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Implications of the *Energiewende* for the Power Sector

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INTRODUCTION

Emiliano López Atxurra

Chairman, Petronor

Chairman of the Trustees of the Orkestra-IVC Energy Chair

Once again, it gives me great pleasure to present this report on Germany's energy transition (*Energiewende*), directed by Dr. Eloy Álvarez Pelegry. During 2015 and 2016, the Energy Chair focused its attention on the German government's strategic energy transition project, which enjoyed broad backing from most of the country's parliamentarians. The reasons were obvious.

The implications of this seismic shift are not only local, but European in scale. The strategic rationale is not simple —as some have suggested— nor is it based on some Old World sense of superiority. On the contrary, it is born, amongst other factors, out of a world in profound transformation —and the subsequent impact that change is having on European energy security— out of the urgent need for a European Energy Union and out of the challenge for European survival which requires a technological and industrial renaissance. At the heart of the debate lies not merely the issue of carbon-dioxide emissions, but the fundamental risk that Europe may find itself technologically and industrially sidelined, leading to its inevitable decline.

The *Energiewende* is not only relevant to Germany; since 2014 it has come to form part of the Franco-German axis, whose strategic agenda covers both the technical-industrial renaissance and the energy transition. It is gradually finding its way to the heart of the EU agenda, converging with matters of fiscal, economic and political governance.

It is because of these strategic connotations of the *Energiewende* that the Energy Chair is interested in learning more about the process and its possible impact on the development of European energy policy — and more specifically the foundations and guidelines of the European Energy Union.

At a time when "fake news" is rife, even in the energy industry, it is often difficult to get to the heart of what is actually going on. Nonetheless, it is essential to continue striving to identify the process of profound transformation upon which the energy industry has embarked. This is why it is so important to understand the deep inner workings of an energy transition which seeks to respond to a market which is evolving, due in part to technological factors.

The world of energy should be synonymous with security, sovereignty, technology, industry and stable and secure supply. It is, in short, the heart of human and urban life. All of these components underpin the *Energiewende*. The underlying reasons for a change in Germany's energy model include its energy dependency on Russian gas; its relative lack of hydrocarbon reserves; the danger of losing technological and industrial ground; the social limitations placed on nuclear energy since the 1970s, and the opportunities held out by the new technological revolution to develop a safe, sustainable and democratic energy source and incentivise self-consumption. The *Energiewende* has already had a major impact on German energy companies.

The purpose of this introduction is not to give my technical opinion on the contents of this report or the lessons (perhaps unconventional) we might draw from it. I shall make just three observations. The European Energy Union must stand at the heart of the new model. The technological and industrial perspective forms a substantial part of the new energy model. It would be unwise to base future models on today's formulae, themselves built on the foundations of a model that dates back to a world that is already being swept away down the river of economic and industrial history.

This new study on the *Energiewende* has been directed by Dr Eloy Álvarez Pelegry, who has a profound understanding of the electricity system and is a keen observer of the evolution of a sector which —like the rest of the energy industry— is now undergoing profound transformation. The world is moving towards democratisation and towards different multi-energy offerings, based on one essential principle — access to safe, affordable, and sustainable energy.

I would offer one piece of advice. As you read this study, keep an eye out for the various challenges implicit to the energy transition. Bear in mind that it is a strategy that has been launched by a country that stands at the geographical and economic heart of Europe. Viewed from this perspective, you may understand the needs that arise from a core notion, the energy transition, which is bringing a seismic change to the European energy market and its industrial and technological heart.

Finally, I would once again like to thank Dr Eloy Álvarez and his team of researchers for their hard work, and for bringing the most significant strategic trends in the field of energy to the attention of our industrial and technological fabric and the decision-makers behind our industrial policies. He should be congratulated for his work at the head of the Energy Chair and the opportunity he has given all of us with an interest in the fascinating world of energy to learn more.

Energy stands at the heart of the planet. Energy is the driving force of humankind. Energy is the prime indicator of human development. Without sustainable energy at the service of individuals, there can be no democracy, in the broadest sense of the term. A true energy transition is only possible if we are capable of advancing towards a new world of sustainable and democratic energy generation.

PREAMBLE

Julio Castro

Executive Vice-President for Regulation of the Iberdrola Group

Member of the Trustees of the Orkestra-IVC Energy Chair

Europe is a world leader in combatting climate change, and within the Union, Germany has established itself as one of the foremost champions of the cause. The EU's contribution has been to commit to specific commitments for 2020 in the domains of greenhouse gas emission reduction, use of renewables and improvement in energy efficiency, with further commitments now being discussed for 2030. Germany, however, has chosen to go one step further, imposing even more ambitious targets on itself.

The *Energiewende* (energy transition) comprises a series of targets and measures, starting in 2010, which which the country seeks to continue spearheading action against climate change. In the fields of energy and climate change, the country has committed, by 2020, to: a 40% cut in CO_2 emissions compared to 1990 levels (the EU target is 20%); 18% renewables in energy in general, and 35% in the electrical sector; a 4% reduction in electricity demand; and finally, complete phasing-out of nuclear power by 2022.

An analysis of the development of the *Energiewende*, the degree to which targets are being met and the type of costs that are involved is therefore helpful to determine whether it might be useful to transpose the model to other countries. Specifically, this report looks at the *Energiewende* from the perspective of the power industry in four key areas: compliance with targets on emission reductions; impact on supply security; economic implications for consumers; and impact on power utilities.

By 2015, Germany had cut its emissions by 27%, and unless any special measures are adopted, the forecasts are for a 33% reduction in 2020. In other words, it is unlikely to meet its target of a 40% reduction. In the electricity industry, the main reason is the continued widespread use of domestic coal in power production. The low cost of coal as compared to natural gas, and the reduced price of CO_2 in the European Emissions Trading Scheme (ETS), has resulted in a continued price differential which has favoured the continued use of coal rather than a switch to gas which would have helped cut emissions in this sector.

Given the economic recovery, the likelihood that the CO_2 price in the ETS will remain insignificant, the lack of any plan to close coal-fired power stations, the fact that lignite-fired plants are currently operating more than 7,000 hours, and the closure of Germany's nuclear power stations, we are inclined to think that coal will continue to play a significant role in the country's power mix, hindering compliance with its emission reduction targets.

As for renewables, although the specific target for the power industry might be attainable (the figure was 30% in 2016), a recent study by the German Renewable

Energy Association shows that the current overall share of 14.6% could rise to 16.7%, somewhat below the 18% targeted.

A major contribution is being made in the area of offshore wind power. Iberdrola's Wikinger offshore wind farm will supply enough energy to meet the needs of more than 350,000 German homes, preventing almost 600,000 tonnes of CO_2 from being released into the atmosphere each year. This project has investment of €1.4 billion and includes a substation built entirely at the Puerto Real shipyard in Cadiz and 70 wind turbines with a total capacity of 350 MW.

Supply security is a key feature of any electrical forecast. By 2022, the forecast is that Germany will have a reserve margin of around 5% (10% is usually considered desirable). This has led to the establishment of a series of capacity reserves to alleviate the problem and a greater dependency on imports. Not all the proposed capacity reserves have yet received the necessary approval from Brussels.

The result of all these developments —particularly large-scale introduction of renewables in power generation— has been an increase in electricity prices for consumers. Although large industrial consumers have seen no major impact, the same cannot be said of domestic customers. Prices in this sector have increased by 24% since 2010 (and doubled since 2000), making them among the most expensive in Europe (after Denmark) and 30% above the European average.

Finally, it is worth noting that these actions have had a major impact on traditional power utilities, dramatically lowering their share price and forcing them to undertake large-scale corporate restructuring.

All of these aspects are comprehensively analysed in this report from the Orkestra Energy Chair and I would like to congratulate the authors on their immense work. I am convinced that this highly comprehensive study will help to guide opinions on the pros and cons of the *Energiewende* and the manner in which it has been implemented.

PURPOSE AND SCOPE OF THE STUDY

Given its economic importance, the strength of its electrical sector and its industry[2] and the extent of the energy transformation (the *Energiewende*) now underway, Germany has become a key point of reference for today's energy world.

While this energy transition —which will take decades to complete— is already beginning to reap the first benefits, it has also run into increasing difficulties and a number of contradictions have arisen. There has been a major increase in output from renewable energy (RE) and a relative drop in greenhouse gas emissions (despite a rise last year).

Nonetheless, 2020 is fast approaching, and with it some key milestones of the *Energiewende*, and there is still a long way to go to meet the targets set by the German government: a 40% reduction in emissions (compared to 1990 figures), 40% renewable electricity, improved energy efficiency, a reduction in electricity demand and a substantial increase in the use of alternative fuels in transport. Moreover, one nuclear power station will be closed in 2017, followed by another in 2019, with all the country’s stations due to shut by 2021-2022.

At the same time, although output from fossil fuels has decreased in recent years, in the medium term they will likely to go on playing a considerable role in the German power mix.

In the electrical area, the German government has adopted a series of measures which have reinforced the irreversible nature of the *Energiewende*. The process of consultation on the electricity market concluded in 2015, with a decision to create a strategic capacity reserve. In 2016, with new consultation documents on the challenges facing the electricity system to 2030 and energy efficiency, amendments were made to the Renewable Energy Act (EEG). Among other changes, an auction model was introduced for the main renewables.

Germany has become a net exporter of electricity, and this has had collateral effects on neighbouring countries. In parallel, a whole industry has been developed related to renewables and energy efficiency.

The transition enjoys widespread popular support (Graichen, Kleiner, & Podewils, 2017), although there has also been renewed criticism of increases in the electricity bill to domestic consumers and the impact on “traditional” power generators.

There has been a fall in the price of some key technologies for the transition —in generation (wind, photovoltaic) and storage (essentially batteries). Offshore wind farms have begun to play an important role in the North Sea, although it will still take some time before this technology makes a major contribution to national output.

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[2] Germany has the highest electrical output in Western Europe (698 TWh, compared to 553 TWh in France), the second highest in Europe after Russia and the sixth highest in the world (behind China, the US, India, Russia and Japan, in order of consumption) (BP plc, 2016).

The construction of new power transmission lines —vital for full roll-out of the *Energiewende*— is running behind schedule. One of the major north-south lines is no longer on track for completion by 2025.

These are some of the key features this report sets out to examine. We will address the current situation and level of implementation of the *Energiewende*, focusing on the area of electricity, and establish the principal implications of the process on the German power industry in energy, economic and environmental terms.

This study is also intended to be a follow-on from the report published by the Orkestra Energy Chair in 2016, entitled "The energy transition in Germany (*Energiewende*). Politics, energy transformation and industrial development"[3] which offered a general analysis of the different energy sectors and aspects of industrial policies related to the energy transformation in Germany.

[3] Available at:
http://www.orkestra.deusto.es/images/investigacion/publicaciones/cuadernos/La_transici%C3%B3n_energ%C3%A9tica_en_Alemania_Energiewende_-_Versi%C3%B3n_web.pdf

CONTENTS

EXECUTIVE SUMMARY

Structure of power and production

Germany has committed itself to moving towards a low-carbon economy through the *Energiewende*. This commitment takes the form of a series of basic targets on greenhouse gas emission reduction, use of renewable energy sources and energy efficiency.

Between 2002 and 2016,[4] the share of gas and renewables in the power mix increased by 44% and 244% respectively. The use of hard coal and lignite-fired power stations has been reduced (by 5% and 17% respectively), and no new coal-fired plants are planned following completion of the Datteln 4 (hard coal) station. The planned closure of all nuclear power stations has also had a major impact, already affecting more than half of all nuclear power output. These are all signs of the major commitments made in the area of renewables, where it seems feasible that 2020 targets will be met.

However, a continued push will be needed to meet 2030 and 2050 targets, with further development of both photovoltaic generation (distributed and in power stations) and wind power (onshore and offshore). Biomass is likely to play a greater role as a back-up energy. Although installed generating capacity is not forecast to increase significantly, it will grow in other uses such as final energy.

Unless there is either a drop in demand during this timeframe or an advance in active demand management, fossil technologies will continue to play a leading role, with coal and natural gas accounting for around 20% each in 2050.

Electricity demand

In light of historical trends, the target of reducing demand by 10% in 2020, compared to 2008 figures, seems too challenging to be achieved.

ENTSO-E forecasts suggest that demand will remain at present levels to 2030; even allowing for improvements in energy efficiency, demand is also likely to rise due to a greater number of electric vehicles on the roads and higher use of electricity in heating applications.

Emissions

Germany is having difficulty meeting its 2020 GHG emissions targets. To speed its progress towards this goal, some forecast plans will have to be put into practise, including the additional measures set out in the National Action Plan on Energy Efficiency. Should these fail to succeed, the government might even decree the temporary early shutdown of more lignite-fired plants, consigning them first to the capacity reserve.

[4] The German *Energy concept* was developed in 2010.

The 2020 targets on air pollutant emissions do seem attainable,[5] although it will be necessary to keep up the present efforts to 2030.

Supply security, transmission networks and interconnectors

In order to meet its targets without compromising supply security, Germany is developing its cross-country transmission grids (where construction is behind schedule despite government support), increasing the capacity of existing interconnections with other countries and building interconnectors to new countries. This will boost north-south energy flows and increase the overall volume of exports and imports. Germany's future position as a net importer or exporter will depend (among other factors) on trends in domestic demand.

As a mechanism to reinforce supply security, Germany has opted for the use of three capacity reserves: a grid reserve, to avoid congestion; a climate reserve, which includes lignite-fired plants; and a capacity reserve (awaiting approval from Brussels), to ensure market matching. Depending on legislative developments in the EU and the use made of them, these reserves could be replaced by other mechanisms.

Electricity prices

The *Energiewende* has already impacted consumers' electricity bills. On the one hand, greater use of renewables has led to a reduction in the price of electricity on the wholesale market. On the other, this change has been financed by a surcharge for renewables (the "EEG surcharge"), an ever-higher levy on electricity consumption.

The combination of these two elements has led to an increase in the electricity bill that has outstripped inflation and is above the European average. It has had a greater impact on domestic consumers and on medium-sized enterprises than large electricity consumers, which enjoy significant exemptions from the EEG surcharge.

In the case of both domestic and industrial consumers, non-electrical items account for a larger share of the electricity bill than energy, transmission and distribution. A similar trend can be seen throughout Europe.

Implications for large power companies

The combination of renewables and energy-only markets has reduced income for conventional generation, with prices forecast to remain low for the short-term. This, combined with the scheduled closure of all nuclear plants, has resulted in a fall in company profits and share value.

The new scenario created by the *Energiewende* has obliged utilities to switch strategy, with a new commitment to renewables —particularly wind power— and storage. There has been an increase in the acquisition of small (photovoltaic and storage)

[5] Note that the targets on reducing pollutant emissions are not included in the *Energiewende* but in the 1999 Gothenburg Protocol.

companies and an internationalisation of business, both in terms of investment in other countries and the emergence of new competitors.

Business activity has been restructured: in different ways, RWE and E.ON have created new companies (innogy and Uniper respectively) to segregate their conventional generation business from renewables, grids and retail markets. In addition, sale of Vattenfall's lignite-fired facilities has led to the emergence of a new player, LEAG, owned by Czech group EPH.

As a result of these new strategies, combined with the agreement to phase out nuclear, payment of the figure agreed with the government for managing nuclear waste and the court decision to refund the nuclear fuel surcharge, the latest forecasts show a certain improvement in profits and share value. Nonetheless, these utilities are unlikely to recover their previous position any time soon.

Conclusions

Germany has made a strong commitment to renewable energy and appears to be on track to meet its 2020 target in this area, although a sustained effort will have to be made to meet its ambitious and challenging 2030 and 2050 targets.

Nonetheless, unless there is a sufficient drop in demand and/or a significant advance in active demand management, conventional fossil-fuel technologies will continue to play a major role, obstructing the decarbonisation process. In light of historical trends, the target of reducing demand by 2020 appears too demanding to achieve. Germany can be seen to be having difficulty achieving its emission targets by 2020.

With a view to meeting these targets while guaranteeing supply security, the country is promoting the development of internal transmission grids (now running behind schedule), international interconnections and centralised capacity reserves.

The *Energiewende* has impacted consumers' electricity bills. Domestic customers and SMEs have seen an increase, largely as a result of the renewables (or EEG) surcharge. Larger consumers, which enjoy major exemptions from the EEG surcharge, are not suffering as much.

The combination of renewables and energy-only markets has led to reduced prices on the wholesale market, which are forecast to continue in the short-term. Combined with the phasing-out of nuclear power, the result has been a fall in the profits and share prices of utilities.

This new scenario has led power companies to switch strategy and restructure their businesses, with RWE and E.ON creating new companies (innogy and Uniper, respectively).

In light of these new strategies and recent developments in the nuclear domain, the latest forecasts are for some recovery of profits and share value. However, these companies are unlikely to return to recover their previous standing anytime soon.

1. INTRODUCTION

The *Energiewende* is a "political/technical/industrial" energy transition project launched in Germany which is likely to span several decades. The process, which has sparked considerable controversy, is rooted in proposals first mooted in the 1970s, reinforced in the 1990s and introduced more generally in the last decade.

A study published in 2016 by the Orkestra Energy Chair (Álvarez Pelegry & Ortiz Martínez) looked at the energy situation in Germany and examined the targets of the *Energiewende* from several different perspectives. Specifically, it explored the history of the *Energiewende* and the rationale for the transition; its political context; the evolution and current situation of the country's energy structure; changes in *Energiewende* targets; and basic regulation. It also discussed the implications of the process and the difficulties in terms of competitiveness, with an analysis of electricity prices and industrial policies and achievements, through German and European industrial policy and analysed the business structure of the German renewables industry (principally wind, solar and biomass).

This new report sets out to offer a more in-depth analysis of the implications of the *Energiewende* in the electrical field, already outlined in the previous study. It is divided into two chapters. The first chapter is divided into three sections, each examining the energy and environmental implications of the *Energiewende* in a different area. The first section explores power generation and demand, in terms of structure, trends and forecasts, including the situation of nuclear and coal-fired power stations and the introduction of renewables. The second section analyses trends and forecasts in wholesale electricity prices and capacity mechanisms and other measures adopted to ensure supply security, with a growing penetration of renewables. The third section looks at the environmental implications of the *Energiewende* in terms of greenhouse gas and air pollutant emissions.

In the second chapter, we explore the economic implications for the power industry. This chapter is divided into two sections. The first examines the price of electricity for domestic and industrial consumers, analysing cost structure, trends and current situation in the European context. The second section examines the impact of the *Energiewende* on traditional German power utilities (RWE, E.ON, Vattenfall and EnBW), and the strategic changes they have made to adapt to the changes.

Each chapter concludes with a summary and a list of the main conclusions, based on the preceding information and analysis.

2. ENERGY AND ENVIRONMENTAL IMPLICATIONS

2.1. Introduction, purpose and scope

The *Energiewende*[6] is built around two essential pillars, increased use of renewables and improved energy efficiency, both with the target of reducing GHG emissions. This will mean reversing Germany's traditional low use of renewable energy (RE)[7] and ensuring that a reduction in primary energy consumption is compatible with economic growth. It will also be necessary to reconcile this change with supply security, energy affordability and environmental sustainability. Another key element of the transition is the phasing-out of the country's nuclear plants. In broad terms, the *Energiewende* takes the form of a series of targets for 2020 and a 2050. The position as at December 2015 is shown in the table below.

TABLE 1. Status of *Energiewende* targets, 2015

<table>
<tr><th colspan="2">Sector</th><th>Baseline</th><th>2015</th><th>2020</th><th>2030</th><th>2040</th><th>2050</th></tr>
<tr><td colspan="2">Greenhouse gases (%)</td><td>1990</td><td>-27.2</td><td>-40</td><td>-55</td><td>-70</td><td>[-80,-95]</td></tr>
<tr><td rowspan="4">Renewables (%)</td><td>Power generation</td><td rowspan="4">-</td><td>31.6</td><td>35</td><td>50</td><td>65</td><td>80</td></tr>
<tr><td>Final energy</td><td>14.9</td><td>18</td><td>30</td><td>45</td><td>60</td></tr>
<tr><td>Heat</td><td>13.2</td><td>14</td><td colspan="3">-</td></tr>
<tr><td>Transport</td><td>5.2</td><td>10</td><td colspan="3">-</td></tr>
<tr><td rowspan="6">Efficiency (%)</td><td>Primary energy demand</td><td rowspan="4">2008</td><td>-7.6</td><td>-20</td><td colspan="2">-</td><td>-50</td></tr>
<tr><td>Electricity demand</td><td>-4.0</td><td>-10</td><td colspan="2">-</td><td>-25</td></tr>
<tr><td>Primary energy demand in buildings</td><td>-15.9</td><td colspan="3">-</td><td>-80</td></tr>
<tr><td>Heating demand in buildings</td><td>-11.1</td><td>-20</td><td colspan="3">-</td></tr>
<tr><td>Final energy productivity (%/year)</td><td>2008-2050</td><td>1.3</td><td colspan="4">2.1</td></tr>
<tr><td>Final energy demand in transport</td><td>2005</td><td>1.3</td><td>-10</td><td colspan="2">-</td><td>-40</td></tr>
<tr><td colspan="2">Nuclear (GW)</td><td>2000</td><td>10.8</td><td>8.5</td><td colspan="3">0</td></tr>
</table>

Note: targets refer to the minimum to be achieved on the given date. The target for renewable power generation is a percentage of gross power consumption.

Source: Authors, based on (BMWi, 2016b) and (Federal Ministry of Foreign Affairs, 2017).

As the table above shows, the timelines for some targets are more clearly defined than others. For example, GHG emission reduction targets are given for the end of each decade from 2020 to 2050,[8] whereas there is only one target (2020) for renewables in transport,[9] and a longer-term target (2050) for reducing primary energy use in

[6] The process is oriented by the directives of the Federal Ministry for the Economy and Energy (BMWi, *Bundesministerium für Wirtschaft und Energie*), the Federal Parliament (*Bundestag*) and the EU.
[7] In 1990, 4% of electricity came from renewables. The target for 2050 is 80%.
[8] The 2050 target corresponds to the EU's long-term target, which is currently non-binding (Council of the European Union, 2009). As with the EU's 2020 emissions reduction target, this will probably vary between member states. Interim targets are more ambitious than the EU's: 20% by 2020, 40% by 2030 and 60% by 2040 (European Parliament, Council of the European Union, European Economic and Social Committee, & Committee of the Regions, 2011).
[9] This target is in line with the EU's Directive 2009/28/EC.

buildings, albeit it impacts many other targets (overall energy demand, heating demand in buildings, etc.).

The *Energiewende* covers a range of concepts in addition to those listed above. These include: (1) Supply security, at any given time; (2) Phasing out nuclear by the end of 2022; (3) Affordability and competitiveness of energy price; (4) Expansion and modernisation of the power grid with integration of distributed generation; (5) Efficient coupling of industries and digitisation; (6) European and international framework promoting measures to mitigate climate change and efficient energy use; (7) Research and innovation, promoting restructuring of the energy supply and (8) Sustainable investment, growth and employment and improvement in quality of life.

Chapter 2 examines the energy implications of the *Energiewende* in the electricity industry. It discusses the past and present structure of power generation and forecasts for the future, analysing the shutdown of nuclear power stations, the present situation of coal-fired stations and the development of new generating plant using renewables. It also explores trends in electricity demand, exports and imports.

The chapter goes on to analyse trends in the energy price on the wholesale market and short-term forecasts, referring to the decision on capacity mechanisms set out in the *Energiewende* and its European context, *vis-à-vis* the country's supply security. Trends in emissions from the sector are analysed and the chapter concludes with a summary and list of conclusions.

2.2. Generation

We shall start by examining the current structure of electricity production and generation and forecasts for the future. We shall also look at the phasing-out of nuclear power, the status of coal-fired facilities and plans for new renewable power stations.

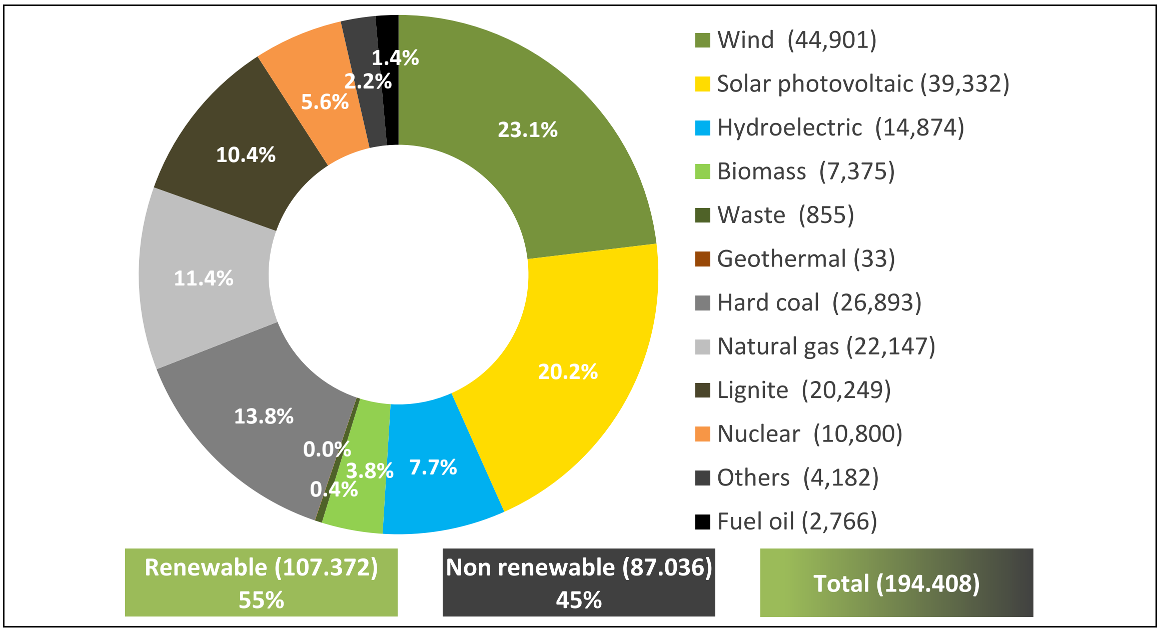
2.2.1. Structure of electrical capacity and production

Installed capacity. Current situation and historical trends

The German power mix includes a wide variety of primary energy sources. figure 1 gives a breakdown by technologies of the country's 194.4 GW[10] of installed capacity in 2016, of which 55% came from renewables.

[10] Installed capacity is not uniformly distributed throughout the country. For details on locations of power stations, see appendix 2.

FIGURE 1. Net installed power capacity (in MW) in Germany, 2016 with percentages



Note: Installed wind capacity comprises 41.4 GW onshore and 3.5 GW offshore. Hydro power includes 9.3 GW of pumped-storage, 4.0 GW run-of-the-river (RoR) and 1.0 GW from non-pumped storage.

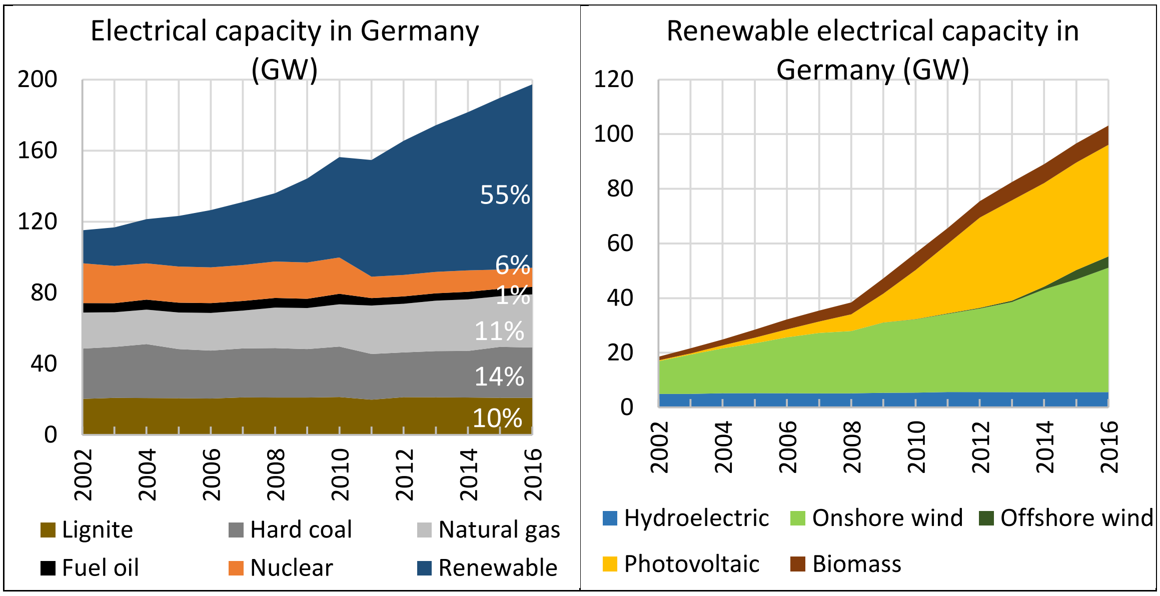
Source: Authors, based on figures from the Federal Network Agency (Bundesnetzagentur, 2016b).

This installed capacity has to be capable of catering for a demand peak of 83.7 GW[11] (2015) (Bundesnetzagentur, 2016d). This figure is currently exceeded by 15% by conventional generation (non-renewable plus pumped-storage hydro). Installed power from renewables exceeds conventional generation by 20 GW. However, as (Birkner, 2016) notes, historically the maximum capacity simultaneously available from renewables is 50% of the total installed capacity (i.e. 54 GW of peak renewable generation).

Installed capacity has increased steadily since 2002, falling only in 2011 due to the shut-down of eight nuclear power stations (8.35 GW). The largest increase has been in the area of solar photovoltaic power, which rose from 0.3 GW in 2002 to nearly 40 GW in 2016. There has also been a major increase in wind power, from 12 GW in 2002 to 44.9 GW in 2016. Natural gas and biomass, too, have experienced significant growth. Installed power from hard coal, lignite and hydro has remained largely unchanged since 2002, while output from nuclear and petroleum products fell by 11.5 GW and 2.6 GW respectively. figure 2 gives a summary of installed capacity during the period 2002-2016, with a breakdown of renewables.

[11] The 2030 scenarios forecast no major changes in the demand peak.

FIGURE 2. Installed capacity in Germany by primary source



Note 1: Does not include data on other sources, renewables (waste, geothermal) and non-renewables (derived and industrial waste). Hydroelectricity does not include pumped-storage hydro, which came to 9.3 GW in 2016.

Note 2: Percentages are for 2016.

Source: Authors, based on Fraunhofer (ISE, 2017).

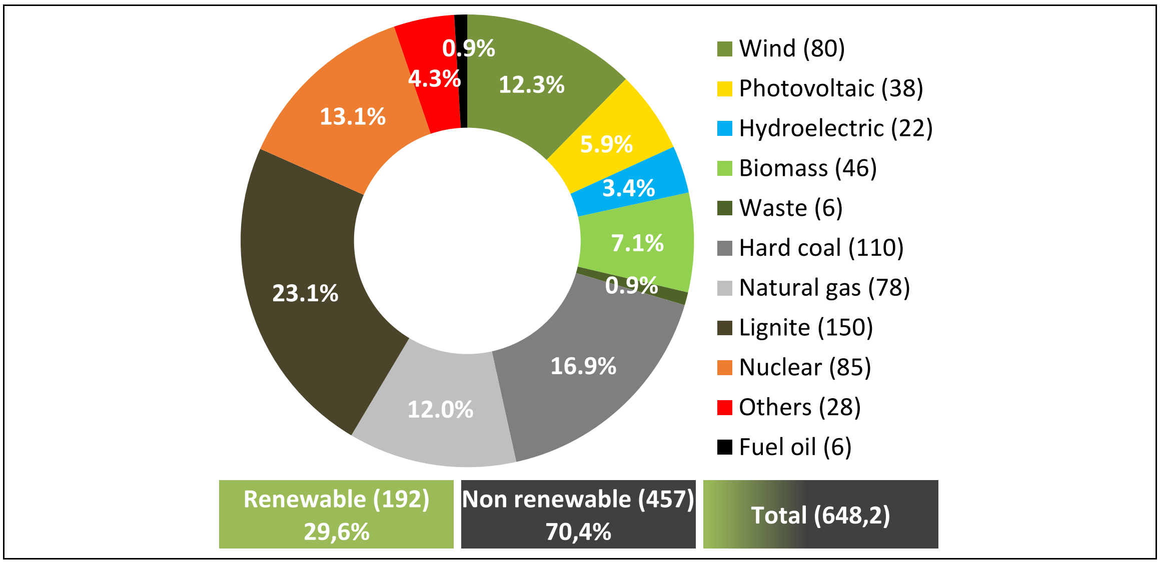
Power generation. Current situation and historical trends

Latest figures from the Ministry of the Economy and Energy show that gross power output in Germany in 2016 came to 648.2 TWh (BMWi, 2017b), slightly above the 2015 figure (AG Energiebilanzen e.V., 2016). This increase was basically due to increased generation in natural gas-fired power stations, in contrast to a drop in output from nuclear, hard coal and lignite. Hard coal and lignite nonetheless continue to play a leading role, accounting for 40% of total gross generation in 2016.

Thus, fossil fuels accounted for 57% of total production in 2016; renewables, 30% and nuclear 13%. (AG Energiebilanzen e.V., 2016). For a breakdown, see figure 3.

The year saw the first major slow-down in renewables since 2009, with a decline in wind power (onshore was down though offshore was up) and solar, offset by an increase in hydro and biomass.

FIGURE 3. Gross power generation in Germany in 2016 (TWh)

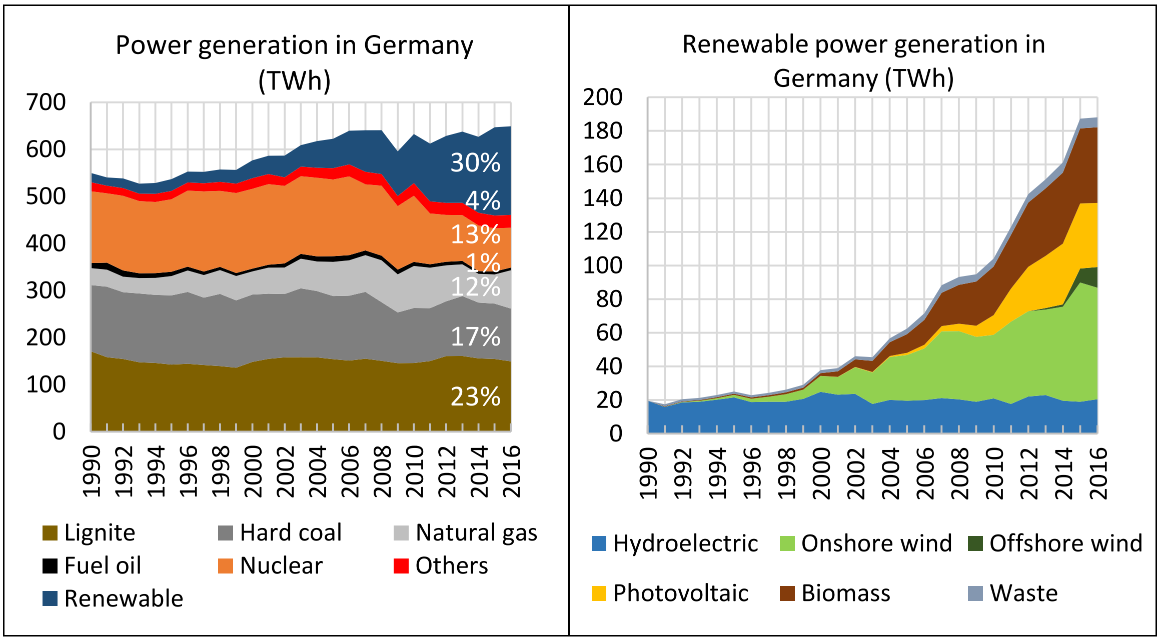


Note: Waste is included in renewable generation.

Source: Authors, based on BMWi (2017b).

Power generation in Germany grew strongly between 1990 and 2016 (see figure 4). Following an initial fall to 1993 due to the shut-down of plants in the former East Germany, the upward trend in output resumed, interrupted only by the economic crisis which began in 2008. Since then, some years with a strong fall in output have been followed by years of recovery. Only in 2015 did generating levels exceed the previous record high set in 2008.

FIGURE 4. Gross power generation in Germany by primary source



Source: Authors, based on AG Energiebilanzen e.V. (2017).

TABLE 2. Power output in Germany by source (TWh)

	2000	2004	2008	2012	2016	2016-2000	2016-2000 (%)
Hydroelectric	21.7	20.1	20.4	22.1	21.0	-0.7	-3%
Wind	9.5	25.5	40.6	50.7	77.4	67.9	714%
Biomass	2.9	8.2	23.1	38.3	45.6	42.7	1,479%
Waste	1.8	2.3	4.7	5.0	6.0	4.2	225%
Photovoltaic	0.1	0.6	4.4	26.4	38.2	38.1	63,518%
Geothermal	0.0	0.0	0.0	0.0	0.2	0.2	-
Hard coal	143.1	140.8	124.6	116.4	111.5	-31.6	-22%
Lignite	148.3	158.0	150.6	160.7	150.0	1.7	1%
Fuel-oil	5.9	10.8	9.7	7.6	5.9	0.0	1%
Natural gas	49.2	63.0	89.1	76.4	80.5	31.3	64%
Nuclear	169.6	167.1	148.8	99.5	84.6	-85.0	-50%
Pumped-storage hydroelectricity	7.7	6.4	6.0	5.8	5.5	-2.2	-28%
Others	16.7	14.9	18.7	19.8	22.0	5.3	32%

Source: Authors, based on BMWi.

Major features of this period (1990 - 2016) included the development of a series of renewable technologies that have helped diversify the German power mix in general, and renewables in particular (wind, essentially onshore, biomass, solar photovoltaic and hydro). There has also been a downturn in the relative share of hydro and an increase in other renewables, especially wind.

Photovoltaic has seen steady growth since it first emerged in 2001, apart from a fall in 2016, while biomass has grown unchecked since 2001. Output from onshore wind has been marked by occasional drops due to meteorological conditions. Hydroelectric output has remained relatively stable, at an average of 20.2 TWh per year.[12] Forecasts indicate that by 2018, output from renewables will come to 204 TWh (BMWi, 2017e).

Output from natural gas has grown strongly, peaking in 2010 at 89.3 TWh. It fell back somewhat in 2014 due to a drop in the price of coal compared to gas (Weale, 2016) and the low cost of CO_2 emission allowances. However, output rose again in 2016 due to favourable meteorological conditions.

Output from all other fossil fuels fell during the period. Output from hard coal declined steadily (down 21%) due to the closure of domestic mines and fuel-oil also fell by 45%. Generation from lignite, however, has remained relatively stable since 1993 (up 1.7%), since local, open-cast, mines are more economically viable (Spiegel Online International, 2007).

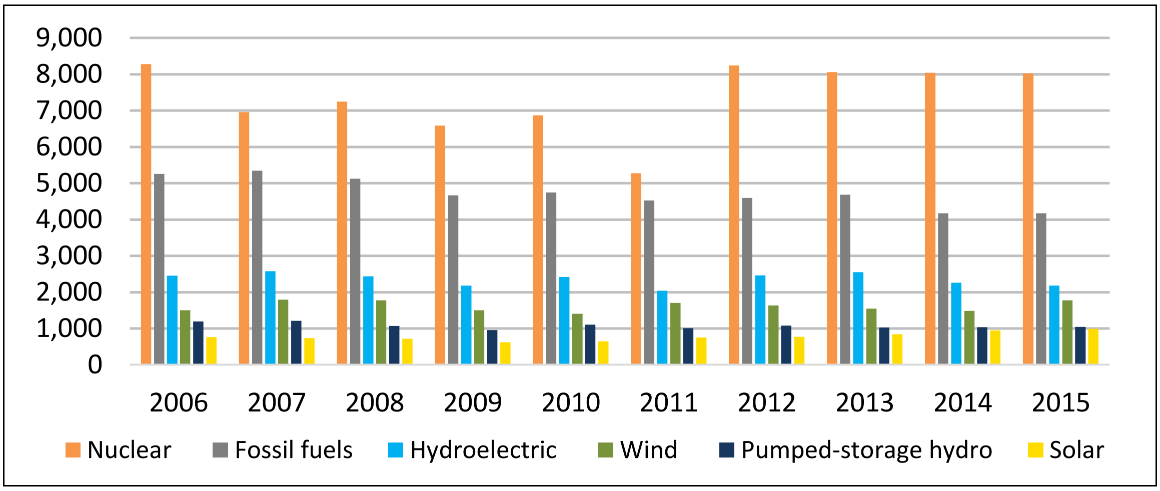
[12] The highest output (24.9 TWh) was in 2000 and the lowest (15.9 TWh) in 1991, a particularly dry year in southern Germany (Demuth & Heinrich, 1997)).

Some power output currently comes from self-consumption, both in industry and in homes. According to Bundesnetzagentur (2016d), of a total net generation of 594.7 TWh in 2015, 34.9 TWh (5.9%) was not exported to the grid. Of this, only 4.9 TWh comes from photovoltaic installations of under 10 kW operating within the renewable generation regime (Deutsch et al., 2016).

Generating losses in 2015 came to 36.8 TWh (5.7%), while losses in transport and distribution accounted for a further 25.8 TWh (4.3% of net generation).[13]

Turning to full load equivalent hours[14] (figure 5), we see a decline and subsequent rise in the use of nuclear power; a continued fall in output from fossil fuels, from 5,000 to 4,000 FLEH; a momentary decline in hydroelectric output in 2011 and a gradual increase in output from solar photovoltaic, although the FLEH figure is lower than for other technologies.

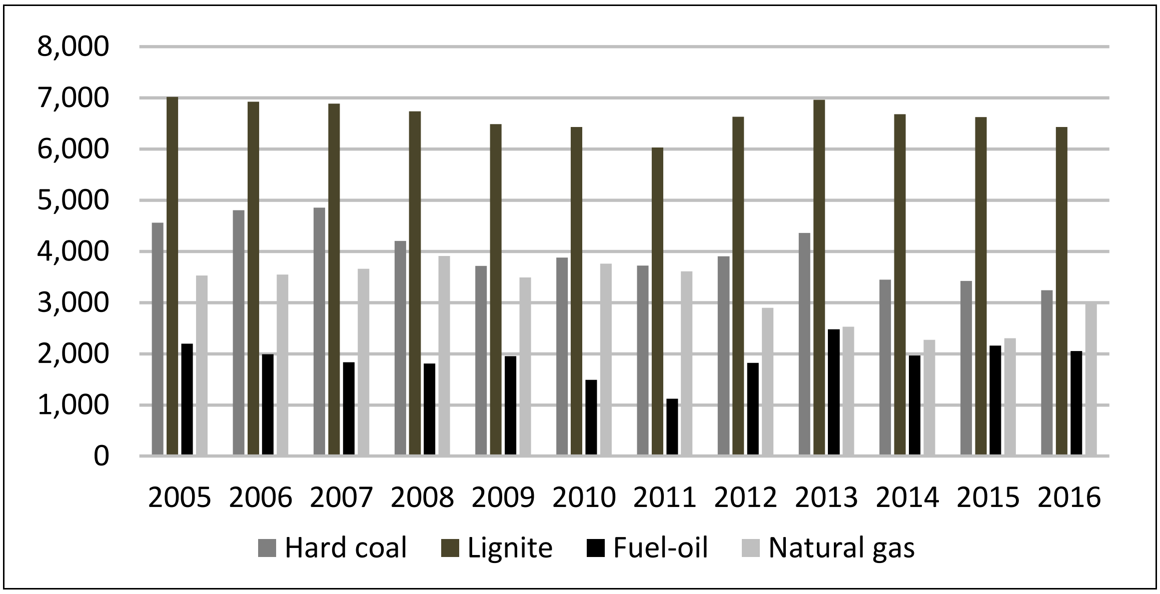
FIGURE 5. Full load equivalent hours by generation type in Germany



Source: Authors, based on Eurostat figures.

[13] These figures differ considerably from Spain, where in 2016 transmission and distribution losses accounted for 2.0% and 8.1% respectively of demand in plant busbars (as opposed to 1.4% and 3.0% in Germany).
[14] FLEH.

FIGURE 6. Full load equivalent hours in facilities using fossil fuels in Germany



Note: Owing to lack of data, 2014 installed capacity figures have been used for 2015 and 2016.

Source: Authors, based on BMWi figures.

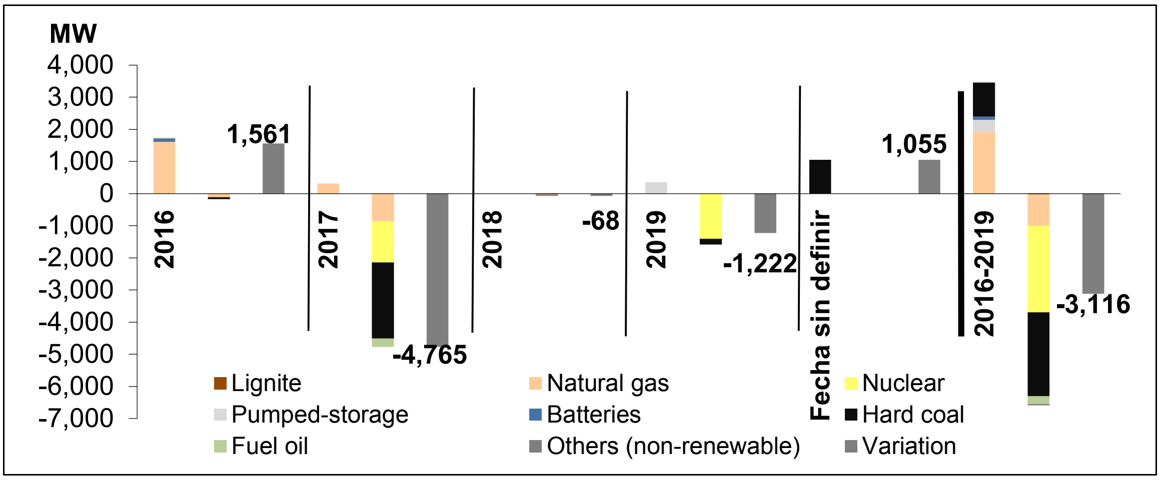
Richter (2014) offers a calculation of full load equivalent hours for power generation in Germany in 2013. The values are close to those estimated using Eurostat data (see figure 6). In this case, coal can be seen to be the most-used fuel, with lignite far outstripping hard coal, both in equivalent hours and energy (around 7,000 FLEH v. 4,200 FLEH). Of the other fossil fuels, natural gas comes in third place, while fuel-oil is the primary energy source with the lowest FLEH.

Forecasts

For the period 2016-2019, a net decline of 3,116 MW is forecast in installed capacity (not taking into account the installation of new intermittent renewables — hydro, solar and wind), (figure 7).

On the one hand, 3,469 MW of power is due to come on line during the period. More than half will come from natural gas and a significant percentage from hard coal, although the figure also includes pumped-storage hydro and batteries. On the other, 6,585 MW will be lost through scheduled shut-downs, mainly of hard coal and nuclear stations. The only increase in installed capacity will be in natural gas and storage, with the largest falls coming in nuclear and hard coal (2,686 MW and 1,553 MW respectively) (Bundesnetzagentur, 2016b). As can be seen in the figure, the forecast is for the greatest activity during the period to be concentrated in 2016 and 2017.

FIGURE 7. Forecast new conventional power stations and closures in Germany



Note: The Uniper GmbH's Datteln 4 power station is due to open during the period 2016-2019, although no specific year is given in the plans. According to Uniper, it is due to open in 2018. (Uniper, 2017b)

Source: Authors, based on figures (Bundesnetzagentur, 2016b) figures.

In the longer term, table 3 shows installed capacity in four different scenarios for the period 2025-2035.[15] They all share certain common hypotheses, such as the programmed shut-down of nuclear plants, the gradual phasing-out of coal and hydrocarbon-fired stations and the incorporation of new natural gas-fired stations and renewable facilities (wind and photovoltaic). The difference between the scenarios lies in the rate of change.

The scenarios of the EU and the European Network of Transmission System Operators for Electricity (ENTSO-E) for 2030 are very similar, and any differences may be attributed to the fact that the EU's scenario does not include pumped-storage capacity. Any other differences are due to the fact that the ENTSO-E has shifted part of the natural gas capacity to other renewables and part of the installed photovoltaic capacity to wind.

The scenario published by the German TSOs shows a higher share from renewables, for several reasons: it uses different means of handling imbalances (for 2030, 4 GW from demand management, 4.5 GW from batteries and 1.5 GW from Power-to-Gas storage,[16] i.e. around 7% of total capacity); it considers a greater number of equivalent hours for renewable generation and a small increase in demand, offsetting improvements in efficiency by incorporating the heating & cooling and transport sectors into power demand (an increase of 3% for 2030 in net capacity compared to

[15] They include the scenarios for 2025 (50Hertz, Amprion, TenneT, & TransnetBW, 2014a) and 2030 (50Hertz, Amprion, TenneT, & TransnetBW, 2016a) published by the German transmission system operators (TSOs), the European Union's scenario for 2050, published in 2016 (Capros et al., 2016) and the ten-year development plan of the ENTSO-E, published in 2016 (ENTSO-E, 2016b).

[16] Power-to-Gas (P2G) technologies involve storing energy by using surplus electricity to produce gas fuels, such as hydrogen (for use in fuel cells) and methane. This fuel can subsequently be used to produce heat or generate electricity. It also covers the use of power-to-liquid (P2L) technologies, which operate similarly, creating a liquid fuel, such as methanol, instead of a gas fuel.

a 5% growth in gross demand in the EU scenario). In other words, demand would be linked to electrification of other sectors, due to the competitiveness of electricity: even if demand rises, it will be linked to greater (renewable) output, and in this scenario, Germany would therefore continue to be a net exporter.

The EU[17] predicts that Germany will become a net power importer. In this scenario, there will be a 46.5 TWh drop in power output during 2015-2020, essentially due to the shutdown of nuclear plants (see figure 9). The difference will widen in subsequent years, levelling out at an annual average import rate of 15 TWh in the period 2030-2050.

TABLE 3. Gross installed power scenarios for 2025-2035

Energy source (values in GW)	EU				ENTSO-E	TSOs			
	2025	2030	2035	2050	2030	2015	2025	2030	2035
Nuclear	0.0	0.0	0.0	0.0	0.0	10.8	0	0	0
Lignite	44.0	36.8	25.7	24.1	12.6	21.1	12.6	9.5	9.3
Hard coal					23.4	28.6	21.8	14.8	10.8
Natural gas	23.1	27.0	39.1	41.4	21.1	30.3	29.9	37.8	41.5
Hydrocarbons	1.5	1.2	1.1	0.7	1.0	4.2	1.1	1.2	0.9
Pumped-storage	-	-	-	-	-	9.4	8.6	11.9	13
Other non-renewables	-	-	-	-	8.7	2.3	3.1	1.8	1.8
Total non-renewables	**68.6**	**65.0**	**65.9**	**66.2**	**66.8**	**106.9**	**77.3**	**79.0**	**79.3**
Onshore wind	62.0	67.2	67.2	86.5	74.1	41.2	63.8	58.5	61.6
Offshore wind						3.4	10.5	15	19
Photovoltaic	55.9	64.0	64.0	86.1	57.2	39.3	54.9	66.3	75.3
Biomass	7.1	6.9	6.7	6.6	-	7	7.4	6.2	6
Hydro	5.7	5.9	6.2	7.2	13.3	5.6	4	5.6	5.6
Other renewables	0.2	0.2	0.2	0.2	7.0	1.3	0.8	1.3	1.3
Total renewables	**130.9**	**144.1**	**144.3**	**186.6**	**151.5**	**97.8**	**141.4**	**152.9**	**168.8**
Total	**199.4**	**209.1**	**210.2**	**252.8**	**218.3**	**204.7**	**218.7**	**231.9**	**248.1**

Note 1: Figures are for gross installed power.

Note 2: The scenarios of the Germans TSOs correspond to medium development (scenario B in the reports) and the EU scenario is based on medium development with a forecast of slow growth. The EU report offers only one scenario.

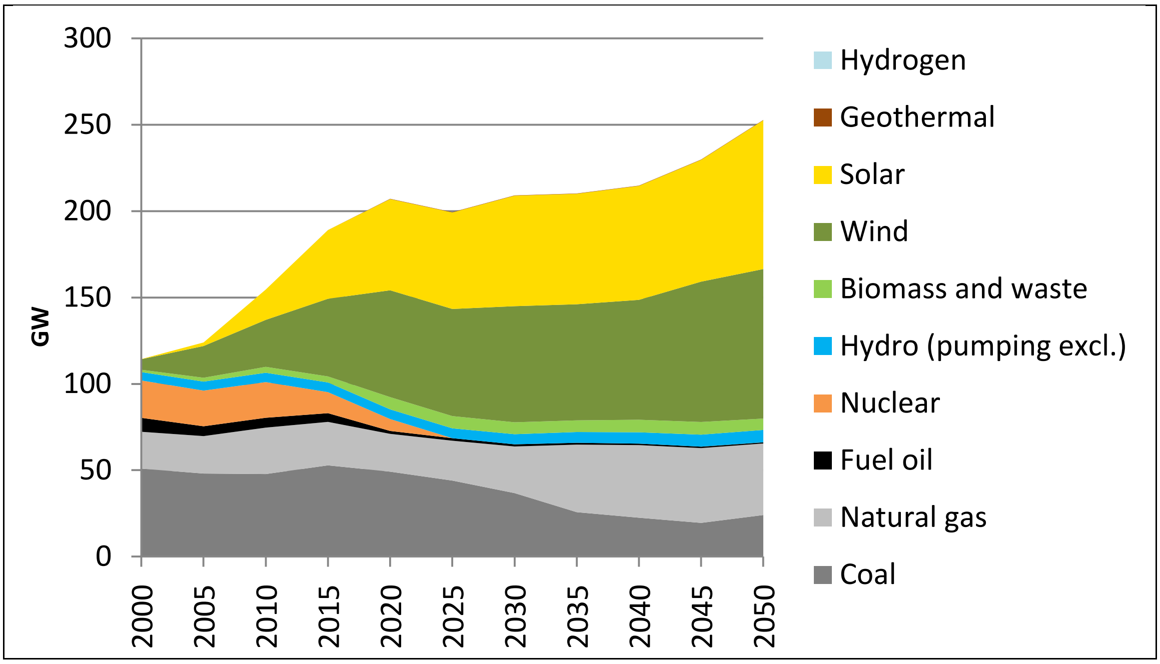
Note 3: The EU scenario does not include pumped-storage hydroelectricity. The ENTSO-E scenario groups all hydro production together and includes biomass with other renewables.

Source: Authors, based on 50Hertz, Amprion, TenneT, & TransnetBW, (2014ª); 50Hertz, Amprion, TenneT, & TransnetBW, (2016ª); Capros et al., (2016); ENTSO-E, (2016b).

For an even longer-term forecast of installed capacity in Germany (to 2050) and a forecast for power generation, see Figures 8 and 9 showing the EU scenario.

