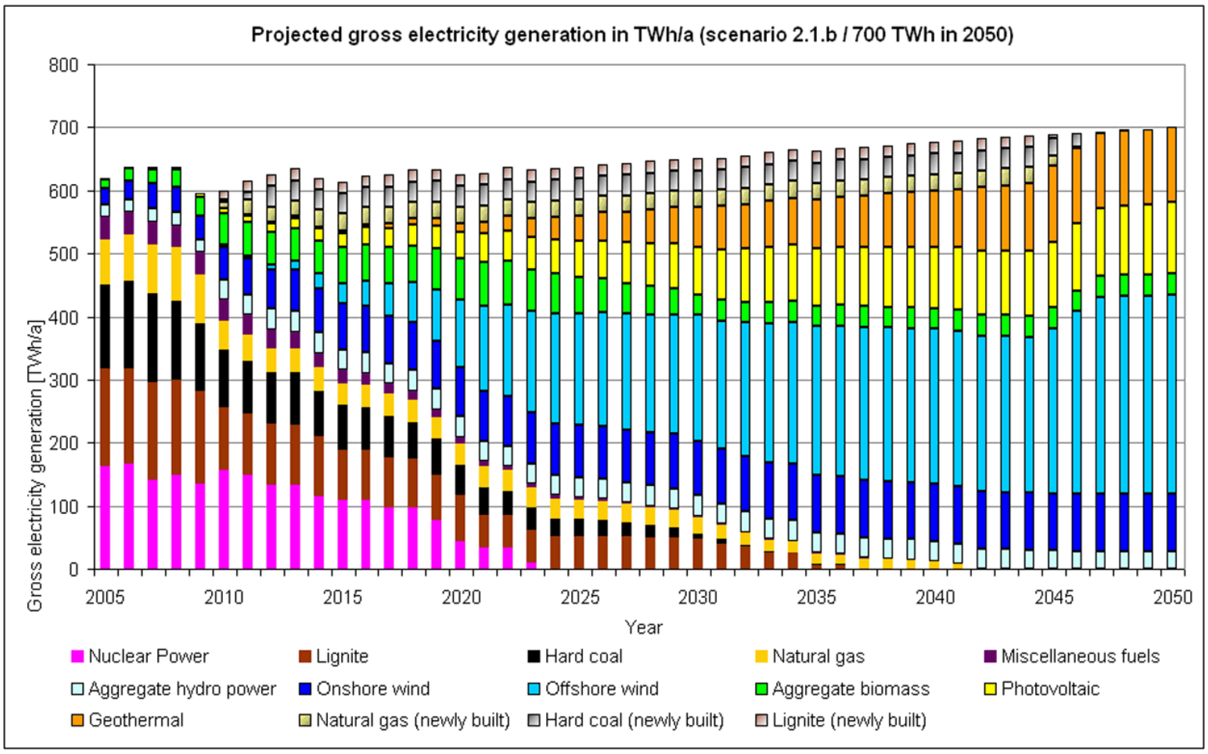
4.2.2 Transition scenario 2.1.b (700 TWh/a in 2050)

17. The eventuality that energy efficiency measures will not be implemented in a timely manner and that at the same time the replacement of other energy sources by electricity will be farther reaching than expected is addressed by scenarios 1.b, 2.1.b, 2.2.b and 3.b, which allow for electricity generation amounting to 700 TWh/a in 2050. These scenarios are also relevant for a situation where energy efficiency targets are reached, but at the same time a substantial portion of the greatly reduced heat demand, in addition to transport, is substituted by electricity. Scenario 2.1.b, which illustrates the putative transition in this regard, allows demand amounting to 700 TWh/a to be met in Germany, and at the same time allows for electricity interchange and the use of Danish and Norwegian pump storage system capacity within the German-Danish-Norwegian network. Figure 4-11 shows projected gross electricity generation in scenario 2.1.b, which calls for a long term increase in electricity generation and replacing conventional generation capacity with renewable energy sources.

Noteworthy here is the substantial proportion of electricity generation accounted for by geothermal energy relative to scenario 2.1.a (see section 4.2.1 and Figure 4-12), where geothermal energy is not used on account of its elevated generation costs but is needed to satisfy the high level of demand in scenario 2.1.b (700 TWh/a).

Figure 4-11

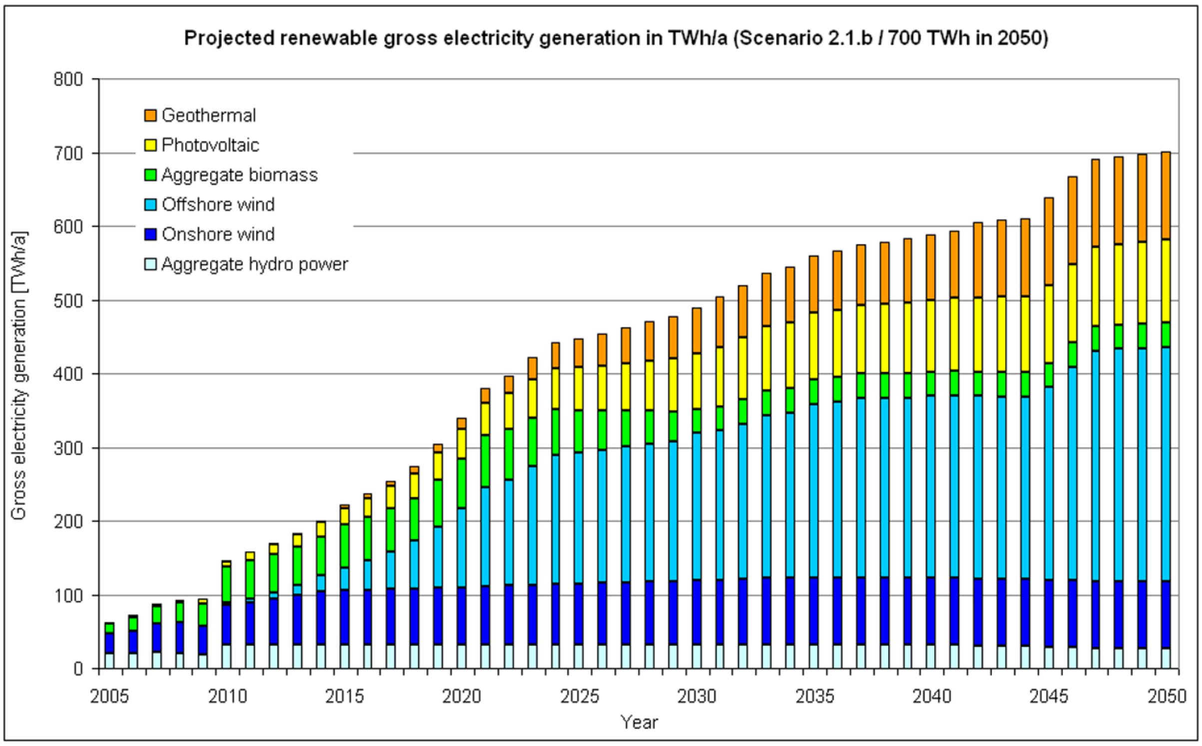
Projected gross electricity generation in TWh/a (scenario 2.1.b/700 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-11; data source: UBA 2009; BDEW 2008

Figure 4-12

Projected renewable gross electricity generation in TWh/a (scenario 2.1.b/700 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-12

The requisite capacity expansion for renewable electricity slightly exceeds the trend of recent years, ultimately reaching installed capacity of just over 150 GW by 2023 (see Figure 4-13). To reach this goal, it will be necessary to expand capacity at a rate of just under 8 GW per year; though 2 GW higher than in transition scenario 2.1.a, this is fully realizable in light of the expansion rates that have been registered in the relevant industries in recent years.

The lion's share of the increased capacity relative to transition scenario 2.1.a is accounted for by an approximately 69 GW increase (to 112 GW) in photovoltaic electricity generation. Generation capacity will have to be increased to just under 250 GW by 2050 (see Figure 4-14) in order to satisfy total electricity demand in that year. Inasmuch as the allowable wind energy expansion in transition scenario 2.1.a (509 TWh/a in 2050) has been reached, the remaining electricity will have to be produced via additional photovoltaic and geothermal capacity amounting to 70 and 120 TWh/a respectively.

Like scenario 2.1.a, scenario 2.1.b allows for continuous transition to new renewable electricity generation structures without any discontinuities in supply structures or the need for extremely high expansion rates. This scenario also necessitates an expansion of installed capacity chiefly by expanding compressed air energy storage in Germany and pump storage in Norway (see section 4.3).

4.3 Transmission and storage capacity expansion

4.3.1 Why expansion?

18. Substantial insolation and wind velocity variation can result in major fluctuations in local electricity generation for wind and solar power installations. Inasmuch as electricity generation must meet demand at all times in order to achieve a reliable electricity supply and grid stability, the so called residual load resulting from this intermittency must be covered. In cases where electricity generation from renewables exceeds demand, production can be reduced or the virtually cost-neutral surplus thus generated can be stored for later use. The following technologies are currently available for balancing intermittency:

– Energy storage

– Wide area transmission network

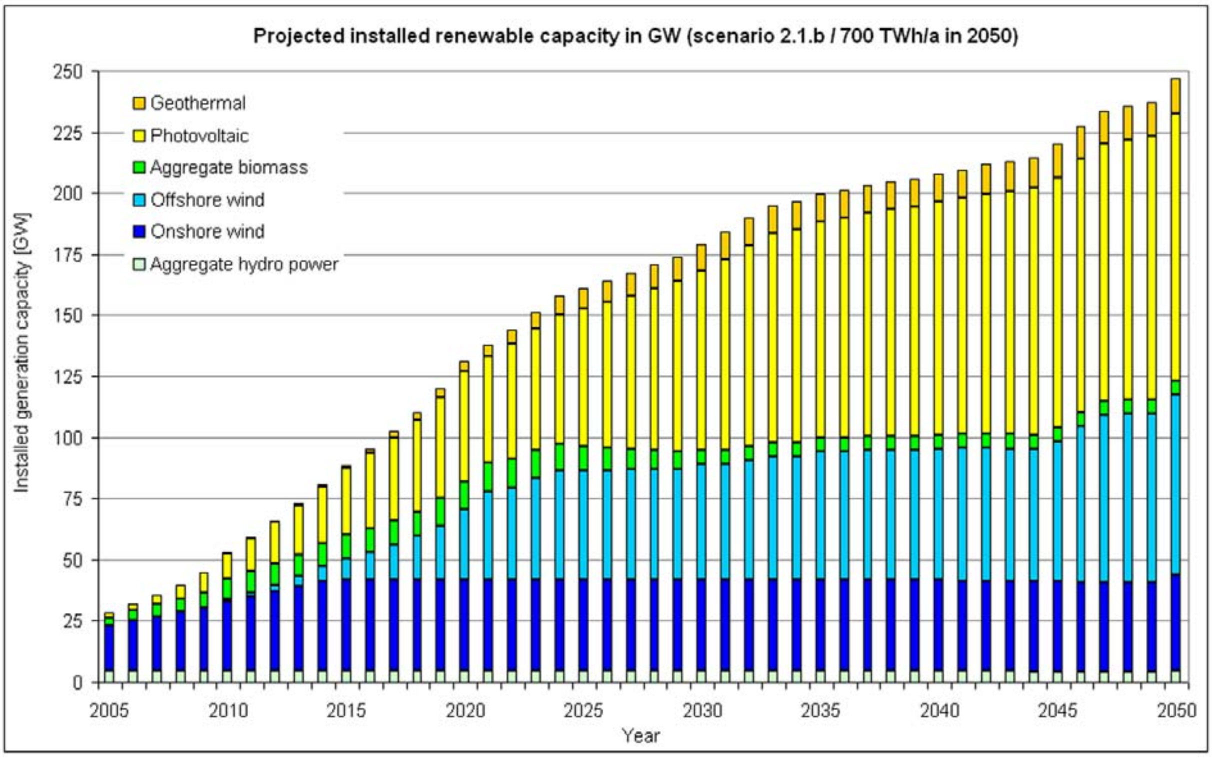
– Dispatchable power stations

– Demand side management (DSM)

These options could be combined in various ways to balance electricity generation and demand. The combinations that would deliver the most cost effective electricity under any given set of conditions can be determined via technical and economic simulations using models such as the German Aerospace Center's REMix model (DLR 2010) or the Czisch model (Czisch 2009).

Figure 4-13

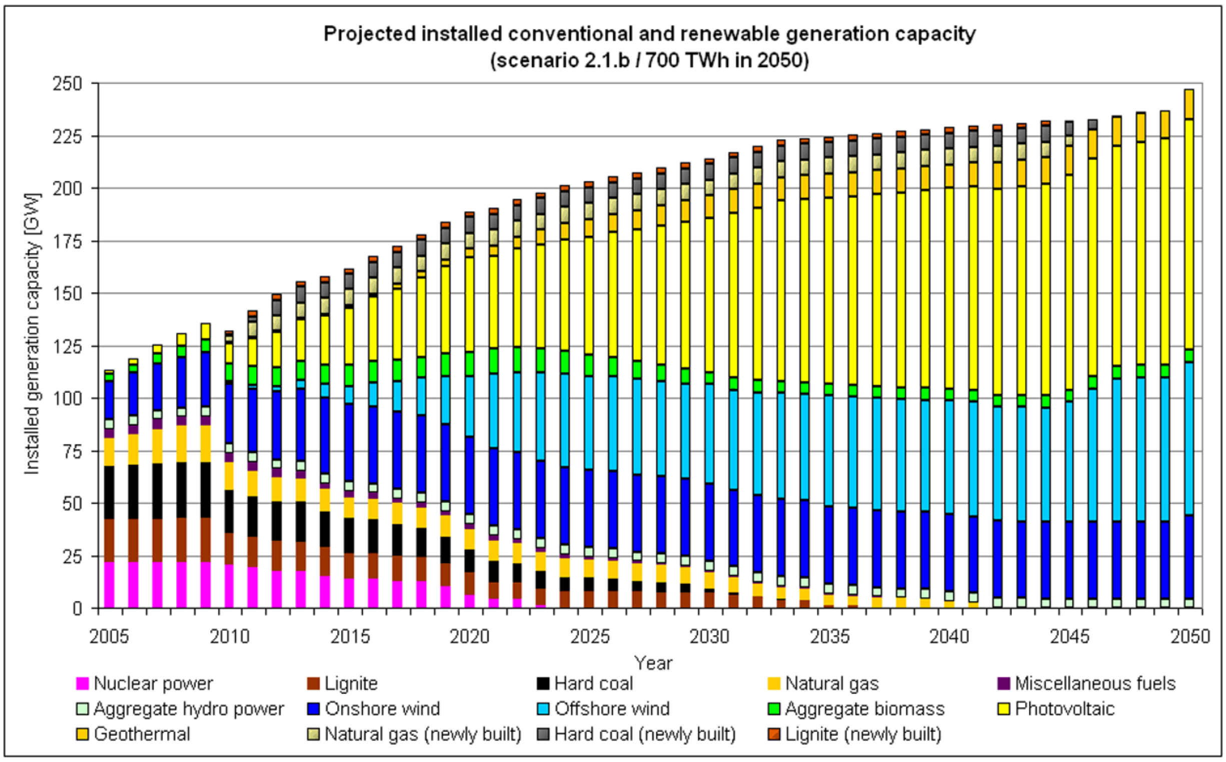
Projected renewable electricity generation capacity in GW (scenario 2.1.b/700 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-13

Figure 4-14

Projected aggregate electricity generation capacity (scenario 2.1.b/700 TWh in 2050)



SRU/Stellungnahme Nr. 15–2010; Figure 4-14; data source: UBA 2009; BDEW 2008

The putative scope of storage and grid expansion described in the following is based on the simulations carried out by the DLR using the aforementioned models. The balancing options using dispatchable power plants and system performance in the German power plant fleet are discussed in section 4.4. We assumed that load dispatching will mainly be used for ancillary services in view of the relatively minor and difficult to develop capacity involved, i.e. maximum potential for energy intensive industries in Germany amounting to approximately 2.9 GW (Grimm 2007, p. 16). However inasmuch as ancillary services and technical grid stability exceed the scope of the present report they will not be discussed further.

4.3.2 Storage systems

19. Inasmuch as electricity can only be used immediately being generated if it is transmitted by power lines, it can only be stored after being converted to another form of energy. This property of electricity has prompted the development of many technologies that are compatible with various applications depending on the characteristics of the storage system involved. The key technical characteristics that are used to assess energy storage system are as follows: storage capacity and performance; efficiency; storage loss; power density; power gradient; and life cycle. The extent to which overall potential can be developed, as well as storage costs, are also relevant in this regard.

The forms of use of electricity grid storage systems include second reserves (which is one of the aforementioned system services), uninterruptible power supplies, and daily, weekly and annual equalization solutions. In keeping with the present report's focus on energy storage in connection with the expansion of renewable energy with a view to achieving a wholly renewable electricity supply in Germany and Europe, the following technologies that allow for large scale electricity storage for daily, weekly and annual equalization purposes are particularly relevant here (Leonhard et al. 2008, p. 21):

– Storage of potential energy via pump storage systems

– Storage of mechanical energy via compressed air energy storage systems

– Storage of chemical energy via hydrogen, hydrogen compounds and the like

– Storage of electrochemical energy using batteries

Storage technologies

20. Pump storage systems are hydro power plants that are designed for both generator and pump operation. In cases where electricity supply exceeds demand, surplus electricity can be used to pump water from a lower basin to a higher basin. During peak load periods or the like, the power plant can then convert the stored energy into electricity via a generator and feed the electricity into the grid.

