Chapter 6
Renewable Energy Sources as the Cornerstone of the German Energiewende

Jonas Egerer, Pao-Yu Oei, and Casimir Lorenz

> *"I'd put my money on the sun and solar energy. What a source of power!I hope we don't have to wait till oil and coal run out before we tackle that."*
> *Thomas Edison (late nineteenth century) (Quoted from James D. Newton (1987):* Uncommon Friends: Life with Thomas Edison, Henry Ford, Harvey Firestone, Alexis Carrel, & Charles Lindbergh. San Diego: Harcourt Brace Jovanovich).

6.1 Introduction

At least since the 1980 study on the energiewende by Krause et al. (1980), renewable energies have been considered a viable alternative in Germany to conventional fossil fuels, and renewable energy technologies were seen as a "soft path" towards a more sustainable energy system. However, the energiewende of the 1980s focused solely on phasing out mineral oil and nuclear power and granting a stronger role to solar energy and energy efficiency, while maintaining a relatively high level of coal-based power generation. This perception has changed, and today there is a broad consensus on renewables being the very core of the energy mix. In fact, the German government's Energy Concept for 2050 declared the development of renewables as its

J. Egerer (✉)
Friedrich-Alexander-Universität Erlangen-Nürnberg, Erlangen, Germany
e-mail: jonas.egerer@fau.de

P.-Y. Oei
Junior Research Group "CoalExit", Berlin, Germany

TU Berlin, Berlin, Germany

DIW Berlin, Berlin, Germany

C. Lorenz
Aurora Energy Research, Berlin, Germany

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number one energy priority.[1] The share of renewables in primary energy consumption was to rise to above 60% by 2050 (2020: 18%, 2030: 30%, 2040: 45%) and targets for the share of renewables in electricity consumption were set even higher: at least 80% by 2050 (2020: 35%, 2030: 50%, 2040: 65%) (BMWi and BMU 2010). These political objectives were formulated in detail in the law on renewable energies.[2] Renewables have thus become a cornerstone of the current energiewende.

This chapter discusses specific features of the German path toward a renewables-based electricity system and some challenges it is facing along the way. It also reports on the implications of a renewables-based electricity system for price formation and interrelations with conventional power plants. The next section recalls the development of renewables in Germany over the last 25 years from a niche source following the first feed-in law of 1990 to what has become Germany's number one electricity source since 2014, contributing over one third of the total supply and leaving lignite, coal, natural gas, and nuclear behind. Section 6.2 also sketches out government plans to reach its ambitious targets and the debate between the three main producers: solar, onshore wind, and offshore wind (plus to a certain extent bioenergy); while the renewable objectives for 2030 have already been clearly defined, opinions differ as to how to reach the 2050 objectives. We also survey the employment impacts of renewables. In Sect. 6.3, we argue that a renewables-based electricity system works very differently than the previous conventional system, for example, with respect to price formation, the dominant weight of fixed costs, the disappearing wedge between "peak" and "base" load, and the increasing role of flexibility. Section 6.4 takes a look at the issue of costs in the renewables transformation of the energy system, both from an aggregate perspective and from the perspective of individual technologies. The section also compares the costs of renewables with conventional generation (coal and nuclear), taking a public economics perspective, considering, for instance, the external (social) costs. We find that the renewables-based energiewende is welfare-enhancing compared to the high social costs of the previous fossil and nuclear-based energy system. Section 6.5 concludes.

6.2 Renewables as the Core of the Electricity System

6.2.1 1990–2015: From a Niche Player to the Main Electricity Supplier

As reported in Chap. 2, Germany introduced the first legal initiative to develop renewable energies in 1990 following similar activities at the European level. The law on feeding in electricity into the grid (*Stromeinspeisungsgesetz*, StrEG) of

[1] "Renewable energies as a cornerstone of future energy supply" (BMWi and BMU 2010, 7).

[2] Introductory paragraphs 1 and 2 of the EEG 2005; according to the Energy law (EnWG 2005), the share of renewables should be "continuously rising" (§ 1).

December 7, 1990, provided for fixed feed-in tariffs (FiTs) to integrate renewable sources, at the time mainly small local hydropower, into the energy system. In a time of purely monopolistic concession owners, the law obliged utilities to compensate producers of renewables and then to pass these costs on to consumers in the final price. A cap of 5% was set for renewables, and the law included the possibility of an exemption for utilities that were particularly affected by the feed-in of renewables.

From 1990 until today, the legislation on renewables has been spread among a number of specific laws, and has not yet been integrated into the more general energy law. One might explain this sector-specificity by the strong lobbying power that proponents of renewable energies had since the first specific legislation was proposed, and they have resisted any integration of this legislation into the more general energy law to this day. In fact, between 1998 and 2014, the responsibility for policies on renewables was with the Ministry of Environment, which worked to some extent in competition with the Energy Department of the Economics Ministry, traditionally more inclined towards conventional energies. However, the sector-specific legislation even survived the merger of the two departments into the Federal Ministry for Economic Affairs and Energy in 2014.

Major reforms of the renewables legislation took place in the EEG 2000,[3] thanks to a red-green initiative pushed by Hans-Joachim Fell (Greens) and Herrmann Scheer (SPD). Subsequently, legislation was extended by the EEG 2004,[4] the EEG 2009,[5] the EEG 2012,[6] the EEG 2014,[7] and the EEG 2017.[8] The EEG 2000 banned the 5% cap and provided for a substantial increase of the use of renewable energies (to 15% by 2015), in order to attract private capital into the sector and allow economies of scale. The 2004 revision of the law adapted the feed-in tariffs and introduced particularly favorable conditions for bioenergy. Whereas all previous laws focused on a fixed feed-in tariff, the EEG 2009 contained the first provision for the direct marketing of renewables by producers (*Direktvermarktung*). The EEG 2012 included specific provisions for offshore wind parks and for geothermal energy, a source that has remained marginal until today.

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[3]Gesetz für den Vorrang Erneuerbarer Energien, March 29, 2000 (EEG 2000), Bundesgesetzblatt 2000, 13, p. 305.

[4]Gesetz für den Vorrang Erneuerbarer Energien, July 21, 2004 (EEG 2004), Bundesgesetzblatt 2004, p. 1918.

[5]Gesetz zur Neuregelung des Rechts der Erneuerbaren Energien im Strombereich und zur Änderung damit zusammenhängender Vorschriften, October 25, 2008 (EEG 2009), Bundesgesetzblatt 2008, 49, p. 2074.

[6]Gesetz zur Neuregelung des Rechtsrahmens für die Förderung der Stromerzeugung aus erneuerbaren Energien, July 28, 2011 (EEG 2012), Bundesgesetzblatt 2011, 42, p. 1634, amended by the law of August 17, 2012, Bundesgesetzblatt 2012, 38, p. 1754.

[7]Gesetz zur grundlegenden Reform des Erneuerbare-Energien-Gesetzes und zur Änderung weiterer Bestimmungen des Energiewirtschaftsrechts, July 21, 2014 (EEG 2014), Bundesgesetzblatt 2014, Part I, 2014, 33, p. 1066.

[8]Gesetz zur Einführung von Ausschreibungen für Strom aus erneuerbaren Energien und zu weiteren Änderungen des Rechts der erneuerbaren Energien, October 13, 2016 (EEG 2017), Bundesgesetzblatt 2016, 49, p. 2258.

From the EEG 2014 onwards, the European Commission took a stronger position vis-à-vis the renewables legislation in Germany (and other Member States), launching a legal debate over whether guaranteed feed-in payments were to be considered as state aid. Subsequently, the renewables laws were revised to include more “market-based” elements: the EEG 2014 started a trial period for contracting 400 MW of large photovoltaic projects with an auctions mechanism and imposed a “market premium”, that is, an uplift on the regular wholesale market price, and direct marketing by the producers of renewable energies.

With the EEG 2017, auctions replaced the feed-in tariff for wind power and large-scale photovoltaic projects (>750 kW). The annual auction budgets until 2022 cover about 2800 MW in onshore wind, 600 MW in large-scale photovoltaic systems (the annual target is 2500 MW including small solar systems), and 400 MW in technology-neutral auctions. Thereby, the auction mechanism applies regional limitations for the share of onshore wind power in the northern coastal regions and of photovoltaics in the south. The process of implementing auctions for offshore wind power is more complex and still ongoing for several years due to the specific characteristics of offshore projects. In general, the practical implementation of “pilot auctions” has proven complex due to increased transaction costs. It is therefore unclear, whether the number of participants will remain high and auctioning is really an appropriate way forward for low-cost renewables supply in the longer term. In 2017–2018, auctions on onshore wind and photovoltaic were oversubscribed several times due to a large project pipeline. This has resulted, so far, in very competitive bids for onshore wind and in particular for large-scale photovoltaic. In fact, the first technology-neutral auction has contracted only photovoltaic projects, bidding lower prices than onshore wind projects.

The institutional framework in Germany has been effective in pushing renewables to become a major source of electricity. In fact, it has led to a boom in renewable electricity, particularly from wind but also to a lesser degree from solar installations and bioenergy. Between 1990 and 2017, the share of renewables in gross electricity production increased from 3.6% to 33.3%, the number one source of electricity, ahead of lignite (22.5%), hard coal (14.1%), natural gas (13.2%), and nuclear energy (11.7%). In absolute terms, production has risen from 20 TWh (mostly hydropower) to 218 TWh.[9]

Figure 6.1 provides an account of the growth of renewables during this period: onshore wind clearly took the pole position from hydropower in the early 2000s, whereas solar power has been showing the highest absolute growth rates for some years since the late 2000s. Still, as large-scale photovoltaic in Germany has become cost competitive to wind power, it might see a comeback in the next years with higher growth rates than currently predicted. Offshore wind has growing numbers

[9]Source: Arbeitsgemeinschaft Energiebilanzen (AGEB). 2018. “Bruttostromerzeugung in Deutschland ab 1990 nach Energieträgern.” Arbeitsgemeinschaft Energiebilanzen e.V. February 2018. In parallel, a 2009 law on heat from renewables aimed at a share of 14% of renewables in energy consumption for heat (space heating and cooling, process heat, warm water).

