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Electricity market developments and key policy changes 2007–2016

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Brief summary

This paper provides an overview of the key power market and energy policy developments in the UK, Germany and Sweden between 2007 and 2016. It covers electricity demand, generation and capacity, trade, prices and system costs for each country as well as a description of the key policy developments affecting the electricity market for each country. In addition, it provides a description of the key elements of the energy and climate policy packages introduced by the EU in 2007-2009 and documents how subsequent power market price developments deviated from the expectations that were prevalent at the time.

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THEMA Consulting Group is a Norwegian consulting firm focused on Nordic and European energy issues, and specializing in market analysis, market design and business strategy.

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CONTENT

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1 INTRODUCTION

This working paper is part of the REMAP project (see box 1) and provides as a descriptive overview of key power market and energy policy developments following the implementation of the 3rd energy package for the EU as well as United Kingdom, Sweden and Germany.

Developing efficient integrated energy markets based on sound market principles has been a prioritized goal for the EU since the mid-1990s. The long-term task is to transform a monopolized, regulated and disintegrated energy sector into a market-based integrated system, the Internal Electricity Market (IEM), by a stepwise introduction of market design rules consistent with the principles of competitive electricity markets. The so-called energy packages[1] and the Energy Union, introduced in 2016, have been designed to achieve this objective.

The REMAP project studies the dynamic interaction between policies and markets. This paper thus serves as a background document, describing the key market developments that followed after the proposal of the third energy package in 2007, focussing in particular on the extent to which market developments deviated from the expectations at the time when the package was proposed, as well as the developments in national energy policies in the REMAP core countries. The mainly descriptive material in this paper serves as an important information basis for the project.

Boks 1: About REMAP

REMAP is a research project carried out by the Fridtjof Nansen Institute and THEMA Consulting Group in partnership with four associated researchers and seven industry partners. The REMAP project analyzes EU Energy Union Reform and impacts on Norway's energy policy strategy. The project, which runs over the period 2018-2021, is jointly funded by the Norwegian Research Council and the projects industry partners.

The main research question is: How are reformed IEM/renewable energy policies likely to affect Norway's ability to pursue its market- and trade-based energy policy strategy?

In line with this main objective for the project, three main research tasks will be conducted in parallel workstreams in the project:

- Assess and explain the output of the IEM/renewable energy reform policies in the Clean Energy for all Europeans package, based on policy and market feedback.
- Assess and explain energy-policy developments in selected EU member states in response to the Clean Energy for all Europeans package.
- Analyse how the reform will impact Norway's energy strategy.

The project offers new approaches to explaining EU energy-policy reform; and how this impact national policies in several countries, with subsequent effects on Norway's room for maneuver regarding its energy policy strategy. More information and results from the project can be found here: https://www.fni.no/projects/remap

[1] The first package, the 1996 Electricity Market Directive (96/92/EC) set out common rules for the internal market in electricity, and was the first step towards an open, common European electricity market. The second package, adopted on 26 June 2003, included Electricity Market Directive II (2003/54/EC) setting minimum requirements and deadlines for opening the market to industrial and household customers and for ensuring a vertical separation of transmission from generation and trading activities and containing rules on consumer protection. Also included was the regulation on cross-border electricity trade (Regulation (EC) No 1228/2003), intended to stimulate cross-border power trade, and a framework for further harmonization of the principles for the use of cross-border transmission capacity between countries, and the basis for establishment of the inter-transmission system operator compensation mechanism (ITC) (Regulation (EU) No 774/2010). The EU's third energy market package was adopted on 13 July 2009 and consists of five legislative acts. Four of these amended existing legislative acts: Electricity Market Directive III (2009/72/EC), Gas Market Directive III (2009/73/EC), Cross-Border Exchanges Regulation II (Regulation (EC) No 714/2009) and Gas Transmission Regulation II (Regulation (EC) No 715/2009). The fifth is Regulation (EC) No 713/2009, which lays down new rules establishing the Agency for the Cooperation of Energy Regulators (ACER). (More information can be found at https://energifaktanorge.no/en/eu-lovgivning/sentrale-direktiver-pa-energiomradet/)

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The paper is structured as follows: In chapter 2, we describe the state of play for European energy and climate policies as the 3rd energy package and the EU's climate policy towards 2020 was implemented in 2007-2009. In chapter 3, we describe the development of power prices in the period 2007–2016 and subsequently compares the development of different power price drivers and market shocks relative to market expectations at the time. In chapters 4-6, the key power market and policy developments between 2007-2016 for the UK, Sweden and Germany.

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2 BACKGROUND - ENERGY AND CLIMATE POLICIES 2007-2009

At the outset of the period that is analysed in this paper, the EU introduced and implemented two policy packages with important implications for power market developments – the 3rd energy package and the 2020 climate and energy package. The 3rd energy package aimed at bringing the EU closer to an efficient and integrated power market, the IEM, according to a market design model sometimes referred to as the 'target model'. The Climate and energy package introduced targets for emission reductions, energy efficiency and share of renewable energy, which indirectly had a considerable impact on the development of the European power markets.

2.1 The 3rd energy package

From 1996 to 2009, the European Commission gradually developed the framework and principles for the internal energy market (IEM) through three energy packages, i.e. Directives 96/92/EC, 2003/54/EC and 2009/72/EC. The legislative package from 2009, i.e. "The third Energy Package" set objectives for 2015, including to ensure optimal use of transmission network capacity, reliable prices and liquidity in the day-ahead market, and efficient forward and intraday markets. According to Hancher and Salerno (2017), a sector inquiry and the Commission's assessment of the first and second packages had identified the need to:

- Strengthen competition through better regulation, unbundling and reduction of asymmetric information,
- Enhance security of supply by improving the incentives for adequate investments in transmission and distribution capacities; and
- Improve consumer protection and prevent energy poverty.

The 3rd package, consisting of two directives and three regulations[2], aimed to address the shortcomings in previous legislation and to complete the internal energy market. While the 2nd Energy Package enabled industrial and domestic consumers to choose their own gas and electricity suppliers freely, the 3rd Energy Package further required effective unbundling between production and supply of energy. Additionally, it required stronger independence of national regulators to enforce a stringent application of market rules and should ensure cooperation between the entities to promote competition, the opening-up of the market and a secure and efficient power system.

It also set up three new co-ordinating bodies: The Agency for the Co-operation of Energy Regulators (ACER), and the two European Networks of Transmission System Operators for electricity and gas (ENTSO-E and ENTSO-G). The new institutions, which serve to improve cooperation between national regulators and system operators, were granted decision-making powers such as the development of Network Codes. The Network Codes set technical and commercial requirements governing the access to energy networks and aim to support the standardisation of trade between member states in order to spur efficient trade and investment in cross-border network capacity.

Further stress was put on achieving consumer protection via open, fair and competitive retail markets, e.g. through simplified supplier switching processes and increased market transparency.

[2] Directive 2009/72/EC concerning common rules for the internal market in electricity, Directive 2009/73/EC concerning common rules for the internal market in gas, Regulation (EC) No 713/2009 (…) establishing an Agency for the Cooperation of Energy Regulators, Regulation (EC) No 714/2009 conditions for access to the network for cross-border exchanges in electricity and Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks

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2.2 The climate and energy package

In 2009, another key policy package with considerable impact on the European power market entered into force: the 2020 climate and energy package. The key policy targets in the package is colloquially known as the 20-20-20 package, whereby the EU should:

- Reduce greenhouse gas emissions by 20 percent compared to 1990-levels by 2020
- Increase the share of renewable energy to at least 20 percent of consumption by 2020
- Achieve energy savings of 20 percent by 2020

The two key measures for achieving the emission reduction target were the EU Emissions Trading Scheme (ETS) and the Effort Sharing Decision (ESD). The ETS served as the key tool for achieving emissions reductions in the power and industrial sectors, while emissions from other sectors were limited by national emission reduction targets under the ESD. The two measures are fundamentally different in structure and governance. While the first relies on a cap-and-trade mechanism where the cost of emissions are determined by the demand for emission permits from power plants and industry and a gradually falling annual supply of such permits, the latter sets binding emission reduction targets for each member state leaving it to national governments to develop policies to ensure the needed reductions.

For the power sector, which is the key focus of this paper, the ETS price level is important for the market development as it affects the relative profitability of different power production technologies. The more the carbon a power production technology emits, the more will the ETS price affect marginal production costs. In the European power markets, this has two key implications:

- In the short run, a higher ETS price means that coal power plants are replaced by gas power plants.
- In the longer run, a higher ETS price increases the competitiveness of low-carbon production technologies, such as wind and solar power.

The renewable energy target was split up into binding, national targets, considering i.a. the current share of renewable energy and relative wealth of each Member State. State aid rules were adapted to ensure that Member States could subsidise build out of renewable energy sources in order to reach their renewable targets.

Importantly, given the scope of this paper, is that these two efforts – subsidising renewable power generation and increased the cost of fossil power production through the ETS – overlap. As renewable energy generation was increased through subsidies, fossil fuel plants were pushed out of the market, reducing their annual emissions and hence their demand for EUAs, putting downwards pressures on the ETS. Introducing binding renewable energy targets to be achieved through state aid, thus reduced the relative importance of the ETS to achieve decarbonisation of the power sector.

The 2020 climate targets are not the core focus in this paper, but their implementation strongly affected developments in the power market and as such the dynamics between market functioning and market design and regulation. Although the adoption of the 20-20-20 targets were closely followed by the 3rd energy package in 2009, Hancher and Salerno (2017) argue that the co-ordination between the two policies was far from optimal. In particular, the three objectives of competition, carbon reductions and energy security did not turn out to be mutually reinforcing.[3]

[3] One could argue that the "packaging" of both climate policies and electricity market design in the Clean Energy Package in 2016 indicates a recognition of the need for coherence between climate and energy policies and market design that was lacking in 2009.

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3 POWER MARKET DEVELOPMENT AND EXPECTATIONS 2007-2016

This chapter sets out to describe the development of power prices in the period 2007–2016 and subsequently compares the development of different power price drivers and market shocks relative to market expectations at the time. The chapter serves to demonstrate whether and how market developments deviated from expectations in terms of fuel cost, CO_2 prices, capacity and demand developments.

3.1 Summary

Over the past decade the European power sector has undergone radical changes, the effects of which were uncertain at the time when the 3rd energy package was developed. The changes include increasing shares of renewable energy, decentralised production and self-consumption, and technology changes. In addition, there were considerable uncertainty relating to key drivers for European power prices such as coal, gas and CO_2 prices as well as demand for electricity.

We find that the power market development after the implementation of the energy and climate packages was strongly affected by the financial crisis and its impact on the CO_2 price. As industrial demand fell, a large surplus of emission allowances built up, and the CO_2 price fell accordingly. Over the same period, the EU saw a strong increase in the build-out of renewable energy sources, driven by national subsidy schemes implemented in order to fulfil binding renewable targets for 2020. The combination of reduced demand growth and a subsidy-driven increase in renewable power generation implied that an expected switch from coal to gas power generation was not needed to keep emissions below the ETS cap. As it turned out, the ETS did not prove crucial for the energy transition. The low CO_2 price, combined with falling coal prices, contributed to a gradual fall in wholesale electricity price in key European markets from 2011 to 2016.

In addition, the strong growth in relatively cheap shale gas led to a shift from coal to gas in the US, leading to falling coal demand. New coal production and export capacity, particularly in Australia and Indonesia, added to a the downwards pressure on the coal price. A falling coal price further added to a falling wholesale power price in the EU in the years leading up to 2016. The Nordic price closely followed the short-term marginal cost of coal generation (SRMC), generally slightly below German prices, but that German and Nordic prices seem to converge towards the end of the period.

The low CO_2 and power prices combined with an outlook were more renewable capacity was built due to subsidy schemes lead to a situation where investment in new, conventional capacity was unprofitable. While the total capacity increased, most of the increase was in the form of intermittent, renewable power sources such as wind and solar power plants.

3.2 Wholesale power price development

3.2.1 Historic price development

The wholesale power price in the German and Nordic power markets from 2008 to 2016 can be seen in Figure 1. As can be seen, price levels drop considerably in 2008, rising somewhat until 2011 before it continually drops towards the end of the period. Figure 1 also illustrates the close relationship between the development of German and Nordic power prices and the short-run marginal costs (SRMC) of coal power in the period 2008–2016. This is due to coal having been the dominant price-setter in the power market.

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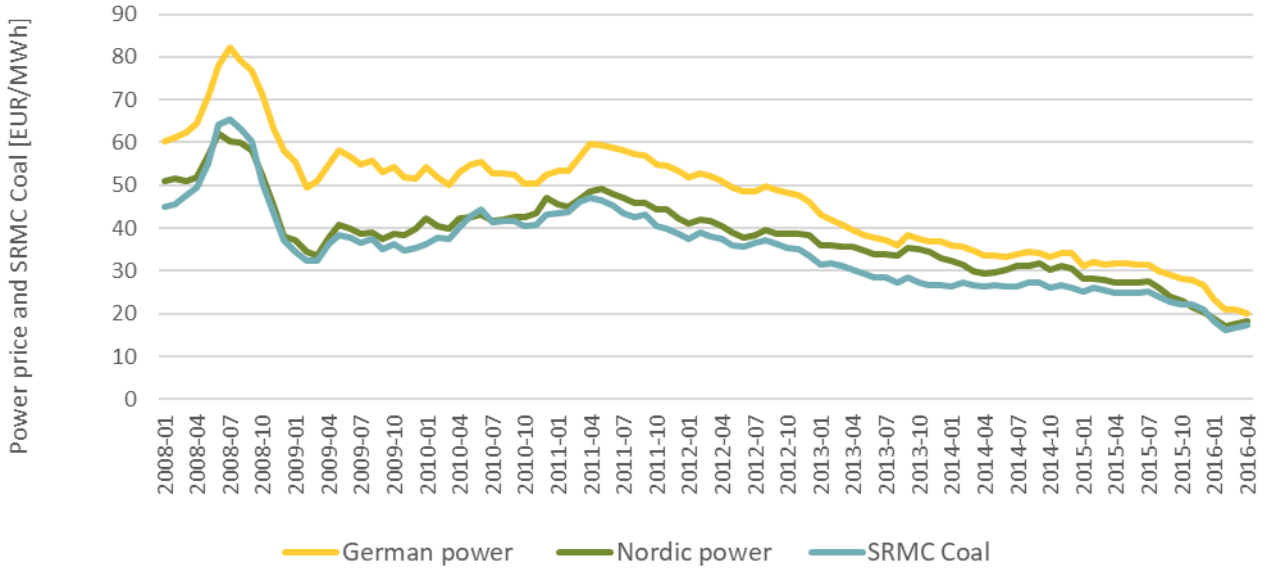
Figure 1: Power price and SRMC coal comparison 2008-2016



Note: Based on "month ahead" contracts. Source: THEMA Consulting Group 2016 – Workshop Nordic Power Market Spring 2016

Before the financial crisis hit Europe, average wholesale prices moved around a level of €65 per MWh. In the very first issue of the Quarterly Report on European Electricity Markets, covering Q2 2008, the Market Observatory for Energy (2008a) reported that wholesale electricity prices continued their upward movement along with a steep increase in the price of input fuels. In September 2008, the Platts Pan European Power Index reached an all-time high of €95.83 per MWh, beating the previous record from June 2008. Following the financial turmoil in the fourth quarter of 2008, the index plummeted by € 30 per MWh (the Market Observatory for Energy, 2008b; 2008c).