Germany currently has approximately 7 GW of pump storage system capacity and approximately 0.04 TWh of storage capacity (Leonhard et al. 2008, p. 21; Oertel 2008, p. 35) whose efficiency ranges from 70-80 percent (Neupert et al. 2009, p. 133).

In light of the topographical criteria that must be met (few high mountains in the area concerned) for pump storage systems and the large scale environmental interventions entailed by their realization, in our view there is little additional potential available for this technology in Germany.

In the rest of Europe, most of this potential is found in Scandinavia and in the Alpine regions. Norway alone has hydro reservoir systems with storage capacity of up to 84 TWh (Nord Pool ASA 2010a), many of which could be converted to pump storage systems by installing the necessary riser pipes and additional pumps. Moreover, Sweden has hydroelectric storage capacity amounting to nearly 34 TWh (Nord Pool ASA 2010b).

The technical and economic parameters that formed the basis for the suppositions in the pump storage system scenarios discussed here are listed in Table 4-2.

Compressed air energy storage (CAES) plants are gas turbine power plants which, with the aid of electrical compressors, use surplus electrical energy to compress ambient air with a view to storing it in salt caverns or aquifers. This air can then be fed into a gas turbine during peak load periods in such a way that electricity is generated. Thus in conventional gas turbines such stored compressed air obviates and replaces the compressor phase that would otherwise consume up to two thirds of the energy used in the power plant (Crotogino 2003, p. 4).

Unlike pump storage, CAES entails the use of additional fuel since the compressors dissipate heat into the environment and the cooled stored compressed air must be heated to several hundred degrees Celsius before being used to generate electricity. This reduces the efficiency of CAES systems to less than 55 percent (Crotogino 2003, p. 4).

This efficiency is currently optimized using advanced adiabatic compressed air energy storage (AA-CAES) systems, which temporarily store compression heat in heat accumulators so that it can be used to reheat the compressed air prior to use. This process uses no additional fuel and increases the efficiency of CAES systems to approximately 70 percent (Neupert et al. 2009, p. 129).

No AA-CAES systems are currently in use in Germany. The only CAES gas turbine power plant in operation in Germany is E.ON’s Huntorf peak load power plant, which has been in operation since 1978 and has storage volume amounting to 300,000 cubic meters and 321 MW of capacity. This storage volume equates to approximately 0.642 GWh under the technical conditions that prevail at the plant. Hence the available compressed air energy storage capacity in Germany is negligible compared to the terrawatt hours of capacity that are needed. Total storage potential via the many salt mines that are available, particularly in Northern Germany, is estimated to be as high as 3.5 TWh (Ehlers 2005, p. 4). However, this estimate was realized within the framework of a University of Flensburg diploma thesis and should thus be regarded as a preliminary assessment only. Scientifically sound results in this domain will necessitate further investigations.

The technical and economic parameters that formed the basis for AA-CAES suppositions in the scenarios discussed here are listed in Table 4-3.

Another storage technology is provided by electrolysis, that can be used to convert surplus electrical energy to hydrogen, which after being compressed is stored in conventional gas reservoirs in caverns or aquifers. However, thanks to the higher energy density of hydrogen, approximately 60 times more energy can be stored in the same space than in CAES storage systems (Leonhard et al. 2008, p. 25). Gas turbines, gas engines, or fuel cells can be used to convert the hydrogen back to electricity. The efficiency of the entire storage process entailing electrolysis, compression and fuel cell conversion is currently around 44 percent (DLR 2010).

The technical and economic parameters that formed the basis for the suppositions in the scenarios discussed here involving hydrogen storage and electricity recovery using fuel cells are listed in Table 4-4.

Table 4-2

Technical and economic parameters used for pump storage systems

	unit	2010	2020	2030	2040	2050
technical parameters						
roundtrip efficiency	kW	0.8	0.8	0.8	0.8	0.8
losses per hour	1/h	0	0	0	0	0
storage capacity in relation to power block size	kWh/kW	8	8	8	8	8
availability factor	-	0.98	0.98	0.98	0.98	0.98
economic parameters						
investment costs converter	€/kW	1600	1600	1600	1600	1600
fixed operation costs converter (percentage of original investme	-	0.01	0.01	0.01	0.01	0.01
fixed operation costs converter (absolute)	€/kW	16	16	16	16	16
life-time converter	a	20	20	20	20	20
investment costs storage	€/kW	0	0	0	0	0
fixed operation costs storage (absolute)	€/kWh	0.1	0.1	0.1	0.1	0.1
life-time storage	a	60	60	60	60	60
variable operation costs	€/kWh	0.000	0.000	0.000	0.000	0.000

Source: DLR 2010

Table 4-3

Technical and economic parameters used for AA-CAES systems

	unit	2010	2020	2030	2040	2050
technical parameters						
roundtrip efficiency		0.7	0.78	0.78	0.8	0.8
losses of pressure and heat per hour	1/h	0.002	0.002	0.002	0.002	0.002
availability factor	-	0.95	0.95	0.95	0.95	0.95
economic parameters						
investment costs converter	€/kW	310	300	300	290	280
fixed operation costs converter (percentage of original investme	-	0.02	0.01	0.01	0.01	0.01
fixed operation costs converter (absolute)	€/kW	6.2	3	3	2.9	2.8
life-time converter	a	25	25	25	25	25
investment costs cavern/container	€/kWh	50	50	50	50	50
investment costs cavern/container, growing share of containers	€/kWh	50	50	140	230	275
fixed operation costs cavern (percentage of original investment	-	0.02	0.01	0.01	0.01	0.01
fixed operation costs cavern (absolute)	€/kWh	1	0.5	0.5	0.5	0.5
life-time cavern	a	40	40	40	40	40
variable operation costs	€/kWh	0.000	0.000	0.000	0.000	0.000

Source: DLR 2010

Table 4-4

Technical and economic parameters used for hydrogen storage

	unit	2010	2020	2030	2040	2050
technical parameters						
roundtrip efficiency		0.44	0.46	0.47	0.48	0.49
losses per hour	1/h	0.002	0.002	0.002	0.002	0.002
storage capacity in relation to power block size	kWh/kW	200	200	200	200	200
availability factor	-	0.95	0.95	0.95	0.95	0.95
economic parameters						
investment costs converter	€/kW	1500	1500	1500	1500	1500
fixed operation costs converter (percentage of original investme	-	0.02	0.01	0.01	0.01	0.01
fixed operation costs converter (absolute)	€/kW	30	15	15	15	15
life-time converter	a	5	5	5	5	5
investment costs cavern	€/kWh	50	50	50	50	50
fixed operation costs storage (percentage of original investmen	-	0.02	0.01	0.01	0.01	0.01
fixed operation costs storage (absolute)	€/kWh	1	0.5	0.5	0.5	0.5
life-time storage	a	20	20	20	20	20
variable operation costs	€/kWh	0.000	0.000	0.000	0.000	0.000

Source: DLR 2010

Despite the low efficiency of the process chain as a whole, this technology holds out promise for the storage of renewable energy in view of the fact that considerable storage capacity potential is available in Germany, and hydrogen produced via renewables can be used in the transport, heat and industrial sectors.

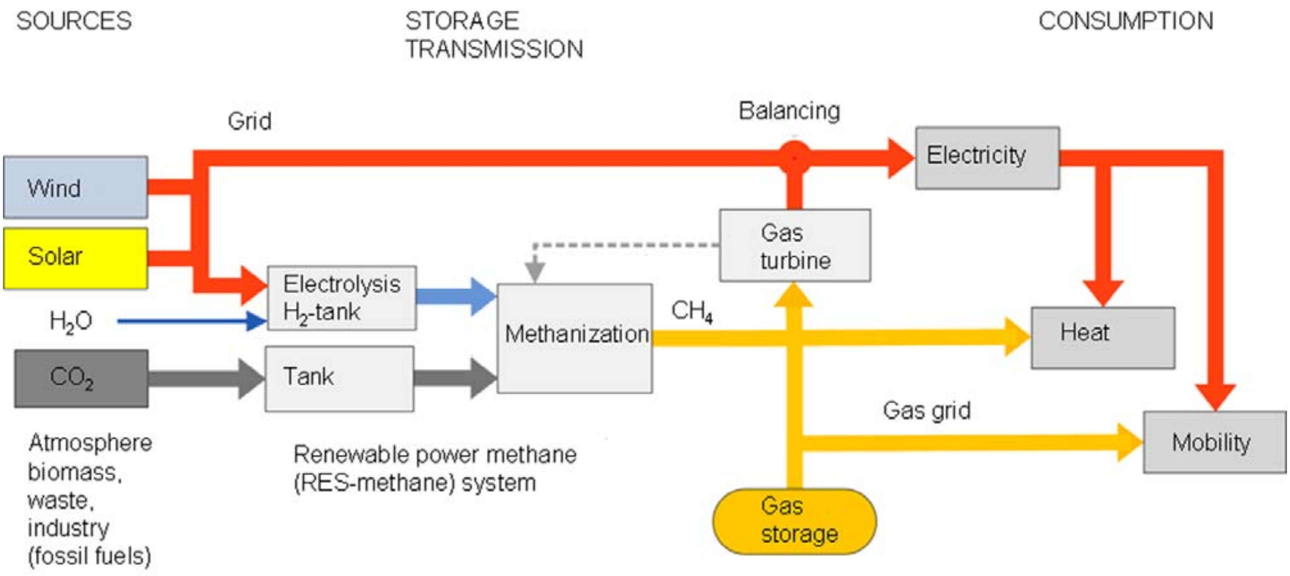
If this kind of multi-sectoral system approach is given more weight, the renewable power methane (RPM) concept (Sterner 2009) (see Figure 4-15) could provide a promising alternative or supplement to hydrogen storage. This concept, which was developed by Fraunhofer IWES (Fraunhofer-Institut für Windenergie und Energiesystemtechnik), is based on hydrogen methanization, a technology that produces hydrogen using renewable electricity.

Although the efficiency of the RPM concept up to the methane storage phase is around 60 percent and is only around 36 percent for the electricity yielded by the process chain as a whole, this concept offers key advantages by virtue of its being applicable in a range of sectors and the fact that methane energy density exceeds that of hydrogen by a magnitude of five. Tremendous capacity potential could be tapped by intermeshing the electricity and natural gas grids and the attendant heating, transport and industrial infrastructures, which are already available, in contrast to the situation in the hydrogen sector.

In view of the fact that aggregate accumulator potential for long term energy storage and the requisite large storage capacity is lower than that of pump, hydrogen or compressed air storage technologies, this capacity was excluded from the scenario simulations discussed in the present report. Accumulators will be used in the coming years chiefly for network applications in the system services sector.

Figure 4-15

Integrative renewable power methane concept



Source: Sterner und Schmid 2009

The role of storage systems in the scenarios discussed in this report

21. In the following, we discuss the role played by energy storage in the scenario simulations and which forms of storage were taken into consideration for the present study. This discussion mainly revolves around scenario group 2 (renewable electricity in the German-Danish-Norwegian energy supply network) and describes in detail the measures necessary for system integration of Scandinavian pump storage capacity. In our view, in all likelihood Germany would need to partner with Norway and other Scandinavian states, which would be a robust strategy even if a relatively large scale European energy supply network is to be established over the long term. For purposes of comparison, the role of energy storage in scenario groups 1 (German self sufficiency) and 3 (Europe-North Africa network) will be discussed briefly.

Scenario 1.a, which is intended as a hypothetical reference scenario (full German self sufficiency with annual demand amounting to 500 TWh), necessarily calls for extensive use of German energy storage potential in 2050, at which time a total of roughly 50 TWh of electricity would be stored as compressed air, and after allowing for energy loss approximately 34 TWh of this amount would be fed back into the grid. Over a 12 month period, approximately 1.2 TWh of energy would be stored in pump storage systems and approximately 1 TWh would be fed back into the grid. The energy difference between storage and output is based on conversion and storage loss, and thus cannot be fed back into the system.

Of Germany's estimated compressed air energy storage capacity amounting to 3.5 TWh (Ehlers 2005), up to 1.4 TWh (the difference between minimum and maximum storage levels) is used in scenario 1.a, whereby the amount stored over the course of a year (except for a few weeks) fluctuates by only 0.8 TWh, which means that effecting the relevant optimization could potentially reduce the amount of aggregate storage capacity needed. The maximum pump storage capacity used amounting to less than 0.05 TWh is only slightly higher than the capacity that is already available in Germany today. This finding is reflective of our simulation supposition to the effect that German pump storage system capacity would not need to be expanded.

Despite the intensified use of compressed air energy storage in scenario 1.a, installed renewable electricity capacity amounting to 230 GW would have to be retained so as to ensure that demand can be reliably satisfied (see section 3.2). However, this translates into a surplus of renewable (gratis) energy that cannot be used in Germany amounting to 53 TWh. This represents 10 percent of total German demand, assuming this figure is 500 TWh. Inasmuch as this surplus production would mainly occur during periods of high wind, it can be avoided by reducing wind power generation. However, this would increase mean electricity generation costs and prices.

Scenario 2.1.a foregoes the self sufficiency restriction, positing that Germany could exchange up to 15 percent of its annual output with Denmark and Norway. This considerably reduces the use of compressed air energy storage capacity in Germany, whereby aggregate annual storage declines from 50 to 5.7 TWh, while the amount of electricity fed into the grid declines from 34 to 4.3 TWh. In this scenario, the lion's share of the requisite storage would be covered by less cost intensive pump storage systems in Norway, thus reducing the installed generation capacity needed in Germany from 230 GW in scenario 1.a to 163 GW and reducing the annual energy surplus from 53 to 0.8 TWh. Even the limited cooperation entailed by the German-Danish-Norwegian network would roll back Germany's electrical energy costs to a greater extent than would be the case in the German self sufficiency scenario. Under the conditions defined for scenario 2.1.a, which disallows net electricity import, Denmark would be an electricity transit state for all practical purposes, whereby Germany's electricity interchange would revolve around Norwegian storage capacity.

In order for German electricity interchange with Norway to be technically and economically feasible, the following three phase procedure would have to be implemented:

– Phase 1: Use of Norwegian electricity demand for load reduction purposes

– Phase 2: In addition, use of available Norwegian pump storage capacity

– Phase 3: Further conversion of hydro reservoir into pump storage systems in tandem with turbine capacity expansion

In phase 1, surplus German renewable electricity output could be used to cover part of Norway's electricity demand and thus replace hydro power plant operation. The consequent dormant water volumes could be used later to export electricity to Germany. The long term minimum load that would be available for this arrangement in the Norwegian supply zone is at least 7 GW, a figure that was not undercut between 2000 and 2010 (Statistics Norway 2010b). Norway is a suitable load reduction "facility" mainly by virtue of the fact that an average of more than 95 percent of Norwegian electricity output comes from storage hydroelectric power stations (Statistics Norway 2010a), which can be reduced at almost no additional cost. Moreover, in contrast to wind power, the used energy remains available as water. As this phase would require no additional investment except for transmission capacity expansion, it could begin immediately insofar as German renewable electricity generation peaks exceed domestic demand and the requisite transmission capacity has been installed.

Germany can currently interchange approximately 1.5 GW of capacity with Norway, via Denmark. Apart from this, the Nordlink and NorGer German-Norwegian transmission lines, which are slated to go into operation in 2018 and 2015 respectively, will each provide 1.4 GW of capacity (Fagerholm et al. 2010, p. 61). In order for the 7 GW of load reduction to be fully used, transmission capacity amounting to approximately 2.7 GW above and beyond the foregoing capacity would need to be installed between Norway and Germany.

Like phase 1, phase 2 would necessitate no additional investment apart from transmission capacity expansion, since only the available Norwegian pump storage capacity would be used. However, the available pump storage capacity would limit the scope of the load reduction to approximately 1 GW (NVE 2010). This load reduction option would be used whenever surplus renewable electricity generation in Germany exceeds the load reduction represented by Norwegian electricity demand (i.e. phase 1). The rationale for this restriction is that pumping and generation loss would translate into higher storage costs for the output replaced in phase 1.