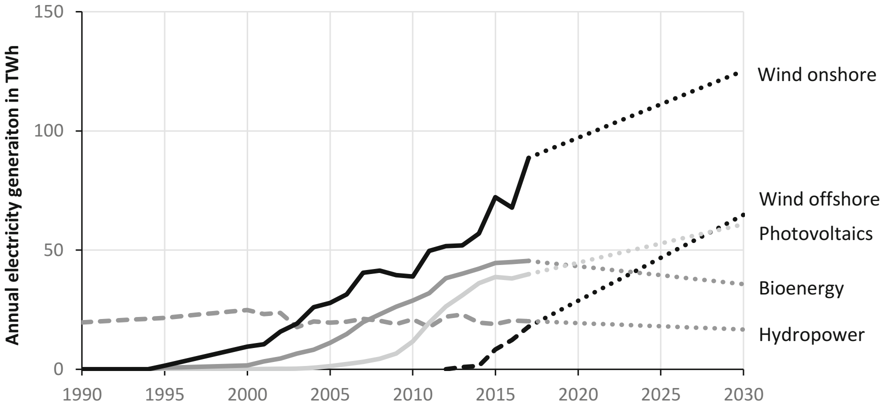

Fig. 6.1 Electricity production from renewable sources (1990–2017) and projection until 2030. Source: Own depiction based on AGEB (2018) and BNetzA (2017) (AGEB. 2018. "Bruttostromerzeugung in Deutschland ab 1990 nach Energieträgern." Arbeitsgemeinschaft Energiebilanzen e.V. February 2018; BNetzA. 2017. "Bestätigung des Netzentwicklungsplans Strom für das Zieljahr 2030." Bonn, Germany)

since 2014, but its future role is still unclear and will depend upon whether the significant cost disadvantage can be reduced. The projections in Fig. 6.1 reflect the main scenario of the German Grid Development Plan[10] which reaches a renewable share of about 55% in electricity generation for the year 2030.

6.2.2 Significant Employment Effects

In macroeconomic terms, too, renewables have grown from a niche segment to center stage of the German energy sector. This is particularly the case for employment, where renewables have outpaced the traditional sectors by far. In the mid-2010s, about 300,000 direct and indirect jobs had been created in the different segments of renewables. Figure 6.2 shows, in comparing the employment effects of renewable energies, that Germany still outweighs other European countries with most jobs being in the field of wind power and bioenergy. The overall number of renewable jobs in Germany has been somewhat higher around 2010, before the photovoltaic business declined and related jobs decreased from over 100,000 to 27,000 in 2016. On the second place follows Italy (180,000), followed by France and Spain (140,000), and the United Kingdom (110,000). The distribution of jobs also differs among the countries, according to the type of renewable energies used. Whereas most jobs in Italy, France, and Spain relate to bioenergy and heat pumps,

[10]BNetzA. 2017. "Bestätigung des Netzentwicklungsplans Strom für das Zieljahr 2030." Bonn, Germany.

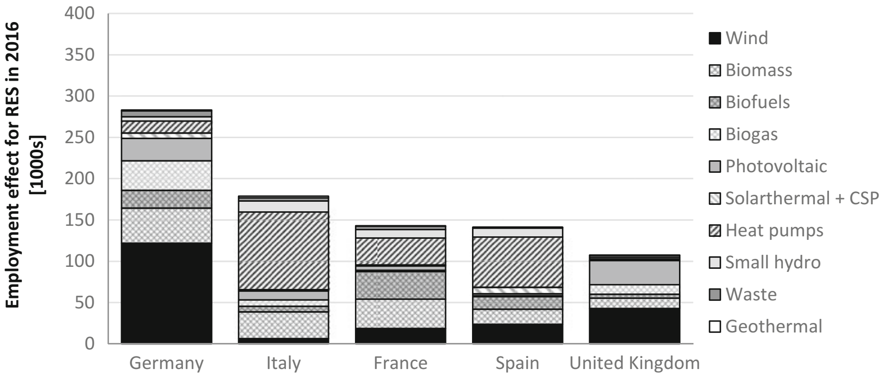

Fig. 6.2 Employment distribution for renewable energies in selected European countries (2016). Source: EurObserv'ER 2017 (2017) [EurObserv'ER. 2017. "The State of Renewable Energies in Europe." 17th EurObserv'ER Report. Paris, France: Observ'ER (FR), ECN (NL), RENAC (DE), Frankfurt School of Finance and Management (DE), Fraunhofer ISI (DE) and Statistics Netherlands (NL)]

the United Kingdom doubled its renewable jobs mainly in wind power and photovoltaics between 2012 and 2016.

The regional distribution of the employment effects within Germany follows mainly the availability of renewable resources. Figure 6.3 shows the distribution of jobs in renewable energy sources (RES) to the federal states of Germany, and its distribution by subsector: jobs in the wind industry focus on northern Germany, solar has become more important in central and southern Germany, and jobs in bioenergy are well distributed and correlated to the size of federal states. Fewer jobs exist in hydro and geothermal energy, most of which are in the South. Estimations on the net employment effect for Germany, including all positive and negative factors, predict the highest rise in employment in the construction sector, where job growth clearly outweighs the job losses in the mining and service sectors. In a study by Dehnen et al. (2015), the authors estimate the future annual net effect up to 2020 to be on average 18,000 jobs.[11]

The broad regional dispersion of employment in the renewables sector (with the exception of the city-states Berlin, Bremen, and Hamburg, which have less space per capita than the other federal states) is also an advantage, when compared with the local clustering of the former, fossil-nuclear energy system. This becomes particularly evident when comparing the employment of renewables with those of the lignite and nuclear sector, which is highly concentrated in a small number of regions. The shift from conventional to renewable capacities, therefore, has different positive and negative effects on the various regions. Both past and remaining jobs in these conventional sectors are mostly concentrated in the lignite mining regions of Brandenburg, NRW, and Saxony. The number of jobs in renewables, however, has

[11]Dehnen, Nicola, Anselm Mattes, and Thure Traber. 2015. "Die Beschäftigungseffekte der Energiewende." Berlin, Deutschland: DIW Econ.

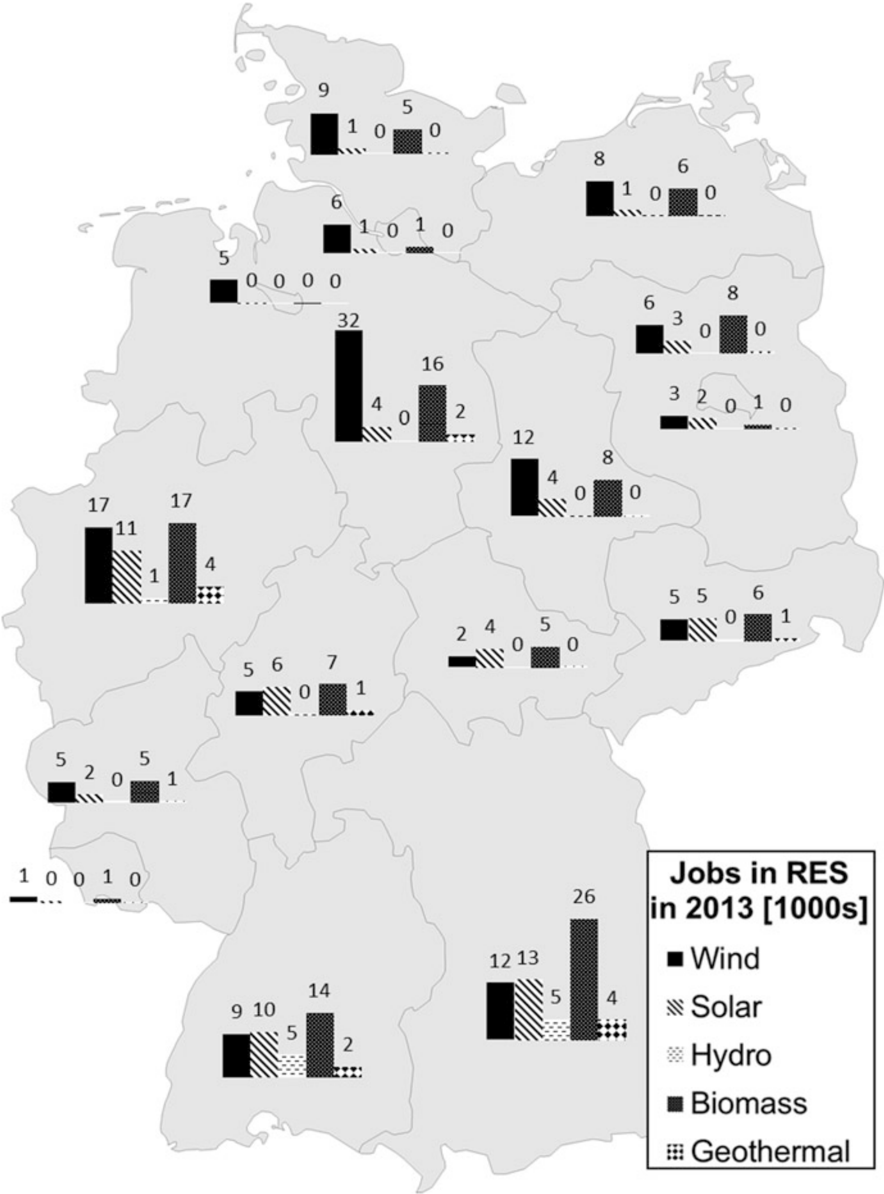

Fig. 6.3 Employment in renewable energies in Germany in 2013. Source: Own illustration based on data from Ulrich and Lehr (2014) (Ulrich, P., Lehr, U.—GWS mbH (2014): Erneuerbar beschäftigt in den Bundesländern: Bericht zur aktualisierten Abschätzung der Bruttobeschäftigung 2013 in den Bundesländern; Osnabrück)

outnumbered by now the remaining jobs in the coal business even in those states (see Chap. 3 on hard coal and lignite).