After a striking, albeit short, price peak with Nordic prices above 60 EUR/MWh and German prices above 80 EUR/MWh when the financial crisis started to impact commodity prices around the world in 2008, prices stabilised again slightly below their pre-crisis levels. In the period between 2009 and mid-2011 the Nordic market exhibited an increasing trend while the German price stayed between 50-60 EUR/MWh.

From mid-2011 to 2016, power prices gradually fell in both the Nordic and German markets. Nordic electricity prices fell to an average of 21 EUR/MWh in 2015, marking the lowest average spot price since 2000. Power prices then started to increase in 2016 and continued to do so in 2017, supported by higher coal and CO_2 prices.

3.2.2 Expected price development

The price forecasting made by THEMA in the relevant period can serve to illustrate how price expectations changed over time. The price forecasts are updated at least once a year and are based on what could be called a market consensus regarding underlying market price drivers such as fuel and CO_2 prices, demand forecasts, investment costs for new generation and other market framework conditions.

Figure 2 shows THEMA's long-term price prognoses for the Nordic market from 2011–2016. The prognosis from 2011 provided the highest expectations for the development of the Nordic system price throughout the period, driven by relatively high expectations for coal, gas and CO_2 prices. At the time, THEMA expected the power price to increase to 53 €/MWh by 2020.

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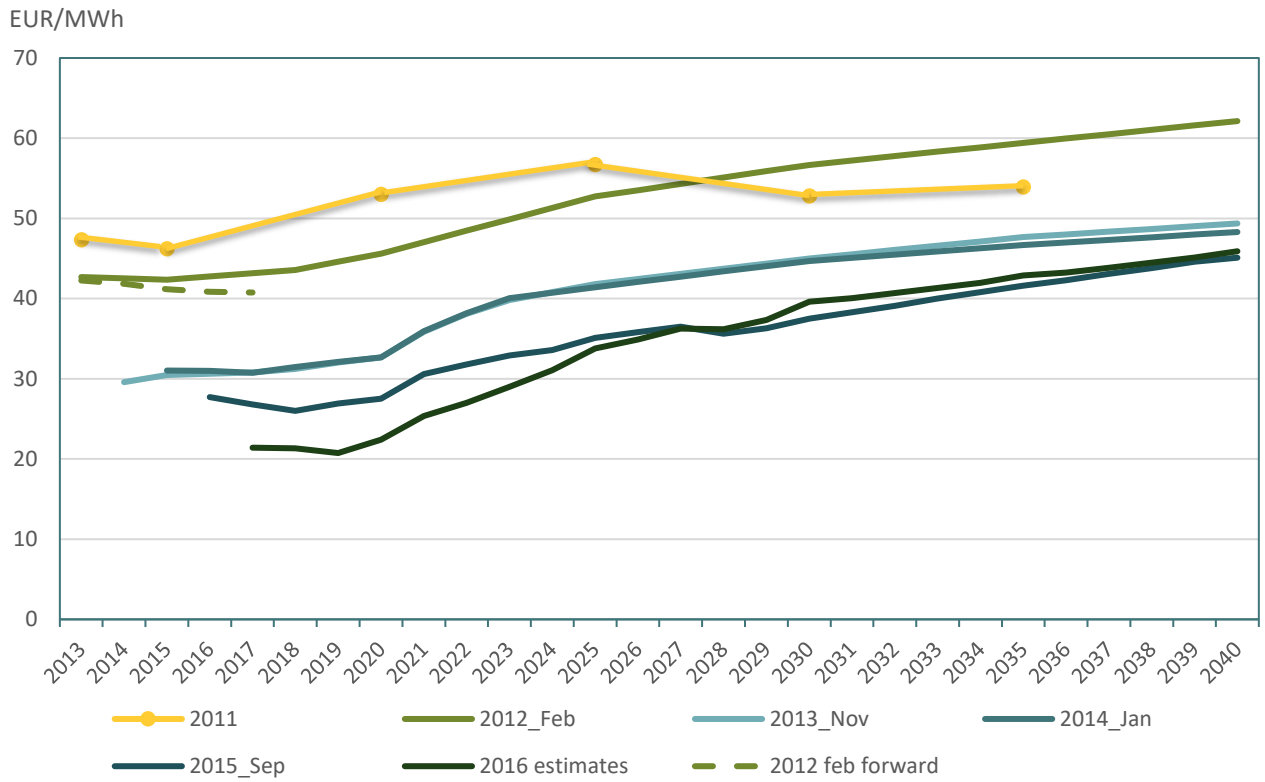
Figure 2: THEMA's historic price prognoses for the Nordic system price for the period 2013–2040



Source: THEMA Consulting Group, Nordic Power Market Forecasts

Two years on, in 2013, expectations for fuel and CO_2 prices were lower with a resulting depression in forecasted Nordic power prices towards 2020. This effect was further amplified by an expected significant strengthening of the power balance due to massive investments in subsidized renewable energy capacity in all the Nordic countries, combined with upgrades of nuclear capacity and a relatively low expected consumption growth rate. From 2011 to 2013 forecast, the expected market price for 2020 fell by €20/MWh, from €53/MWh to €33/MWh. In the subsequent years, price forecasts were revised further down, with the price prognosis for 2020 dropping to 22 €/MWh in the 2016 publication.

In comparison, the IEA (2012) expected wholesale electricity prices in the European Union to approach 100 USD (72 EUR) per MWh in 2020 before increasing towards 110 USD (80 EUR) per MWh in 2035.[4] The high expectations were largely due to an expected increase in the CO_2 price, which alone accounted for just under half of the increase in IEA's estimates (IEA, 2012). By 2015, the IEA had also revised down their long-term power price forecasts significantly, expecting the wholesale prices in the European Union to increase gradually to 80 USD (60 EUR) per MWh by 2040.[5]

3.3 Coal price developments

As illustrated in the previous section, the short run marginal cost (SRMC) of coal power has been the main price-setter for European power prices. The most important drivers for the SRMC are the price of CO_2 emission permits and the price of coal. In this section, we consider the development in coal prices and the price forecasts for coal between 2011 and 2016.

[4] The IEA (2012) applied an exchange rate of 0.72 EUR per 1 US Dollar
[5] The IEA (2015) applied an exchange rate of 0.75 EUR per 1 US Dollar

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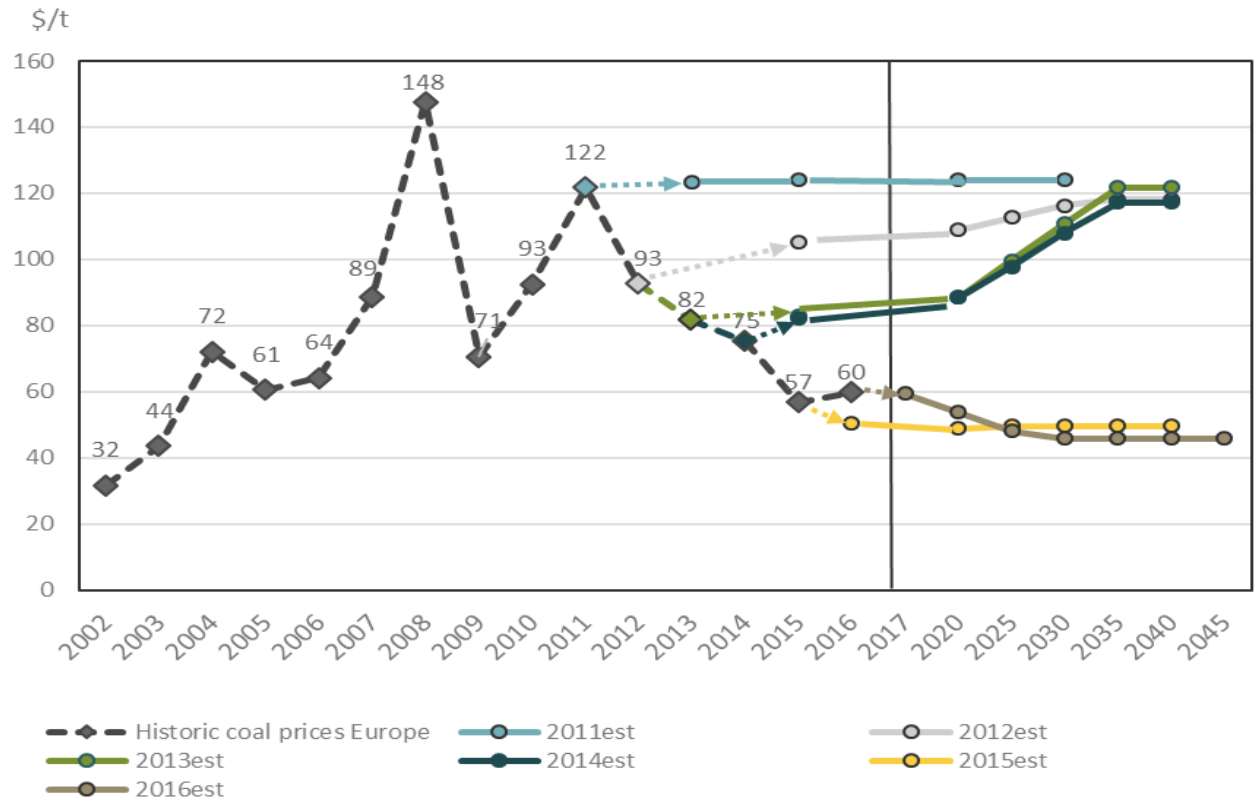
Coal prices have fluctuated significantly in the past two decades, as illustrated in Figure 3. In 2008, the coal price reached an all-time high of 148 $/t, marking an almost five-fold price increase from the price average of 2002. In the following year, the financial crisis caused the coal price to plummet to 71 $/t in 2009. It then climbed again to 122 $/t in 2011 in the wake of the Fukushima nuclear disaster.

The shale revolution in the US depressed gas prices and drove increased fuel switch from coal-fired to gas-fired power generation, leading to reduced global demand for coal and contributing to falling coal prices between 2011 and 2015. The fall in coal prices was further consolidated by increased supply of seaborne coal following significant investments in coal mine and port capacity in the period leading up to 2011, particularly in Australia and Indonesia. Despite increasing demand, especially from China and other fast-growing developing countries, supply kept outstripping it, leading to drastically falling coal prices since 2011.

The following gradual decline in coal prices towards a level around $60/t in 2016 was reflected in the power prices in the German and Nordic markets.

Figure 3: Historic coal price developments and expected long-term price developments



Source: THEMA Consulting Group - European power market forecasts, IEA World Energy Outlook 2018

3.4 Gas price developments

The price of natural gas affects the power market in the hours of the year where gas plants are the price-setters in the power market. Historically, the coal price has been the key price-setter in the German and, indirectly, the Nordic market, however, gas prices also has an impact on the power price.

Figure 4 shows the development of European gas prices between 2007 and 2016, as well as the expected price development assumed in THEMAs price forecasts from 2012 onwards. A similar pattern can be identified for gas as for coal. Price levels fell strongly in 2008, with a gradual increase towards 2013, when the prices started to fall. From 2012, expected price development tended to be higher than actual development.

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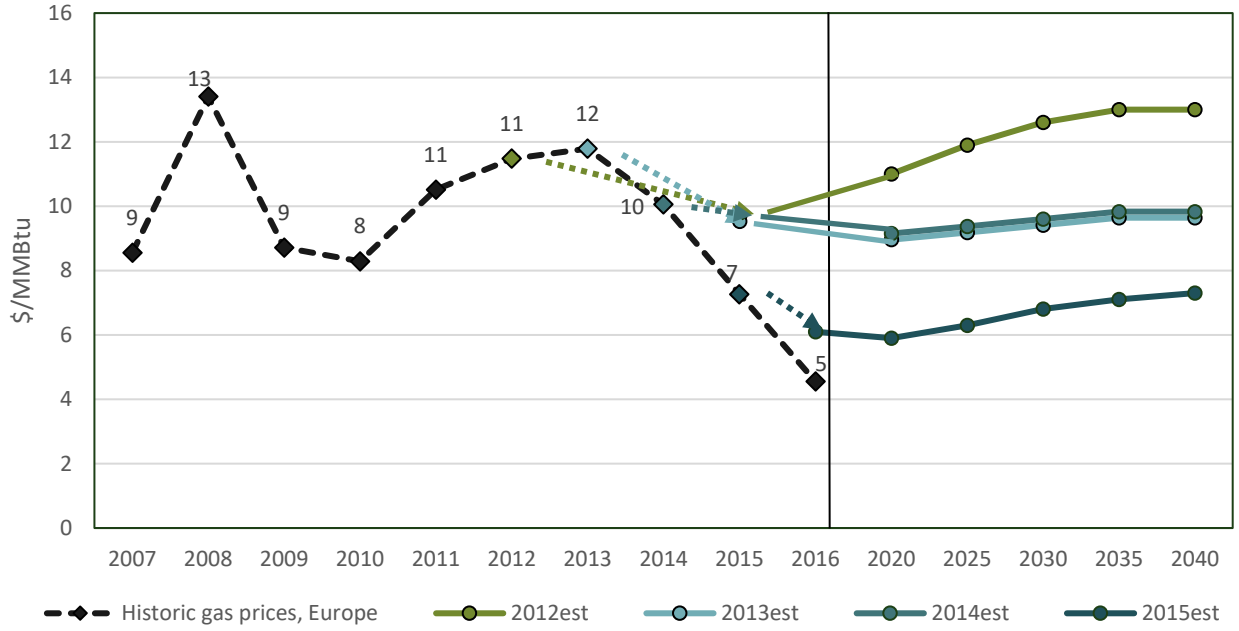
Figure 4: European gas prices and gas price forecasts, 2007–2016



Source: THEMA Consulting Group - European power market forecasts, IEA World Energy Outlook 2018

Whereas coal prices fluctuated heavily in the observed timeframe, gas prices remained more stable. Since 2010, the European gas market has been holding the middle ground between the high-priced Asian market and the low-priced American market (THEMA, 2015). The US gas market underwent a major transformation as the boom in shale gas production boosted overall gas supplies, discarding the anticipated need for the US to import LNG and driving down gas prices globally. Meanwhile, gas prices in Asia were pushed up by solid economic growth from major emerging economies such as China and India, but also increased Japanese reliance on LNG shipments after some of the country's nuclear reactors were shut down in the aftermath of the Fukushima disaster.

In 2015, forward gas prices exhibited a slight downward trend, which THEMA expected to cease around 2020 (THEMA, 2015). In line with the IEA, THEMA (2015) expected the global demand for gas to grow steadily towards 2040. Despite continuously strong supply growth from US shale, the IEA-coined anticipation of a "golden age of gas" implicated stable price trends as supply was expected to be met by strong demand growth, rather than the actual outcome of falling prices due to oversupply that manifested from 2013 onwards, as shown in Figure 4.

3.5 CO_2 price development

With weak global demand in the wake of the financial crisis, industrial lobbyists argued that a high European carbon price could hamper the competitiveness of European industry. While the 20-20-20 targets were maintained, several measures of the EU Emission Trading System were moderated before the EU climate package was adopted in December 2008 (BBC, 2008). In particular, full auctioning was delayed for industrial sectors at the risk of carbon leakage, including most of the processing industries, as well as for Central-European power producers, largely consisting of fossil-fired producers. Free allocation of permits should help to prepare energy-intensive industry for the changes and ease exposure to the ETS to lower fears of incurring competitive disadvantage globally. In addition, the package allowed for meeting a substantial amount of the emission cuts through international credits (Kyoto Mechanism). These provisions contributed to a large oversupply of Emission Allowances, which kept prices at low levels for the years to come.