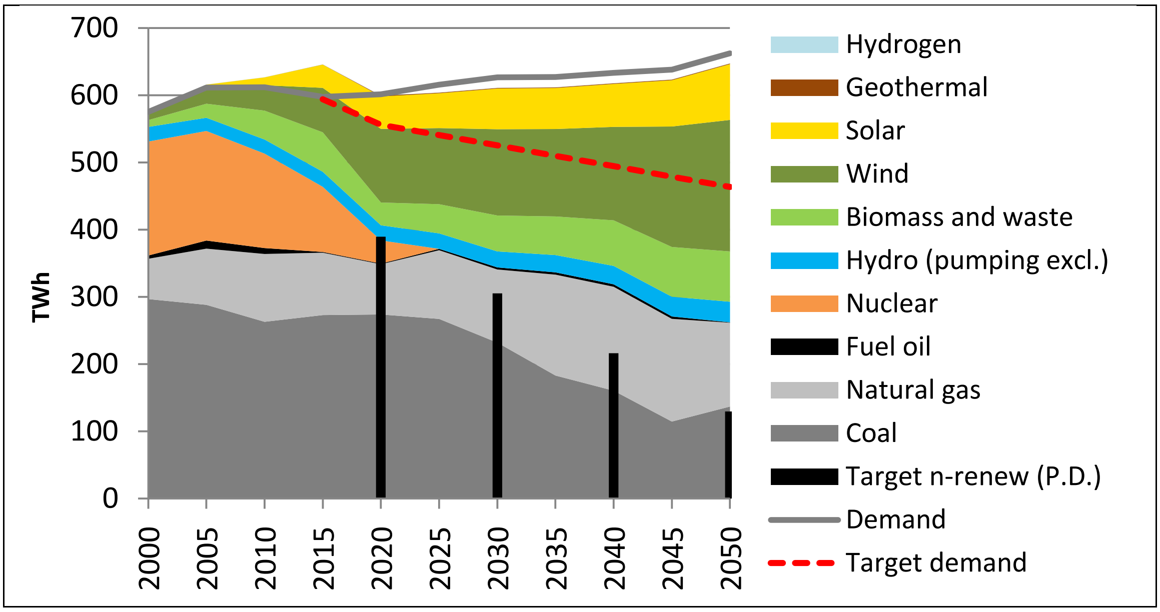
[17] (Capros et al., 2016).

FIGURE 8. Forecast trend in installed capacity in Germany, 2000-2050



Source: Authors, based on Capros et al. (2016).

FIGURE 9. Forecast trend in power generation in Germany, 2000-2050



Note 1: Annual targets for non-renewables are based on the difference with targets for renewables. This gives 65% in 2020, 50% in 2030, 35% in 2040 and 20% in 2050.

Note 2: Demand is classed by source. The demand target is that set by the German government.

Source: Authors, based on Capros et al. (2016).

The EU estimates for 2030, 2040 and 2050 can be seen to entail higher production figures from conventional energy types than those corresponding to compliance with targets on renewables. However, if the reduction in electricity demand planned by the German government is achieved, the scenario would change.

2.2.2. Nuclear and coal-fired power stations. Situation and outlook

This section examines the current situation and outlook for nuclear and coal-fired power stations in Germany. Issues related to the cost of coal and natural gas are not discussed here (see Section 2.2.4).

Nuclear Power Stations

Traditionally, the installation and continued maintenance of Germany's nuclear power stations has met with organised opposition. As a result of this movement, an agreement was reached in 1998 between the coalition partners parties in government (the SPD and the Greens) to amend the Nuclear Energy Act (*Atomgesetz*) and reduce the service life of the country's nuclear power stations. Following a preliminary commitment in 2000, agreement was reached in 2001 on decommissioning (*Atomkonsens*) between the government and the nuclear industry. The agreement also precluded the construction of any new nuclear power stations and introduced the principle of on-site storage of spent fuel. This accord, which led to the 2002 Phase-Out Amendment (*Ausstiegsnovelle*), limited the useful service life of the nineteen power stations still in operation to an average of 32 years, less than the 35-year figure the industry was seeking. As a result, the Stade and Obringheim power stations closed in 2003 and 2005, followed by Brunsbüttel in 2007 and Krümmel in 2009 (World Nuclear Association, 2016).

In 2009, a new government was formed by the Christian Democrats (CDU) and Liberal Democrats (FDP), which signed a new agreement in 2010. Under this accord, the operating life of power stations built before 1980 was extended by a further 10 years over and above the 2001 agreement and all others by 14 years. The price of this extension was the introduction of a surcharge on nuclear fuel (€145/g of uranium or fissible plutonium for six years, representing €2.3 billion per year or €16 per MWh) and payment of €300 million per year in 2011-2012 and €200m per year in 2013-2016 to subsidise renewables and finance rehabilitation of the old Asse salt mine to be used as a repository for nuclear waste. From 2017, this payment was to be replaced by a tax on generation of €9/MWh.

However, in May 2011, following the Fukushima disaster in japan, the government decided to reverse its previous decision, ordering that eight nuclear power stations be switched off that same year (March 2011) and the remainder by 2022. This plan for the phasing-out nuclear power, the *Atomausstieg,* is shown in table 4. The tax on nuclear fuel remained in place until the end of 2016 and the government established the construction of new coal and gas-fired stations and an increase in renewables, keeping GHG emission targets unchanged.

TABLE 4. Status and planned phase-out of nuclear power stations in Germany

Station	Net capacity (MW)	Commissioned	Operator	Provisional shutdown 2001	Agreed shutdown 2010	Status or scheduled shutdown
Biblis A	1,167	Feb-75	RWE	2008	2016	Closed 2011
Neckarwestheim 1	785	Dec-76	EnBW	2009	2017	Closed 2011
Brunsbüttel	771	Feb-77	Vattenfall	2009	2018	Closed 2011
Biblis B	1,240	Jan-77	RWE	2011	2018	Closed 2011
Isar 1	878	Mar-79	E.ON	2011	2019	Closed 2011
Unterweser	1,345	Sep-79	E.ON	2012	2020	Closed 2011
Phillipsburg 1	890	Mar-80	EnBW	2012	2026	Closed 2011
Krümmel	1,260	Mar-84	Vattenfall	2016	2030	Closed 2011
Grafenrheinfeld	1,275	Jun-82	E.ON	2014	2028	Closed June 2015
Total closed (9)	**9,611**					
Gundremmingen B	1,284	Apr-84	RWE	2016	2030	End of 2017
Gundremmingen C	1,288	Jan-85	RWE	2016	2030	2021
Grohnde	1,360	Feb-85	E.ON	2017	2031	2021
Phillipsburg 2	1,392	Apr-85	EnBW	2018	2032	2019
Brokdorf	1,370	Dec-86	E.ON	2019	2033	2021
Isar 2	1,400	Apr-88	E.ON	2020	2034	2022
Emsland	1,329	Jun-88	RWE	2021	2035	2022
Neckarwestheim 2	1,305	Apr-89	EnBW	2022	2036	2022
Total in operation (8)	**10,728**					
Total (17)	**20,339**					

Note: For the location of these power stations, see appendix 2.

Source: Authors based on data from World Nuclear Association (2016).

The cost of the closure and dismantling of the power stations has to be met by each firm. In 1977, the four main utilities (E.ON, RWE, EnBW and Vattenfall) created GNS (*Gesellschaft für Nuklear-Service mbH*) for the transport and ultimate disposal of the nuclear waste (World Nuclear Association, 2016).

TABLE 5. Scheduled closure of nuclear power stations in 2013

Owner	Forecast	Paid 2013	Closure and dismantling	Waste disposal	Total
E.ON	14,607	1,134	10,308	5,433	15,741
RWE	10,250	790	4,769	6,271	11,040
EnBW	7,664	570	4,515	3,719	8,234
Vattenfall	1,659	91	1,155	595	1,750
Kernkraftwerk Krümmel	1,805	149	900	1,054	1,954
Total (5)	35,985	2,735	21,647	17,072	38,719

Source: Authors based on data from Däuper, Dörte, & Irrek (2014).

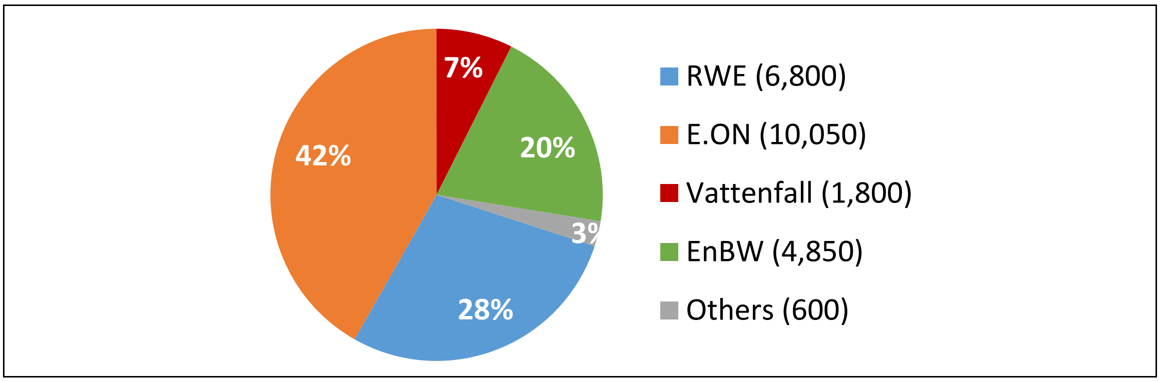
A parliamentary commission set up to debate the issue calculated that the provisions would be insufficient to meet the total expenses generated throughout the lifetime of the waste, which could come to €50-70 billion (Wille, 2015). It therefore recommended increasing the provision the utilities were required to set aside for waste management to €23.6 bn.

The government reached an agreement at the end of 2016 with the four major utilities, together with the public company Stadtwerke München GmbH, under which the companies would hand over the €23 bn agreed by the commission to a government-managed fund. This fund would be used to dispose of the waste, while the cost of decommissioning the power stations would still be met by the utilities. The amount was broken down into a base cost of €17.4 billion to come from the utilities' provisions plus an additional 35.5% to cover extraordinary costs. In accepting this extraordinary cost, the companies were absolved of all liability related to storage of the waste. The companies would have until 2022 to pay the amount, but would have to pay a surcharge for every year they defaulted on repayment (Wettengel, 2016).

In June 2017, the European Commission approved creation of the *Fonds zur Finanzierung der kerntechnischen Entsorgung*, or Nuclear Waste Disposal Fund (European Commission, 2017a), and the full amount finally agreed, €24.1 billion (somewhat higher than the original figure) was paid in in July of the same year (BMWi, 2017d). The German government's plan is that this fund should rise to around €70 billion in 2100 through investments.

To manage the waste, the BMU and GNS created a joint-owned company BGZ (*Bundes Gesellschaft für Zwischenlagerung mbH*), which was subsequently transferred in its entirety to the German government (World Nuclear Association, 2016). The final breakdown of the cost is shown in figure 10.

FIGURE 10. Distribution of the cost of the Nuclear Waste Disposal Fund



Source: Authors, based on company websites.

As shown in the figure, the company most affected by the fund, because of its volume of nuclear assets, was E.ON, which had to raise additional capital of €1.35 billion to ensure sufficient liquidity (E.ON, 2017e). RWE declared that it had sufficient liquidity to meet the payment (RWE, 2017c).

The actual decommissioning of power stations is still the responsibility of the utilities, which have to initiate the legal procedures for each power station on an individualised basis. The first decommissioning application was lodged in 2017 for E.ON's Isar I. The process is expected to last fifteen years at a forecast cost of around €1 billion (World Nuclear Association, 2016).

Coal-fired stations

There is no such plan for the shutdown of coal-fired stations[18] and new high-capacity hard coal and lignite-fired stations were still being built until recently (Álvarez Pelegry & Ortiz Martínez, 2016).

The German government's target for 2030 is to substantially reduce GHG emissions (see Section 2.5.1). As the then environment minister Barbara Hendricks said on the presentation of the Climate Action Programme 2050 (*Klimaschutzplan 2050*), this implicitly entails closing half of the coal-fired stations operating in 2014 (Götze & Schwarz, 2016).

Following an agreement with RWE, Vattenfall and MIBRAG,[19] the first step has been to consign the oldest and most inefficient lignite-fired plants to a "climate reserve" (see Section 2.4.2), a gradual process which began in 2016[20] (see table 6). This involves taking a total capacity of 2.7 GW off the electricity market, at an annual cost of €230 million over seven years in payment to the owners (BMWi, 2015b). The impact on the electricity bill will be an average increase of €0.50/MWh for consumers. The plan will prevent emission of 11-12.5 MMTCDE in 2020. A further appraisal will be carried out in 2018; if the measures are found to be insufficient, new ones will be introduced (BMWi, 2015b).

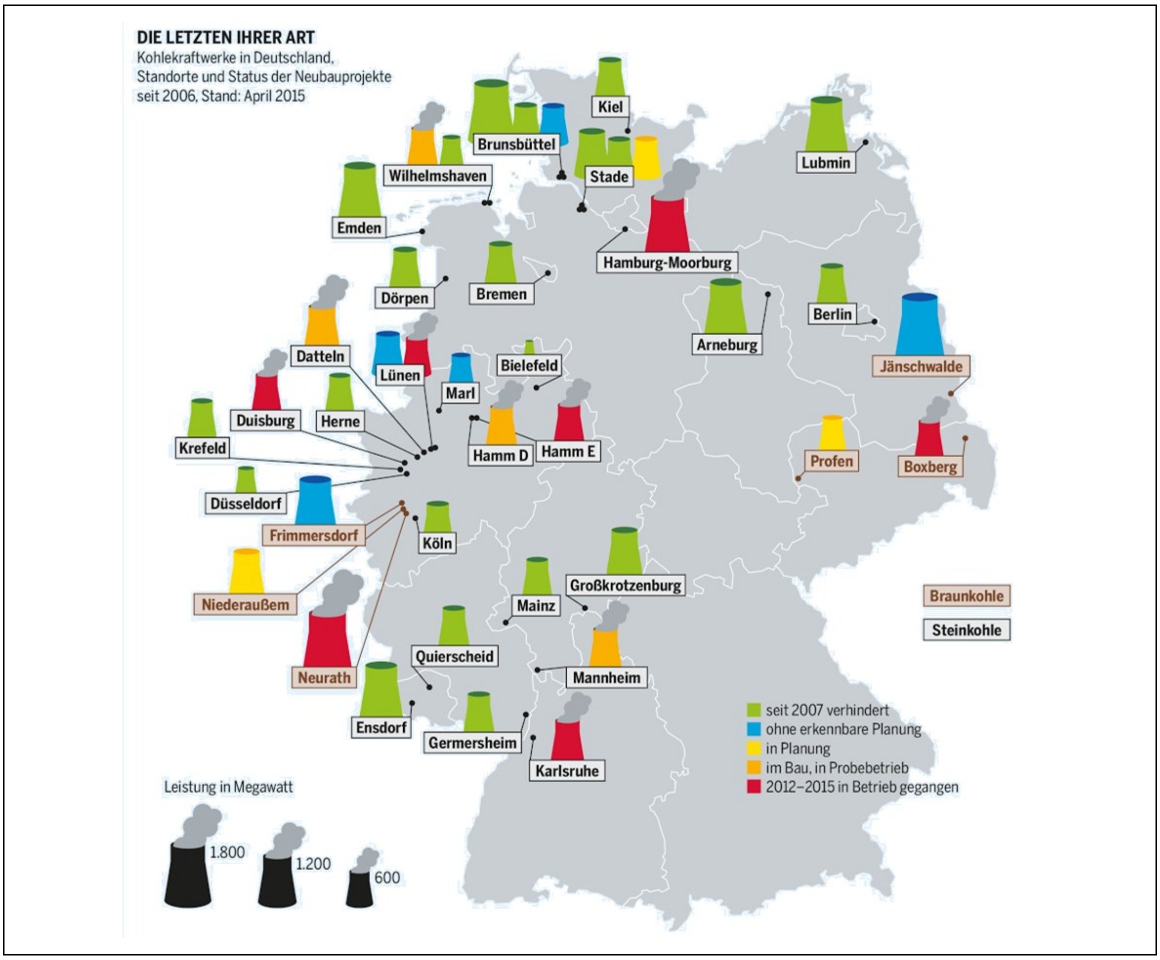
TABLE 6. Germany: scheduled consignment of lignite-fired plants to the reserve

Station	Net capacity (MW)	Commissioned	Operator	Consigned to reserve	Shutdown
Frimmersdorf P	284	1966	RWE	2017	2021
Frimmersdorf Q	278	1970	RWE	2017	2021
Niederaußem E	295	1970	RWE	2018	2022
Niederaußem F	299	1971	RWE	2018	2022
Neurath C	292	1973	RWE	2019	2023
Jänschwalde E	465	1987	Vattenfall	2017	2020
Jänschwalde F	465	1989	Vattenfall	2018	2022
Buschhaus D	352	1985	MIBRAG	2016	2020
Total (8)	**2,730**				

Source: Authors, based on data from Bundesnetzagentur (2016b) and company websites.

[18] For the location of hard coal and lignite-fired power stations currently in operation, see appendix 2 and the 2006 plan in Figure 11.
[19] MIBRAG (Mitteldeutsche Braunkohlengesellschaft) is a mining firm, originally from the DDR, basically involved in lignite mining. It has several lignite-fired plants, such as Wählitz and Deuben, which had a joint output of 836 GWh in 2015. It is owned by the Czech group EPH, which in Germany also owns LEAG (EP Power Europe, 2017).
[20] For further information, see Section 2.4.2. Reserve power Plants. Grid, climate and security reserve.

FIGURE 11. Situation of coal-fired stations to 2015, as planned in 2006



Note: From top to bottom, the categories in the legend are: suspended since 2007; no plan; under planning; under construction, testing and commissioning between 2012-2015.

Source: Böll Stiftung (2015).

In the medium term, the current plan rules out the construction of new lignite-fired plants (see figure 7 and table 3). The schedule for closure of these stations has been sped up by unbundling it from the closure of open-cast mines, following criticism of the previous plan.

These criticisms included doubts as to the economic viability of several lignite-fired plants;[21] the fact that the lack of flexibility of lignite-fired plants prevented introduction of a larger quantity of renewables, necessitating larger expansion of the power grid; and the fact that operation at partial load of the lignite-fired plants accelerates the aging process (50Hertz, Amprion, TenneT, & TransnetBW, 2014b).

Nonetheless, operators are seeking to modernise these power stations to tackle these two issues, while continuing to improve efficiency (Álvarez Pelegry & Ortiz Martínez, 2016). In this regard, work is being carried out to allow modifications to the capacity

[21] According to (50Hertz, Amprion, TenneT, & TransnetBW, 2016a), the current cost of generation will remain unchanged, but emission allowances may increase.

of lignite-fired plants which in previous years had played a similar role to nuclear, providing base capacity.

In the specific area of hard coal, modern higher-efficiency power stations have recently been installed[22] with CHP capacity. Construction of the new Datteln 4[23] hard coal-fired plant is scheduled for an as-yet unspecified date between 2017-2019. No further new power stations are planned. Indeed, the plan envisages that by 2030, installed capacity will be 15 GW — half of the figure for 2015.

Work is also being carried out to improve these installations. For example, the capacity of the hard coal-fired plant at Moorburg, opened by Vattenfall in 2015, can vary by 36% from its rated capacity (600 MW of a maximum of 1,654 MW) (Vattenfall, 2017d), as compared to a traditional regulation reference of 30%(Gallego, 2016).

Approximately 90% of the hard coal used in Germany is imported. Local hard coal mining is dependent on grants, which, under EU regulations, will be ended in 2018. After that date, all hard coal is likely to be imported (Álvarez Pelegry & Ortiz Martínez, 2016).

For its part, RWE has 10 GW in lignite capacity, as well as sufficient reserves of the mineral to keep up significant production for another 30 years (Brough, Brand, Sanz de Madrid, & Duncan, 2017b).

2.2.3. Penetration of renewables

The *Energiewende* has considerably increased the level of electrical output from renewables. Specifically, between 1995 and 2015 the share of renewables in Germany's total output tripled to 30% (see figure 4).[24] The German government wants to keep up this momentum and plans further increases to 35% by 2020, 50% by 2030 and 80%-95% by 2050. A study by Deutsche Bank (Brough & Brand, 2016) forecasts that by 2020 42.5% of all Germany's electricity will come from renewables.

The development has been promoted by the 2000 Renewable Energy Act (*Erneuerbare-Energien-Gesetz* or EEG),[25] which established a system of feed-in-tariffs to ensure revenue from renewables. The act has been amended several times, to

[22] As a result of the 2013 decisions. For further information, see Álvarez Pelegry & Ortiz Martínez (2016).

[23] CHP power station developed by Uniper with a single 1,055 MW set, running at 45% efficiency, located in North Rhine-Westphalia, due to come on line in the first half of 2018. The project has run into a number of setbacks since 2007, the latest involving difficulties in obtaining government authorisation — eventually granted in January 2017. By the end of 2016, over €1 billion had been invested in the project, and it is estimated that it will take another €400 million to complete commissioning (Uniper, 2017a).

[24] Comparing these figures to those for mainland Spain (18% in 1990 and 41% in 2016), it is clear that renewables play a greater role in Spain than in Germany. Nonetheless, Germany has practically twice the installed capacity in renewables (107 GW compared to 51 GW in Spain (2016)) and output (192 TWh compared to 100 TWh in Spain (2016)). We shall not discuss here the relative effort and cost for consumers of the two developments.

[25] For a list of relevant legislation, see Álvarez Pelegry & Ortiz Martínez (2016).

varying degrees, in order to comply with EU directives, the federal government's targets and market trends.

The reform of 2014 brought an end to the policy of feed-in-tariffs, establishing instead a system of pilot auctions for photovoltaic facilities.[26] Following the success of the auctions, the reform of the Renewable Energy Act which came into force on 1 January 2017 established that this mechanism of incentives would apply to photovoltaic solar, wind and biomass energy. Henceforth, there will be specific auctions for each type of technology (i.e. wind, photovoltaic, etc.) and the frequency of the auctions will vary from one technology to another: three per year for photovoltaic and three to four per year for onshore wind and biomass. Projects classed as low power (less than 750 kW in the case of wind and photovoltaic, and 150 kW for biomass), will continue to receive premiums from feed-in-tariffs (Appunn, 2016a). Other renewable technologies (hydro, geothermal, etc.) will be incentivised through feed-in-tariffs, as they are considered not to be sufficiently competitive.

The auction system is based on the idea of presenting a total capacity of renewable generation to be installed with a maximum cost per unit of energy (MWh). Projects using the same source of primary energy then compete on the basis of their capacity for implementation with the lowest subsidies. The winning projects are paid at the tendered price for a period of 20 years.

In order to favour their introduction, bids from cooperatives may enjoy certain advantages, such as receiving the maximum payment allocated at auction, rather than the amount tendered.

By energy source, it is planned to build 2.8 GW per year of onshore wind between 2017 and 2019 and 2.9 GW from 2020. Incentives will be introduced for wind farms to be built throughout the country and not only in windy sites close to the coast. These auctions will account for 80% of new construction (Falk, 2016). According to the TSOs' calculations, taking an average wind farm life of 20 years, by the end of 2030, total installed capacity from onshore wind will come to 58.5 GW.

The target for offshore wind[27] is to build 500 MW in 2021 and 2022, 700 MW per year between 2023 and 2025 and 840 MW annually from 2026, to achieve a total of 15 GW

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[26] The auctions have been considered a success, achieving low prices in 2015 and 2016, from €91.7/MWh in the first auction to €69.0/MWh in the last (Bundesnetzagentur, 2016a). Similar auction systems have also been put in place in other countries. In France, for example, there have been auctions for power from small roof-mounted photovoltaic facilities since 2011 (Förster, 2016). in Spain, an auction was held in January 2016 which resulted in allocation of 700 MW from new renewable power stations —500 MW wind and 200 MW biomass (Agencias, 2016)— and another in May 2017 of 3,000 MW, mostly assigned to wind.

[27] According to figures presented at the Marine Energy Week 2015, the cost of generating power from offshore wind (measured in LCOE terms), is between €60 and €160 per MWh, with a considerable reduction in costs already being observed at that time. It was expected to fall further as installed capacity increased. Previously, in 2014, generating costs had reached a level of between €170 and €230/MWh.

by 2030. Auctions will also be held, but the amount still remains to be determined.[28] This would bring total installed wind capacity in 2030 to 73.5 GW, of which 20% would be offshore.

600 MW of solar photovoltaic will be auctioned each year. The target is to achieve an annual rate of installation of 2.5 GW, with the remaining 1.9 GW coming from small facilities paid via feed-in-tariffs. Once a total installed capacity of 52 GW has been achieved, the feed-in-tariffs system for solar photovoltaic will be phased out. According to the TSOs' calculations (see table 3), this expansion plan will entail installing 76.8 GW by the end of 2030. This estimate is considered optimistic and is based on the assumption that photovoltaic will be competitive when feed-in-tariffs are phased out.

The TSOs thus calculate that it is possible to meet the government's target of 50% renewables in 2030 by targeting 1.9 GW of new photovoltaic per year, bringing the total installed by that date to 66.3 GW (table 3). According to Deutsch et al. (2016), photovoltaic facilities of under 10 kW operating in the renewable generation system will account for 10.4 GW of production in 2025 (compared to 4.9 GW in 2015) and 15.1 GW in 2030. They calculate that the proportion being used for self-consumption will rise from 28% in 2015 to 32% in 2030.

Finally, the target for biomass is to install 150 MW per year between 2017 and 2019 and 200 MW in the three following years. According to the TSOs, taking the closure of existing power stations into account, this will mean a drop in total capacity of 0.05 GW, leaving installed capacity at the end of 2030 at 6.2 GW. After that date, a new target will have to be established by law (Förster, 2016). Biomass facilities will only receive incentives for 50% of their operating hours, in an attempt to encourage usage during the periods of highest market price (i.e. at times when the contribution of other renewables is lowest).

2.2.4. Generating costs

The measure normally used to calculate the generating costs of a series of power stations using different technologies is the Levelized Cost of Electricity or LCOE. The costs of each power station are calculated based on their useful service life and the average annual power generation of the plants.

table 7 shows the base figures for the LCOE study conducted in VGB PowerTech e.V., (2015) for different generating sources/technologies in Germany in 2015. figure 12 shows the result of this calculation and the results for Germany of a similar study by the International Energy Agency (IEA) and the OECD's Nuclear Energy Agency (NEA) in the same year, covering a total of 22 countries. The NEA study (IEA & NEA, 2015)

[28] For example, in 2017 only one auction has been held (and announced). It had a value of 1,550 MW and resulted in four projects of a total of 1,490 MW.

only takes into account different values in the weighted average cost of capital (WACC) and the FLEH, which are generally higher than in the VGB study.

TABLE 7. LCOE figures for generating sources in Germany in 2015, according to VGB

Source / Technology	Investment (€/kW)		Useful service life	O&M (€/kW/yr)		Fuel cost (€/MWh$_{th}$)		Electrical efficiency (%)		Emissions factor (tCO_2 / MWh$_{th}$)	Emissions factor (tCO_2 / MWh$_e$)	FLEH (h)	
	Min	Max	(years)	Min	Max	Min	Max	Min	Max			Min	Max
Supercritical Hard Coal St.	1,200	1,700	40	32	39	7	11	44	46	0.339	0.737-0.770	2,000	4,500
Supercritical Lignite St.	1,350	1,800	40	35	43	4	6	41	43	0.404	0.940-0985	3,000	7,000
Natural gas CCGT	550	800	30	19	23	19	28	59	61	0.202	0.331-0.342	750	2,500
Nuclear	3,000	5,000	60	36	44	6	9	32	37	-	-	7,000	8,000
RoR hydroelectric	2,300	4,500	100	25	50	-	-	-	-	-	-	3,400	5,500
Onshore wind	1,000	1,800	25	30	50	-	-	-	-	-	-	1,800	3,200
Offshore wind	2,800	4,500	25	100	120	-	-	-	-	-	-	3,000	4,200
Ground-mounted photovoltaic	900	1,600	25	13	25	-	-	-	-	-	-	900	2,000

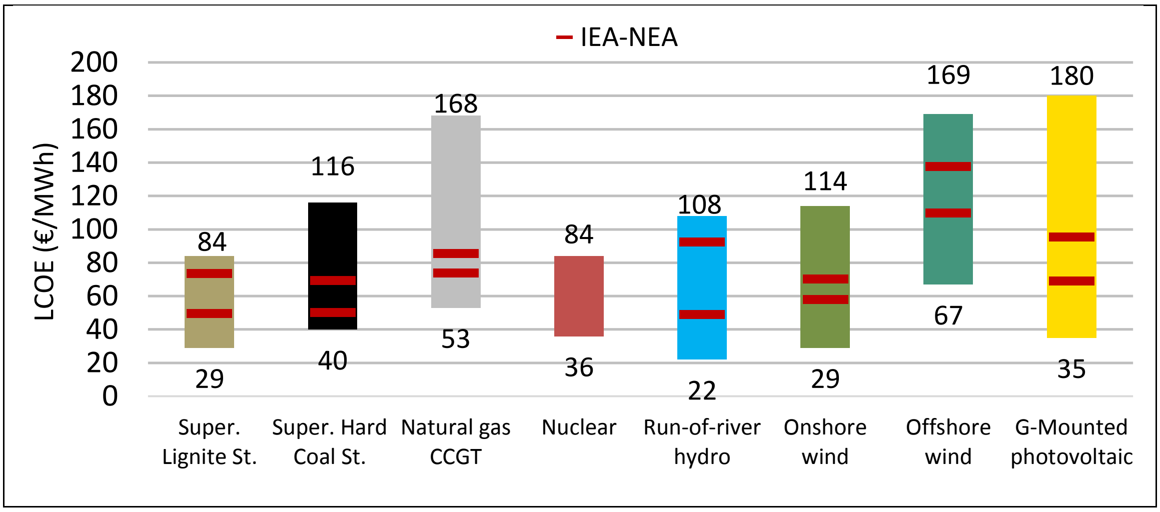
Note 1: Natural gas refers to combined-cycle gas turbine (CCGT) stations.

Note 2: The minimum WACC is 4% and the maximum 7%. The minimum price of CO_2 is €5/t and the maximum is €10/t.

Note 3: The values used in the study (Graichen & Kleiner, 2017), cited below, are in the region of those shown in this table for conventional generation.

Source: Authors based on data from VGB PowerTech e.V., (2015).

FIGURE 12. LCOE of the main generating sources in Germany in 2015 according to VGB and IEA-NEA



Note 1: Maximum and minimum values based on VGB estimations.

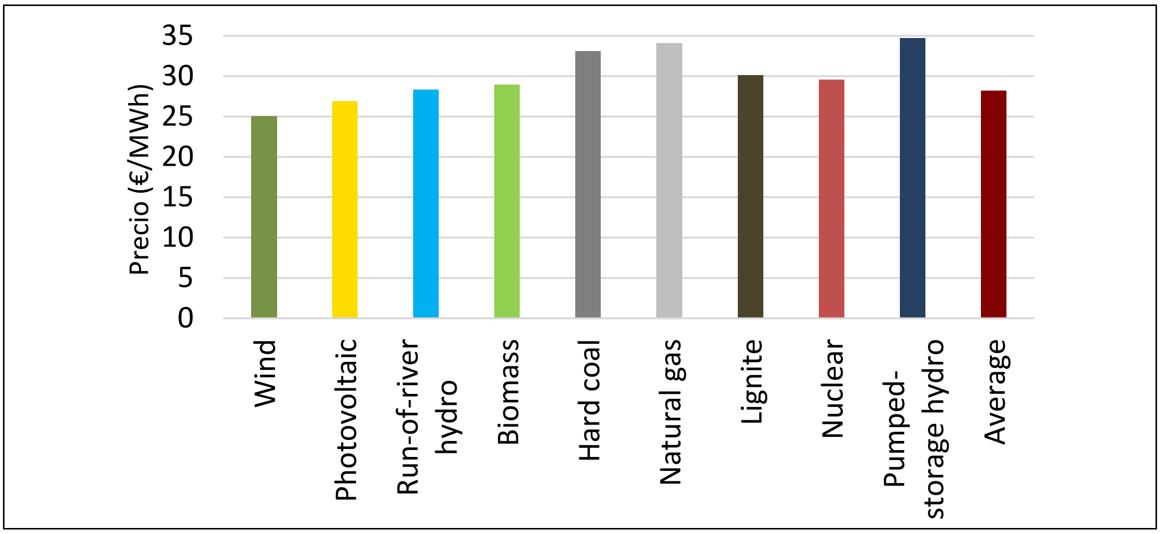
Note 2: The IEA-NEA's minimum value for lignite, hard coal and natural gas is based on 6450 FLEH and a WACC of 4%; the maximum value is based on 4300 FLEH and a WACC of 7%. For all other sources, only a variation in the WACC is considered.

Note 3: IEA-NEA data are based on a 2013 exchange rate of $1 = €0.75.

Source: Authors, based on VGB PowerTech e.V., (2015) and IEA & NEA, (2015).

These LCOE values are reflected in the average day-ahead market price, when the different energy sources are sold or "matched" (figure 13). As can be seen, renewables have a lower average price on the day-ahead market than non-renewables, including nuclear energy. Pumped-storage hydroelectricity comes in last place.

FIGURE 13. Average price on day-ahead market by energy type



Source: Authors, based on figures from Burger (2017).

Based on the above data, an estimate is given below of the LCOE of conventional generating sources for 2030. The estimate is made for two scenarios. The first takes into account the generating costs (fuel and CO_2) for the TSOs' central 2030 scenario (50Hertz, Amprion, TenneT, & TransnetBW, 2016a) at constant FLEH; the second uses the above costs and assumes the increase in number of hours given in the EU's scenario for 2030.

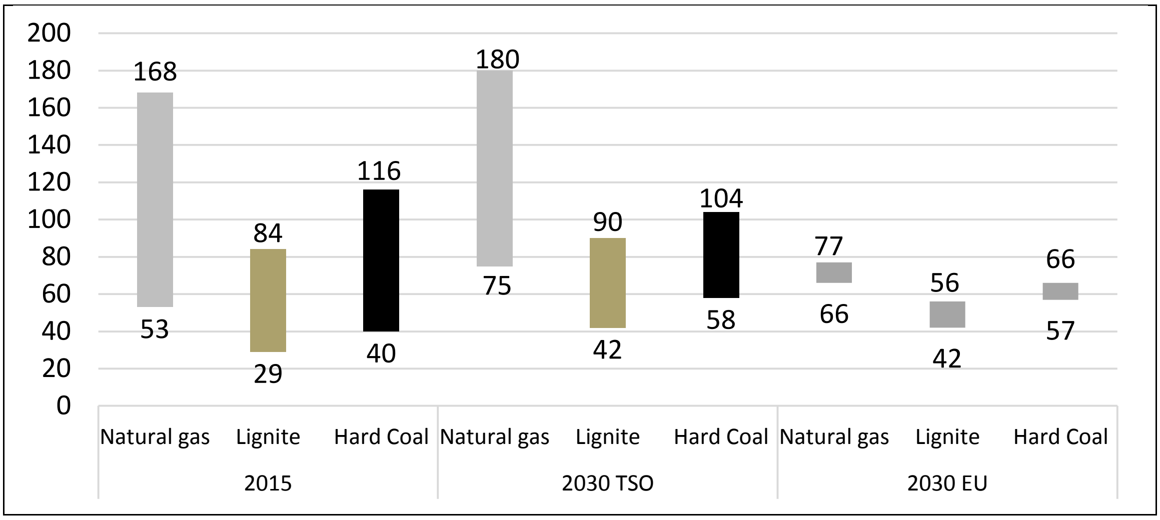
TABLE 8. LCOE figures for generating sources in Germany in 2030

Source	Fuel cost (€/MWh_{th})	CO_2 emissions cost (€/t)	FLEH (h)	
			VGB	EU
Hard coal	9.46	23	2,000-4,500	4,877
Lignite	40		3,000-7,000	7,000
Natural gas	30		750-2,500	4,610

Note: The 2015 maximum has been used to calculate the lignite FLEH. HEPC for hard coal was calculated based on the value of the EU scenario and the hard coal-lignite proportion provided by German TSOs to 2030.

Source: Authors.

FIGURE 14. Forecast LCOE of thermal power stations in Germany in 2030



Source: Authors, based on VGB PowerTech e.V. (2015).

As can be seen, based on the above cost forecasts (see table 8), natural gas only begins to be competitive compared to lignite and hard coal with a high FLEH, which is not clearly true in any of the scenarios analysed. These observations are in line with those given in the EU's scenario to 2050 (Capros et al., 2016), which show that, without taking into account the prices of emission allowances, the LCOE of gas is higher than that of hard coal and lignite in the 2030 horizon. A similar conclusion may be drawn from Graichen & Kleiner (2017),[29] with natural gas only matching or displacing hard coal in scenarios with high costs of CO_2 emission allowances (€50/t and €103/t), and lignite remaining as the main form of generation.

Based on the figures in table 7, we have selected certain parameters —in some cases intermediary— for investment, WACC, operation & maintenance and performance. FLEH figures are based on the average for the period 2010-2016 (see figure 6). These parameters are shown in table 9.

TABLE 9. Calculation hypotheses for LCOE of generating sources in Germany between 2010 and 2016

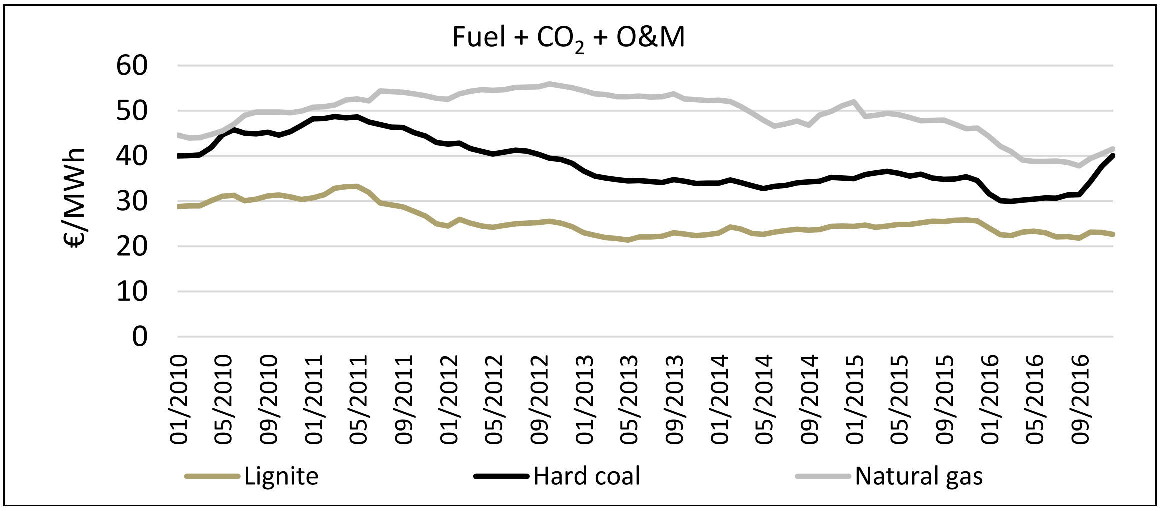
Source / Technology	Investment cost (€ / kW)	WACC (%)	Useful service life (years)	O&M (€ / kW / year)	FLEH	Efficiency	Emissions factor (t/MWh_{th})
Lignite	1,575	5.5	40	39	6,542	42%	0.404
Hard coal	1,450	5.5	40	35.5	3,712	45%	0.339
Natural gas	675	5.5	30	21	2,909	60%	0.202

Source: Authors.

[29] The fuel prices used in this study for lignite, hard coal and natural gas (€6.1/MWh, €11.9/MWh and €33.8/MWh respectively in 2030 in the lowest price scenario; figures taken from (Repenning et al., 2015)) are higher than those considered by the TSOs, whereas the operating costs lie within those given in table 7.

We also used the data on hard coal, lignite and natural gas prices given in VGB PowerTech e.V. (2015) and Destatis (see figure 78). Using all of the above, we have calculated the variable costs of fuel, CO_2 (see figure 30) and operation & maintenance. These are shown in figure 15.

FIGURE 15. Estimated variable cost of lignite, hard coal and natural gas power stations between 2010 and 2016



Source: Authors, based on VGB PowerTech e.V., (2015) and Destatis.

As can be seen, with these cost components, lignite is lower and from 2014 on, the gap with hard coal narrows. The cost of natural gas can also be seen to be higher throughout the entire period.

When the LCOE is calculated using the investment hypotheses in table 9, hard coal and natural gas power stations are close in cost, although the cost of hard coal plants is generally lower. Note too that lignite plants are the most "economic". These total costs (LCOE) can be seen to stand towards the bottom of the cost bands calculated by VGB and the IEA-NEA (see figure 12).

2.3. Electricity demand, exports and imports

2.3.1. Electricity demand

Gross electricity demand[30-31] in Germany in 2016 stood at 594.7 TWh, 0.7% down on the previous year (598.6 TWh). Demand has thus fallen since the recovery of the previous year, at a considerable remove from the record of 2007 (nearly 622 TWh (AG Energiebilanzen e.V., 2016)).

Trends in gross electricity demand in Germany over the last decade are shown in figure 16. As can be seen, in 2009 there was a major fall in consumption due to the financial crisis. Despite recovery in 2010, there has been no return to a similar level

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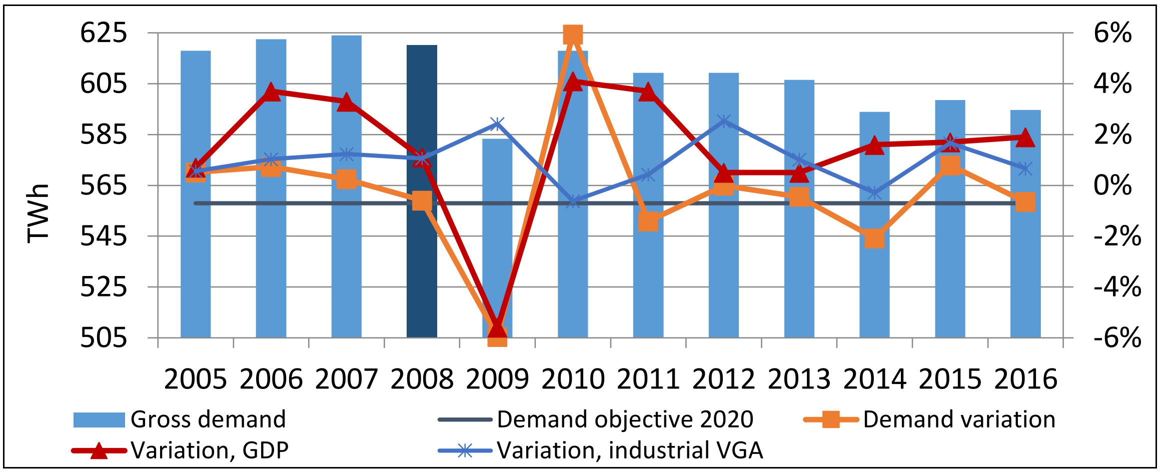
[30] Gross power generation plus international balance (imports minus exports).

[31] Electricity accounts for around 20% of total final energy consumption (gross electricity demand minus generation and transmission losses) in Germany. In 2015, 515 TWh of electricity was used in final energy out a total of 2,467 TWh (Eurostat).

of gross demand. As well the decline in economic activity, this fall can also be ascribed to more efficient electricity consumption.

FIGURE 16. Gross electricity demand in Germany (TWh)



Note 1: Gross demand is identified as gross generation minus exports plus imports.

Note 2: 2008 demand, which is used as the baseline for the 2020 target, is shown in dark blue.

Source: Authors, based on figures from Eurostat and (Graichen et al., 2017).

Just as there is a target for introducing renewables in electricity production, there is also a target for reducing electricity consumption by 10% in 2020 (compared to 2008 figures). This will mean achieving gross annual demand of around 556 TWh.[32-33] For 2050, the target is for a 25% reduction (compared to 2008) to 463.5 TWh.

In contrast to this challenge of reducing demand, for the period 2020-2025 the ENTSO-E forecasts that total electrical demand will remain virtually unchanged from 2016 levels (a 0.3% reduction). Greater demand from an enlarged fleet of electric vehicles on the roads and greater use of electricity in heat applications will be offset by greater efficiency.

The EU scenario for demand stands somewhere between the two, envisaging a fall from 2015 to 2020 with a return to 2010 levels by 2025. In the longer term, it predicts that demand will increase by 11% compared to 2015. This scenario is in contradiction with the German government's scenario.

2.3.2. Imports and exports

Since 2003, Germany has been a net power exporter. figure 17 shows that both exports and imports have increased, partly as a result of greater integration of the

[32] The German government's goal is to reduce gross primary energy consumption (which includes electricity demand) by 20% in 2020 compared to 2008 levels. This target is much more ambitious than that set by the EU for 2020 (20% reduction compared to 2007-2020 projection (European Parliament, 2012)). The EU target for 2030 is for 30% (European Commission, 2016e)) and Germany's target for 2050 is 50%.

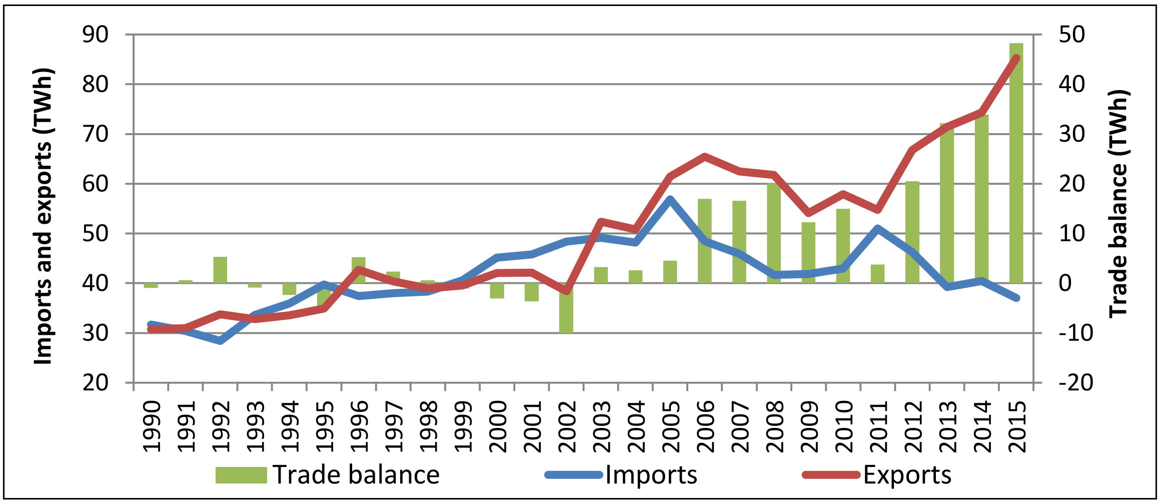
[33] Eurostat values tend to be 2 TWh higher than those provided by the German government. This correction has been applied to 2016 values, for which Eurostat data are not available.

central-European power grid. Recent years have seen major growth in net exports, except for 2011, when exports were down due to the shutdown of several nuclear power stations (see figure 17).

In 2016, Germany had net power exports of 47.5 TWh.[34] Net exports were down 10.2 TWh (17.6%) on the previous year, in a general context of falling imports and exports.

It is important to note that there are no contractual agreements on these volumes of exports and imports between countries; instead, they are based on market flows (and therefore market contracts) and the development of the European power network (Graichen et al., 2017). Specifically, net exports are partly due to surplus energy from German wind farms. In the winter of 2015, the Polish system operator decided to cut one of the interconnections with Germany until 2018 and install phase-shifting transformers at frontier substations to regulate the flow of electricity from Germany. (Korab & Owczarek, 2016)

FIGURE 17. Germany's international power exchanges

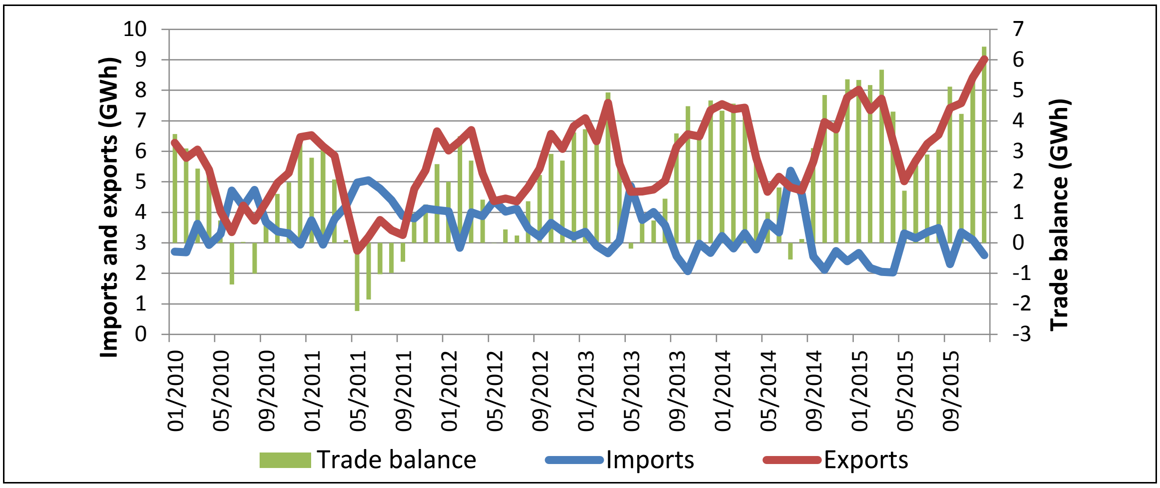


Source: Authors, based on Eurostat figures.

The net balance between imports and exports varies greatly throughout the year. As can be seen in figure 18, in 2010 and 2011, Germany exported electricity during the winter months and imported it during the summer months. This trend is due to a number of factors, such as greater demand for electricity in Europe in winter and the fact that nuclear power stations generally carry out their annual inspections in the summer (Platts, 2014). However, since 2012 Germany has been a net exporter practically throughout the year.

[34] In the same year, Germany had net exports of 28.2 TWh to Austria, 5.9 TWh to Switzerland, 5.8 TWh to the Netherlands, 5.3 TWh to France and 4.8 TWh to Luxembourg. During the same period, net imports from Czech Republic came to 0.9 TWh, Sweden 0.7 TWh, Poland 0.6 TWh and Denmark 0.3 TWh. Note that exports to the Netherlands are not consumed exclusively on the Dutch market, with part going to Belgium and the UK.

FIGURE 18. Monthly trend in Germany's cross-border electricity exchanges



Source: Authors, based on ENTSO-E data.

Structurally, Germany needs these exports, since it cannot manage all its surplus output solely by reducing regulation capacity. In the most critical possible case of a certain lack of exports (1 GW), the situation could be resolved by switching off any generating capacity that can handle a sudden halt, such as wind turbines (ENTSO-E, 2016c).

Germany is one of five countries (the others are Denmark, Ireland, Poland[35] and Romania) that require international interconnectors to take off their power surplus. Together with Spain and the Netherlands, Germany is among the few European countries that do not need to import electricity to meet severe conditions, as tends to happen in other European countries with a major industrial weight, such as France, Italy and the UK.

The scenarios analysed above forecast a net importing or exporting balance depending on whether they predict that domestic demand will increase (EU), remain steady or fall (TSOs).

As the EU's reference scenario for 2016 indicates, the future decommissioning of the country's nuclear power stations is expected to alter this exporting trend (Capros et al., 2016). Indeed, in this scenario Germany would have net imports of around 13 TWh annually from 2020 to 2050. However, this appears excessive, given historical trends and the country's industrial development (Graichen et al., 2017).

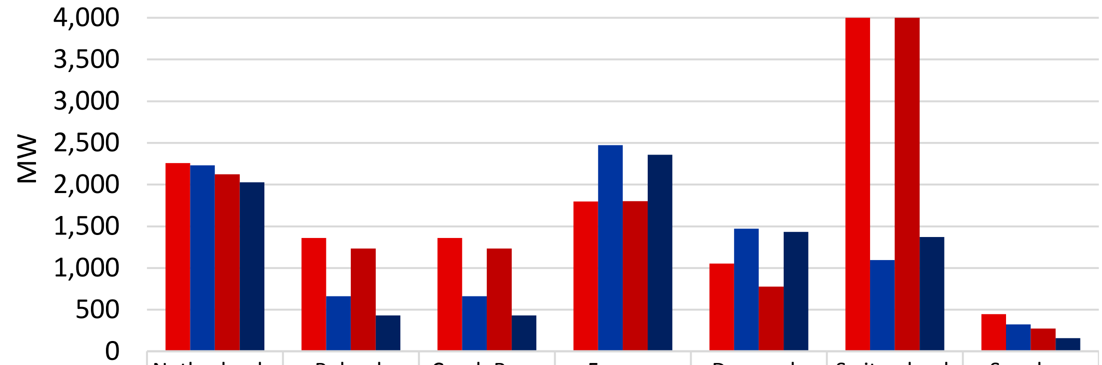
The TSO forecasts consider that imports may be particularly important in meeting peak demand, which it keeps at 84 GW. It is critically important in the scenario to 2025, when there will still not be enough capacity to deal with imbalances (demand management and storage amount to 10 GW in 2030) and the total installed capacity of thermal power stations will be reduced.

[35] Only at night.

2.3.3. International connections

Germany has interconnectors with a total of nine countries. figure 19 shows the average available net capacity of these interconnectors in 2014 and 2015 (Bundesnetzagentur, 2016d). As can be seen, there was a general fall both in import capacity (from 12,279.7 MW to 11,443.1 MW, down 6.8%) and export capacity (from 8,913.5 MW to 8,209.3 MW, down 7.9%). In the previous period, 2013 and 2014, export capacity increased slightly (+0.6%) and there were no significant changes in imports (0.0%) (Bundesnetzagentur, 2015).

FIGURE 19. Net available average capacity of Germany's international electrical interconnections



	Netherlands	Poland	Czech Rep.	France	Denmark	Switzerland	Sweden
Imp. 2014	2,257.20	1,361.20	1,361.20	1,798.50	1,054.20	4,000.00	447.6
Exp.2014	2,231.20	660.6	660.6	2,472.20	1,471.50	1,094.20	323.3
Imp. 2015	2,123.80	1,233.10	1,233.10	1,800.00	778	4,000.00	275.2
Exp.2015	2,026.60	430.9	430.9	2,356.30	1,432.40	1,373.40	158.8

Note 1: Imports refer to import capacity in Germany and export capacity from Germany.

Note 2: The net capacity of interconnections with Austria and Luxembourg is not included, as it falls within the area controlled by the ENTSO-E.

Source: Authors, based on figures from Bundesnetzagentur (2016d).

As can be seen, apart from the market with Austria and Luxembourg, Germany's largest import capacity is with Switzerland, followed by the Netherlands and France. The largest export capacity, on the other hand, is with France, followed by the Netherlands and Denmark. It is striking to note the imbalance between import and export capacity with Switzerland, Poland and the Czech Republic, where import capacity is up to three times greater than export capacity.

The ENTSO-E's ten-year network development plan includes five interconnectors with Germany: Great Britain with continental Europe and the Nordic countries; the Nordic countries with continental western Europe; the North Sea and Baltic countries with continental eastern Europe; Poland with Germany, the Czech Republic and Slovakia to increase market capacity, and Italy with its neighbouring countries (ENTSO-E, 2016b).

For the ENTSO-E, interconnection with the Nordic countries would make it possible to tap into those countries' hydroelectric and nuclear resources. Extending the interconnection with Poland would reduce the possible additional charges for Poland of an increase in coal-fired generation (either from an increase in the price of the raw material or through an increase in the cost of CO_2 emission allowances). Finally, the interconnection between Italy and central Europe is intended to reduce the variability of renewable generation by connecting up the intermittent renewable resources (wind and photovoltaic) of northern and southern Europe, as well as hydroelectric power from the Alps.

table 10[36] shows Germany's planned interconnections in 2020 and 2025. Note the new interconnector with Belgium planned for 2020, the increase in underwater interconnections (Norway by 2025), the increase in export capacity to Poland and reinforcement of the interconnector with the Czech Republic.