6.2.3 Rising Ambitions Towards 2030 and 2050

6.2.3.1 2030: Scenario Framework Defined by the Regulator

The future path of renewables is sketched out quite clearly for the long term with a share of at least 80% of electricity demand in 2050 and it is broken down in quite some details for the next 10–15 years. In fact, the renewable goals have been converted into the scenario frameworks, defined by the transmission system operators (TSOs) and confirmed by the national regulator (BNetzA, Bundesnetzagentur 2017)[12]: in accordance with the goals set out in the Energy Concept for 2050, it envisions a share of renewables of at least 50% by 2030, and of 55–60% by 2035.[13] This phase is still considered relatively safe from a system perspective, since there remains a mix of renewables and conventional power plants (coal, lignite, and natural gas). The scenarios assume that wind power (onshore and offshore) will provide most additional renewable generation compared to slow growth for photovoltaics and even decreasing numbers in electricity generation from bioenergy. The numbers in the main scenario "B 2030" in Fig. 6.4 predict an increase of renewable capacity from about 104 GW in 2016 to 153 GW in 2030. Even in the most pessimistic scenario "A 2030", renewables reach 50% of overall electricity generation in 2030 while scenario "C 2030" predicts a 60% share (Fig. 6.5). After phasing out nuclear in 2022, lignite, hard coal, and gas provide the residual demand not covered by renewable production (see Sect. 6.3.4). The price assumptions in the modelling exercise for the network development plan (on CO_2 emission certificates, hard coal, and natural gas) assume a world where variable costs remain the lowest (and utilization highest) for lignite power plants, followed by hard coal, and natural gas which also gains some share in generation from utilization of gas-fired combined heat-and-power plants.

The example of wind power, with 74 GW in scenario "B 2030", of which 59 GW is expected to be onshore and 15 GW offshore, shows the dynamic of the renewable transformation process. Already at the end of 2017, total installed onshore wind capacity in Germany broke the 50 GW mark, following 4 years with an unforeseen 4.6 GW in average annual capacity additions. Consequently, the preliminary

[12]BNetzA. 2017. "Bestätigung des Netzentwicklungsplans Strom für das Zieljahr 2030." Bonn, Germany.

[13]The scenario framework of the four TSOs, produced every 1–2 years in the context of the network development plan, provides a firm corridor for future developments. The exercise produces an outlook with three 2030 scenarios and one 2035 scenario calibrated to governmental objectives that establishes a "roadmap" not only for the subsequent network development plan but also for all of the stakeholders involved in the process.

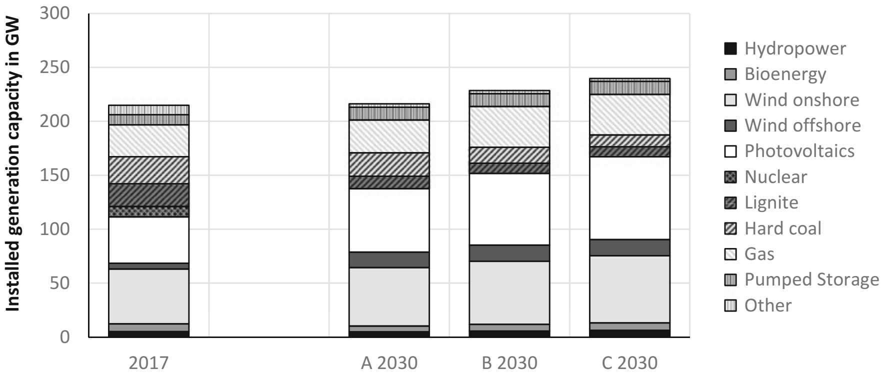

Fig. 6.4 Generation capacity in Germany (2017 and official scenarios for 2030). Source: Scenario framework in the Grid Development Plan (BNetzA 2017)

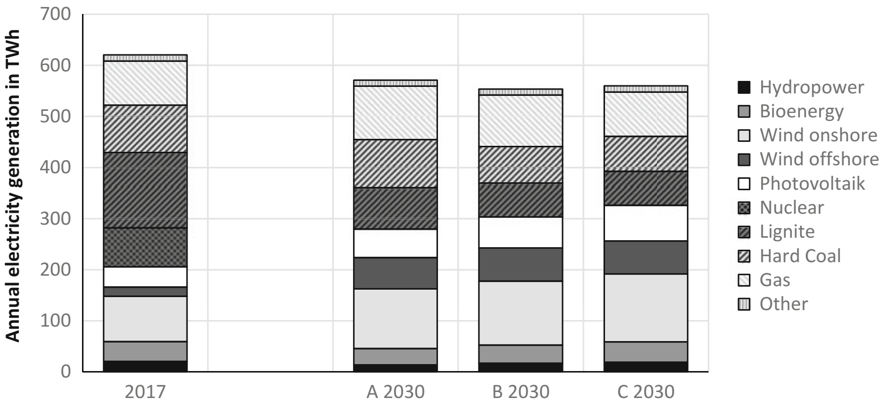

Fig. 6.5 Electricity generation in Germany (2017 and official scenarios for 2030). Source: Scenario framework in the Grid Development Plan (BNetzA 2017)

scenario framework has been adjusted in the 2019 version of the network development plan, increasing mainly onshore wind capacity (+11 GW) and some photovoltaics (+2 GW) for 2030.

6.2.3.2 2050: Pathway Beyond 80% Renewable Electricity

By contrast, the path from 2030 to 2050, the date by which renewables have to cover at least an 80% share of demand, is more uncertain. Higher renewable share challenges the role of conventional power plants. Due to the ongoing decline in costs for renewable electricity generation, onshore wind and large-scale photovoltaic have become competitive to new fossil-fired power plants in Germany. On the contrary, fossil-fired power plants see raising generation costs by lower utilization

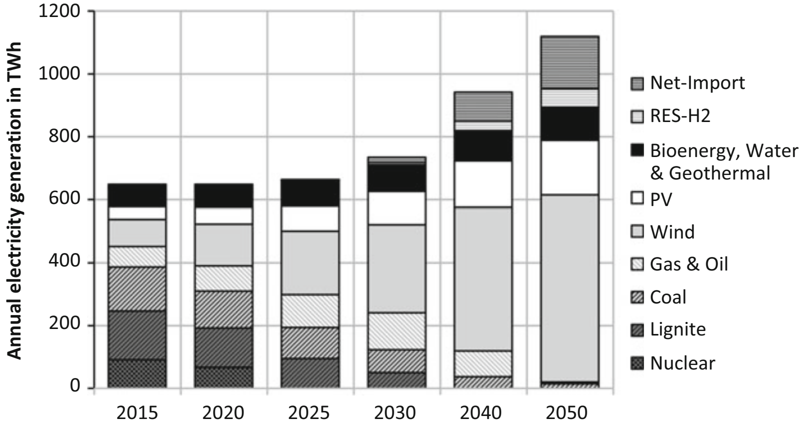

Fig. 6.6 Pathway towards a low-carbon energy system in Germany in 2050. Source: Nitsch (2016, 33)

rates and higher prices for CO_2 emission certificates in a carbon-constrained world. Between 2030 and 2050, large fossil-fired power plants, serving as "base load" capacities, will widely have been phased out and the role of storage and other flexibility options will have to increase. The scenarios of the grid development plan describe the first phase of this transformation towards sector coupling with assumptions on heat pumps, e-mobility, power-to-gas, power-to-heat, small battery storages for photovoltaic systems, and demand-side management of large electricity consumers. Several pathways have been sketched out for that future, and they all converge that, while the technology mix cannot be predicted with certainty, there is no doubt about the technical feasibility of scenarios reaching the target of 80% of renewables or even close to 100%, by 2050.[14]

The German government has regularly relied on a team of economists and engineers to produce bi-annual scenarios for the electricity system in 2050, called "lead study" (*Leitstudie*). Figure 6.6 shows a scenario leading to 2050, designed by the main author of the team, (Nitsch 2016, 21), that is in line with the climate targets for 2050. The scenario calculations show that fossil-fuel generation is largely phased out after 2030, and the future system largely relies on wind, photovoltaic, bioenergy, and some hydrogen. The scenario foresees a significant increase in electricity consumption, from currently 600 TWh to over 1100 TWh, due to the large-scale electrification in the transport and heating sectors. Imports of renewables from other countries might also play a significant role, but rather in the medium- or long-run.

[14]For example, the vision of a 100% RES-based system sketched out by SRU (2011) relies on extensive exchanges with the neighbouring countries, mainly Scandinavia.

6.3 A New Era for the Electricity System

Clearly the focus on renewable energies in the electricity system constitutes a major break with the conventional, fossil-nuclear system. At the beginning of the energiewende, the fundamental character of this transformation was not widely understood, and some observer still consider it as a short-term phenomenon, believing that conventional power will remain the pillar of the system, requiring only marginal modifications to the regulatory framework; this vision has been expressed, for instance, in the European Roadmaps of the European Commission (EC 2011). However, when considering the technical, economic, and institutional implications of a system based on a very high share of renewables, such as Denmark or Germany, there are clear indications of disruption with the old system, in which many of the traditional features of the past are modified, such as the "energy-only market", the differentiation into "base" load and "peak" load, etc. This subsection describes some of the elements of this disruption, and we also report on a similar line of argumentation presented by the think tank Agora Energiewende, summarized in Box 6.1: "12 Insights on Germany's energiewende".