As can be seen in Figure 5, CO_2 prices remained below 10 €/tCO_2 in the period 2011-2017, which was well below the levels expected before 2012. In 2011, the CO_2 price averaged 17 €/tCO_2 and forward markets expected the CO_2 price to reach 18€/tCO_2 by 2013 and 19 €/tCO_2 by 2015. THEMA

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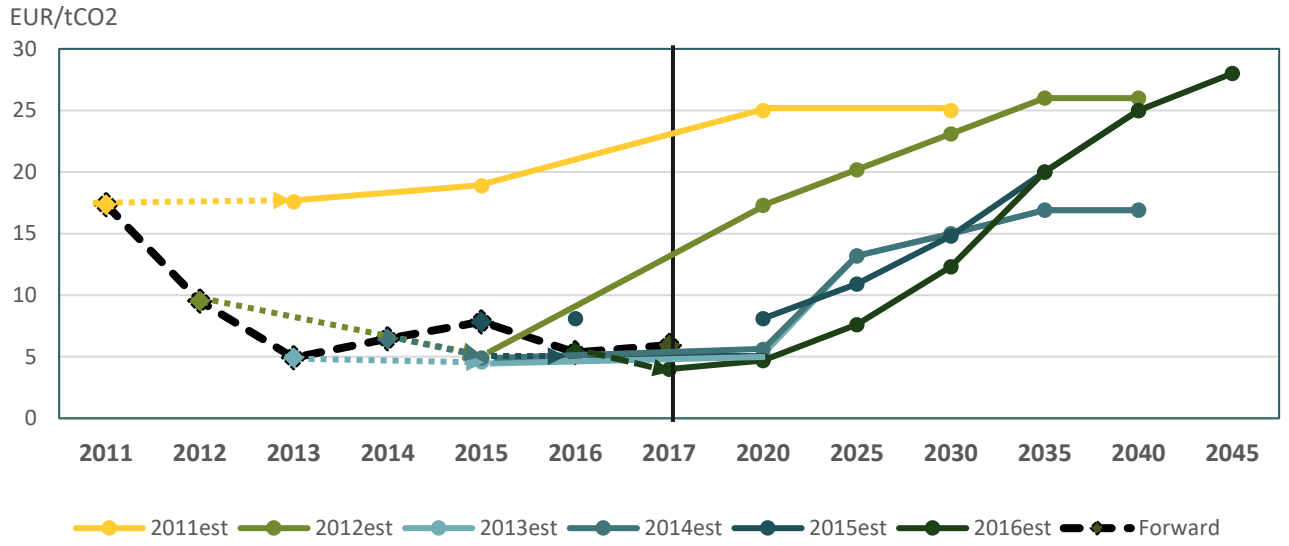
forecasted the CO_2 price to stabilize around 25 €/tCO_2 between 2020 and 2030, granted that the cap would be tightened somewhat towards 2020. At the time, several players expected that a new global climate agreement would ensure a tightening of the cap in the EU ETS.

Figure 5: Developments in EUA market prices and price expectations 2011–2017



Source: THEMA Consulting Group - European power market forecasts, IEA World Energy Outlook 2018

From June 2011 to January 2012 the CO_2 price plummeted from 17 €/tCO_2 to 7 €/tCO_2. The low prices reflected a vast oversupply of allowances in Phase II (2008–2012), which had been steadily increasing since 2009. Several factors have been attributed to the surplus of allowances, including the economic stagnation in the wake of the financial crisis, high imports of Kyoto credits and overlapping climate policies in the EU, in particular the ambitions for and support to renewable electricity generation. The low prices can be further explained by market players attesting regulators a lack of credibility. Since it had proven to be difficult to agree on common legislation to support a price increase beforehand, no adequate response was expected during the time.

After the EU ETS entered phase III in 2013 (2013–2020), low CO_2 prices prevailed, dropping below 4 €/tCO_2 in June 2013. The surplus that accumulated in the market due to the slump of the economy, less generation from fossil fuel-powered generation etc. reached its highpoint during that period, as can be seen in Figure 5. In January 2014, the European Commission put forward a legislative proposal for a Market Stability Reserve (MSR) and, in September 2015, adopted the decision to implement backloading as a short-term measure to postpone the auctioning of 900 million allowances until 2019-2020. The proposal might have restored some faith in the market, as the annual average price increased slightly to 6.5 €/tCO_2 in 2014. In 2016, the CO_2 prices again began to fall to an average of 5 €/tCO2, suggesting that traders had low expectations that the prevailing surplus in the EU ETS would be effectively removed. Over two years of negotiations on the specific design of the MSR and the backloading mechanism with some resistance against a final resolution led to generally subdued confidence in an incisive solution to depart from the low price levels. The achieved compromise failed to immediately instil assurance and thus still failed to have an effect. Only after a few months did the market react to the soon-to-be-introduced measures and prices drastically increased to levels of above 20 EUR/tCO_2.

Thus, as the CEP was developed and eventually published, the general impression was that of a CO_2 pricing mechanism that had contributed less than foreseen to the energy transition, in part due to the increase in RES generation driven by national support schemes.

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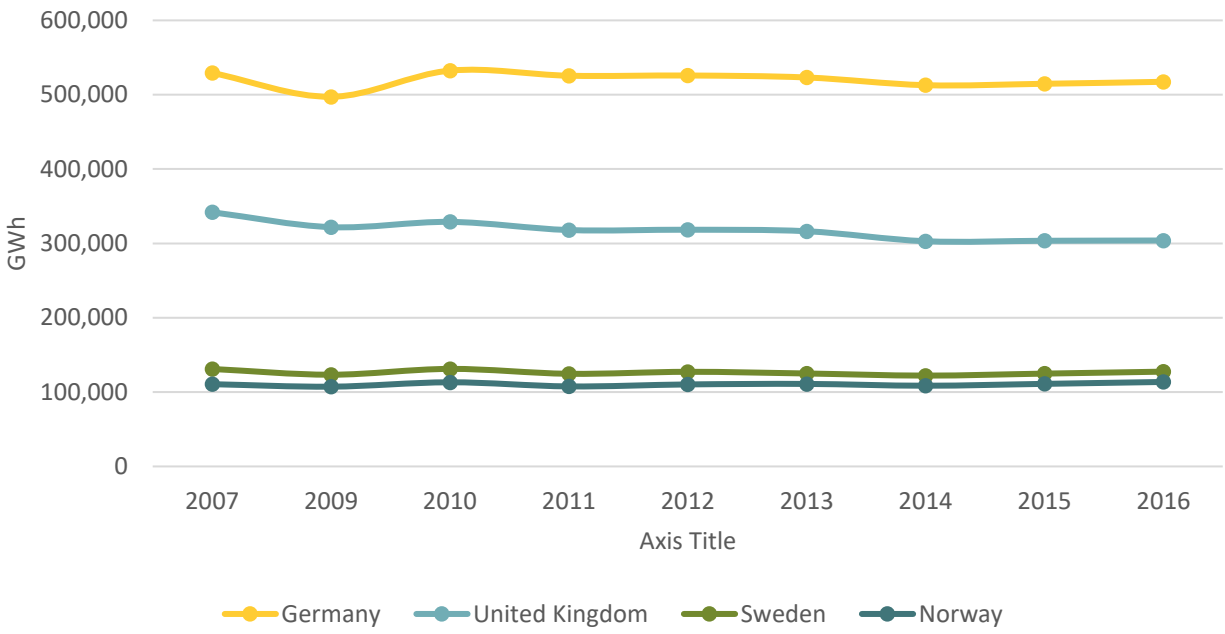
3.6 Demand side developments

Figure 6 illustrates how the development of the electricity demand has changed from 2007 to 2016. The financial crisis had a noticeable effect on the energy markets, as energy demand fell on the back of lower economic activity. After regaining pre-crisis demand in 2010, electricity consumption remained stable and decoupled from GDP growth, mainly due to energy efficiency gains.

Figure 6: Development of final power consumption 2007—2016

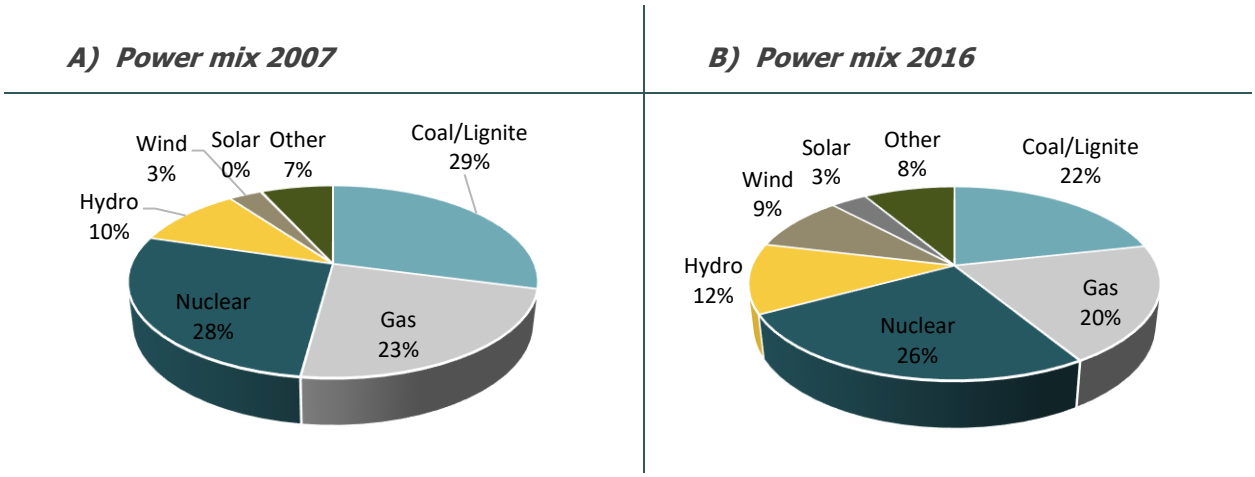


Source: Eurostat (2018)

3.7 Supply side developments

Figure 7 shows the generation mix in the 28 Member States in 2007 and 2016. As can be seen, the share of nuclear, coal and lignite and natural gas fell by 2, 7 and 3 percentage points respectively year-on-year. Renewable sources such as wind, solar and hydro power on the other hand, increased by 6, 3 and 2 percentage points. The replacement of fossil and nuclear energy with renewable sources was thus clearly manifested over the period leading up to the CEP.

Figure 7: Power generation mix in 2007 and 2016 for EU28. Percent.



Source: EU Commission – Energy Statistics 2018

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Figure 8 illustrates how the energy transition affected the load factors of different production technologies from 2007 to 2016. The average load factor across all technologies fell by 11 percentage points, from 47 to 37 percent. The fall was caused by a reduced load factor for fossil fuel plants as well as an increased share of wind and solar power, which generally had a lower load factor than the fossil fuel plants they replaced. Figure 9 summarizes the percentage point changes in the load factor for the different technologies year-on-year from 2007 to 2016.

Figure 8: Load factor pr. generation technology 2007 – 2016[6]. Percent.

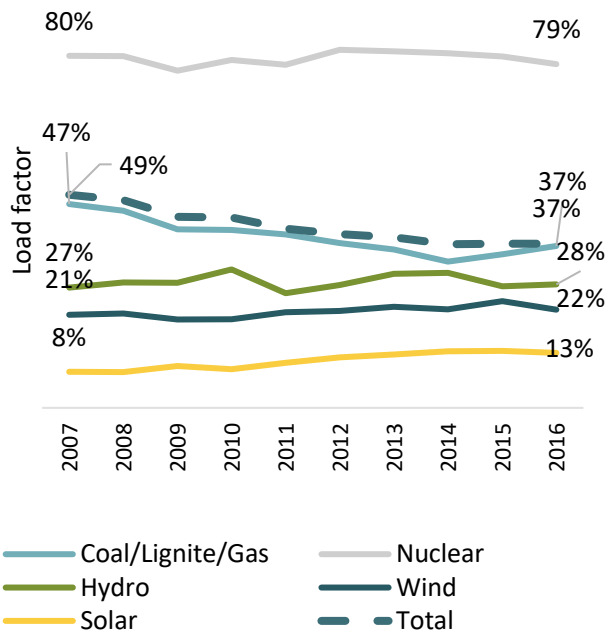

Figure 9: Change in average load factor pr. technology in the EU28 2007 – 2016. Percentage point

Source: EU Commission – Energy Statistics 2018

Figure 10 illustrates the load factor development for fossil fuel plants and the increasing share of intermittent solar and wind power in the electricity mix of the EU 2007-2016.

[6] Calculated as the total generation pr. year divided by the theoretical generation assuming production at maximum capacity all hours of the year.

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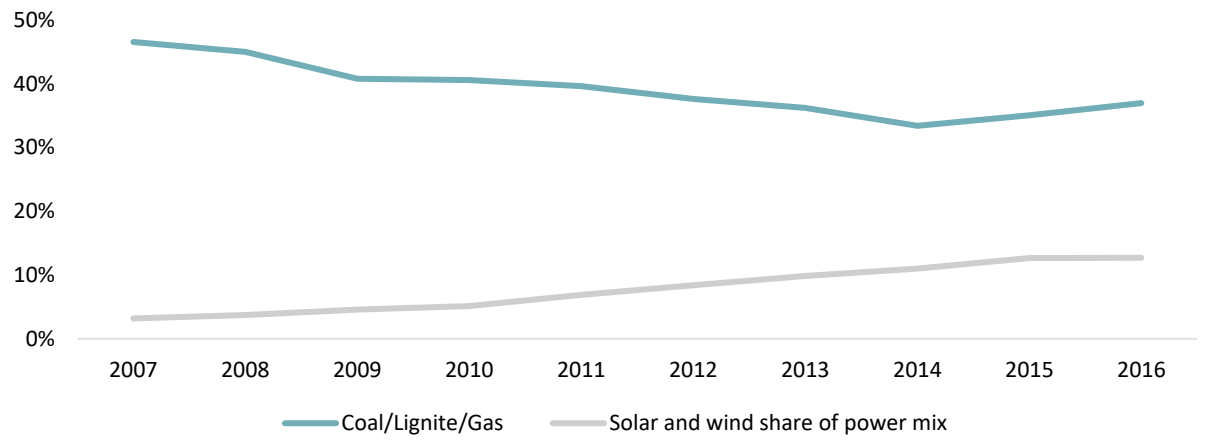
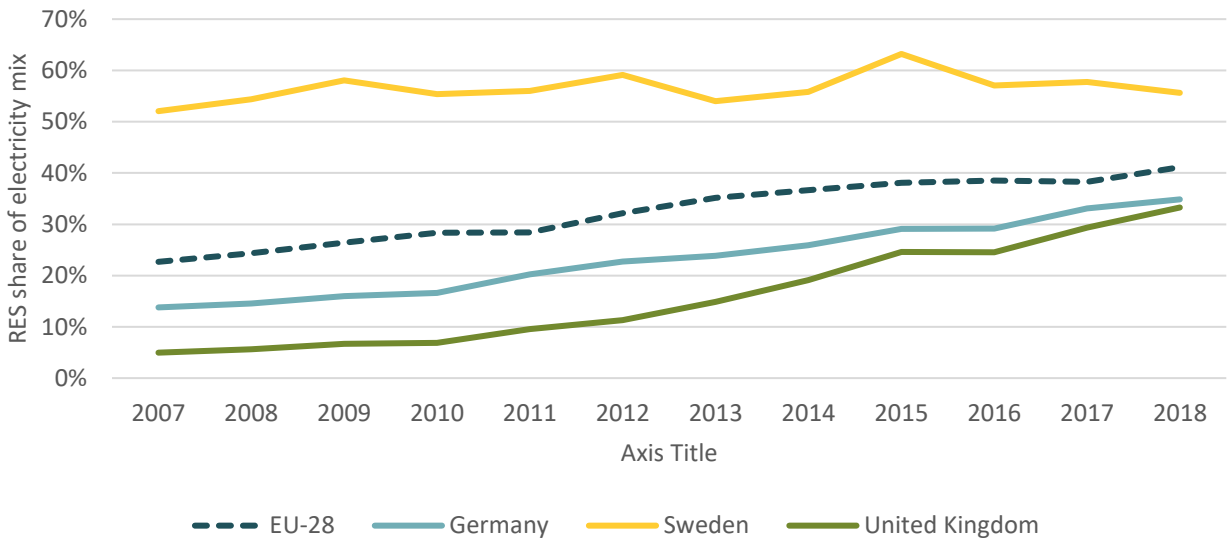
Figure 10: Load factor for thermal power plants running on fossil fuels and the share of wind and solar power in the energy mix 2007-2016. Percent.