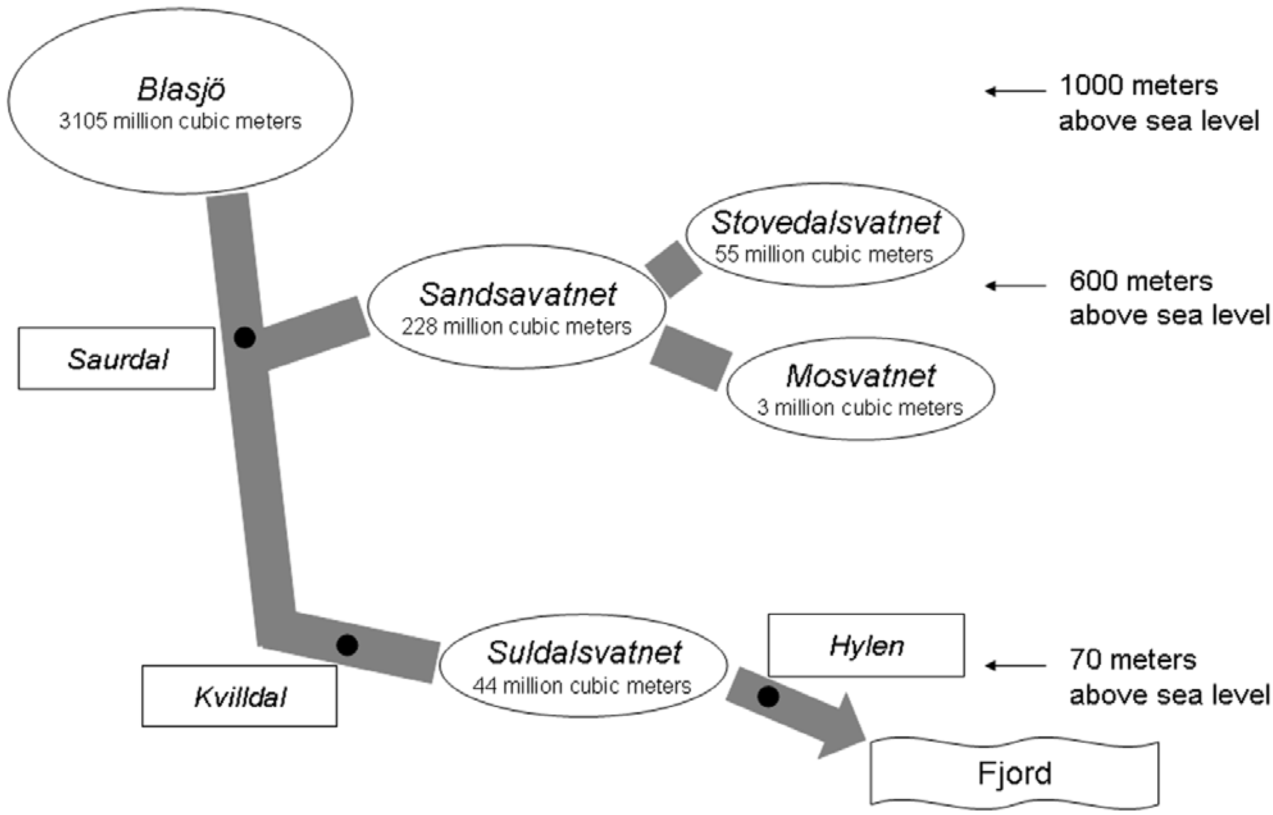
If these first two phases involving use and storage of Germany's surplus production fail to achieve the desired results, in phase 3 it would be possible to incrementally use Norwegian pump storage potential by converting storage hydroelectric power stations into pump storage systems. Most of Norway's approximately 370 storage hydroelectric power stations comprise a multi-lake systems whose various lakes are oftentimes interconnected by underground tunnels and pressure shafts. As Figure 4-16 shows, such systems – as in the example in the diagram, which actually comprises a series of additional lakes and power plants – are cascades of various lakes and power plants that can be converted to pump storage systems at a relatively low cost.

Our initial research shows that the height of drop and volume capacity of the Tonstad and Kvilldal storage hydroelectric power station lower lakes alone offer theoretical pump storage potential amounting to some 12 TWh (based on one circulation cycle of the storage content). However, inasmuch as Norway's hydro power system comprises a vast number of storage hydroelectric power stations that have lower lakes, it is safe to assume that a substantial portion of the available storage hydroelectric power station capacity amounting to 84.3 TWh (Nord Pool ASA 2010a) can be converted to pump storage capacity. In view of this supposition, scenario 2.1.a calls for maximum demand amounting to 22 TWh (maximum energy input or output).

To obtain the approximately 50 GW input and output capacity required for scenario 2.1.a, the turbine capacity of Norwegian power plants (currently 22 GW) would have to be expanded, apart from stepping up pumping capacity. This would necessitate the construction of additional inflow tunnels, pressure shafts, pumps and turbines whose realization would necessitate long term planning and sufficiently long lead times. According to our calculations, these expansion projects could be completed more rapidly than the counterpart North Sea transmission line build-out or installation of high voltage line capacity from the German North Sea coast to German centers of electricity consumption. These relatively short lead and planning phases are mainly attributable to the fact that no new storage lakes would have to be created and that most of the construction work would take place underground (excavating pump/turbine tunnels and caverns).

Figure 4-16

Schematic drawing of a characteristic Norwegian storage hydroelectric power station complex (Ulla-Førre power plants)



SRU/Stellungnahme Nr. 15–2010; Figure 4-16; data source: Statkraft

We projected the curve of the requisite storage capacity by elaborating a possible capacity development roadmap using the prognosticated scope of renewable electricity generation expansion laid out in section 4.2, in conjunction with German electricity load that will have to be handled. Figure 4-17 shows the wind or photovoltaic energy induced capacity peaks exceeding the minimum and maximum German grid loads in our simulation, amounting to 35 and 81 GW respectively. The consequent surplus capacity is thus indicative of the scope of the need to expand storage capacity and cross-border transmission capacity. However, Figure 4-17 also overstates the demand that could be met reasonably from an economic standpoint, by virtue of the fact that this graph takes account of all surplus capacity, even if it only occurs for one hour each year. But of course such rare load peaks do not allow for the economically requisite capacity use of storage systems and transmission lines. Hence it is safe to assume that the capacity needed during the transitional period will fall far short of the capacity shown in Figure 4-17. However the projected storage and transmission capacities for 2050 are not unduly optimistic by virtue of having been derived from technically and economically optimized simulations. Inasmuch as scenario 2.1.a allows Germany to interchange electricity only with Denmark and Norway, the entirety of the 42 GW of Germany's projected surplus capacity in the 2050 scenario would be passed to Denmark and Norway, where it would be used to satisfy electricity demand and/or stored in pump storage systems.

As Figure 4-17 shows, the scope of load reduction options and available pump storage system capacity in Norway entailed by the first and second expansion phases amounting to 8 GW would soon (between 2014 and 2020) be insufficient to absorb Germany's surplus capacity. The transition scenario 2.1.a simulation of the requisite storage capacity for the proposed wind energy expansion (based on projected demand for 2050) showed that more than 8 GW of Norwegian storage capacity would be needed as from 2017; this figure would roughly double by 2020 and by 2025 would rise by an additional 10 GW. This also holds true for transmission capacity expansion, where the shortfall would be even larger. The available and envisaged transmission capacity between Germany and Norway is currently only slightly above 4 GW, of which only about 1.5 GW actually exists. Larger scale expansion of renewable electricity generation in Germany (which the government has also called for) would necessitate the following, even if the expansion rate is lower than defined in our scenarios: connecting of wind energy capacity to German demand centers (see below); and optimally expeditious expansion of (a) transmission capacity between Germany and Scandinavian storage hydroelectric power station facilities; and (b) conversion of Scandinavian storage hydroelectric power station capacity to pump storage system capacity.

As our scenario 2.1.a simulations showed, Norway could potentially be the key driver of successful German expansion of renewable electricity capacity by virtue of (a) Norway’s large storage hydroelectric power station capacity (84 TWh), which is based on hydropower use derived from storage lake cascades; and (b) the fact that transmission lines to intermesh this capacity with German North Sea wind farms would be relatively easy to install as these lines would not pass through densely populated areas. Moreover, Sweden could assume an analogous role and supplement Norwegian capacity by virtue of Sweden’s (a) storage hydroelectric power station grid similarity to that of Norway; and (b) approximately 34 TWh of storage hydroelectric power station capacity. On the other hand, Austria and Switzerland could not play this role in view of (a) their far lower storage capacity amounting to an aggregate less than 30 TWh; (b) the absence of lower lakes in many cases; and (c) the fact that their capacity is already used by a numerous other states.

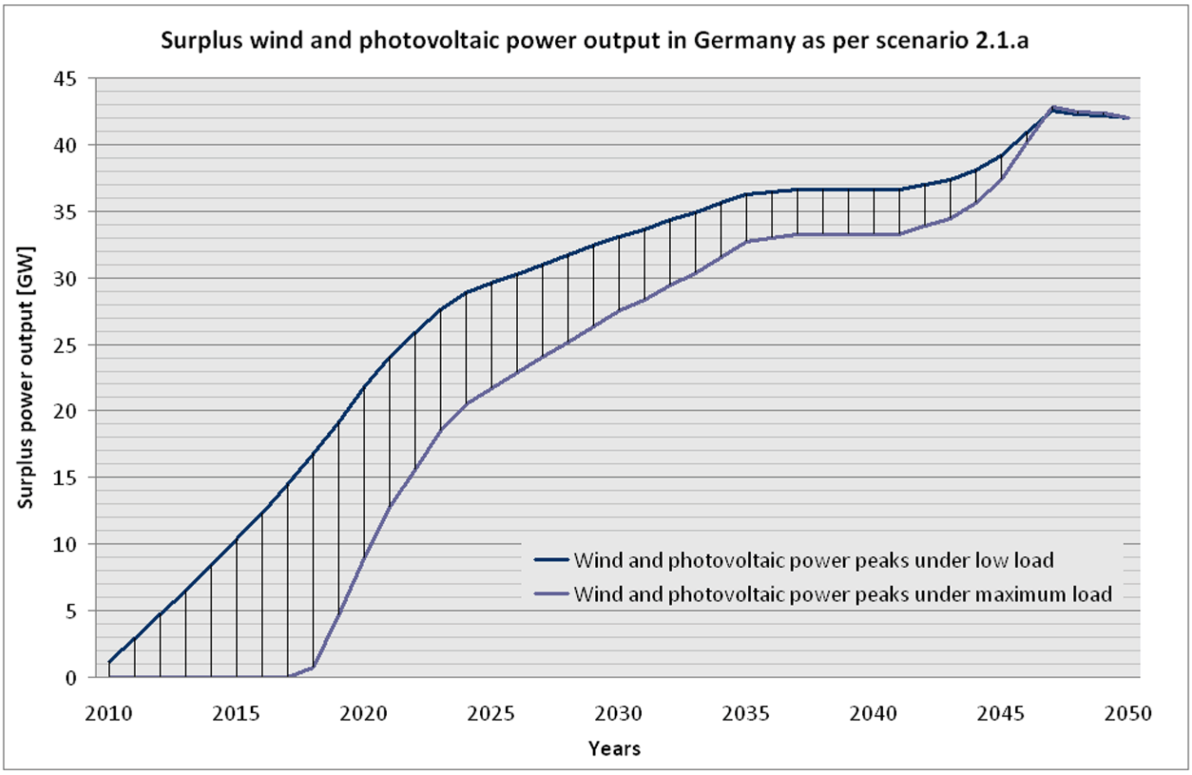
In view of the projected lead times, expansion of Norwegian pump storage capacity and of transmission capacity between Germany and Norway should get underway as soon as possible. Indeed, our simulations show that such projects should have long since taken center stage in the German energy policy debate.

Assuming that Norwegian hydro power plays a central role in compensating for fluctuations in German renewable electricity generation, the question arises as to whether Norwegian electricity generation and storage capacity will be sufficient not only overall, but also at all times throughout the year.

The starting point for our assessment of this issue was the cumulative Norwegian reservoir fill level in 2008, plus the minimum and maximum reservoir fill levels between 1990 and 2007 (see Figure 4-18). If the requisite storage input and output from scenarios 2.1. and 2.2 is added to the mean Norwegian storage fill level for 2008 as per Figure 4-18, it emerges that additional storage capacity use would result in neither undercutting nor exceedance of (respectively) the aforementioned minimum and maximum fill levels; the latter are in fact (as Figure 4-18 shows) equalized over the course of the year. Moreover, in spring the aggregate filling level lies within the range of the annual fluctuations that occur in any case. Over the summer, Norway’s substantial storage hydroelectric power station capacity is used via additional German demand, whereby fall and winter reservoir fill level is even higher than the prior year by virtue of additional storage input, which in turn reduces net draw-down in the following spring. All told (including natural inflow into storage lakes), reservoir fill levels tend upwards, further improving the reliability of Norway’s electricity supply, which is currently assured via the import of Danish energy from coal fired power plants during periods of low annual water inflow. This analysis shows that the often expressed concern that Norwegian reservoir capacity is too low to compensate for shortfalls in German renewable electricity generation is unfounded. In point of fact, Norwegian hydro power would dovetail extremely well with German renewable electricity generation.

Figure 4-17

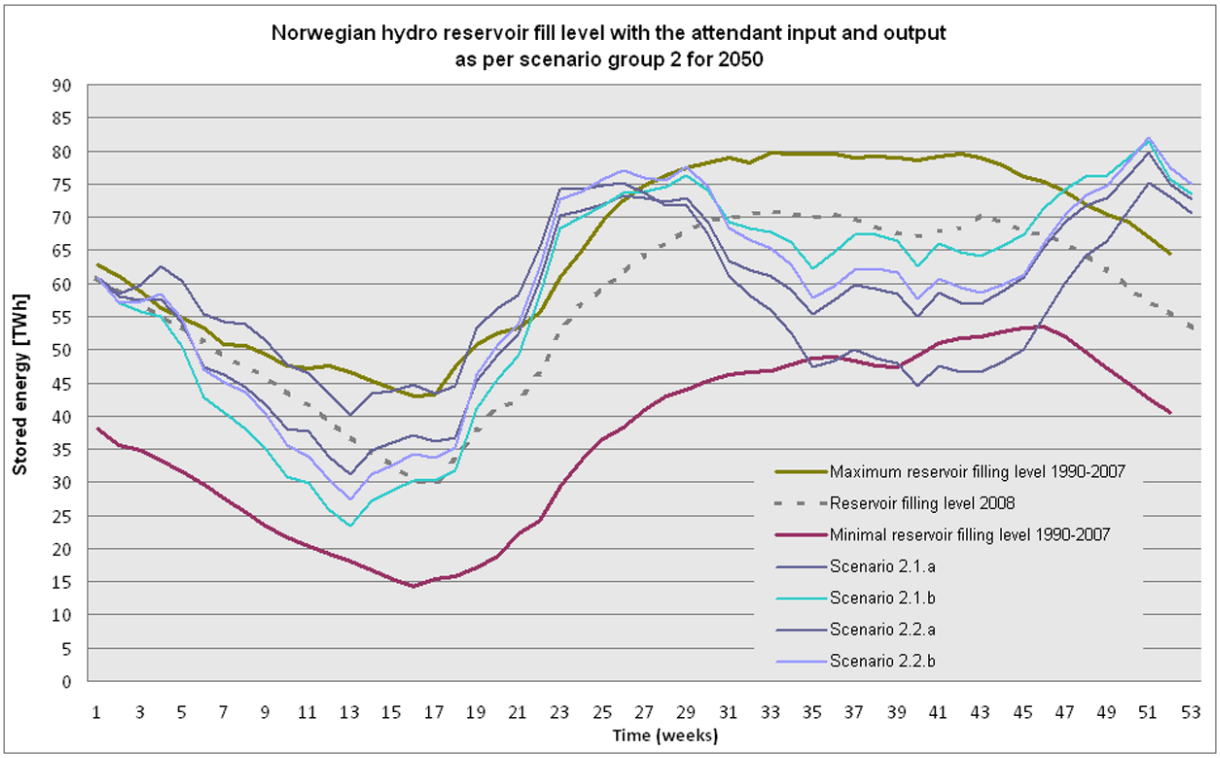
Surplus wind and photovoltaic capacity in Germany as per scenario 2.1.a



SRU/Stellungnahme Nr. 15–2010; Figure 4-17

Figure 4-18

Norwegian reservoir fill level with the attendant input and output, as per scenario group 2 for 2050



SRU/Stellungnahme Nr. 15–2010; Figure 4-18; data source: Nord Pool ASA 2010a

Admittedly, scenario group 2 involving a German-Danish-Norwegian network is an idealized case; for if Norwegian and Swedish storage hydroelectric power station capacity offers substantial potential for pump storage system capacity expansion, it stands to reason that other European states that greatly expand their renewable electricity use would also want to take advantage of this potential. Scenario 3.a., which analyzes an analogous situation for the Europe-North Africa network, shows that Norway converting its storage capacity to pump storage capacity in such a case would exhaust this capacity, but would create sufficient aggregate storage capacity. It is also relevant in this context that a considerable portion of Swedish storage capacity exhibits similar structures to those of Norwegian hydro power. Factoring in Sweden's capacity would increase the potential from the 84 TWh offered by Norway to approximately 118 TWh. Moreover, other Europe-North Africa network states such as France, Austria, Switzerland, Italy and Spain also have considerable storage hydroelectric power station capacity; it would have to be determined, to what extent this capacity could potentially be converted to additional pump storage capacity. Hence, inasmuch as the real-world situation is far more favorable than that indicated by the DLR simulations in scenario 3.a, it stands to reason that there would be no storage capacity shortfall if the requisite capacity conversions are carried out.

4.3.3 Electricity grids

Wide area electricity networks and their balancing function

22. A study we commissioned in 2009 (Czisch 2009) clearly shows that a higher capacity trans-European network would constitute a far less cost intensive but also far more politically ambitious option in terms of achieving a wholly renewable electricity supply.

Compensation for volatile electricity generation in a large-scale energy network would be based on the principle of diversification, whereby the key criterion for volatility mitigation would be energy output correlation over time with a view to using minor or negative correlations in the network's generation portfolio to offset capacity fluctuations in the second and minute ranges, as well as energy output fluctuations at the seasonal level. Inasmuch as the availability of renewable energy, notably wind and solar power, depends on the weather, energy generation can only be statistically correlated using the distances of networked power stations from each other and combinations of various renewable energy sources. In practice, this would entail incorporating a maximum number of power stations with a range of weather correlations into a network extending over the largest possible geographical area.