These interconnections are advancing at a reasonable pace (OECD & IEA, 2016). Scheduled commissioning of the interconnection with Norway has been brought forward to 2020 (TenneT, 2017) and the interconnection with Belgium is on schedule (Elia, 2017).

TABLE 10. Forecast for Germany's interconnections in 2020 and 2025 (MW)

	2015		2020		2025			
Country	**Exports**	**Imports**	**Exports**	**Imports**	**Exports**	**Increase 2020-2025 (%)**	**Imports**	**Increase 2020-2025 (%)**
Norway	0	0	0	0	1,400	-	1,400	-
Poland	431	1,233	500	3,000	2,000	300	3,000	0
Sweden	159	275	615	615	1,315	114	1,315	114
Switzerland	1,373	4,000	1,586	4,000	3,286	107	4,700	18
Austria	NA	NA	5,000	5,000	6,000	20	6,000	20
France	2,356	1,800	2,300	1,800	3,300	43	3,300	83
Denmark	1,432	778	2,500	2,780	4,000	60	4,000	44
Czech Rep.	431	1,233	1,500	1,586	1,500	-	2,100	32
Netherlands	2,027	2,124	4,450	4,450	4,450	-	4,450	-
Luxembourg	NA	NA	2,300	2,300	2,300	-	2,300	-
Belgium	0	0	**1,000**	**1,000**	1,000	-	1,000	-
Total	**15,509**	**18,743**	**21,751**	**26,531**	**30,551**	**40%**	**33,565**	**27%**

Note 1: Figures are for net capacity available for international exchange. The sum total of net capacities of each of the interconnections between countries may be greater than shown.

Note 2: Import and export capacity is given from a German perspective.

Note 3: The net capacity of the 2015 interconnections with Austria and Luxembourg is not included, as it falls within the area controlled by the ENTSO-E. For the 2015 total, 2020 values have been assumed.

Source: Authors, based on figures from ENTSO-E (2016a). The estimate for 2025 coincides with the 2030 estimate made by ENTSO-E (2016b).

[36] appendix 4 shows the geographical location of European countries with which Germany has interconnectors planned for 2025 and their forecast capacity.

2.4. Wholesale market and capacity mechanisms

In this section, we analyse trends in energy price on the wholesale market since 2010 and in greater detail in 2016 and 2017, and discuss the short- and medium-term forecasts. We then go on to study the decision on capacity mechanisms taken by the German government, its present situation, and forecast for the future. We also examine the importance of expanding the transmission network and other measures intended to augment the flexibility and security of the electricity system.

2.4.1. Price on wholesale day-ahead market

The German electricity market can be divided in two parts: the organised market or exchange, in which individual supplies and demands take the form of standardised products, which are matched by the market operator; and the bilateral or over-the-counter (OTC) market between parties, in which the seller (i.e. the producer) and the buyer (i.e. the consumer) come to a specific, non-standardised agreement, for delivery of energy. In both cases, there are long-term products (futures on the exchange, and contracts or forwards between individual parties on the OTC markets) and short-term products. In the case of the wholesale market there are two variants of short-term product, the day-ahead market (sale of energy for the next day) and the intraday market (sale of energy up to a short time before delivery; 45 minutes in the case of Germany). In addition, other complementary services may also be offered on the exchange: secondary regulation, tertiary regulation, etc. [37]

This study of prices focuses on the day-ahead market, for which most information is available and because it underlies the prices of futures and OTC transactions. However, it is important to bear in mind that most energy is sold on the OTC market, for which the day-ahead market is used as a reference price (Möller, 2010). For example, in the fourth quarter of 2016, roughly 1,700 TWh was sold on the OTC market, as opposed to 600 TWh on the exchange[38] (Market Observatory for Energy of the European Commission, 2017).

Recent trends

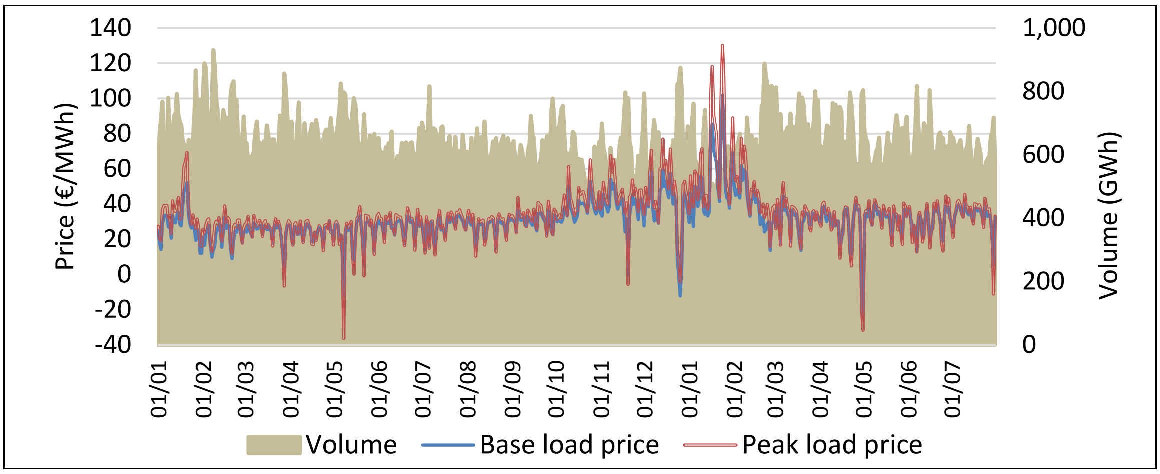
figure 20 shows daily electricity prices between January 2016 and July 2017. Generally speaking, the electricity market showed greater price variability between October and March than during the rest of the period analysed. The highest prices were attained in the second fortnight of January 2017, when a combination of circumstances (cold weather, low wind and closures and strikes in French power stations) pushed electricity prices up in much of Western Europe (Weixin Zha, 2017). This variability also occurred at the beginning of 2016, although not to the same

[37] For a description of the day-ahead, intra-day and forward exchanges, see Appendix 3.

[38] Germany has one of the highest churn rates (rate of energy marketed and sold). During the second quarter of 2016, for every TWh generated, more than 17.5 TWh was sold on the market. Spain has one of the lowest churn rates, with the bulk of sales taking place on the day-ahead market.

degree. There were also occasional negative prices, with two very significant ones in May of both years. These are discussed further on and in Appendix 5.

FIGURE 20. Electricity prices and volume of electricity transactions on the EPEX SPOT in 2016-2017

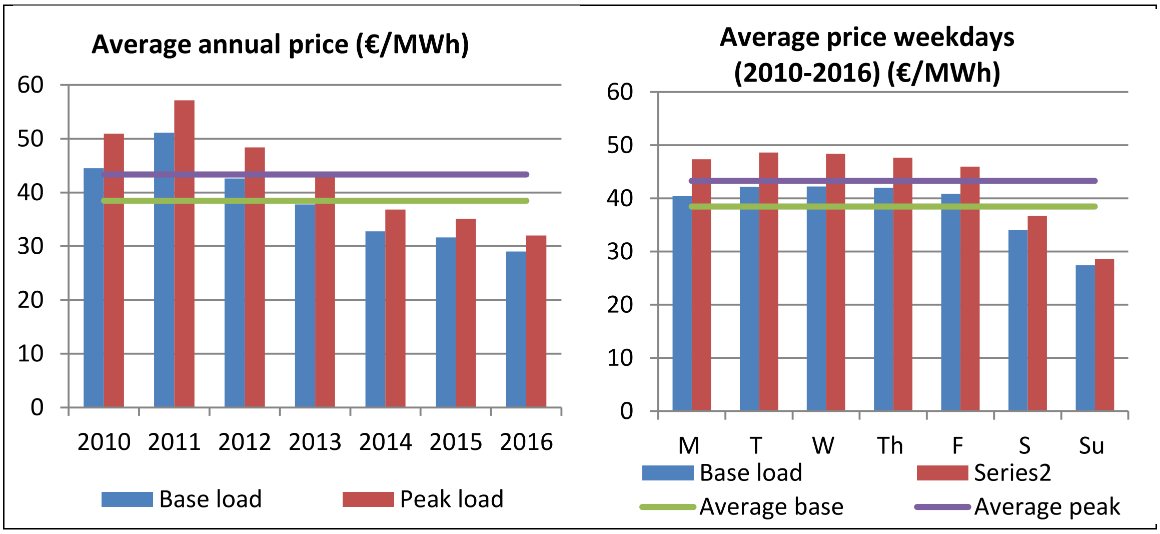


Note: The base load refers to hourly offers or block offers affecting all hours of the day. The peak load refers to hourly offers or block offers affecting times between 08:00 and 19:00 on the day.

Source: Authors, based on figures from EVE (2017) (taken from EPEX SPOT SE (2017)).

From a broader perspective, during the period 2010-2016, following an initial increase in prices from 2010 to 2011, the price on the wholesale market has continued to fall, both for the base and peak load (see figure 21). With regard to the weekday average, a slight difference can be seen in favour of the central days of the week (Tuesday, Wednesday and Thursday) over other working days (Monday, Friday). This difference is more marked when compared to the average price for Saturday and even greater when compared to Sunday.

FIGURE 21. Average annual and weekday price of the electricity market



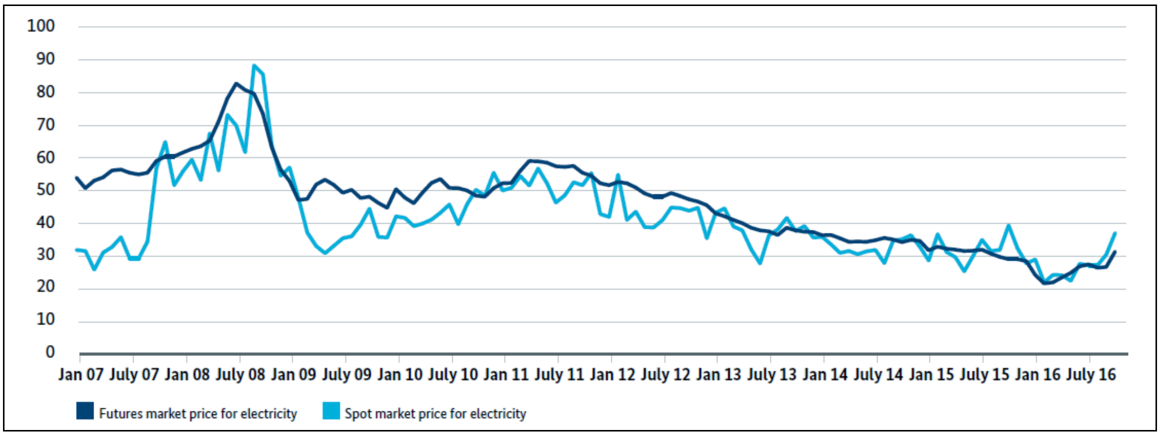
Note: in bars, on the left the annual average price and on the right the daily price for 2010-2016. In lines, the average value over the period analysed.

Source: Authors, based on figures from EVE (2017) (taken from EPEX SPOT SE (2017)).

Penetration of renewables has led to negative prices, which correlate with large-scale generation of renewables and low flexibility of conventional generation, particularly on days of low demand. The effect of these negative prices moderated in 2015, but rose again in 2016. It is reasonable to expect that they will continue to rise with greater installed renewable capacity if neither renewable or conventional generation are flexible enough to allow output to vary, or there are no incentives to do so, or if demand does not have enough flexibility to increase consumption. For more details on these prices, see appendix 5.

Kallabis, Pape, & Weber (2016) show the price of emission allowances to be the main cause of the fall in the price of electricity on futures markets between 2007 and 2013, followed by the increase in renewable generation and the fall in internal demand. For trends in prices during this period, see figure 22.

FIGURE 22. Trend in spot and futures price of electricity on the EEX market (€/MWh)



Source: BMWi (2016b).

According to Hørthe Kamperud & Sator (2016), different energy sources impact differently on the price of the German electricity market by day and by night. The influence of coal is greater at night, whereas during the day it is used as base power, leading to lower prices during these times. Gas is used mainly as back-up power during demand peaks and ramps related to renewables, during both the day and (less frequently) at night. Moreover, it is strongly displaced by the peaks in photovoltaic output during the central hours of the day. These results concur with those of Frydenberg, Onochie, Westgaard, Midtsund, & Ueland (2014), who found that coal had a greater influence on the German market than gas.

Forecast for wholesale market prices

With the increase in renewable output, this downturn in prices is expected to continue in the short term, although with some slowdown compared to the early years (with average falls of €8 and €9 per MWh between 2011 and 2012 as compared to a drop of €1 and €2 per MWh between 2014 and 2015 for base and peak load respectively).

A study by Deutsche Bank (Brough & Brand, 2016) gives further details, showing that, in contrast to the price increase of 2016, the forecast for the future remains ahead of the forward price curve, with prices falling to 2015 levels (figure 23). It also adds a later increase from 2019 on.

FIGURE 23. Forecast for long-term wholesale electricity price (€/MWh)

Source: Brough & Brand (2016).

The THEMA Consulting Group also predicts a recovery in prices, forecasting a figure of close to €30 per MWh for 2020 and up to €36 per MWh in 2025 (THEMA Consulting Group, 2016). Statnett, too gives an average price of €30 per MWh in 2020 and raises future prices to €45-50 per MWh between 2025 and 2030 (Stattnet, 2016).

At the beginning of 2017 RWE sold the bulk of its power output in Germany for 2018 and 2019 at below the market rate, which then stood at around €30 per MWh. The sale price for 2018 was around €27 per MWh and for 2019, €25 per MWh (Eckert & Goodman, 2017). Uniper (Franke & Dart, 2017) has taken a similar approach, adding to the predictions of a fall in prices.

The longer-term forecasts differ greatly depending on the hypotheses used (energy mix, fuel price, price of CO_2),[39] as the study by Afman, Hers, & Scholten (2017) shows, with average prices varying between €29.3 per MWh (high share of renewables and low cost of CO_2) and €58.6 per MWh (low share of renewables and high cost of CO_2) for 2020 and €31.4-69.8 per MWh in 2030. Similarly, Verhaeghe, Roques, & Li (2016) estimate prices of €41.8-48.2 per MWh in 2020 and €31.7-71.8 per MWh in 2030, which are in line with the other European countries analysed (France, Belgium and the Netherlands).

As for the causes of price trends, the main influences will be the price of gas, which is currently rising (Berman, 2017), and the price of CO_2 emission allowances, which it is currently planned to raise in order to cut greenhouse gas emissions. Knopf et al.,

[39] See price forecasts for coal, natural gas, and CO_2 in appendix 6.

2014; Traber & Kemfert (2012) concur that the nuclear phase-out will impact the price on the day-ahead market, but that it will not be as significant as those previously cited.

If changes are not made to the design of the market, these factors, together with the increase in renewable capacity to be installed, will lead to a scenario of price volatility (Ketterer, 2012).

2.4.2. Capacity mechanisms and supply security

Capacity mechanisms

Output from renewable generation is volatile. Wind generation depends on wind strength, which is easy to forecast in the short term but offers great variability in the medium term. Photovoltaic generation follows a known curve throughout the day, although there may be occasional local fluctuations due to passing clouds, a drop in production due to overcast conditions or, in extreme cases, a deep and widespread fall due to solar eclipses (BMWi, 2015a). For its part, hydroelectric generation is very flexible, but capacity and reserves are limited by the water capacities of the region. In the German case, this resource is currently limited, although there are projects to transform old mines into new pumped-storage hydro facilities (Parkin, 2017).

Power generation from biomass offers similar levels of availability, volume and regularity to fossil fuel generation, although its use is limited by the limited availability of the raw material used. Because it is a scarce resource (competing with food production) with multiple uses, biomass will play a less important role as wind and photovoltaic generation become increasingly capable of supplying electricity to the system in technically and economically viable conditions. Use of biomass may then shift to other sectors, where it is less easy to substitute, such as transport (air and shipping in the form of aviation biofuel and other liquid and gas biofuels) and industry (heat for certain processes) (BMWi, 2016a).

The variable and intermittent nature of renewable generation has led authorities, regulators, utilities and other stakeholders to propose a “new role” for conventional generation:[40] as a back-up to renewables. As long as sufficient and sufficiently available volumes of flexible demand do not exist, it will be necessary to keep a certain number of conventional power stations running which can increase output in periods when production from renewables is lower and reduce it when renewable output is high.[41] Greater price variability and lower use of conventional generation mean that there is a certain degree of uncertainty when it comes to investing in new generating

[40] Due to technical limitations, not all conventional power can be used as back-up in the same way. Classed in order of flexibility, the technologies are as follows: hydroelectric, natural gas, hard coal, lignite and nuclear. It should be noted that more modern facilities tend to be more flexible.
[41] A similar limitation exists in the complementary services required by the system; while renewable generators are unable to provide these services, a minimum level of conventional generation will continue to be necessary.

capacity and maintaining existing power stations. In order to resolve this problem, several capacity mechanisms have been proposed or established.

According to Álvarez Pelegry (2014), these mechanisms of electrical capacity (or "capacity mechanisms") can be classified into payments for capacity, capacity markets and capacity reserve.

In the case of payments for capacity, a fixed amount is paid for (existing or newly-constructed) conventional generation integrated into the electricity market. This is a simple mechanism determined by government, but it is not subject to the market.

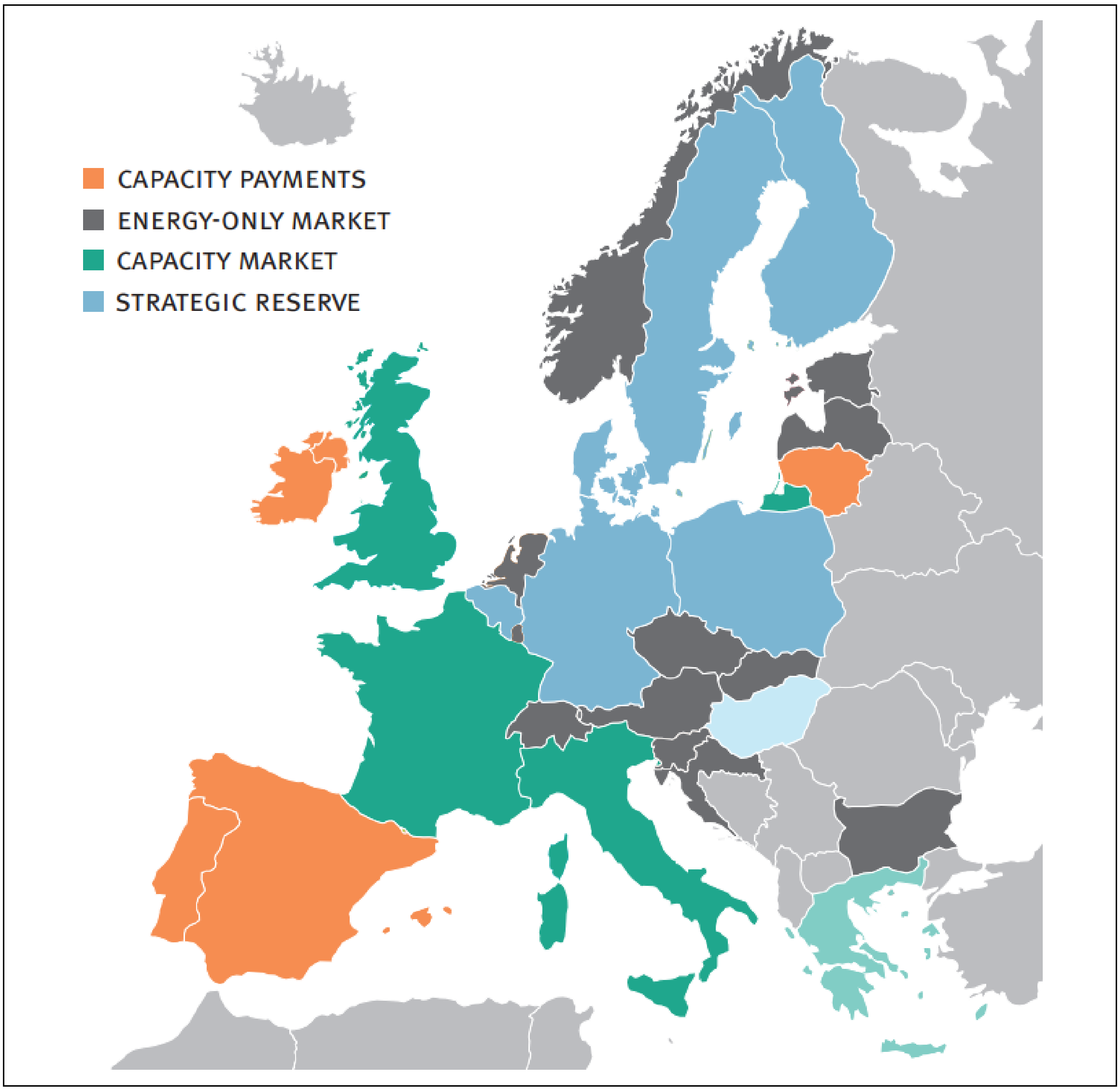
In capacity markets, there are essentially three types of mechanism. The first are capacity obligations, in which obligations are imposed on distributors or retailers to maintain certain capacity reserves. Normally they are required to contract a given percentage of their volume of contractual obligations in generating capacity. The second mechanism are the capacity auctions through a centralised system. The body that runs these auctions acts on behalf of all the distributors/suppliers. This facilitates a market structure which is more open to all market agents. Thirdly there are the reliability options. This is also a centralised system where the capacity contract takes the form of an option, so that if the electricity price contracted as an option is lower than the market price, this will be the price paid for the electricity.

The capacity reserve[42] consists of paying an amount for operational upkeep of a set of power stations which are kept off the electricity market, often by means of an auction mechanism. These stations only generate energy if and when the market is incapable of matching the supply from active power stations with total demand.

figure 24 shows the European countries that in 2016 had opted for capacity markets, capacity payments and capacity/strategic reserves, as well as those that had opted for an energy-only market.

[42] Sometimes also known as the strategic reserve.

FIGURE 24. Capacity mechanisms in Europe in 2016



Source: Edited from Eurelectric (2016).

Note that in the German case, the country finally opted for a capacity reserve "divided" into different reserves. The following section analyses the process that led the government to decide to implement this system.

German government decision on capacity mechanisms

In October 2014 the BMWi published a document entitled *"An Electricity Market for Germany's Energy Transition. Green Paper"* to launch a public debate on the future electricity market. It advocated a more developed (energy-only market) power market, known as "electricity market 2.0", together with a capacity reserve. In addition, the document suggested a series of preventative ("no regret") measures, independent of the decision on capacity management. It was structured into five main sections: Strengthening market price signals for producers and consumers; Expanding and optimising the power grids; Maintaining a single price zone; Intensifying European co-operation; and Delivering on climate protection goals

(BMWi, 2014). In July 2015 the BMWi published a White Paper with its conclusions on the debate, its final decision to promote the electricity market 2.0 and twenty specific measures (see appendix 7) (BMWi, 2015a).

The first of the reasons given by the BMWi for adopting the electricity market 2.0 is that it can guarantee supply security. The reports consulted by the German government indicated that in the market area of relevance to Germany, the capacity for the coming years was adequate (50Hertz et al., 2015; Consentec, 2015). According to ENTSO-E (2014),[43] at the time of writing the report, there was 60 GW of overcapacity in the German and European electricity market.

The best approach to follow to ensure supply security was considered to be to increase international exchanges (exports/imports). The paper also states that the simultaneous residual peak load in 2015 for Germany and the countries with which it has or plans interconnectors (see Section 2.3.3) was 10 GW lower than the total respective national residual peak loads in the same area (and was estimated to be at least 20 GW lower in 2025). It also stated that the peaks (or troughs) in renewable generation varied substantially from country to country.

Moreover, according to the BMWi, the electricity market 2.0 was cheaper. Given the complexity of designing capacity markets and the difficulty of determining the required level of capacity, capacity markets are susceptible to design errors that substantially increase their cost. It also adduced that a capacity market would involve major state intervention in the competitiveness of the electricity market, resulting in a distortion of the market. At the same time, for proper operation, the electricity market 2.0 makes it possible to have technology-neutral competition between the different flexibility options, not only in generation. This incentivises the search for the cheapest option, which is difficult for the regulator to determine.

Finally, the electricity market 2.0 permits innovations and sustainability. A capacity market would delay the necessary transformation of the energy supply system. The electricity market 2.0 incentivises the development of the technologies needed for greater integration of renewables, such as the development of batteries, flexibility of demand and better coupling between the electricity system and heat and transport systems.

According to the German government, the main advantage of the electricity market 2.0 is its immediate effect on the country's emissions. Capacity markets might keep power stations active which they are trying to close because of their emissions levels, whereas the electricity market 2.0 would substantially halt their activity. Moreover, greater price variations, correlated with greater penetration of renewable generation, would encourage the emergence of new energy-regulating technologies making use of this feature of the market.

[43] See page 51 for further information on the latest version of the study available.

The fundamental disadvantages are the halting of low-cost generation (lignite and hard coal), replaced by higher-cost power generation (natural gas) or by imports from abroad, and greater price volatility, which increases consumer insecurity. Similarly, there are underlying doubts on the development of technological alternatives, both in terms of the cost and the capacity to integrate them into the electricity market.

In this debate, the recent report (European Commission, 2016b) from the EU on capacity mechanisms indicates that the strategic reserve was better suited to meet transitory issues with capacity. The document argues that capacity obligations and centralised capacity auctions constitute a long-term solution, although they depend on the level of competition in the market. It also stress the role of the electricity price as a driving force of exchanges between countries and the need to harmonise the way in which supply security is managed in different EU countries.

This position is reflected in the document on capacity mechanisms of the Winter Package 2016, which indicates that, despite surplus capacity in Europe, current distribution cannot guarantee the supply security of the member states in the near future. It therefore advocates continuing to introduce reforms on the electricity market and the introduction of interruptibility in states where it is deemed necessary.

In June 2016, the German Parliament approved the government's reforms on the electricity market 2.0: the Electricity Market Act, a decree on capacity reserve and an act on digitisation of the electrical transition (Bundesanzeiger Verlag, 2016). As well as underlining the Government's commitment not to interfere in pricing, the Electricity Market Act tightens the regulations on suppliers to ensure that they contract the amount of energy they have to supply; it increases competition to bring greater flexibility to the system, allowing charge managers, flexible power producers and owners of distributed energy (such as batteries) to provide balancing power; it reduces the maximum reference power for wind and solar farms used in planning power grids, and extends the grid reserve beyond 2017.

Reserve power stations. Grid, climate and security reserve

Up until the latest reforms, Germany had used a single reserve of power stations, the "winter reserve", which had been in operation since the winter of 2013/2014. This was comprised of thermal power stations in the south of the country which did not participate on the market and was used to alleviate north-south congestions in the transmission grid. This allowed the TSOs to balance the system, ensuring that Germany would remain as a single market. Power stations in Austria and Italy could also be contracted in this reserve so that they would follow demand in the system.

In winter 2016-2017 it had a forecast value of 5,400 MW, although in the end 8,383 MW was required. The government estimated the cost of maintaining this reserve in 2016 at €177 million or €0.38 per MWh on the electricity bill,[44] to which must be added the operating costs of the power stations (€71m), redispatches on the market (€103 million in the first three quarters of 2016), countertrading[45] (€23.5m in 2015)[46] and the shutdown of power stations with feed-in-tariffs[47] (€121 million in the first three quarters of 2016). For 2017/2018 a reserve is planned of 10,400 MW, to fall to 3,700 MW by 2018/2019.

With the reform of the electricity market, the German government has set up three types of power station reserve: grid reserve, climate reserve and capacity reserve.

The grid (or network) reserve (*Netzreserve*), is the new name for the former winter reserve, and operates in the same way as before. In December 2016, the EU temporarily approved this reserve until 2020, judging that it did not substantially distort competition on the electricity market (European Commission, 2016d). This reserve will now be made up of off-market power stations and will include power stations whose applications for closure have been turned down on the grounds that they are considered to be system critical (as is the case with several gas-fired power stations). In order to ensure the remaining power that cannot be covered with these power stations, the TSOs will enter negotiations with station operators.

The goal of the climate reserve is the ultimate closure of lignite-fired plants with high emission levels (See section 2.2.2). A series of lignite-fired plants with a total capacity of 2.7 GW will be added to the reserve between 2016 and 2019 until their eventual closure in 2023. These stations may only be switched on if forecasts suggest that all other supply security measures will be insufficient (with a maximum active time of ten days from notification). This reserve has received approval from the European Commission, which considers it to be environmentally positive and to have a limited impact on the electricity market (European Commission, 2016c). The estimated total cost comes to €1,600m over seven years, which will result in an average increase in rates to consumers of €0.5 per MWh.

The capacity reserve (*Kapazitätsreserve*), consists of a set of power stations that do not participate in the electricity market and which would only be switched on in the event of a mismatch between supply and demand on the market. The reserve will have a capacity of up to 2 GW for winter 2018-2019 and of up to 5% of forecast yearly peak demand in subsequent years (up to 4.4 GW). The power stations to be used in the capacity reserve and the price will be decided on the basis of a technology-neutral competition. According to the draft of November 2016, the plants must be capable of

[44] Assuming a cost in the bill equal to that used to calculate the other reserves.
[45] Countertrading involves the transfer of energy between different market areas (e.g. Germany and Austria form a single market area) begun by the TSOs to reduce grid congestion.
[46] No data available for 2016.
[47] Compensation for switching off a renewable generation set in periods in which it is surplus, in order to maintain stability of the electricity system.

cold-starting[48] in a maximum of 12 hours (BMWi, 2016d). This will make it easier for gas-fired plants to participate than most coal-fired stations.

The government expects this reserve to cost between €130 and 260 million per year, i.e. between €65,000 and €130,000 per MW. The reserve would result in an average increase in rates of €0.28-€0.55 per MWh, well below the EEG surcharge (Amelang & Appunn, 2016). The document *Strom 2030* (Electricity 2030) includes the possibility of sharing this capacity reserve with other countries, as far as permitted by technical restrictions. (BMWi, 2016a)

table 11 shows a summary of some key features of the three reserves.

TABLE 11. Key figures of the different reserves

	Grid reserve[49]			Climate reserve	Capacity reserve	
Start date	2016/17	2017/18	2018/19	2016/19-2019/23	2018/19	2019+
Capacity (GW)	8.4	10.4	3.7	2.7	1.2	Up to 4.4
Estimated cost (€M/yr)	177	220	78	230	130-260	
Estimated cost (€/MWh)	0.38	0.47	0.17	0.50	0.28-0.55	
Type of power station	Thermal: domestic and European			Lignite	Thermal: domestic and European	

Source: Authors

The current proposal establishes that it should be the German system operators (TSOs) German who monitor the capacity reserve. Whether or not it is activated would thus depend on the report from the operators (the report has been positive, advising the construction of the maximum established capacity of 2 GW) and approval from the German government, which in a later report reduced the amount of this reserve to 1.2 GW (BMWi, 2017a). The European Commission has launched an investigation to analyse whether the reserve meets community regulations on state aid, since it considers that it might distort competition and favour power station operators over companies operating in the area of demand management (demand reduction, batteries, other storage, etc.) (European Commission, 2017b).

Forecasts for the margin of capacity reserve[50] associated with supply security differ from source to source. The latest review of the study on short and medium-term capacity by the ENTSO-E predicts that by 2020 Germany will have a capacity margin

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[48] Cold-starting is defined as the operation of connecting the power station to the grid from a state of complete stoppage.

[49] 2017/18 and 2018/19 values calculated based on 2016/2017 unit cost of the reserve.

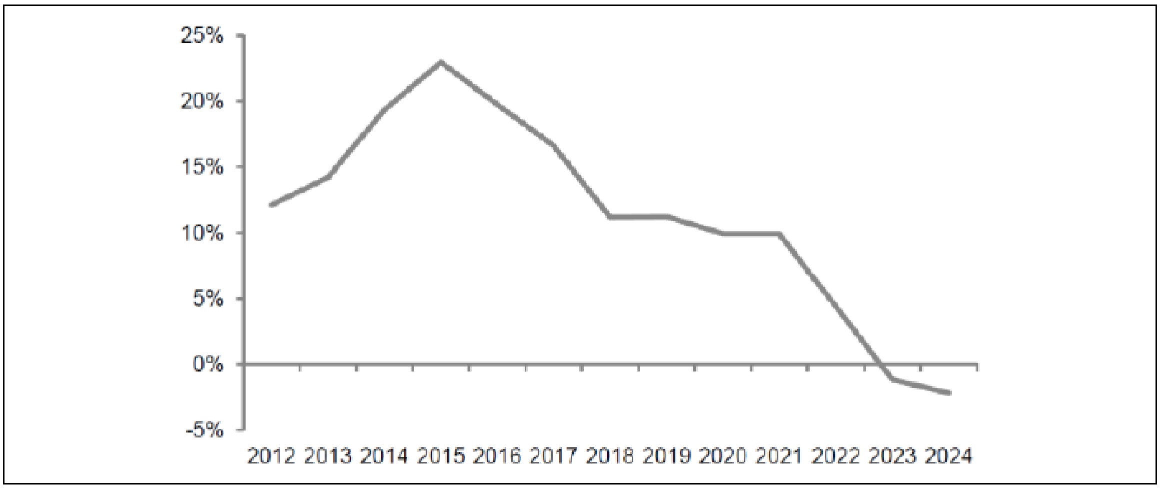
[50] Difference between reliable generation capacity available (taking faults into account) and system demand (expected demand minus demand flexibility). The ENTSO-E has abandoned use of this deterministic term since the 2016 report, when it began to use stochastic scenarios.

of 8 GW[51] (ENTSO-E, 2016a), while for 2025 it will be -3.7 GW (i.e. peak demand will exceed available conventional output).

Nonetheless, including renewable generation, in the ENTSO-E's stochastic scenarios[52] problems only arise in meeting demand in the most conservative scenario. This contrasts with other European countries (e.g. France, the United Kingdom and Italy) where problems also arise in more general scenarios. The study stresses that inclusion of capacity reserve would ensure a sufficient generating capacity, although it does not specify the amount of this reserve that would be required.

A study by Deutsche Bank (Brough & Brand, 2016) offers a less optimistic vision of Germany's capacity margin. It estimated that the decline in the capacity reserve would lead to a situation in which available capacity would not exceed 10% of peak demand in 2020 and would even fall below this peak demand in 2023 (figure 25). The study forecasts that the reduction may be even greater by the end of the 2020s as a result of aging of thermal power stations (see figure 26). Nonetheless, the report provides mechanisms for aid to the construction of gas-fired CHP stations and limitations on the closure of power stations considered to be system-critical. This will ensure supply security even with electricity prices below levels that would be profitable for construction.

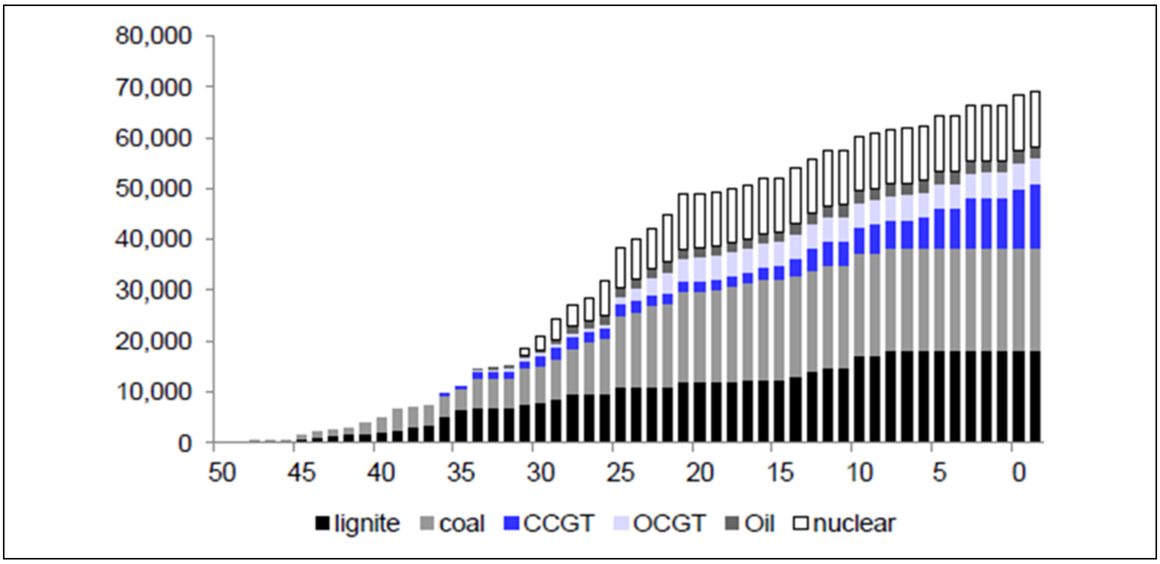
FIGURE 25. Margin of capacity reserve above peak demand



Source: Brough & Brand (2016).

[51] Difference between conventional installed generation and maximum hourly demand.
[52] These scenarios take into account different situations of plant availability for reasons of climate (water, wind and light) and plant maintenance.

FIGURE 26. Conventional power capacity in Germany by age (MW)



Source: Brough & Brand (2016) based on Reuters.

Enlargement of the power grid

Enlargement of the power grid is one of the government's key objectives, as stated in *Strom 2030* (BMWi, 2016a). It is seen as being the most economically effective way of increasing system flexibility, since it does not require resorting to regulation using power stations, which would be more expensive. Enlargement of the network must follow the expansion of renewables, with both being necessary to meet renewables targets.

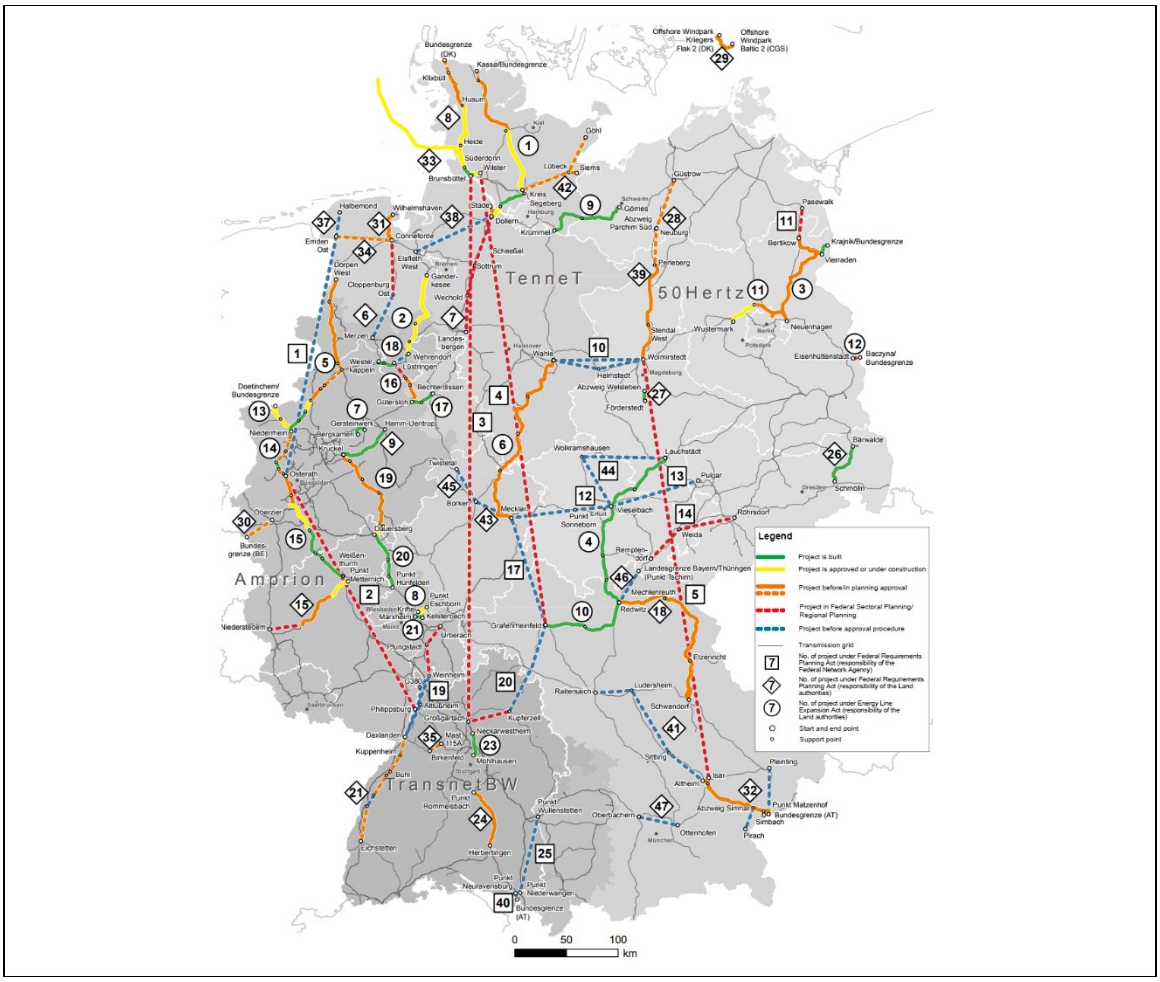
The projects for expansion of the German power grid are set out in acts containing specific projects: the 2009 Power Grid Expansion Act (*Energieleitungen*, EnLAG), the 2015 Federal Requirement Plan Act (*Bundesbedarfsplangesetz*, BBPlG), marine connection projects with the North Sea and Baltic Sea and EU Projects of Common Interest (PCIs) and other acts that do not include specific projects, such as the NABEG (Bundesnetzagentur, 2017b).

By the end of the first half of 2017, the EnLAG covered twenty-two projects with a total length of 1,800 km, of which 1% were in operation, 38% were completed and 53% had been approved. Of these, 45% (810 km) are expected to be completed by the end of 2017 and 80% by the end of 2020. The BBPlG covered forty-three projects with a total length of 5,900 km, of which 150 km has been completed and 450 km approved.

In the latter plan, the Federal Network Agency (*Bundesnetzagentur*) wants to complete the three planned HVDC lines by 2025: A-North, SuedLink and SuedOstLink (projects 1-5 of the BNetzA in the figure 27). Initially these projects were due to be completed by 2022, but the German government decided to route the lines underground, leading to a three-year delay in commissioning (Bundesnetzagentur, 2017a). The agency had previously rejected another two HVDC projects initially planned: a line between Wehrendorf and Urberach and a third line in SuedLink (Bundesnetzagentur, 2016c).

As for undersea connections, in the North Sea nine power lines are now operative with a total capacity of 5.2 GW and three more are under construction, one AC and two DC. The present connection needs for an additional 2.0 GW will involve four new DC power lines.

FIGURE 27. Situation of planned power lines as of June 2017



Note 1: Line B (Project 4) was cancelled and the southern end of Line D was changed, with Gundremmingen being replaced by Schwandorf, thus moving the line eastward.

Note 2: See appendix 8 for a more detailed figure.

Source: Bössner (2015).

In the Baltic Sea, it is planned to continue using only alternating current, as at present. Two lines are currently operative with a capacity of 390 MW, with three more under construction bringing the total to 750 MW. The need to connect an additional 700 MW will mean building three new lines.

The aggregate expense of the transmission grid for the four system operators increased to €2,361 million in 2015 from €1,796 million in 2014. The increase in the cost was strongly influenced by growth in investment in expansion and new construction, which rose from €1,248 million to €1,673 million.

This investment in expansion of the power grid must also be geared towards reducing the number of power redispatches and its cost, which in 2015 came to €411.9 million, more than twice the year before. This strong need for redispatching was due to a combination of the closure of the Grafenrheinfeld nuclear power station, high levels of wind generation, a delay in building the projects in the transmission network, switch-off of part of the grid while the work was being carried out and a high level of exports, particularly to Austria (Bundesnetzagentur, 2015; Bundesnetzagentur, 2016d).[53]

The expansion of the power grid must, moreover, ensure that consumers are integrated into smart grids. 90% of installed capacity of renewables is connected to distribution networks, which account for 98% of the German power grid.

Other measures

In parallel with the core goal of expanding the power grid, other measures must be introduced to ensure supply security in the system.

Here there is a very important role for auxiliary or complementary services, which must ensure the stability of the system in a situation of increasing renewable generation. These services are currently included in the market or required in the technical specifications of the power stations. The German government has set itself the goal of extending the role of the market, in such a way that it will facilitate this type of service as economically as possible and involve all the different agents: conventional power stations, renewables, distributed storage and demand management.

Measures have also been proposed to increase the flexibility of the generators and thus reduce the emergence of negative prices. In this regard, CHP power stations could use heat storage and generate heat using electricity to gain in flexibility. The use of CHP stations is indispensable, given their greater efficiency and flexibility compared to non-CHP stations and they will have a very important role until 2030, meeting much of the power and heat needs of the energy system. From 2030 it is forecast that these power stations will become less significant, although they will continue to play an important role. Taking a life span of 20 years for power stations and 40 years for heat distribution networks, proper planning is essential to meet the system's supply, flexibility and efficiency targets.

Another measure that could be adopted involves self-consumers ("prosumers"), for whom it should be more economical to acquire low-cost energy from the market than generate it when there are energy surpluses.

[53] See a summary of the redispatching situation in appendix 9.

For their part, in the event of low demand or grid restrictions and high production, renewable plants should be capable of reducing output or temporarily storing the surplus to be subsequently taken up to the grid. Other options are also considered, such as solar thermal generation, geothermal energy and residual heat in industry.

One final measure is related to certain components of the electricity price, which are superimposed on or "added" to the variable price (fixed rates). This does not facilitate their use to incentivise demand flexibility. They also reduce the inter-relationship between sectors (electricity, heat and transport). Encouraging this inter-relationship would, in the medium term, make it possible to give the system greater flexibility with the use of heat storage and EV-charging. In the case of the latter and of other storage systems such as batteries, their use in primary regulation and other auxiliary services could prove attractive in the short to medium term. Long-term power storage, currently under development, will be necessary once a large proportion of renewable generation has been reached.

In this regard, Birkner (2016) argues that several different stages or phases in the integration of renewables can be identified in conceptual terms. The first involves integration of renewables in the power grid to achieve a 35% penetration rate. This stage is characterised by expansion and reinforcement of the grid, flexible generation and transmission (smart grids) and the use of conventional generation to complement renewables. In order to achieve penetration rates of up to 60% (around 2030) it will be necessary to integrate the electricity system with the heat system using power-to-heat[54] technologies, demand management and energy efficiency. Achieving a figure of 80% would also require integration with the gas system using power-to-gas technologies. Specifically, Henning & Palzer (2016) states that by 2050 approximately 80-130 GW of this technology will be needed to ensure electrical supply security and for the transport sector; and up to 180 GW in the scenario with the lowest use of fossil fuels.

2.5. Environment

This section analyses trends in emissions from the power industry and government targets. We start by examining CO_2 emissions, government targets and the policies to be introduced to meet those targets and go on to analyse air pollutant emissions.

[54] Power-to-Heat (P2H) refers to technologies that use the surplus power generated (typically from renewables) to provide heat. Either resistances or heat pumps could be used. The latter are more efficient but slower and have a higher investment cost. This would allow a reduction in the use of fossil fuels. Normally they are accompanied by some form of heat storage system to increase the flexibility of the whole.

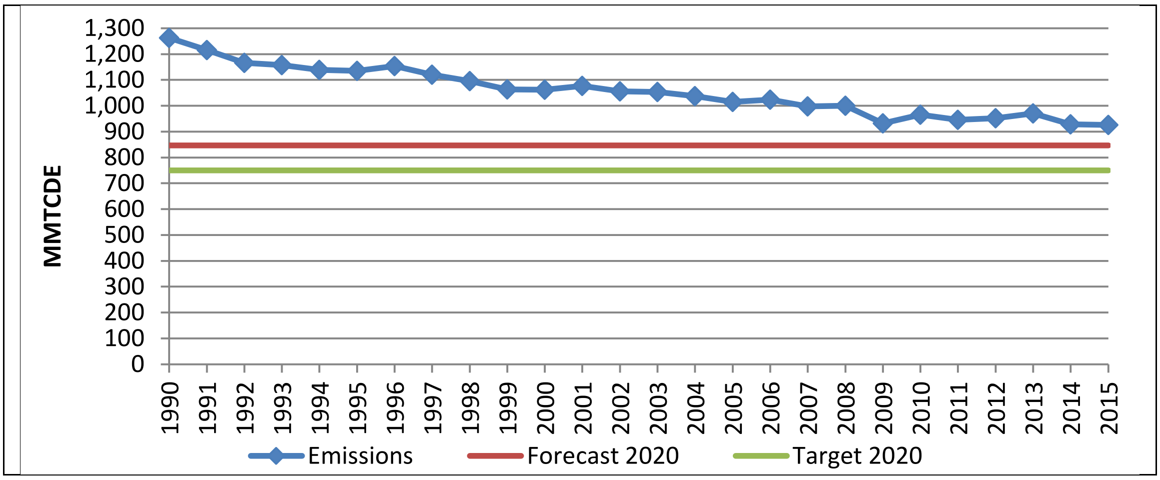
2.5.1. GHG emissions

Historical trends and targets

According to Eurostat data, in 2015, GHG emissions measured in terms of CO_2 equivalent (CO2eq) in Germany[55] had fallen by 27% compared to 1990, taken as the baseline year for EU targets (see figure 28).[56] This is well short of the target of reducing emissions by 40% by 2020 (compared to 1990).

In the early 1990s, there was a major reduction in emissions due to restructuring in the states of the former German Democratic Republic (East Germany). This process included the closure of many lignite-fired plants in the ex-GDR, which in total consumed 300 Mt (million tonnes) of lignite per year (Irfan, 2014), as opposed to 80 Mt at present. It also involved a move towards the use of cleaner energy sources, and this energy transition is still continuing at present (Strogies & Gniffke, 2016).

FIGURE 28. Total GHG emissions in Germany (in million tonnes of CO_{2eq})



Note 1: Does not include LULUCF (land use, land use change and forestry), memo items, or international aviation.

Note 2: Total GHG emissions in 2016 increased by 8 MMTCDE (million metric tonnes of carbon dioxide equivalent) compared to 2015. (Graichen et al., 2017).

Source: Authors, based on Eurostat figures.

Emissions of liquid fuels (petrol, diesel, etc.) have been cut by 20% compared to 1990 levels and emissions from solid fuels (hard coal, lignite, etc.) by 40%, whereas emissions from gas fuels (natural gas, waste gases, etc.) are up 25%.

By sector, transport, dominated by road traffic, has seen no significant change: emissions grew slightly as a result of economic activity until 1999 and then declined slowly as a result of a reduction in consumption, greater use of diesel over petrol, the

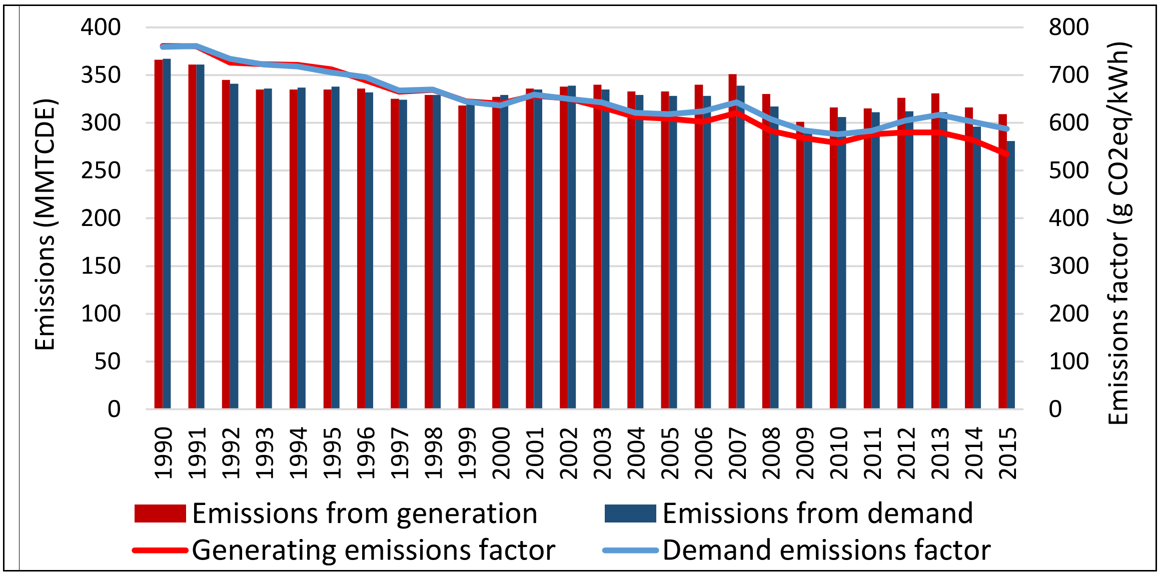
[55] Emissions related to the energy industry are distributed very differently among the Länder or federal states, as appendix 10 shows.
[56] At EU Level, Germany's target is to reduce its GHG emissions by 20% by 2020 as compared to 1990. This entails a 21% cut in emissions from industries subject to the EU Emission Trading Scheme and a 14% reduction in non-ETS sectors. Germany has therefore already met these targets.

introduction of biofuels, etc. The current trend shows an increase in emissions, particularly in road transport.

The fall in CO_{2eq} emissions in power and heat generation has been more moderate, at 19%. Nonetheless, the lowest figure came in 1999, with 344 million tonnes of CO_2 equivalent. It then fluctuated until 2015, with a maximum in 2007 of 351 million tonnes of CO_2 equivalent. In 2016, CO_2 emissions fell in power generation for the third year running, to 306 MMTCDE.

The increase in emissions from power generation between 1999 and 2007 (see figure 29) is related to a sustained increase in power generation between 1999 and 2007 (see figure 4). Greater use of renewables helped stem this trend, while a subsequent fall-off in economic activity between 2007 and 2009 led to a major drop in emissions from industry. The subsequent economic recovery, combined with a fall in the relative price of coal compared to gas (Weale, 2016) and the low cost of CO2 emission allowances has led to a return to greater emission levels.

FIGURE 29. GHG emissions in power generation in Germany



Note 1: Information for 2014 is provisional. Information for 2015 is based on preliminary estimates.

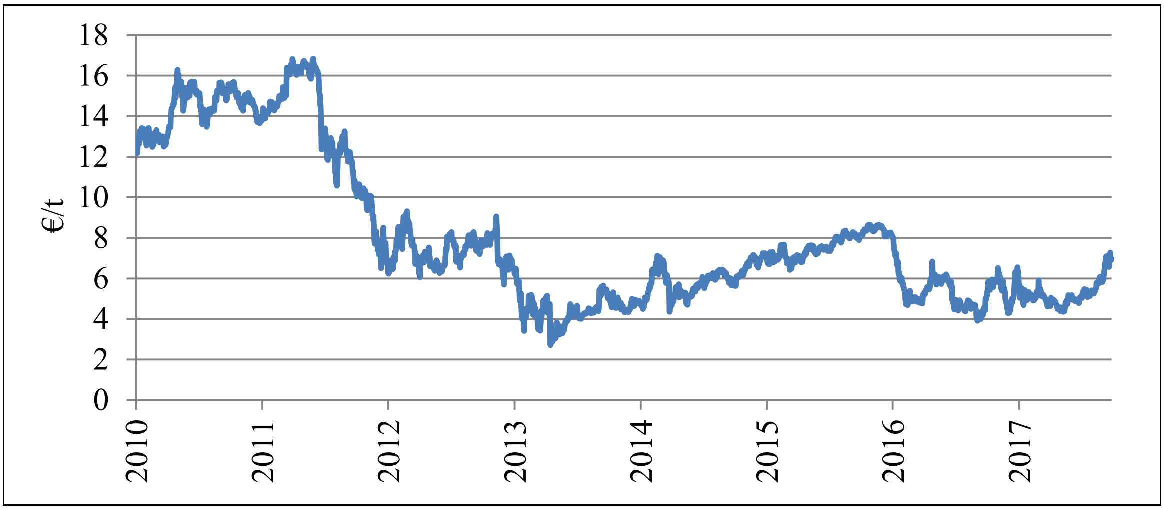
Note 2: GHG emissions from power generation fell in 2016 by 5 MMTCDE: (Graichen et al., 2017).