6.3.1 The Merit Order Effect

The rise of variable renewables from a small niche market to the center stage will bring with it significant modifications to the electricity system. While some of the effects are still ongoing and many other changes will affect the functioning of the German and the European electricity markets, it is already evident that the conventional electricity market is no longer working as it used to, and business models for energy companies are undergoing substantial change as well. An important change has been introduced with the cost structure of the variable renewable technologies wind and solar: both are capital-intensive but have negligible incremental costs in contrast to classical conventional energy sources, which feature relatively high incremental costs and comparable low capital costs.

An increasing supply of renewable electricity at almost zero marginal costs changes the hourly wholesale electricity market price by shifting the supply curve to the right, in particular in hours with high availability of renewable generation (see Fig. 6.7). In a fully competitive market setting, the marginal power plant that sets the hourly price (intersection between supply and demand curve) will have lower costs than before the energiewende. The difference between the two prices is called the "merit order effect", which reduces profits of power plants in the short-term and in the medium-term requires adjustments of the power plant portfolio. Assuming that the slope of marginal generation costs increases with supply, the merit order effect will be stronger in hours of high demand (peak) and weaker in hours with low demand (off-peak). The strength of the effect depends on whether demand is assumed to be elastic or inelastic and the level of time disaggregation (number of

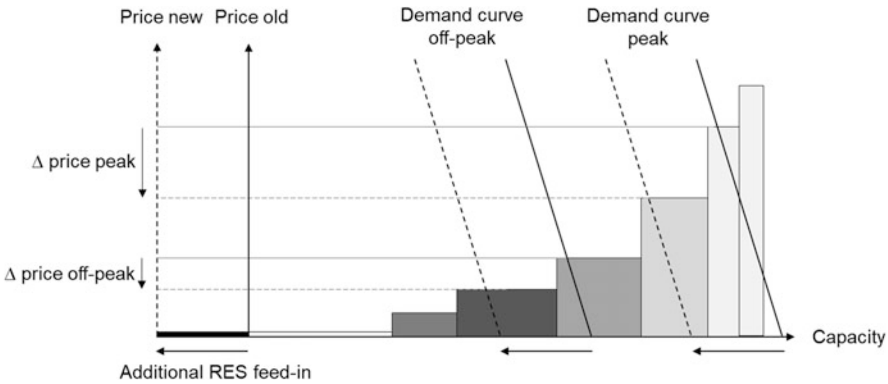

Fig. 6.7 The merit order effect in off-peak and peak demand hours. Source: own depiction

time slices): the higher the level of aggregation (averaging), the lower the merit order effect will be.

Different studies and papers have produced different estimates of the merit order effect attributable to renewable electricity. Table 6.1 shows a solution of ex-post estimations of the merit order effect in Germany in the years 2006–2011. While there is some variance due to different methodological approaches and data used, the merit order effect appears to be significant, at an average of ~0.7 cent/kWh; this corresponds to 15% of the wholesale electricity price (averaged over the entire period).[15]

6.3.2 *No More Distinction Between "Peak Load" and "Base Load"*

The conventional electricity system has long relied on a clear distinction between "peak load," defined by high prices and eventual price spikes, and a "base load," with relatively modest prices. Power plants have all been calibrated to this structure, consisting of base load plants, such as lignite and nuclear, "mid load" by hard coal and combined cycle gas turbines (covering higher demand during the day), and "peakers," such as gas turbines. Figure 6.8 shows the development of hourly average electricity prices in Germany, in 2011 and 2014, which allows the identification of different effects. Overall, spot prices significantly decreased, by almost 20 €/MWh, mainly due to the merit order effect, lower fuel prices, lower CO_2 prices, and also due to reduced demand. In addition, one also identifies the dampening effect of midday solar electricity (9–16 h), which further reduces prices, by about 4.50 €/MWh during that time. A similar, somewhat weaker effect is triggered by wind in the early evening

[15]Assuming inelastic demand, the renewable electricity has thus reduced the annual electricity bill of wholesale consumers by 3.5 billion € (500 TWh × 0.7 cents/kWh).

Table 6.1 Ex-post estimations of the merit order effect in the years 2006–2011

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Cludius et al. (2013)				−0.52	−0.72	−1.14			
Sensfuß and Ragwitz (2007)	−0.78								
Sensfuß (2011)		−0.58	−0.53	−0.6	−0.52	−0.87	−0.89		
Traber et al. (2011)									−0.32
Weigt (2009)	−0.62	−1.04	−1.3						
EWI (2012)								−0.2	−0.5
Speth and Warzecha (2012)					−0.56	−0.56			
Speth and Klein (2012)						−0.748			
Vereinigung der Bayerischen Wirtschaft e.V. (2011)	Average −0.8 ct/kWh (2006–2010)								

Source: Bundesministerium für Wirtschaft und Energie (BMWi). 2014. Zweiter Monitoring-Bericht “Energie der Zukunft”. p. 38. https://www.bmwi.de/Redaktion/DE/Publikationen/Energie/zweiter-monitoring-bericht-energie-der-zukunft.html

hours, when a lot of wind blows. With a rising share of renewables, and higher flexibility on the demand side, but also on the supply side, the traditional differentiation between “peak” and “off-peak” prices is strongly reduced.

Conceptually, the previous concept of “base load” disappears in a renewables-based electricity system. This has significant economic consequences as conventional power plants are unable to cover their fixed costs through high inframarginal rents obtained in “peak” hours. It has also consequences for the cost coverage of younger (recently built) power plants and for decisions on future investments, which become less attractive; it also affects the additional rents to be gained from old, amortized power plants, and the decision when to retire them.

6.3.3 Wholesale Electricity Prices in Germany

While the “merit order effect” has certainly contributed to a reduction in the overall wholesale price, it is not the only factor driving the decline in electricity prices observed over the past years. Figure 6.9 shows the general trend of the electricity wholesale price at the EEX-Energy Exchange, by annual averages, from 2007 to

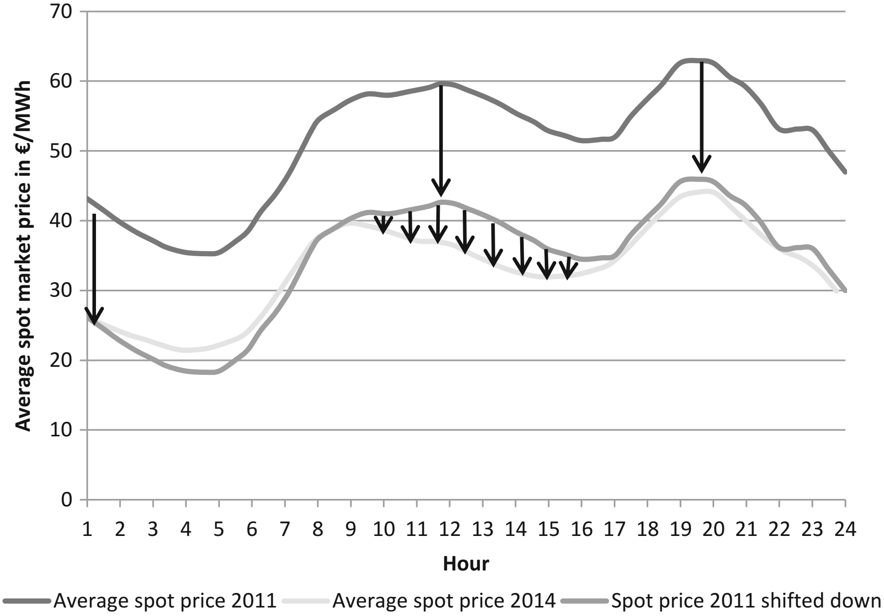

Fig. 6.8 The disappearing difference between "peak" load and "base" load in a renewables dominated system. Source: Own depiction, based on BDEW (2015) (BDEW—Bundesverband der Energie- und Wasserwirtschaft e.V.—BDEW. 2015. Erneuerbare Energien und das EEG: Zahlen, Fakten, Grafiken; Energie-Info, Anlagen, installierte Leistung, Stromerzeugung, EEG—Auszahlungen , Marktintegration der Erneu erbaren Energien und regionale Verteilung der EEG—induzierten Zahlungsströme, Berlin)

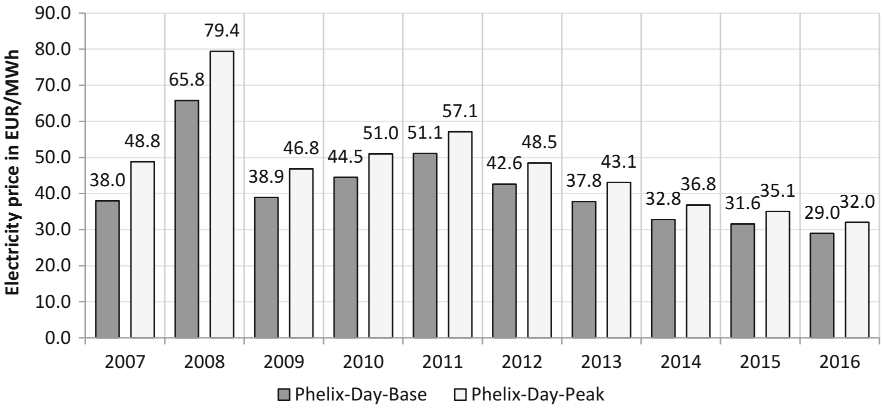

Fig. 6.9 Average electricity wholesale price in Germany (2007–2016). Source: BNetzA (2015, 2017) (BNetzA. 2015. "Monitoringbericht 2015." Bonn, Germany; BNetzA. 2017. "Monitoringbericht 2017." Bonn, Germany)

2016.[16] Apart from the price peak in 2008, driven by high coal and natural gas prices, the level has remained surprisingly stable, hovering around 50 €/MWh up to 2011. Surprisingly, the nuclear moratorium on seven plants in Germany in March 2011 did not have a lasting effect on electricity prices. In fact, after the first nuclear phase out decision in 2001, the large utilities decided to invest in eight new hard coal power plants, adding 6.2 GW in new generation capacity after 2012. All in all, one observes a general trend of decreasing wholesale prices since the beginning of the energiewende, as well as converging day-peak and day-base prices. The price decline indicates, that in many hours with some renewable generation, the price setting marginal generator becomes lignite or the most efficient hard coal generators. In result, the low wholesale prices have caused major disturbances for short-term operation and high write offs for new investment projects by the incumbent energy industry.