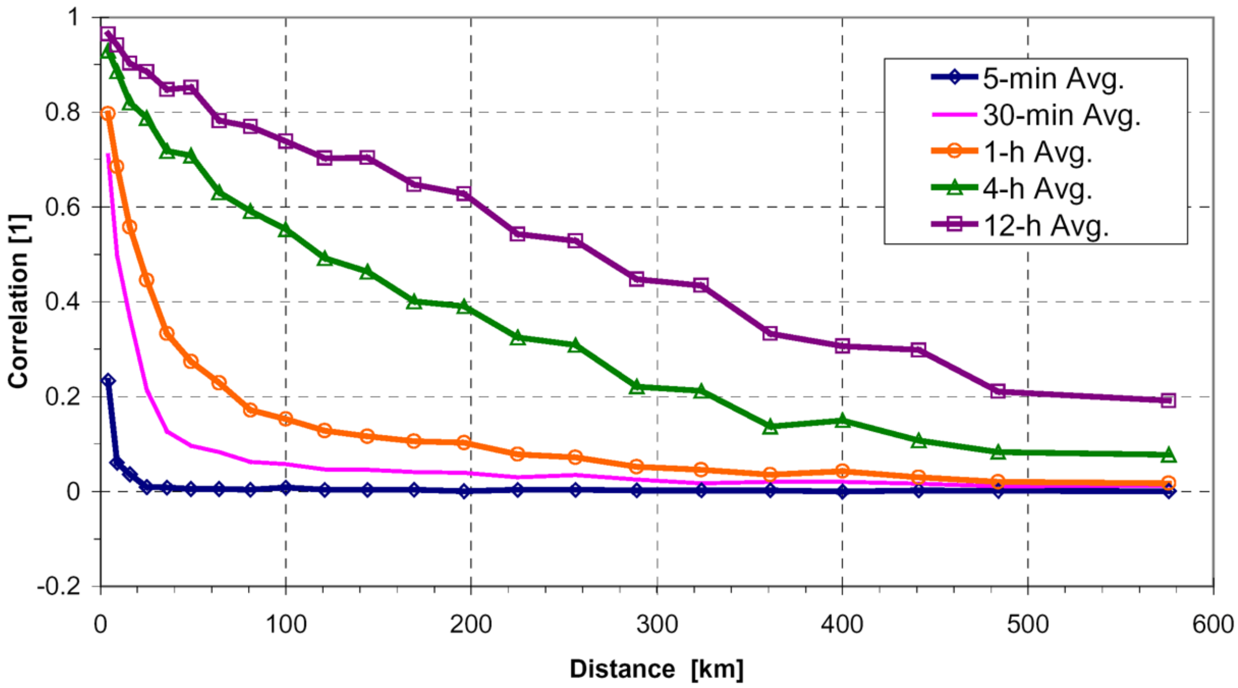
The time curves and equalization effects as determined by the relevant geographical distances will now be described using wind energy as an example.

Wind energy fluctuations that last only a matter of seconds (occasioned by wind gusts or the like) could be offset within individual large wind farms, whereas fluctuations lasting a matter of minutes would have to be offset over a catchment area diameter of approximately 10 kilometers. This distance would be 40 km for 30 minute fluctuations, 100 km for fluctuations lasting one hour or more, upwards of 1,000 kilometers for day long fluctuations and approximately 2,000 kilometers for month-long fluctuations; whereby for the larger of these distances, the nature of the location would have a major impact on the actual correlation. Seasonal energy fluctuations can only be offset via locations in different climate zones, e.g. by intermeshing power stations in Europe and North Africa. However, in order for such a network structure to work, it would have to include the southern areas of North Africa, which are particularly windy during the warm season.

The statistical background of the correlation of capacity fluctuations as determined by the distances and timelines of the relevant fluctuations is shown in Figures 4-19 and 4-20. In this context, the weaker the correlation, the sooner the capacity offered by various wind turbines is equalized.

Figure 4-19

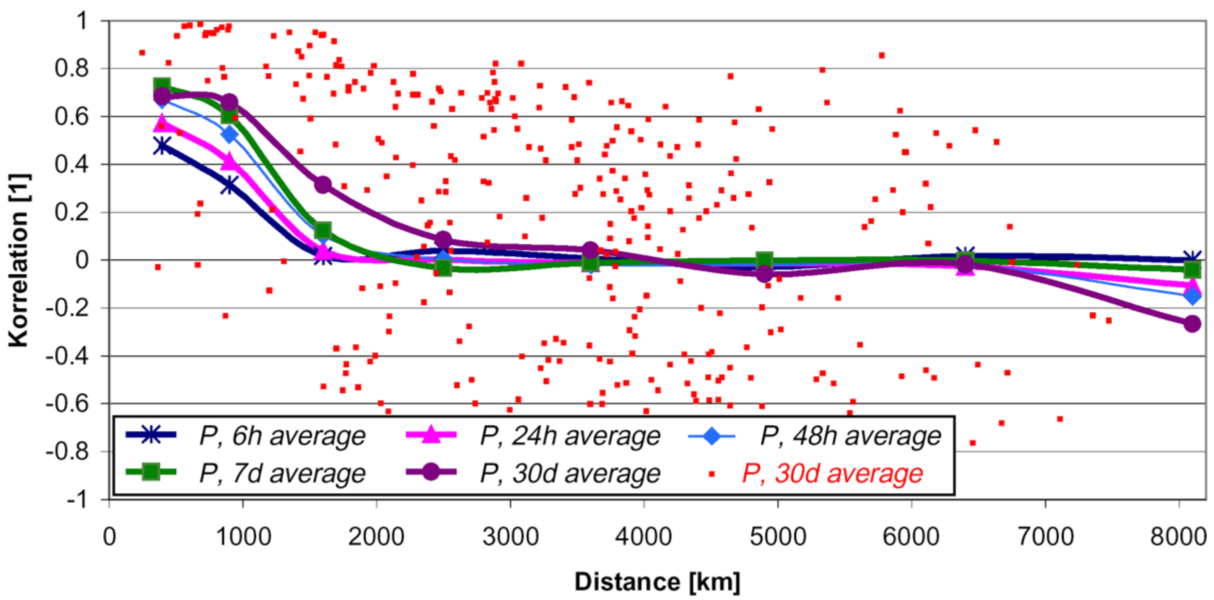
Capacity fluctuation correlation for wind power



Source: Czisch 2009

Figure 4-20

Capacity fluctuation correlation for wind power for distances ranging up to 8,000 kilometers



Source: Czisch 2009

The role of grids in our scenarios

23. Offshore wind power is likely to be Germany's main source of renewable electricity in the coming years from a technical and economic standpoint. In virtually all of our renewable electricity scenarios for the year 2050, offshore wind farms account for nearly 320 of Germany's aggregate 509/700 TWh demand, with the main generation capacity located at a considerable distance from the electricity demand centers in western and southern Germany. In addition, a large proportion of Germany's onshore wind energy capacity is located in the northern coastal region (56-90 TWh/a). In view of the fact that according to transition scenario 2.1.a (see section 4.2), both of these energy sources are poised for substantially increased electricity generation in the coming decade, large scale transmission capacity expansion between Germany's North Sea coastal region and the electricity demand centers in western, central and southern Germany is urgently needed. According to scenario 2.1.a, this increase would take the following form: from approximately 40 TWh in 2009 to 100 TWh in 2015, 180 TWh in 2020 and 260 TWh in 2025. At the same time, maximum offshore wind farm generation capacity is slated to increase from 8 GW in 2015 to 27 GW in 2020, 44 GW in 2025, 49 GW in 2030, and more than 80 GW in 2050. In order for this potential wind energy capacity to be of use to our national energy supply, we will need to step up the pace of expansion of our energy grid. But unfortunately, none of the current plans and government studies (DENA 2010) go far enough in terms of their timelines and the scope of wind energy capacity expansion, with the result that the importance of grid expansion aimed at allowing renewable electricity to be supplied to German electricity consumption centers has been woefully underestimated.

In our view, the energy policy debate in Germany has abysmally failed to recognize the central importance of establishing a network structure involving Scandinavian pump storage potential and entailing the conversion of Swedish storage hydroelectric power stations to pump storage systems.

Assuming that our policymakers do not call for German energy self sufficiency, we can only achieve cost effective renewable electricity generation by engaging in electricity interchange with other states via cross-border grid expansion, even if such a partnership comprises only a handful of countries as per scenario group 2. In such a network (as was pointed out in section 4.3.1 in regard to the need for energy storage capacity expansion), viable electricity transmission capacity must be available no later than at the point where we are unable to use all of our own renewable electricity and the first energy interchange expansion phase with Norway for example (as per scenario 2.1.a) becomes necessary. The scenario 2.1.a timeline for load-dependent surplus wind and photovoltaic electricity generation (see Figure 4-17) shows that based on the renewable electricity expansion suppositions in section 4.2, Germany's need for a cross-border electricity interchange is set to expand exponentially in the foreseeable future. For example, the scenario 2.1.a development roadmap indicates that already in 2020 we will need 16 GW transmission capacity for transmitting energy to Norway (see section 4.3.1).

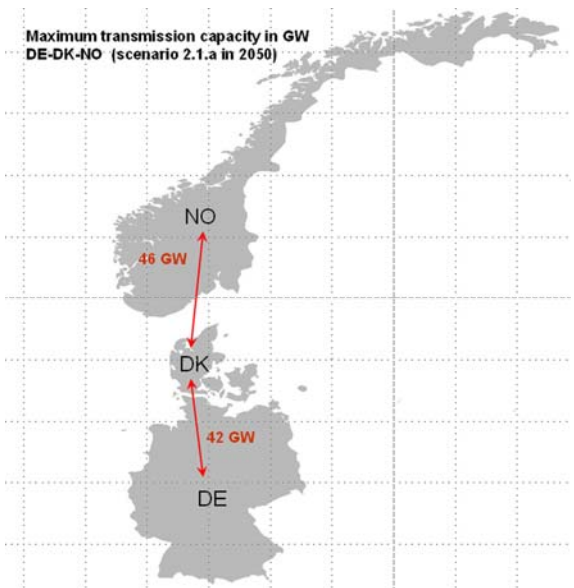
In view of the enormous transmission capacity that we will presumably be needing in the near future, expanding the scope of cross-border electricity transmission to Norway or elsewhere would be a wise move from an ecological standpoint, but also economically feasible; for the rapid rate of expansion of Germany's wind farm fleet will ensure that the capacity of every single new transmission line we build will be fully used before very long. The aggregate 2.8 GW of capacity of the Nordlink and NorGer high voltage transmission lines that are currently in the pipeline would increase overall line capacity only to slightly more than 4 GW. Thus, by 2020 we will need upwards of 10 GW of transmission capacity above and beyond this 4 GW in order to interchange electricity with Norway.

Hopefully, a sea cable can be realized in far less than the up to ten years of lead time normally required in Germany for electricity grid expansion planning, authorization and implementation (Kurth 2010, p. 39). If planning and expansion of these international transmission lines are not begun immediately, the missing transmission capacity and the consequent non-accessible Norwegian storage capacity in conjunction with expansion of the German transmission grid will constitute a second bottleneck in terms of the rapid expansion of Germany's renewable electricity capacity, which is both necessary and desirable from a climate protection standpoint.

Up to 42 GW of transmission capacity will be needed between Germany and Norway by 2050 as per scenario 2.1.a, with German demand amounting to 509 TWh/a; and up to 62 GW will be needed in scenario 2.2.b with 700 TWh/a of demand (see Table 3-6 in section 3.2.2). Figure 4-21 shows the transmission capacity that will be needed in 2050 for electricity transmission with a wholly renewable electricity supply in the German-Danish-Norwegian network.

Figure 4-21

Maximum transmission line capacity for the German-Danish-Norwegian inter-regional network in 2050



SRU/Stellungnahme Nr. 15–2010; Figure 4-21; data source: DLR 2010b

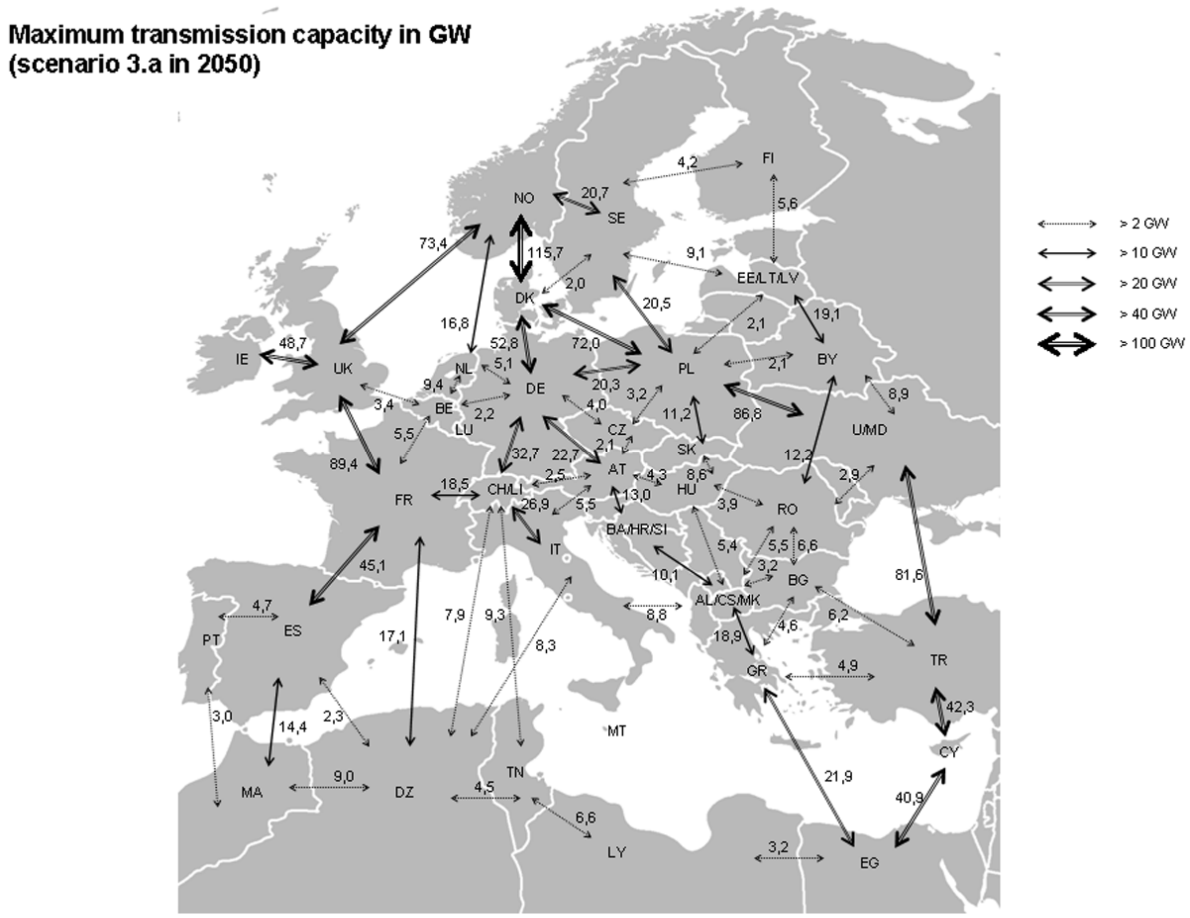
As scenario 3.a shows for the Europe-North Africa network, the kind of transmission lines needed for the relatively small scale German-Danish-Norwegian counterpart in all likelihood will prove to be economically viable even in far more extensive expansion scenarios. Even in the Europe-North Africa region energy interchange allowed for by scenario 3.a, the lion's share of Germany's surplus renewable electricity would be interchanged with Norway in the context of a technical and economic system optimization.

The 2050 scenario 3.a transmission capacity simulation for the Europe-North Africa region with German demand of 509 TWh/a is shown in Figure 4-22, which indicates that the lion's share of Germany's electricity interchange would be realized to Norway via Denmark, as well as to Switzerland, Austria and Poland. The requisite line capacity between Germany and Denmark would increase from 47.1 to 52.8 GW and between Germany and Norway from 50 to 115.7 GW relative to scenario 2.2.a, which is analogous to scenario 3.a. The transmission capacity that would be needed for the German-Danish-Norwegian regional network would also be necessary for wider ranging European electricity interchange, and in all probability would exhibit better capacity use and would thus be more cost effective.

In view of the fact that establishment of a Europe-North Africa wide area high-capacity network (such as an HVDC overlay grid) would undoubtedly face myriad political and legal hurdles, an expansion strategy based on a smaller scale cooperation involving fewer states that already have the requisite political stability and energy technology would be far more likely to succeed, at least at first. Once such a moderate sized inter-regional network was established, other states could accede to it over time, with a view to building an a far-flung system. For Germany, this incremental approach would initially entail installing transmission lines between Germany and Norway in the guise of point to point connections via sea cables or indirect links via onshore cables passing through Denmark. The onshore cable solution would probably provoke far greater opposition if it did not entail direct advantages for Denmark. However, inasmuch as Denmark is set to increasingly use Norwegian storage capacity for fully tapping its wind power potential, joint transmission lines could be installed for a portion of the transmission capacity in such a way as to allow for input and draw-down in Denmark. In a subsequent expansion phase, point to point lines could be installed linking Germany with Switzerland and Austria, providing these two countries are able to convert some of their storage hydroelectric power stations to pump storage systems. However, such an approach would probably meet with far greater obstacles than would be the case in Norway, as in such cases it is often necessary to create additional upper or lower storage lakes. Whether a Europe-North Africa overlay grid ever comes to fruition will mainly hinge on which countries with which generation and storage potential will join a smaller scale system.