Note 3: Emissions from power generation are those attributed to generation in Germany.

Source: Authors, based on figures from Icha & Kuhs (2016).

It should be noted that this fall in emissions has not, as expected, helped European CO_2 Emission Allowances. This is due to the fact that in contrast to the estimated allowance price of €25 per tonne (Álvarez Pelegry & Ortiz Martínez, 2016), since late 2011 the price has not risen above €10 per tonne (see figure 30).

FIGURE 30. Price of European CO_2 emission allowances



Source: Authors, based on Markets Insider figures.

According to the Green Paper on the electricity market (BMWi, 2015a), this European mechanism needs to be strengthened to ensure that European carbon emission targets are met. In particular, Buck & Redl (2016) note that a stable medium-range price for emission allowances is needed to promote low or zero-emission capacity reserves. Along these lines, France proposed setting a minimum price for emissions of €30 per tonne. However the plan was eventually withdrawn (De Clercq, Jarry, & Oatis, 2016).

Increasing the price of CO_2 to €30 /tonne might lead to the closure of hard coal and lignite power stations. According to some estimates, it might mean an increase in the price of electricity on the wholesale market of more than €10/MWh (28%) (Brough, Brand, Sanz de Madrid, & Duncan, 2017a).

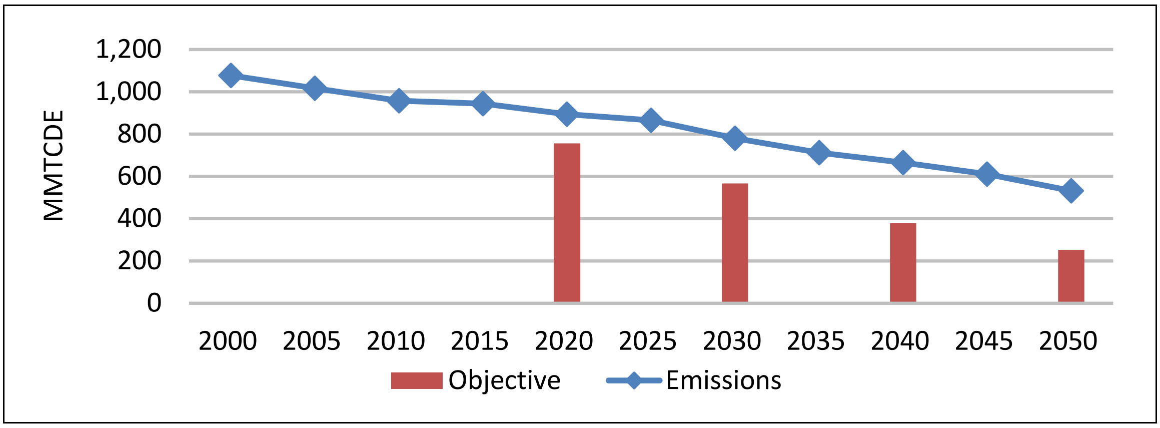
Targets for 2020-2030 and 2050

For forecast emissions in Germany, we have been taken the values of the EU's scenario of trends to 2050, published in 2016.

The forecasts fall well short of the target of reducing CO_{2eq} emissions by 40% by 2020 compared to 1990 values.[57] The same is true of the 2050 target of reducing emissions by 80%-95% to between 252 and 63 MMTCDE, in stark contrast to the forecast level of over 500 MMTCDE (Umweltbundesamt, 2015).

[57] The 1990 reference figure is 1,260 MMTCDE.

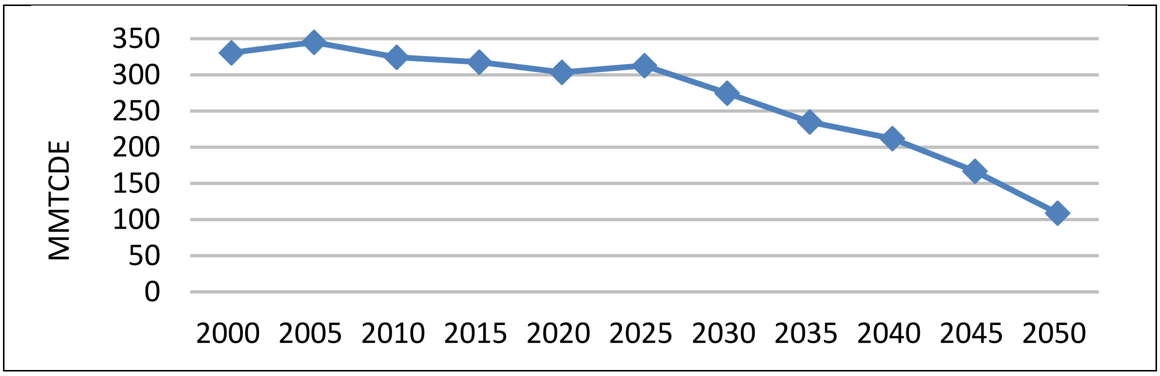
FIGURE 31. EU forecast for total emissions of greenhouse gases in Germany (in MMTCDE)



Source: Authors, based on Capros et al. (2016).

In the case of power and heat generation, the forecast is for a 4% decline in emissions during 2015-2020, to 303.7 million tonnes of CO_2 equivalent (MMTCDE). Between 2020 and 2025, emissions are expected to rise again by 3%. The trend in overall emissions is somewhat more favourable, with a 5% reduction over the period 2015-2020 and a 3% drop between 2020 and 2025.

FIGURE 32. EU forecast for greenhouse gas emissions in power and heat generation in Germany (in MMTCDE)



Source: Authors, based on Capros et al. (2016).

In December 2014 the Ministry for the Environment, Nature Conservation, Construction and Nuclear Safety (*Bundesministeriums für Umwelt, Naturschutz, Bau und Reaktorsicherheit* — which we shall henceforth refer to simply as the Ministry of Environment) published the German Government's Climate Action Programme 2020 (*Klimaschutzplan 2020*), which sets out the principal measures to be taken by the German government to meet its emissions targets for 2020 and advances the lines to be followed for 2030 to 2050 (BMUB, 2014).[58]

The document examines trends in equivalent CO_2 emissions in key sectors of the German economy and assesses the potential for reducing them. It starts from the

[58] See Table 1.

basis of a forecast reduction in emissions for 2020 without additional measures of 33% (compared to 1990 levels), well behind the target figure of 40% (see table 12). The action plan includes a broad programme of measures intended to meet this target.

The two principal measures are, first, the National Action Plan on Energy Efficiency[59] in three areas: energy efficiency in the building industry, energy saving as a business model and individual saving and responsibility in energy efficiency (which would entail a reduction of 25-30 MMTCDE); and second, the climate change attenuation measures in power generation, which include an improvement in conventional power stations and greater use of renewables (which will reduce emissions by 22 MMTCDE).

Also important are the strategy on sustainable construction and habitability (with a reduction in emissions of 5.7-10 MMTCDE, and 1.5-4.7 added to those of the NAPE); the target of reducing non-energy GHG emissions in the industrial, trade and services sectors and waste disposal (forecast reduction of 3-7.7 MMTCDE) and agriculture (with an approximate reduction of 3.6 MMTCDE); and measures on sustainable climate action in the transport sector (with a forecast reduction in emissions of 7-10 MMTCDE).

Complementing these measures are the Emissions Trading Scheme and European and international climate policy (whose results will depend on EU decisions). The government will also attempt to promote its own role as an example-setter in good practice, research and development and the launch of consultations, awareness-raising plans and initiatives at all levels of climate action.

At the end of 2016, the German government set out the first specific GHG emissions targets by sector for 2030 in its Climate Action Programme 2050 document (*Klimaschutzplan 2050*) (see table 12). The document will be reviewed in the future, outlining the measures to be taken in each sector.

[59] *National Action Plan on Energy Efficiency*, NAPE.

TABLE 12. GHG emissions in Germany in 2014 by industry with 2020 forecasts and 2030 targets (in MMTCDE)

Sector	**1990**	**2014**	**2020 forecasts**	**2030 targets**	**Reduction 2014-2020 (%)**	**Reduction 2014-2030 (%)**
Energy	466	358	263	175 – 183	27%	49 – 51
Housing	209	119	105	70 – 72	12%	39 – 41
Transport	163	160	141	95 – 98	12%	39 – 41
Industry	283	181	172	140 – 143	5%	21 – 23
Agriculture	88	72	68	58 – 61	5%	15 – 19
Others	39	12	10	5	17%	58
Total	**1,248**	**902**	**759**	**543 – 562**	**16%**	**38 – 40**

Note 1: The figure for total 1990 emissions used in this study is 1,249 million tonnes equivalent, slightly lower than the figure cited by Eurostat.

Note 2: Distribution of the 2020 target is based on the 2020 forecast by BMUB (2014) plus the effect of the measures set out in that document. To reach the 2020 target it will be necessary to cut a further 10 MMTCDE.

Note 3: The 2020 target for housing is divided into homes (80 MMTCDE) and trade and services (35 MMTCDE).

Source: Authors, based on BMUB, 2014; BMUB (2016).

Turning to the energy industry, in line with the White Paper (see section 2.4.2), the document places special emphasis on the use of an effective and reliable carbon dioxide emissions trading market, and greater use of renewable energy in power generation and, where possible, in final uses. This means that power generation with natural gas and more modern coal-fired stations (which are more efficient and flexible) will play a key role in this transition. At the same time, it will be necessary develop systems of demand flexibility and power storage, such as batteries, as well as power-to-gas and power-to-liquid systems.

The document stresses the need to develop smart grids, for which the first steps have been taken in the Energy Transition Digitisation Act (*Gesetz zur Digitalisierung der Energiewende*). The act, which came into force in September 2016, establishes the formal basis for installation and operation of demand-linked smart meters, including issues related to cost and IT security. In order to facilitate introduction of these meters, the government has promised that they will involve no more cost to consumers than the amount that they can save by using them. By 2017, large consumers using more than 10 MWh/yr must have a smart meter. By 2020, it will be the turn of homes and companies with a consumption of more than 6 MWh/yr.

2.5.2. Air pollutant emissions

The graphs below show trends in air pollutant emissions in Germany for the period 1990-2014, examined in this study; they include both the total figures (figure 33) and those for the energy industry (power and heat) (figure 34). A significant decrease can be seen in nearly all cases, except for ammonia, where emissions have remained unchanged (Umweltbundesamt, 2015).

The main sources of these emissions and the reason for trends in the figures are listed below, with Germany's emission target for 2020 (based on the 2012 review of the 1999 Gothenburg Protocol).[60]

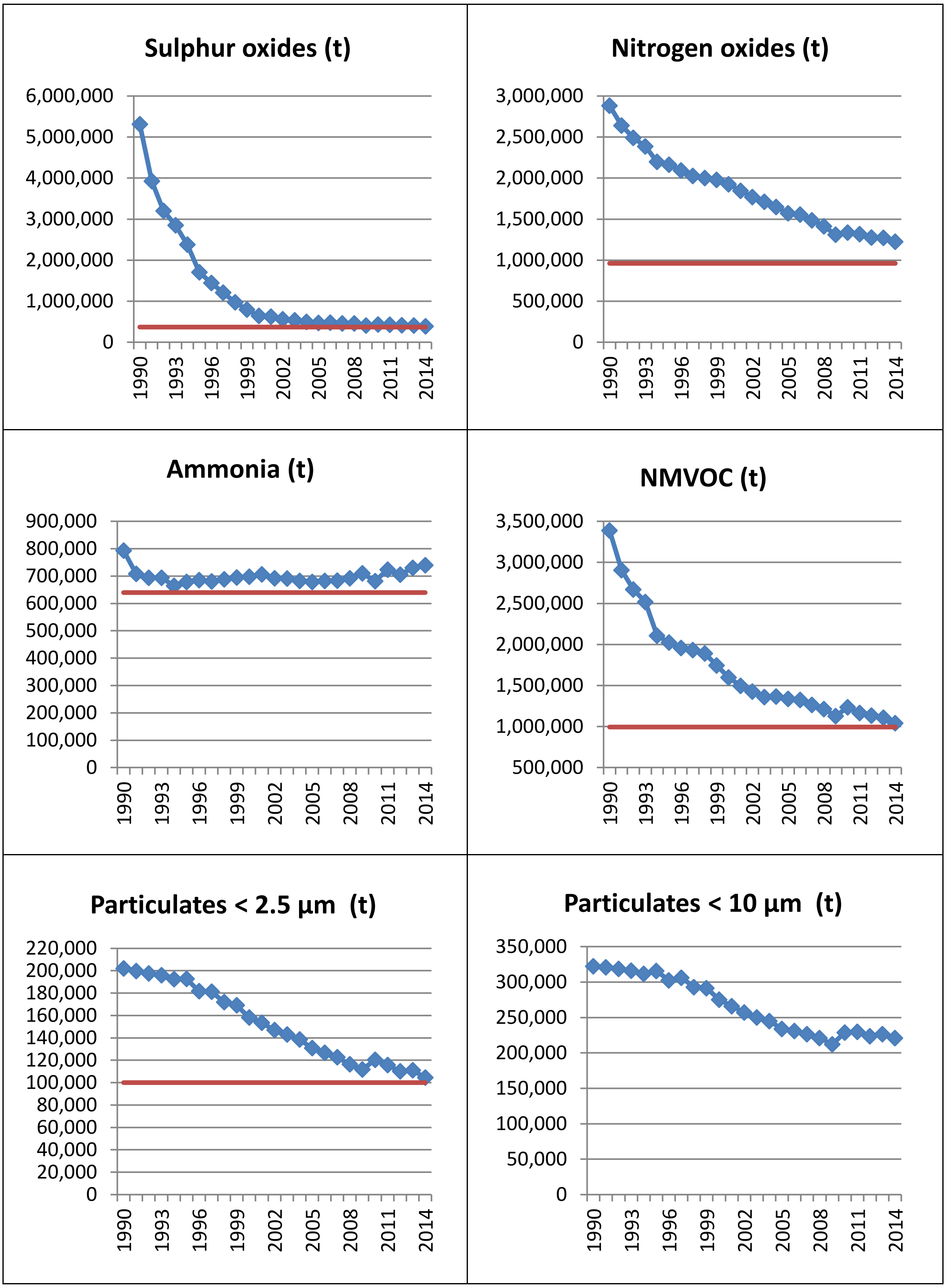
The main source of sulphur oxide emissions is the use of sulphuir-bearing fossil fuels. The sharp fall in emissions is due essentially to the closure of plants in the former GDR and the use of modern emission control technologies. Germany's target for 2020 is to reduce sulphur oxide emissions by 21% compared to 2005 levels, to approximately 370,000 tonnes. For 2030 the target is to reduce them by 58% to approximately 200,000 tonnes.

The main cause of nitrogen oxide emissions is transport, and a decline in emissions from this source is the principal reason for the reduction in this pollutant. Germany's target for 2020 is to reduce nitrogen oxide emissions by 39% compared to 2005 levels, to approximately 960,000 tonnes. For 2030 the target is to reduce them by 65% to approximately 550,000 tonnes.

The main source of ammonia is agriculture and, in particular, livestock farming. An initial fall was caused by a reduction in livestock in the states of the former GDR, with emissions in other sectors remaining largely unchanged. Germany's target for 2020 is to cut ammonia emissions by 5% compared to 2005 levels, to an approximate total of 640,000 tonnes. For 2030 the target is to reduce them by 29% to approximately 480,000 tonnes.

[60] Protocol to abate acidification, eutrophication and ground-level ozone and the 2030 target set out in Directive EU 2016/2284 of the European Parliament and of the Council on the reduction of national emissions of certain atmospheric pollutants (European Parliament, 2016).

FIGURE 33. Total emissions of atmospheric pollutants in Germany



Note: 2020 targets are shown in red.

Source: Authors, based on Eurostat figures.

The source of NMVOC (non-methane volatile organic compounds) emissions is the use of solvents. The largest reduction has taken place in transport; other sources include homes, fuels and industrial processes. There has been no change in the target of reducing non-volatile organic compounds by 2020, compared to 2010 figures (995,000 tonnes) (13% lower than 2005), a figure which has yet to be reached. For 2030 the target is to reduce them by 28% to approximately 825,000 tonnes.

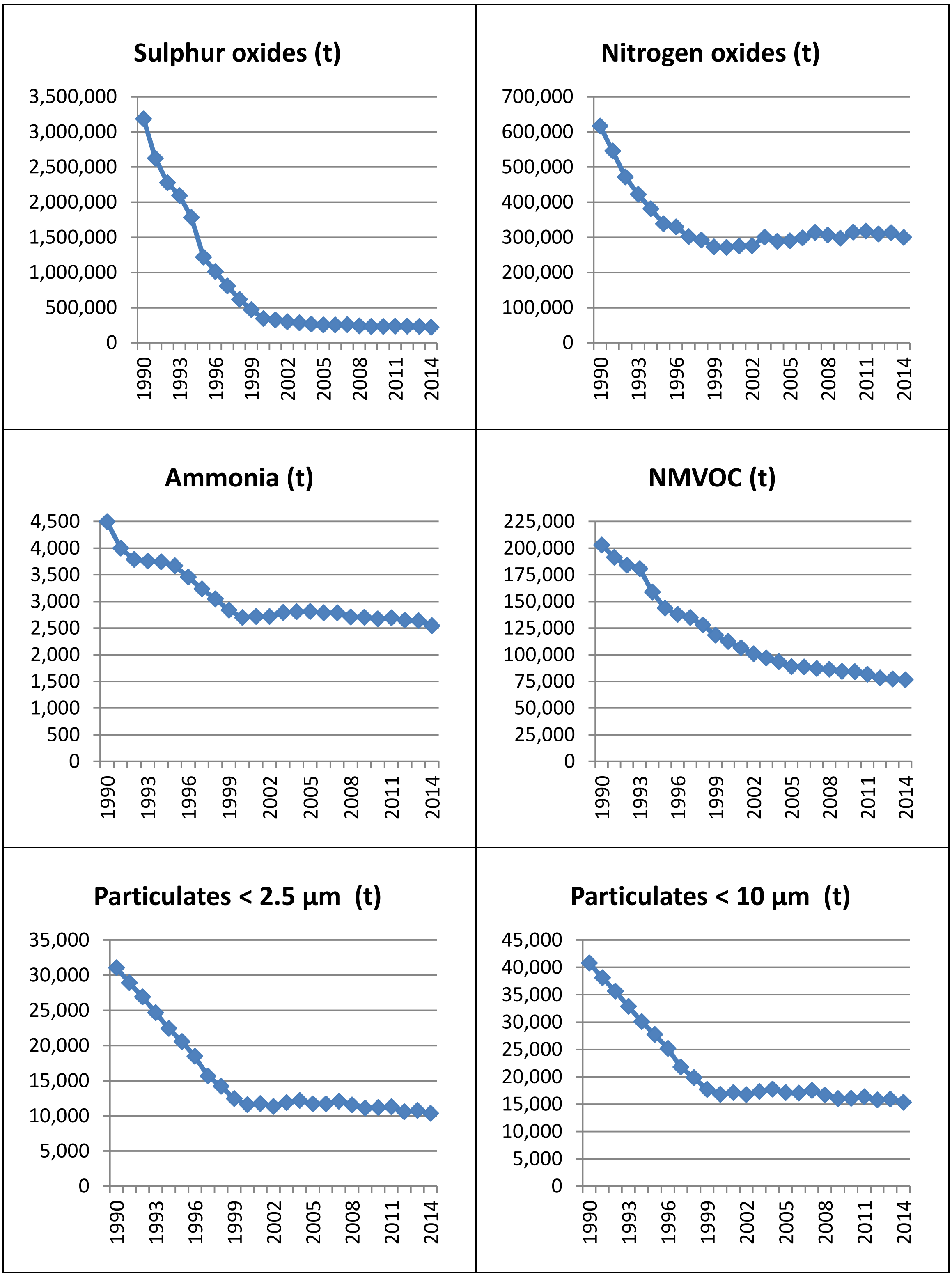
Two thirds of particulate emissions of <2.5 µm come from combustion processes, mainly in transport, homes and commerce. Germany's target for 2020 is to reduce emissions of these particulates by 26% compared to 2005 levels, to approximately 100,000 tonnes. For 2030 the target is to reduce them by 43% to approximately 77,000 tonnes.

A third of particulate emissions of <10 µm come from production processes, mainly from bulk products (sand, coal, grain). Agriculture accounts for 22% and road transport and homes 15% each. Neither the original 1999 version nor the 2012 revision of the Gothenburg Protocol include country-specific targets for reducing these emissions. In this category, the EU has a target of not exceeding an annual average of 50 $\mu g/m^3$ or a daily average of 100 $\mu g/m^3$.

As can be seen, of all the emissions with specific targets, ammonia is furthest from meeting its target. Further measures are not expected in the area of power generation, which has little impact on ammonia emissions.

Trends in air pollutant emissions from the power and heat sectors can be seen in the graphs below. During the 1990s, there was a sharp fall in emissions of sulphur oxides, nitrous oxides and particulates. However, since 2001, nitrous oxides have shown a certain resistance to further reduction.

FIGURE 34. Atmospheric pollutant emissions in power and heat generation in Germany



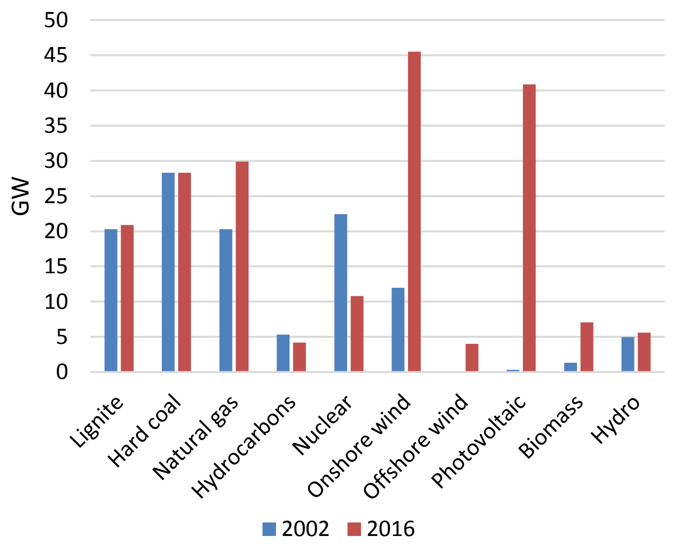
Source: Authors, based on Eurostat figures.

2.6. Summary and conclusions

2.6.1. The power mix

The period from 2002 to 2016 saw continued growth in installed capacity of renewables (a strong rise in wind power and a very strong rise in photovoltaic), no change in coal (hard coal+lignite),[61] a rise in installed gas-fired capacity, and a drop in nuclear power as a consequence of the shutdown of eleven power stations.

TABLE 13. Installed capacity by technology in Germany in 2002 and 2016 (GW)

GW	2002	2016	Installed capacity
Lignite	20.30	20.90	
Hard coal	28.29	28.32	
Natural gas	20.30	29.89	
Hydrocarbons	5.30	4.20	
Nuclear	22.43	10.80	
Onshore wind	11.98	45.50	
Offshore wind	0	4.00	
Photovoltaic	0.30	40.85	
Biomass	1.32	7.06	
Hydro	4.95	5.6	
TOTAL	115.17	197.12	

Note: this table shows only the principal energy sources and does not necessarily coincide with the figures shown in other graphs in this report.

Source: Authors, based on Fraunhofer ISE (2017).

The introduction of renewables has taken different forms. In the case of solar photovoltaic power, the increase has been in the area of distributed generation, whereas in the case of wind power, it has been in the area of the traditional power utilities. The development of wind power, together with biomass, is very closely related to the system of auctions and incentives.

During the period 2002-2016, power output from hard coal and nuclear fell, as did (to a lesser extent) lignite, while gas-fired generation rose. Altogether, generation from fossil fuels fell by 3% and together with nuclear power saw a reduction of 17%. There has been a strong increase in renewable production, especially from wind power and a very sharp increase in photovoltaic power.

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[61] The relative share of lignite has actually increased slightly by 0.6 GW (3%).

TABLE 14. Gross generating output by technology in Germany in 2002 and 2016 (TWh)

Technology	2002 (TWh)	2016 (TWh)	Variation 2002-2016 (TWh)	Percentage variation 2002-2016
Lignite	158	150	-8	-5%
Hard coal	134.6	111.5	-23.1	-17%
Natural gas	56	80.5	24.5	44%
Subtotal coal+gas	**348.6**	**342**	**-6.6**	**-2%**
Hydrocarbons	8.7	5.9	-2.8	-32%
Subtotal fossil fuels	**357.3**	**347.9**	**-9.4**	**-3%**
Nuclear	165	84.5	-80.5	-49%
Subtotal fossil fuels + nuclear	**522.3**	**432.4**	**-89.9**	**-17%**
Onshore wind	15.8	65	49.2	311%
Offshore wind	0	12.4	12.4	
Photovoltaic	0.2	38.2	38	19000%
Biomass	4.5	45.6	41.1	913%
Hydro	23.7	21	-2.7	-11%
Subtotal renewables	**39.7**	**136.6**	**96.9**	**244%**
Total	**562**	**569**	**7**	**1%**

Note 1: This table shows the principal energy sources.

Note 2: Figures for subtotals are orientative.

Source: Authors, based on AG Energiebilanzen e.V. (2017).

Renewables have gone from accounting for 3.77% of output in 2001 to 30% in 2016, and in principle the target of a 35% share in power generation by 2020[62] seems feasible.

Nonetheless, taking into account the relative weight of fossil fuels in the power mix, there is a clear need to make an important effort to meet targets on reducing CO_2eq emissions by 2030 (and then by 2050). This will be especially important if there is no reduction in demand and/or an improvement in active demand management; in this case, conventional fossil-fuel technologies will continue to be important, maintaining a presence that is not compatible with targets on renewables and a 10% reduction in electricity demand by 2020 and a 25% reduction by 2050 (compared to 2008 figures).

[62] Comparing these percentages for renewables with mainland Spain (15.2% in 2002 and 41% in 2016), the penetration of renewables in the power industry can be seen to be clearly higher in Spain than in Germany. Nonetheless, Germany has practically twice the installed capacity in renewables (107 GW compared to 51 GW in Spain (2016)) and output (192 TWh compared to 100 TWh in Spain (2016)). We shall not discuss here the relative burden and cost for consumers of the two developments.

The generating facilities with the greatest annual operating hours were lignite-fired and nuclear-powered plants (measured in full load equivalent hours, FLEH). The technologies that have seen the greatest reduction in operating hours are hard coal, lignite and, to a lesser extent, gas (the last two well below lignite). Photovoltaic power is very widely distributed, with a high concentration in the south of the country. There has been a major increase in biomass and hydro, which are important for meeting 2020 targets.

TABLE 15. Full load equivalent hours by technology

Technology	2002 (FLEH)	2016 (FLEH)	Variation 2002-2016 (FLEH)	Percentage variation 2002-2016
Lignite	7,783	7,177	-606	-8%
Hard coal	4,757	3,937	-820	-17%
Natural gas	2,773	2,693	-80	-3%
Subtotal coal+gas	**15,313**	**13,807**		
Hydrocarbons	1,641	1,408	-233	-14%
Subtotal fossil fuels	**16,954**	**15,215**		
Nuclear	7,347	7,833	486	7%
Subtotal fossil fuels+nuclear	**24,301**	**23,048**	**-1,253**	**-5%**
Onshore wind	1,318	1,428	110	8%
Offshore wind	0	3,002	3,002	
Photovoltaic	666	935	269	40%
Biomass	3,409	6,459	3,050	89%
Hydro	4,797	3,750	-1,047	-22%
Subtotal renewables	**10,190**	**15,574**	**5,384**	**53%**
Total	**34,491**	**38,622**	**4,131**	**12%**

Note 1: This table shows the principal energy sources.

Note 2: The values differ to those shown in Figures 8 and 9 because they take different sources into consideration, which differ mainly in the lower installed capacity of the coal-fired stations considered in this graph.

Source: Authors, based on AG Energiebilanzen e.V. (2017) and Fraunhofer ISE (2017).

This trend could be due to the fact that the cost of producing electricity with hard coal and lignite, together with the prices of emission allowances have not been capable of sending the anticipated price signals. The forecast is for a reduction in the difference in the cost of generating with hard coal and lignite as opposed to natural gas. However, the change will not be enough to allow natural gas to take over from coal as Germany's leading power source without additional measures.

Looking to the future, given the size of the German electricity system and the targets for penetration of renewables, the anticipated increases in absolute values of wind power and photovoltaic from 2015 to 2030 are very significant (from 45 GW to 73 GW for wind and from 39 GW to 66 GW for photovoltaic). The target of having 6 GW in electrical storage by 2030 is also important. For its part, biomass is likely to play a more significant role as a back-up energy, allowing it to be used for other energy purposes (heating/cooling and transport).

The system of feed-in-tariffs for promoting renewables and the auction system, which has partially replaced the previous system, will play an important role in this development. Nonetheless, it is striking that greater penetration of photovoltaic is being promoted than wind, when in economic terms, the part of the EEG surcharge devoted to the former is higher than the latter.

At the same time, no long-term forecast can ignore the fact that the nuclear shutdown is on schedule[63] and all nuclear facilities will be closed by 2022.

As for coal-fired stations, no new lignite- and hard coal- burning plants are planned beyond Datteln 4 (1,055 MW), a hard coal plant, which has a single generating set with 45% efficiency. In any case, improvements can be made to existing plants in terms of increasing efficiency and complying with emission regulations.

There is also a plan for early closure of lignite-fired plants by first moving the facilities to the capacity reserve (2.7 GW) between 2016 and 2023. The Government does not rule out early closure of more lignite-fired plants if it does not manage to meet the emission reduction targets by other means (BMUB, 2014). As already stated, this is likely to be the case.

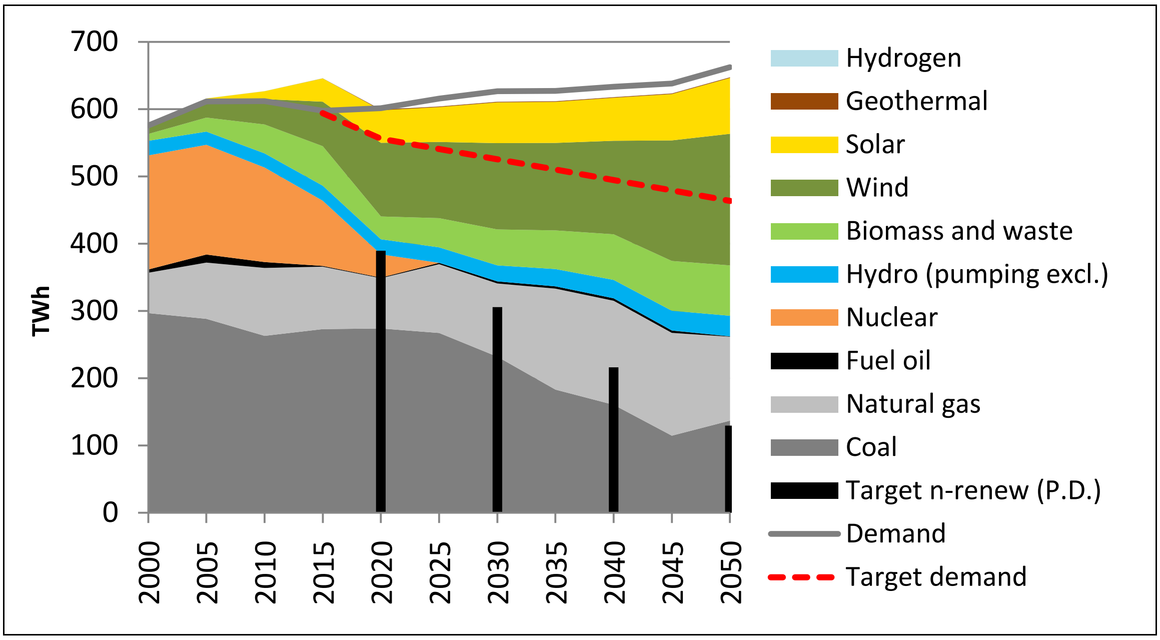
2.6.2. Electricity demand, imports and exports

During the period 2002-2016, demand measured in plant busbars remained practically unchanged. It seems likely to be too challenging to meet the target of reducing demand by 10% in 2020 compared to 2008, since this would involve an annual reduction of 1.6%. A reduction of this scale was only achieved in one year, 2014, when the industrial GVA fell. Thus, in order to meet the target of reducing demand to 2050 (by 25% compared to 2008) greater efforts would needed in subsequent years.

The forecasts suggest that demand will not fall as planned. Combined with possible trends in output from renewables, this would mean that in 2030 fossil-fuel-fired facilities would have a 56% share of the total (21% coal and 19% gas) and 40% in 2050 (21% coal and 19% gas), which would not contribute to a reduction in CO_{2eq} emissions unless CO_2 capture and storage is achieved (which seems unlikely).

[63] It has been decided to introduce a state fund as a mechanism for transferring responsibility for nuclear waste to the state. As a result of a court ruling, the German state has been forced to refund the cost of the tax on nuclear fuel.

FIGURE 35. Forecast trend in power generation in Germany, 2000-2050



Note 1: Annual targets for non-renewables are based on the difference with targets for renewables: 65% in 2020, 50% in 2030, 35% in 2040 and 20% in 2050.

Note 2: Demand is classed by source. The demand target is that set by the German government.

Source: Authors, based on Capros et al. (2016).

International exchanges are playing an increasingly important role in the German electricity market. Based on the level of domestic production and demand, in 2003 Germany became a net exporter of electricity. Since 2012, there have been net exports in all months. The reason is the need to export surpluses of renewable energy, given the difficulty of making large-scale load reductions in conventional power.

Germany has major interconnections with nine countries. Export capacity is forecast to double between 2015 and 2025, with interconnections with two new countries, Belgium and Norway. In the future, Germany is committed to increasing the capacity of its international import and export interconnections with most of its neighbours, which would mean an increase in the overall volume of exports and imports. In this way it plans to guarantee supply security.

The forecast reduction in the reserve margin *vis-à-vis* peak demand to 5% in 2021-2022 means that interconnection import capacity will be a key security element for covering these peaks.

In any event, on-schedule construction of internal transport networks within the country will vitally important. One goal of these projects (which are suffering significant delays) is to carry electricity from the north (offshore renewable wind power) to consumption points in the south and to satisfy industrial demand in this area of the country, where several nuclear power stations have already been shut down (for example in Bavaria). This has led to an increase in costs from redispatching (€412m in 2015 plus a €478m shadow price resulting from the fact that not all renewable output can be taken up into the grid) and the network reserve (€177m in 2016), which had to be extended in time.

This situation contrasts with the large-scale regulatory and government support for the development of power grids, with more than 65 projects for high-voltage lines (7,700 km, nearly 6.5% of the total). These include projects for underwater connections to offshore wind farms in the North Sea and the Baltic, which were planned for 2022 but have been delayed.

In addition, the development of distributed generation makes it necessary to extend the network, involving higher costs and an increase in the access tariff. Moreover, as neighbouring countries develop renewable generation or implement measures to prevent Germany from overloading their own power grids, the country will require an increase in its own infrastructure.

2.6.3. The wholesale market and capacity mechanisms

The German government has decided to opt for an energy-only market, as well as a centralised capacity mechanism in order to ensure supply security. This has led to the creation of three reserves from differentiated power stations: the grid (or network) reserve, the climate reserve and the capacity (or strategic) reserve.

The purpose of the grid reserve is to prevent congestion between the north and south of the country which might lead to a price increase on electricity exchanges. The climate reserve is made up of lignite-fired plants totalling 2.7 GW, which do not participate on the market; these plants are being put into reserve between 2016 and 2019 and will be shut down after four years. The capacity reserve comprises power stations which could come into operation in the event of a mismatch between supply and demand on the power market.

TABLE 16. Key figures of the different reserves

	Grid reserve[64]			Climate reserve	Capacity reserve	
Start date	2016/17	2017/18	2018/19	2016/19-2019/23	2018/19	2019+
Capacity (GW)	8.4	10.4	3.7	2.7	1.2	Up to 4.4
Estimated cost (€M/yr)	177	220	78	230	130-260	
Estimated cost (€/MWh)	0.38	0.47	0.17	0.50	0.28-0.55	
Type of power station	Thermal: domestic and European			Lignite	Thermal: domestic and European	

Source: Authors

Unlike Germany, the EU views the use of reserves as a temporary measure. The reserves created in Germany might therefore be replaced by other mechanisms in the future or might even be phased out altogether, depending on forecast needs.

The combination of renewables and energy-only markets entails a reduction in revenue for conventional generation, given the forecast for stable prices in the short term. In this context, prices are forecast to stand at around €29-58/MWh in 2020 and €31-72/MWh in 2030. As a result, power stations with higher costs are likely to be clear candidates for closure in the medium term.

2.6.4. The environment

Total GHG emissions in 2015 were 27% lower than in 1990, having increased in 2016 (from 908 to 916 MMTCDE). Greenhouse gas emissions from power generation account for a third of the country's total emissions and fell for the third year running in 2016 (to 306 MMTCDE). GHG emissions from transport are still at 1990 levels. In industry and the residential sector they fell between 1990 and 2014 (from 283 to 187 MMTCDE and from 209 to 119 MMTCDE respectively).

Germany is having difficulty reaching the target of a 40% reduction in GHG emissions by 2020 compared to 1990, in both electricity and transport, despite the introduction of renewables. As a result, the most significant reductions are being kicked down the medium/long-term road.

In order to meet its short- and medium-term targets, plans are needed, some of which have already been identified (such as the NAPE and the climate reserve). In the plans for 2020 the greatest emphasis is on energy efficiency (reduction of 25-30 MMTCDE) and power generation (22 MMTCDE). It is also felt that the price of CO_2 should be higher, to incentivise a change in generating technologies in the short term[65] (i.e. replacing coal with natural gas).

[64] 2017/18 and 2018/19 values calculated based on 2016/2017 unit cost of the reserve.
[65] Here it is worth recalling community initiatives such as the amendment to the ETS directive.

Success in meeting emissions targets to a great extent depends on the implementation of these plans. Otherwise, the government might even decree early closure of more lignite-fired plants, consigning them first to the capacity reserve.

In order to meet the 2030 targets, more effort will be required to reduce emissions. Transport electrification, energy efficiency and the use of renewables in heating and cooling will be vital.

As for trends in air pollutant emissions from the power industry, it can be seen that starting in the 1990s, major reductions were achieved in emissions of sulphur oxides, nitrogen oxides and particulates. However, since the 2000s, there has been a certain degree of stagnation or rigidity when it comes to reducing levels of nitrogen oxides.

3. ECONOMIC IMPLICATIONS FOR THE ELECTRICITY INDUSTRY

3.1. Introduction, purpose and scope

The *Energiewende* has had a major economic impact on the entire value chain of the power industry. The links in the chain that have been most affected in economic terms lie at the two ends, consumers and producers.

On the demand side, household consumers have seen major changes in their electricity bills. Among industrial consumers, the price difference between small and large consumers has increased gradually since 2011. In contrast to medium and small consumers, large industrial consumers have even experienced a reduction in their electricity bill as a result of the fall in the costs of the electricity supply and exemptions related to the renewables (EEG) surcharge.

On the supply side, "traditional" utilities (RWE, E.ON, Vattenfall and EnBW) have seen a fall in annual profits, with losses over several consecutive years, pushing down their share prices. This situation has forced companies to re-examine their strategies, bringing major changes to a market which they previously dominated.

Taking all these factors into account, in this third chapter we study the economic implications of the *Energiewende* on the electricity industry. In particular, we analyse prices for final consumers and the impact on the large utilities.

In the first section, we examine prices for household and industrial consumers, studying the different price components and how they have evolved over time, together with their impact on the total price. We then compare these figures with those of other European countries, particularly the big five EU economies (Germany, France, United Kingdom, Italy and Spain). The chapter ends with an analysis of the EEG surcharge, the component of the electricity bill that has increased most in recent years and the aid policies implemented by the German government.

The second section analyses the impact of the *Energiewende* on the four large German utilities: RWE, E.ON, Vattenfall and EnBW. We begin by examining the strategic changes made by the companies, their market share, their generating structure and the restructuring of the companies themselves — especially RWE and E.ON, which have made the most far-reaching changes. Secondly we study the economic performance of the companies, their share price and their financial situation.

3.2. Prices for household and industrial consumers

In 2016, final electricity demand in Germany stood at 525.1 TWh (BDEW, 2017b), up 10 TWh on the previous year, bringing it back to 2011-2013 levels. According to data from the Federal Energy and Water Management Association (BDEW, *Bundesverband der Energie- und Wasserwirtschaft e.V.*), industrial consumption accounted for 47% of final electricity consumption in Germany in 2016, at around 247 TWh. In second place came consumption in commerce and services, totalling 137 TWh (26% of total consumption). Finally, in third position is the household sector with 25% of total demand, 131 TWh. The remaining 2% corresponds to transport. According to

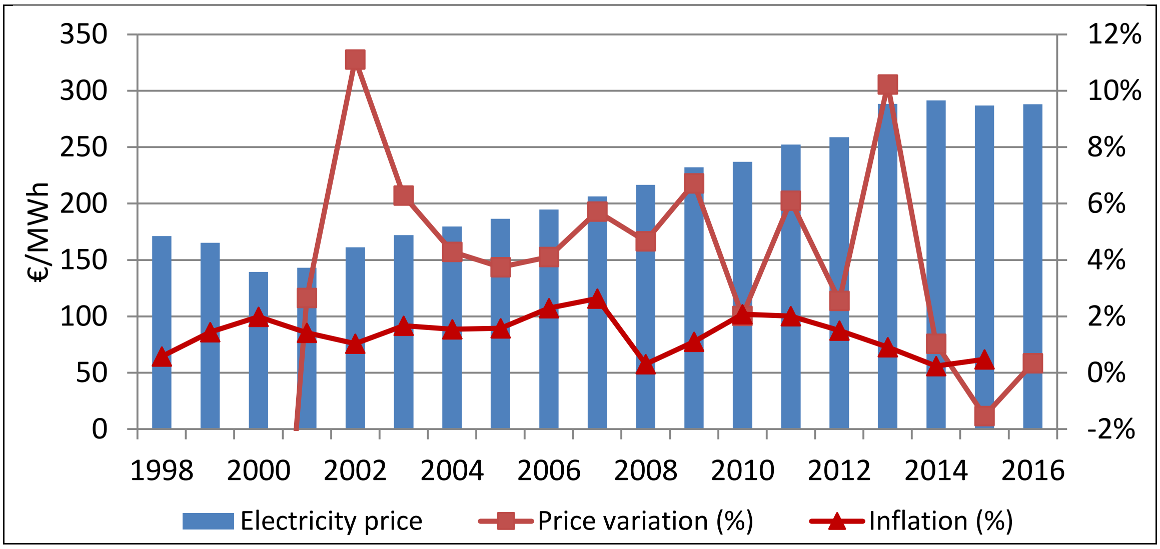
Eurostat, a decline in industrial activity has led to changes in this consumption distribution in recent years. Nonetheless, in 2016 the levels were back to a similar position as ten years ago.

3.2.1. Prices for household consumers

Current situation and trend in Germany

Following liberalisation of the power generation market in 1998 (OECD, 2004), the price of electricity for German household consumers fell to a record low in 2000 (see figure 36). Between 2001 and 2013 it rose at an annual average of 5.4%, well above inflation (1.5%). In contrast, between 2014 and 2016 it rose below inflation, even declining in 2015.

FIGURE 36. Price of electricity for a German home compared to inflation



Source: Authors, based on BDEW (2017a).

The final price is subdivided into three cost components: energy, network access charges, EEG surcharge and other taxes and levies (see figure 37). The energy component refers to the price of electricity on the wholesale market or in a bilateral (Over-the-Counter) contract. Network access charges refer to the rate paid for the use of transport and distribution networks. Finally, in addition to VAT, a number of different taxes and levies are charged in Germany, as listed in figure 38. This is the largest component of the bill.

The cost of the energy component fell by nearly 11% in 2016 compared to 2015. This continues the trend of falling prices which began in 2013, with an accumulated drop of 13% since 2008. Nonetheless, given that this component represented only 21% of the electricity bill of the average German home in 2016 (figure 38), and because the other components of the bill have increased, the price paid by German homes for electricity has scarcely changed since 2013.

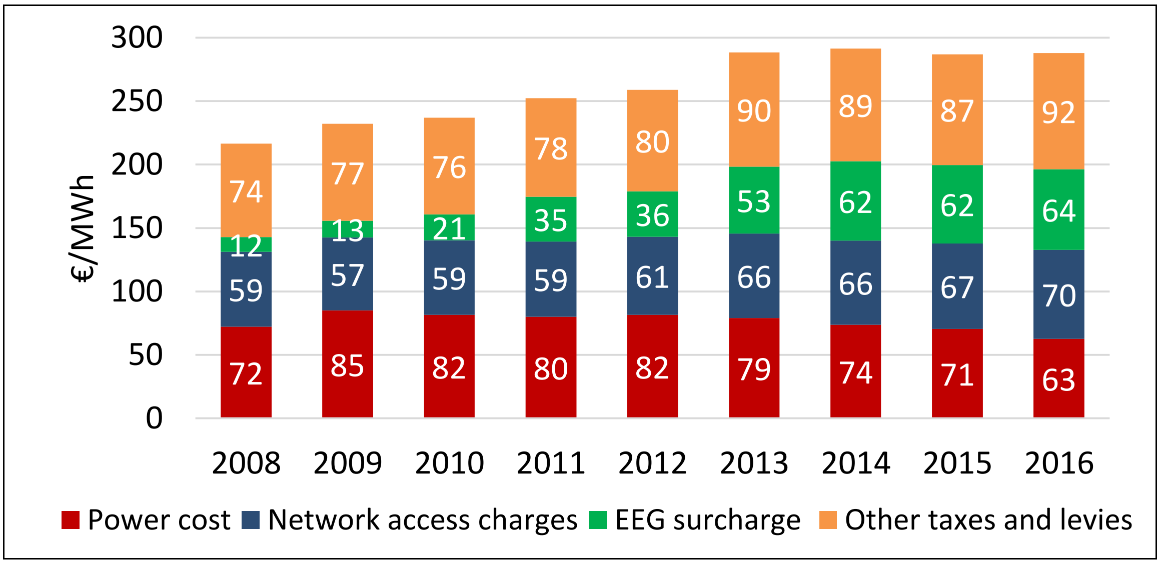
As mentioned in Chapter 2, the cost of electricity on the wholesale market has gradually fallen since 2012. This led to a reduction in the cost of supply, but with one year's delay, since it did not begin to fall until 2013. Based on forecasts for the wholesale market, these costs are expected to continue falling until 2019.

In 2016, network access charges for the first time comprised the largest item in the German household electricity bill, followed by the EEG surcharge.[66] The reason lies in the slow rate of expansion of the power grid, which in the words of TenneT is not advancing apace with the incorporation of renewables. Among the reasons given are the political decision to run the north-south HVDC lines underground, the slow pace of administrative and legal processes and popular protests over the routes (it was these protests that led the German government to bury the HVDC lines).

Most of this increase in the network cost is due to the additional cost caused by redispatches (see Section 2.4.2), while only 5% is due to network expansion (Agenturmeldungen, 2016). This trend is predicted to continue in 2017, since German transport network operators have announced an increase in the network access charge(50Hertz, 2016; Agenturmeldungen, 2016; Amprion, 2016; TransnetBW, 2016).

It is striking, therefore, that the cost of energy and network access charges accounted for only 46% of the electricity bill of household consumers in 2016, with taxes and levies making up the remaining 54%.

FIGURE 37. Components of the cost of electricity for a German household with an annual consumption of 3.5 MWh



Source: Authors, based on BDEW (2017a).

In the area of taxes and levies, there was a major increase in the EEG surcharge in 2017 (see Section 3.2.4), rising to €68.8/MWh from €63.5/MWh the year before (50Hertz, Amprion, TenneT, & TransnetBW, 2016b). This surcharge is the one item

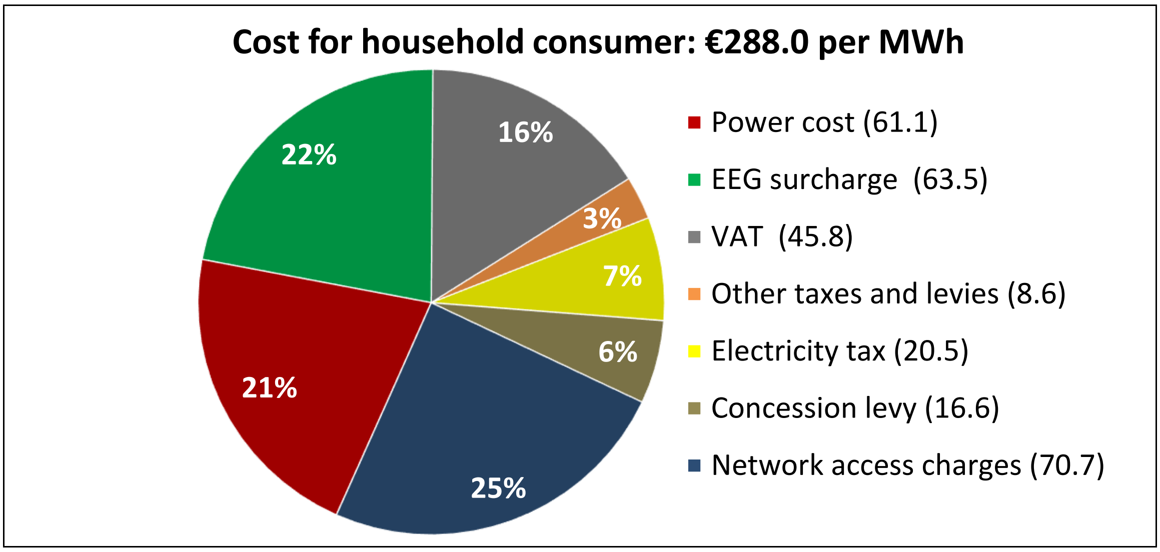
[66] The cost of the EEG surcharge has been differentiated from other taxes because of its relative weight in the invoice.

that has increased most since 2008, and we shall therefore examine it in greater detail in Section 3.2.3.

After the EEG surcharge and VAT, the highest taxes and levies in 2016 were (figure 38) the concession levy[67] and electricity tax,[68] whose costs have remained stable over time. Of the remainder, which account for scarcely 3% of the total, the most significant developments have been a rise in the CHP surcharge[69] which practically doubled in 2016, and the surcharge for distribution losses[70] (*§19 StromNEV-Umlage*), which has oscillated between €0.90 and €3.80/MWh since it was first introduced in 2012 The offshore liability insurance surcharge,[71] which reached a maximum of €2.50/MWh during the first years, stood at €0.4/MWh in 2016. Finally, the interruptibility payment[72] has never risen to above €0.10/MWh, and in 2016 it stood at €0/MWh.

The graph below shows the breakdown of the electricity price for a typical German household in 2016, as indicated above.

FIGURE 38. Breakdown of the price of electricity for a German household with an annual consumption of 3,500 kWh, 2016



Note: "Other taxes and levies" includes the CHP surcharge (4.45), the surcharge for distribution losses (3.78), the offshore liability insurance surcharge (0.4) and the payment for interruptibility (0).

Source: Authors, based on BDEW (2017a).

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[67] This is a tax on the use of public space for power lines. The cost depends on the user's location.
[68] The electricity tax is similar to that levied in other countries, such as Spain.
[69] A surcharge used to fund a guaranteed price for combined heat and power (CHP) plants.
[70] End consumers can request individual network access charges if they fulfil certain criteria (e.g. if they only have a high rate of power consumption during certain months of the year). This surcharge was introduced in 2012 to compensate operators of the distribution networks for losses resulting from this concept.
[71] This surcharge was introduced in 2013 to compensate for loss of earnings due to delays in connecting offshore wind farms.
[72] This surcharge was introduced in 2014 for the payment of interruptible loads, large consumers whose power loads can be disconnected in the event of a major impact on the power system that might result in a severe fault.

As can be seen in table 17, of the different components of the electricity price for household consumers, during the period 2008-2016 only the power cost has fallen, whilst all other items have increased. As mentioned, the rise in the EEG surcharge has been particularly steep (448%).

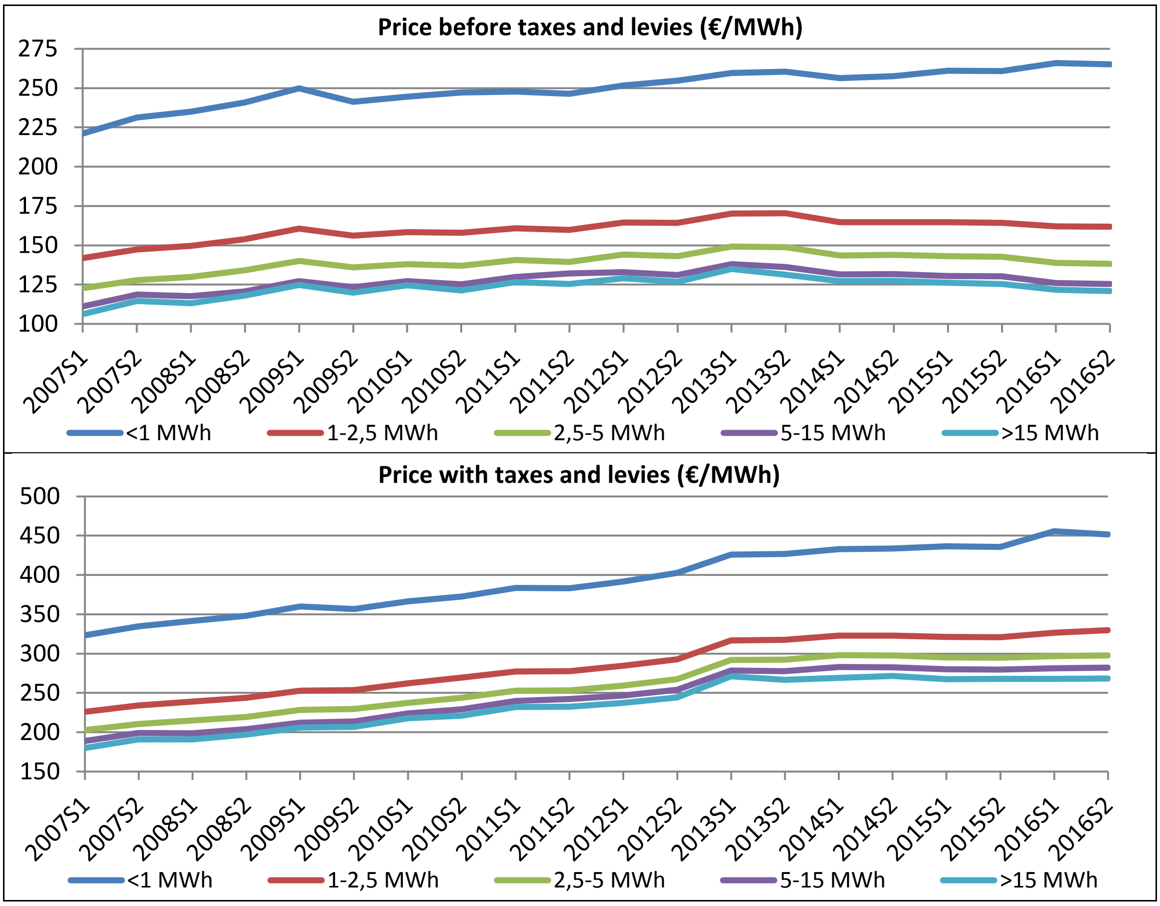
TABLE 17. Variation in the components of the electricity price for an average household consumer in Germany (2008-2016)

Power cost	Network access charges	EEG surcharge	Other taxes and levies	Total
-13%	19%	448%	24%	33%

Source: Authors, based on BDEW (2017a).