Source: EU Commission – Energy Statistics 2018

Figure 11 portrays the development of renewable electricity as a share of total generation in the EU and the countries focused on in the subsequent chapters. Germany and the UK have seen rapid increases in their share of RES generation, albeit starting from levels below 15%, whereas Sweden enjoyed a favourable start from above 50% RES production and has increased this share above 60% only to then lose some ground and end up with a share of just above 55%.

Figure 11: Renewable electricity share in the EU, Germany, Sweden and the UK, 2007-2018



Source: BP Statistical Review (2019)

This rapid growth and the changed market environment also manifest themselves in EU projections of the share of RES by 2020. In the wake of the crisis, forecasts for electricity demand were adjusted downwards, both in the short term and in the long term. While the 2007 Baseline forecasted that EU27's gross electricity generation would need to reach 4400 TWh in 2030, the 2009 Reference Scenario adjusted its 2030 forecast downward to 4100 TWh. In the 2016 Reference scenario forecasted demand was further downgraded, to about 3500 TWh, 20 percent lower than the forecast at the time of adoption of the third package in 2007.

In Figure 12, an overview of the forecasted shares of different generation sources is shown. In 2009, the updated publication of *EU Energy Trends to 2030* included both a Baseline Scenario and a Reference Scenario. Taking the RES target for 2020 into account, the 2009 Reference scenario

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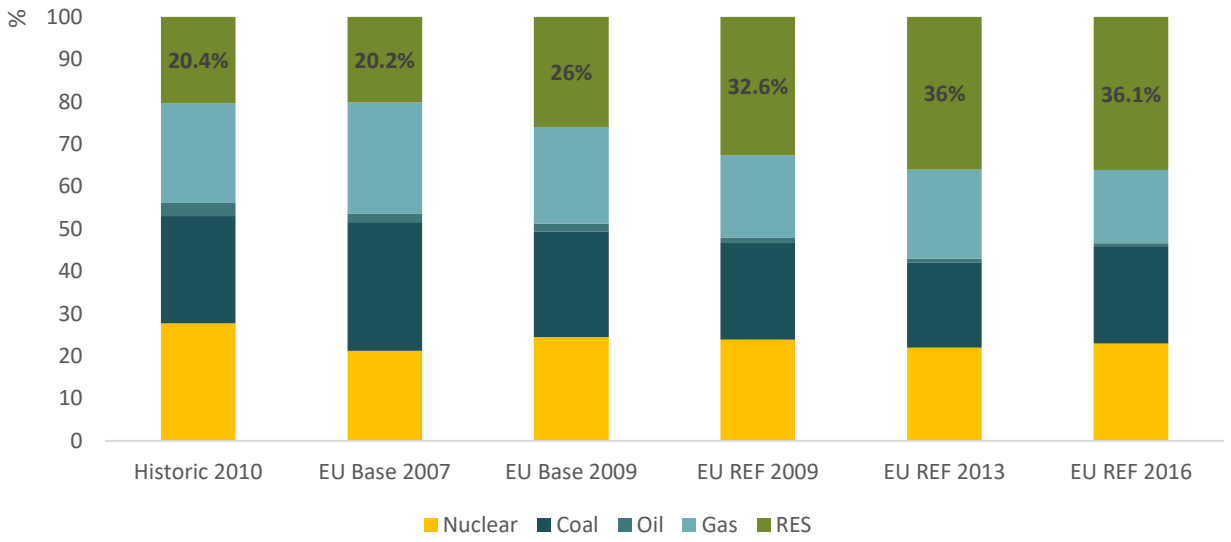
expected a major increase in generation from renewables up to a share of renewables in final electricity consumption of 32.6 percent. That constituted a major increase from the baseline scenarios of 2007 and 2009, where 20.2 percent and 26 percent, respectively, were forecasted. The expectations for the carbon price were lower in the Reference scenario (18.7€/tCO_2 in 2030) than in the 2009 Baseline scenario (39 €/tCO_2 in 2030), reflecting lower electricity demand and a higher RES share which would give some slack to the ETS carbon cap. Thus, it seems that the Commission recognized that increased RES generation would impact the market price for EUAs.

The prospects for growth in renewables were further strengthened in the 2013 Reference scenario, which envisioned a renewable energy share of 36 percent in 2020 and 45 percent in 2030. While the 36 percent target remained in place in the 2016 projections, the 2030 target was corrected slightly downwards again to 43 percent in the 2016 Reference scenario. The upwards corrections of RES shares reflect higher ambitions on part of the EU to achieve increasing targets, the latest being at least 32 percent renewable energy in the EU's final energy mix in 2030, as decided in the CEP. Meanwhile, the long-term forecast for coal shifted significantly, with its share of the 2030 electricity mix being adjusted downward from more than 30 percent in the 2007 Baseline to 20 percent in the 2013 Reference Scenario for 2020 and 12 percent for 2030.

Figure 12: Comparison the EU28 generation mix in 2020 by fuel in EU's scenarios from 2007, 2009, 2013 and 2016



Sources: European Commission (2009). EU Energy Trends to 2030; EU Commission (2013, 2015). Reference Scenario 2013/2016;

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4 UNITED KINGDOM

4.1 Summary

Between 2007 and 2016, the power market in the UK underwent a rapid transformation where the role of coal power decreased considerably, mostly being replaced by gas and renewables. While coal and lignite made up more than a third of the power mix in 2007, it was down to 11 percent by 2016. Wind power made up the lion's share of the increase in renewable production, up by 32 TWh year-on-year from 2007 to 2016. Two new interconnectors, one to the Netherlands and one to Ireland, were commissioned. Both demand and generation of electricity fell over the period, but with generation falling by 23 TWh more than demand, the UK's net imports rose by the same amount.

The wholesale prices in the UK are closely correlated to the gas price development. As an increasing amount of coal power capacity was taken out of the market towards the end of the period, prices increased as the marginal producer was more expensive gas power plants. The system costs appear to have increased over the period; however, it is difficult to conclude just how must should be attributed to the increase in renewable energy capacity.

Embedded in the overall EU 2020 agenda, the UK's policies showed strong support early on to decarbonise the energy sector with a unilaterally binding target to cut GHG emissions by 50 percent by 2027 from 1990 levels. The Electricity Market Reform (EMR), implemented in 2013, has so far played a key role to decarbonize the sector by introducing a feed-in premium subsidy scheme for renewable energy (CfD), a carbon price floor and emission performance standards (Lockwood, 2017).

One measure that the UK government at the time heavily pursued was the continued reliance on nuclear power. With Hinkley Point C and additional endeavours to realise nuclear projects, the UK pushes its decarbonisation narrative but has also come under fire for expensive contracts and suffered from public scepticism towards nuclear power in general.

4.2 Market developments after 2007-2016

4.2.1 Demand

Figure 13 shows the development of final electricity consumption in the UK 2007–2016. In total, consumption fell by 12 percent (38 TWh) over the period, mostly within industry (21 TWh) but also within the residential sector (15 TWh). Demand in the service sector and other sectors has remained fairly stable throughout the period. The dent in total demand is hardly visible in the curve, the main impression is that of a falling trend over the entire period, both in industry and households.

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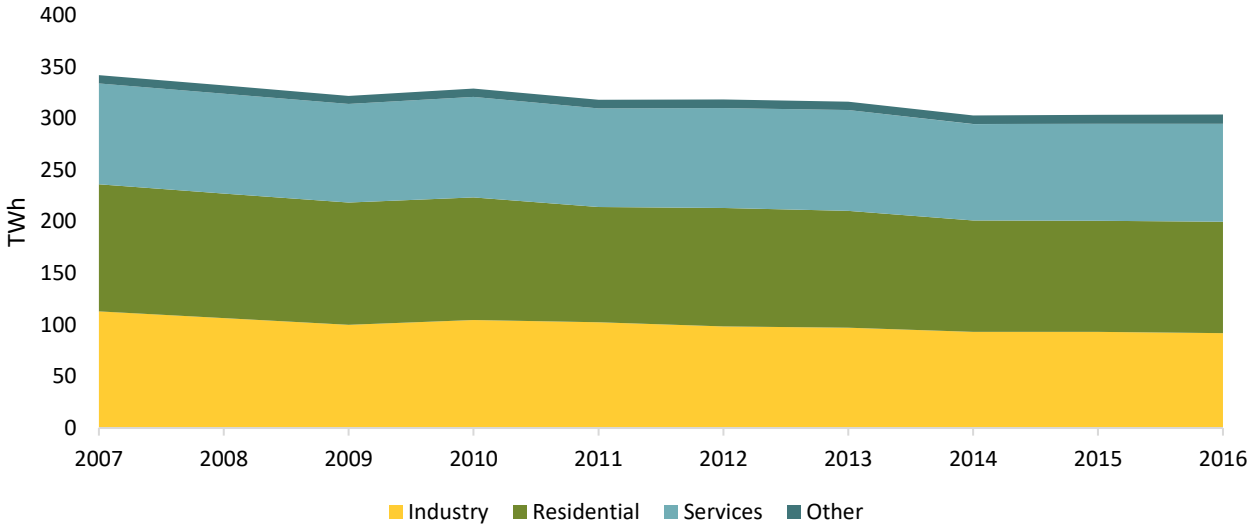
Figure 13: Final electricity consumption pr. sector in the UK 2007-2016



Source: Eurostat (2018)

4.2.2 Generation and capacity

More dramatic changes have taken place in the electricity generation mix. Annual electricity generation fell by about 15 percent (61 TWh) from 2007 to 2016, mostly due to a reduction in coal/lignite (-105 TWh) and gas (-23 TWh) generation, while generation from wind (+32 TWh), solar (+10 TWh) and other renewables (+17 TWh) increased.

The decline in coal-fired generation was partly offset by an increase in gas power generation that grew by 43 TWh in 2016 compared to the year before. However, it still does not exceed its peak generation of 178 TWh from 2008.

Even though the overall trend for coal and lignite over the period 2007-2016 is clearly negative, between 2011 to 2014 there was a temporary strong increase in coal generation and a reduction in generation based on gas, likely driven by falling coal prices between 2011 and 2016 combined with increasing gas prices between 2011 and 2013.

Figure 14 shows the development in the power generation mix in the UK. We note that coal/lignite generation maintained its substantial role in the power sector and grew from 2009 to 2012 but has rapidly declined since. From December 2012 to December 2015, a number of coal plants (totalling 8 GW of coal capacity) was closed in the UK, partially as a result of the EU's Large Combustion Plant (LCP) Directive. According to the Directive, plants built before 1987 had a choice between investing in equipment to comply with specific emissions limits (opt-in) or closing the power stations (opt-out). Opt-out plants were exempt from the emission limit for a maximum of 20,000 operating hours between the beginning of 2008 and the end of 2015[7].

In addition, the carbon price floor (CPF) that the UK introduced in April 2013 further incentivized fuel switching from coal to gas. The higher cost of running coal plants decreased their competitiveness in relation to gas stations and other power generation. At the same time, generation from renewable energy sources has increased fast in recent years.

[7] Energy Trends (2015): "Large Combustion Plant Directive (LCPD): Running hours during winter 2014/15 and capacity for 2015/16". September issue 2015. Available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/462364/LCPD.pdf

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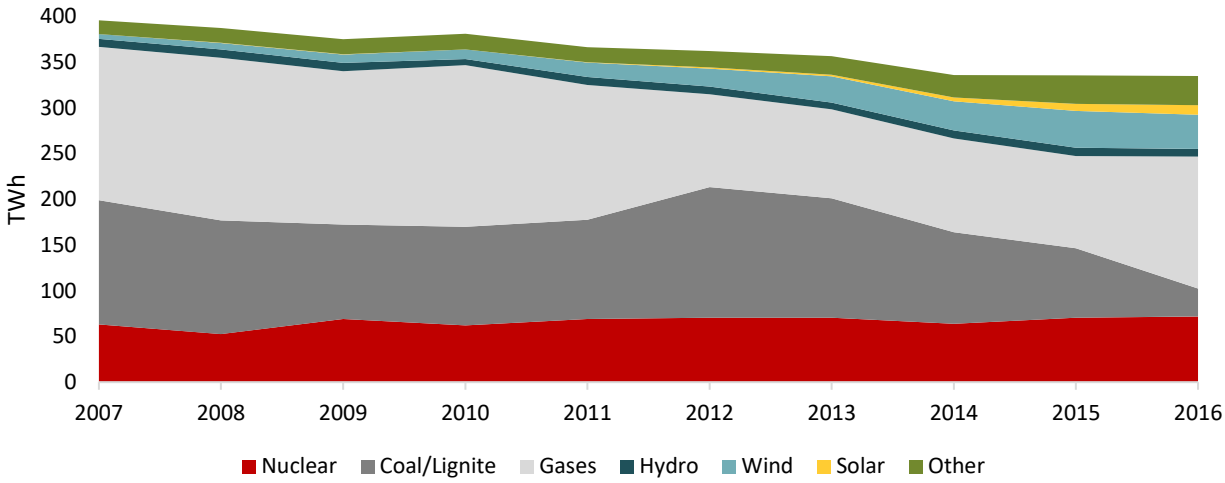
Figure 14: Power generation mix 2007-2016 in United Kingdom (in TWh)



Source: Eurostat (2018)

Figure 15 compares the generation mix in the UK in 2007 and 2016. The share of coal/lignite in the electricity mix declined from 35 percent in 2007 to 9 percent in 2016, while wind and solar PV increased their combined share from about 1 percent in 2007 to 14 percent in 2016. The share of gas generation is about the same in 2016 as in 2007, just above 40 percent of total generation. Thus, the UK electricity sector have undergone a remarkable transition in less than a decade, replacing large volumes of coal generation with renewable energy.