Figure 4-22

Maximum transmission capacity for the Europe-North Africa region in 2050



SRU/Stellungnahme Nr. 15–2010; Figure 4-22; data source: DLR 2010b

According to a study we commissioned in 2010 (Brakelmann and Erlich 2010), the technologies and attendant costs of the various elements of the grid expansion differ greatly from each other as follows:

– Onshore power transmission lines for distances ranging from 400 to 500 kilometers are currently realizable in Germany via standard three-phase current 50 Hz technology at voltages ranging from 380 to 500 kV using underground VPE cabling (plastic cables with cross-linked polyethylene). The advantage of underground cabling is that it would allow for trouble free installation and approval of the new north-south and north-west transmission lines needed in Germany.

– Individual non-networked onshore electricity transmission lines for distances ranging from 400-2,000 kilometers can be realized using high voltage direct current technology (e.g., HVDC Classic) for up to 500 kV, via overhead lines (insofar as possible) and if not via ground cables. If the requisite technological advances are made, 800 kV high voltage direct current (HVDC) lines with 800 kV low-pressure oil cables laid in concrete channels and steel pipes could be used.

– In view of the development uncertainties entailed by high voltage direct current (HVDC) cables and circuit breakers, the report recommends that the wholly realistic goal be pursued of creating a 16.7 Hz overlay grid in Europe. To this end, 500 kV voltage capability would be rolled out, for which VPE cable or the three-phase grid technology either already exists or could be developed at a relatively low cost compared to the technological challenges that would be entailed by high voltage direct current (HVDC) technology. This approach would also reduce the ratio between line length resistance and frequency, which would represent a threefold reduction relative to today's 50 Hz frequency.

The report recommends that the following transmission technologies be used for ocean cables (Brakelmann and Erlich 2010, p. 9):

– For German wind farms that are up to 120 kilometers offshore: conventional 50 Hz three-phase current technology, if necessary in bipolar mode.

– For German wind farms that are more than 120 kilometers offshore, the report states that high voltage direct current voltage source converter (HVDC-VSC) technology is the only possible solution at present, and according to Brakelmann and Erlich 6.7 Hz three-phase current technology is highly advantageous for such solutions, possibly in combination with bipolar cable connections. This would allow for direct input via wind turbine converters, which would translate into considerable cost savings on offshore converter stations for HVDC transmission. This solution could be rendered more advantageous still through the use of 16.6 Hz onshore grids.

The report recommends that German offshore wind farms be linked to Norwegian pump storage systems via HVDC ocean cables with the highest possible voltage, which could likewise be supplied via a 16.7 HZ offshore grid.

Inasmuch as transmission grid expansion normally involves the realization of point to point connections that are separated from existing high voltage transmission grids via voltage level, frequency, or transmission modality (direct current), it would be altogether possible to install the requisite lines progressively over time via a range of technologies. In our view, such an approach would allow for installation of the initial lines without the need for prior European consensus concerning the technology that is to be used, even if the long term goal is to establish an inter-regional network encompassing all EU and North African states.

That being said, the requisite expansion of grid and storage capacity will undoubtedly be the greatest stumbling block to expanding the scope of renewable electricity use in Germany and Europe that is necessary and desirable from a climate protection standpoint. At the same time, all of the simulations and calculations we have carried out in this regard clearly indicate that no such stumbling blocks would arise in connection with either usable potential for or the availability of the requisite technologies in renewable electricity generation scenarios.

4.4 Future role of base load power plants

24. Steadily expanding use of renewable electricity with a view to achieving a wholly renewable electricity supply will not only result in the gradual replacement of conventional power plant capacity and to grid and storage capacity expansion, but will also have a considerable impact on the possible future role played by base load power plants in a new electricity supply system. In view of the fact that to date the discourse on the future of Germany's electricity supply has conveyed the impression that we cannot achieve a reliable electricity supply without base load power plants, in the following we will discuss the role of such power plants in a changing electricity supply system.

4.4.1 The current electricity supply system

25. Today, daytime and nocturnal electricity demand is satisfied using variable output base, medium and peak load power plants. A base load power plant normally means a facility that generates electricity for anywhere from 7,000 to 8,760 hours a year; the figure for medium load facilities ranges from 2,000 to 7,000 hours and for peak load facilities is less than 2,000 hours (Fraunhofer IWES and BEE 2009, p. 32). The correlation between these differences is shown in Figure 4-23 via a stylized daily electricity demand curve.

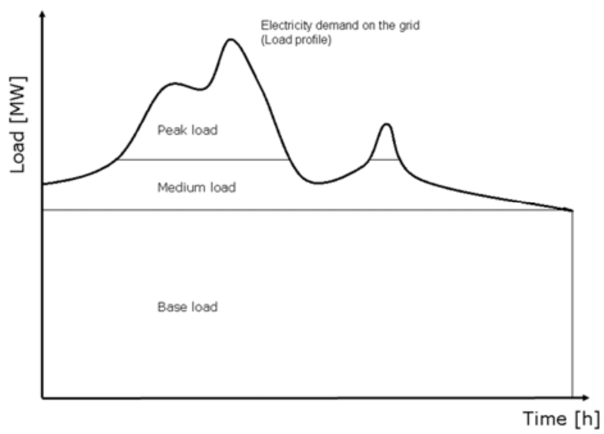
In this context, a so called dispatch determination is made at 15 minute intervals as to which of the available variable output power plants should be used to ensure that electricity demand can be satisfied at all times. Such decisions are mainly based on the variable costs of the available power plants, which are ranked in ascending order of their costs (referred to as a merit order).

In this process, power plant capacity is held in reserve in the event of demand and frequency fluctuations lasting minutes or seconds. This reserve is known as primary, secondary and tertiary reserve and the attendant capacity is referred to as controlling power range.

Base load electricity is normally generated by large nuclear and coal fired power plants, which despite their higher investment costs relative to other types of power plants, use relatively inexpensive fuel and thus exhibit low variable costs (Nicolosi 2010, p. 2). Such power plants therefore have higher merit order rankings than power plants with relatively high variable operating costs such as gas power plants, whose fuel costs tend to be elevated.

Figure 4-23

Schematic graphic of how daily electricity demand is met in the current electricity system



SRU/Stellungnahme Nr. 15–2010; Figure 4-23

4.4.2 Substantial proportion of renewable electricity generation in the system

26. Inasmuch as, unlike fossil fuel or nuclear energy plants, wind and photovoltaic energy require no fuel and thus exhibit virtually no variable operating costs, these forms of energy are always used to satisfy electricity demand before electricity generated by variable cost and output power plants is dispatched.

However, in the presence of a high proportion of virtually non-variable wind and solar electricity most of which is fed into the grid, radically different dispatch decisions are made for variable output power plants. In such cases, the primary goal is no longer to service grid demand via variable output power stations, but rather – and solely – to offset the difference between severely and possibly rapidly fluctuating renewable electricity generation (notably from wind power) on one side, and demand resulting from the dispatch of electricity from variable-output power stations on the other. This dynamic is illustrated schematically in Figure 4-24.

In a scenario involving a difference between electricity demand and intermittent input, variable output energy is in demand in the presence of a capacity shortfall (residual load) and electricity storage is in demand in the presence of surplus capacity. Residual load can only be provisioned via variable output power stations, which means that the scope of this load at any given moment is determined by (a) electricity demand; and (b) the amount of intermittent renewable energy (mainly wind power but also photovoltaic) that is fed into the grid.

According to transition scenario 2.1.a (see section 4.2.1), by 2020 installed wind and photovoltaic energy capacity in Germany will amount to approximately 67 and 30 GW respectively, for an aggregate approximately 97 GW whose electricity production cannot be precisely forecast since wind and sunshine availability fluctuates greatly over time.

4.4.3 Requirements for Germany’s future electricity system

27. In order for us to greatly expand the use of renewable energy we will need to adapt our electricity supply system to new conditions. To integrate into such a system a high proportion of renewable electricity whose output varies (as is the case with wind and solar energy), it will be necessary to do the following: dispatch conventional electricity more flexibly; expand the capacity of electricity storage systems; establish variable-output renewable electricity systems; and institute effective electricity demand management. The expansion of renewable electricity energy should go hand in hand with increased uses of the technical and economic potential for a flexible electricity generation system (Nicolosi 2010).

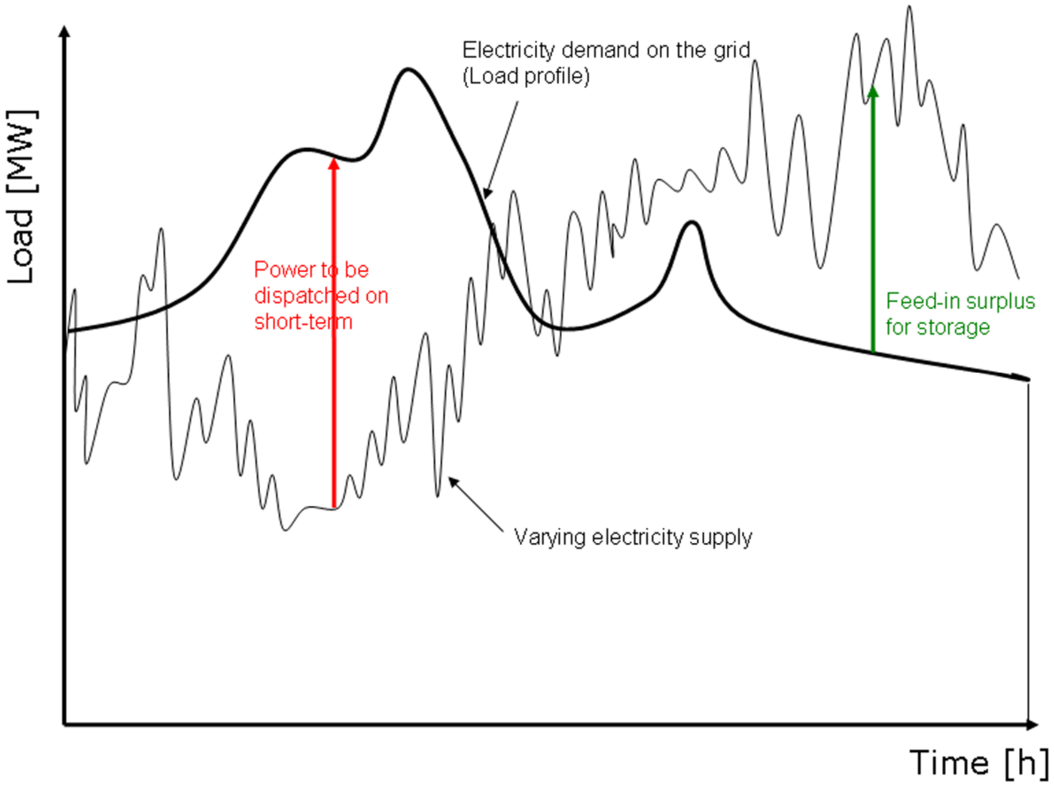
Congruent with the foregoing, based on a simulation of Germany’s electricity supply system in 2020 and a Bundesverband Erneuerbare Energien (BEE) projection of the scope of renewable electricity expansion, Fraunhofer Institut für Windenergie und Energiesystemtechnik (IWES) concluded that in light of more frequent and sharper capacity changes necessitated by intermittent grid input from renewable energy sources, by 2020 the need for medium and peak load electricity will rise and “classic base load” electricity will become obsolete (Fraunhofer IWES and BEE 2009, p. 37).

A simulation of the structure of our transition scenario 2.1.a for 2020 in light of the system’s residual load illustrated in Figure 4-25 prompted Sterner et al. (2010) to conclude that base load coverage by conventional power plants will have gone out of existence by 2020.

The fact, however, that base load provision and the prerequisite flexibility of conventional power plants will be obviated has been given short shrift in the German debate concerning the future evolution of our electricity generation system in the coming years.

Figure 4-24

Meeting daily electricity demand in an electricity system with a high proportion of wind power



SRU/Stellungnahme Nr. 15–2010; Figure 4-24

Up until now, most continuous operation of Germany's nuclear power plants and lignite fired power plants has been realized at nominal capacity, and few plants are operated in load following mode (Hundt et al. 2009, p. iii). Various view are expressed in the literature concerning the capacity of these facilities to handle the ever rising need for operation in load following mode. According to the study of University of Stuttgart's Institut für Energiewirtschaft und Rationelle Energieanwendung (Department of energy management and rational energy use), (Hundt et al. 2009, p. 28), capacity modification rates ranging from 3.8 percent to 5.2 percent per minute (based on nominal capacity) are achievable in normal operating mode in a facility preserving fashion. Another study (Grimm 2007, p. 9) indicates a capacity gradient ranging from 5-10 percent per minute for nuclear power plants under partial load. However, elevated wind power input over a lengthy period may entail base load power plant downtime. According to Hundt et al. (2009, p. 26), it is safe to assume that a nuclear power plant operating under a partial load can be reduced to 50 percent of its nominal capacity. But in the presence of less than a 50 percent load, nuclear power plants must be shut down completely. One author's analysis of historical data in this regard shows that in the past it has not been possible to shut down more than 54 percent of the capacity of base load power plants (chiefly nuclear power plants and lignite fired power plants) (Nicolosi 2010, p. 15). According to data from the coal industry organization Bundesverband Braunkohle (DEBRIV 2010), 75 percent of the nominal load of newer hard-coal power plants can be down regulated.

However, the fact remains that frequent and sharp capacity changes in nuclear and coal fired power plants entail at least three untoward effects, one being increased specific electricity production costs secondary to reduced efficiency under partial load, the second being that frequent capacity changes provoke material fatigue, notably in power plant components that are subject to high pressure or temperatures in electricity generation circuits and the third – a consequence of the first two – being a shorter service life (Nicolosi 2010, p. 2). In addition, a major expansion of renewable electricity capacity would entail a complete shutdown of conventional power plants from time to time. Such shutdowns are subject to minimum additional downtime to reduce thermal stress (Grimm 2007, p. 45 ff.), thus further reducing the facility's potential number of annual full load hours. An evolving electricity generation system will increasingly impose requirements on conventional thermal base load power plants in terms of required load following operation, as well as increasingly frequent shutdowns; such facilities are not suited for such operating modalities from either a technical or economic standpoint.

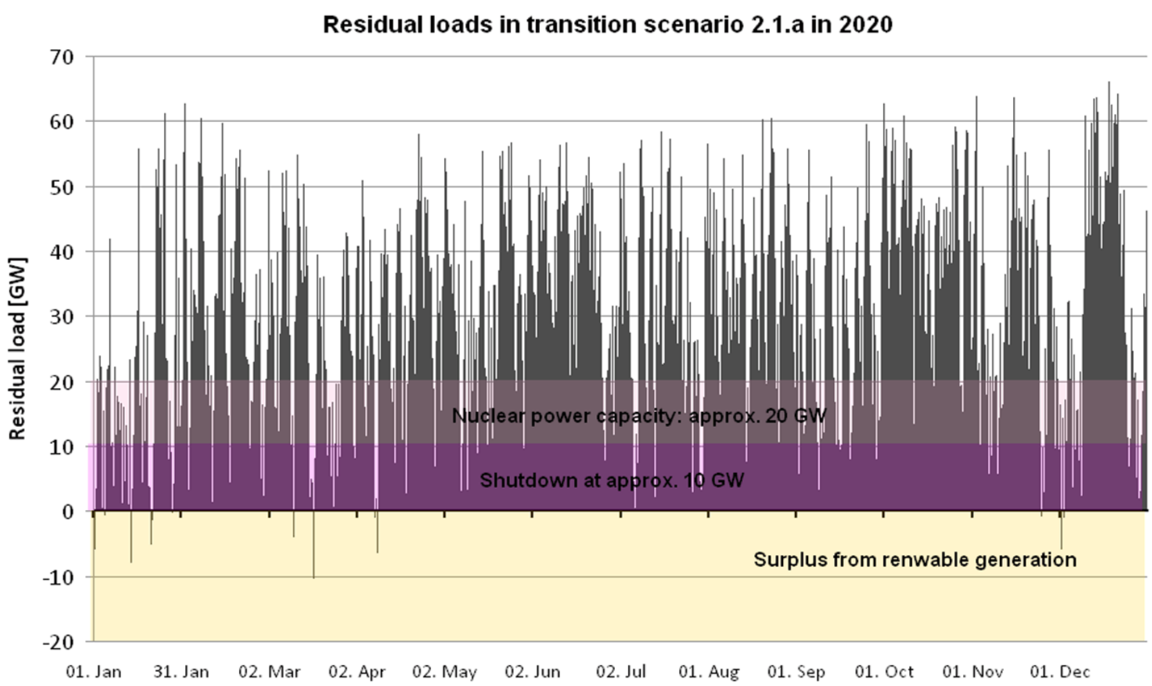
It was for this reason that a study commissioned by E.ON found that “unambiguous (idealized) allocation of load ranges to specific types of power plants” is set to become “increasingly blurred” in the coming years (Hundt et al. 2009, p. 22).

Rising input fluctuation will eliminate the demand for base load power plants (see Figure 4-25), whereby any residual demand of this type should be met, for technical and economic reasons, by power plants that are designed for operation under medium or peak loads.