The existence of a fixed rate (demand charge) in the electricity price means that not all consumers are impacted equally by the different components of the electricity bill. As figure 39 shows, while the price before taxes and levies has fallen for most consumers since 2013, for those with an annual consumption of under 1 MWh, the price has risen. If taxes and levies are included, prices grew continuously between 2007 and 2013 for all consumer segments. This growth slowed in 2014, leading to relatively stable prices for consumers with higher consumption levels.

FIGURE 39. Price of electricity in Germany for a household consumer



Note: These graphs use the classification of "Households" given in the Eurostat database, although some of the consumption brackets shown here might fall within the scope of SMEs or small industry.

Source: Authors, based on Eurostat figures.

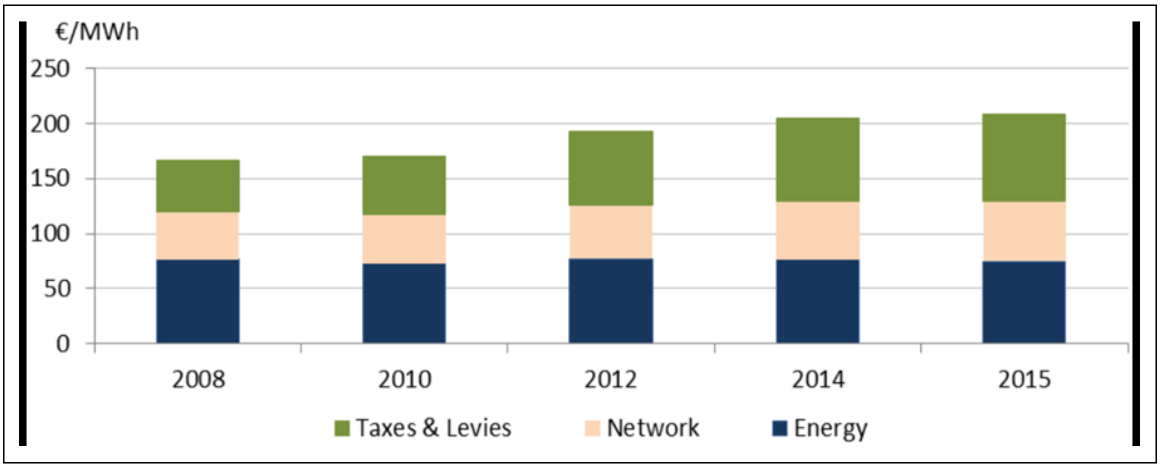
Comparison with European countries

The price of electricity for the average German household has grown above the European average. figure 40 shows that between 2008 and 2015 the average annual increase in Europe was 3.2%, rising to a value of €208.7 per MWh by the end of the period. In Germany there was a 4.2% increase over the same period, to an average price of €287.0 per MWh in 2015.

The largest increase in costs across the EU occurred between 2010 and 2012, whereas in Germany the electricity bill rose most in 2009 and 2013. It is therefore significant that the increase in total costs and their components occurred gradually in the average European household, whereas in Germany there were sharp increases at particular points in time, alternating with others when the increase was close to —or even below— inflation.

The share of the different components in the final price remained largely similar in both the EU average and in Germany. The power cost remained stable or fell[73] (by 15%); the grid component increased by 3.3% per year, while the highest growth was in taxes and levies (their contribution to the total bill went from approximately 28% to 38%, a rise of 7.2% per year) (European Commission, 2016)

FIGURE 40. Components of the electricity price for an average European household (2.5-5 MWh/yr)

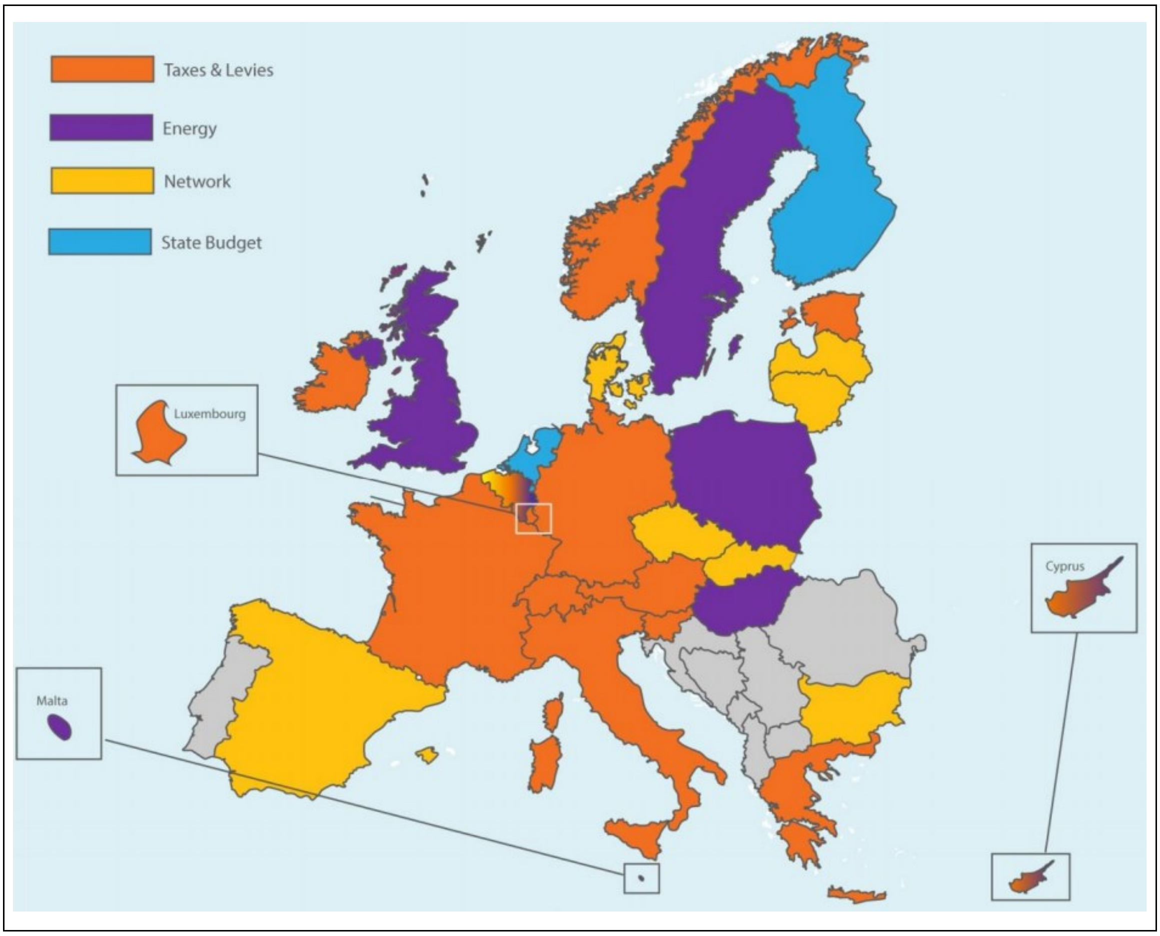


Source: European Commission (2016) based on data from member states and the European Commission.

These data should be treated with some caution, as a 2014 report by Eurelectric[74] suggested that EU member states used different criteria to allocate the components of their electricity bill resulting from state aid policies. figure 41 shows in which category (taxes and levies, costs of power grid and energy) the different EU states included their aid policies in the period 2008-2012 (Eurelectric, 2014). As can be seen, Germany assigned the figures for state aid to taxes and levies.

[73] The difference in household power costs between different countries fell by 19% in the period analysed, showing the impact of the domestic market.
[74] Eurelectric (The Union of the Electricity Industry) is the union of European utilities.

FIGURE 41. Category of the electricity bill to which state aid was allocated (2008-2012)



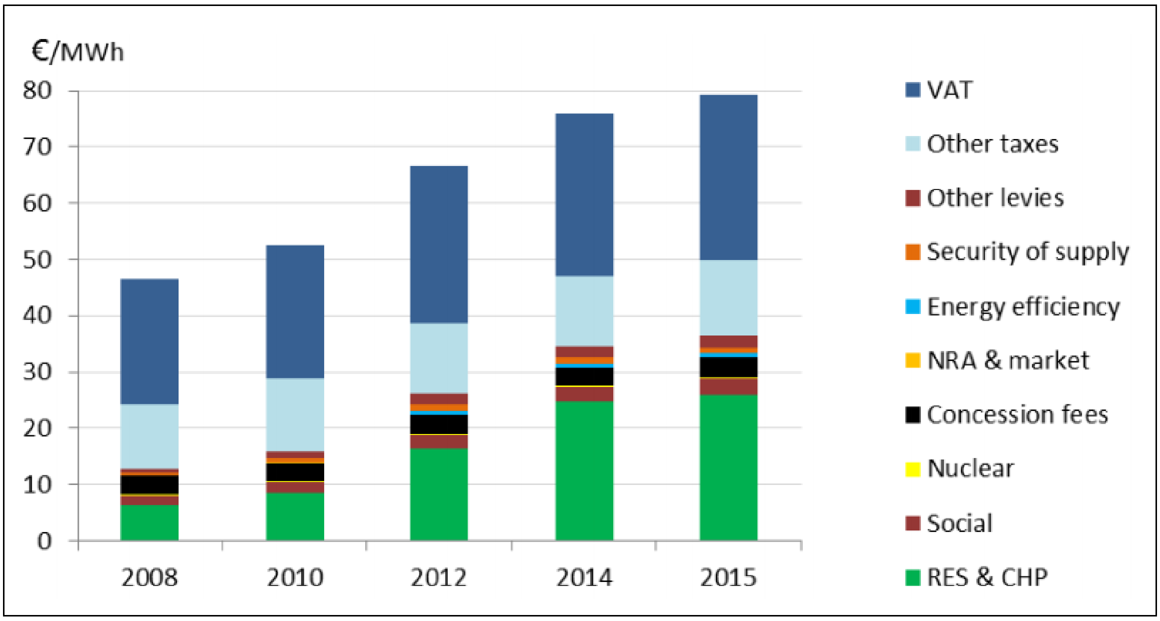
Source: Eurelectric (2014).

According to this report, the cost of the energy component fell between 2008 and 2012 at an average of 4% for residential consumers, whereas the cost of the power grid increased by 9%, and taxes and levies by 31%. Overall, the cost of electricity increased by 9% in the period 2008-2012.

According to the European Commission (2016), VAT forms the largest component of taxes and levies in EU countries, accounting for 37% in 2015 (31% in Germany). Nonetheless, its share has fallen from 48% in 2008 (41% in Germany). The second largest levy is that related to subsidies for renewables and CHP, which accounted for 33% of this category in 2015 (41% in Germany) up from an average of 14% in 2008 for European countries, including Germany.

The distribution and importance of the surcharges in the final price varies greatly from country to country. VAT, for example, accounts for 59% of the final value in Denmark and just 5% in Malta; the renewables and CHP surcharge varies between 22-23% in Portugal and Germany and 0-2% in Hungary and Ireland.

FIGURE 42. Taxes and levies as a share of the electricity price in Europe



Source: European Commission (2016) based on data from member states and the European Commission.

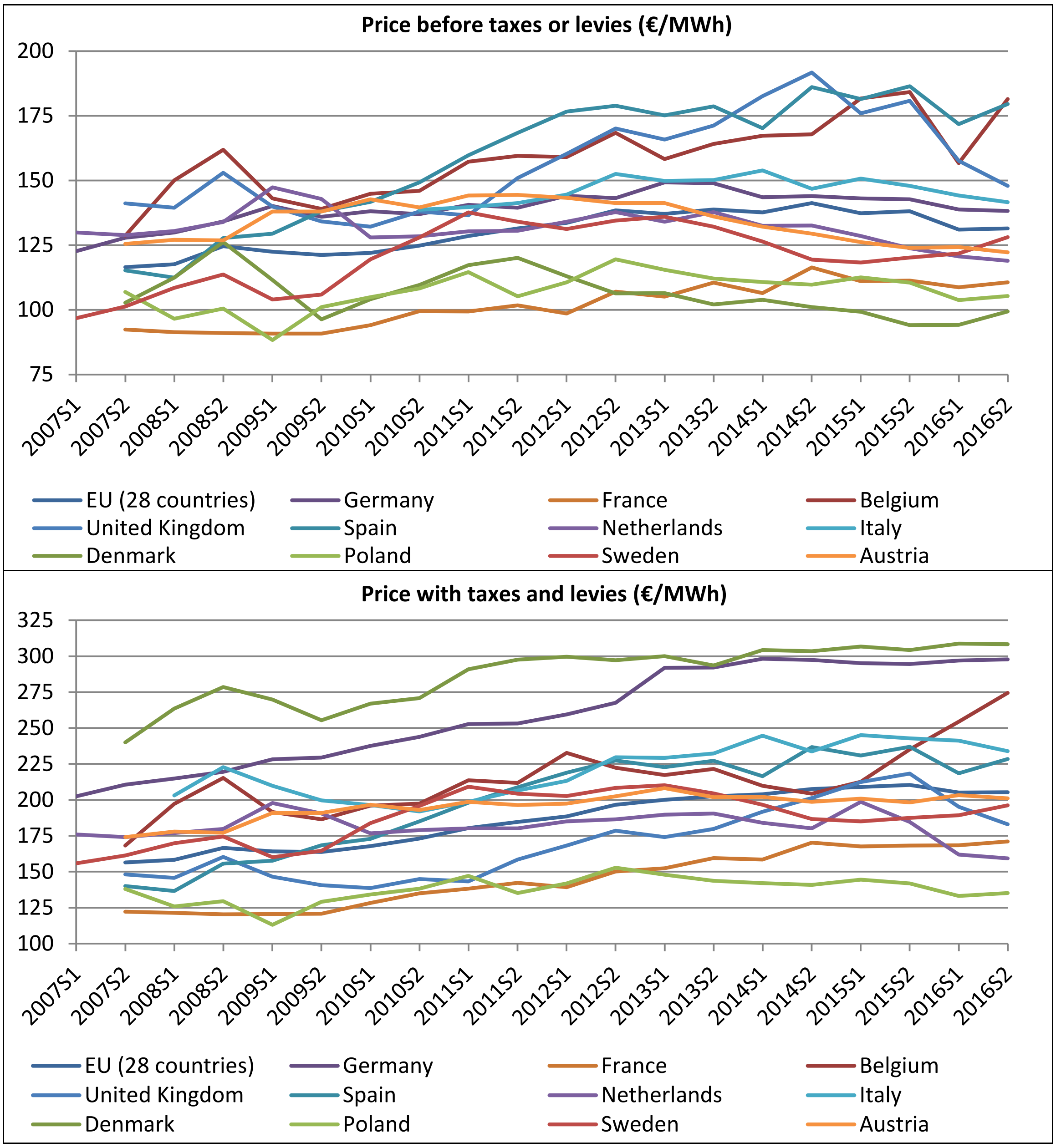
In a comparison of the electricity price before taxes and levies in different countries in the second half of 2016 (see figure 43), Germany stands ahead of its neighbours, except for Belgium. Strikingly the price in Austria is 11% below Germany's despite the fact that they share a common market (both in power supply and in network access charges).

Nonetheless, Germany had the second lowest electricity price before taxes and levies of the five leading economies in the EU (Germany, France, United Kingdom, Italy and Spain). The country with the price closest to that of German households is Italy, while prices are considerably higher in the United Kingdom and Spain. Here it is worth noting that the countries with the highest energy supply costs are islands or peninsulas:[75] Ireland, Spain, the United Kingdom, Malta, Italy, Cyprus and Greece.

The picture is entirely different when it comes to taxes and levies. Only Denmark had a higher final price for electricity than Germany in the second half of 2016, a trend which has been maintained since the historical data series was begun in 2007.

[75] In Portugal the percentage of taxes and levies is very high, but this is offset by a lower supply cost.

FIGURE 43. Electricity price for average household consumers (2.5-5 MWh/yr)[76] in different European countries

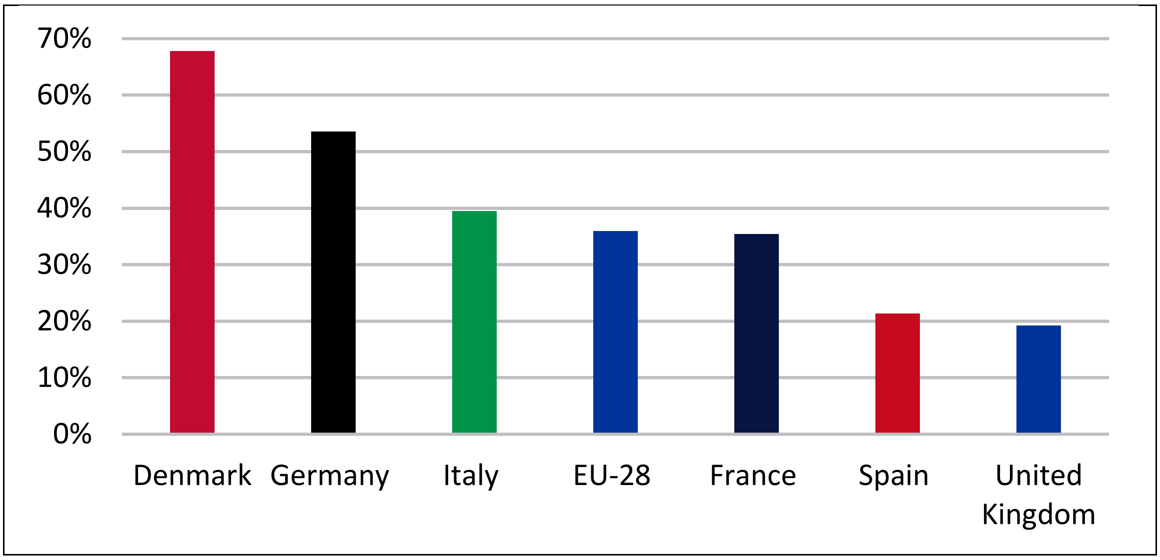


Source: Authors, based on Eurostat figures.

In Danish households, taxes and levies accounted for 69% of the bill, as compared to 53% in Germany. The EU-28 average is considerably lower, at 34%. Of the big five economies in the EU, Germany has the highest share of taxes and levies in the household electricity bill (see figure 44).

[76] According to Eurostat, in 23 of the 28 countries in the EU-28 the 2.5-5 MWh consumption bracket is the most representative.

FIGURE 44. Weight of taxes and levies in different European countries



Note: State aid is allocated to other items of the bill in Denmark (Network), Spain (Network) and United Kingdom (power), which distorts part of the graph (see figure 41).

Source: Authors, based on Eurostat figures.

3.2.2. Prices for industrial consumers

Industrial consumers cover a very broad swathe of consumption, ranging from some with an annual consumption of less than 20 MWh/yr to others with over 150 GWh/yr. According to Eurostat, the most representative range of industrial consumers is between 2 GWh/yr and 20 GWh/yr. Here we shall start by comparing prices in the 160-2,000 MWh/yr bracket (widely represented in Germany) and the 2-20 GWh/yr bracket with other international references. To include the profile of large industrial consumers, we shall also highlight 70-150 GWh/yr consumers, the highest bracket for which Eurostat publishes figures, which, according to the study by PwC (2014), has no major differences with large industrial consumers in all the countries analysed, including Germany.[77]

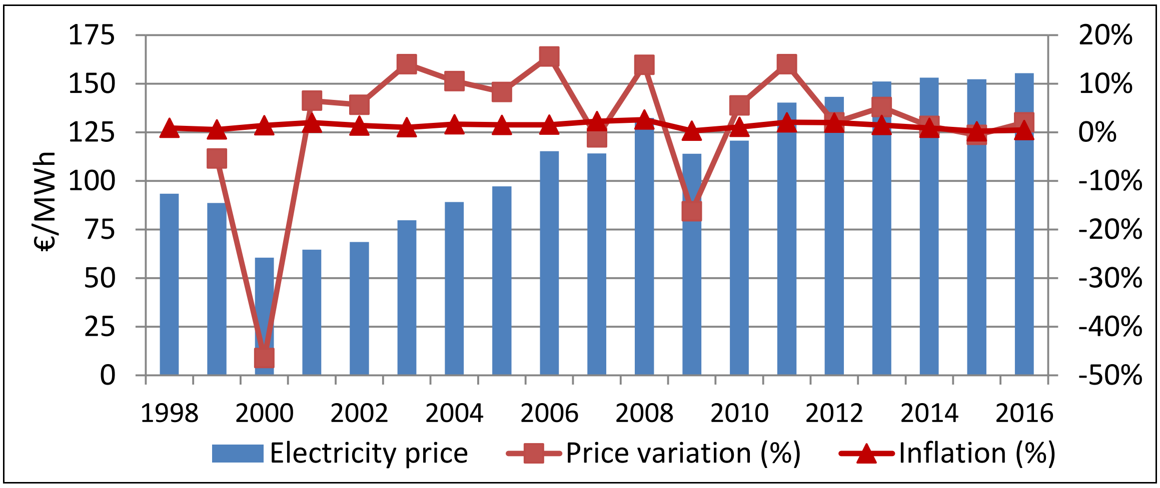
Current situation and trends in Germany

The price for industrial consumers is marked by the fact that this group has a higher proportion of non-tariff contracts, a feature which becomes more widespread the greater the annual consumption. This study notes that large consumers tend to pay less than medium and small consumers. This is because, due to their importance and volume of consumption, they benefit both from greater purchasing power and from the possibility of generating their own power. According to BDEW (2017a), while industries with an annual consumption of 160-2,000 MWh/yr had an average price of €156/MWh in 2016, among industries with a consumption of between 70 and 150 GWh, the average price was €79.6/MWh.

[77] This is the same criterion used in other price reports, such as the quarterly price monitor published by the BDEW (BDEW, 2017a).

As in the case of household consumers, the electricity price for industrial consumers fell to a record low in 2000, following market liberalisation in 1998 (see figure 45). Likewise, between 2001 and 2013 the electricity price grew annually at a rate of 7.3% (well above inflation (1.5%) and the industrial price index (1.7%)).[78] Between 2014 and 2016 the increase slowed, and in 2015 the figure fell. For 2017 a renewed rise is predicted to €171.2/MWh as a result of an increase in power grid costs and a rise in the EEG surcharge.

FIGURE 45. Electricity price for an average German industrial consumer with annual consumption of 160-2,000 MWh

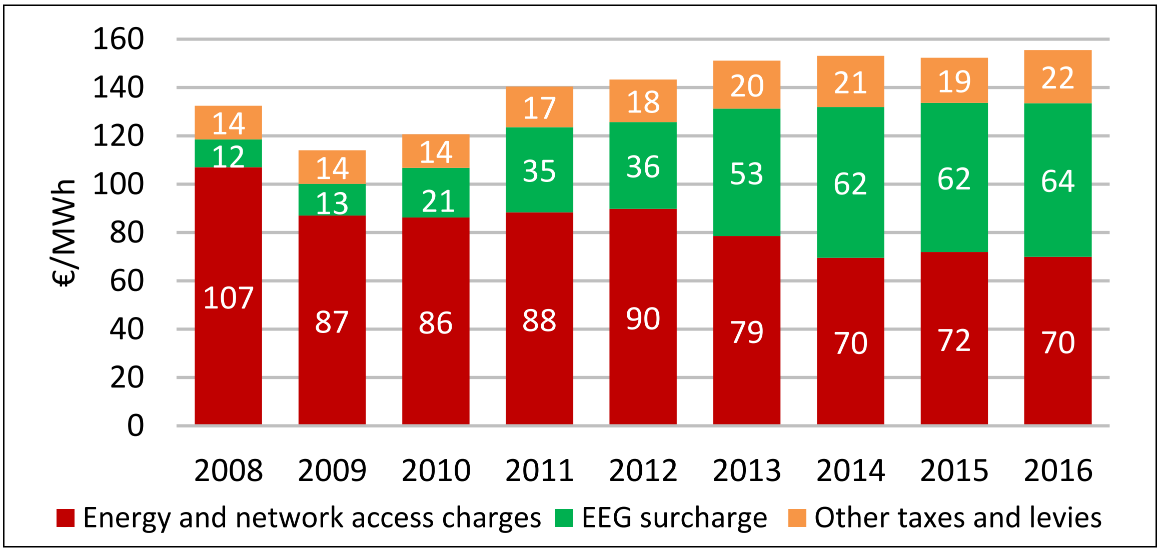


Source: Authors, based on BDEW (2017a)

The fall in the price of electricity on the German power market (before taxes and levies) has also affected the average industrial consumer. Since 2008 the cost of power and networks (power transmission and distribution) has fallen by a third, although there have been no major changes since 2014. Nonetheless, its effect has been obscured by an increase in the EEG surcharge, which has risen fivefold since 2008. This aspect is discussed in greater detail below (See figure 46 and table 18).

[78] Eurostat Data.

FIGURE 46. Price of electricity by component for a German industrial consumer with annual consumption of 160-2,000 MWh



Source: Authors, based on BDEW (2017a)

Note that for industrial consumers, network access charges are bundled together with supply cost, as was the case for household consumers before 2006. According to Eurostat data[79] for the 20-500 MWh/yr consumption bracket, the distribution of the cost in the second half of 2016 was €49.0/MWh in supply cost and €49.2/MWh in network access charges (59%-41% of the total of the two), to a total of €98.2/MWh. For the 500-2,000 GWh/yr bracket, it was €43.6/MWh and €35.7/MWh respectively (55%-45%), €79.3/MWh in total.

Analysing how these items have developed over time, we see that in the second half of 2008 the power supply accounted for €78.9 per MWh and €72.5 per MWh for industrial consumers of 20-500 MWh/yr and 500-2,000 MWh/yr respectively. In other words, there has been a 38% and 40% fall in the supply cost for these two groups of consumers. Network costs came to €34.9 per MWh and €22.6 per MWh in the second half of 2008 for these groups, giving an increase of 41% and 58% respectively between 2008 and 2016. The table below shows the variation in the components of the electricity price of consumers in the 160-2,000 MWh bracket for the period 2008-2016.

[79] Eurostat does not use a 160-2,000 MWh bracket. Instead it has one for 20-500 MWh/yr and another for 500 -2,000 MWh/yr.

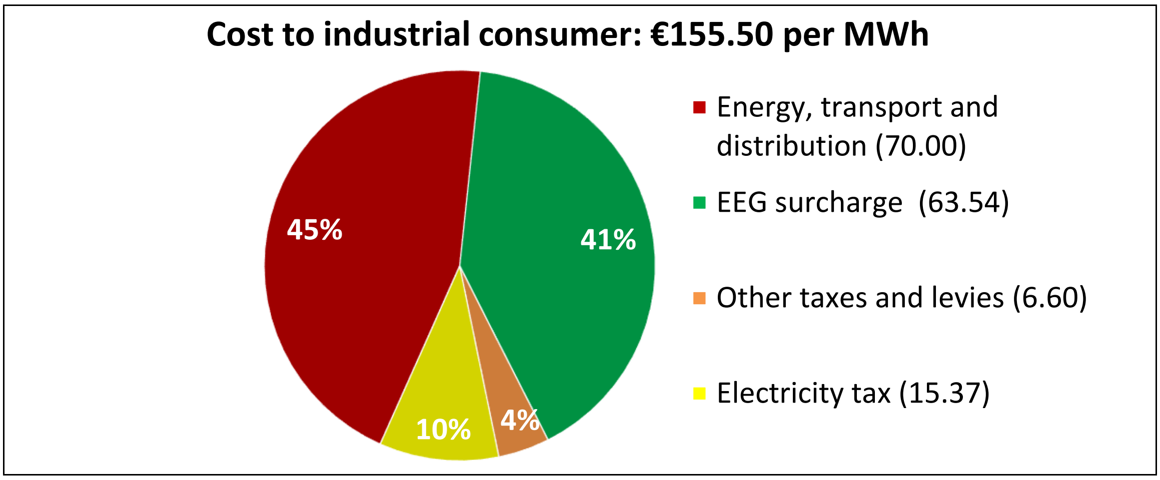
TABLE 18. Variation in the components of the electricity price for an average industrial consumer in Germany (2008-2016)

Energy and network access charges	EEG surcharge	Other taxes and levies	Total
-35%	448%	58%	17%

Source: Authors, based on BDEW (2017a).

BDEW (2017a), basing itself on Eurostat sources, finds that for large industrial consumers (70-150 GW), the cost of power and network access charges has fallen by 44% to €42.9 per MWh, whereas the cost of taxes and levies has multiplied four and half times over since 2008 to €40.8 per MWh. In total, the final electricity price has fallen by 2% for large industrial consumers, as opposed to a 17% increase for average industrial consumers. A more detailed breakdown for 2016 can be seen in figure 47.

FIGURE 47. Breakdown of the electricity price for an average German industrial consumer in 2016 with an annual consumption of 160-2,000 MWh



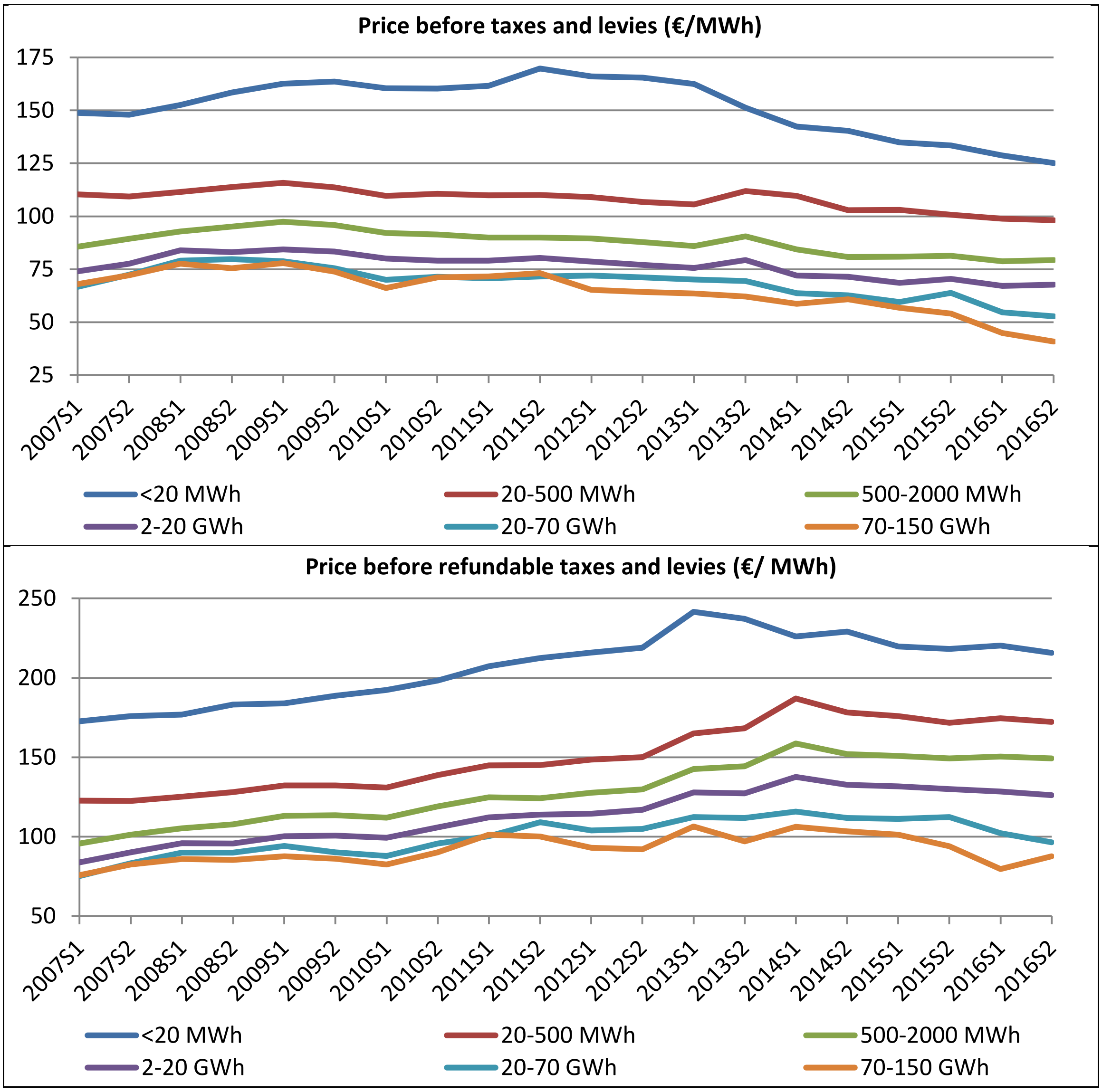
Note: “Other taxes and levies” includes the CHP surcharge (2.8), the surcharge for distribution losses (*§19 StromNEV-Umlage*, 2.4), the offshore liability insurance (for delays in connecting offshore wind farms, 0.3) and the payment for interruptibility (0 in 2016). Note that the figures do not include VAT.

Source: Authors, based on BDEW (2017a).

figure 48 shows that the price before taxes and levies falls as energy use increases. This situation remains true when non-recoverable taxes and levies are included.[80] The price before taxes and levies has been falling since the second half of 2013, although in some cases the descent began earlier. Without taking into account refundable taxes and levies such as VAT —which do not impact the company— the upward trend continued until 2013-2014, and has remained stable or even fallen for larger consumers since then.

[80] Fundamentally VAT (19% in Germany), although according to Eurostat, refundable taxes and levies accounted for an additional 33% of the total without them in 2016 for the 2-20 GWh bracket (essentially in reductions in these charges such as the EEG surcharge).

FIGURE 48. Price of electricity in Germany for an industrial consumer

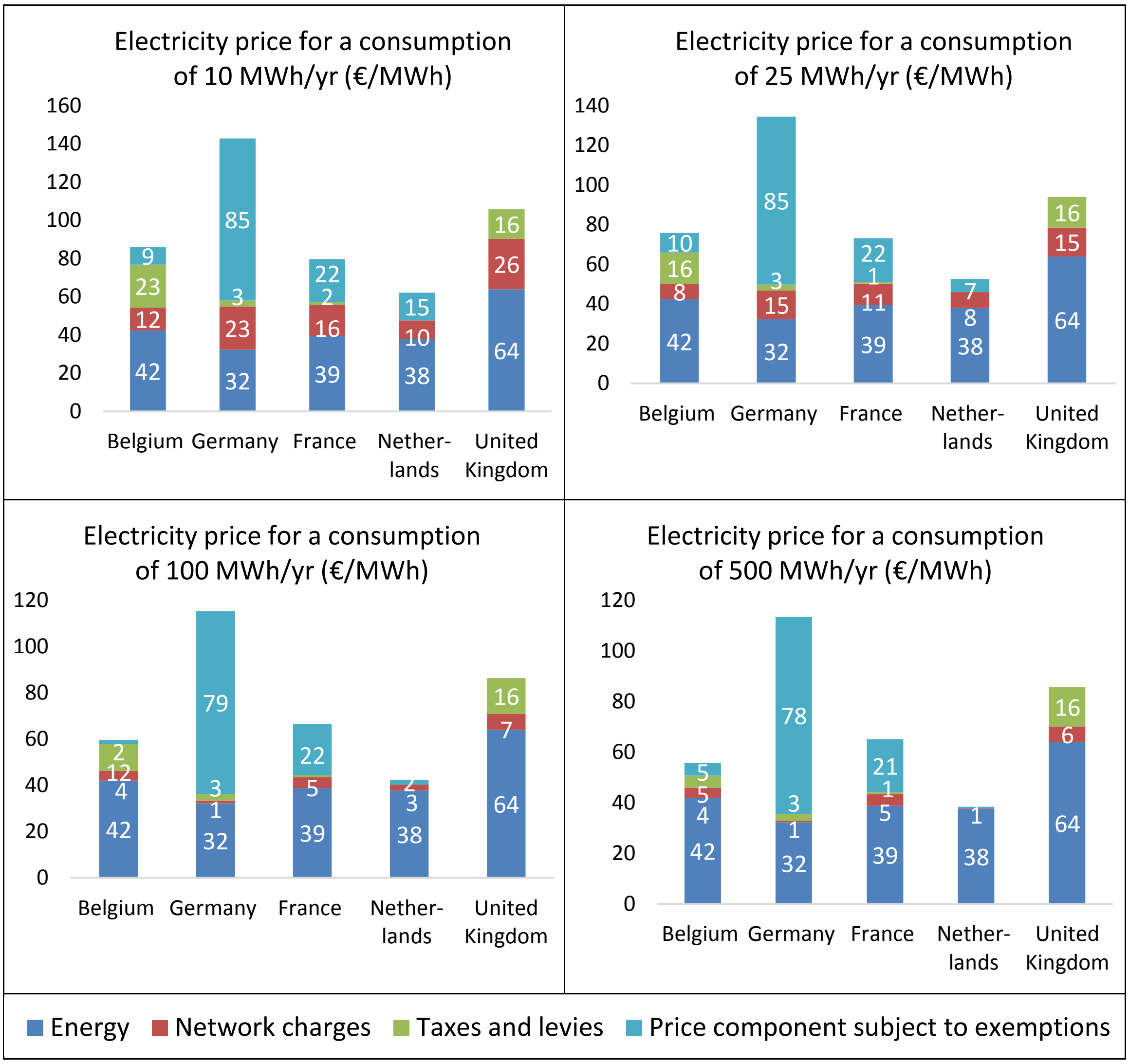


Source: Authors, based on Eurostat figures.

Comparison with other European countries

In the wider European context, the greatest difference about the German situation is the gap between the amount paid by small companies and large industrial consumers. This gap is the result of exemptions for energy-intensive industry. Small and medium-sized enterprises pay a large amount of taxes and levies whereas companies with annual consumption of around 2 GWh pay an average of less than half as much as the first group, and industrial consumers (industry and large industry in the graph) only pay a very small proportion (€2/MWh). Moreover, Germany is the only country analysed whose large companies hardly pay any network access charges. Differences in electricity supply costs (the energy rate) and in the margins of profit for the different consumers are not significant.

FIGURE 49. Breakdown of the bill by consumption level in different European countries (2016)



Note 1: For Germany, the network access charge used is that of the transport system with the lowest charge (the difference between the maximum and the minimum is €6.5 per MWh). The maximum price for non-intensive industry is based on the maximum price for these access charges.

Note 2: For Belgium, the taxes and levies shown are for the region with least taxes (Flanders, Wallonia or Brussels). The maximum price of non-intensive industry corresponds to the region with the highest taxes.

Note 3: The maximum range includes the maximum variations in all categories. These are fundamentally taxes and levies that cannot be passed on or for which there are no exemptions.

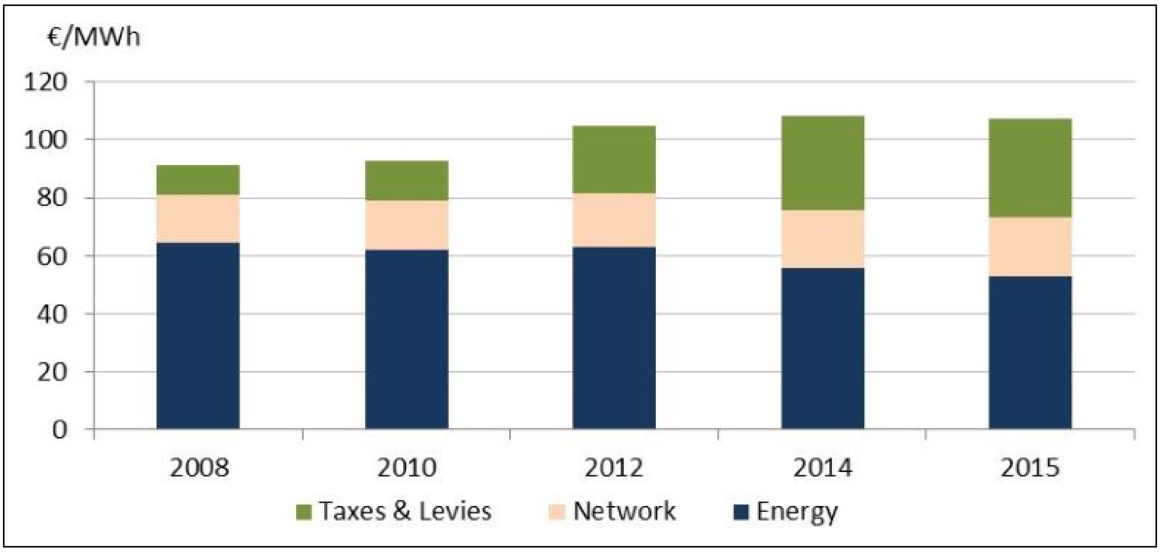
Note 4: Price subject to exemptions essentially comprises taxes and levies that intensive industrial consumers can avoid paying. Electricity-intensive industry can pay a part of this cost. Other smaller components are also included, such as the differences in network access charges between operators in the same country (e.g. Germany and Belgium).

Source: Authors, based on PwC (2017).

As shown in the price breakdown in figure 49, an industrial consumer in Germany using 10 MWh/yr would pay a minimum of €58 per MWh if all exemptions were applied, whereas otherwise, it would pay up to €143 per MWh. The proportional difference between price with and without exemptions rises for an industrial consumer of €500 per MWh, whose minimum cost is €36 per MWh as opposed to a maximum of €114 per MWh. It is striking that while the majority of countries (the UK is the exception) apply exemptions, it is Germany that has the greatest differences between consumers.

According to the report (European Commission, 2016), the electricity price for the industrial consumer (2-20 GWh/yr) has increased by less than for households, varying between 0.8% and 3.1% per year between 2008 and 2015 (figure 50).

FIGURE 50. Components of the electricity price for average European industry (2 -20 GWh/yr)



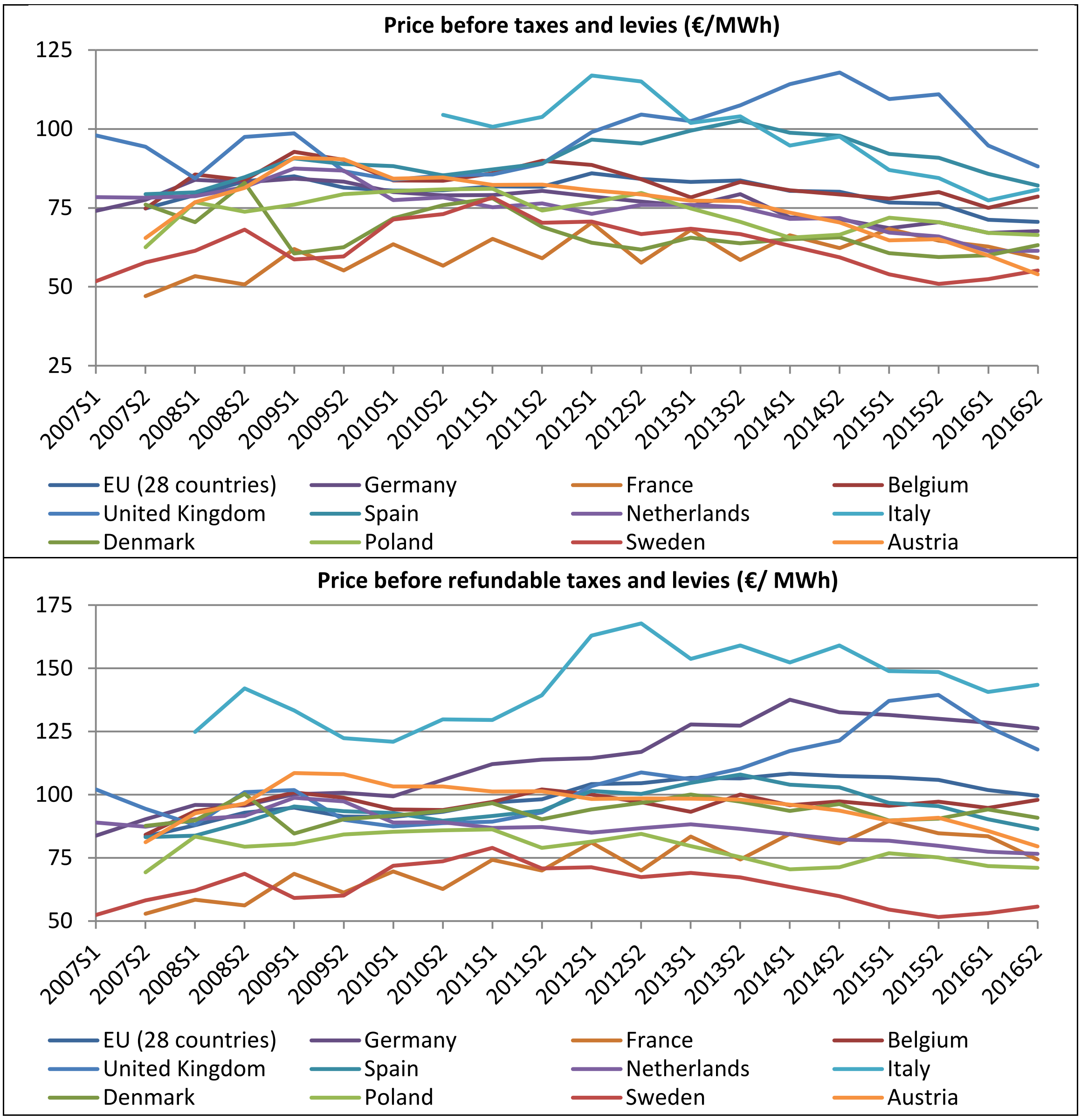
Source: European Commission (2016) based on data from member states and the European Commission.

Since 2010, the electricity price in Germany for the industrial consumer in the range of 2-20 GWh/yr without taking taxes or levies into account is below the EU-28 average, as can be seen in the upper section of figure 51. Among the main economies in Europe, the country with the most similar price to Germany's between 2011 and 2015 was Austria, with the gap widening in the last period. Germany has lower costs than the five leading economies of the European Union excluding France.

As can be seen from the bottom section of the graph, the price panorama once again changes when taxes and levies are included.[81] Italy (45% of final price in taxes and levies) and Germany (48%) were the countries with the highest final price of electricity for industrial consumers of this size in the second half of 2016. Despite this, Germany is closer to the EU-28 average for industrial consumption than for household consumption. In particular, Germany comes close in this regard to the UK, but a long way from the other two large economies in the European Union, France (25% in taxes and levies) and Spain (5%).

[81] Unlike household consumers, VAT and other recoverable or refundable taxes and levies have not been considered.

FIGURE 51. Electricity price in Europe for industrial consumers (2-20 GWh/yr)

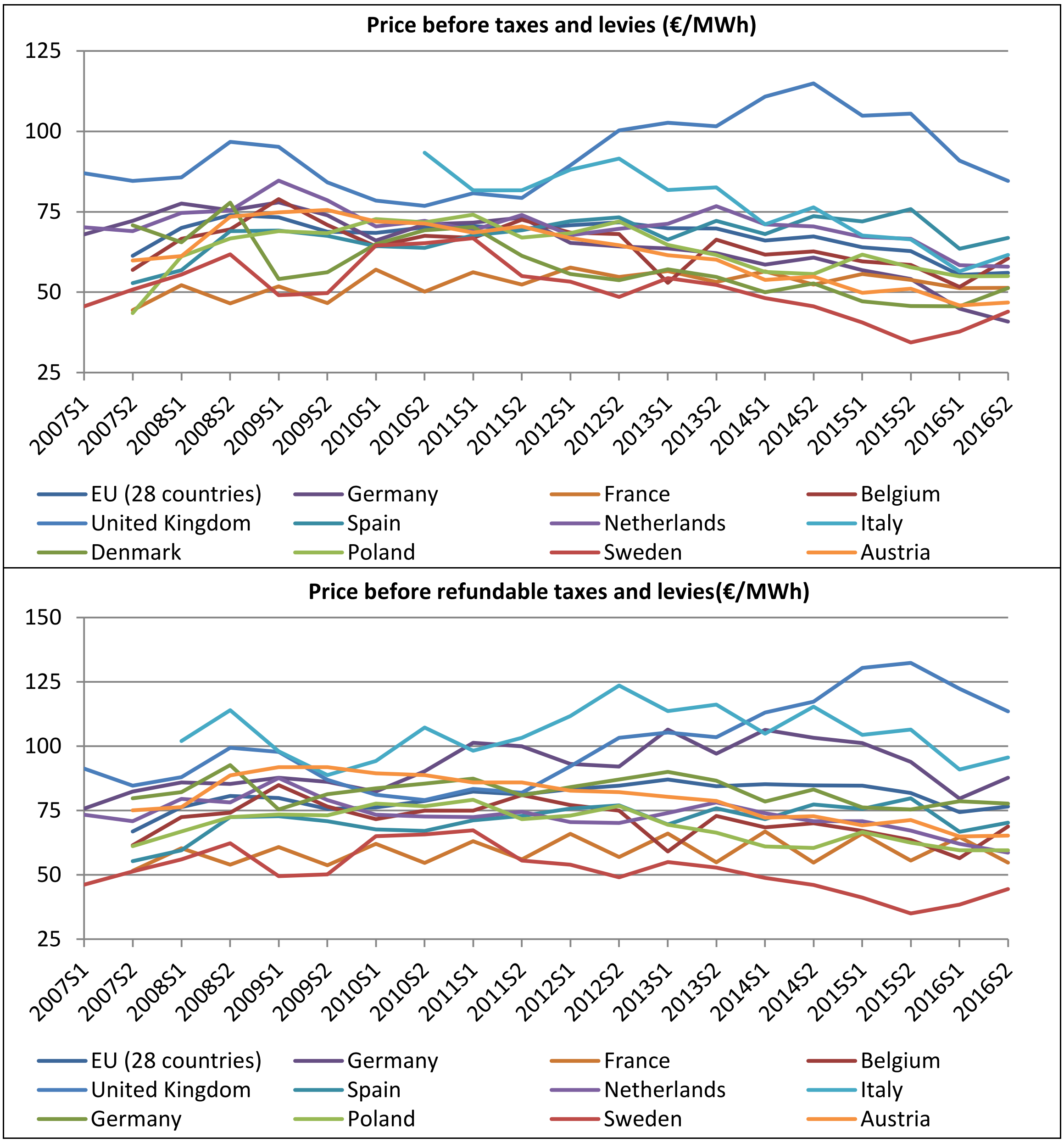


Note: According to Eurostat, the industrial consumption bracket considered (2 GWh-20 GWh/yr) is the most representative.

Source: Authors, based on Eurostat figures.

With regard to the price for the large industrial consumer and as mentioned above, prices in Germany before taxes and levies in the second half of 2016 were the lowest of all EU countries, with the Nordic countries and Austria coming relatively close. Including taxes and levies, prices in Germany are once again amongst the highest in Europe, albeit lower than in Denmark and the UK, and German prices for this segment are closer to the EU-28 average than for "industrial comsumers". (see figure 52).

FIGURE 52. Electricity price in Europe for large industrial consumers (70-150 GWh/yr)

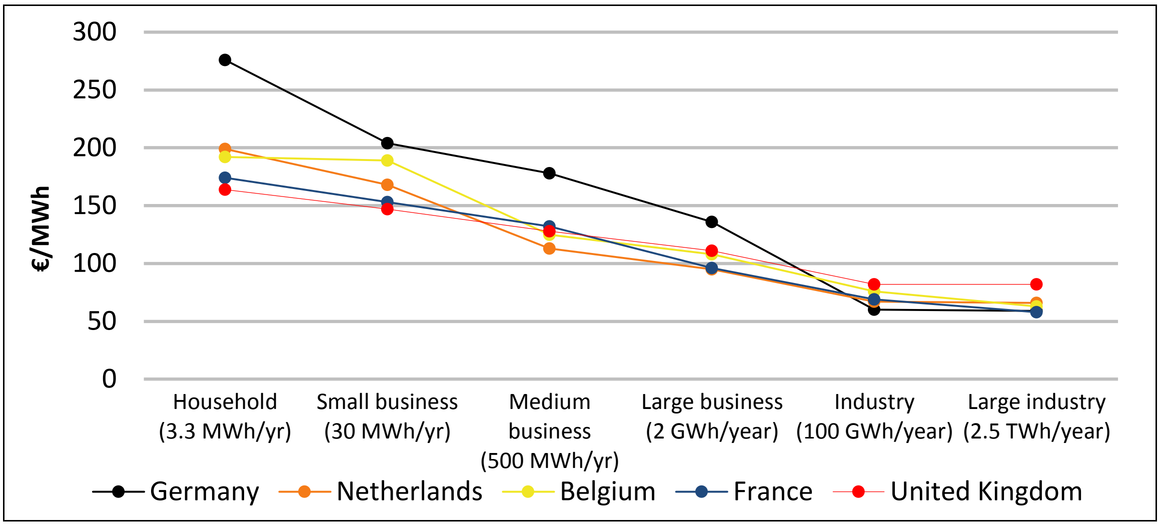


Note: For most countries, no information is available for consumers of over 150 GW.

Source: Authors, based on Eurostat figures.

The difference between small and large industrial consumers is much more marked in Germany than in other European countries, as figure 53 shows. Whereas household consumers and non-industrial companies have high electricity costs compared to their European counterparts, in industry the opposite is true. In this case, medium and large industrial consumers have similar costs.

FIGURE 53. Final price of electricity in 2013 in different European countries by type and level of consumption



Note: The categories used (small enterprise, medium-sized enterprise, etc. are those used in the original document)

Source: Authors, based on PwC (2014).

As can be seen, the UK's price distribution is quite different to Germany's. Although they share the same trend with regard to differences in prices between different consumers, the gap between household consumers and large consumers is smaller in the UK than in Germany.

It should also be noted that in all countries, the smallest price difference is between industry (100 GWh/yr) and large industry (2.5 TWh/yr). The largest gap is between large companies and industry (except in the Netherlands, where the gap between residential and small enterprise is somewhat larger).