Figure 15: Power generation mix in the United Kingdom in 2007 and 2016

2007 **2016**

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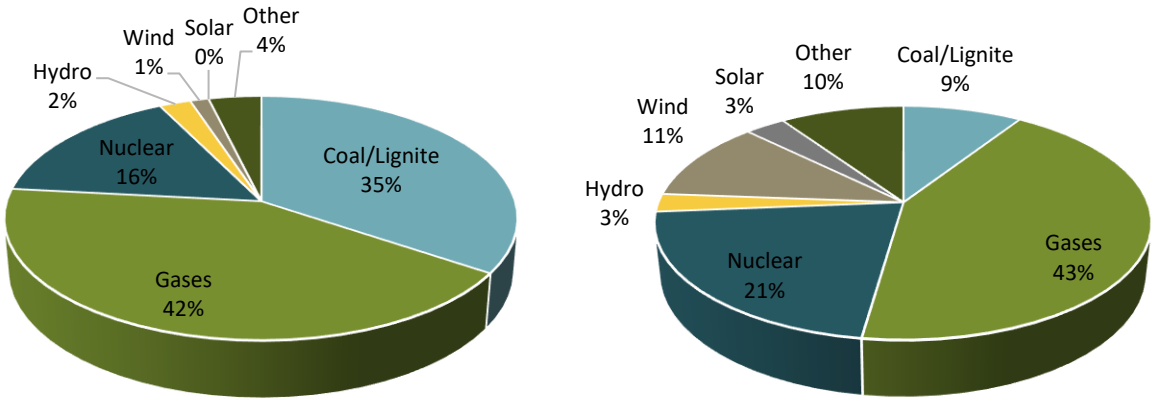
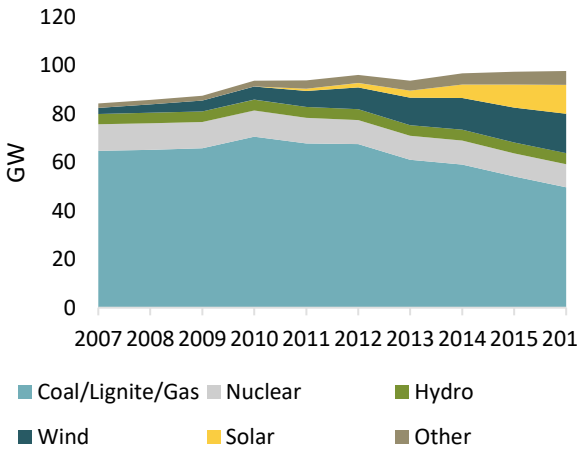


Source: Eurostat (2018)

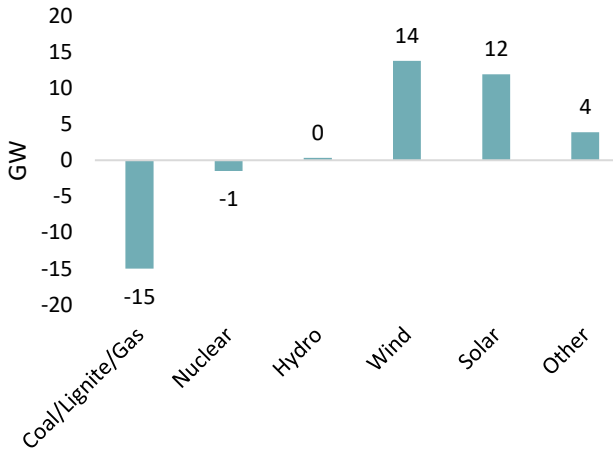
Looking at the development of the installed generation capacity in the UK confirms the picture, showing a clear falling trend for fossil fuelled capacity and a growth in renewable capacity as illustrated in Figure 16 below. In total, the installed capacity increased by 16 percent (13 GW) over the period while total generation declined.

Figure 16: Capacity development in the UK electricity sector 2007 – 2016 (in GW)

a) Capacity development pr. fuel, 2007-2016 (GW)



b) Change in installed capacity pr. fuel, 2007-2016 (GW)



Source: Eurostat (2018)

Increased capacity and reduced generation imply a lower average load factor for the overall generation capacity, which fell by 14 percent from 2007 to 2016. The decline in the load factor is in part attributable to an increasing share of renewable energy sources, which have a lower load factor than conventional power plants. Wind and solar power had load factors of 26 and 10 percent respectively in 2016.

However, Also power plants running on fossil fuels on average have a lower load factor in 2016 than in 2007 as can be seen in Figure 17 a and b. The average load factor for coal/lignite/gas plants

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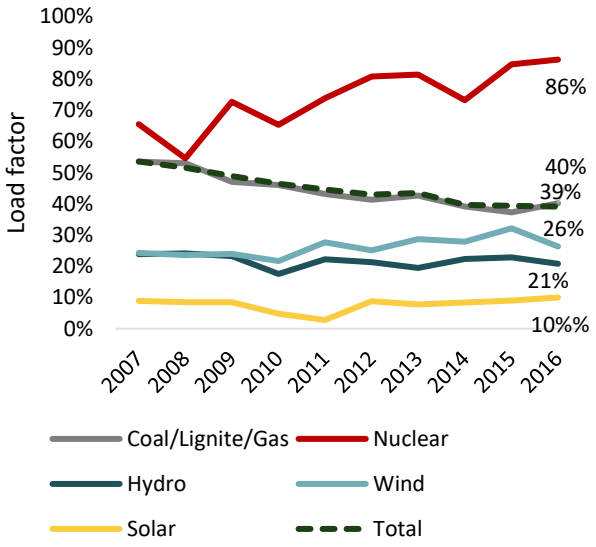
has fallen steadily and by 13 percentage points since 2009. This is linked to the growing volumes in of intermittent renewable electricity and the ability of gas power generation to provide flexibility.

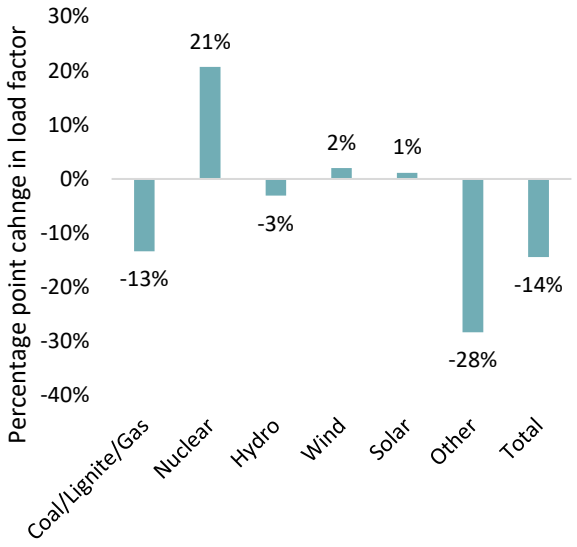
The decline in load factor for fossil-based thermal capacity may partly explain why the six big utilities in the UK (British Gas, EDF, Npower, E.ON UK, Scottish Power and SEE) advocated the introduction of a capacity mechanism over other security of supply measures, as these companies saw their revenues decline in the observed period (Van der Burg & Whitley, 2016). DECC's gas generation forecast, on the other hand, showed the need to counteract a diminishing capacity margin. Adequacy concerns in the face of coal and oil plant closures thus also played an important role in the introduction of the capacity market (DECC, 2012).

Figure 17: Load factor pr. generation technology in the United Kingdom 2007-2016

a) Load factor development pr. generation technology in the UK 2007-2016.



b) Percentage point change in load factor pr. production technology 2007-2016



Source: Eurostat (2018), own calculations

4.2.3 Trade

From 2007 to 2016, two new interconnectors with a total power rating of 1.5 GW were commissioned. The BritNed power cable (1 GW) between the UK and the Netherlands was commissioned in 2011, while the 0.5 GW East-West Interconnector between the UK and Ireland became operational in 2012. In addition, the UK already had the IFA interconnector (2 GW) connecting the UK and France, which was commissioned in 1986.[8]

Figure 18a shows the development in imports, exports and total trade of electricity as reported by Eurostat for the UK 2007–2016. Whereas exports have declined only slightly over the period, the imported volumes of electricity increased sharply from 2011. Figure 18b shows that the share of traded electricity volumes as a percentage of total production almost tripled from 2011 to 2014 before slightly declining. The additional interconnection capacity in combination with higher wholesale electricity prices drastically increased imported volumes from around 10 TWh in 2007–2011 to the to date peak of 26 TWh.

[8] *National grid - Interconnectors, Ofgem – Electricity Interconnectors*

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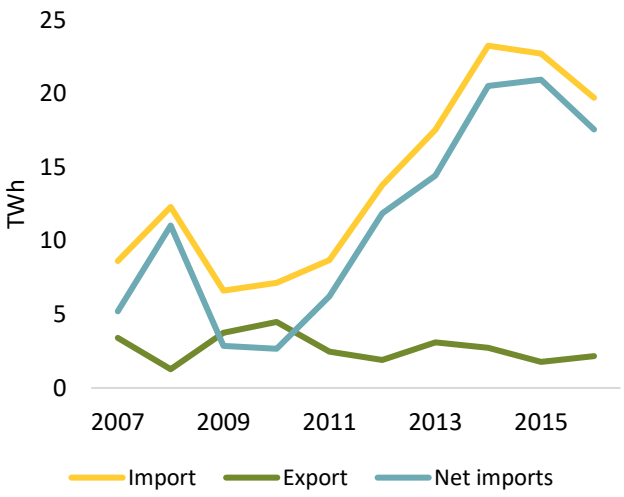
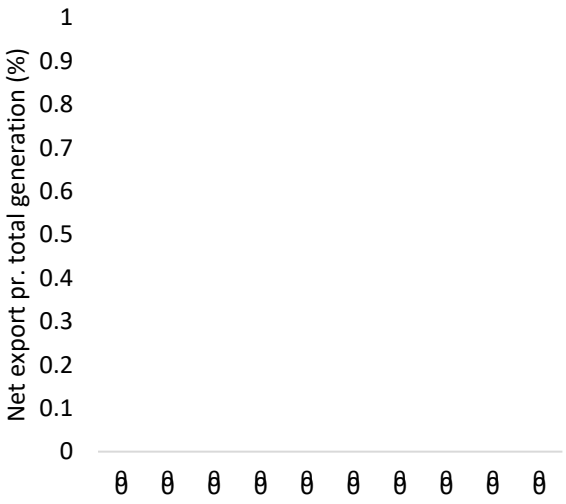
Figure 18: Development in imports, exports, net cross-border trade, and net electricity trade as a share of total generation in the UK

a) Development of import, export and net cross-border trade of electricity in the UK 2007-2016 (TWh)



b) Net cross-border electricity trade as a share of total electricity production in the UK. (percent)



Source: Eurostat (2018)

4.2.4 Retail and wholesale prices

Since the beginning of the decade, UK wholesale electricity prices have been closely related to gas prices, with a correlation coefficient of 0.75 between prices in the day-ahead gas and power (baseload) markets (Ofgem, 2017). The parallel movements can be seen in Figure 19.

The significant volumes of coal-fired generation taken offline between 2013 and 2015 created upward pressure on the UK's wholesale power prices as more expensive natural gas to a larger degree set the marginal price in the wholesale market.

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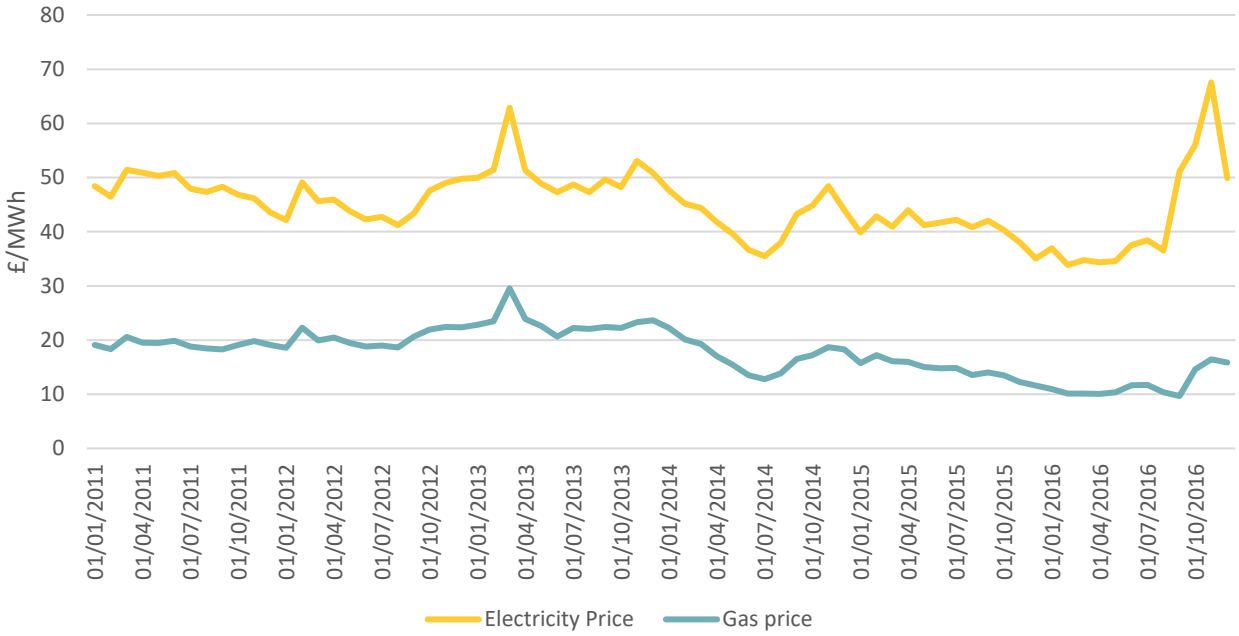
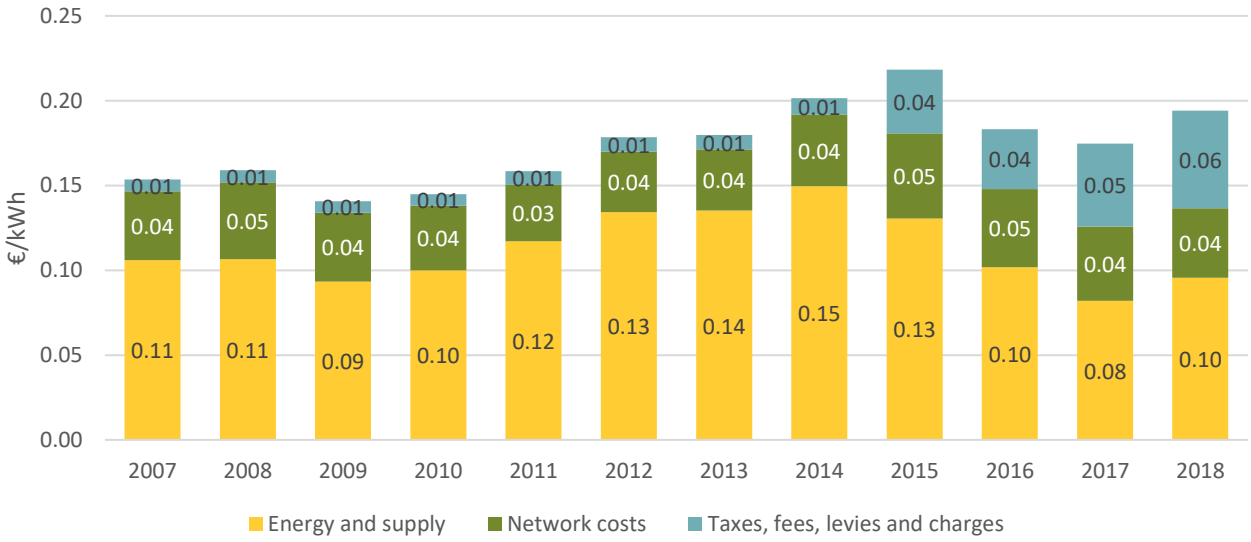
Figure 19: Monthly average wholesale electricity and gas prices in the UK, 2011–2016 (in £/MWh)



Source: Ofgem (2019), Data portal: Wholesale electricity and gas charts

While wholesale prices (and gas prices) have declined since 2013, retail prices have continued to increase until 2015. The increase is mostly due to increased taxes and levies introduced that year, while grid costs stayed mostly constant (cf. Figure 20).