According to an SRU-commissioned simulation of the year 2020 using our transition scenario 2.1.a and comparing the 2007 and 2020 annual electricity demand curves (Sterner et al. 2010), the requisite capacity of power plants whose annual full load hours exceed 8,000 will decrease from 43.9 GW in 2007 to approximately 10 GW in 2020 (see Figure 4-26). It should be noted, however, that this scenario allows a substantial portion of the peak load attributed to gas power plants to be serviced via existing storage capacity comprising approximately 16 GW of pump storage capacity in Norway, and 7 GW of pump storage hydroelectric power capacity and initial compressed air energy storage capacity in Germany (Sterner et al. 2010). But it should also be noted that these technologies are not included in Sterner’s model (Sterner et al. 2010)) and thus the necessary capacities are allocated to gas power plants. If the necessary storage systems are not incorporated into the German grid in a timely fashion, additional gas power plants will have to be built to fill this gap.

Figure 4-25

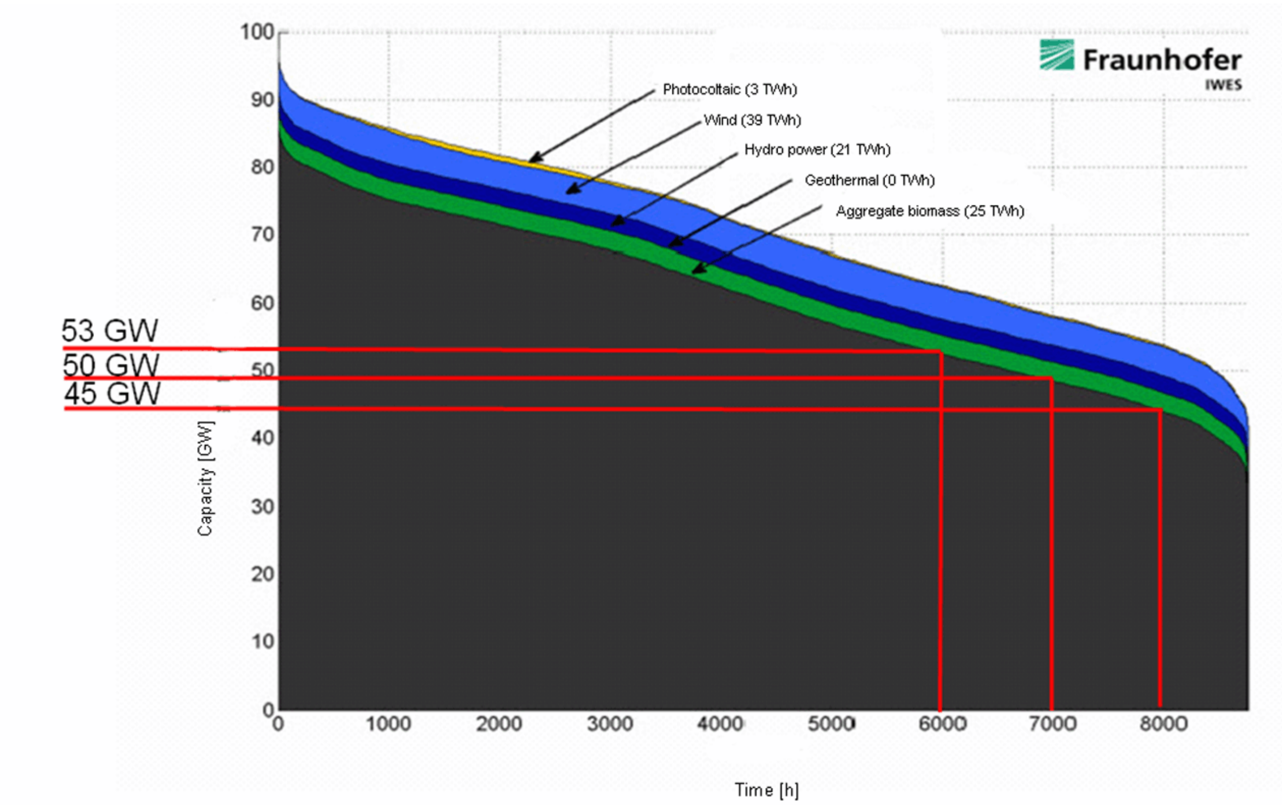
Residual loads in transition scenario 2.1.a in 2020



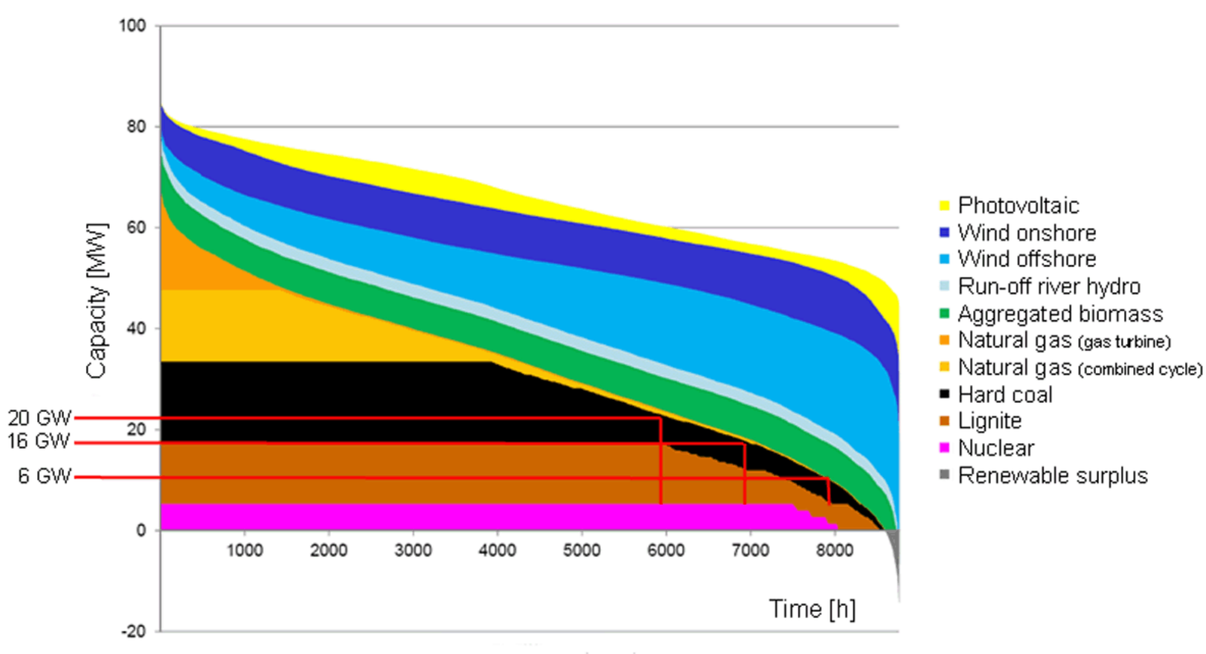
Source: Sterner et al 2010

Figure 4-26

Annual German electricity generation in 2007



Annual German electricity generation in 2020



Source: Fraunhofer IWES and BEE 2009; Sterner et al. 2010

Figure 4-26 shows the annual hourly load curve for capacity demand over the cumulative number of hours entailed by this demand, whereby residual load is indicated by the black area, and the colors above the black represent renewable energy.

Extending nuclear power plant service life – an option some have advocated (see CDU et al. 2009) – would unnecessarily exacerbate the aforementioned problems, for nuclear power plants lack the flexibility that will be needed in the energy system of tomorrow. Moreover, construction of new base load coal fired power plants would not be a useful addition to our electricity system, nor would the attendant investments yield the anticipated returns for investors since the number of operating hours posited by the plans for such facilities cannot possibly be reached.

Hence in our view, we are faced with a choice between the following two radically different roadmaps for our electricity system:

– A massive expansion of renewable energy sources, a program that would have to be combined with power plants that can be started up rapidly (i.e. gas power plants), electricity storage systems, and a large scale grid expansion.

– A power plant system expansion program based on base load power plants (coal fired power plants with carbon capture and storage (CCS) systems and/or nuclear power plants), to the exclusion of large scale expansion of wind and solar electricity generation capacity, since a higher proportion of such energy cannot be viably combined with a base load oriented power generation system using coal and nuclear power.

In our view, the inherent antithesis between power plants that are based technically and economically on a base load paradigm on one side, and strongly fluctuating renewable energy sources on the other means that (a) proposals to extend nuclear power plant service life and the envisaged major capacity increase by building new coal fired power plants; and (b) a strategy of transitioning to a wholly renewable electricity supply are mutually exclusive.

4.5 Costs associated with the renewable energy development roadmap

28. Our projected cost curve for the development of renewable electricity is based on the renewable energy simulations and projections described in section 4.2, whereby transition scenario 2.1.a was used as a specimen cost scenario in this regard. Our suppositions concerning the timeline for specific electricity generation costs were (a) based on a German government "Reference Scenario A" (Nitsch 2008); and (b) scaled in the REMix-model scenario (2.1.a), whereby the REMix model's 2050 cost projections are derived from those of Nitsch.

Fluctuations in renewable electricity generation costs as posited in our simulations (see Figure 4-27) will be chiefly attributable to factors such as improved efficiency, cost reduction potential resulting from economies of scale, and the assumed capital interest rates, all of which are subject to uncertainty in view of the four decade period that comes into play here. As noted (see section 2.2), the cost decrease potential posited for our simulations is in the range of various projections in the literature. For wind power, our backward projection of the relevant costs was based solely on German installed capacity in scenario 2.1.a entailing learning rates amounting to 11.5 percent and 18.6 percent for onshore and offshore wind power respectively (see Table 4-5). Neij's most recent study yielded learning rates, by 2050, ranging from 18-22 percent for wind power, 15-22 percent for photovoltaic power and 0-10 percent for biomass energy (Neij 2008, p. 2,209). Hence our posited wind power learning rates resulting from our backward projections should be regarded as being extremely conservative, as should the 2.2 percent learning rate for biomass energy use that was posited using this same procedure. The backward projection for the posited photovoltaic power learning rate yielded a value of 26 percent, which is marginally higher than the upper limit of the range quantified by Neij (Neij 2008, p. 2,209). Hence this figure should be regarded as being highly optimistic. The posited photovoltaic power cost curve is likewise somewhat optimistic, particularly for the post-2035 period, as an analogously large scale expansion of photovoltaic energy use would have to occur globally in order for German installed photovoltaic capacity to achieve the highly ambitious goal of electricity generation costs amounting to considerably less than 15 euro-cents per kWh. Were it to emerge that the posited value of 8.9 euro-cents per kWh was unduly optimistic and that a cost reduction to only 15 euro-cents per kWh was achievable by 2050, the mean electricity production costs in scenario 2.1.a would rise from 7 to 7.56 euro-cents per kWh. In scenario 2.2.a, which allows for net electricity import, electricity generation costs would remain at 6.5 euro-cents per kWh since photovoltaic energy is not used in this scenario.

Table 4-5

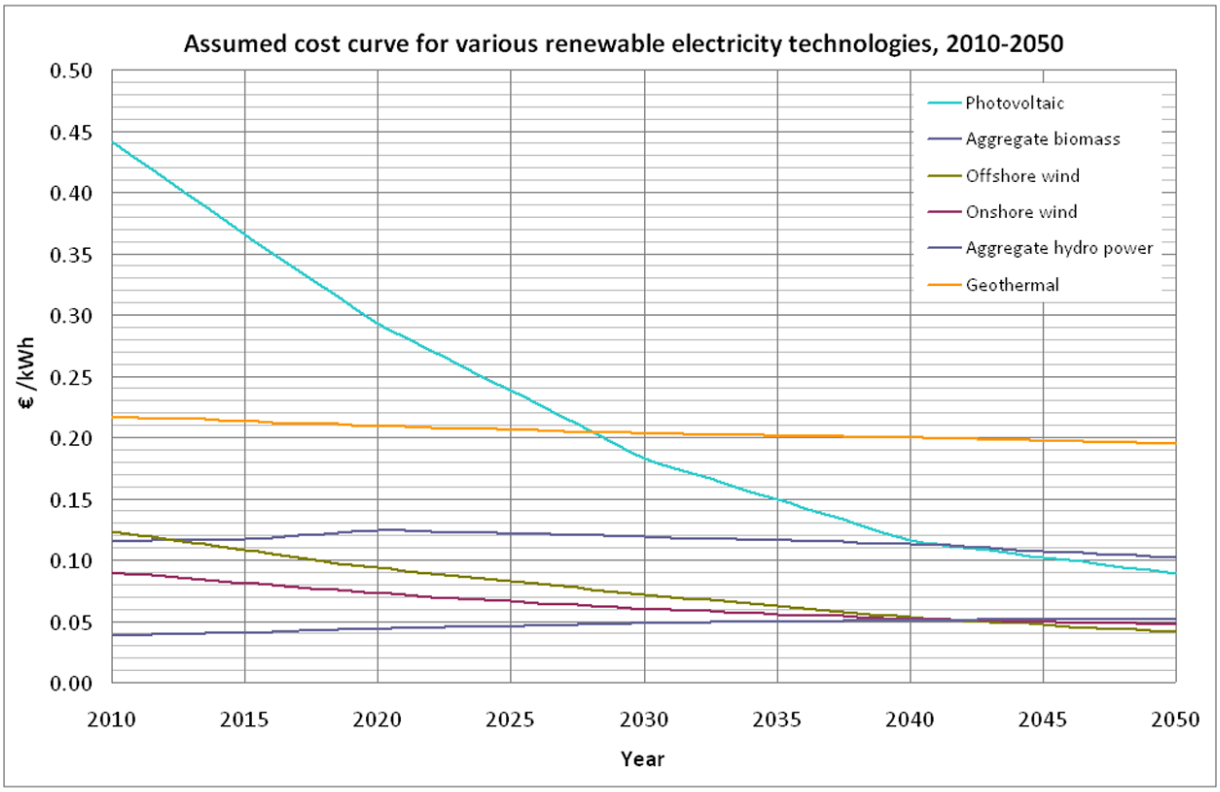
Posited learning rates (percentage reduction in electricity production costs accompanied by a doubling of production) relative to the rates indicated by Neij (2008)

	Our posited learning rates	Learning rates posited by Neij (2008)
Onshore wind farms	11.5%	18 – 22%
Offshore wind farms	18.6%	18 – 22%
Photovoltaic energy	25.9%	15 – 25%
Biomass energy	2.2%	0-10% (technical learning rate)

SRU/Stellungnahme Nr. 15–2010; Table 4.5. Data source: Neij 2008

Figure 4-27

Posited cost curve for various renewable electricity technologies, 2010-2050



SRU/Stellungnahme Nr. 15–2010; Figure 4-27; data source: Nitsch 2008

Our posited biomass cost curve presupposes moderately decreasing capital investment costs for biomass technology, but at the same time posits that the price of energy crops and forestry fuels will evolve similarly to conventional fuel prices.

Our suppositions concerning the cost reduction potential for geothermal electricity should be regarded as relatively conservative, since the figures that are currently under discussion presuppose far greater cost reductions.

Figure 4-27 shows the posited specific cost curves we used in our scenarios for the various renewables, whereby all scenario simulations presuppose a 6 percent public sector interest rate on capital investments, to the exclusion of any higher private sector rates.

The cost of conventional electricity generation in the coming years will be mainly determined by energy prices, as well as by the environmental protection costs entailed by carbon certificates, the evolution of whose prices is highly uncertain and will be strongly affected by climate protection policy goals in the coming years, as well as by the size of the markets for these certificates. As for fossil fuel prices, in view of the four decade period under consideration here they are subject to far greater uncertainty than renewable electricity costs, which are mainly governed by technological factors. Various studies have shown that extending emission trading to all countries of the world could potentially reduce the price of emission rights by a factor of five relative to the price that will result from trading that is limited to OECD member states (IPCC 2001, p. 537). Our simulations were predicated on the price curves for (a) fossil fuels (price delivered to power plants) and (b) emission rights posited by Reference Scenario A of BMU (Nitsch 2008).