6.3.4 Simulations of a Renewable System in Germany in 2030

The effects of renewables on the energy system also modify the way that conventional sources are dispatched, both in the yearly aggregate and in an hourly cycle. An analysis of 15-min load, wind, and photovoltaic data (published by ENTSO-E and the TSOs) can be used to demonstrate the effects of a dominant share of electricity from renewables. Figure 6.10 shows the “residual load”, i.e. the part of load not covered by renewable electricity, for the years 2017 and 2030 (with projections based on the latest B 2030 scenario, cf. Sect. 6.2.3), respectively. The peak load is only modestly reduced, as the calculation does not consider demand-side flexibility and increased flexibility in generation from bioenergy; however, both the shape of the curve, and the aggregate electricity produced by conventional sources are substantially modified, as renewables enter the sector at scale. For example, total electricity provided by conventional power plants decreases by about 40%, from 415 TWh (2017) to 250 TWh (2030). Depending on CO_2 and fuel prices in 2030, one can estimate the operational hours by technology.[17] In 2030, renewables will see excess supply in about 1200 h. Assuming no other must-run generation, the remaining 9.5 GW in lignite capacity will have between 6350 and 6950 full-load hours. If combined cycle gas turbines become cheaper than firing hard coal, they might operate in 4900–6350 h, while the remaining 14.8 GW in hard coal capacity only run in 2150–4900 h. Clearly, this raises the question how these firm capacities can be financed, which we address in the next section.

[16]Since 2016, EEX prices have somewhat recovered to about 40 EUR/MWh after the mothballing and shut-down of several conventional power plants.

[17]The analysis of the residual load neglects on the one side possible trade with neighbouring countries, which might allow higher operational hours for lignite power plants. On the other side, must-run CHP generation and the variable character of wind and photovoltaics might favor more flexible conventional power plants.

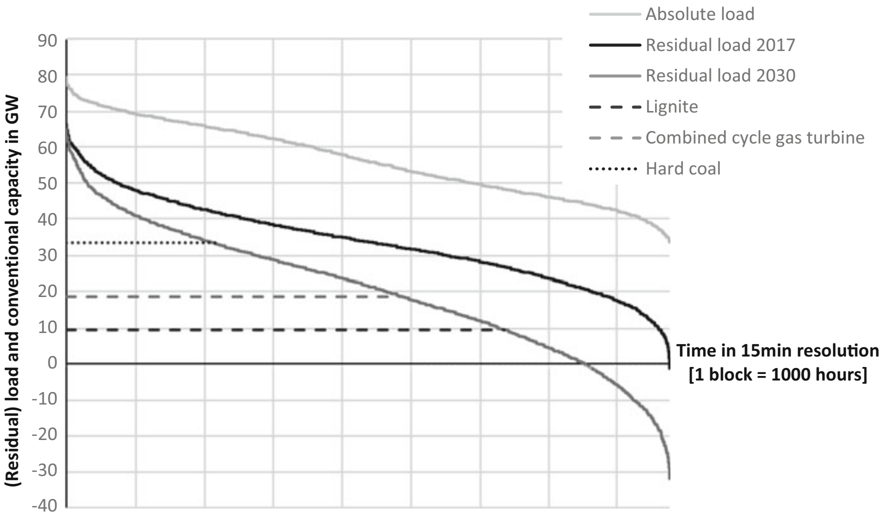

Fig. 6.10 Residual load for conventional electricity (2017 and 2030). Source: Historic TSO data and modeling results, based on scenario framework defined by BNetzA

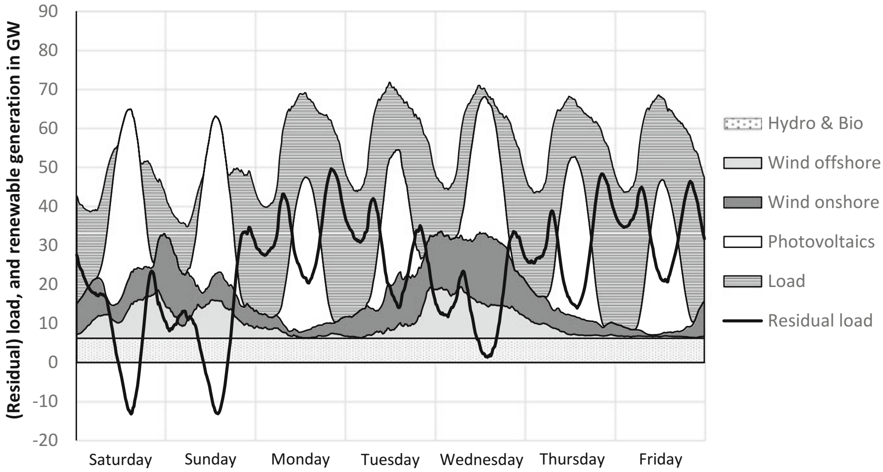

Fig. 6.11 Renewable supply and load for a solar-intensive week (week 22) in 2030. Source: Own calculation based on ENTSO-E and TSO data

Figures 6.11, 6.12, and 6.13 provide examples of the potential effect of renewables at certain specific hours of the year in Germany (based on 2017 weather data): Fig. 6.11 shows a representative week in spring (calendar week 22, month of May), with significant hours of solar penetration. One observes a morning and evening peak in residual load as photovoltaic generation cuts into the peak demand at noon

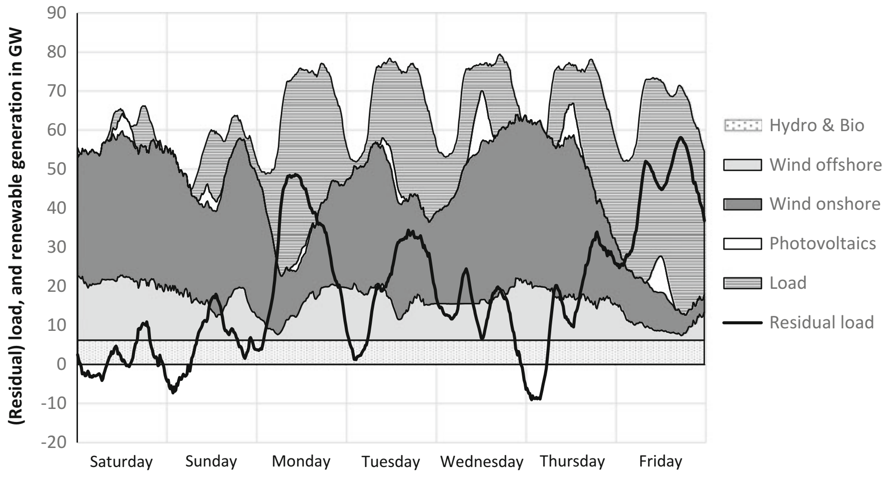

Fig. 6.12 Renewable supply and load for a wind-intensive week (week 50) in 2030. Source: Own calculation based on ENTSO-E and TSO data

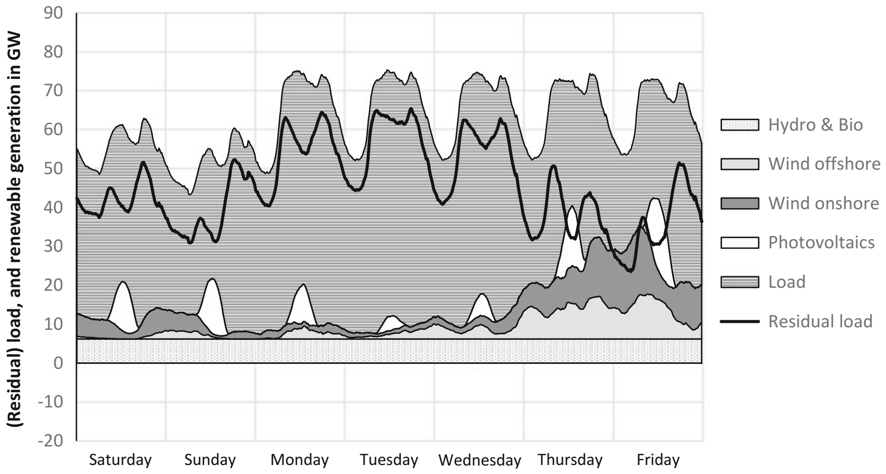

Fig. 6.13 Electricity supply and load for a week with little renewables (week 4) in 2030. Source: Own calculation based on ENTSO-E and TSO data

and steep residual load changes of almost 50 GW within few hours. Figure 6.12 depicts a similar situation in a week with high wind (here: calendar week 50, in December): while the electricity from solar capacities is quite modest, onshore and offshore wind provide sufficient electricity to cover the entire demand during the weekend but show similar residual load ramps as photovoltaics. Figure 6.13 shows a situation where neither wind nor photovoltaics provide significant generation for several days. In this case, backup capacity is required to assure load with both natural gas and coal power plants. This leads us to the question of how these could be financed.

6.3.5 Is a New Market Design Required?

6.3.5.1 Conceptual Issues . . .

The massive introduction of capital-intensive renewables changes the way prices are set, and suggests that the conventional, "energy-only" market design may not be well suited for the new system. In fact, as in other European countries, the discussion about the design of appropriate capacity instruments in Germany is vivid and controversial. In particular, after the introduction of the energy concept for 2050 in September 2010 and the nuclear moratorium of March 2011, the German energy industry and policy makers have been engaged in intensive discussion over the advantages and disadvantages of capacity instruments to guarantee the proper functioning of the electricity sector and to ensure supply security as well as resource adequacy. On the one hand, the "carbon power push" of the 2000s led to high overcapacities and low prices in the German electricity system, making it difficult to see the need for capacity instruments. On the other hand, a relatively strong merit order effect and low wholesale electricity prices throughout the 2010s, in combination with the planned closure of nuclear power plants in the near future, lead some observers to conclude a need for capacity instruments.