Figure 20: Annual average retail electricity prices for a household consumer with annual consumption between 2 500-5 000 kWh, 2007-2018 (in €/kWh)



Source: Eurostat (2019)

4.2.5 Electricity system costs

The development in electricity system costs may also be an indicator of increased system stress due to changes in the generation mix. It generally takes longer for the grid to adapt to relatively rapid market changes. Figure 21 shows the total Balancing Services Use of System (BSUoS) costs for the

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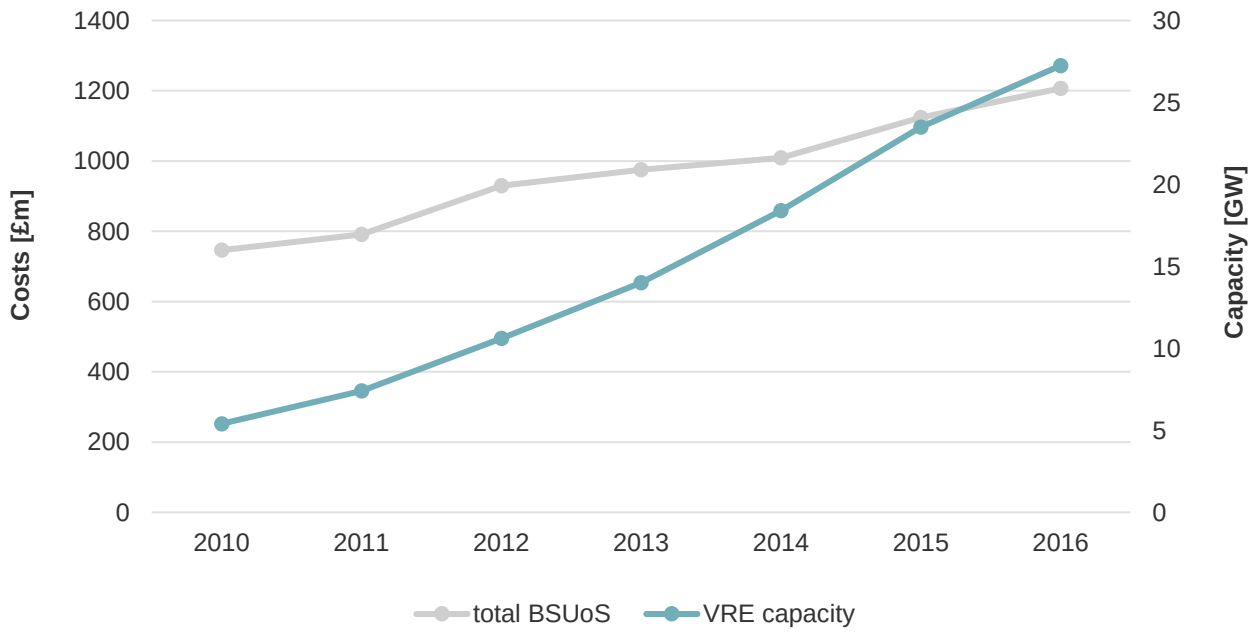
UK between 2010 and 2016. The costs have increased significantly, by about 50 percent, from just under £800 million up to £1200 million from 2010 to 2016. The figure shows that VRE (variable renewable energy) capacity quadrupled in the same period. To accommodate the variability of solar and wind generation, costs are incurred for operating reserve and back-up power available.

The correlation is, however, far from perfect, and we cannot conclude that the increased system costs are mainly due to increased VRE generation, i.e. since the trend of rising BSuoS costs precedes the massive expansion of wind and solar power. Another explanation brought forward by Joos and Staffell (2018) identifies the commissioning of new thermal plants and ongoing grid upgrades as contributing factors to the increasing cost.

Figure 21: Costs of electricity system operation in Britain



Source: Joos and Staffell (2018)

Constraint costs are seemingly directly linked to the increase in intermittent production, as Figure 21 depicts. While the costs of dealing with grid constraints amounted to around €140m in 2009 with annual wind generation slightly above 10 TWh, costs reached their highest point in 2013 at €340m with annual wind power at almost 30 TWh. Despite further rising wind output, constraint costs declined from then onwards. Joos and Staffell (2018) explain this by pointing out that the bulk of constraint costs comes from curtailment payments to gas power plants which have decreased since 2013. Between 2008-2011, when the share of wind power was still around 5 percent, constraint costs were also at a high level. Still, when looking at costs that can be specifically traced to wind curtailments, an increase over the years is still visible. It can be expected that the impact of grid expansion will suppress constraint costs once new major transmission lines are completed.

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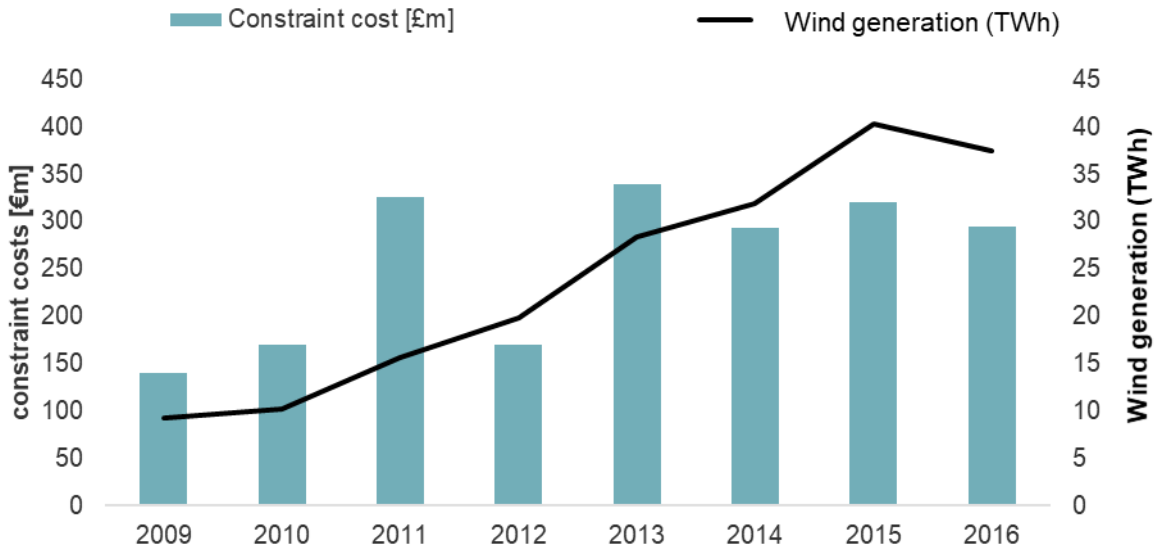
Figure 22: Annual constraint costs in the UK



Source: Joos and Staffell (2018)

Nonetheless, rising onshore wind curtailment[9] linked to increased generation plays a clear-cut role and demonstrates the need for further grid expansion to accommodate higher shares of VRE. Whereas the percentage of offshore wind curtailment is far lower, indicating a better linkage to Britain's grid, 16 percent of onshore wind generation was curtailed in 2015, either due to grid constraints or because supply exceeded demand. This might be the result of most onshore wind farms being connected to the distribution grid, while offshore parks are usually connected to the transmission grid. Thereby their output can be transported to demand centres more easily without facing constraints. With more wind added to the system, curtailment grew in unison with a correlation coefficient of 99 percent, according to our calculations.

[9] Curtailment is a term for when the system operator asks a power producer to reduce or stop production due to lack available grid capacity.

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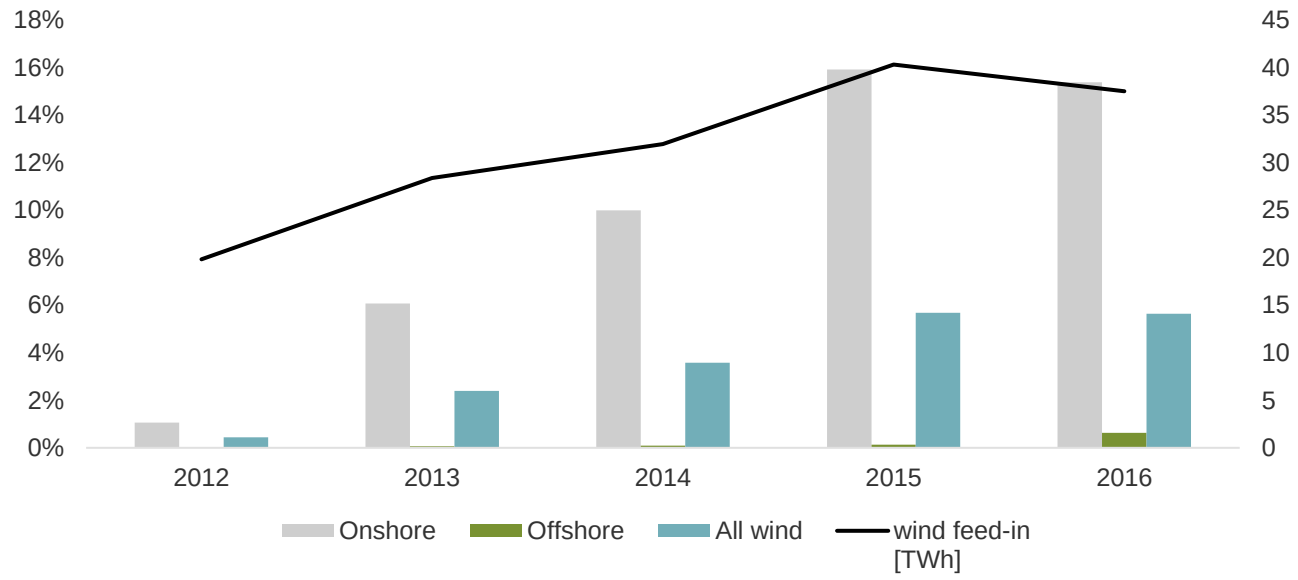
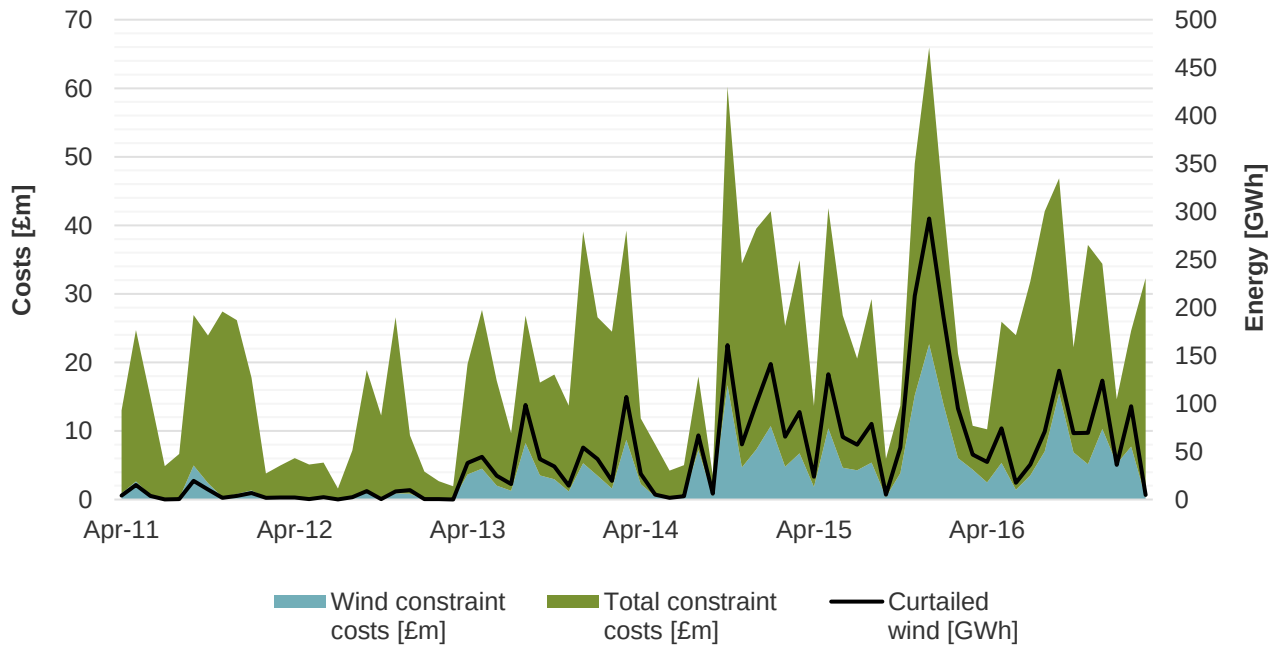
Figure 23: Annual aggregated curtailment rates of all observed wind farms (volume weighted average) in Britain



Source: Joos and Staffell, 2018

As can be seen in Figure 24, the cost associated with wind curtailment represents an ever-larger part of total constraint costs. Generally, the constraint costs associated with other sources seem to coincide with high wind curtailment, even though such a correlation can only be observed starting in mid-2013.

Figure 24: Monthly absolute amount of wind energy curtailed in Britain's Balancing Mechanism, with the compensation costs for wind and overall constraint costs



Source: Joos and Staffell, 2018

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4.3 Energy policy developments after 2007

4.3.1 The Electricity Market Reform (EMR)

In July 2011, the UK Government introduced a series of reforms, collectively known as Electricity Market Reform (EMR), to ensure that the UK's future electricity supply is secure, low-carbon and affordable (EMR Settlement Ltd, n.d.). Extensive consultations and analyses had revealed that security of supply would be threatened by plant closures and growing electricity demand, while decarbonisation of the electricity sector would be necessary if the government were to reach its targets for reduced greenhouse gas emissions (DECC, 2011; DECC, 2010; Ofgem, 2012).

The Energy Act of 2013 was the primary legislation enabling the EMR. The EMR consists of four main policy components:

- Contracts for Difference (CfD) for renewable energy,
- Capacity Market (CM),
- Emission Performance Standard (EMS), and
- Carbon Price Floor (CPF).

The main objective of the capacity market is to ensure security of supply, while the three other mechanisms serve to reduce CO_2-emissions.

In several ways, the EMR represented a shift away from the market-based principles that had guided UK energy policy over the past two decades (IEA, 2012). The policy measures reflected concerns that market-based incentives alone may not be sufficient to meet the government's targets for security of supply and decarbonisation.

Prior to the introduction of the capacity market, the UK relied on an energy-only market arrangement to deliver sufficient capacity.[10] In times of low capacity margins and high loss-of-load probability, an uplift factor on market prices was still applied in this market setup. However, expectations of an increased share of intermittent renewables coupled with concerns that around a quarter of existing generation capacity would shut down by 2020 strengthened the support for introducing a capacity market to enhance energy security (Leiren, Rayner and Inderberg, 2017).