Table 4-6

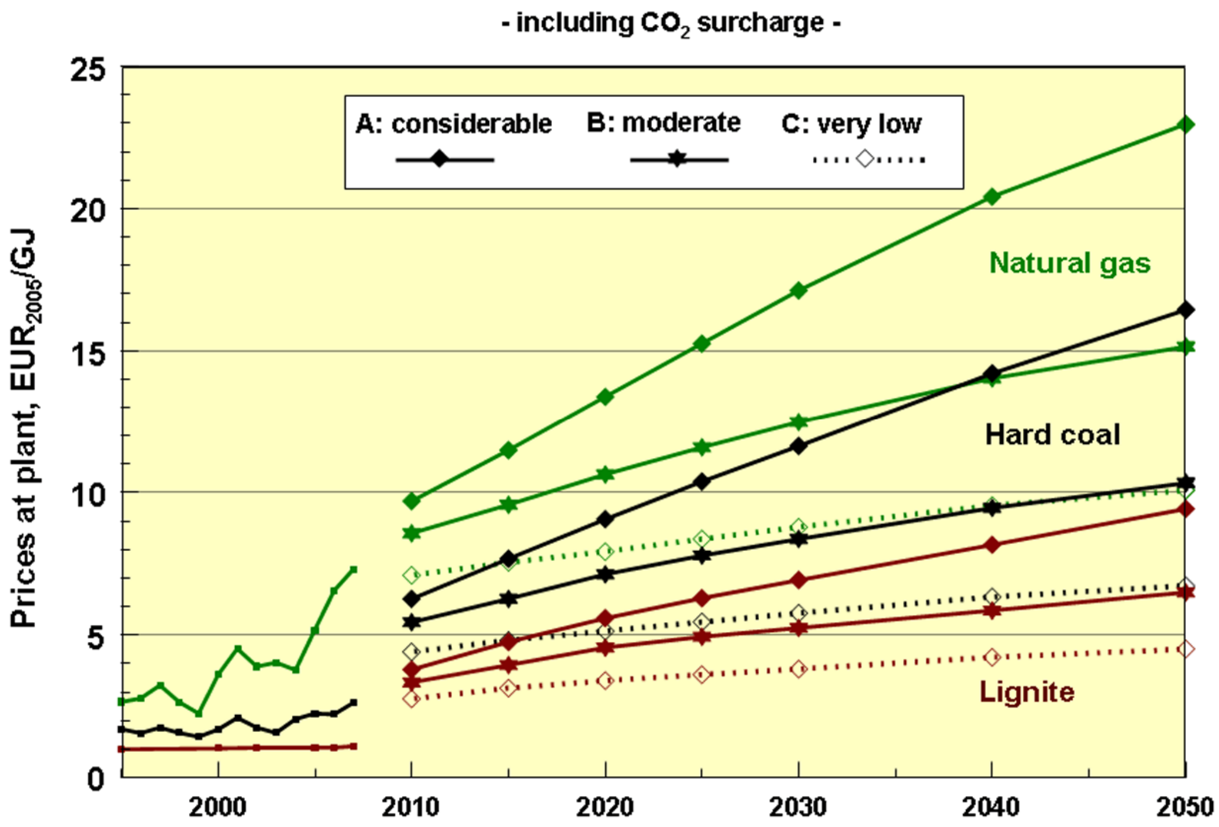
Projected fossil fuel and carbon emission rights within the framework of a very significant price increase (as per curve "A" below)

Brennstoffpreise frei Kraftwerke; reale Preise, (Preisbasis 2005) mit CO2 - Aufschlag											
	2000	**2005**	2006	2007	2010	2015	2020	2025	2030	2040	2050
Preispfad A: DEUTLICH											
CO2-Aufschlag; EUR/t					**24,0**	**32,0**	**38,0**	**45,0**	**50,0**	**60,0**	**70,0**
Erdgas											
ct/kWh th	1,30	**1,86**	2,36	2,64	3,49	4,14	4,82	5,49	6,16	7,35	8,27
EUR/GJ	3,61	**5,17**	6,56	7,34	9,70	11,51	13,40	15,26	17,12	20,43	22,99
Anteil CO2-Aufschl. (%)					15,9	18,6	19,6	19,9	19,6	19,7	20,7
Steinkohle											
EUR/t	49,5	**66,1**	65,1	77,1	183,8	225,1	265,9	304,6	341,3	416,4	481,8
ct/kWh th	0,61	**0,81**	0,80	0,95	2,26	2,76	3,26	3,74	4,19	5,11	5,91
EUR/GJ	1,69	**2,26**	2,22	2,63	6,27	7,68	9,07	10,39	11,64	14,21	16,44
Anteil CO2-Aufschl. (%)					54,3	62,2	65,5	66,3	65,4	63,6	64,4
Braunkohle											
ct/kWh th	0,37	**0,38**	0,38	0,40	1,36	1,71	2,01	2,27	2,49	2,94	3,40
EUR/GJ	1,02	**1,06**	1,06	1,11	3,78	4,75	5,59	6,31	6,92	8,17	9,45
Anteil CO2-Aufschl. (%)					240	298	347	383	408	444	476

Source: Nitsch 2008, p. 108

Figure 4-28

Comparison of the three price scenarios posited by the BMU *Leitstudie*, including carbon emission surcharges



Source: Nitsch 2008, p. 107

This price scenario would indubitably entail substantial fossil fuel price increases by 2050 relative to Reference Scenario B involving moderate price increases; the aforementioned study presupposes that the very low price Reference Scenario C will not occur (see Figure 4-28).

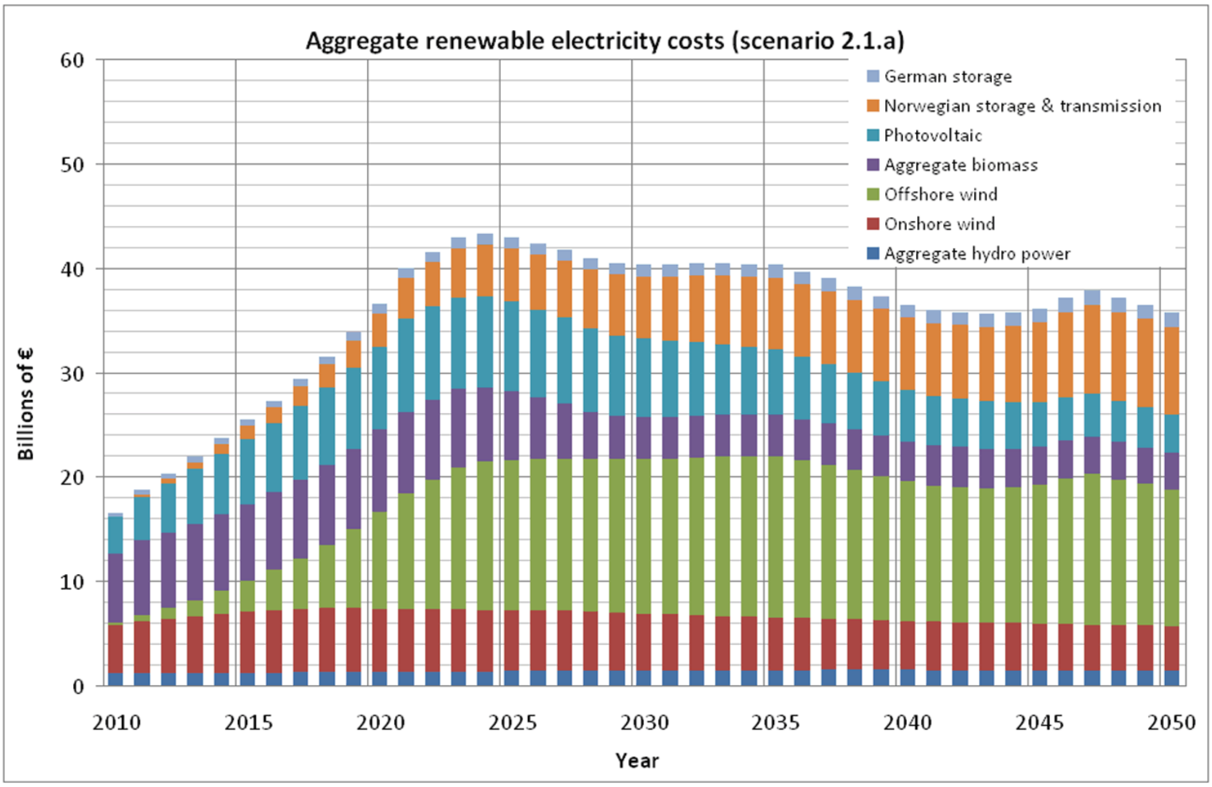
We computed aggregate annual renewable electricity costs on the basis of posited annual renewable electricity capacity expansion, in conjunction with electricity production as determined by specific costs. Figure 4-29 shows these costs broken down by renewable resource, storage costs in Germany, and the cost of transmitting electricity to and from Norway and storing it there. This graphic shows that the aggregate costs of renewable electricity generation will rise steeply from 2010-2024, an evolution attributable to (a) a substantial increase in the share of overall electricity generation accounted for by renewables; and above all by (b) the expansion of offshore wind energy capacity, which is still relatively cost intensive in this initial phase. However, despite the steady expansion of renewable electricity (see section 4.2), having peaked at approximately € 43 billion in 2024 aggregate costs will decrease steadily to approximately € 36 billion by 2050 on account of technology induced cost degressions (learning curve). Moreover, unlike the aggregate costs of renewable electricity generation, projected cross-border electricity transmission and storage costs will rise steadily.

Geothermal energy was excluded form scenario 2.1.a on account of its low potential and the elevated posited costs in 2050 (see section 4.2).

Figure 4-30 shows the mean specific renewable electricity generation costs from scenario 2.1.a, including the cost of storage use and installing transmission lines between Germany and Norway. For purposes of comparison, this cost curve is shown here alongside that for electricity generation using fossil and nuclear fuel, the latter in accordance with price scenario A in the BMU *Leitstudie*. The specific cost calculations were based on the aggregate cost curves as determined by annual electricity generation for each of the various renewables.

Figure 4-29

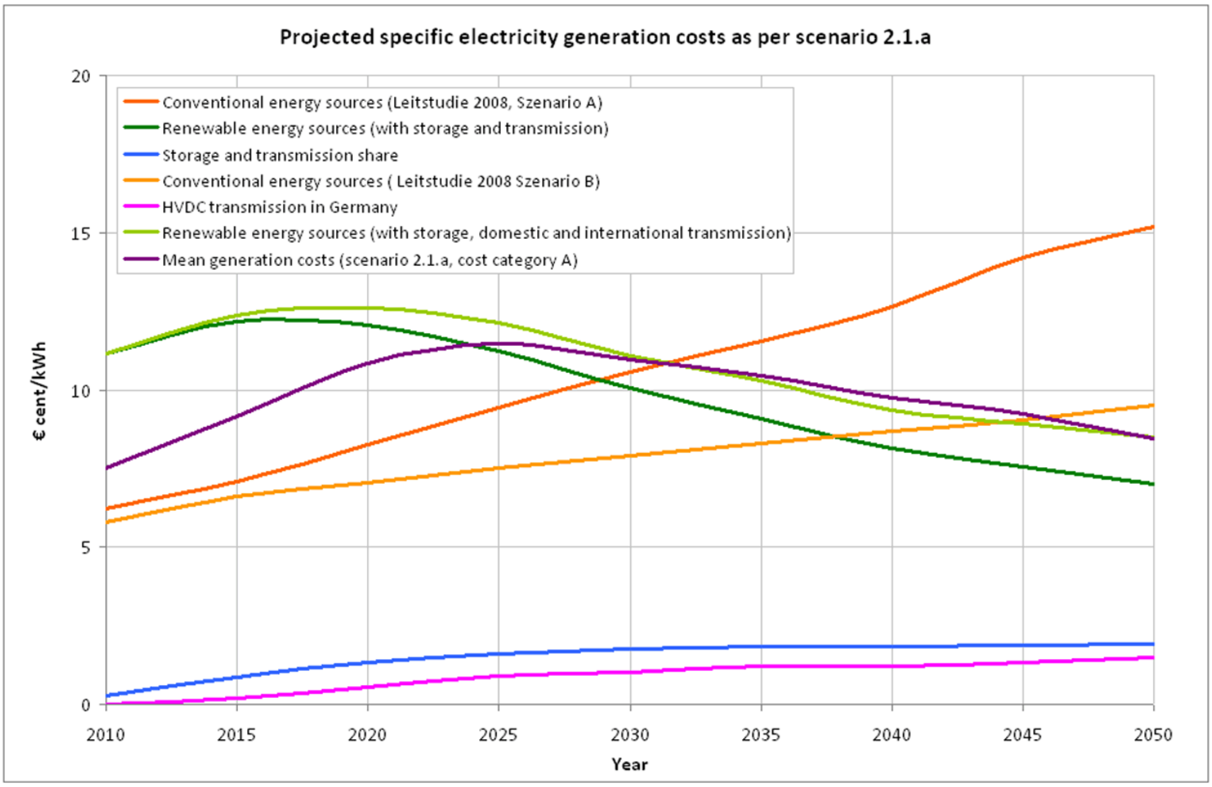
Aggregate renewable electricity cost as per scenario 2.1.a



SRU/Stellungnahme Nr. 15–2010; Figure 4-29; data source: Reference Scenario from Nitsch 2008; DLR 2010

Figure 4-30

Specific electricity generation costs as per scenario 2.1.a



SRU/Stellungnahme Nr. 15–2010; Figure 4-30; data source: Reference Scenario A from Nitsch 2008; DLR 2010

Figure 4-30 shows that, following an initial rise, mean specific renewable electricity generation costs (green curve) decrease steadily as from 2017 owing to technological developments and their not being affected by the increasing scarcity of fossil fuels, reaching approximately 12 euro-cents per kWh by 2010 and approximately 7 euro-cents per kWh by 2050. Whereas cross-border and German storage costs will account for only 3 percent of specific electricity generation costs in 2010, this figure will rise to 27 percent by 2050, when the cost will be approximately 2 euro-cents per kWh. The latter figure includes the use of 42 GW of Norwegian storage capacity and more than 18 GW of German compressed air energy storage capacity that can be summoned very quickly. Norwegian pump storage system capacity equates to reimport of just under 123 TWh/a of electricity that would be stored in Norway until needed. It was also posited here that transmission and storage loss in Norway and Denmark will be offset by the purchase of renewable electricity in Norway and will be paid for accordingly.

The costs of grid expansion within Germany were excluded from our computations of mean conventional and renewable electricity generation costs. Assuming expansion entailing 3,000-4,000 kilometers of high voltage direct current (HVDC) transmission lines between northern, southern and western Germany with 30 to 45 GW of transmission capacity allowing for the transmission of 350-500 TWh/a (aggregate 2050 wind turbine generation in scenario 2.1.a amounts to approximately 408 TWh/a), additional costs (including the consequent grid loss) would amount to approximately 1-2 euro-cents per kWh, according to our rough estimates. Aggregate mean renewable electricity generation costs, including storage costs and the cost of domestic and international grid expansion would then amount to approximately 8-9 euro-cents per kWh. Figure 4-31, which shows the electricity generation cost curves, including the cost of domestic electricity transmission (light green curve) based on a posited 2050 cost of 1.5 euro-cents per kWh, presupposes that high-voltage direct current transmission (HVDC) line expansion within Germany will be on a par with that of wind power.

However, the additional costs arising from accelerated expansion of renewable electricity use will not increase mean electricity prices as much as the aggregate cost difference between renewable and conventional electricity generation (respectively, as per the dark green and red or orange curves in Figure 4-30) and are instead solely factored in with the portion of mean electricity generation costs accounted for by renewables. Figure 4-31 shows this initial increase and subsequent decrease in mean electricity generation costs (only the cost changes are shown to the exclusion of aggregate costs) relative to the costs of generating conventional electricity in scenario 2.1.a, against the backdrop of a substantial increase in the costs of conventional energy resources (light green curve) and a moderate increase in these costs (red curve). Allowing for net imports would decrease the costs of renewable electricity by 0.5 euro-cents per kWh in 2050, and institution of an inter-regional Europe-North Africa network would lower these costs by an additional 0.5 euro-cents per kWh. The orange and dark green curves in Figure 4-31 show the impact of a 1 euro-cent per kWh decrease in renewable electricity costs on mean electricity generation costs. This projection presupposes that these cost reductions will be realizable continuously from 2010 to 2050.

A comparison of average electricity generation costs with costs of conventional generation as in Figure 4-31 shows that at some point between 2029 and 2044 (depending on the development of prices of conventional energy sources) the cost of renewable electricity may become lower than that of conventional electricity.

In any case, in the long term renewable electricity in Germany will result in lower electricity prices than would be the case if our current electricity supply structures are retained. Moreover, conversion to a wholly renewable electricity supply would ensure a reliable and climate friendly electricity supply for up to thousands of years.

The down side of such a conversion, however, is that electricity costs would need to be 2-3.5 euro-cents per kWh higher for the next few decades in order to finance the timely transition to a wholly renewable electricity supply that is indispensable for successful climate protection. Although such cost increases would peak in Germany at between € 10 and 15 billion around 2020, costs would decline to a far lower level thereafter, and beginning in 2030 costs savings ranging up to € 40 billion per year would be achievable.

This additional expense to promote climate protection strikes us as a highly worthwhile investment in our country's future, in view of the fact that we would be completely solving the global warming problem in a domain that currently accounts for some 35 percent of our greenhouse gas emissions.