3.2.3. Renewables or EEG surcharge

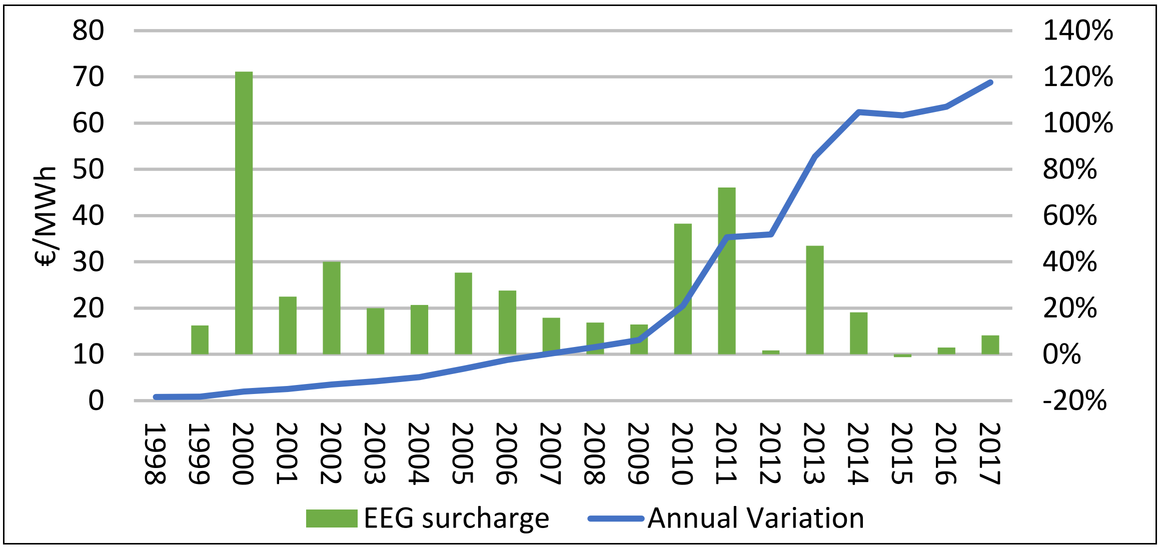
Aid ("premiums") for renewables is raised via the "EEG surcharge" (*EEG-Umlage*), defined in the 2000 Renewable Energy Act (Deutschen Bundestag, 2000), although there is a precedent in the 1990 Electricity Supply Act (Deutschen Bundestag, 1990). This section analyses the development of this levy,[82] its relationship with the price on the power spot market and how it breaks down according to the type of technology rewarded.

As shown in figure 54, the EEG surcharge has risen continuously since it was introduced in 2000, when it experienced the largest increase (122%). In that year the levy came to only €2.00/MWh (0.2€c/kWh), whereas for 2017 a levy of €68.80 per MWh (6.88c/kWh) was set. This means that the charge has increased 3,340% in this time.

[82] The cost of the EEG surcharge is calculated by the transmission companies and is identical in all four networks.

Clearly, the annual increase in this surcharge has generally been very high, with an annual average of nearly 25% since 2000 and an annual maximum of 72% in 2011. Only since 2014 has this upward trend slowed, rising on average 7% between 2014 and 2017, as compared to 30% between 2001 and 2013, with a fall in 2015 (-1%).

FIGURE 54. EEG surcharge

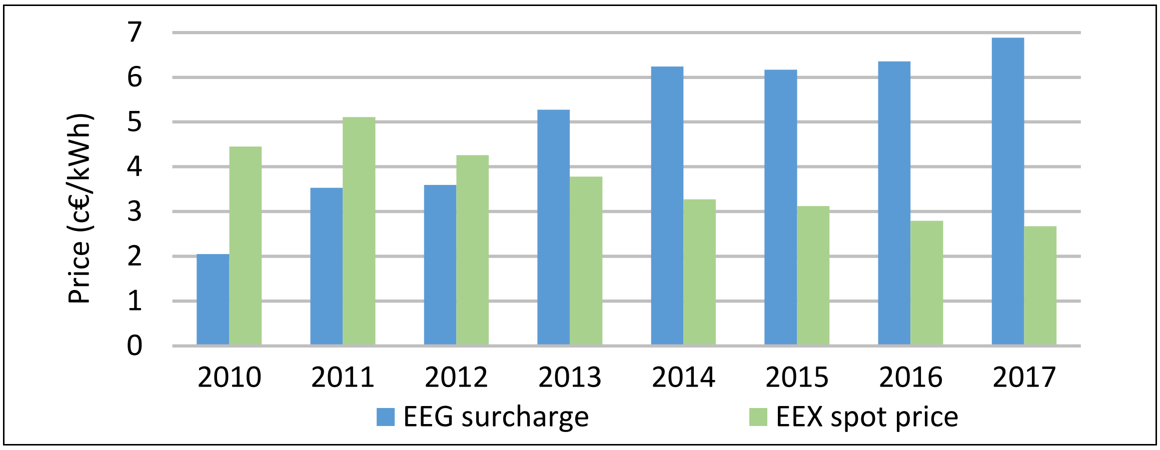


Source: Authors, based on BDEW (2017a).

There are two reasons for this increase in the EEG surcharge. On the one hand, the increase in installed renewables means that there is a greater quantity of renewable output to receive grants. On the other hand, the fall in the price of power on the electricity market has made it necessary to increase this levy so that producers receive the amount established under current law at the time of building the facility, since the difference between the price set by law and the market price has increased over time (figure 55).

This means that if, for example, the basic remuneration for a new wind facility in the 2012 Renewable Energy Act was €48.7 per MWh, the payment received from the EEG surcharge was €6.1 per MWh in 2012, increasing to €10.9 per MWh in 2013 and €22.0 per MWh in 2016. In other words, in the event of a low price on the electricity market, consumers without exemptions pay a higher percentage for renewables than consumers with exemptions.

FIGURE 55. EEG surcharge v. electricity price

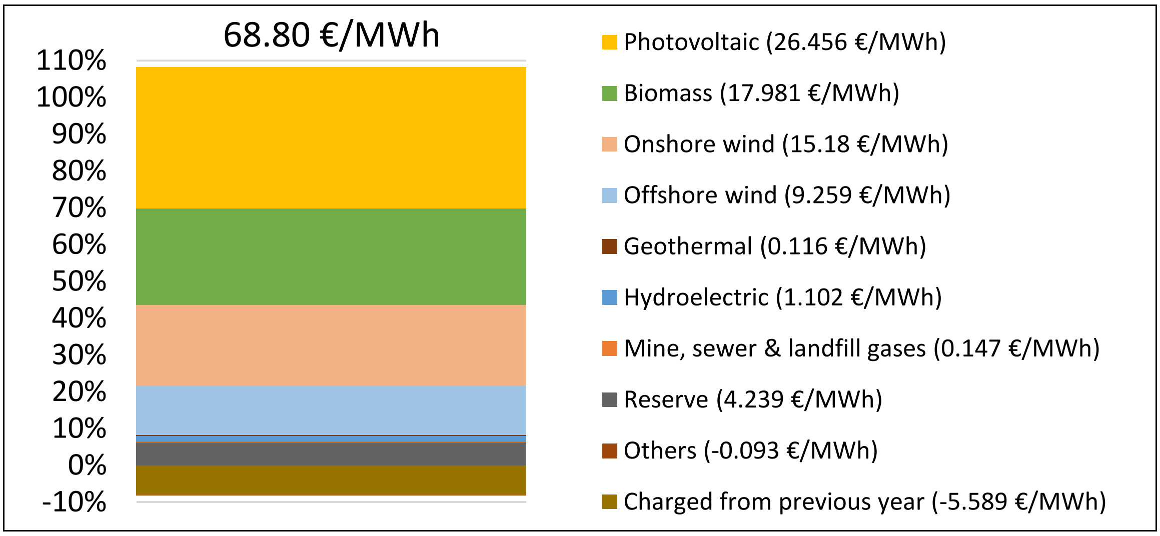


Note: The electricity price given is the spot price on the European energy exchange (EEX) in Germany. Prices for 2016 and 2017 are provisional.

Source: Authors, based on 50Hertz, Amprion, TenneT, & TransnetBW (2016b).

figure 56 shows the forecast breakdown of the EEG surcharge for 2017. The highest costs are for photovoltaic (38%) and biomass (26%), followed by onshore (22%) and offshore (13%) wind (the latter has seen a major increase in recent years). Other technologies account for a much smaller share (8% altogether). Finally, it is worth noting the negative surcharge of the previous year (revenue from the levy was higher than grants), meaning that the cost of the different items is more than 100% of the bill in 2017.

FIGURE 56. Breakdown of 2017 EEG surcharge (€/MWh)



Source: Authors, based on 50Hertz, Amprion, TenneT, & TransnetBW (2016b).

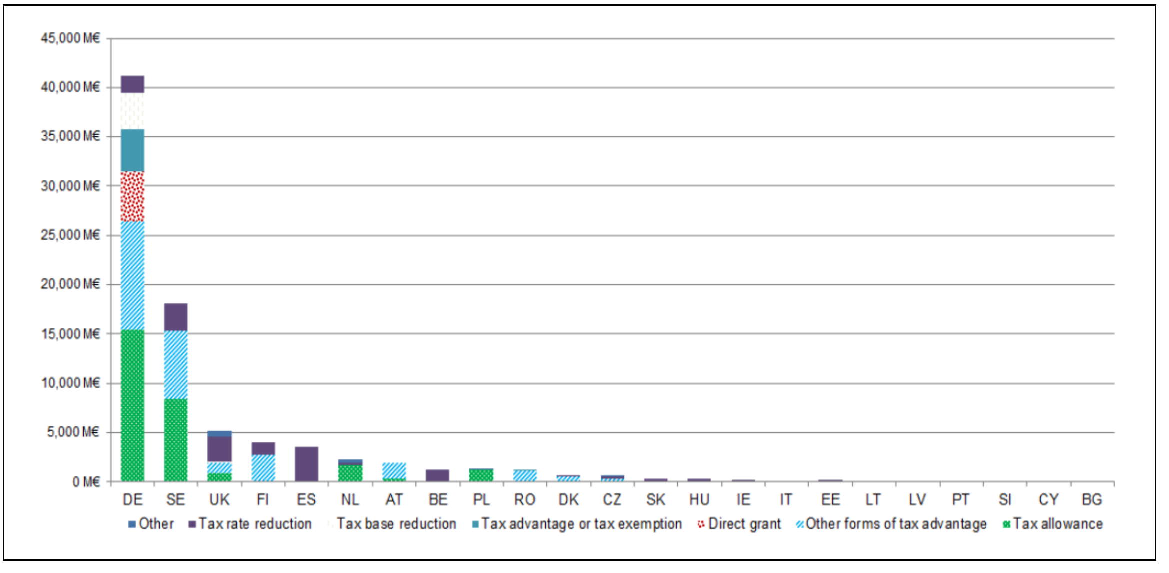
In 2018 the EEG surcharge will come to 6.792 eurocent/kWh (BMWi, 2017e).

3.2.4. Exemptions

Germany awards higher subsidies to electricity than any other country in the European Union (figure 57), with more than €40 billion between 2008 and 2014 and a maximum of €9.8 billion in 2014 (figure 58). In order to avoid the ever-greater burden of taxes and levies on electricity in Europe from placing a burden on industrial competitiveness, most EU countries allow for subsidies to industry in the form of exemptions and direct grants, especially to the most energy-intensive industries. Nonetheless, the European Commission is seeking to eliminate these grants, and these exemptions are now being cut.

The primary source of aid comes in the form of tax allowances,[83] totalling nearly €15 billion. This is followed by other tax advantages[84] (€10 billion), direct grants[85] (€5 billion) and tax advantages & exemptions (around €4 billion each). For its part, the reduction in the tax base comes to less than €4 billion and reductions in the tax rate total €2 billion.

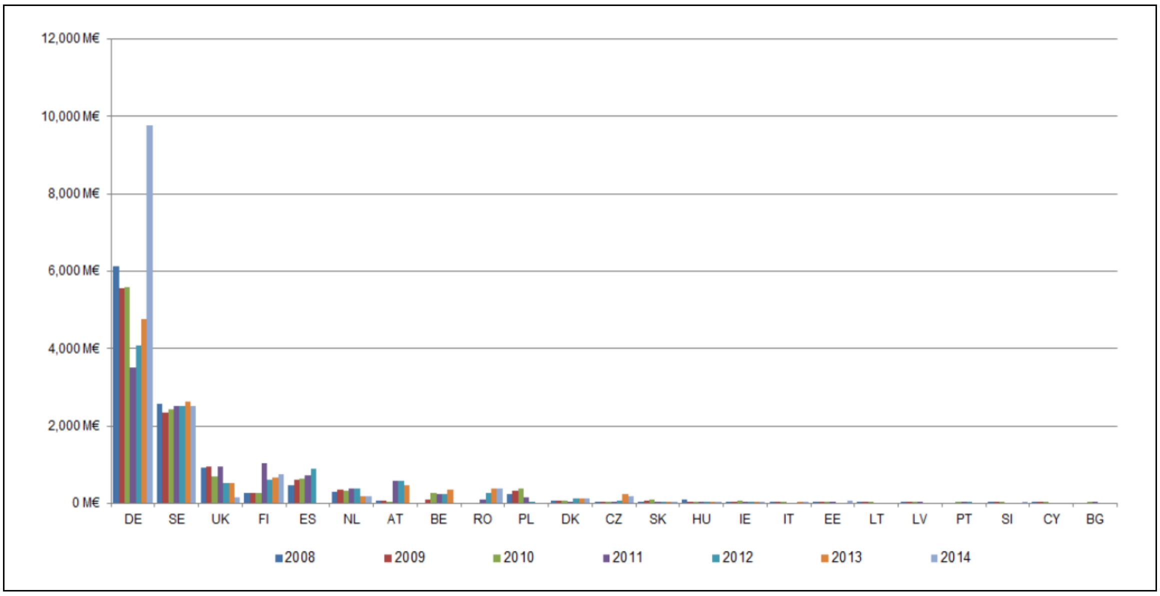
FIGURE 57. Accumulated allowances and grants in the European Union (2008-2014)



Source: European Commission (2016a).

[83] Mainly reductions or exemptions from taxes and levies.
[84] Such as allowances on fuel purchase, tax reductions on biofuels and other climate-related taxes.
[85] Mainly aid to energy-intensive industry.

FIGURE 58. Annual allowances and grants in the European Union (2008-2014)



Source: European Commission (2016a).

German power-intensive companies have enjoyed exemptions from the EEG surcharge, paying only a small percentage of the levy. Companies could even manage to avoid paying the charge altogether if they fulfilled certain criteria, such as the *Grünstromprivileg* (Green Electricity Privilege).[86]

Under the 2014 reform, German companies enjoyed an exemption if their annual consumption exceeded 1 GWh and their electricity cost was greater than 14% (rising later to the 17%) of their Gross Value Added (GVA). Companies with 1-10 GWh per year paid 10% of the levy; between 10-100 GWh, 1% and for consumption of over 100 GWh, only €0.50/MWh.

From 2017 on, these criteria were changed, with companies classified in two lists, one with a minimum consumption of 17% of GVA and others with a minimum of 20%. All companies pay the levy in its entirety for the first GWh they consume. Thereafter, they pay 15% of the levy on the remaining consumption. Those whose annual consumption stands between 14% of their GVA and the previous minimum (17-20%) pay 20% of the EEG surcharge. Payment of the EEG surcharge must not exceed 4% of the company's annual GVA. This falls to 0.5% if the company's electricity cost represents more than 20% of its GVA. For all cases, minimum payment of the EEG surcharge is €1/MWh except for production and primary processing of copper, aluminium, lead, zinc and brass, for which the minimum is €0.50/MWh.[87] The regulation is summarised in table 19.

[86] The purpose of this exemption, introduced in the 2009 reform, was to increase the amount of renewable generation sold directly to generators. The exemption, which was for 100% of the EEG surcharge in 2009, was partially cut in the 2012 reform and was removed altogether in the 2014 reform.
[87]These values compare with a €68.80/MWh EEG surcharge in 2017.

TABLE 19. Percentage of EEG surcharge to be paid by companies under EEG 2017

Group	% of annual GVA on electricity	Payment of EEG surcharge (after first GWh)	Maximum payment of EEG surcharge	Minimum payment of EEG surcharge
G1 (Steel, cement, glass, foundries, batteries, vegetable processing, electronic components, etc.)	≥17%	15%	**Cost of electricity ≥ 20% GVA**: EEG payment ≤ 0.5% GVA	**Production and primary processing of copper, aluminium, lead, zinc and brass**: €0.50/MWh **Others**: €1/MWh
	14-17%	20%		
G2 (Coins, jewellery, optic fibre, adhesives, meat, fish and milk processing, motor engines and vehicles, etc.)	≥20%	15%	**Cost of electricity ≥ 20% GVA**: EEG payment ≤ 4% GVA	
	14-20%	20%		

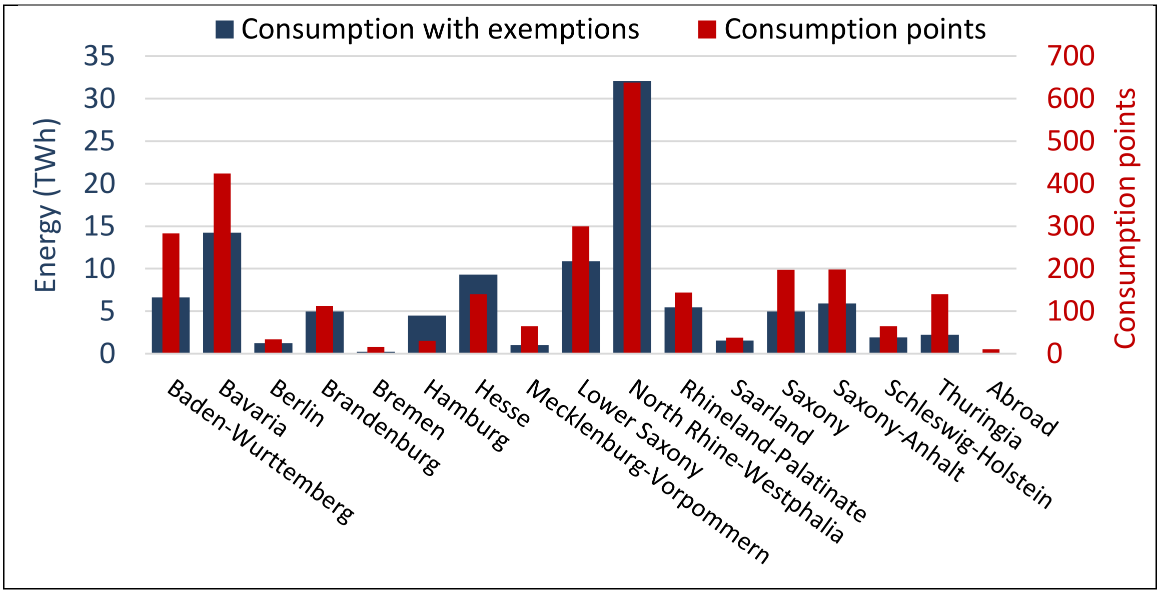
Note 1: In the event of a discrepancy, the minimum payment takes precedence over the maximum.

Note 2: In 2016, an EU court of first instance ruled that the exemption to the EEG surcharge under the Renewable Energy Act 2012 (EEG 2012) constituted "state aid", a claim which had been refuted by the German state on the grounds that the levy was distributed by power system operators (Henze et al., 2016). The EEG 2014 exemption was authorised by the European Commission (BMWi, 2016c). Subsequent negotiations resulted in feed-in-tariffs being accepted as legitimate state aid, since they form part of the target of reducing EU emissions, and because the discount applied to companies would not be backdated (i.e. they would not have to return money received as aid from previous years).

Source: Authors, based on Deutschen Bundestag (2016).

At state level, exemptions to payment of the EEG surcharge are concentrated in those Länder that have the highest presence of large energy-consuming industry, as figure 59 shows. North Rhine– Westphalia accounts for approximately 30% of all exemptions, and Bavaria, Lower Saxony and Hesse together account for another 30%. Approximately one fifth of total electricity demand in the country (107 TWh) enjoyed exemptions (BMWi & BAFA, 2016).

FIGURE 59. Exemptions in Länder in 2015 (power and consumption points)



Source: Authors, based on BMWi & BAFA (2016).

3.3. The principal electrical utilities in Germany

Germany is home to three of the largest power production companies in Europe (RWE, E.ON and Vattenfall), as Figure 60 shows.

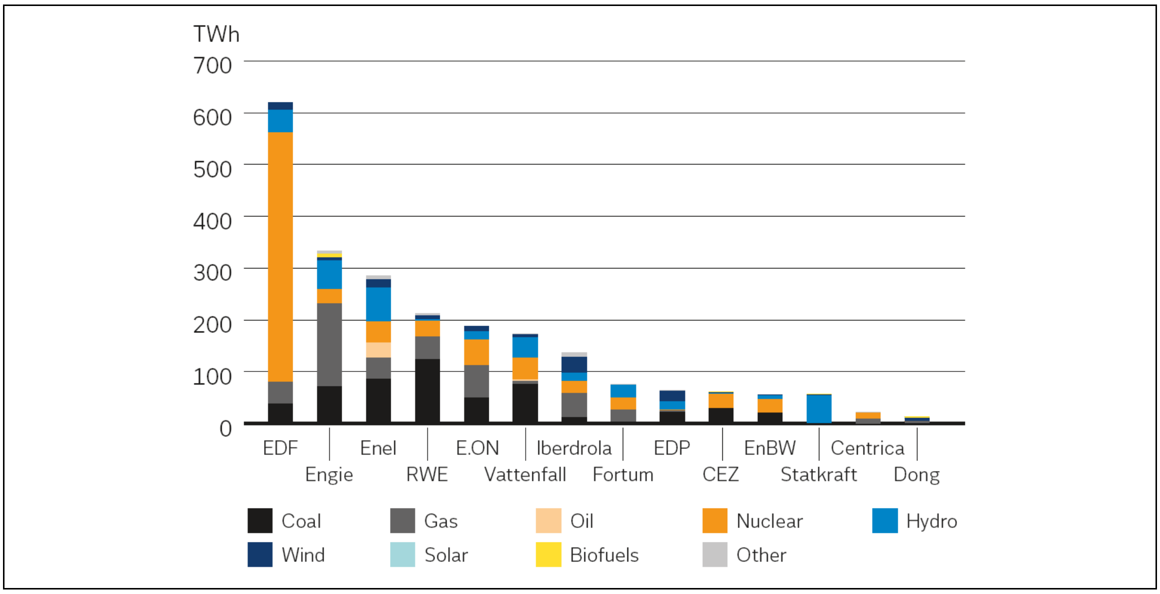
RWE and E.ON are privately-owned German companies whose main assets are in Germany and the UK, although they also have a major presence in other European countries.[88]

Vattenfall, for its part, is a Swedish public-sector company and the leading power generator in that country. Although it had similar production levels in Germany to RWE and E.ON in previous years, the sale in 2016 of nearly all its lignite-burning plants in Germany (which produced more than 55 TWh in 2015) has significantly reduced its presence there

Finally, EnBW stands in a clear fourth place, having traditionally focused on Baden-Württemberg, Germany's third-largest region in terms of land and population.

Measured in terms of international power generation in 2015, the companies ranked as follows: RWE, E.ON, Vattenfall and EnBW[89] (figure 60).

FIGURE 60. Electricity production of Europe's largest producers in 2015



Note: The output of each firm has been taken as 100% for stations or generating sets in which they have a holding of over 50%; 50% where they have a 50% stake and zero where they have a holding of under 50%.

Source: (Vattenfall, 2017b) based on the companies' annual reports in 2015.

In 2016 RWE and E.ON had similar output, close to or above 200 TWh. Vattenfall had output of approximately 120 TWh, while for EnBW the figure was around 60 TWh. Even so, the leading German utilities rank behind the largest European producers

[88] RWE is the market leader in the Netherlands and E.ON has a significant presence in Sweden.
[89] For an individual description of these companies (turnover, power stations and their location) see Appendix 11.

such as EDF and Engie in France and Enel in Italy, all three of which have a major international presence outside Europe.

3.3.1. Strategic changes

Shares of conventional power generation

The *Energiewende* has led to a change in energy strategy in Germany whose most visible effect has been a change in the power mix of the four companies analysed. Initially, they were forced to prematurely close down their nuclear power stations as a result of a change in policy decisions. Subsequently, the progressive rise of renewables, in which they did not have large investments, led to a gradual fall in output from their conventional stations, increased the use of these stations for balancing the system and reduced the price of electricity on the market.

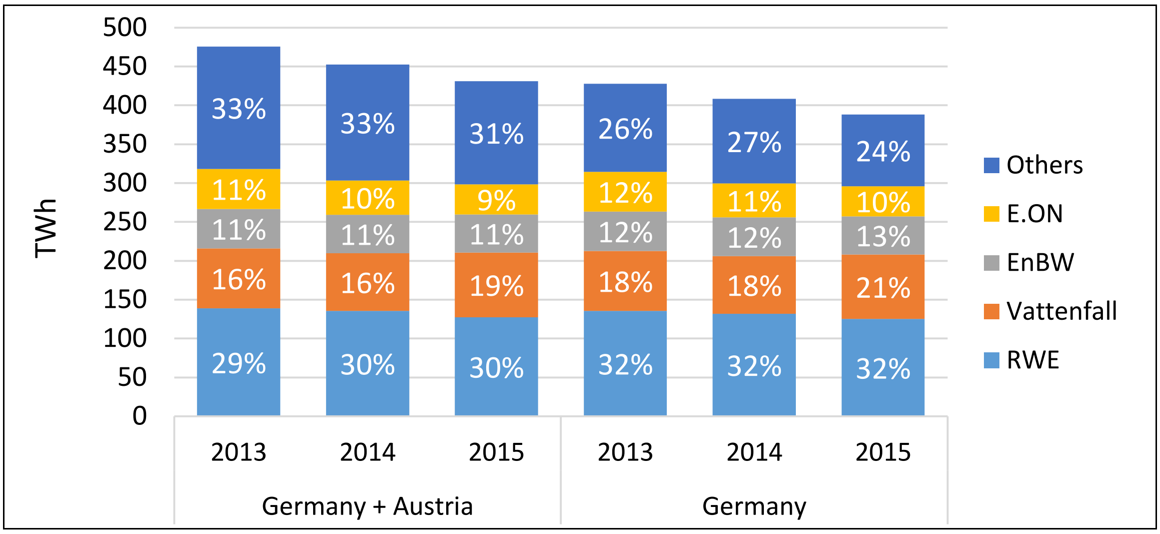
Ultimately, the limits imposed on emissions of CO_2 and atmospheric pollutants (see Section 2.5) has required power stations to adapt (or close if they failed to comply), or, in more recent years, it has led to them being moved into a capacity reserve to be shut down later (see Sections 2.2.2 and 2.4.2).

figure 61 shows the distribution of the common power generation market in Germany and Austria. This graph was drawn up by the Federal Grid Agency (*Bundesnetzagentur*) based on the power sold on the market for the first time[90] by affiliates of the four largest generators in Germany and Austria. It does not include energy from power stations that receive a fixed payment under the Renewable Energy Act, which are not subject to market competition.

As can be seen, the total in the primary market is getting smaller by the year. Nonetheless, their share of this market has increased over time, except in the case of E.ON, where it has fallen. Going back to 2008, according to data from the *Bundesnetzagentur* the Germany / Austria market had a volume of 508 TWh and together the four main utilities had a 52% share, with 264 TWh (50Hertz, Amprion, TenneT, & TransnetBW, 2009). This means that since then, the volume of the market has fallen by 15%, while the volume generated by the four companies has increased by 13%.

[90] This power is bought and resold subsequently by different market agents.

FIGURE 61. Power generation market not subject to premiums in Germany and Austria



Note 1: On the joint Germany+Austria market, Germany accounts for 90% of power generation and Austria for the remaining 10%. See notes 88 and 89.

Note 2: Only RWE and E.ON have conventional generation in Austria, although it is limited by the majority position of Verbund AG, which is primarily owned by the Austrian state.

Source: Authors, based on Bundesnetzagentur (2015); Bundesnetzagentur (2016d).

In Germany, only Vattenfall increased exchange-traded generation[91] between 2014 and 2015, due to the opening of the hard coal CHP plant in Moorburg. This increase was short-lived, since the sale of most of its lignite-burning plants in 2016 to the Czech group EPH (*Energy a průmyslový holding, a.s.*), together with the future move to the climate reserve of its last lignite plant, Jänschwalde, has cut Vattenfall's share in the conventional generation segment, and in 2017 it stood below any of the other large utilities. Indeed, if it does sell the Moorburg plant, as has also been mooted (Ringstrom, 2016), the company's presence in the conventional segment would fall further and would be based entirely on hydroelectric and gas-fired power stations.

Of the remaining companies, EnBW and RWE have hardly been affected, whereas E.ON saw a 25% reduction in conventional power generation between 2013 and 2015 as a consequence of the scheduled closure of several plants (mainly hard coal and nuclear). Other companies (not including these four large utilities) also saw a sharp fall in this period, close to 19%.

A side-effect of the sale of Vattenfall's lignite-burning plants has been to introduce a new competitor onto the German market in the conventional segment; LEAG (joint-owned by the EPH group and the financier PPF), has firmly committed itself to lignite as a power source in Germany, against the expectations of the German government. This strategy may be based on expectations of a recovery in the electricity price; an

[91] Renewable output is not included, since it is subject to a feed-in-tariff or a market rate with an additional premium.

increase in the profitability of the power stations prior to their closure; postponement of the switch-off date because supply security cannot be assured with renewables and other distributed resources; and/or that they can obtain profits from the capacity reserves analysed in Chapter 2.

Structural changes

As mentioned, two of the companies analysed are either fully or partly publicly-owned (Vattenfall, owned by the Swedish state and EnBW, which is 46.5% owned by the state of Baden-Württemberg, with a further 46.25% in the hands of a grouping of districts, *Landkreisen*, the next territorial unit down from the Länder). The structures of these two firms has not been as severely affected as the privately-owned RWE and E.ON. These companies had high turnover before restructuring, as shown in table 20.

TABLE 20. Key business figures of E.ON and RWE in 2015, before restructuring

Item	E.ON	RWE
Sales (€m)	116,218	48,599
Employees	56,490	59,792
Installed capacity in conventional generation (MW)	38,509	44,470
Installed capacity in renewable generation (MW)	7,889	3,582
Distribution networks in Germany (km)	383,000	330,000
Customers (million)	33	16 electricity and 7 gas

Note: In the case of E.ON, the figure for installed capacity includes its subsidiaries. For RWE it also includes power available from other companies via bilateral contracts.

Source: Authors, based on company websites.

Equally important is the fact that these companies have a major presence outside Germany, albeit they are concentrated in Europe. RWE has operations in countries in central and eastern Europe; Poland, the Czech Republic, Slovakia, Hungary, Denmark, Croatia, Slovenia, as well as the UK, the Netherlands and the rest of Benelux.

E.ON focuses more on the UK, Sweden, France and also on some central/eastern European countries such as Hungary, the Czech Republic, Slovakia and Romania. It differs from RWE in also having interests in Turkey and Russia. Similarly, E.ON has greater gas capacity than RWE, whereas RWE has activities in water distribution and supply which E.ON does not.

The restructuring processes of RWE and E.ON are paradigmatic and quite similar. The process of strategic change began in November 2014. E.ON chose to implement a new strategy, leading to the segregation of part of its business in the new firm Uniper in 2016. Uniper thus began operating in January and in September the separation process concluded when it was floated on the stock exchange. For its part, RWE announced in December 2015 that it would follow a similar path, (RWE, 2015), creating innogy SE[92] in April 2016 and floating it in November of that year.

The fundamental reasons for the changes lie in the need to adapt strategically to the energy transition and to focus development with legally distinct companies, although mostly holding on to either a controlling stake (at the end of 2016 RWE held 77% of innogy SE[93]) or a minority one (the E.ON group has a non-majority stake in Uniper of 46.65%).

In this regard, the corporate processes have been different and, because it has held onto a majority of shares, RWE's process has been more complex than E.ON's. The companies accept that there has been a loss of synergy, but with this move they have sought to segregate different risks related to their business segments.

The RWE and E.ON groups continue with their business of nuclear generation, purchase of fuel and long-term contracts and wholesale sale of electricity.

E.ON manages its nuclear assets through its subsidiary PreussenElektra (formerly E.ON Kernkraft), in which it has a 100% stake. Initially, E.ON sought to transfer its nuclear assets to Uniper, together with all conventional generation. However, the German government, fearing that E.ON might not pay its corresponding share of the cost of the nuclear phase-out, forced the company to hold onto these assets(Chazan, 2016a).

Likewise, RWE has kept nuclear with its conventional power, transferring networks, renewables and the retail market to innogy (table 21).

TABLE 21. Restructuring of E.ON and RWE

E.ON	**RWE**
Networks	Conventional gas
Renewables	Nuclear
Customer solutions	Conventional generation
Retail market	Global commodities
Nuclear Germany (PreussenElektra)	International generation
Group management	Administration/consolidation
	Group management
Uniper	**innogy**
Conventional generation	Networks
Nuclear, Sweden	Renewables
Global commodities	Retail market
Gas and electricity storage	

Source: Authors, based on company websites.

The focus on the “new world”, which both companies recognise, will be developed alongside the conventional, and both companies believe it holds out new

[92] The list of RWE group subsidiaries includes several bearing the name innogy (e.g. innogy Italy S.p.A.), in nearly all which RWE has a 100% holding. The company referred to in this document as innogy is innogy SE.
[93] RWE owns 100% of other companies.

opportunities. In this vision of the future, networks and infrastructures (electricity and gas), renewables (wind and solar) and supply to small and medium-sized customers (retail) will be three mutually complementary pillars. In this vision, decarbonisation, decentralisation and digitisation are the three “driving forces” that will power the three pillars and establish the inter-relationship with them.

Both companies are large utilities, which have a very strong representation in electricity and gas, and which until recently continued to invest in gas- and coal-fired power stations. E.ON, (now Uniper) had a hard coal-fired station under construction, Datteln 4, for which it received permission from the government of Münster in early 2017 (Uniper, 2017b).

It is therefore very important to understand that in the new energy world these two “giants” are not starting from scratch; that is to say, they are not start-ups. Innogy, for its part, in networks is the largest distributor in Germany with €13.3 billion in regulated assets and 23 million electricity and gas customers in Germany, the Netherlands, Belgium, the UK and in some of the countries already mentioned. In renewables, its figures are not as high (more than 3 GW of installed capacity), although it is the third largest in installed offshore wind capacity.

To conclude this section, it is worth noting that EnBW has also undergone, on a smaller scale, a restructuring of its assets and holdings in its relationship with EWE AG, the public-sector electricity, gas and telecommunications utility. EnBW bought EWE's shares in VNG,[94] while EWE bought back the shares EnBW had in EWE (EnBW, 2016b).

On the basis of all of the above, these strategic changes —which have been the subject of much analysis and debate in the companies— all point in the same direction. One can therefore conclude that Germany's *Energiewende* now has so much political force that the process is irreversible, despite the vast costs it will entail for the consumer.

Wind power

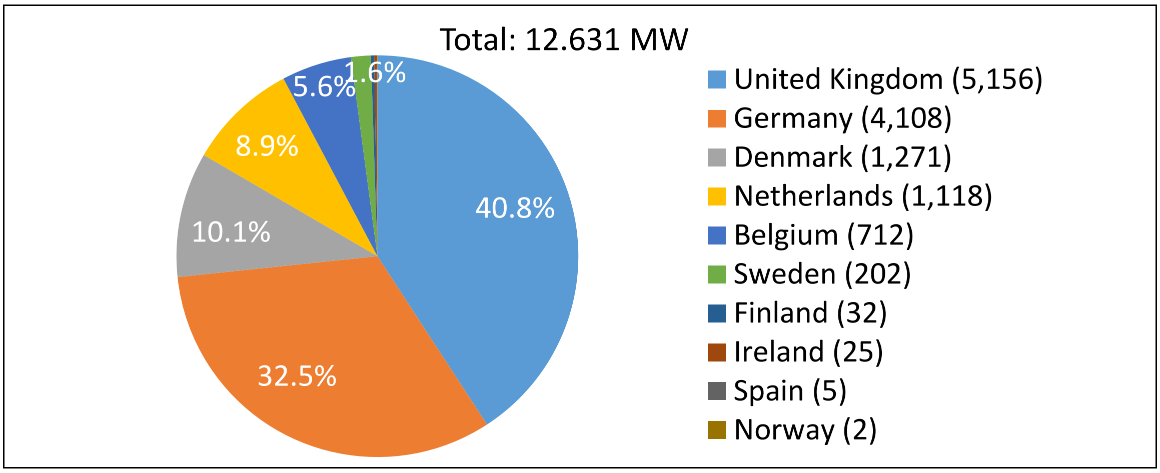
In wind power, the largest developments among the four large generators are taking place in the area of offshore wind. Because of their size, and given the technical difficulties involved in construction, such projects are not an option for small companies involved in onshore wind projects. Offshore wind is also a gateway for other large companies with no significant prior presence in the country, such as the Spanish Iberdrola, with the Wikinger wind farm, and DONG Energy which has three projects totalling 590 MW approved in the first auction of 2017.

Germany has established itself as a major offshore wind market with 4,108 MW installed (figure 62). The four companies analysed have all managed to develop

[94] VNG (Verbundnetz Gas Aktiengesellschaft) is a privately-owned gas utility with business in gas marketing, transport and storage. It operates in several European countries besides Germany itself (Denmark, France, Italy, etc.)

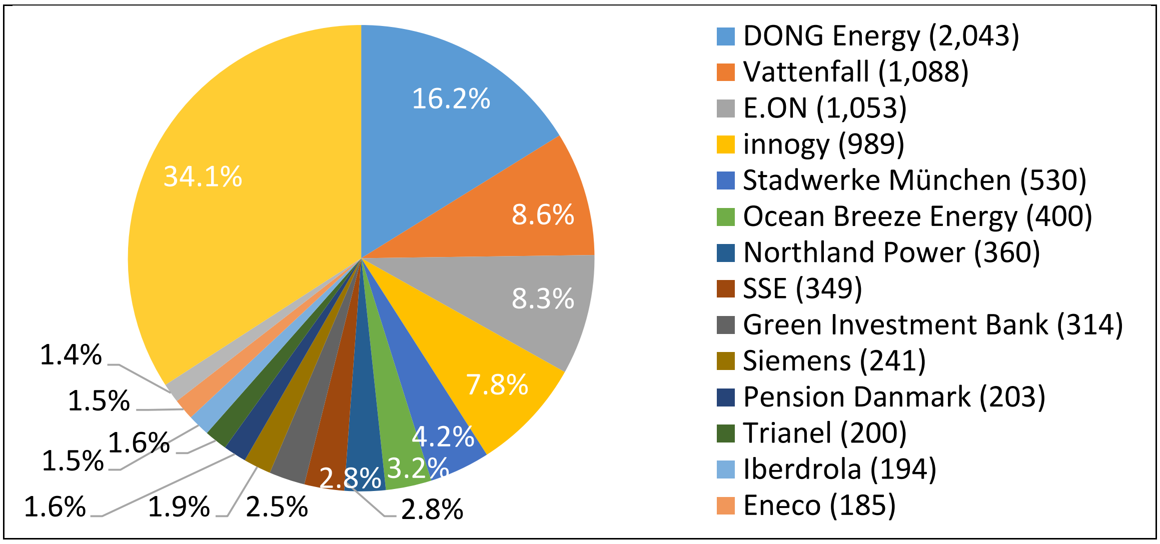
business in this area, as DONG Energy did in Denmark[95] (figure 63). The big four had a combined total of 3.3 GW installed at the end of 2016, 26% of the European market.

FIGURE 62. Installed offshore wind capacity in Europe at end of 2016



Source: Authors, based on Wind Europe (2017).

FIGURE 63. Installed offshore wind capacity in Europe at end of 2016 by company (MW)



Note 1: Figures refer to owned capacity. EnBW features quite far down because it shares ownership of its offshore wind subsidiary with Macquarie Capital, which owns nearly 50% (4C Offshore, 2017).

Note 2: There is a difference of 2 MW in the total shown in this graph and the previous one which is not explained in the source.

Source: Authors, based on Wind Europe (2017).

The installed wind capacity of the four large generators came to nearly 2.5 GW in Germany at the end of 2016, representing 6% of total wind power. Of the four, RWE, which has currently transferred its renewable generation assets to innogy, is the

[95] This is unlike the position in the UK, the largest offshore wind market, where most of the companies with the highest installed capacity are foreign owned.

company that has invested most in wind, both onshore (around 1.9 GW installed) and offshore (0.9 GW). In Germany it has a total of 862 MW installed and it nearly 2 GW abroad, of which more than 900 MW is in the UK.

E.ON has 510 MW in wind capacity in Germany, more than 34 onshore farms totalling 209 MW and the offshore farm of Amrumbank West with 302 MW. Overseas, it has over 3.6 GW installed. Its presence in the UK is particularly important, with sixteen onshore farms and four offshore farms.

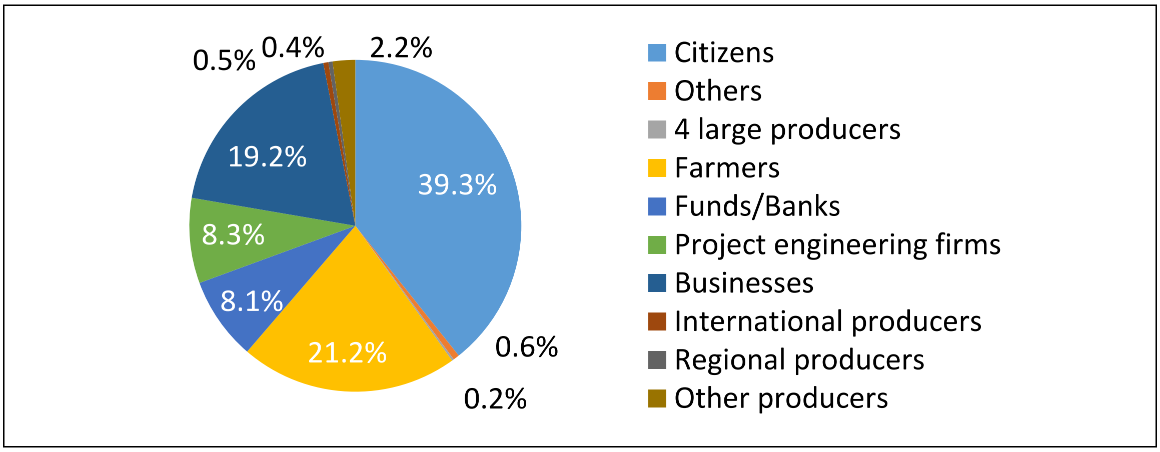
In Germany, Vattenfall has focused both on offshore and onshore wind power, with a total at the end of 2016 of 516 MW, to which in early 2017 it added a further 288 MW from the Sandbank offshore wind farm. The strong position of offshore wind in Germany contrasts with the situation in Sweden, which has barely 120 MW installed, because of the lack of government incentives (Vattenfall, 2017b). Nonetheless, the UK is the country in which Vattenfall has installed the most wind capacity, essentially offshore, with a total of 698 MW at the end of 2016. Including Denmark, nearly half of all wind power installed by Vattenfall is in countries in which it has no other source of generation, an indication of the importance of wind for the company in its launch onto new markets.

For its part, in 2013 EnBW redirected its activities towards renewable generation in order to diversify its mix. EnBW has promoted the development of wind farms throughout almost all of Germany, including the Baltic Sea and the future developments in the North Sea, as well as other projects abroad (Turkey). At the end of 2016, in Germany alone it already had 29 onshore farms with capacity of around 270 MW and two offshore wind farms in the Baltic Sea with 336 MW, giving a total of 606 MW.

Photovoltaic power

The situation of photovoltaic is particularly significant. According to (Wirth, 2017), in 2010 only 0.2% of photovoltaic capacity (around 34 MWp) belonged to any of the big four generators (figure 64). The following years saw very little change in installed capacity by these companies, resulting in a widening of the gap with the total figure. These companies have focused their efforts on developing household photovoltaic solutions and on buying out photovoltaic companies, but not on building and managing large photovoltaic farms.

FIGURE 64. Ownership of installed photovoltaic capacity in Germany at the end of 2010



Source: Authors, based on Wirth (2017).

RWE, which moved its renewable assets to innogy, had only a minority holding in some solar power stations. Its positioning in this area has been based on: the development of subsidiaries such as "Shine" (developer of a photovoltaic production and electricity consumption management system) and "ucair" (focusing on maintenance of photovoltaic panels); the acquisition of companies such as Belectric Solar & Battery Holding GmbH[96] (part of the Belectric group dedicated to the international development of projects for photovoltaic power stations and battery installations); and taking holdings in other companies (such as the photovoltaic cell producer, Heliatek).

E.ON does not currently have solar power stations in Germany and only 19 MW installed abroad, having sold several facilities in countries such as Italy and Spain. It has opted for the sale of household photovoltaic solutions (panels, batteries, management systems.) and collaboration with other companies (for example with Sixt Leasing for the development of a combination of photovoltaic panel, charger and electric vehicle).

EnBW is the only one of the big four generators which (following acquisition) has its own photovoltaic power stations in Germany at the end of 2016, with ten stations

[96] Belectric is a company with a staff of 500 which installs solar photovoltaic power stations, solar roofs and power storage systems, for grid applications in power stations (high-intensity lead-acid and ion-lithium batteries) and for off-grid systems (ion-lithium batteries).
It has built more than 290 solar photovoltaic power stations and roof-mounted photovoltaic systems, with a total installed capacity of 1,500 MWp. It is also responsible for operation and maintenance (O&M) of solar plants with a total capacity of 1,100 MWp and an asset value of more than two billion dollars, placing it among the top three companies offering O&M for solar power stations, and making it the largest in Europe.
It has over 120 patents and has attained a number of milestones in its sector, such as installation of the first photovoltaic plant in India, the first 700 V photovoltaic system and the first 1,500 V photovoltaic power plant. Its geographical interests are in Europe and emerging markets in the MENA region (Middle East and North Africa), as well as India, Israel, Australia, South America and the US.

totalling over 35 MW. It also has developments of household photovoltaic solutions with batteries.

Globally, Vattenfall had only 7 MW in the Netherlands and 5 MW in the UK. Vattenfall's reluctance to invest in solar developments is understandable given the relative lack of solar potential in its home country, Sweden, where the development of non-conventional renewables has centred on biomass and onshore wind. (Vattenfall, 2017b).

Batteries

Together with photovoltaic panels, batteries are the second pillar in the line of home solutions undertaken by the four big utilities. Moreover, battery worklines have other areas of usage, such as renewable farms and electric vehicles. An example is Belectric Solar and Battery GmbH, which was bought over by innogy in January 2017. Innogy has also opted for collaboration agreements with manufacturers from the industry, as is the case of Accumotive[97] to integrate its batteries into its household power storage system.

E.ON has opted for collaboration agreements with manufacturers from the industry. One of these is Samsung, with which E.ON signed a collaboration agreement in 2016 to develop household solutions.

Vattenfall has also moved into the field of batteries. On the one hand, it has signed a contract with the German manufacturer BMW for BMW to supply batteries for wind farms. The first storage centre will be created in Denmark with 3.2 MW; another will be built in a future plant in Hamburg-Bergedorf, while the largest planned project will be in the UK with 22 MW (Vattenfall, 2017a). At the same time, it has invested in the battery manufacturer Northvolt, which plans to open Europe's largest battery factory in Sweden in the second half of 2018 (Vattenfall, 2017c). It has also sought collaboration with other companies to launch the InCharge project, a network of electric vehicle chargers with charging stations in Sweden, Germany and Netherlands.

As for EnBW, in the customer service sector it collaborates with and has a 15% holding in DZ-4, which is devoted to leasing roof-mounted solar panels and storage systems (EnBW, 2017a). It has also collaborated on initiatives with other companies, such as Tank & Rast for electric transport.

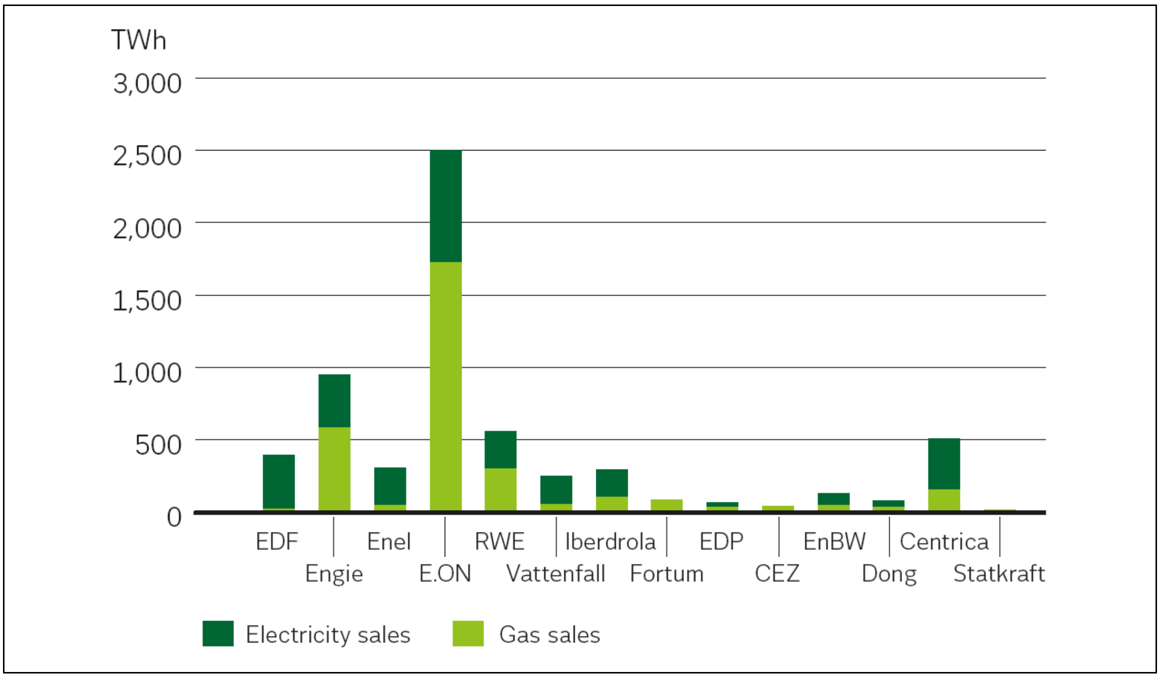
[97] Accumotive is a subsidiary 100% owned by the Daimler group which has 420 employees and sales of around 75,000 batteries since 2012. It is developing ion-lithium batteries for future electric vehicles and hybrids, notably Mercedes-Benz's EQ vehicle with a range of 500 km, and for household applications (modules of 2.5 kWh up to a total of 20 kWh) and industrial applications (in 5.9 kWh modules). To meet future demand for batteries, Daimler is investing more than €500m in a second factory.

3.3.2. Economic trend

Sales[98]

In terms of sales volume, the situation varies greatly. E.ON was the European leader in gas and electricity Sales in 2015 (figure 65), having transferred its gas sales and most of its electricity sales business to its subsidiary, Uniper. This move is reflected in the results of the two companies in 2016: Uniper had turnover of 691 TWh of electricity and 1,726 TWh of gas, whereas E.ON's electricity sales came to just 147 TWh.

FIGURE 65. Turnover of largest electricity and gas suppliers in Europe



Source: (Vattenfall, 2017b) based on the companies' annual reports in 2015.

At some distance behind were RWE and Vattenfall which had sales of approximately 530 TWh and 250 TWh of electricity and gas, respectively. Lastly came EnBW, in a marginal position with nearly 130 TWh.

EBITDA and EBIT

figure 66 shows the adjusted EBITDA[99] of the big four power utilities in Germany. As already mentioned, in 2016 RWE and E.ON split off its two subsidiaries, innogy and

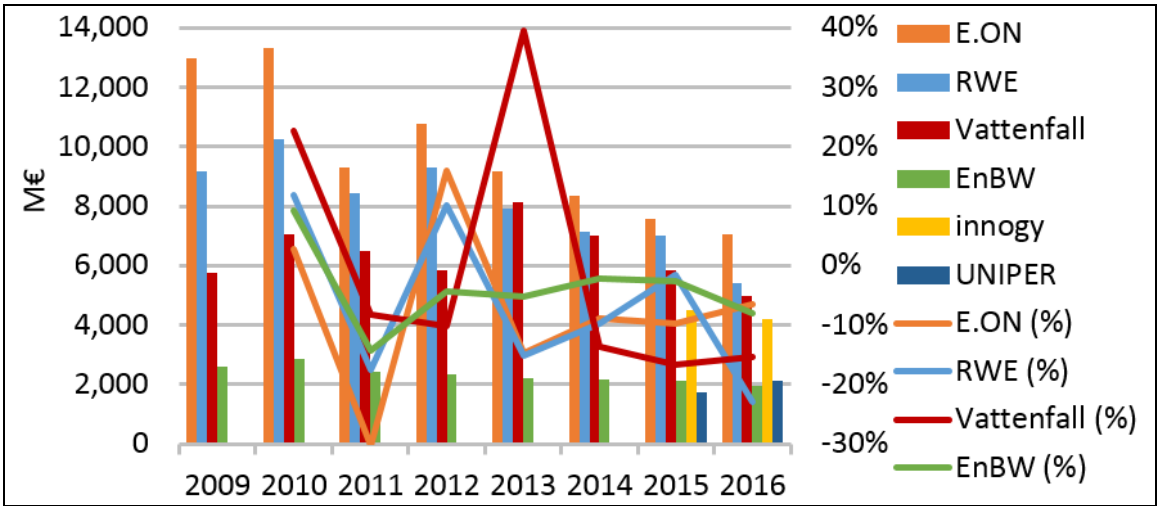
[98] Includes trading.

[99] EBITDA = earnings before interests, taxes, depreciation and amortization. Adjusted EBITDA is calculated by adding extraordinary profits and losses to the EBITDA. This section uses adjusted EBITDA as the most representative figure in the companies' reports, since profits and losses from extraordinary accounting items (e.g. restructuring plans) are not included and it can be used to compare the results of different companies, which allocate each type of income and expense quite differently. In July 2016 the European Securities and Markets Authority (ESMA) guide called on companies not to use ambiguous terms, in order to facilitate transparency and comparison. As a result, in its Annual Report for 2016, RWE uses the term “adjusted EBITDA” rather than “EBITDA”. Vattenfall does not state whether it is referring to EBIDTA or adjusted EBITDA.

Uniper. The graph therefore shows a separate breakdown of the EBIDTA of these two companies. Again, it is important to note that Uniper is a separate group to E.ON, whereas innogy forms part of the RWE AG group.

All of them, and especially RWE and E.ON, have seen a decline in EBITDA since 2011, apart from a rise in 2012 in the case of RWE and E.ON. RWE recorded a sharp fall in 2016 due to the allocation of provisions resulting from the nuclear shut-down, although it has announced profits for 2017 (RWE, 2017a). In the case of E.ON, the company says that this capital increase highlights the difficulties currently being faced by the organisation, although it also forecasts profits in 2017 (E.ON, 2017d).

FIGURE 66. Adjusted EBITDA of the large utilities in Germany



Note 1: Interannual variation in EBITDA given in percentage terms.

Note 2: The 2016 values for RWE and E.ON include the results of innogy and UNIPER respectively. Separately, RWE would be valued at €1.2 billion (a drop of 52%) and E.ON at €4,939 (down 15%).

Note 3: From 2014, RWE began to use a new accounting standard (IFRS 11 Joint Arrangements), leading to variations with respect to the figures for previous years.

Note 4: The values shown are for adjusted EBIDTA in the annual report of the year following that shown (e.g. the adjusted EBIDTA for 2015 is that given in the Annual Report for 2016), with the exception of 2016. 2015 values for innogy and Uniper are estimates, since they were split off from the parent company in 2016.

Note 5: Vattenfall posts its results in Swedish Krona (SEK). For the purposes of comparison, the exchange rate on 31/12/2016 is used here (€1 = SEK 9.58325).