Capacity market

In 2013, the government assessed that, without intervention, wholesale prices would be insufficient to spur investments in new generation capacity. To address the risk of "missing money" for investments in capacity necessary to cover peak demand, the government introduced a market-wide capacity market that rewards all generators that provide reliable, available capacity during the winter months. Four of the Big Six UK Utilities had favoured such a market-wide centralised auction system. Critics argued that the missing money would ease before the first delivery year, as reforms of the balancing market that would open it up to services ensuring the reliability of the system such as demand side response, new technologies (batteries, RES), would cause energy prices to more fully reflect scarcity values (Leiren, Rayner & Szulecki, 2019).

The Capacity Market remunerates capacity providers to ensure that reliable capacity is available. The market is constructed around a bidding system where electricity generators compete for long-term contracts with contract lengths ranging from one to fifteen years, depending on the offered capacity (e.g. existing, interconnectors and new capacities). The costs are passed on to the consumers through a levy issued via electricity suppliers. The first auction was held in early 2017 to cover the first delivery period for winter 2017–2018, with total payments amounting to around £380

[10] The former electricity pool arrangement contained a mark-up on marginal bid prices in hours with a high loss of load probability that can be interpreted as a form of capacity payment. The payment was however based on energy production in these scarcity hours. The mark-up was based on an assessment of the value of lost load and the probability of lost load.

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million (£6.95 kW / year for 54.43 GW, National Grid, 2017), less than forecasted after the auction featured strong competition resulting in lower bids.

The target capacity level is ultimately set by the Government based on recommendations from the system operator, which procures the capacity. In 2013, the UK government published a "reliability standard" (based on Loss of Load Expectation - LoLE) for the system, implying that the System Operator, National Grid, should expect to use its "out of market" measures[11] to balance supply and demand for no more than three hours per year on average (Ofgem, 2017). The standard is equivalent to standards used in France and Germany and is used to assess future capacity adequacy. The three-hour reliability standard implicitly assumes that it is less expensive for end-users to have three hours of out-of-market measures each year (including the associated costs of interruptions) than it is to build extra generating capacity for those last three hours. In the period 2005–2016, National grid has been forced to carry out-of-market actions only one hour per year on average, indicating that security may have been maintained at a higher cost than necessary for the consumer (Ofgem, 2017).

In order to determine the demand for capacity, National Grid models the level of de-rated capacity (i.e. the average expected level of available capacity in scarcity hours) for the delivery year, which is necessary to ensure a maximum LoLE of three hours per year.[12]

Although the UK capacity market is technology neutral, power plants that receive other support measures are not eligible for participation. Consequently, most renewable energy power plants and new nuclear power plants cannot participate. Their derated capacity is however taken into account in the determination of total capacity need.

Congestion management

Great Britain has constituted one bidding zone since 2005 when the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) resulted in a merger of the England and Wales bidding zone with the Scottish bidding zone (OFGEM, 2014). Electricity is traded freely within Great Britain, regardless of the physical limitations in the grid. After the trading period closes, the system operator National Grid applies various re-dispatch methods to manage the supply-demand balance across the network.

4.3.2 Cap-and-floor regime to boost the development of cross-border interconnectors

Due to Great Britain being an island, the bidding area has one of the lowest levels of cross-border capacity relative to peak load when compared to other European countries (European Commission, 2017c). Increased cross-border capacity is expected to reduce electricity wholesale prices in Great Britain as a result of price convergence with the continent where wholesale prices tend to be lower (Ofgem, 2017).

In 2014, the regulator Ofgem introduced a cap and floor regime to encourage investments in cross-border interconnectors by reducing risks for both developers and consumers. Before that, only a few interconnectors had been either built or proposed (Ofgem, 2016). Under the new option, the revenues from an interconnector are limited by a cap that restricts the maximum revenue and a floor that guarantees a minimum revenue from its operation. Hence, if the revenues from arbitrage (congestion rent in the spot market), the Capacity Market and ancillary services fall below a certain threshold, the interconnector developers receive a "top up" to the floor level from the system operator National Grid. Analogously, the interconnector must transfer its excess revenue to the system operator if the revenues exceed the cap. The duration of the cap and floor regime is 25 years. Any

[11] Out of market measures are actions that the System Operator employs when additional activities are required to balance supply and demand beyond those provided by the normal operation of the market (Ofgem, 2017)

[12] Nordic Energy Council (2016): Regional Electricity market

surplus or deficit is passed on to the consumers through adjustments in transmission charges (The Parliamentary Office of Science and Technology, 2018).

The NEMO Link between the UK and Belgium, which is the pilot cap-and-floor project, started operations in 2019. In 2015, five more projects were approved under the cap-and-floor regime in principle, namely the NSL project to Norway, the Viking Link project to Denmark, the IFA2 project to France, the FAB Link project to France and the Greenlink project to Ireland. The five projects were expected to start operation between 2020 and 2022 (Ofgem, 2016). Following a second round of applications, Ofgem granted approval in principle for the Grid Link to France, Neu Connect to Germany and North Connect to Norway, under certain conditions. In addition, a 2 GW interconnector between the UK and France is being built outside the cap-and-floor regime and is expected to start operation in 2021.

4.3.3 Energy policies

Renewable energy targets

The 2006 energy review set a target of 20 percent renewable electricity production by 2020. The Low Carbon Transition Plan of 2009 increased the renewable energy target to 30 percent of the electricity mix by 2020. Together with targets to increase the renewable energy share to 12 percent in the heating sector and 15 percent in the transport sector, the UK pledged to increase the renewable energy share in the energy mix to 15 percent to support the EU-wide target of 20 percent renewable energy by 2020. The target represented a sevenfold increase in the UK's renewable energy share of final energy consumption from 2 percent in 2008.

Table 1: The UK's renewable energy targets

	Final energy consumption	Electricity	Heating	Transport
2006 energy review		20 % by 2020		
2009 Low Carbon Transition Plan	**12 % by 2020**	30 % by 2020	12 % by 2020	15 % by 2020

The Low Carbon Transition Plan further set a target to increase the share of low carbon sources in the electricity mix to 40 percent by 2020, by supplementing the renewable energy targets with policies to build new nuclear power stations and fund carbon capture and storage facilities from coal power plants.[13] The Electricity Market Reform (EMR), which was implemented in 2013, was designed to be the most cost effective means to meet the UK's energy and climate change objectives.

Support for renewables - Contracts for Difference

In 2015–2016, the UK government introduced Contracts for Difference (CfD) to replace the Renewables Obligation as the main support mechanism for low-carbon electricity. CfD is a support mechanism for low-carbon generation, such as renewable energy sources and nuclear energy, and is designed as a long-term contract guaranteeing the generator returns at a pre-agreed level (the strike price). The mechanism is based on competitive pay-as-cleared auctions for the different technologies, thus encouraging cost reductions. For example, the target strike price for offshore wind of 100 £/MWh was met four years ahead of time. While the clearing price for CfDs for offshore wind

[13] HM Government (2009). The UK Low Carbon Transition Plan–National Strategy for Climate and Energy https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/228752/9780108508394.pdf

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was 120 £/MWh (including the wholesale price) for farms deployed in 2017–18, it fell to 57 £/MWh for offshore wind farms to be deployed in 2021–22 (Ofgem, 2017).

The CfD regime replaced a green certificate scheme (Renewables Obligation scheme - RO). Under the CfD scheme, electricity providers are paid the difference if the market price is below the contracted strike price and must pay the difference to the government if the market is above the strike price. According to Leiren, Rayner and Inderberg (2017), the CfD was considered a good fit with the carbon tax which was expected to increase wholesale prices over time and thereby reduce the level of subsidies needed.

The funding of the government's low-carbon policies for electricity and heat varies. While the costs of support to low-carbon heating is financed through general taxation, carbon taxes and subsidies for renewable electricity are passed on to consumers' electricity bills (Ofgem, 2017).

4.3.4 Climate policies

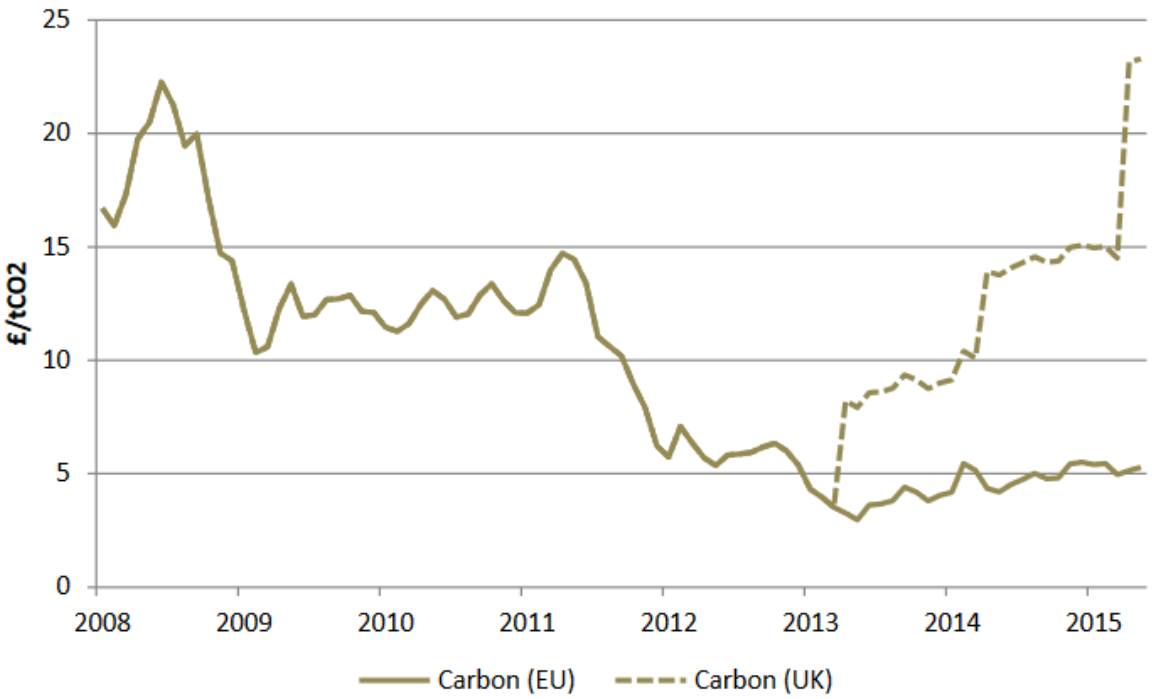
Carbon price floor

On April 1st, 2013, the UK adopted the Carbon Price Floor (CPF) as a measure to drive low-carbon investment, which the EU ETS had not achieved (Hirst, 2018) due to low prices. As such, the CPF must be viewed in relation to how the EUA price prevailed at low levels during the second trading period.

The Carbon Price Floor is a tax levied on fossil fuel electricity generation and consists of two components: the EU ETS allowance price and the Carbon Price Support (CPS), which is added on top of the former. The maximum CPS is gradually increased, and the sum is not to exceed the CPF. The Carbon Price Floor mechanism increases the short-run marginal cost for CO_2-emitting generators and thus impacts electricity wholesale prices. It is designed to monetise the environmental cost of greenhouse gas emissions.

Figure 25 illustrates the development of the monthly average prices for European Emissions Allowances and the UK Carbon Price Floor in the period 2008–2016.

Figure 25: Monthly average carbon prices in Europe and the UK, 2008-2015



Source: Based on Bloomberg, DECC, Bank of England

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When the CPF was introduced on 1 April 2013, it was due to increase every year until 2020, to a price of £30/tCO_2. The CPS component was increased from £4.94/tCO_2 in 2013–2014 to £18/tCO_2 in 2015–2016. However, at Budget 2014, the Government announced that the CPS component of the carbon price would remain capped at a maximum of £18/tCO_2 from 2016 to 2020 to protect British businesses due to the continued low price of the EU ETS.[14] In Budget 2016, this price cap was extended to 2021.[15]

According to Ofgem (2017), the additional £18 per tCO_2 could increase operation costs for a typical gas (CCGT) plant by around £7 per MWh and by around £17 per MWh for a typical coal plant.

Emission Performance Standard

The *Emission Performance Standard* was introduced in Autumn 2014, limiting emissions from new power stations to 450g CO_2/kWh at base load. As the level is set at around half of the emissions level produced by unabated coal, the instrument ensures that any new coal-fired power plant can only be built if equipped with Carbon Capture and Storage technology.

The reform caused significant coal-fired generation capacities to be taken offline in 2013, which created an upward pressure on the UK's wholesale power prices in the short term (European Commission, 2014).

[14] Hirst (2018). Carbon Price Floor (CPF) and the price support mechanism.
[15] House of Commons Library (2018). Carbon Price Floor (CPF) and the price support mechanism. https://researchbriefings.parliament.uk/ResearchBriefing/Summary/SN05927

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5 SWEDEN

5.1 Summary

The Swedish power system is dominated by hydro and nuclear. These remain the key components over the period considered, but there has also been strong development of wind power generation, growing from a negligible 0.5 TWh in 2007 to 17.5 TWh in 2016.

Total generation and consumption have remained relatively stable year-on-year 2007-2016. Reduced industrial demand has been made up for by increased demand from households, while the increase in wind power production has led to increased net exports (dependent on hydrology and other factors). The increasing share of intermittent wind power generation makes the power system balancing more complex and demanding, and the number of mFRR activations has doubled over the period.

The Swedish electricity market was deregulated and coupled with the Norwegian market in 1996. Until 2011, the Swedish market was organized as one bidding zone. In November 2011, after a dispute with Denmark, including involvement of the EU Commission, the Swedish market was divided into 4 permanent bidding zones. While Northern Sweden tends to have an electricity surplus, the populous Southern bidding zones normally have a deficit (Svenska Kraftnät, 2017). Consequently, the electricity tends to flow from the North to the South. Sweden has maintained a strategic capacity reserve since 2003 when the nuclear plant Barsebäck was decommissioned.

In 2009, Sweden adopted ambitious new targets under the “integrated climate and energy policy” framework. The framework included defined objectives for 2020 and decarbonisation priorities for 2030 and 2050 (IEA, 2013a):

- a reduction of energy intensity by 20 percent below 2008-levels by 2020
- a share of at least 50 percent renewable energy in gross final consumption by 2020
- a reduction of greenhouse gas emissions by 40 percent by 2020, of which two-thirds are to be implemented by domestic measures and one-third by international efforts and EU measures (including the EU Emissions Trading Scheme)
- a fossil fuel-independent vehicle fleet by 2030
- zero net greenhouse gas emissions by 2050

As part of the framework, Sweden increased the ambition for the electricity certificate (Elcert) system. The Elcert system has been the main Swedish support system for renewable power generation since 2003. The target has been increased several times. In 2012, Norway joined the Elcert system, creating the first multinational support system for renewables in Europe. The Elcert system has been highly successful in providing investments in particular in wind power generation, implying that Sweden is well on track to reach and surpass its targets for renewable electricity generation.

In 2016, the social democrat/green coalition government, and the opposition parties, the Conservative party, the Centre party and the Christian democrats, entered an agreement on Sweden’s long-term energy policy. The agreement included a common road map for a transition to 100 percent renewable electricity production by 2040 (Government Offices of Sweden, 2016). It was however explicitly stated that this did not constitute a decision to phase out nuclear capacity.

The agreement emphasises the need to strengthen the network infrastructure within Sweden, remove congestion between countries and push for increased interconnectivity in the EU as a whole. It emphasises cooperation in the Nordic market and in the Baltic Sea region in this regard.