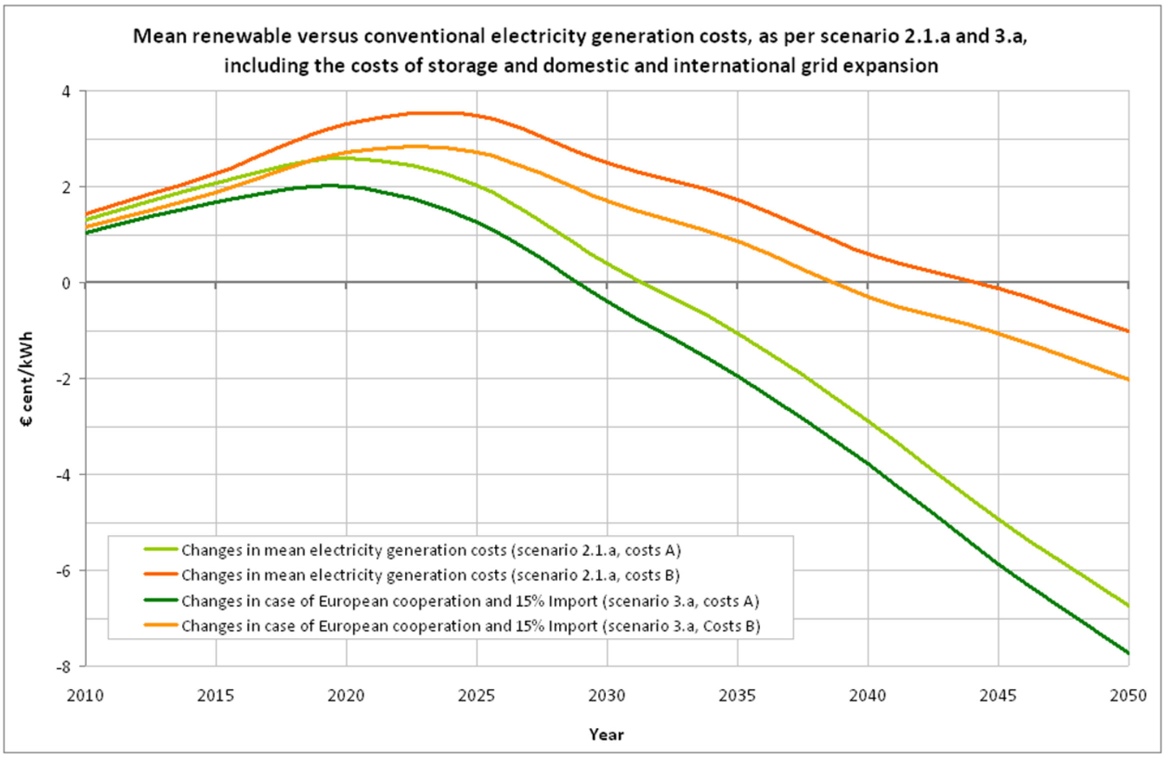
5 Summary and recommendations

Executive summary

29. The German Advisory Council on the Environment (Sachverständigenrat für Umweltfragen, SRU) is currently elaborating a Special Report on the future of Germany's electricity generation between now and 2050. This report, describing a possible roadmap for transitioning to a wholly renewable electricity supply and the policy instruments that would be needed to implement such a grid, will be based on a series of technical and economic scenarios for a wholly renewable electricity supply that were developed by the German Aerospace Center (DLR). The present SRU Statement describes the initial findings of these scenarios with a view to making them available for the current debate concerning which energy model the federal government will ultimately adopt. The policy and legal requirements for transitioning to a wholly renewable electricity supply do not fall within the scope of this Statement, but they will be addressed in the upcoming Special Report.

Figure 4-31

Mean renewable versus conventional electricity generation costs, as per scenarios 2.1.a and 3.a, including the costs of storage and domestic and international grid expansion



SRU/Stellungnahme Nr. 15–2010; Figure 4-31; data source: Reference Scenario A from Nitsch 2008; DLR 2010

All of our scenarios presuppose that Germany can and will implement a wholly renewable electricity supply by 2050, albeit under varying conditions in respect to grid connections with other countries and the electricity demand that will need to be met.

The model that we applied in this regard presupposes implementation of a system that will have the capacity to precisely satisfy electricity demand at all times over the course of any given year, in such a way that we can meet the challenges posed by a system that makes increased use of wind and solar energy, whose availability varies over time. An electricity supply that satisfies demand at all times can only be achieved either through the use of overlapping renewable electricity resources and/or stored electricity. To this end, we modelled (a) the use of hydro power, in conjunction with wind, solar, biomass and geothermal energy as well as storage technologies; and (b) cost optimized constellations of these energy technologies for each relevant instance.

30. The scenarios described in section 3 show that there are various options to realize a wholly renewable electricity supply in Germany. The renewable energy potential in Germany and Europe would allow for the satisfaction of maximum posited electricity demand at each given hour throughout the year. Available technology such as wind energy and photovoltaics is sufficient. Although a wholly renewable domestic electricity supply without any electricity imports would be feasible, this option should definitely not be pursued in light of the evolving EU-wide internal market for energy. Hence our study focuses on European inter-regional networks, which would promote electricity cost reductions and electricity supply reliability. The envisaged upgrading of Germany's power plant fleet offers a golden opportunity to transition to a wholly renewable electricity supply at a relatively low cost and without engendering any discontinuities in supply structures.

Findings of the 2050 scenarios at a glance

– Renewable energy source potential would be sufficient to fully satisfy electricity demand in Germany and Europe at all times throughout the course of any given year.

– This presupposes, however, expansion of the relevant generation capacity and creating an electricity generation and supply system that would allow fluctuating electricity input to be offset by storage capacities for electricity.

– In view of the fact that electricity costs in an inter-regional German-Danish-Norwegian or Europe-North Africa network would be substantially lower than would be the case in a self sufficient German system, under no circumstances should the latter option be pursued.

– Ambitious and far reaching energy saving and energy efficiency policies would reduce the economic and ecological costs of an electricity supply based on renewables.

– Our current fleet of conventional power plants would suffice for a smooth and incremental transition to a wholly renewable electricity supply, assuming a 35 year service life for these facilities. To do this, the annual rate expansion of renewable electricity generation capacity would have to be moderately increased, relative to current planned levels, between now and around 2020.

31. According to our computations, instituting a wholly renewable electricity supply in Germany by 2050 would entail economic advantages in addition to promoting climate protection, whereby the aggregate costs of such a system would be largely determined by the extent to which we establish a network comprising other European countries. According to our simulations, a self sufficient wholly renewable German electricity supply (a strategy which, as noted, is not worth pursuing in our view) would entail relatively high electricity generation costs ranging from 9 to 12 euro-cents per kWh (depending on demand), whereas an inter-regional smaller-scale German-Danish-Norwegian or larger-scale Europe-North Africa network would provide electricity at a cost of only 6 to 7 euro-cents per kWh, including the cost of international grid expansion. Our rough estimates indicate that expanding the German grid would entail additional costs amounting to approximately 1-2 euro-cents per kWh.

Thus (according to our computations) the aggregate long term cost of a renewables based inter-regional network would be lower than for conventional electricity. Depending on how the costs of conventional energy sources evolve, a renewable electricity system would become the less cost intensive option at some point between 2030 and 2040.

In this context, energy saving measures would ease the task of transitioning to a wholly renewable electricity supply. Hence Germany should institute a policy of stabilizing and capping electricity use nationwide. This would reduce system costs, improve system robustness, and promote rapid implementation of the necessary transformation process.

32. One of the key preconditions for establishment of a wholly renewable electricity supply is the availability of storage capacity or of a larger-scale network that can compensate for fluctuations in renewable electricity generation. The proposals in the present Statement are predicated on the tremendous potential that would become available to Germany through cooperation with Scandinavian countries and use of the pump storage system capacity available there. However, the requisite transformation also urgently necessitates increased transmission capacity from the offshore wind farms to electricity demand centers in central and southern Germany by installing very long distance transmission lines within Germany, particularly from north to south.

In our view both domestic and international grid expansion poses the greatest challenge for transitioning to a wholly renewable electricity supply; and we feel that facing this challenge is a matter of great urgency. Hence, in view of the lengthy lead times entailed by grid expansion projects, planning for transmission line routes of particular strategic importance should begin immediately; for timely realization of the requisite transmission and storage capacity is one of the key preconditions for a successful transition to a renewable electricity supply.

33. The transition scenarios described above (see section 4) show that the importance of so called bridging technologies in an age of renewable electricity has been overestimated. A smooth and incremental transition to renewable electricity can be realized by successively shutting down conventional power plants when they reach the end of their service lives and replacing these facilities with renewable electricity capacity. Our transition scenarios presuppose that the mean service life of conventional power plants will be 35 years and that the current rate of renewable electricity expansion will be maintained (which are rather restrictive conditions). To do this the annual absolute capacity expansion rate for renewable electricity would have to be increased to an average of 6 GW per year by 2020; and in the unlikely event that no electricity saving measures are instituted, this figure would be 8 GW, as per, respectively, scenarios 2.1.a and 2.1.b. This renewable electricity capacity expansion increase would be consonant with that of recent years, and in our view would pose no problem for the industries involved. The absolute expansion rate could be drawn down each year starting in 2021.

These scenarios (2.1.a and 2.1.b) obviate the need to extend the service life of nuclear power plants or to build new coal fired power plants with carbon capture and storage (CCS) systems. In other words, our existing fleet of conventional power plants, combined with a handful of newly built gas power plants, would provide a sufficient bridge for a transition to a wholly renewable electricity supply.

Planning for the transition entailed by our scenario that posits a conservative service life of 35 years for conventional power plants would build in a sufficient margin for error and thus satisfactory system flexibility. In the event that, for unforeseen reasons, the required grid, storage, and/or generation capacity expansion is delayed, some conventional power plants could remain in operation for longer than planned so as to ensure that any supply shortfalls can be covered.

A largely renewables based system would have less of a need for base load power plants. Owing to the high volatility of renewable energy, the powerband that is available over the entire year decreases substantially, and the number of shutdowns and startups of such facilities rises accordingly. Hence, once renewable electricity begins accounting for approximately 30 percent of aggregate electricity capacity, the construction of new conventional power plants will become unprofitable since it will no longer be possible to operate them at a sufficiently high capacity use level. And if proportional renewable electricity use rises further still, base load power plant operation will become problematic from a technical standpoint as well. Moreover, extending nuclear power plant service life or building new coal fired power plants would entail the risk of surplus capacity over increasingly longer periods, thus necessitating renewable capacity downtime or cost intensive underuse of conventional capacity and unnecessarily ramping up the costs of the transitional phase. Hence a blanket and pronounced extension of the service life of our nuclear power plant fleet would be incompatible with our scenarios involving a transition to a wholly renewable electricity supply.

Conditions and sensitivity of scenario findings

34. The present Statement is based on model-based scenarios that demonstrate (a) that transitioning to a wholly renewable electricity supply is feasible and (b) how this can be achieved. However, as is always the case with long range scenario studies, the findings are subject to significant uncertainty as it was necessary to make a series of assumptions concerning evolutions that are difficult to forecast. Using eight scenarios, we conducted a sensitivity analysis of our assumptions that did not, however, include all possible variants. The main difference between these scenarios lies in energy demand levels, as well as the extent to which other states come into play via energy interchange. This resulted in a broad spectrum of assumptions ranging from conservative to moderately optimistic. It should be noted that our findings are not intended as a forecast of the evolutions that come into play here nor do they constitute a concrete plan for achievement of a wholly renewable electricity supply.

35. In view of the fact that the present report concerns itself solely with electricity supply issues, the dynamic interplay between energy use in the heating and transport sectors were not explicitly mapped out in the simulations that formed the basis for our scenarios.

That being said, electricity demand may rise considerably in the coming years on account of evolutions in the transport and building heating sectors. For example, Germany’s entire automobile fleet going electric could ramp up electricity demand by roughly 100 TWh/a, whereby 1 TWh/a equates to the annual production of fifty 5 MW offshore wind turbines and 4,000 hours of full load operation for each such turbine. Electricity use could also become a more attractive building heating option if, for example, comprehensive energy efficiency upgrading greatly reduces the residual building heating needs and capital intensive heating modalities become less profitable. Our scenarios that presuppose 700 TWh demand in 2050 allow leeway for a considerable increase in demand on account of additional uses of electricity. If far reaching energy efficiency and energy saving policies are implemented, 700 TWh of electricity capacity would allow for the following additional uses: most of Germany’s auto fleet could go electric; electric heating could be used to cover the residual heating needs of buildings whose energy efficiency has been upgraded across the board; coverage of a far greater proportion of industrial process heat requirements.

36. The electricity generation costs for the wholly renewable electricity system posited by our scenarios of course hinge on the underlying German Aerospace Center (DLR) assumptions concerning the cost curves of renewable technologies going forward. These assumptions, which are based on the DLR's REMix model and are the fruit of thorough research and continuous updating, are regarded in some quarters as rather optimistic and in others as rather pessimistic (see section 2). In any case, over the long term renewable energy will become less cost intensive than conventional low carbon technologies such as carbon capture and storage (CCS) or new nuclear power plants, whose costs are set to rise owing to a dearth of carbon storage facilities for the former and uranium scarcity in the case of the latter. Emission trading will also drive up the cost of coal fired power plants, whereas renewable energy costs will decline thanks to learning curves and economies of scale. If timely short term expansion of renewable electricity capacity is more cost intensive than extending the service life of existing power plants, it will nonetheless allow for considerable cost savings in the long term and is thus a worthwhile investment in the future. Should renewable electricity energy costs decline more slowly than posited in section 4.5, renewable electricity will become competitive later than would otherwise have been the case and the cumulative costs of climate protection via renewable electricity will be higher in the run-up to 2050.

Challenges for policy

37. If our political leaders intend to pursue a strategy involving a wholly renewable electricity supply and implement such a strategy in a timely manner, they will need to set the course for this goal and implement the requisite measures very soon. The success of a transition from conventional to renewable energy will mainly hinge on the extent to which the infrastructures needed to compensate for grid input fluctuations can be established.

Against this backdrop, it seems to us that the government will need to pursue the following priorities in the coming years:

– Define and communicate clear policy messages. Our political leaders will need to set clear goals, and in so doing render transparent for the general public the inherent conflict between base load and renewable electricity systems, and the consequent need for decisions at the system level. Clear and dependable decisions on the part of our leaders will also promote the establishment of stable conditions for investment planning.

– Elaboration of an integrated transition program. A national energy program should combine a roadmap for the phase-out of conventional power plants with a coherent plan for the consequent expansion of renewable energy and of the requisite grid and storage capacity. In our view, neither a pronounced service life extension for nuclear power plants nor building new coal fired power plants apart from those that are currently under construction would be compatible with the transition to a wholly renewable electricity supply since the operation of conventional power plants would become problematic from both an economic and technical standpoint as the proportional use of renewable energy rises.

– Fostering public debate and support among the general public. It is necessary to gain broad public support for the measures necessary for transitioning to a wholly renewable electricity supply, particularly when it comes to expanding renewable energy capacity and the transmission grid. The political will to implement the necessary measures must go hand in hand with a willingness to communicate on a broad basis with the general public and foster public debate, so that the transition to a wholly renewable electricity supply can be positioned as a project that will benefit society as a whole and so that the necessary public support can be gained in this regard.

– Resolving the relevant legal issues. The legal issues entailed by transitioning to a wholly renewable electricity supply will have to be discussed and resolved in a timely manner at both the national and European level, and any necessary statutory changes will have to be effected.

– Expansion of renewable energy capacity. The capacity to generate electricity using renewables, notably via offshore wind farms, should be rapidly expanded in the coming years.

– German transmission lines. Expanding the scope of German transmission lines between new renewable energy capacity, particularly offshore wind farms, and demand centers in central and southern Germany should be prioritized. This expansion can be achieved notably via strategic point to point connections.

– German-Scandinavian energy cooperation. The political groundwork should be laid for an energy cooperation between Germany and Norway, and possibly other Scandinavian countries. To this end, installing the transmission lines necessary for the use of Scandinavian pump storage system capacity for the storage of Germany's surplus renewable electricity should be prioritized.

– Storage technology development. Improvement of compressed air energy storage technology should be accompanied by optimization of Germany's electricity storage capacity. To this end, development of technologies that allow for waste heat recovery, as well as quantification of the available potential via studies of the relevant geological formations should be a priority research and development goal. Other storage solutions such as the possibility of storing energy as methane produced using renewable electricity (see section 4.3) should also be explored.

About the forthcoming Special Report

38. The present Statement is essentially an excerpt from our Special Report scheduled for the end of 2010, which will address the legal, economic and political issues that are relevant for the transition to a wholly renewable electricity supply. The Special Report will mainly focus on the political and statutory challenges entailed by such a transition at both the national and European level.

It will first discuss the political and legal challenges for a transformation at the national level within an EU context. We will also discuss the restrictions and opportunities entailed by the new EU separation of powers in the energy and environmental policy sphere in light of the Lisbon treaty. Against this backdrop, the report will propose approaches to implementing the transition to a wholly renewable electricity supply.

To this end, we will begin by discussing the following: the interplay between European emissions trading and other instruments such as Germany's Renewable Energy Act (Erneuerbare-Energien-Gesetz); and whether additional long term instruments apart from emissions trading are needed for renewable energy and the shape such instruments would take. We will then go on to discuss ways to expedite the process of expanding transmission and storage capacity at the domestic and European levels, and how long term planning could be carried out in this regard. Here, economic incentives as well as statutory planning, authorization, and nature conservation considerations will come into play, whereby measures aimed at gaining public acceptance of the requisite programs will be of special importance. As investments in a reliable, affordable and future oriented electricity supply, energy saving and energy efficiency measures are particularly significant, our final report will contain further recommendations on such matters.

Bibliography

Section 1

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Key to abbreviations

AA-CAES	Advanced Adiabatic Compressed air energy storage (CAES)
BEE	Bundesverband Erneuerbare Energien
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit
CAES	Compressed air energy storage (CAES)
CCS	Carbon Capture and Storage
CSP	Concentrated Solar Power
DE	Germany
DK	Denmark
DLR	Deutsches Zentrum für Luft- und Raumfahrt (German Aerospace Centre)
Fraunhofer IWES	Fraunhofer-Institut für Windenergie und Energiesystemtechnik
GW	Gigawatt
HVDC	High Voltage Direct Current
IER Stuttgart	Institut für Energiewirtschaft und Rationelle Energieanwendung der Universität Stuttgart
IPCC	Intergovernmental Panel on Climate Change
NO	Norway
RPM	Renewable Power Methane
SRU	Sachverständigenrat für Umweltfragen (German Advisory Council on the Environment)
TW	Terawatt
VSC	Voltage Source Converter

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