The conceptual discussion about capacity instruments is broad and unlikely to lead to a consensual assessment. One approach is to find a theoretically optimal structure, e.g. welfare-optimal, that designs an „optimal" market independently of time and space. Such a discussion has emerged, e.g., between proponents of an „energy-only" market design (such as Professor Hogan from the Harvard Electricity Policy Group, HEPG) and a capacity-based market design (Cramton and Ockenfels 2011; Cramton and Stoft 2005). It was largely conducted on theoretical grounds and with an assumed objective of welfare maximization; likewise, Cramton and Ockenfels (2011) suggestion of reliability contracts abstracted from the concrete country or region under consideration. Another stream of literature insisting on the institutional aspects focusses more on the transaction costs of implementing different instruments, and combining different objective functions, e.g., supply security, consumer interests, climate impact, etc. (Beckers and Hoffrichter 2014). The main argument here is that recovering high fixed costs through random price variations implies significant risks for the investor, and thus high capital costs.

6.3.5.2 ... And a Pragmatic Solution for Germany

The German response to the challenges of new market designs was very pragmatic and politically sensible at the same time: on the one hand, several capacity instruments were introduced, quite ad-hoc, after 2011; but on the other hand, political attempts were made to contain the capacity debate to certain market segments, and to maintain the "energy-only" design as long as possible (see Neuhoff et al. 2013).

In reality, capacity instruments were gradually introduced into the German market, of different sized and institutional design:

- As early as summer 2011, the German regulator (*Bundesnetzagentur*, BNetzA) put in place a capacity instrument (without calling it such): It was a small strategic reserve, negotiated bilaterally between the BNetzA and potential providers, focusing primarily on a balance between supply and demand in South Germany. Sometimes called a "winter reserve", this strategic reserve was calibrated to the winter peak demand, and a market design that emulated a "copperplate" in Germany, that is, an electricity system without any network congestion (see the Chap. 8 for a critical discussion of this assumption). The strategic reserve was formalized in an ordinance (*Kraftwerksreserveverordnung*) in 2012. Originally expected to expire in 2017, it was later extended to 2021.[18]
- A second capacity instrument was introduced in 2014: a full-fledged "strategic reserve". Old capacities that utilities have nominated for closure, can enter the strategic reserve, where they bid for electricity delivery in cases of particular capacity shortage; however, once they entered the strategic reserve, they are not allowed to participate in the ordinary wholesale market.[19]
- Last but not least, a very peculiar capacity instrument was later introduced to compensate some lignite power plants, the so-called "lignite reserve", in 2015 (Oei et al. 2015; SRU 2017) In fact, 2.7 GW of rather old lignite plants in East and West Germany were placed into this reserve, and obtained some fixed payments (1.6 billion € in total) for being "on reserve" for another 4 years.

The German utilities pursued no clear strategy, but increasingly moved away from the energy-only market concept, to embrace different forms of capacity instruments. In particular, after Germany's two large European neighbors, the UK and France chose to pursue a strong national strategic reserve, the mood changed and the German industry, too, demanded a comprehensive capacity instrument to assure

[18]In 2015, the reserve for the winter 2016/2017 was about 4 GW, contracted both in South Germany and in neighboring countries, mainly Austria.

[19]In 2016, the strategic reserve contained about 5 GW of capacity, plus an additional 2 GW of capacity allocated explicitly to South Germany.

system stability.[20] An alternative instrument was developed by Matthes et al. (2012), targeting a "low-carbon" capacity market, essentially a selective capacity instrument open only for flexible natural gas-fired capacity. This specific instrument became particularly popular in Southern Germany, where the general preference is for local and (relatively) clean electricity from natural gas plants rather than coal electricity "imported" mainly from North German coal power plants.

The de facto establishment of different segments of capacity markets was accompanied by an "energy-only" rhetoric by the government. In fact, the government's energy strategy of 2015 included a strong statement in favour of an energy-only market, in connection with a small strategic reserve. With hindsight, the pragmatic compromise, i.e., a sufficiently large strategic reserve but no general instruments favoring CO_2-intensive power plants, appears as appropriate for the first phase of the energiewende; in particular, it avoided a "watering can approach" for CO_2-intensive power plants. This approach may have to be revisited, though, as the energiewende enters into the next phase, in the mid-2020s, with nuclear and coal plants leaving the market, and renewables becoming not only the leading, but also by far the dominant source of supply.

Box 6.1 12 Insights on Germany's energiewende by Agora Energiewende

Along similar lines to the arguments presented in this chapter, Agora Energiewende (2013), a think-tank on technical and economic reforms of the German energy system, also argue that the functioning of a renewables-based electricity market will substantially change in the near future. They describe their findings as follows:

Insight 1: <u>It's all about wind and solar</u>

Two winners have emerged from the technology competition initiated by the German Renewable Energy Act: wind power and photovoltaics, the most cost-effective technologies with the greatest potential in the foreseeable future. All other renewable technologies are either significantly more expensive or have limited potential for further expansion (water, biomass/biogas, geothermal energy) and/or are still in the research stage (wave power, energy from osmosis processes, etc.).

Insight 2: <u>"Base-load" power plants will disappear altogether, and natural gas and coal will operate only part-time</u>

(continued)

[20]Insiders have reported that the rather liberal position favoring an energy-only market by RWE, the largest German utility, was eliminated with the decision adopted by the French Parliament ("Assemblée Nationale") on December 18, 2012, to introduce a national capacity instrument ("tradable certificates") that was originally supposed to benefit mainly the French incumbent EdF. As one of the most powerful companies within the energy industry, RWE contributed to the shift of the association toward a strong capacity instrument.

Box 6.1 (continued)

Wind and PV will form the basis of the power supply, with the rest of the power system being optimized around them; most fossil-fueled power plants will be needed only at those times when there is little sun and wind, they will run fewer hours, and thus their total production will fall: "Base load" power plants will be a thing of the past. Rapid changes in feed-in from renewables as well as forecasting uncertainties will create new requirements for both short- and long-term flexibility. Over the medium term, combined heat-and-power as well as biomass plants will need to be operated according to the demand for electricity. Demand-side management and storage contribute to maintaining system balance.

Insight 3: There's plenty of flexibility—but so far it has no value

In the future, fluctuations in wind and PV production will demand significantly greater flexibility from the power system. Technical solutions to provide sufficient flexibility readily exist today. The challenge is not about technology and control, but rather about incentives. Leveraging small-scale flexibility options at the household level by using smart meters is currently too expensive.

Insight 4: Grids are cheaper than storage facilities

Grids decrease the need for flexibility: fluctuations in generation (wind and PV) and demand are equilibrated across large distances. Grids enable access to cost-effective flexibility options in Germany and Europe. Transmission grids reduce overall system costs with relatively small investment costs. Expanding and upgrading distribution grids is also less expensive than local storage facilities. New storage technologies will only become necessary as the share of renewable energy exceeds 70%. Local PV battery systems may provide a business case for individual investors sooner because of savings in taxes and fees.

Insight 5: Securing supply in times of peak load does not cost much

At certain times (e.g., during windless days in the winter), wind and PV are not sufficient to cover peak loads, and, for this reason, controllable resources will be required in the same order of magnitude as today. Peak load can be met reliably by firm generation capacity, or be reduced through demand-side measures; almost a quarter of the demand (approx. 15–25 GW in Germany) arises in only very few hours of the year (<200). Gas turbines can meet this demand quite cheaply (35–70 million € per year per GW), controllable loads or retired power plants might be even cheaper. European cooperation reduces the cost and simplifies securing supply in times of peak loads.

Insight 6: Integration of the heat sector makes sense

The heat sector offers enormous potential for increasing system flexibility. CHP plants already provide a link between the electricity and heat sectors; in the medium term, dual-mode heating systems, capable of using either fuel or

(continued)

Box 6.1 (continued)
electricity will be deployed; over the longer term, the systems will be integrated through use of a common fuel: natural gas, biogas, or power-to-gas.

Insight 7: Today's electricity market is about trading kilowatt hours—it does not guarantee system reliability

Today's electricity market handles energy quantities (Energy-Only). The energy-only market may not provide sufficient incentives for new and existing resources to continuously ensure system reliability. The energiewende brings this issue to the forefront because power production from wind and PV will reduce the average market price of electricity and with it the operating times of fossil-fueled power stations.

Insight 8: Wind and PV cannot be refinanced through marginal-cost based markets

Wind and solar power have operating costs close to zero. Wind and PV produce electricity when the wind blows and the sun shines, regardless of electricity price. Therefore, in principle, wind and PV cannot be refinanced in a marginal-cost based market, even when their total costs are below those of coal and gas. High CO_2 prices do not fundamentally change this effect.

Insight 9: A new energiewende market is required

The future energiewende market must fulfill two functions: i/ steer the installation of capacity in order to achieve an efficient balance between demand and supply; ii/ send investment signals for renewable energy as well as for conventional facilities and make energy demand and storage (longer term) more flexible. The new market will create two sources of revenue: i/ revenue (as before) from the sale of electricity quantity (MWh) in the marginal-cost based Energy-Only Market, and ii/ revenue from a new investment market for megawatts (MW). In addition, fossil-fueled power plants, renewable energy, demand-side resources, and storage systems will compete to provide ancillary services (e.g., balancing energy). Installing a new mechanism instead of the current feed-in tariffs for renewables is only justified if it results in increased efficiency.