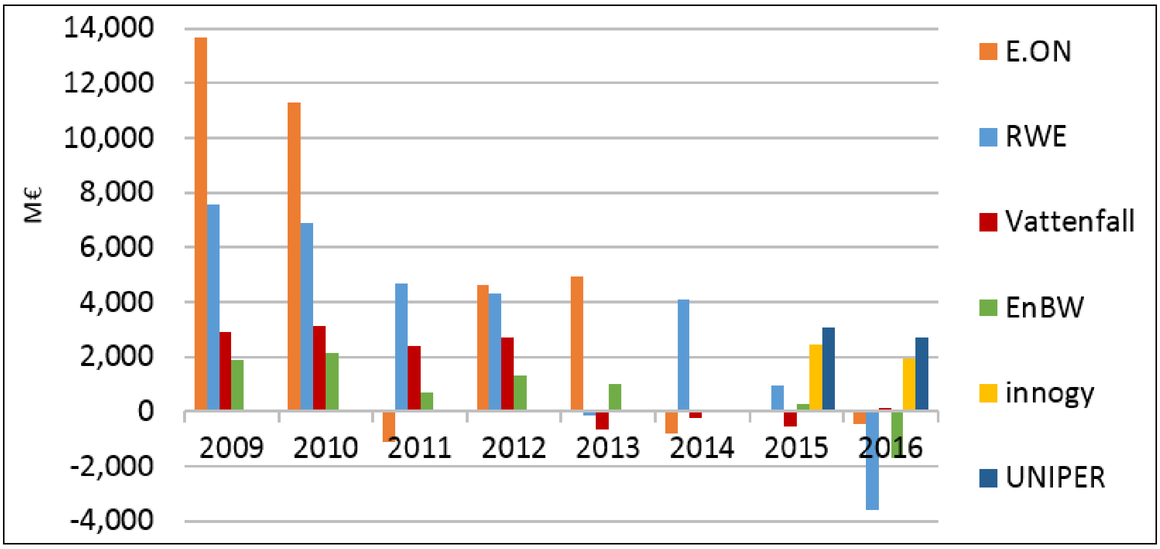
Source: Authors, based on the companies' annual reports

EnBW, the smallest of the four, has seen the lowest drop in percentage terms, because of its geographical distribution. Geographical limitations have lessened over time and, in the current context of renewable energy and distributed generation, the company has installed renewable farms, mostly wind, in different areas of Germany and other countries. The forecast for 2017 is also positive with an increase in EBITDA of between 15 and 25% (EnBW, 2017b).

Turning to the EBIT[100] (figure 67), we can see losses in several years. The situation in 2016 was particularly significant, when only Vattenfall and the recently formed innogy and Uniper had positive results. E.ON went through three years with losses, having been the utility posting the best results in the years before the nuclear shut-down (2009-2010). The fall in 2010 was mainly due to the loss in value of assets and the restructuring of 2016.

The fall in EBIT was also significant in the other companies and was sharpest in RWE in 2016. This result can be explained by restructuring costs,[101] which came to nearly €6 billion in 2016 and €3.2 billion in 2015.

FIGURE 67. EBIT of the large utilities in Germany



Note: Vattenfall posts its results in Swedish Krona (SEK). For the purposes of comparison we use the exchange rate on 31/12/2016 (€1 = SEK 9.58325).

Source: Authors, based on the companies' annual reports

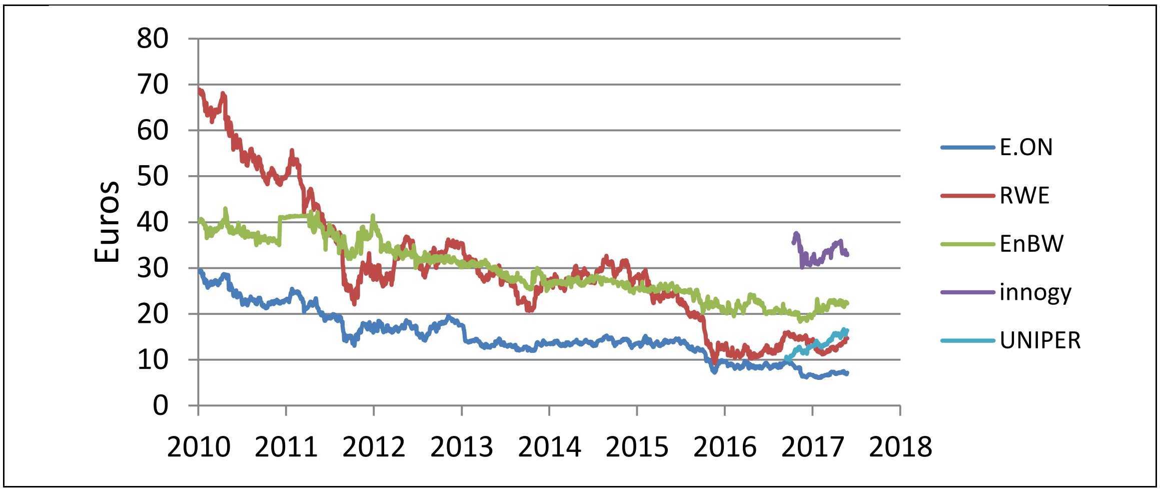
Share price of the companies

figure 68 shows the share price of the different companies analysed, with the exception of Vattenfall, a public-sector company which is not listed on the stock exchange. As can be seen, for a period, RWE and E.ON's share prices fell more or less sharply with the nuclear shut-down in May 2011. The subsequent period can be classed as a gradual decline, with successive rises and falls in the share price, which were sharper for RWE than for E.ON.

[100]EBIT = Earnings before Interest and Tax. Here we have used the unadjusted EBIT, reflecting other activities such as the costs derived from restructuring.

[101] The amount is listed in RWE's Annual Report as "Restructuring, others". It includes for example figures for "Impairments of assets" to a value of €4.3m in 2016 and €2.7m in 2015.

FIGURE 68. Share prices of the different companies analysed

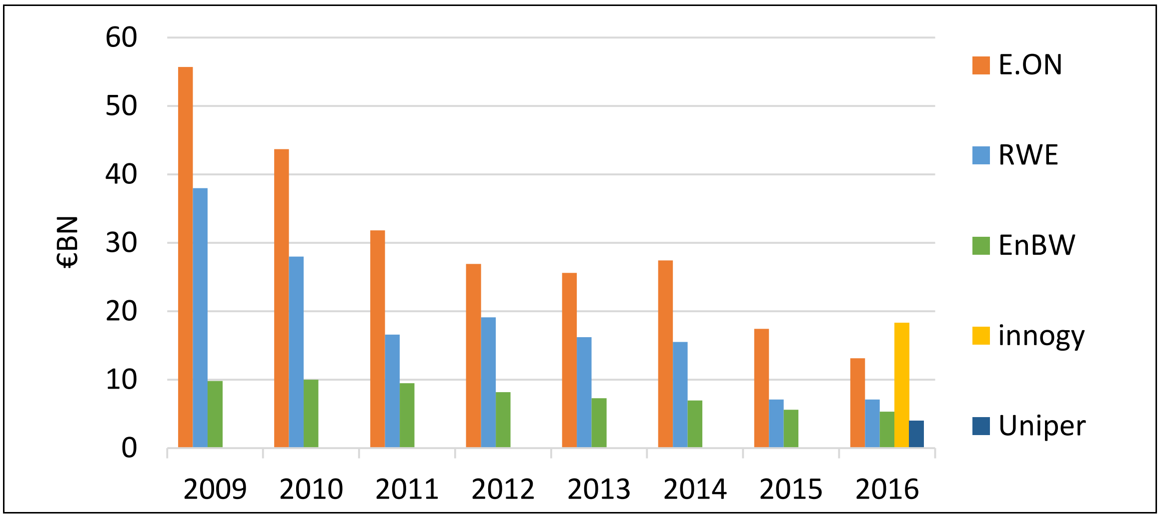


Source: Authors, based on (E.ON, 2017a; RWE, 2017b) and Google Finance.

This trend has led to a steady fall in the companies' market capitalisation, as shown in figure 69. Particularly striking is the progressive fall of the three large listed utilities and the strong rise of innogy in 2016, which had higher market capitalisation than any of the others, even its parent company. During the period analysed, RWE issued 81.2 million new shares (the most significant stock issue came in 2012, when 75.5 million shares were issued), to a total of 614.7 million shares outstanding;[102] E.ON has done the same, with 47 million new shares (26 million issued in 2014 and a further 20 million between 2015 and 2016) to a total of 1,952 million shares outstanding and EnBW issued 20.8 million new shares in 2012, to a total of 276.6 million.[103]

[102] RWE has two types of share, common shares (547.7 million at the end of 2016) and preferred shares (39.0 million). Preferred shares have no voting rights, but receive a larger dividend.
[103] Of these shares, 270.9 million are outstanding. The rest are held by the company itself as treasury stock.

FIGURE 69. Market capitalisation of the different companies analysed at the end of their annual financial years



Source: Authors based on the companies' annual reports

RWE and E.ON's share prices fell sharply in the second half of 2015, when the full impact on their businesses of the provisions for closure of nuclear power stations became apparent (Kaeckenhoff et al., 2015). Spiegel Online reported that, according to a provisional report from BMWi, the nuclear operators (RWE, E.ON, EnBW and Vattenfall) would require €30 billion in additional provisions. This estimate contrasted with the operators' own predictions that the provisions made until then (around €39 billion) would be more than enough to meet requirements for the nuclear phase-out (Dohmen, 2015).

In a later statement, the Economy Minister, Sigmar Gabriel asserted that the existing provisions would be enough (ultimately an additional €6.2 billion was required) (Chazan, 2016b), allowing a full or partial recovery in share price (Vasagar, 2015). Even so, share prices continued to fall slowly in the following months affected, *inter alia*, by the posting of continued losses, RWE's announcement that it would not be paying out dividends that year (as also happened in 2016) and the reduction in E.ON's dividend.

The last event to have a major impact on the shares of the large companies was the flotation of RWE and E.ON's subsidiaries, innogy and UNIPER. The companies have fared differently since.

UNIPER's share price has risen, whereas innogy suffered a major fall initially as a result of the reduction in its profits (7%), from which it has gradually recovered (Steitz, 2016).

For its part, RWE share price rose on its profit figures, following inclusion of new provisioning in 2016 for the nuclear shut-down (Becker, 2017), while E.ON has continued to fall on the market with the announcement of a capital increase to meet this outlay(Chazan, 2017).

With the reforms made, RWE and E.ON's results for the first half year have been positive, and the trend is predicted to continue in the second half (Brough & Brand, 2017a). Other positive factors have been the agreement on the creation of the nuclear waste disposal fund (see Section 2.2.2), and the German Constitutional Court's decisions to award adequate compensation to the companies for the nuclear shut-down (which the companies themselves estimated at €19.3 billion) and to declare the levy on nuclear fuel unlawful, mean that the companies will be refunded around €6 billion (Steitz, 2017).

Following a complicated decade for the companies, the forecast is for stabilisation and improvement in cash flow and a reduction in debt. This would mean that leverage would no longer be a problem and would result in healthier accounts for 2018. As a result, E.ON and RWE have again announced the payment of dividends. The forecasts are also good for innogy, as a consequence, among other factors, of the predicted growth in renewable generation. In any case, the financial reports show that the results of the companies analysed also depend on economic developments in the countries in which they operate (Brough & Brand, 2017a).

In this context, an increase in share prices —which some experts believe to be undervalued— is considered feasible (Brough, Brand, Sanz de Madrid, & Duncan, 2017a).

3.4. Summary and conclusions

3.4.1. Consumer prices

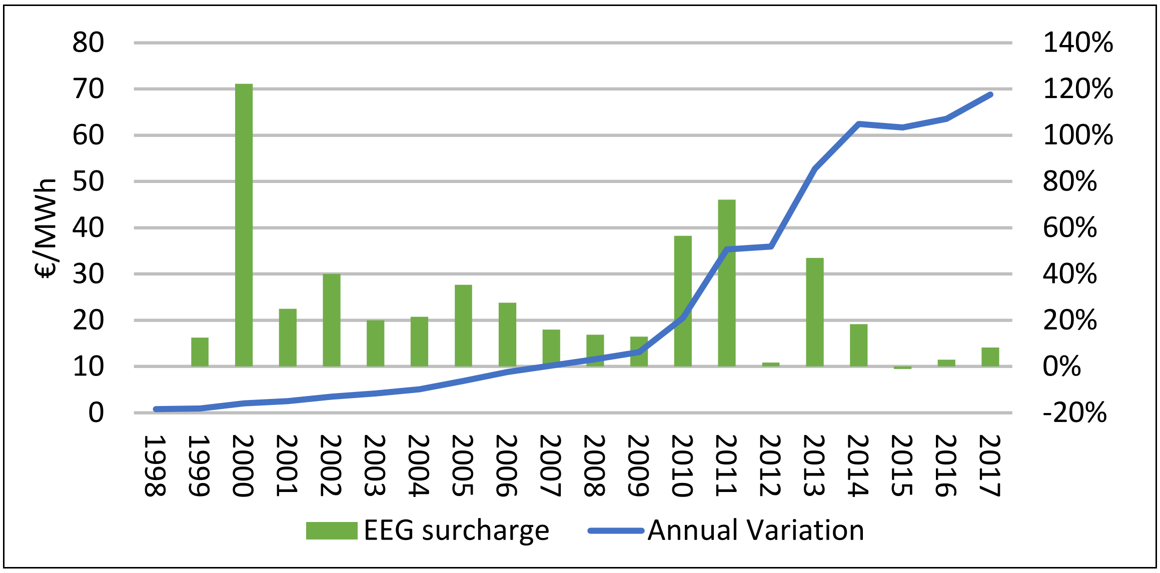
In the period from 2001 to 2016, German electricity consumers have seen a profound change in their electricity bill, both in terms of the structure and the final price. These changes have not affected all consumers equally.

Greater use of renewables has led to a reduction in the price of electricity on the wholesale market. However, this penetration has been financed through the renewables levy (EEG surcharge), a levy on electricity consumption which has risen continuously since its inception.

The increase in the electricity price for the household consumer has therefore been due mainly to the upward trend in installed renewable capacity and the EEG surcharge. In this regard, the decline in the price of electricity on the wholesale market has not compensated for the increase in the cost of introducing renewables. It has led to an overall increase in the electricity price which is well above inflation and above the equivalent cost in other European countries. Another important feature has been the increase in network access charges and other taxes. In 2016, the cost of power generation, transmission and distribution accounted for 46% of the bill.[104]

[104]Fuel costs account for 21% of the bill and network access charges 25%.

FIGURE 70. EEG surcharge



Source: Authors, based on BDEW (2017a).

The average industrial consumer has also seen an above-inflation increase in their electricity bill, levelling out from 2014 on. In 2016, the cost of power, transmission and distribution accounted for 45% of their bill. The remaining 55% consisted of the EEG surcharge and other taxes and levies.

The large industrial consumers, however, enjoy important exemptions on the final price by way of a very reduced payment of the EEG surcharge (between 0.5% of GVA and 15-20% of the total levy), as well as a reduction in the power cost component of the final price. Nonetheless, the European Commission wants to get rid of these grants, and these exemptions are now being cut.

3.4.2. Power utilities in Germany

Germany is home to some of Europe's leading power companies: RWE, E.ON, Vattenfall and EnBW. These companies have an important share of conventional generation in Germany, a market which fell by 15%[105] between 2008 and 2015 with the introduction of renewable energy.

The annual profits of these companies, impacted by the reduction in the global market, the nuclear shut-down and the fall in the electricity price on wholesale markets, have even slipped into the red, leading to a fall in their share prices and therefore in their market capitalisation.

This decline, which began before 2011, was further aggravated that year with the nuclear shut-down, which was followed by a slow but steady decline in their share value. Nonetheless, the latest summer forecasts show a recovery in the worth and economic situation of these companies.

[105] However, the overall volume of generation of the four utilities increased by 13%.

The companies have adopted different strategies to deal with the new situation. The process of strategic change begun by E.ON in November 2014 ended in 2016 with the flotation of its subsidiary Uniper, in which it has a minority holding. E.ON has held onto renewable generation, moving its conventional generating assets to Uniper.

RWE followed a similar path, announcing the strategic change in December 2015, but maintaining a majority stake in its subsidiary innogy, floated in November 2016. RWE has held onto conventional generation and split off renewables, networks and retailers customers to innogy.

These two companies have opted for different solutions for conventional and renewable generation, but have retained their nuclear generation assets in Germany until they are closed by decision of the German government.

Vattenfall, for its part, has sold its lignite business, leading to the emergence of a new player, the Czech company EPH. EnBW, the least affected of the four, has had to develop its business outside its usual geographical area to increase its share of renewables.

The four companies have committed to offshore wind generation —with important projects in Germany and abroad— and to the purchase of photovoltaic companies (there is a striking lack of large solar photovoltaic farms) and battery manufacturers; and the development of household solutions.

This new scenario can therefore be said to have led power companies to change strategy. They share a commitment to renewables —in particular wind power— and storage, as well as an emphasis on distribution networks and the retail market. In this context the increased internationalisation of the activity is significant, both for the investment in other countries, and for the emergence of new competitors, particularly in offshore wind.

As a result of these new strategies, combined with the agreement on management of the nuclear phase-out and the court decision to refund the nuclear fuel levy, the latest forecasts augur an improvement in profits and market capitalisation, although a return to pre-decline values does not seem likely in the short-term. In any case, it remains to be seen whether or not this trend is confirmed in the future.

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5. APPENDICES

APPENDIX 1. ABBREVIATIONS AND ACRONYMS

BDEW: *Bundesverband der Energie- und Wasserwirtschaft e.V.* (Federal Energy and Water Management Association)

BMWi: *Bundesministerium für Wirtschaft und Energie* (Federal Economy and Energy Ministry)

CO_{2eq}: CO_2 equivalent

EBIT: Earnings Before Interest and Taxes

EBITDA: Earnings Before Interest, Taxes, Depreciations and Amortizations

EEG: *Erneuerbare-Energien-Gesetz* (Renewable Energy Act)

ENTSO-E: *European Network of Transmission System Operators for Electricity*

EU: European Union.

FLEH: Full load equivalent hours

GHG: Greenhouse Gases

GNS: *Gesellschaft für Nuklear-Service mbH*

GVA: Gross Value Added

IEA: International Energy Agency

LCOE: Levelised Cost of Energy

MMTCDE: Million tonnes of carbon dioxide equivalents.

MWh/yr: Megawatt-hours per year

MW_{th}: Megawatts thermal

NAPE: National Action Plan on Energy Efficiency

NEA: Nuclear Energy Agency

NMVOC: Non-Methane Volatile Organic Compounds.

NRA: National Regulatory Authority

OTC: Over-the-Counter (bilateral exchange between parties)

RE: Renewable energy

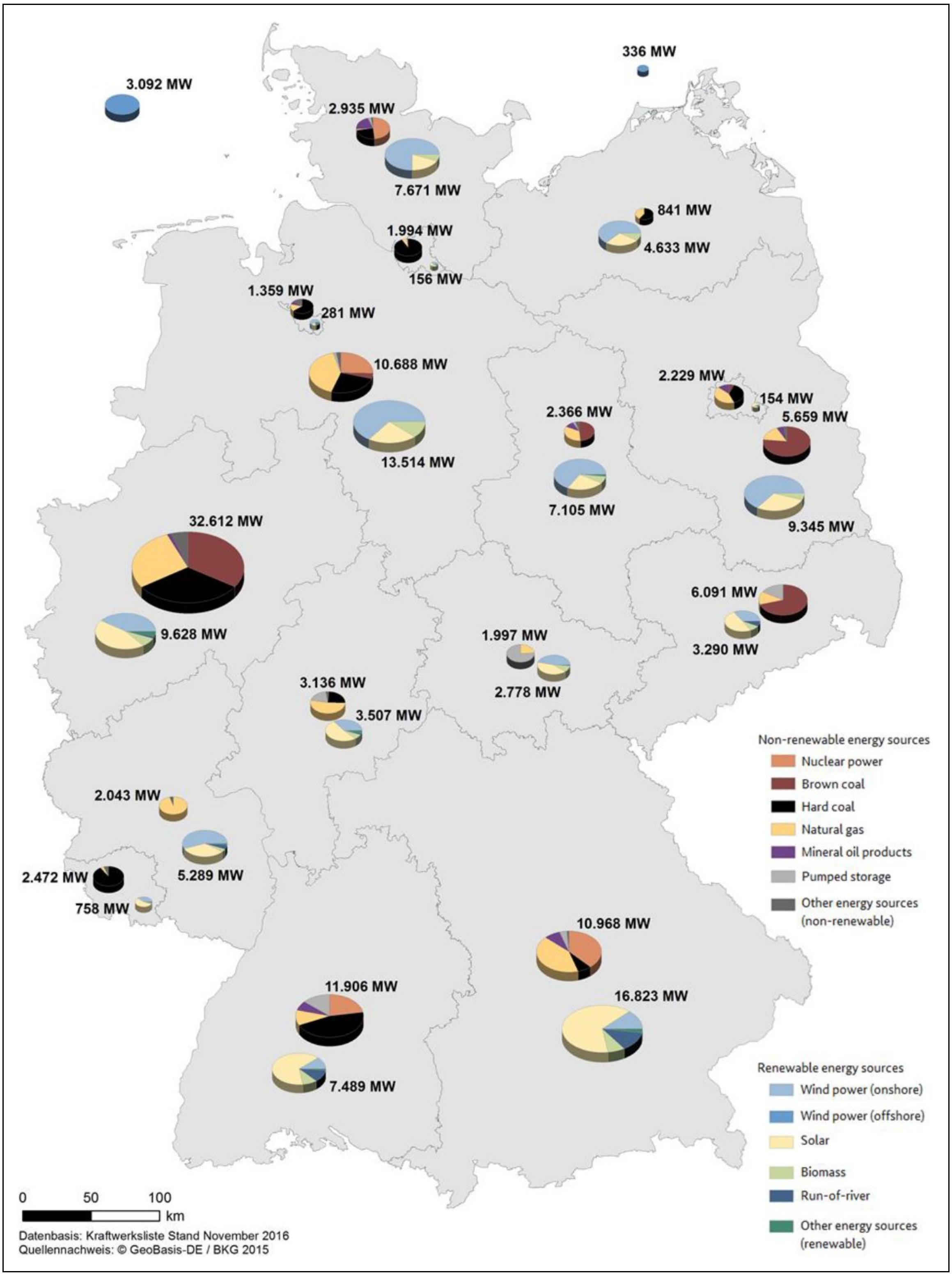
TSO: Transmission System Operator.

WACC: Weighted Average Cost of Capital

€/MWh: euro per megawatt-hour

APPENDIX 2. DISTRIBUTION OF POWER GENERATION IN GERMANY.

FIGURE 71. Location of power generation in Germany by Länder



Source: Hausanschrift Bundesnetzagentur (2016) (English version).

TABLE 22. Location of power generation in Germany by Land (MW)

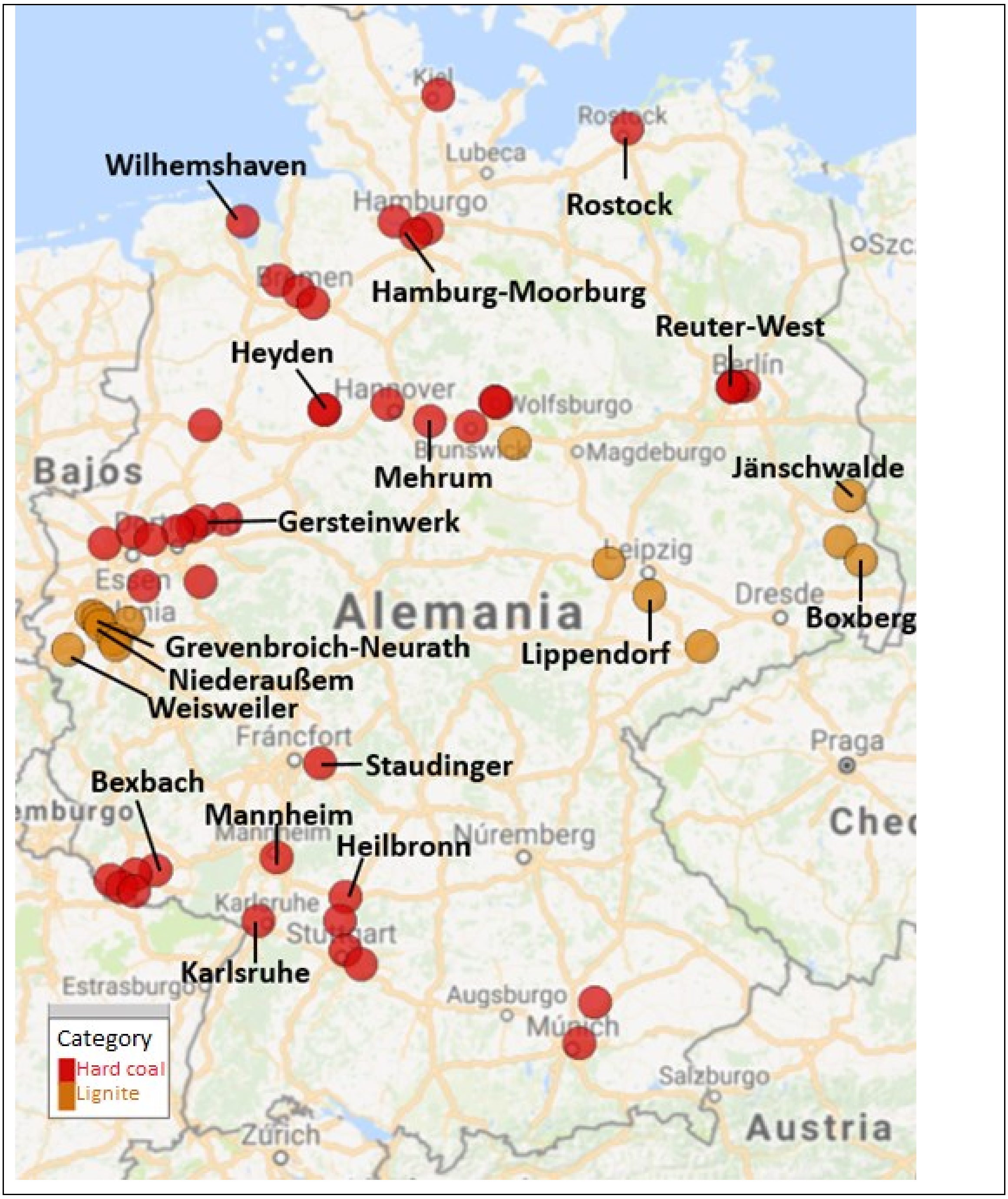
Land	Hard coal	Lignite	Natural gas	Nuclear	Pumped-storage	Fuel oil	Other non-renewables	Biomass	RoR hydro	Offshore wind	Onshore wind	Solar	Other renewables	Total
BW	0	5,526	1,045	2,712	1,873	700	49	778	780	0	735	5,117	79	19,394
BY	0	847	4,491	3,982	543	969	136	1,439	1,922	0	1,821	11,309	332	27,791
BE	164	777	943	0	0	327	18	43	0	0	9	84	18	2,383
BB	4,409	0	733	0	0	334	183	437	5	0	5,831	2,982	91	15,004
HB	0	896	170	0	0	88	206	7	10	0	174	41	48	1,640
HH	0	1,794	150	0	0	38	12	44	0	0	63	37	12	2,150
HE	34	753	1,620	0	623	25	82	243	63	0	1,280	1,811	110	6,643
MV	0	514	318	0	0	0	9	353	3	0	2,843	1,414	20	5,474
NI	352	2,933	4,102	2,696	220	59	326	1,355	59	0	8,457	3,580	62	24,201
NW	10,442	11,371	7,972	0	303	504	2,021	742	146	0	4,046	4,364	330	42,241
RP	0	13	1,922	0	0	0	107	168	223	0	2,908	1,920	69	7,331
SL	0	2,206	114	0	0	0	154	19	11	0	298	416	14	3,231
SN	4,325	0	657	0	1,085	17	8	291	211	0	1,161	1,608	19	9,381
ST	1,148	0	772	0	80	231	135	418	26	0	4,590	1,963	109	9,472
SH	0	730	31	1,410	119	575	70	411	5	0	5,728	1,498	30	10,606
TH	0	0	482	0	1,509	0	6	250	32	0	1,297	1,187	12	4,774
NS	0	0	0	0	0	0	0	0	0	3,092	0	0	0	3,092
BS	0	0	0	0	0	0	0	0	0	336	0	0	0	336
Total	**20,873**	**28,360**	**25,521**	**10,800**	**6,355**	**3,866**	**3,522**	**6,999**	**3,495**	**3,428**	**41,241**	**39,332**	**1,354**	**195,145**

Note: BW (Baden-Wurttemberg), BY (Bavaria), BE (Berlin), BB (Brandenburg), HB (Bremen), HH (Hamburg), HE (Hesse), MV (Mecklenburg-Verpommern), NI (Lower Saxony), NW (North Rhine-Westphalia), RP (Rhineland-Palatinate),SL (Saarland), SN (Saxony), ST (Saxony-Anhalt), SH (Schleswig-Holstein),TH (Thuringia),NS (North Sea), BS (Baltic Sea)
Source: Authors, based on Hausanschrift Bundesnetzagentur (2016).

FIGURE 72. Location of nuclear power in Germany

Source: Appunn (2015).

FIGURE 73. Location of coal-fired power in Germany



Note 1: Figures are for installed generating capacity at 31/12/2016 as per Bundesnetzagentur.

Note 2: Hard coal-fired power stations may have units using other fuels, in some cases with greater output than the hard coal itself (e.g. Staudinger).

Source: Authors using GPSvisualizer.

FIGURE 74. Location of offshore wind power in Germany

■ In operation ■ In partial operation ■ Under construction ■ Approved

Note: Situation as at 31.12.2016

Source: modified from BWE (2017).

APPENDIX 3. ELECTRICITY MARKETS IN GERMANY

The German electricity market is essentially made up of three components: the futures market, the day-ahead market and the intraday market. Although most transactions take place by way of bilateral agreements off the exchanges, their importance is growing.[106] There are three main exchanges trading in electricity: the EEX (European Energy Exchange) in Leipzig, the EPEX SPOT (European Power Exchange SE) in Paris and the EXAA (Energy Exchange Austria) in Vienna.

The EPEX SPOT exchange is part of the EEX group. EEX has a 51% holding in the exchange, with the remaining 49% owned by TSOS, and its functions are shared between the two organisations. On the EPEX SPOT, trading is carried out on the day-ahead and intraday market, whereas the EEX works with the futures market. Trading on the day-ahead market is also carried out on the EXAA.

Day-ahead market ("spot market")

On the day-ahead market, energy is bought and sold for delivery the next day (known as the Delivery Day). The particular features of this market are explained below (EPEX SPOT SE, 2016b).[107]

Both individual hours and blocks of hours can be sold on this market. Hourly bids contain between 2 and 256 price-quantity combinations for each hour of the following day. Prices may be between -€500/MWh and €3,000/MWh and can be different for each hour.

Block bids contain bids for several hours and the quantities for each hour may be different. Blocks are bought or sold as a single indivisible whole by comparing the average price of the hours contained in the block with the price corresponding to the hourly bids. Block bids are given lower priority in matching than hourly bids. The maximum volume for a block is 600 MW and a maximum of 100 block bids may be entered per day. There are also other options for block sales, such as linked block orders and exclusive block orders, which link the bids of different blocks.

Hourly and block bids are made in increments of 0.1 MW and can be positive, negative or nil. The minimum price variation between offers is of €0.10 per MWh.

Trading takes place round the clock and opens 45 days before delivery. The market closes at 12:00 pm on the day before the Delivery Day, and the results are published between 12.55 and 13.50 (unless the market has to be uncoupled).

The energy can be delivered in any of the networks of Germany's TSOs (Amprion GmbH, Tennet TSOS GmbH, 50Hertz Transmission GmbH and TransnetBW GmbH)

[106] For example, in 2015, exchanges accounted for 53% of the electricity supplied in Germany/Austria. (EPEX SPOT SE, 2016a)
[107] This section describes the operation of the EPEX SPOT, given its importance over the EXAA.

and of the main operator Austrian, Austrian Power Grid. These five transmission networks form a single market area.[108]

Solely in the case of Germany a new energy auction is also held for 15-minute blocks, known as the intraday auction. This auction also begins 45 days before the Delivery Day, closing at 3.00 pm on the day before. It is similar to the spot market described above, differing only in the size of the blocks (15 minutes), the stipulation that prices must be between -3,000 €/MWh and 3,000 €/MWh and the fact that the Austrian operator Austrian Power Grid is not one of the power delivery networks (EPEX SPOT SE, 2016b). The Austrian exchange EXAA also has quarter-hour blocks for its area.

Intraday market

On the intraday market energy is bought and sold for delivery on the same day or the next day once the day-ahead market has been matched.

On the EPEX SPOT SE, both one hour and quarter hour packages are traded. Every hour, and up to 30 minutes before delivery, it is possible to trade with both blocks. Trading in the one-hour packages for a given day can begin from 3.00 pm on the previous day. Trading in the quarter-hour packages for a given day can begin from 4.00 pm on the previous day, in other words, one hour after closure of the intraday auction, which is also carried out in quarter-hour packages.

Bids are made in 0.1 MW packages. The minimum price variation between bids is €0.1 per MWh, with a range of -€9,999.90 to €9,999.90. (EPEX SPOT SE, 2016b)

The two types of order that can be processed are Limit Orders and Market Sweep Orders. These may include the following restrictions: "Immediate-or-cancel" (IOC), "Fill-or-kill" (FOK), "All-or-none" (AON) and "Iceberg" (also known as hidden-quantity). An IOC order must be filled immediately or cancelled. It can be partially filled. FOK orders must be filled immediately in their entirety or they will be cancelled.

[108] Germany and Austria constitute a single market. This means that any contract made in this area can be cleared at any point in the transmission networks of Germany and Austria. Altogether, Germany has the four TSOs listed in Chapter 2 (section 2.1.1), while the Austrian grid is operated by three companies: APG (Austrian Power Grid), TIWAG (Tiroler Wasserkraft AG) and VUEN (Vorarlberger Übertragungsnetz GmbH).
In May 2017, it was decided to split up the common market, separating the Austrian and German areas, by October 2018. Tests will begin in July 2018. This comes in response to complaints from neighbouring countries, the Czech Republic, Switzerland and Poland that their networks were being used to transmit renewables from the north to the south.
The market operator EPEX SPOT had previously seen maintenance of the link as being important for players in the two countries and as a Europe-wide achievement (EPEX SPOT SE, 2016a). A report by Loreck, Hermann, Chr. Matthes, Emele Lukas, & Rausch (2013) drew attention to this North-South flow, which is collapsing neighbouring networks and preventing them from being supplied with cheaper power. Erni (2012), however suggests that there is almost no bottleneck in power transmission between Germany and Switzerland. Brough & Brand (2016) note that limiting the interconnection capacity between Germany and Austria would split the market and could result in a drop in the price in Germany and a rise in Austria. A situation might even arise where Germany was divided into in different pricing areas, the north benefitting from lower prices to the detriment of more expensive power for the south. This would have consequences for exports from third countries, such as Sweden, which mainly exports power from its nuclear and hydroelectric stations.

AON orders are filled in their entirety or not at all. Finally an "Iceberg" is one that is divided into several which come on the market sequentially.

The energy can be delivered through any of the networks of the German TSOs (Amprion GmbH, Tennet TSOS GmbH, 50Hertz Transmission GmbH and TransnetBW GmbH). Once again, the Austrian operator, Austrian Power Grid is not included.

Regulating power market (RPM)

German TSOs work to maintain a balance between power supply and demand using an arrangement of primary, secondary and tertiary regulation (*Minutenreserveleistung*) similar to that used in many other European countries, such as Spain. To do this, they calculate certain levels of regulation for each hourly block which are sold on an auction which is open and non-discriminatory, though generators have to meet certain requirements. The amount of regulation to be traded is offered jointly by the four operators of the German system via the Regelleistung platform (50Hertz, Amprion, TenneT, & TransnetBW, 2017).

The price of the regulation is calculated for quarter-hour blocks jointly for the whole of Germany. This price may be expressed as contracted power (primary and secondary) or energy (secondary and tertiary), and the energy price can be negative. The cost of the energy demanded by the regulation is distributed evenly between all generators that have had an imbalance.[109]

The volume traded on the RPM has fallen considerably since 2009, from €828m to €337m in 2015. This has been due to a reduction in requirements and use of secondary and tertiary regulation, whereas primary regulation has remained stable, and is the least costly of the three. Another contributing factor has been an increase in the number of companies authorised to provide regulation, particularly secondary and tertiary (Hirth, 2016).

Futures market

On futures markets, electricity is traded with a delivery period of up to seven years. Nonetheless, normally only trades with a period of up to three years are considered and, indeed, most transactions are for periods of less than a year. The possible delivery periods of futures on EEX Power Derivatives, the main power futures exchange in Germany, are up to the following nine months, the following eleven quarters or the following six years. They are traded in packages of 1 MW with a minimum value of €0.01 per MWh. There are futures for delivery in either Germany or in Austria and futures for exclusive delivery in Germany or Austria.

The members of EEX Power Derivatives and EPEX SPOT can request a total or partial delivery of their futures position for the electricity day-ahead market. Futures

[109] In some markets, such as France and Belgium, the distribution of the cost varies from generator to generator depending on whether its imbalance works to the system's favour (if it has under-generated in the event of a production surplus) or its detriment (when it has over-generated in the event of a production surplus).

positions on EPEX SPOT are monthly and weekly, and it is possible to differentiate between off-peak hours and peak hours outside weekends. Monthly bids are valid throughout the delivery month and must be sent to the market operator two trading days before the start of the delivery month. Similarly, weekly offers are valid throughout the week of delivery and must be sent on the Friday prior to that week (EPEX SPOT SE, 2016c).

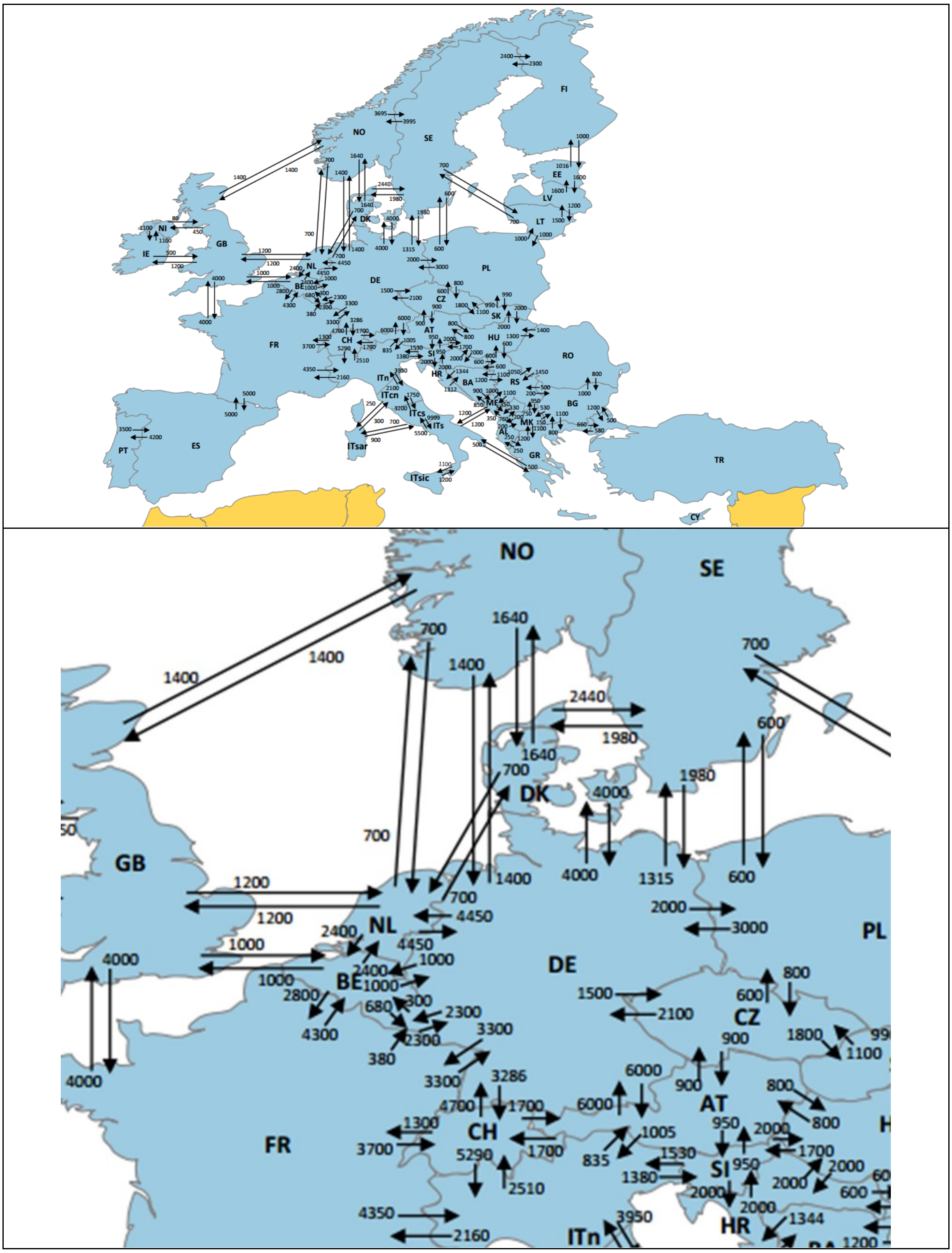
There is also an options exchange[110] in EEX Power Derivatives, with similar conditions to the futures exchange. The main differences are that the minimum price is €0.001 per MWh and the delivery periods are up to the following five months, the following six quarters or the following four years.

[110] The options are derivative, meaning that there is no obligation to buy the goods (electricity in this case) on maturity at the price offered in the option.

APPENDIX 4. PLANNED INTERNATIONAL CONNECTIONS IN EUROPE IN 2025

The figures below show the ENTSO-E's planned international connections in Europe as set out in its 2015-2020-2025 plan.

FIGURE 75. Planned international connections in Europe in 2025



Top: Planned for Europe. Bottom: detail of Germany. Values in MW.

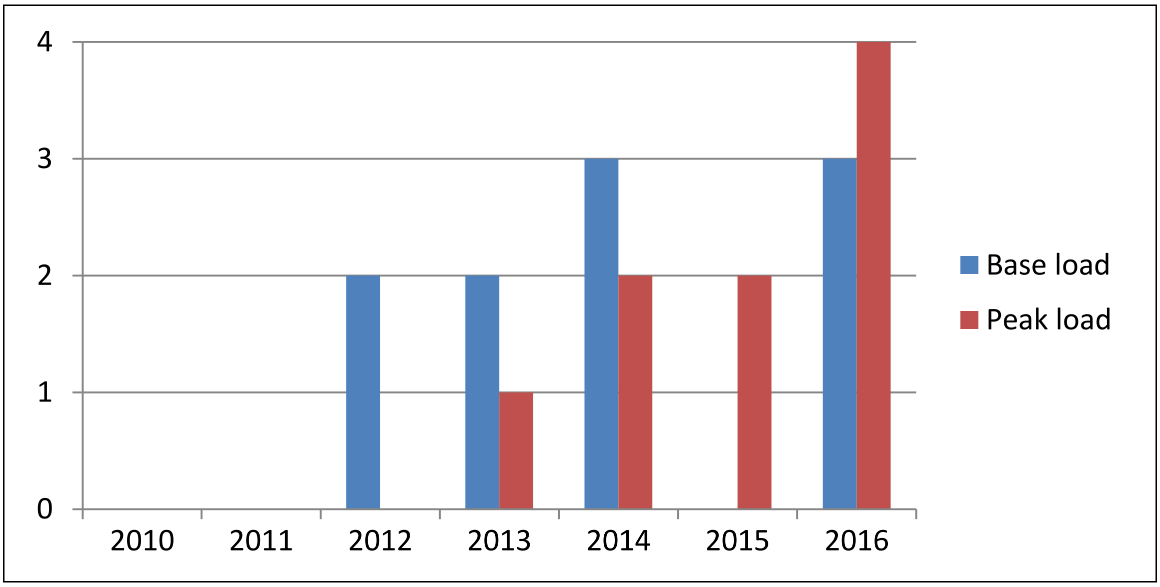
Source: ENTSO-E (2016a).

APPENDIX 5. NEGATIVE PRICES

The penetration of renewables has led to the emergence of the phenomenon of negative prices. The possibility of bidding negative prices was introduced on the electricity market for the first time in 2007 for the intraday market in Germany and in 2008 for the day-ahead market in Germany and Austria (EPEX SPOT SE, 2017). As mentioned, negative prices are linked to large-scale penetration of renewables on the market and low flexibility in conventional generation, particularly on days of low demand (see figure 76, where the majority of DAYS IN THE WEEK with negative prices are non-working days), which creates a surplus of generation on the market which cannot be absorbed by demand.

For a variety of reasons, many conventional generators have difficulty flexibly altering generating levels: they may need several hours to appreciably reduce output (particularly nuclear); switching the system off and on again may be more costly than enduring a negative price; they may need to fulfil contractual obligations on balancing the system or they may have separate heat generation contracts, etc. (Appunn, 2016b). As a result, they often opt to lower their prices in order to offload surplus output. When renewables are not flexible enough to cut productions or have no incentive to do so (for which, under the 2014 Renewable Energy Act, wind turbines of over 3 MW do not enjoy feed-in tariffs after six hours of negative prices (Global Legal Insights, 2015)) and demand is not flexible enough to increase consumption, sub-zero prices result.

FIGURE 76. Number of weekdays with average negative price (2010-2016)



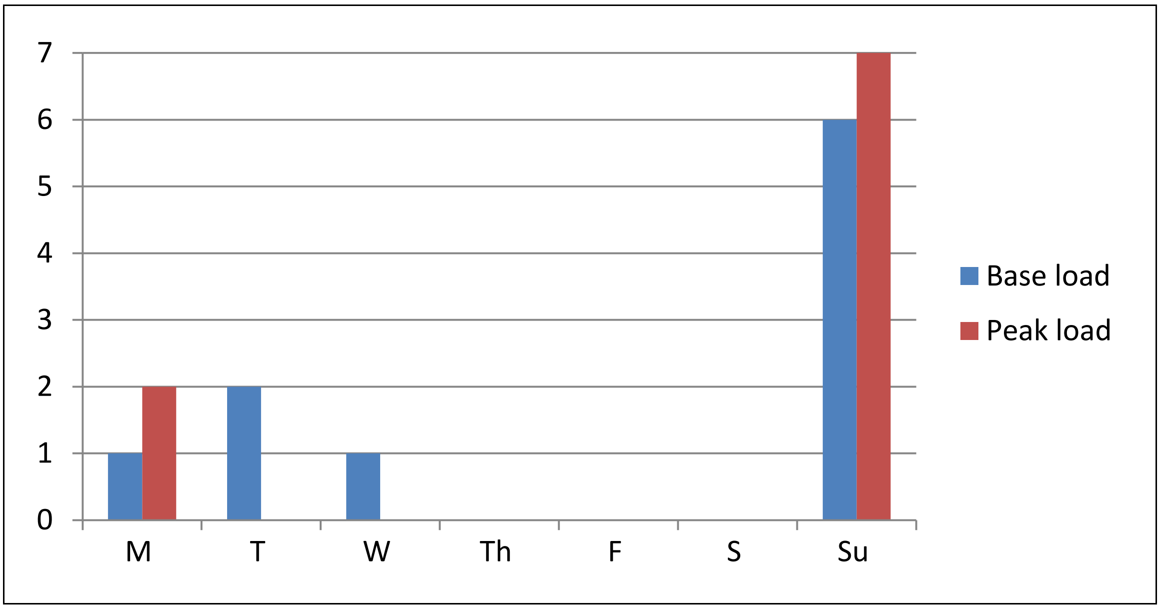
Note: the base load is between 00:00 and 24:00 and the peak load between 08:00 and 19:00.

Source: Authors, based on figures from EVE (2017) taken from EPEX SPOT SE (2017)).

Although the number of days of negative prices fell somewhat in 2015, the figure rose again in 2016 with one extra day for both base load and peak load (see figure 77). The lowest average price (the highest negative number in absolute terms) in 2016 occurred on 8 May, a public holiday, when penetration of renewables rose to 86.3% of demand. A study by the consultancy firm Consentec found that during periods of negative prices, up to 25-30 GW of surplus conventional generation was supplying power even when the minimum conventional generation to maintain system security was 20 GW (balance and load redispatches). (Consentec, 2016)

It should be noted that the analysis of the average daily value is based on the number of days with negative prices, not the number of hours. For example, although the number of days with negative prices fell from 2014 to 2015, the number of hours doubled during the same period of time: 126 hours in 2015 compared to 64 in 2014. As a result, average negative prices were higher in absolute terms in 2014 (-€15.55) than in 2015 (approximately -€9) (Graichen, Kleiner, & Podewils, 2016).

FIGURE 77. Number of days with average negative prices between 2010 and-2016

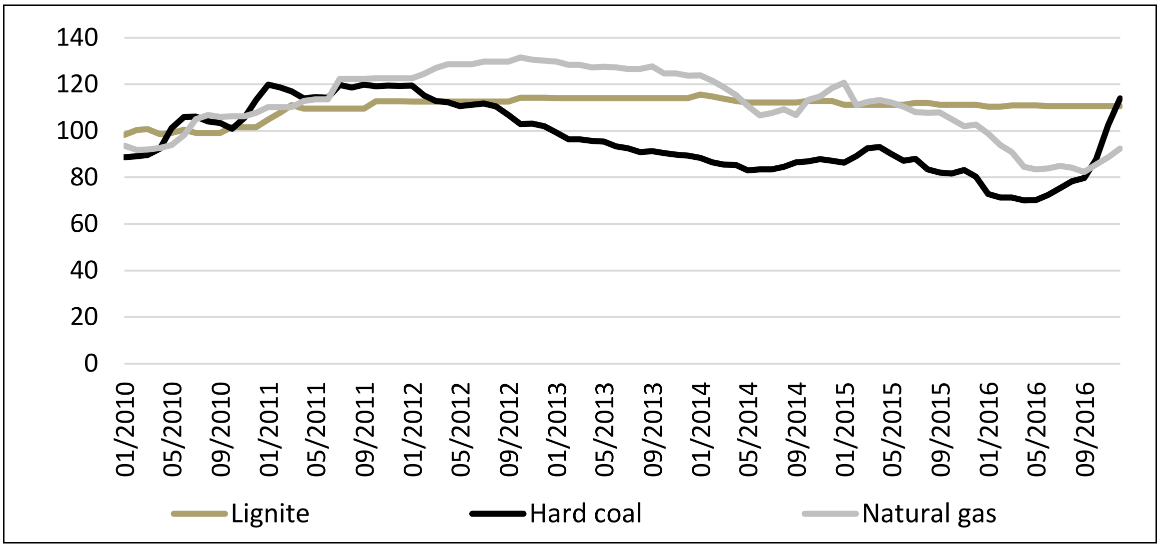


Source: Authors, based on figures from EVE (2017) taken from EPEX SPOT SE (2017)).

APPENDIX 6. TRENDS AND FORECAST FOR PRICES OF COAL, NATURAL GAS AND EU EMISSION ALLOWANCES

figure 78 shows trends in price indexes for industrial consumers of lignite, hard coal and natural gas, drawn up by the German Federal Office of Statistics (*Statistisches Bundesamt*, Destatis). These indices are calculated on the base of the average price in 2010.

FIGURE 78. Price index for industrial consumers of the main fossil fuels in power generation

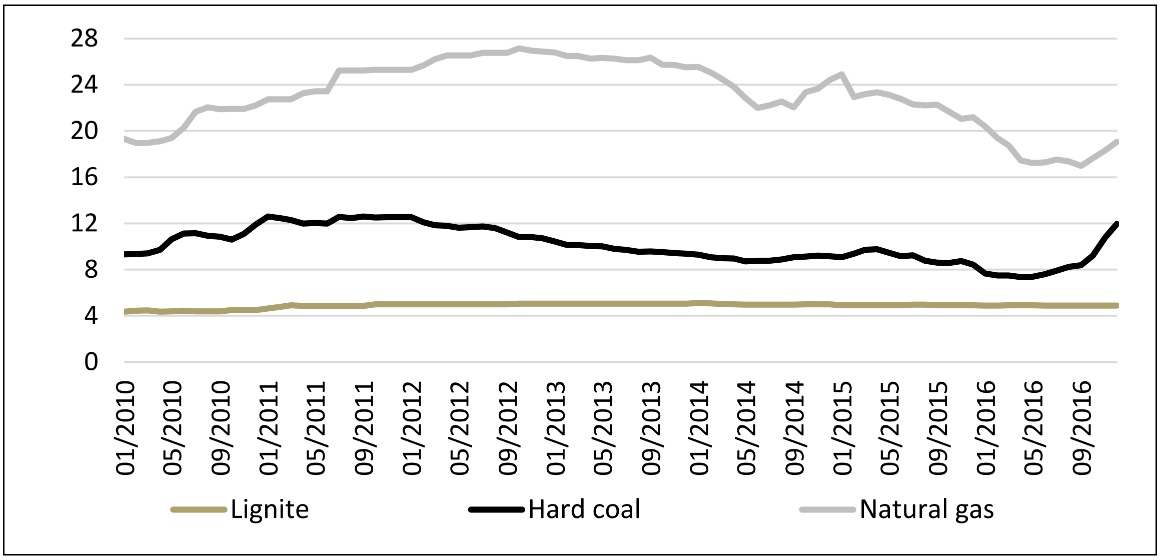


Source: Authors, based on Destatis.

figure 79 shows an estimate of trends in the price of fossil fuels between 2010 and 2016. These values have been calculated using these price indexes, taking as their base the average price of energy sources shown in table 7, corresponding to the average cost of these sources in 2014.[111]

[111] This is calculated as the average maximum and minimum price in table 7 multiplied by the price index for the corresponding month and divided by the average price index for 2014.

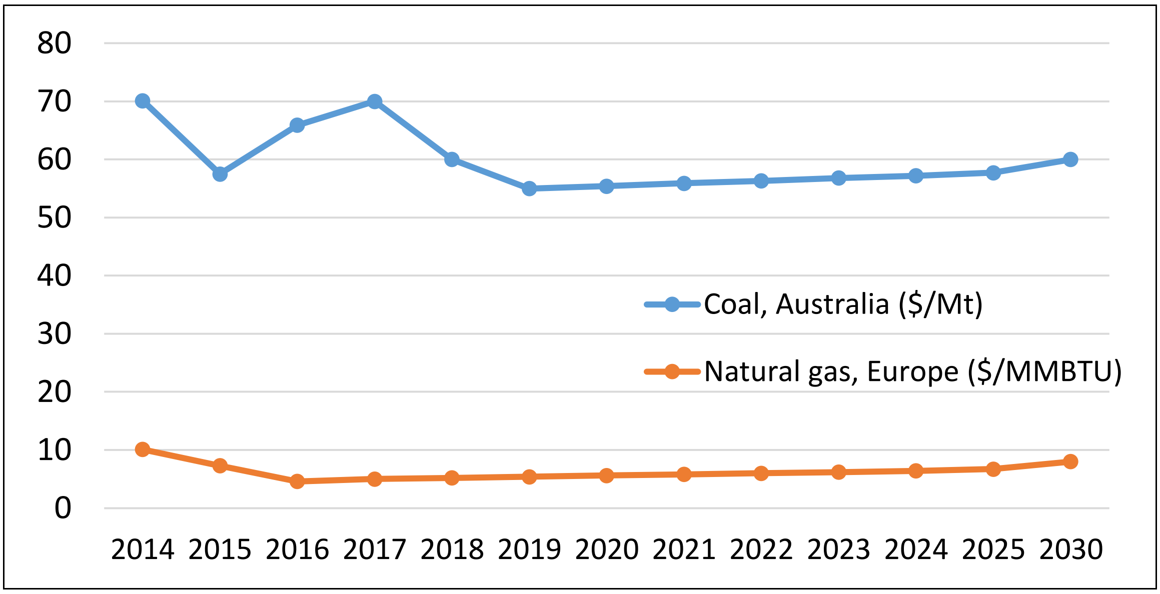
FIGURE 79. Estimation of the price of the main fossil fuels in power generation (€/MWh$_{th}$)



Source: Authors, based on Destatis and (VGB PowerTech e.V., 2015).