Insight 10: The energiewende market must actively engage the demand side

Greater demand-side flexibility is fundamental to increasing the use of wind and PV. Demand response is usually cheaper than electricity storage or supply-side options. Current regulations for grid tariffs and ancillary services often work at cross purposes with demand response, and should therefore be reformed. The new market for investments in firm capacity must be designed such that demand-side resources able to shift loads can actively participate.

Insight 11: The energiewende market must be considered in the European context

The ongoing integration of the German power system into the European system makes the energiewende simpler and more affordable because i/ the

(continued)

Box 6.1 (continued)
fluctuations of wind and PV energy production become less pronounced over a larger geographic region, ii/ firm capacity can be collectively shared, and iii/ low-cost flexibility options in Europe can be more fully utilized (e.g., energy storage resources in Scandinavia and Alpine countries). European electricity trading stabilizes market prices.

Insight 12: Efficiency: A saved kilowatt hour is the most cost-effective kilowatt hour

Energy efficiency decreases total costs; increased energy productivity enables the decoupling of economic growth from energy consumption. Every kilowatt saved means less burning of natural gas and coal and lower investments in new power plants (fossil and renewable). The challenge lies less in technology and more in creating the right incentives.

Source: Agora Energiewende (2013).

6.4 What About Costs?

One of the main points of arguments both for and against the renewables-based energiewende in Germany relates to the costs involved. Since different cost concepts are used in this debate, one can make arguments against the renewables-based energiewende ("too expensive") as well as arguments for it ("economically efficient"). In this subsection, we apply different approaches to assess the "costs" of the renewable targets. Needless to say, results differ depending on the concept of "costs" used, the observed time horizon, and the alternatives in the comparison. This subsection presents three different cost analyses: i) a short-term analysis of additional costs of renewables compared to the existing fossil-nuclear electricity system, the so-called EEG surcharge ("EEG-Umlage"); ii) a dynamic perspective on the private costs and benefits of renewables in the context of total system costs within a more and more carbon constrained world; and iii) a public economics perspective taking into account the external, environmental costs of the competing fuels.

6.4.1 Short-Term Private Costs of Renewables: The EEG Surcharge

One commonly cited measure of cost is the renewables surcharge ("EEG-Umlage") designed to pass on the additional costs of the renewables feed-in law to consumers of electricity. The surcharge is calculated as the differential costs between the feed-in payments and the spot market revenues of renewable electricity generation. Figure 6.14 shows the development of the renewables surcharge from 2003 until 2018. In the years 2010 and 2011, one can observe a steep increase following high annual

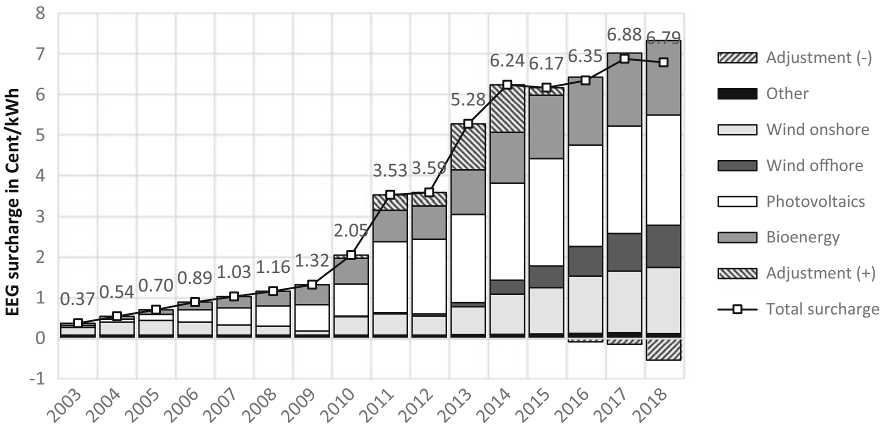

Fig. 6.14 The renewables surcharge to private households in Germany. Source: Own depiction based on 50Hertz (2018) (50Hertz. 2018. "EEG-Umlage." www.netztransparenz.de; BMWi. 2014. "Wie hat sich die EEG-Umlage über die Jahre entwickelt?" www.bmwi-energiewende.de)

investment levels in photovoltaics at a time when feed-in tariffs have still been in the range of 20–40 €cents/kWh. In 2013 and 2014, too low projection of EEG costs in previous years and resulting negative levels of the EEG account required another steep increase. Since then these additional payments could be reduced, resulting in only small increases of the EEG surcharge due to large investments in mainly onshore and offshore wind capacity.

The mid-term private cost of renewables will depend on the combined development of the renewable surcharge and the wholesale electricity price. Scenarios with stable wholesale prices result in a surcharge, which plateaus in the mid-2020s around 7.6 €cents/kWh and decrease thereafter to about 4.4 €cents/kWh in 2035 for a system with more than 60% in renewables supply (Oeko-Institut 2016). Main drivers are the phasing out of historically higher subsidies and the decreasing technology cost for new capacity investments in wind and solar. The winners of the 2017 renewable auctions for new onshore wind and large-scale photovoltaic projects receive only a guaranteed feed-in tariff of 3–5 cent/kWh. Overall, the projections for the surcharge are very sensitive to changes in the cost allocation amongst consumers and related exemptions, changes in overall electricity demand levels, and to higher wholesale prices.

From a political economy perspective, the distribution of the 24.2 billion € (2016) in renewables surcharges is very interesting. An even allocation per kWh would result in a renewable surcharge of less than 4 cent/kWh for a gross electricity demand of about 595 TWh per year in Germany. However, 4% of all German companies, mainly energy intensive industries, are to some extend exempt from these charges, i.e., paying less than 1.38 cents/kWh instead of the full fee of 6.88 cents/kWh in the year 2017. As these companies stand for more than half the industrial demand (Fig. 6.15), the majority of industrial electricity consumption pays no or a significantly lower EEG surcharge, resulting in higher surcharges for consumers that are

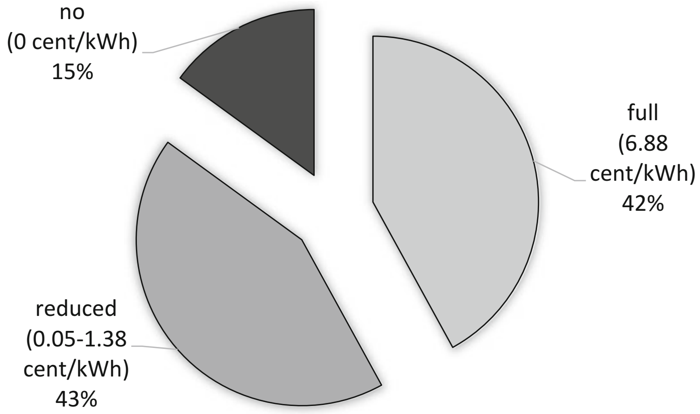

Fig. 6.15 Renewable surcharge (*EEG-Umlage*) levels for the industry in 2017. Source: BDEW (2017) (BDEW. 2017. "Erneuerbare Energien und das EEG: Zahlen, Fakten, Grafiken." Berlin, Germany: Bundesverband der Energie- und Wasserwirtschaft e.V.—BDEW)

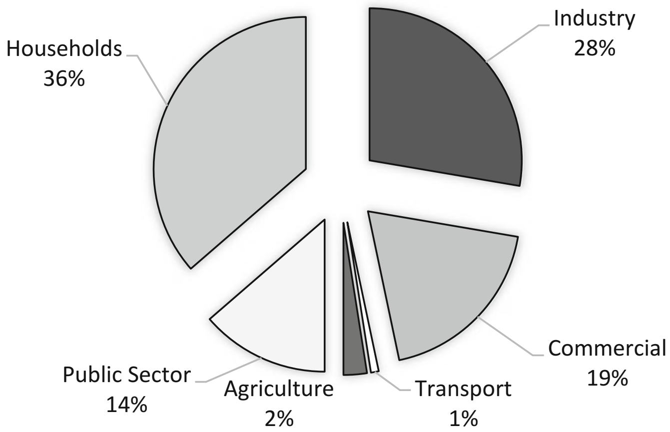

Fig. 6.16 Distribution of renewable surcharge (*EEG-Umlage*) costs to consumers in 2016. Source: BDEW (2017)

not exempt. Small household consumers contributed most (36%), compared to industry consumers (28%), the rest being distributed between the commercial sector (19%), the public sector (14%), agriculture (2%), and transportation (1%) (Fig. 6.16). Therefore, large energy intensive companies in Germany may be seen as strongest short-term beneficiaries of the energiewende, paying no or reduced renewable surcharges and one of the lowest electricity price in Western Europe because of the merit order effect.

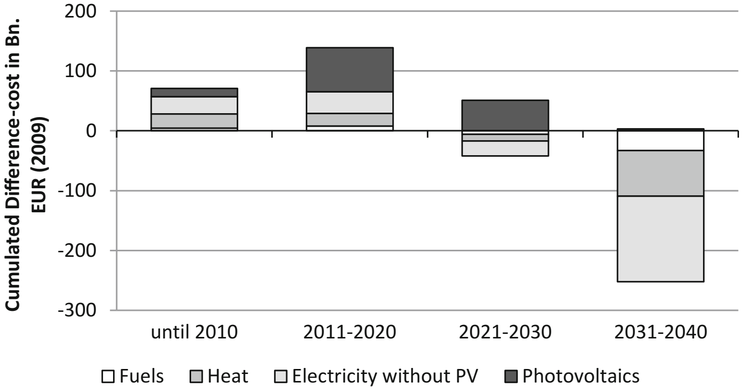

Fig. 6.17 Energy system costs of the energiewende, as compared to a conventional "business-as-usual" (BAU) case. Source: BMU (2012)

6.4.2 Dynamic Perspective on Private Costs: Renewables as a Sound Long-Term Investment

The dynamic analysis of long-term costs and benefits of the energiewende towards renewables provides another perspective, which considers future cost reductions of renewable technologies. A study (so-called *Leitstudie*) for the Ministry of Environment (BMU 2012) conducted a comparison between the cumulative renewables costs of this renewable transformation (RES scenario) relative to a benchmark, that is, to the costs incurred under a business-as-usual (BAU) framework. Figure 6.17 shows the difference between the two scenarios in terms of private production costs (i.e., excluding the social costs). Private production costs include capital costs, variable fuel costs, and costs for carbon emission certificates. While results indicate that the decade 2011–2020 of the RES scenario is particularly expensive in the electricity sector, due to the high feed-in still guaranteed to solar (for 20 years), the differences disappear in the subsequent decade (2021–2030). Payments to solar start to decrease and other renewable technologies already reduce costs, in both, the remaining electricity system and the heat sector, compared to the BAU framework. The cost difference vanishes completely in 2026, meaning that renewables start to stabilize and even decrease energy costs for consumers in the RES scenario. After 2030, the trend is fully reversed, and total energy system costs are significantly lower than in the BAU framework. In 2040, initial higher costs for the RES scenario have been fully compensated.