Shown below is the World Bank's forecast[112] for prices of Australian coal and natural gas in Europe and the EU's forecasts for fuel prices and emission allowances in the European Union. As can be seen, long-term trends in hard coal and natural gas follow a similar path.

FIGURE 80. World Bank forecasts for price of Australian coal and natural gas in Europe

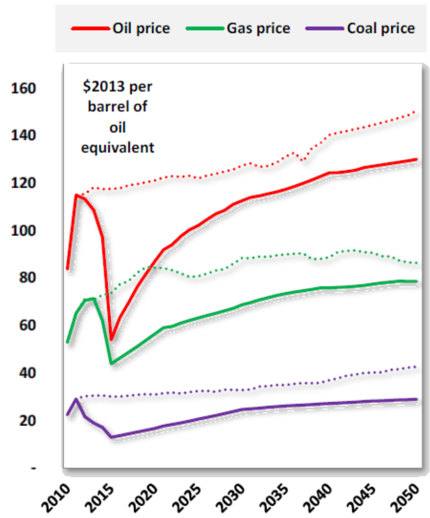


Source: Authors, based on World Bank (2017).

[112] The World Bank's only coal reference is the price of Australian coal, whereas for gas it takes into account differences between America and Europe. Although in 2016 Australia was the world's largest coal exporter, it was Europe's third supplier after Russia and Colombia (Eurostat figures).

For its part, the EU's forecast for the 2050 scenario suggests that the rise in the price of natural gas will outstrip that of hard coal. For lignite, it considers a scenario in which the LCOE, without taking emission allowances into account, will remain stable.

FIGURE 81. EU forecasts for price of lignite, hard coal and natural gas in Europe

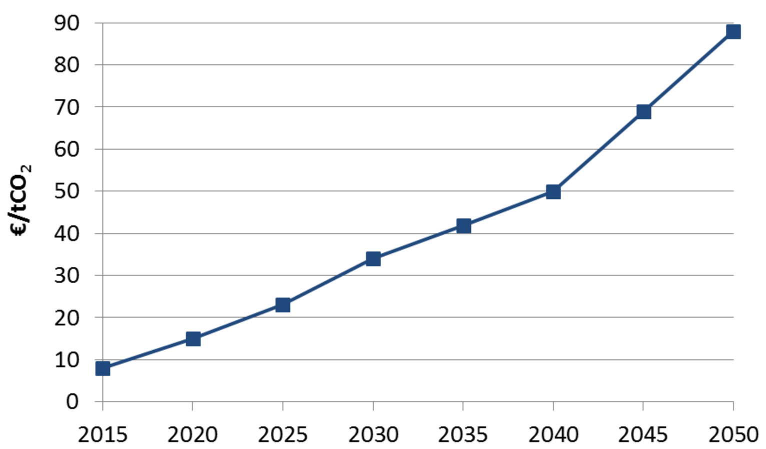


Note: the dotted lines show the forecast in the EU's previous report.

Source: Capros et al. (2016).

The forecast for European emission allowances has been taken from the EU's 2050 scenario used for long term forecasting of power generation in Germany in Section 2.2. Trends in these emission allowances can be seen in figure 30 (Section 2.5.1)

FIGURE 82. Forecasts for future price of EU emission allowances



Source: Authors, based on (Capros et al., 2016).

APPENDIX 7. MEASURES FOR STRENGTHENING MARKET MECHANISMS IN THE WHITE PAPER

In order to promote the electricity market 2.0 in the short-term, the BMWi in its White Paper announced its intention of applying twenty specific measures[113] grouped into three categories: strengthening market mechanisms, ensuring a flexible and efficient electricity system and incorporating additional security measures.

The document includes the following items intended to strengthen market mechanisms: guaranteeing free price formation on the electricity market; making supervision of abuse of dominant market positions more transparent; strengthening obligations to uphold balancing group commitments[114] and billing balancing groups for each quarter hour.

The measures designed to ensure a flexible and efficient electricity supply are: anchoring the further development of the electricity market in the European context; opening up balancing markets for new providers; developing a target model for state-induced price components[115] and grid charges; revising special grid charges to allow for greater demand side flexibility; continuing to develop the grid charge system; clarifying rules for the aggregation of flexible electricity consumers; supporting the wider use of electric mobility; making it possible to market back-up power systems;[116] gradually introducing smart meters; reducing the costs of expanding the power grid via peak shaving of renewable energy facilities; evaluating minimum generation;[117] integrating combined heat and power generation into the electricity market; and creating more transparency concerning electricity market data.

Finally, the options to provide additional security are as follows: monitoring security of supply; introducing a capacity reserve; continuing to develop the grid reserve (see Section 2.4.2).

The EEX and EPEX SPOT[118] exchanges, which are particularly relevant in contributing to the electricity market 2.0, announced in June 2015 that they would make the necessary reforms to all of the twenty measures that affected them: an intraday market with periods closer to the energy supply, progress in the development of "capacity futures" and new weather-related options and derivatives. Hogan & Weston

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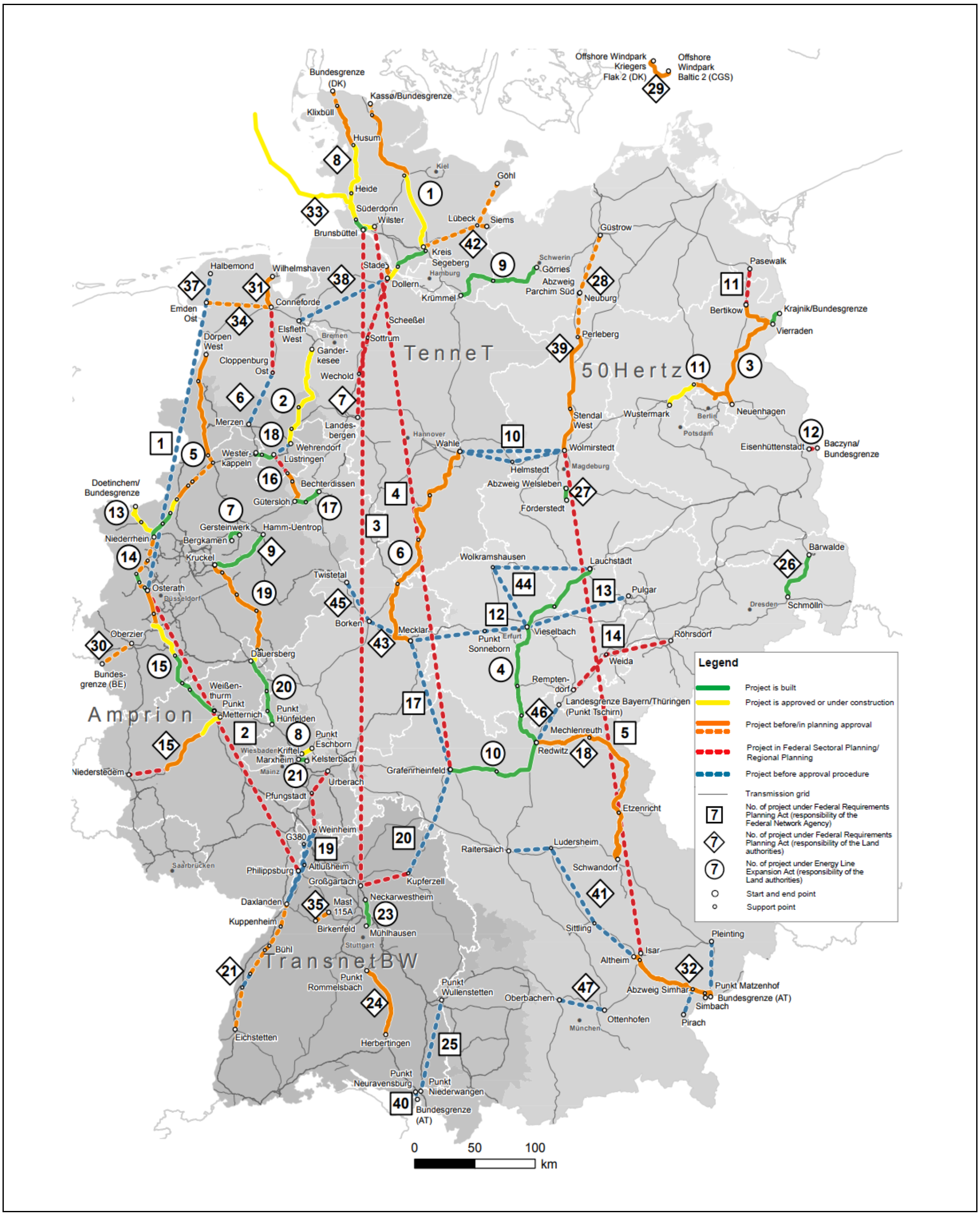
[113] Many of them were already listed as "preventative measures" in the Green Paper.
[114] A balancing group is a virtual grouping of suppliers and consumers whose power generation and demand is balanced. They require a representative person or institution (Balancing Group Representative) who is tasked with ensuring this balance.
[115] Essentially the surcharge, the CHP levy, the electricity levy and the concession tax. See Section 3.1.
[116] Back-up systems are those entrusted with supplying electricity to infrastructures (e.g. hospitals) in the event of a fault in the external power grid.
[117] Minimum generation is the difference between total demand and renewable generation, in other words, that part of the generation that is not obtained through renewable resources. This thermal-powered generation is mostly responsible for providing the "complementary services" to the system, and renewable generation will also have to take over from thermal-powered generation in this task for greater integration in the power grid.
[118] For more information on regulation of the electricity markets in Germany, see Appendix 3.

(2014) argue the advisability of reducing even further the time between sale and supply of energy, with differences of just five minutes linked to weather forecasts only a few hours before supply.

APPENDIX 8. LARGE POWER TRANSMISSION PROJECTS IN GERMANY

Transmission network projects included in the BBPlG and EnLAG programmes are shown below.

FIGURE 83. Situation of transmission projects as of June 2017



Source: modified from BMWi (2017c), based on BMWi (2016b).

APPENDIX 9. CURRENT SITUATION OF REDISPATCHES IN THE POWER GRID

TenneT performed the greatest number of redispatches of any operator in 2015 (with a sharp increase in the volume redispatched), both in terms of duration and energy. 50Hertz comes close, while Transnet BW and Amprion hardly required any (see table 24).

TABLE 24. Redispatches of power generation by system operator

TSOs	Duration (h)		Volume (GWh)	
	2014	2015	2014	2015
TenneT	5,000	9,095	813	4,030
50Hertz	3,230	6,512	1,751	3,930
Transnet BW	119	126	16	16
Amprion	104	78	20	18

Source: Authors, based on Bundesnetzagentur (2015); Bundesnetzagentur (2016d).

The redispatches were mostly due to network congestion and totalled 13,660 hours. Of these, most incidents were due to a small number of factors (20) which accounted for 99% of total hours. The lines with most redispatches were Remptendorf – Redwitz (4,115 hours and 3,704 GWh), Vierraden – Krajnik (Poland) (2,833 hours and 1,498 GWh) and Brunsbüttel – Hamburg North (2,039 hours and 763 GWh), which together accounted for 66% of the redispatch time for electrical causes. These congestions are expected to become less common once the new transmission lines come on line between the north and the south of the country, although this will still take several years.

At the same time, redispatches resulting from voltage levels came to 2,151 hours and 440 GWh, practically all in TenneT's network. The areas most affected were those located between Ovenstädt, Bechterdissen and Borken (mainly in North Rhine–Westphalia) and the Conneforde substation (North West Bremen, close to the North Sea).

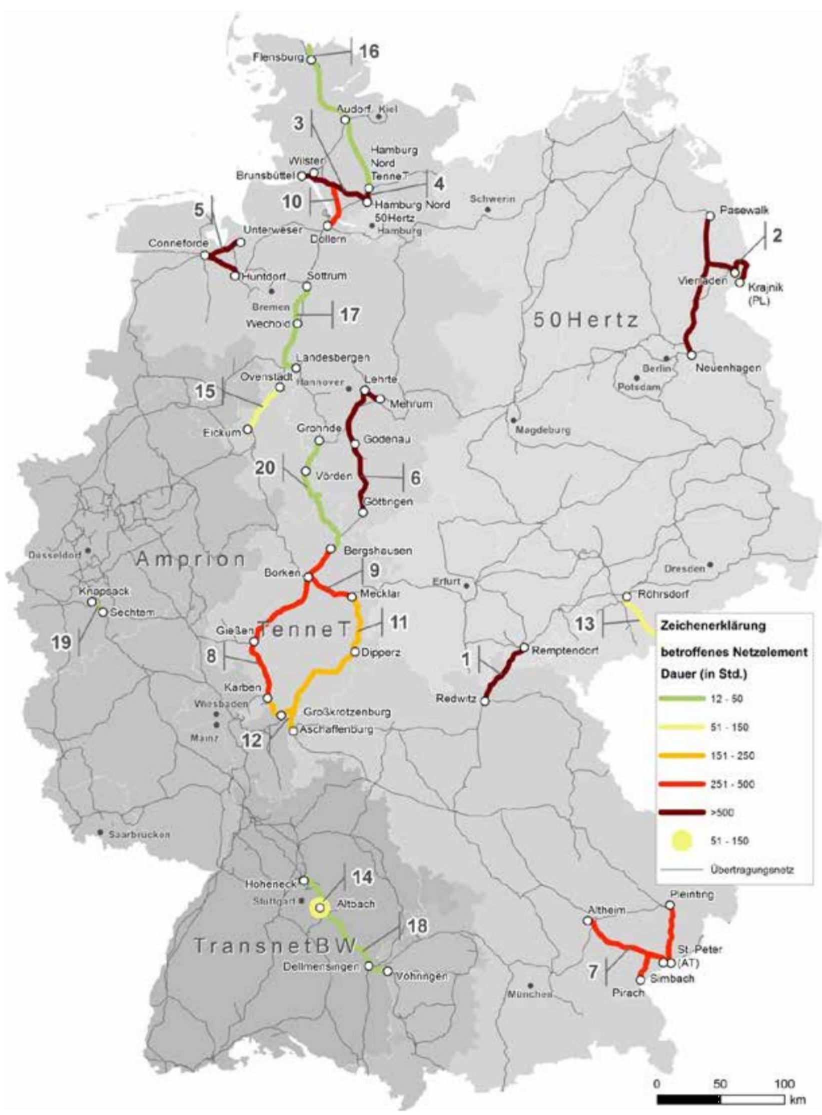
Redispatching was based on use of the network reserve, which for winter 2015/2016 came to 7,515 MW, 3,000 MW domestic and 4,500 MW foreign. Usage rose strongly compared to the previous winter, up from seven days to ninety-three. The use of foreign (particularly Austrian) power stations proved more efficient than resorting to domestic ones. table 25 shows a summary of their use.

TABLE 25. Use of network reserve in winter 2015/2016

Month	Days	Average use (MW)	Total (MWh)
October	3	190	4,295
November	15	1,130	154,718
December	16	850	243,673
January	14	1,079	265,213
February	16	1,045	266,573
March	17	560	163,702
April	12	719	122,038
Total	**93**	**796**	**1,220,212**

Source: Authors, based on Bundesnetzagentur (2016d).

FIGURE 84. Lines with highest duration of redispatches due to congestion in the German transmission network in 2015



Source: Bundesnetzagentur (2016d).

APPENDIX 10. TRENDS IN EMISSIONS FROM THE ENERGY INDUSTRY BY LAND

TABLE 26. Trends in emissions from the energy industry by Land (in MMTCDE)

Land	1990	2010	Reduction (%)
Baden-Wurttemberg	74.4	69.3	6.9
Bavaria	84.5	80.0	5.3
Berlin	26.9	19.8	26.4
Brandenburg	81.9	55.5	32.2
Bremen	13.4	13.8	-3
Hamburg	12.7	11.7	7.9
Hesse	50.2	42.9	14.5
Mecklenburg-Vorpommern	15.5	10.0	35.5
North Rhine-Westphalia	362.7	307.3	15.3
Rhineland-Palatinate	27.4	27.3	0.4
Saxony	91.5	48.7	46.8
Saxony-Anhalt	50.9	27.4	46.2
Lower Saxony	77.1	69	10.5
Saarland	23.7	19.1	19.4
Schleswig-Holstein	24.2	19.0	21.5
Thuringia	28.1	10.7	61.9

Source: Authors, based on BMUB (2014).

The area with the highest emissions is North Rhine-Westphalia, the most populated Land in Germany, which has a long coal and steel tradition and where many of Germany's largest companies are based: E.ON, RWE, Deutsche Telekom, ThyssenKrupp, Bayer, Henkel, Deutsche Post, Rewe Group, etc. The cities with the highest emission rates were those in the Rhine-Ruhr metropolitan area, which has a combined population of seventeen million.

The Länder which have reduced emissions most, to date, are the states of the former GDR: Brandenburg, Mecklenburg-Vorpommern, Saxony, Saxony-Anhalt and Thuringia. This reduction has not been constant. For example, in the case of Brandenburg, the increase in output from lignite-burning plants led to an increase in emissions between 2010 and 2012 (Greenpeace, 2015).

Bremen is the only state in which emissions of CO_{2eq} have increased. In this city-state, emissions in the energy industry have increased, mainly due to an increase in electricity demand (i.e. an increase in emissions linked to electricity in the trade and services sector) and a rise in the use of district heating (which does form part of the energy industry, unlike autonomous climate control of buildings) from 6% to 13%. This development has led to a notable drop in emissions from heating in buildings (Pressestelle des senats (Bremen), 2013)

APPENDIX 11. PRINCIPAL ELECTRICAL UTILITIES IN GERMANY

RWE

RWE is a German company whose main business is in the power and gas industries, where it is involved in generation, distribution and supply. It also has business in selling energy (RWE, 2017d).

At the end of 2016, RWE had a total of 58,652 employees, more than half of whom were based in Germany (34,835 or 59%). Its total workforce that year was down 2% on the previous year (59,762). Apart from Germany, its main markets are the UK, Belgium and the Netherlands, although it also does business in the Czech Republic, Hungary, Poland, Slovakia and Turkey and, to a lesser extent, in Croatia, Slovenia and Romania. In France, Italy and Spain it operates in the renewable generation sector.

In 2016, it had electricity sales of 264.6 TWh to 16 million clients and gas sales of 265.1 TWh to 7 million clients. Its power generation totalled 216.1 TWh. Net sales came to €45,833 million, nearly 5% down on the previous year (€48,090 million). For the second year running, the company had net losses of €5,710 million, following losses of €170m the previous year, with a continued reduction in net debt to €22,709 million.

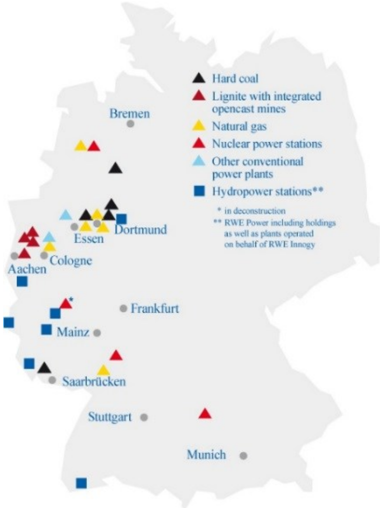
Its share price continued to fall, through there has been a certain levelling out at record lows since the end of 2015.

FIGURE 85. RWE share price (2010-2016)

Source: Authors, based on figures from RWE (2017b).

In early 2017, RWE had installed capacity and assets in the west of the country (see figure 86 and Table 26) (RWE, 2017b).

FIGURE 86. RWE power Stations in Germany



Note: the Biblis nuclear power station, to the south of Frankfurt, shut down in 2016.

Source: RWE (2017b).

TABLE 27. RWE's installed capacity by technology/generating fuel

Technology/fuel	Installed capacity
Natural gas	Bochum, 21.5 MW of electricity and 300 MW_{th}, North Rhine-Westphalia, 1905 (the gas turbines date from 2003-2004). Dortmund, 26.5 MW of electricity and 234 MW_{th}, North Rhine-Westphalia, 2014 (on the site of a former power station dating from 1897). Emsland, 876 MW of electricity, Lower Saxony, 2009 (59.2% efficiency).
Hard coal	Gersteinwerk, 732 MW net electricity, North Rhine-Westphalia, 1984 (one 620 MW coal-fired steam turbine and one 112 MW gas-fired turbine; overall efficiency of 42%).
Lignite	Frimmersdorf, 635 MW of electricity, North Rhine-Westphalia, 1955-1970 (currently has two 300 MW generating units; the old 100 MW units were shut down between 1988 and 2005 and the 150 MW ones in 2012). Neurath, 4,414 MW gross and 4,200 MW net of electricity, North Rhine-Westphalia, 1972. It has three 300 MW units, two 600 MW units and two 1,100 MW units. The two 1,100 MW units, Neurath F and G (BoA 2&3, using RWE optimised systems technology), were added in 2012; they have an efficiency rate of 43% and can adjust output upward and downward by 500 MW in 15 minutes. Niederaußem, 3,669 MW of electricity, North Rhine-Westphalia, 1963 (the 1,012 MW unit using BoA technology, a predecessor of the Neuraths units, was opened in 2002). Weisweiler, 2,596 MW of electricity, North Rhine-Westphalia, 1955 (built on the site of a 1913 power station. It has two 300 MW lignite-fired units, two 600 MW lignite-fired units and two 270 MW gas-fired units).
Nuclear	Gundremmingen, 1,344 MW of electricity, Bavaria, 1984. Emsland, 1,400 MW of electricity, Lower Saxony, 1988.
Hydro	Bernkastel operating group: RWE operates 24 run-of-river hydroelectric stations and three storage power plants on the Moselle, Saar and Nahe rivers, on behalf of innogy. They have a total capacity of 254 MW and are controlled by the Fankel central control station in Rhineland-Palatinate. Herdecke operating group: RWE operates the 153.6 MW Herdecke pumped-storage station (which is in charge of controlling the group) and 20 run-of-river stations (17 owned by innogy) on the Ruhr, Sieg and Lippe rivers and their tributaries. They have a total capacity of 36.6 MW.

Note: MW_{th}= Megawatts thermal.

Source: Authors, based on RWE (2017b).

RWE also operates the 1,096 MW Vianden pumped-storage hydro station in Luxembourg beside the border with the German state of Rhineland-Palatinate. This plant is owned by Société Électrique de l'Our, S.A., whose main shareholders are RWE and the Grand Duchy of Luxembourg, each with a 40.3% stake. (RWE, 2017b).

E.ON

E.ON is a German company whose main business is in the power and gas industries, where it is involved in generation, distribution and supply. It also has business in heat (generation, distribution and supply) and household solutions for customers (E.ON, 2017b).

At the end of 2016, E.ON had a total of 43,138 employees, mostly based in Germany (17,239, 40.0%), the UK (9,850, 22.8%), Romania (5,464, 12.7%) and Hungary (5,000, 11.6%). It also operates in the Czech Republic, the USA, Sweden and Italy. Its workforce fell by only 25 on the previous year.

In 2016, it sold 147.2 TWh of electricity (down 3.8 TWh) and 170.4 TWh of gas (down 23.9 TWh) to a total of 22.4 customers. Total electricity generation in Germany came to 50.3 TWh: 13.7 TWh of renewables (+0.8 TWh) and 36.6 TWh of nuclear, via its subsidiary PreussenElektra (-10.7 TWh). It had sales of 8.5 TWh of heat to 375,000 homes.

Net sales came to €38,173 million, 11% down on the previous year (€42,656m). Although the company had losses for the third year running (€16 billion), it reduced its net debt by €1,394 million. These losses, and the reduction in debt, were mostly due to the splitting-off its subsidiary Uniper.

FIGURE 87. E.ON share price (2010-2016)

Source: Authors, based on figures from E.ON (2017a).

At the beginning of 2017 E.ON had the following power stations installed in Germany:

TABLE 28. E.ON's installed capacity by technology/generating fuel

Technology/ fuel	Installed capacity
Onshore wind	34 windfarms installed throughout the country totalling 209 MW, with different holdings by the company (ranging from 7% to 100%) all subject to feed-in-tariffs. The largest were Dargelütz (22 MW, 25 GWh in 2016, 100% owned, Mecklenburg-Vorpommern, 2006) and Ketzin (18 MW, 26 GWh in 2016, 67% owned, Brandenburg, 2005) (E.ON, 2017c).
Offshore wind	Alpha Ventus I and II, 60 MW, North Sea, 2010 (28 km north of Borkum island). 26.25% share; the other shareholders are a subsidiary of EWE AG (47.5%) and Vattenfall (26.25%). Amrumbank West, 302 MW, North Sea, 2015 (located 35 kilometres to the north west of the Heligoland islands and connected to the onshore network by an 85-kilometre submarine cable).
Nuclear	E.ON's subsidiary PreussenElektra operates or participates in the following nuclear power stations: Brokdorf, 1,410 MW electricity, Schleswig-Holstein, 1986 (operated by PreussenElektra, shut-down scheduled by 2021; 80% share). Emsland, 1,335 MW electricity, Lower Saxony, 1988 (shut-down scheduled by 2022; 12.5% share). Grohnde, 1,360 MW electricity, Lower Saxony, 1985 (operated by PreussenElektra, shut-down scheduled by 2021; 83.3% share). Gundremmingen B, 1,284 MW electricity, Bavaria, 1984 (shut-down scheduled by 2017; 25.0% share). Gundremmingen C, 1,288 MW electricity, Bavaria, 1988 (shut-down scheduled by 2021; 25.0% share). Isar 2, 1,410 MW electricity, Bavaria, 1988 (operated by PreussenElektra, shut-down scheduled by 2022; 75.0% share).

Source: Authors, based on E.ON (2017a).

E.ON's subsidiary Uniper, in which it retains a 46.65% holding, had electricity sales in 2016 of 716.4 TWh (-3.5% down on 2015) and gas, 1,725.7 TWh (-1.0% down on 2015). In 2016 it had net losses of €3,234 million, mostly due to a fall in gas prices, leading to a fall in sales of 31.8% (€17,313 million), together with a fall in electricity sales of 19.4% (€6,637 million), mainly attributed to a reduction in electricity prices, although also to the closure of its operations in Italy and Belgium.

At the beginning of 2017 Uniper had the following power stations in Germany.

TABLE 29. Uniper's installed capacity by technology/generating fuel

Technology /fuel	Installed capacity
Fuel-oil	Ingolstadt, 840 MW electricity, North Rhine-Westphalia, 1973-1974 (two 420 MW units).
Natural gas	Franken, 483 MW electricity, Bavaria, 1973 (one 395 MW unit dating from 1973 and another 448 MW unit from 1976; it also takes fuel-oil). Kirchmöser, 160 MW, 1994 (two 80 MW units; it also takes fuel-oil). Irsching, 1869 MW, Bavaria, 1969 (one 415 MW fuel-oil unit from 1974 and two natural gas units, one of 860 (2010) and another of 570 MW (2011); one 330 MW unit in reserve) Staudinger, 1132 MW net of electricity and residual heat, 1977 (two units, one of natural gas of 622 MW from 1977 kept by TenneT as capacity reserve and another 510 MW hard coal-fired unit from 1992; three blocks closed between 2012 and 2013).
Pumped-storage hydro	Waldeck I and II, 623 MW electricity, Hesse, 1995-1996 (Waldeck I, 143 MW (1931) and Waldeck II, 480 MW (1974)). Walchensee, 124 MW electricity, Bavaria, 1924 (listed industrial monument).
Hard coal	Heyden, 875 MW net electricity, North Rhine-Westphalia, 1987 (one 620 MW coal-fired steam turbine and one 112 MW gas-fired turbine; overall efficiency of 42%) Scholven, 762 MW net electricity, 68 MW_{th} heat and 250 MW steam, 1968 (three units, one of 345 MW (1968), another of 345 MW (1969) and a third 70 MW CHP unit (1985); three earlier units closed in 2014). Wilhelmshaven, 757 MW net electricity, 68 MW_{th} heat and 250 MW steam, 1976 (also takes fuel-oil).
Lignite	Schkopau, 900 MW net electricity and 110 MW_{th} heat, North Rhine-Westphalia, 1995-1996 (has two 450 MW units). 58.1% holding; 41.9% owned by Saale Energie GmbH.

Source: Authors, based on Global Energy Observatory (2017); Uniper (2017b).

Vattenfall

Vattenfall is 100% owned by the Swedish state. Its main business is in the electricity, gas and heat industries. In electricity and heat it is involved in generation, distribution and supply, whereas in gas it only operates in sales.[119] It also has business in energy sales (Vattenfall, 2016).

At the end of 2016 Vattenfall had a total of 19,935 employees, compared to 28,567 in 2015. This reduction was due, on the one hand, to sale of its lignite business in Germany (6,800 employees), and a programme of financial savings. Most of its workforce is based in four countries: Germany (6,998), Sweden (8,684) and Belgium/Netherlands (3,595). It also has operations in Denmark (231 employees), the UK (217), Finland (66) and other countries.

It had sales of electricity of 193.2 TWh to 6,225,000 customers; gas, 53.1 TWh and heat, 20.3 TWh. It had net turnover of SEK 139,208 million[120] (€14,525 m), slightly below that of the previous year,[121] €143,576 m (€14,981 m, -3.1%). Although the company suffered losses for the fourth year running (SEK 26,004 m, €2,713 m), its net debt was down SEK 13,477 million (€1,406 m).

[119] In Sweden, the power transmission operator is Svenska Kraftnät. In gas, transmission and storage facilities are operated by Swedegas.
[120] SEK = Swedish krona (also abbreviated as "kr."), the official Swedish currency. This report uses the exchange rate at 31 December 2016 (€1 = SEK 9.58391) for 2015 figures and for preceding years.
[121] The interannual comparison does not take into account discontinued operations, such as the lignite sold.

Electricity generation came to 119.0 TWh: 46.9 TWh nuclear; 34.8 TWh hydroelectric; 30.8 TWh FROM fossil fuels; 5.8 TWh from wind, and 0.7 TWh from biomass and waste . At the beginning of 2017 Vattenfall had the following power stations installed in Germany.

FIGURE 88. Vattenfall power stations in Germany

Source: Vattenfall (2017d) using Google (2017).

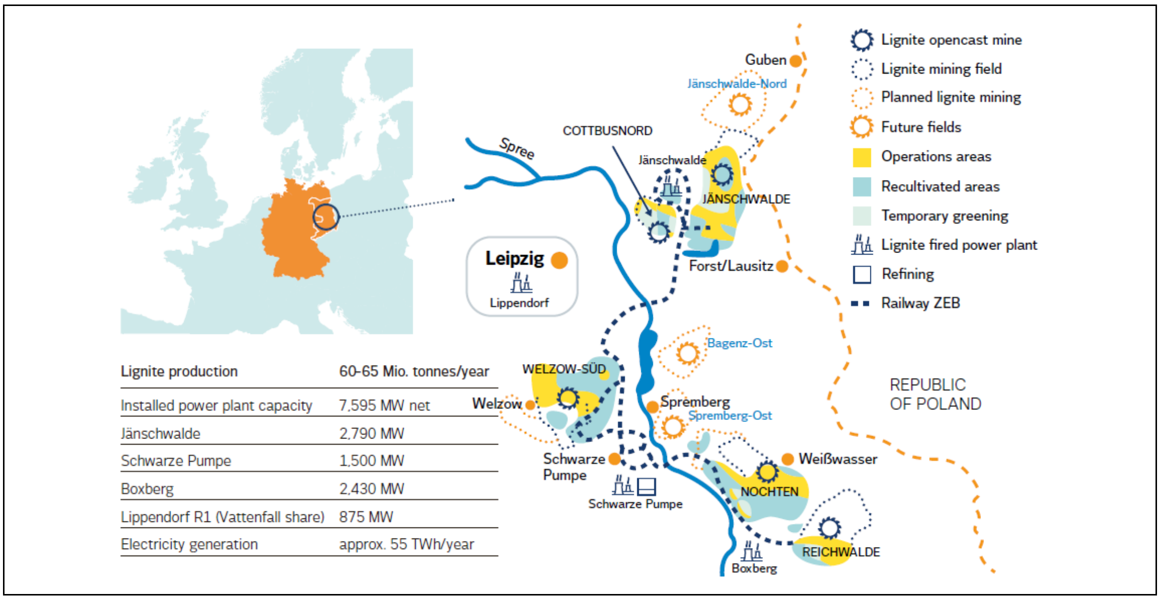
TABLE 30. Vatenfall's installed capacity by technology/generating fuel in 2017

Technology /fuel	Installed capacity
Biomass	Märkisches Viertel, 5 MW electricity and 18 MW heat, Berlin, 1960 (converted from coal and subsequently natural gas and fuel-oil).
Onshore wind	Jänschwalde, 12 MW, Brandenburg, 2004. Westküste, 7.4 MW (after three upgrades), Schleswig-Holstein, 1987.
Offshore wind	Alpha Ventus I and II, 60 MW, North Sea, 2010 (28 km north of Borkum island). 26.25% share; the other shareholders are a subsidiary of EWE AG (47.5%) and E.ON (26.25%). DanTysk, 288 MW, North Sea, 2015. 51% share; Stadtwerke München (SWM) holds the remaining 49%. Sandbank, 288 MW, North Sea, 2017. 51% share; SWM holds the remaining 49%.
Natural gas	Buch, 5 MW electricity and 132 MW_{th}, Berlin, 1905 (in 2014 the fuel-oil unit was replaced by a natural-gas-fired one). Lichterfelde, 432 MW electricity and 650 MW_{th}, Berlin, 1972 (in 1988, 1997 and 1998 each of the fuel-oil units was changed to natural gas; It is currently building another natural gas-fired CHP plant). Mitte, 440 MW electricity and 680 MW_{th} heat, Berlin, 1996. Niederau, 8.3 MW electricity and 72 MW_{th} heat, North Rhine-Westphalia (operated by Nuon, owned by Vattenfall since 2009). Oberbruch, 22 MW electricity and 92 MW_{th} heat, North Rhine-Westphalia (operated by Nuon since 2000, owned by Vattenfall since 2009).
Pumped-storage hydro	Geesthacht, 119 MW, Schleswig-Holstein, 1958. Goldisthal, 1053 MW, Thuringia, 2003/2004. Hohenwarte I, 63 MW, Thuringia, 1942 (enlarged in 1959). Hohenwarte II, 317.8 MW, Thuringia, 1966. Markersbach, 1046 MW, Saxony, 1979 (last upgrade in 2007/2008). Niederwartha, 119.4 MW, 1930 (only two machines operating since 2001).
Waste	Rugenberger Damm, 24 MW electricity and 146 MW_{th} heat, Hamburg, 1999 (55% owned by Vattenfall and 45% owned by the city of Hamburg). Rüdesdorf, 30 MW electricity and 118 MW_{th} heat, Brandenburg, 2009 (also biomass).
Hard coal	Moabit, 140 MW electricity and 240 MW_{th}, Berlin, 1900 (multiple upgrades; the latest in 2013 added biomass use). Moorburg, 1,548 MW electricity, Hamburg, 2015. Reuter, 160 MW electricity and 331 MW_{th}, Berlin, 1930 (rebuilt in 1948, CHP since 1956 and allows use of pellets). Reuter West, 564 MW electricity and 758 MW_{th}, Berlin, 1987. Tiefstack, 564 MW electricity and 758 MW_{th}, Hamburg, 1987. Wedel, 260 MW electricity and 423 MW_{th}, Schleswig-Holstein, 1961 (CHP since 1987, upgraded in 1991).
Lignite	Klienberg, 164 MW electricity and 1,010 MW_{th}, Berlin, 1927 (upgraded in 1970 for CHP, also allows use of natural gas; there are plans to replace the use of lignite).

Source: Authors, based on Vattenfall (2017d).

In 2015 Vattenfall opened the DanTysk offshore wind farm (North Sea), 288 MW, and the thermal coal-fired power station of Moorburg (Hamburg), 1,654 MW. Moorburg is a latest-generation power station with two thermal units with an efficiency rate of 46.5%, higher than the 41% average of hard-coal thermal power stations. Nonetheless, one of the possibilities being planned by Vattenfall is to sell this power station within a period of 5 years, as it has already done with several open-cast mines (Jänschwalde, Nochten, Reichwalde and Welzow-Süd) and lignite-fired power stations (Boxberg, Jänschwalde, Schwarze Pumpe and half of the Lippendorf station) to the Czech group EPH (*Energy a průmyslový holding, a.s.*) (Ringstrom, 2016). The last power station in the area owned by Vattenfall (figure 89), Jänschwalde, with two 500 MW units, will be transferred to the capacity reserve between 2018 and 2019, prior to its subsequent closure four years later.

FIGURE 89. Lignite mines and power stations sold in 2016 by Vattenfall or which have been transferred to the capacity reserve



Lignite production	60-65 Mio. tonnes/year
Installed power plant capacity	7,595 MW net
Jänschwalde	2,790 MW
Schwarze Pumpe	1,500 MW
Boxberg	2,430 MW
Lippendorf R1 (Vattenfall share)	875 MW
Electricity generation	approx. 55 TWh/year

Source: (Vattenfall, 2017d).

The Brunsbüttel and Krümmel nuclear power stations were switched off in 2011 and according to Vattenfall, provisions for their closure came to €3.2 billion. Both are partially owned by Vattenfall (67% -33% E.ON- and 50% -50% E.ON). It also holds 20% of Brockdorf (80% E.ON), which is scheduled to close down by 2021. Although the situation is different in Sweden, Vattenfall has also announced the early closure of two of its nuclear power stations, Ringhals 1 and 2, between 2019 and 2020, as opposed to a scheduled closure date of 2025. The remaining power stations will continue on schedule, remaining in operation until 2040-2045.

For the future, Vattenfall is developing business models within decentralised generation in Germany and future changes in the flexibility management and network stability. It is also installing small-scale CHP plants and heat storage and selling household solutions in Germany. This boost to renewables is backed by the Swedish government, which has stipulated that state companies must serve as sustainable business models.

In addition, the Sandbank offshore windfarm in the North Sea, may be enlarged to a capacity of 500 MW. In this area, Vattenfall wants to be a leader in the development and operation of windfarms in north-western Europe, having also added in 2015 three new onshore plants in the UK, Denmark and Sweden and extended an offshore wind farm in the UK (Vattenfall, 2017d). In terms of power distribution in Germany, Vattenfall is the market leader in Berlin (it sold its distribution network in Hamburg); in gas distribution it is the market leader in Berlin and Hamburg.

EnBW

EnBW (*Energie Baden-Württemberg AG*) is a German company whose main activities are in the industries of electricity, gas, water and energy-related products and services. In 2016 it serviced a total of 5.5 million customers. Its main centre of activity is the region of Baden-Württemberg, where its subsidiary TransnetBW operates the power transmission system (EnBW, 2017c) and where most of its 18,923 employees (2016) are based.[122]

In 2016 it supplied 43.2 TWh of electricity and 52.3 TWh of gas. Electricity generation came to nearly 53 TWh. By sources, most of its generation came from nuclear power stations (25 TWh), and thermal stations (21 TWh). Its main renewable source was hydroelectricity, with 1 TWh from pumped-storage stations and 5 TWh from run-of-river. Other renewables contribute around 2 TWh. In 2016, its generation was down on the previous year, due to a decline in generation from nuclear (4 TWh) and hard coal (2 TWh) which has been partially offset by an increase in generation from gas (2 TWh).

Profit before taxes from total sales (also including management of different transmission and distribution networks) came to €19,368 million, down 8.5% on the previous year (€21,166 million). The group had final losses of €1797.2 million compared to profits in the previous year of €158.2 million. Trends in EnBW's share price are shown in figure 90.

FIGURE 90. EnBW share price (2010-2016)

Source: Authors, based on Google Economics.

Just as most of its business is in the region of Baden-Württemberg, most of EnBW's power stations are also in this region. Nonetheless, it also has power stations in other regions of Germany, in the Baltic Sea and abroad: Czech Republic, Switzerland and Turkey.

At the beginning of 2017 EnBW had power stations installed in Germany (see Table 30 and Figure 91).

[122] In 2015 it had a workforce of 18,763 (full-time equivalents).

TABLE 31. EnBW's installed capacity by technology/generating fuel in 2017

Technology /fuel	Installed capacity
Biomass	EnBW operates and produces gas for a set of five power stations, three owned by the company, with maximum output of 160 GWh.
Onshore wind	A set of twenty-five farms in Baden-Württemberg with total capacity of 41.2 MW.
Offshore wind	EnBW Baltic 1, 48.3 MW, Baltic Sea, 2011. EnBW Baltic 1, 288 MW, Baltic Sea, 2015.
Natural gas	Marbarch, 413 MW electricity and 320 MW_{th}, Baden-Württemberg, 1943 (a gas-fired turbine and another fuel-oil-fired one).
Pumped-storage hydro	Glems, 90 MW, Baden-Württemberg, (68 MW pumped-storage). Rudolf-Fettweis-Werk, 68 MW, Baden-Württemberg, 1914-1926 (20 MW pumped-storage).
Run-of-river hydroelectric	Upper Rhine, 333 MW, Baden-Württemberg, 1898 (complete remodelling of the first power station in 2010). Iller, 47.0 MW, Baden-Württemberg, 1923 (latest power station in 1996). Neckar, 3.9 MW, Baden-Württemberg, 1923 (latest power station in 2011).
Nuclear	Neckarwestheim 2, 1,305 MW, Baden-Württemberg, 1989 (shut-down planned for 2022; Neckarwestheim 1 closed in 2012). Philippsburg 2, 1,392 MW, Baden-Württemberg, 1984 (shut-down planned for 2018; Philippsburg 1 closed in 2012).
Geothermal	Bruchsal, 0.5 MW. Soultz-sous-Forêts, 1.5 MW
Waste	Stuttgart-Münster, 184 MW electricity and 447 MW_{th}, Baden-Württemberg, 1908 (one waste/coal-fired unit and another natural gas-fired unit; latest upgrade in 2007).
Hard coal	Altbach/Deizisau, 1,215 MW electricity and 280 MW_{th}, Baden-Württemberg, 1950 (first plant built on the site in 1899; the two present units were installed in 1985 and 1997; there are also 3 gas turbines and a diesel unit in the reserve). Heilbronn, 1,010 MW electricity and 320 MW_{th}, Baden-Württemberg, 1923 (latest upgrade in 2009). Rheinhafen, 1,815 MW electricity and 440 MW_{th}, Baden-Württemberg, 1955 (the latest group was installed in 2014; it has some natural gas/fuel-oil units in reserve). Stuttgart-Gaisburg, 194 MW electricity and 273 MW_{th}, Baden-Württemberg, 1950 (one coal-fired unit on a fluidised bed and another gas-fired unit; a third unit in reserve). Walheim, 391 MW electricity, Baden-Württemberg, 1964 (recommissioned in 2005; the natural gas-fired turbine is not in operation).
Solar	A set of eight farms in Baden-Württemberg with total power of 29.3 MW.

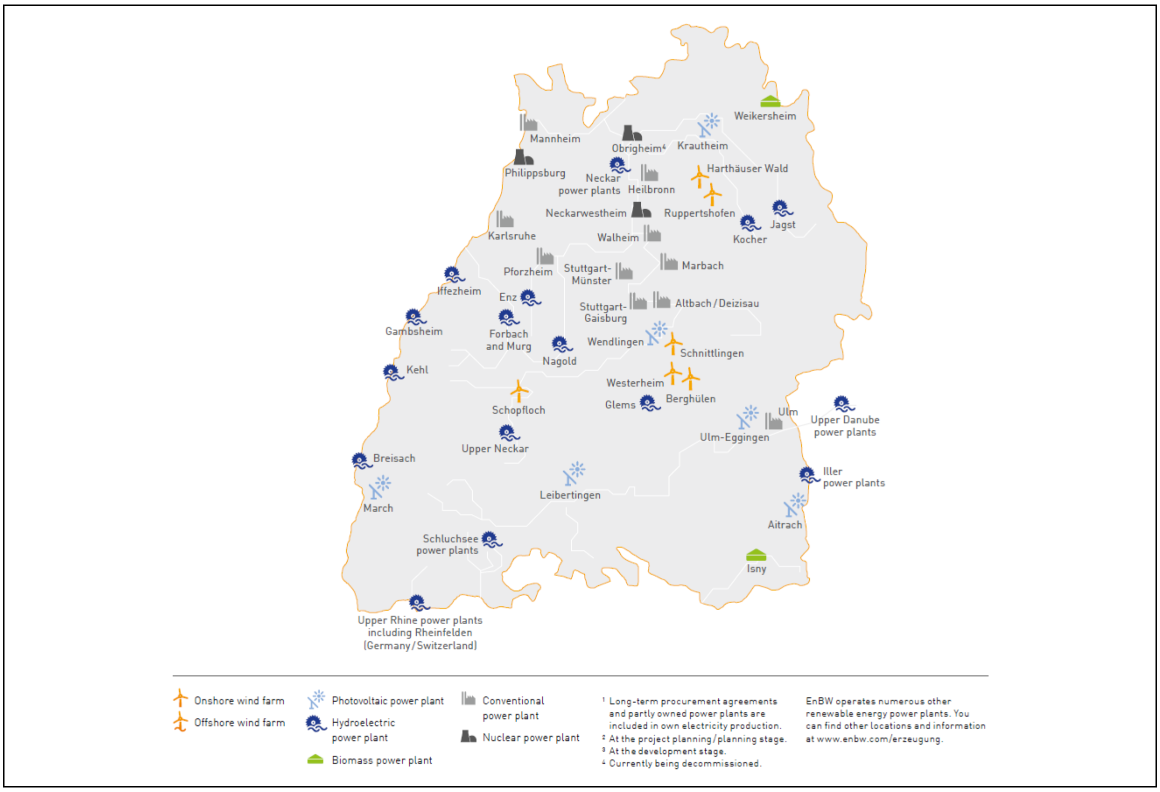
Source: Authors, based on EnBW (2017a).

EnBW also has holdings in the following power stations: Lippendorf (lignite, Saxony), Rostock (hard coal, Mecklenburg-Vorpommern), Fernwärme (biomass, Hesse), Mannheim (hard coal, Baden-Württemberg) and Stadtwerke Düsseldorf (natural gas, North Rhine-Westphalia).

Prior to the closure of nine nuclear power stations in 2011, in 2008 EnBW had closed the Obrigheim station, the first pressurised-water power station in West Germany.

EnBW currently has, either planned or under construction, three offshore wind farms, twenty onshore wind farms in Baden-Württemberg and eleven outside the region, four onshore photovoltaic farms planned or under construction in Baden-Württemberg and two in Rhineland-Palatinate.

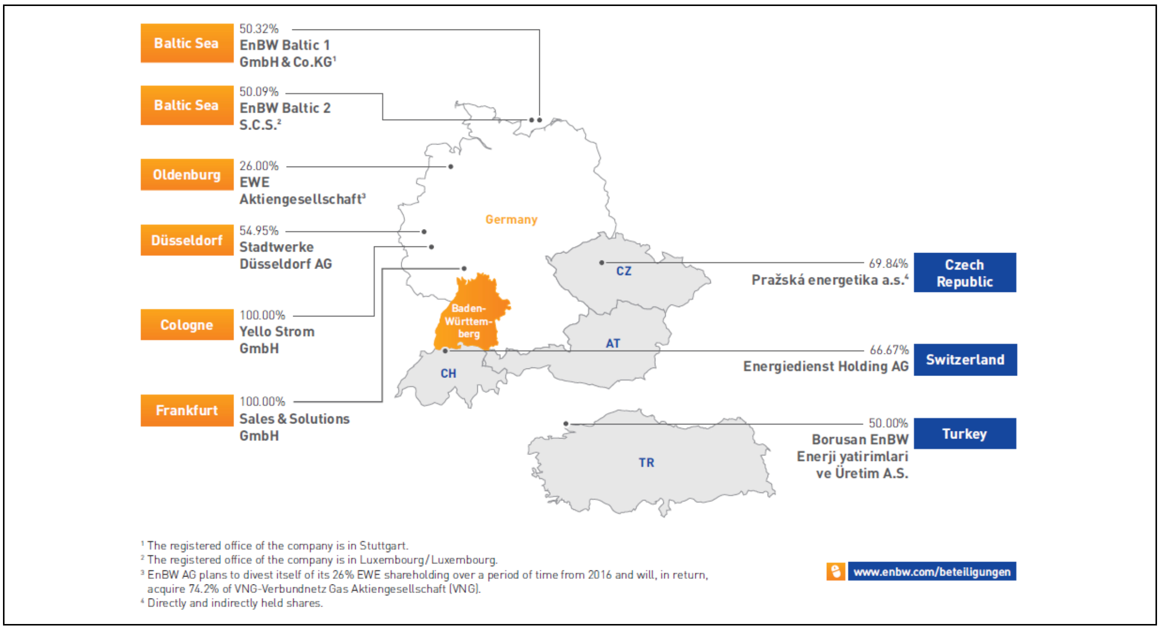
FIGURE 91. EnBW's main facilities in Baden-Württemberg



Source: EnBW (2016a).

It also has facilities outside Baden-Württemberg, as shown in Figure 92.

FIGURE 92. EnBW's main facilities outside Baden-Württemberg



Source: EnBW (2016a).

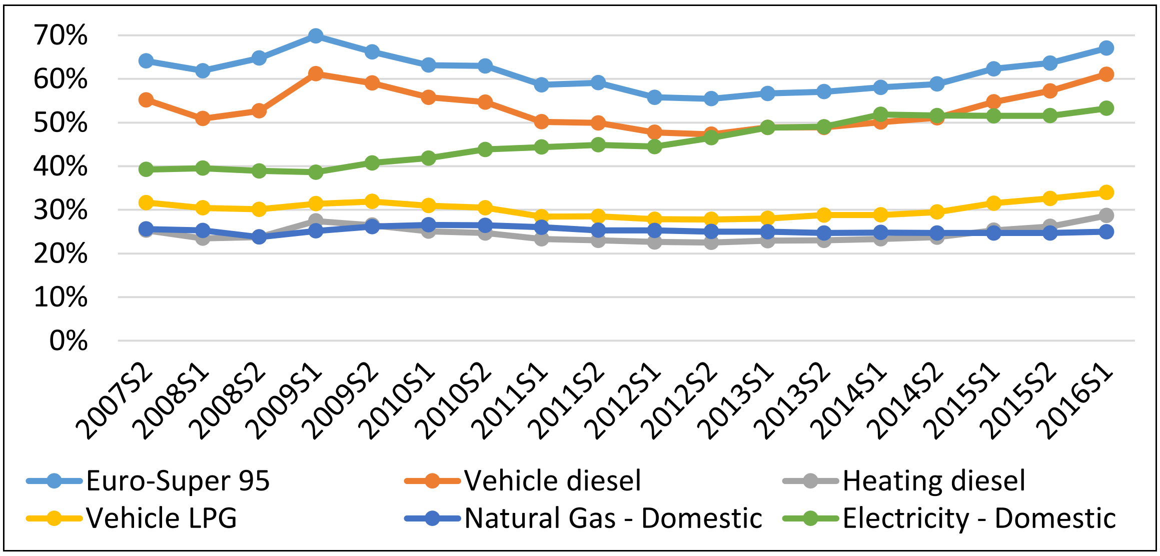
As part of its actions to adapt to the *Energiewende*, in 2016 EnBW began an advertising campaign to publicise its compliance with *Energiewende* goals and improve the company's image. The campaign was based on five points: investment in renewables, particularly offshore wind; distributed generation, with household products developed by EnBW; safety and reliability, building and modernising the networks to prevent bottlenecks; quality service, including options to contract tariffs for 100% German-generated renewables; and innovation.

APPENDIX 12. BRIEF NOTES ON SOME ISSUES RELATED TO TAX ON ENERGY

The German government's *Strom 2030* (Electricity 2030) document identifies twelve industry trends, the first of which is that the future power system will be shaped by intermittent generation (especially from the wind and sun). It notes that the current structure of surcharges and levies (and taxes) hampers flexibility of the system and identifies as the first barrier the fact that more surcharges, grid charges and levies are placed on electricity for the financing of the energy transition than on fuels, particularly for heating.

In this regard, it is worth noting that the percentage of taxes, surcharges and levies on electricity in Germany is among the highest on any energy source, next to petrol and diesel for vehicles (figure 93).

FIGURE 93. Tax rate for different household consumption energy sources in Germany



Note: the prices of Euro-Super 95, motor diesel and motor LPG given are prices at the pump; the price of heating diesel is for a supply of 2,000 – 5,000 litres; the price of household natural gas is for consumption of 20 – 200 GJ/year (5.56 – 55.56 MWh/yr) and household electricity is for 2.5 – 5, MWh/yr. The tax rate for industrial consumption is similar to the household rate, although the final prices are higher in household consumption because the price before taxes and levies is lower.

Source: Authors, based on figures from Eurostat and the Oil bulletin of the European Environment Agency.

According to a study by Agora on a new energy pricing model, in absolute terms there is a considerable imbalance in that taxes, levies and surcharges on one kWh for heating diesel come to 0.6 eurocent, 2.2 for natural gas, 4.7 for motor diesel, 7.3 for petrol and 18.7 for electricity (Podewils, 2017). This study includes non-tax levies, with cost items such as network access charges, land concessions and invoicing costs among others (Agora Energiewende., 2017). It also includes the EEG surcharge[123] and

[123] For further information, see Section 3.2.3.

the surcharge for the emission allowances acquired. However, it does not include value added tax.

Our own estimate,[124] covering only the tax burden[125] on the different energy sources in Germany, shows that in reality, there are fewer differences; although household consumers pay higher taxes on electricity than on motor fuels for example (€112 per MWh compared to €94.26 per MWh on petrol and €65.49 per MWh on diesel), the same is not true of industrial consumers who pay €59.50 per MWh in taxes for their electricity consumption.

In any case, natural gas for heating for household consumers and motor LPG have a much smaller tax burden (€6/MWh and €20.40/MWh respectively) than electricity, petrol and motor diesel.

If these figures are viewed from the perspective of the energy price for the final use, thus taking into account the efficiency of the equipment (around 30% in the case of internal combustion engines as compared to roughly 90% for electric vehicles), the tax burden for the same use of energy would be more than twice as much for petrol (€314.19 per MWh) and nearly twice as much for motor diesel (€218.29 per MWh) as for household electricity (€124.44 per MWh), while the figure for LPG (€67.9 per MWh) and electricity for industrial usage (€66.11 per MWh) would be similar. Again, natural gas has a much lower burden, around €4.5 and €6.7 per MWh depending on the consumer (household or industrial).

Given the above, one of the main challenges facing the energy transition in Germany is the restructuring of taxes and levies. It is also considered necessary to restructure the way in which renewables are financed (Robinson, Keay, & Hammes, 2017).

As can be seen from the figures above, the restructuring of taxes, levies and surcharges in Germany will depend on the approach considered: the energy price for use, or the price actually borne by the consumer in final energy use.

[124] Calculations based on Eurostat data, recent rates and conversion factors established by the European Commission. In the case of electricity and gas, figures are broken down by special taxes (excise duty), VAT and others. In the case of petrol, diesel and LPG, it has only been possible to give separate figures for VAT and special taxes (excise duty).
[125] Includes 19% VAT.

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