6.4.3 Public Economics Perspective

Yet another perspective emerges when adopting a public economics perspective, that is, when taking into account not only the private costs to the consumer, but also the social costs incurred by society through different forms of electricity provision. The simplest analysis compares the *social* costs of the three pillars of the old electricity system: nuclear, coal, and renewables. For better comparison, we discuss levelized cost of electricity (LCOE), a common measure for the cost of electricity provision per kWh. In addition to private costs, which have fixed price cost components (investment cost, lifetime, interest rate, full-load hours per year, and fixed operation & maintenance (O&M) costs) and variable price components (fuel cost and efficiency), this measure can also include additional social costs specific to the generation technology.

From the social perspective, nuclear appears to be the most expensive of all electricity sources, in particular when accounting for all types of costs. With respect to LCOE, Toke (2012) and Boccard (2014) indicate that nuclear has no cost advantage over other sources of electricity generation, in particular due to its high capital costs;[21] the capital costs of nuclear power plants have risen continuously since the 1970s, and initial investment costs for ongoing projects are likely to be in the range of 6000 €/kW.[22] In addition, significant costs incurred in R&D and the development of new reactors are all being paid by the public sector as will be the largest share of costs for disposing spent fuel which are still largely unknown. Even after six decades of nuclear energy use there are no permanent disposal sites anywhere in the world that guarantee safe storage of nuclear fuel rods for tens of thousands of years. Another important cost factor is insurance against potential major accidents. The high costs of major accidents at nuclear power plants are difficult to quantify; currently, society is bearing the majority of these costs because nuclear power plant operators are subject to very few insurance requirements. Irrespective of what form or combination of insurance forms (public, private, or a mix) proves most economically advantageous, the costs must be included in the cost calculation. The economic viability of nuclear power will also be diminished due to reduced full-load hours and higher flexibility requirements in a renewables-based electricity system and further tightening of safety regulations currently being developed at the pan-European level.[23] Depending on the assumptions, total social costs of nuclear energy range between 20 and 40 cents/kWh.

[21] Boccard (2014) concludes “the future cost of nuclear power in France to be at least 76 €/MWh and possibly 117 €/MWh.”

[22] See discussion in Hirschhausen (2017), and the survey paper by Wealer et al.(2018).

[23] After the Fukushima nuclear disaster, EU Energy Commissioner Günther Oettinger recommended mandatory stress testing of European nuclear power plants. The results pointed to the urgent need for retrofits at some plants. A draft regulation will form the basis for the binding rules on liability and compulsory inspection routines to be introduced in all countries. See European Commission, Draft proposal for a Directive amending Nuclear Safety Directive IP/13/532, June 13, 2013. Francois Lévèque (2013, Nucléarie On/Off. Paris, Dunod, p. 171) provides the most intuitive explanation of why the civil use of nuclear power cannot be considered an economical energy alternative: “Nuclear power is the child of science and the military” (“L`énergie atomique est la fille de la science et de la guerre”), own translation.

The social costs of fossil fuel based electricity includes the greenhouse gas externalities, the effects of sulphurdioxydes (SO_2), nitrogene oxides (NO_x), mercury (H_g), and groundwater contamination. Local negative externalities are fine dust particles and noise, the displacement of local populations to make way for new opencast lignite mines as well as long-term costs for later subsidence damages of underground coal mining. Estimates of the social costs of lignite, the most CO_2-intensive fuel, are in the range of 80–120 €/MWh, or about two to three times the current wholesale price of electricity (see Chap. 4). Clearly, from a social perspective, burning coal (and other fossil fuels) reduces welfare and there is no serious progress in making fossil-fired generation a component of the future energy system by reducing negative externalities. System-wide carbon capture, transport, and sequestration (CCTS), required for reducing carbon emissions, seems very unlikely and even small steps towards tighter regulation in the Industrial Emissions Directive at European level (e.g., for SO_2 and NO_x) have almost been blocked by Germany and its eastern neighbors in 2017.

Compared to nuclear and fossil fuel based electricity generation, the costs of externalities of renewable electricity generation are significantly lower (e.g., 0.2 cent/kWh for wind and 1.3 cents/kWh for photovoltaic, (Küchler and Wronski 2015). However, being less centralized and smaller than conventional power plants, they are more numerous and therefore more visible to the public. In consequence, especially onshore wind power can be exposed to regional "not in my backyard" (NIMBY) opposition. In terms of LCOE, the costs for the EEG surcharge indicate that renewables have been more costly than operation of the existing and written-off nuclear and fossil-fired power plants, when social costs are not internalized. However, already today, cost reductions in the last years allows LCOE for new onshore wind and large-scale photovoltaics to be lower than those of new nuclear or coal-fired power stations in Germany. As a result of expected cost reduction for new investments in wind and photovoltaics and increasing costs for burning fossil fuels in a carbon-constrained world with a significant price for carbon emissions, renewables are likely to replace most of fossil fuel generation in the electricity sector in Germany years before 2050.

In addition to the LCOE, a technical-economic analysis of renewables also has to take into account the costs of system security: that is, it must balance the intermittency of the renewable supply. Different approaches have been developed in the literature to calculate the costs of system integration. However, these approaches often hinge on a series of assumptions on the costs of transmission allocated to the renewables, the social costs of firm capacity, such as the use of natural gas plants as a backup, etc. However, recent technological trends have led to a situation in which the intermittency of renewables is mitigated by low-cost storage technologies and renewables are still competitive with the social costs of other generation technologies. Deutsch and Graichen (2015) calculate scenarios in which the combination of solar and storage (e.g., Lithium-Ion) costs less than 10 cents/kWh, with further cost reductions in the future; this is below the social costs of any electricity generated from fossil fuels, let alone nuclear power. Thus, from a social-welfare policy perspective, it is clear that renewable generates electricity at the lowest cost independent of the intermittency issue.

6.5 Conclusions

Variable renewable energy sources such as wind and solar are the cornerstone of the energiewende. Because of this focus, the German energiewende has become a unique case of low-carbon transformation worldwide. This chapter has provided a survey of the evolution of renewables from a niche player to the dominant market player, implying a fundamental change in the functioning of the electricity market. In general, we find that although there are new technical, legal, and economic challenges related to the large-scale use of renewables in Germany, the process is unfolding as it should, and is turning out to be less difficult than it is sometimes considered to be from an outside perspective. From the viewpoint of public economics, the focus on renewables is socially efficient since the costs are lower than the two main alternatives, coal and nuclear.

Since the first specific law on renewables in 1990, the use of renewables in Germany has grown exponentially, based mainly on onshore wind resources with contributions from bioenergy, photovoltaics, and offshore wind. Meanwhile, extensive support for photovoltaics has benefitted the global breakthrough of the most freely available of all technologies. Several updates of the law on renewables (EEG 2000, 2009, 2012) have not changed the overall approach (Morris and Pehnt 2016). Systematic reductions to tariffs have brought technical progress and cost reductions in the manufacturing industry, and industry has been flourishing as a result (Weigt and Leuthold 2010). Since 2014, electricity from renewables has been surpassing all other conventional energies in terms of market share, and expections forsee more than 50% in 2030 and beyond 80% by 2050. At present, no technical nor political obstacles can be identified that would prevent these targets from being reached.

Clearly, the focus on variable renewables has had a disruptive effect on the electricity sector and led to significant changes not only in market design and price formation but also in corporate strategies. The conventional thinking in terms of regular base load and high-price peak load no longer holds sway; the merit order effect is lowering variable prices and the clear need to rethink the financing of capital cost-intensive renewables with negligible variable costs has become patently clear. The German government has so far resisted creating a formal capacity market for conventional generation, although the instruments have been put in place that provide fixed-cost support to some selected conventional generators.

We have also revisited three different concepts to judge the costs of the focus on renewables. The renewables surcharge has risen from 1 €cent/kWh in 2009 to almost 7 €cents/kWh in 2018, to large extend driven by overpayment for solar installations; this conceptual error has since been corrected so that the surcharge will decrease over time. A more dynamic analysis of the differences between a renewables-based and a conventional system shows clear advantages of the former: the lion’s share of investment will be made in the period 2011–2030, and large benefits are to be expected beyond 2030. Last but not least, renewables clearly have an advantage over coal, and fossil fuels in general, and all the more over nuclear, in terms of "social costs"; this effect is intensified as low-cost storage technologies (such as batteries) and cross-sectoral integration of the energy system become more established, which reduces concerns about intermittency and integration costs. The public economics perspective therefore suggests that the renewables-based strategy is clearly economically efficient; that renewable energies have lower social costs than coal, burdened by carbon emissions, and nuclear energy, burdened by high capital costs, long-term costs for nuclear fuel disposal, and uninsured risks. From a dynamic perspective, the German approach is also beneficial in reducing outlays for imported energy fuels (coal, gas, and uranium). In sum, although the initial costs were high (and unevenly distributed) renewables deployment in the German energiewende has been so far a success, indicating the feasibility of this approach to low-carbon transformation.

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