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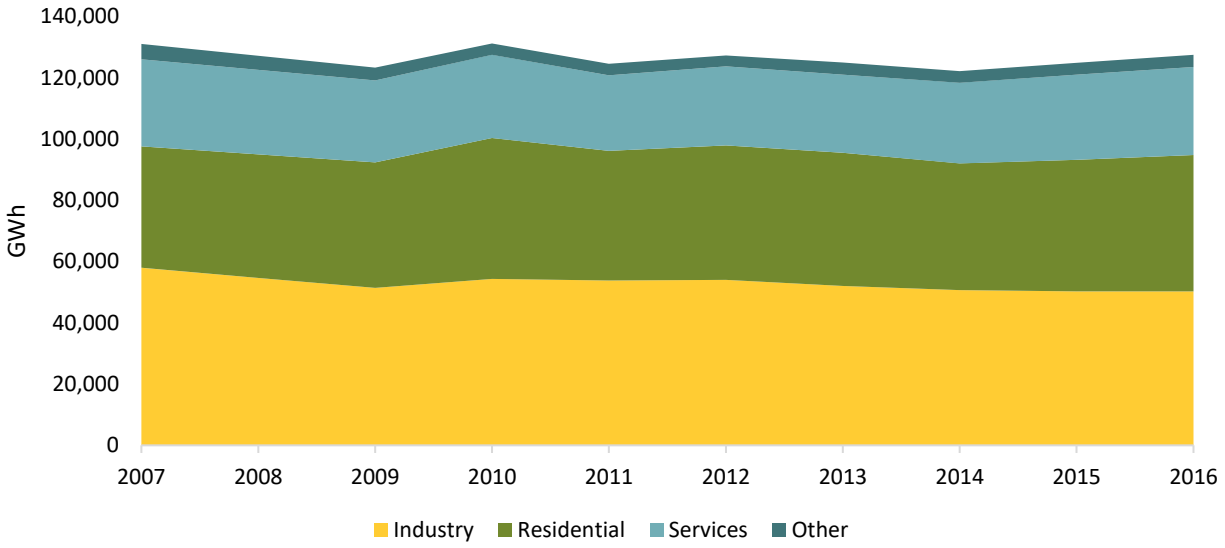
5.2 Market developments 2007–2016

5.2.1 Demand

Sweden's electricity consumption is characterized by a relatively large share of power-intensive industry and an extensive use of electricity for heating in households.

Figure 26 shows the development of electricity demand in Sweden 2007–2016. Annual electricity demand varies somewhat from year to year at level of around 125 TWh. Despite the financial crisis, causing a dip in total electricity demand, the level in 2010 was on par with 2007. The recovery was however due to increased household consumption. As shown in the figure, industry consumption only increased slightly from 2009 to 2010, and has tapered off since. In 2016, industrial electricity demand was 13 percent lower than in 2007, and two percent lower than in 2009. The increase in household electricity consumption outweighs most of the decline in industrial consumption.

Figure 26: Annual electricity consumption in Sweden 2007–2016 (in GWh)



Source: Eurostat

5.2.2 Generation and capacity

The generation mix in Sweden has historically been dominated by nuclear and hydro power generation which together made up 80–90 percent of total generation in the period from 2007 to 2016 as can be seen in Figure 27. The total generation increased somewhat over the period, from 148 TWh in 2007 to 154 TWh in 2016. The key change in the Swedish power generation these years is the strong increase in wind power generation, which increased by 17 TWh from 2007 to 2016.

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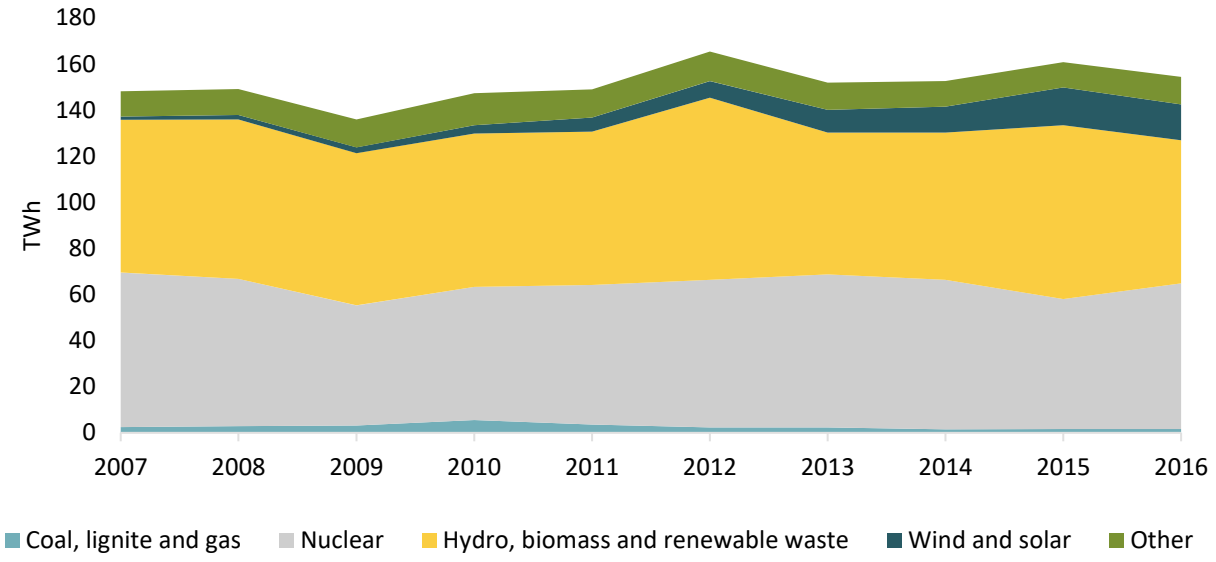
Figure 27: Electricity generation mix for Sweden 2009–2016 (TWh)

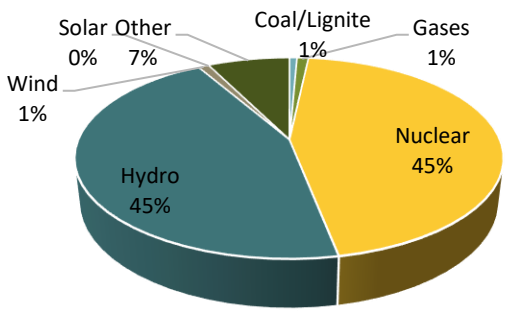


Source: Eurostat (2018)

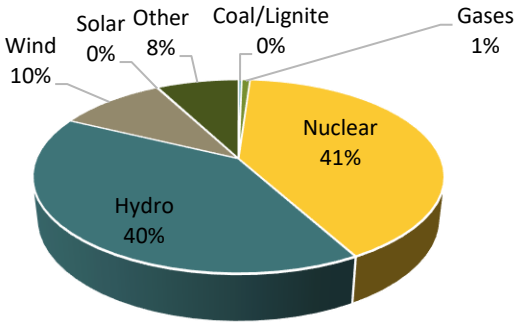
The change in the generation mix since the implementation of the third package in 2009, is illustrated in Figure 28. Most notably, wind power grew to 10 percent of total generation in 2016, an increase by 9 percentage points from 2009. Meanwhile, the originally modest share of fossil fuels have been almost completely phased out of the generation mix. Nuclear power generation, by contrast, fell from 45 to 38 percent, but varies considerably from year to year.

Figure 28: Electricity generation mix in Sweden 2007 and 2016 (in %)

a) Electricity generation mix in Sweden in 2007



b) Electricity generation mix in Sweden in 2016



Source: Eurostat (2018)

Looking at the installed capacity in Sweden in Figure 29, we see that wind power increased by almost 6 GW while fossil capacity was halved. Nuclear capacity increased due to upgrades of existing plants and combined heat and power capacity increased due to the elcertificate system. Total installed capacity increased by 18 percent.

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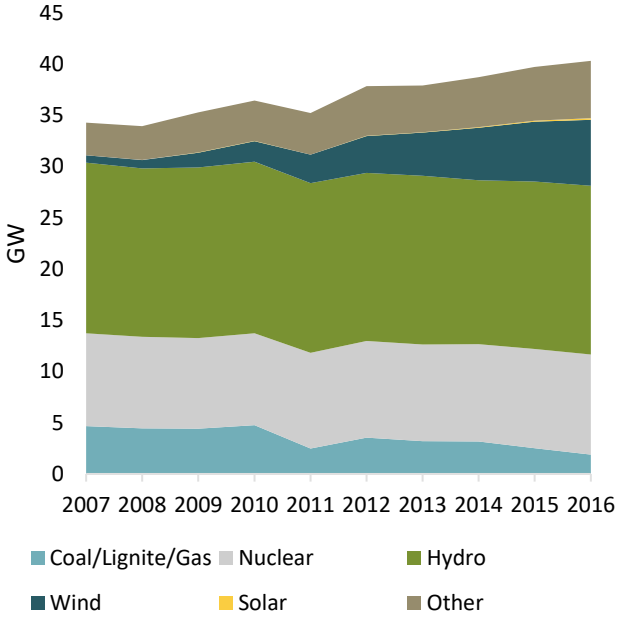
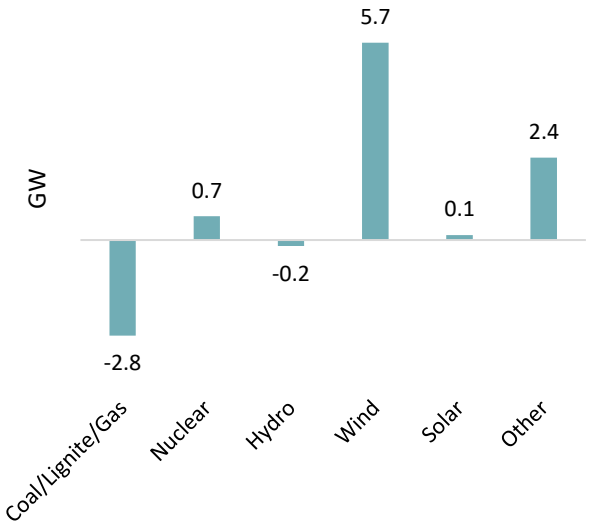
Figure 29: Development of installed electricity capacity 2007-2016 for Sweden (in GW)

a) Development of installed electricity capacity 2007-2016 for Sweden. GW



b) Change in installed electricity capacity pr. technology in Sweden 2007-2016. GW

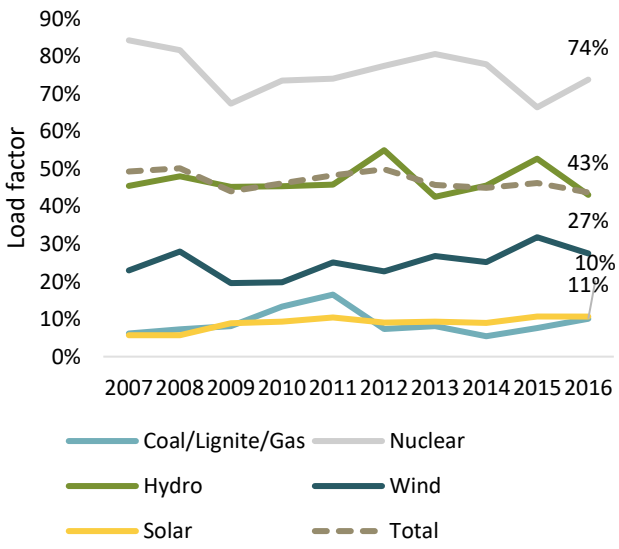


Source: Eurostat (2018)

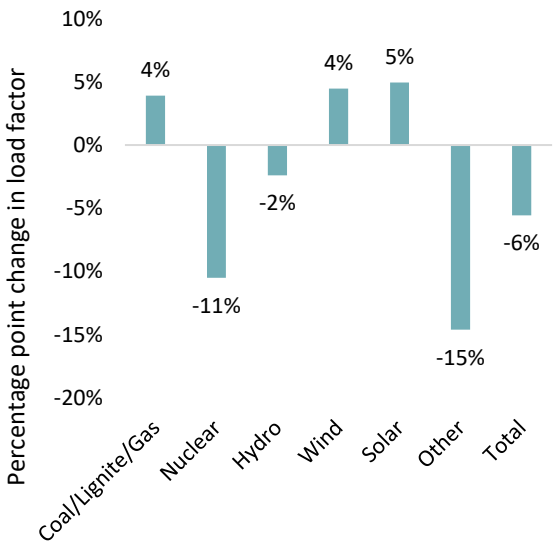
The load factor across all generating technologies remained more or less stable at about 43 percent over the period as shown in Figure 30a and b. It should be noted that coal and gas capacity was mainly used as back-up capacity in the strategic reserve, hence the low load factor.

Figure 30: Load factor pr. generation technology in Sweden 2007-2016

a) Load factor development pr. generation technology in Sweden 2007-2016.



b) Percentage point change in load factor pr. production technology in Sweden 2007-2016



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Source: Eurostat (2018)

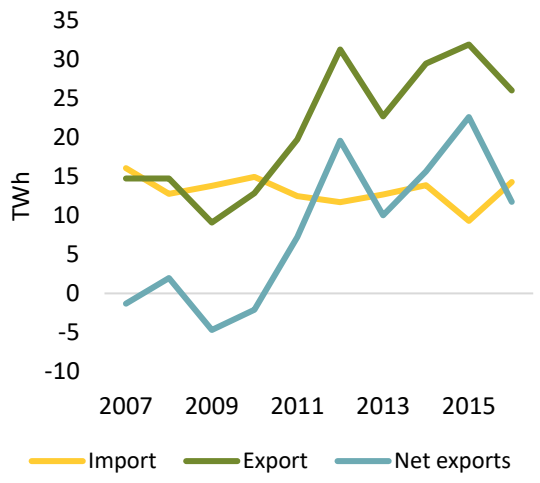
5.2.3 Interconnectors and trade

The Swedish power system is well connected to neighbouring countries. There are two interconnectors to Finland, four to Norway, two to Denmark and one each to Poland, Germany and Lithuania.[16] Most interconnectors have been in place since before 2009, the exception being the NordBalt interconnector (700 MW) between Sweden and Lithuania, which was commissioned in 2016.

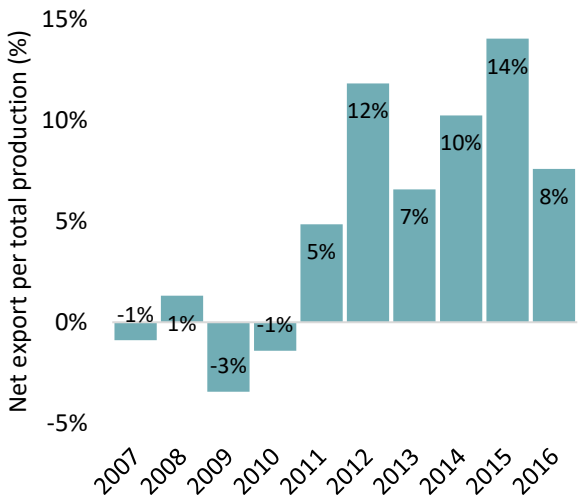
Figure 31a shows the development in electricity imports, exports and net trade as reported by Eurostat for Sweden 2007–2016. Export volumes vary somewhat from year to year, but overall the export volumes have increased significantly over the period, from 15 TWh in 2007 to close to a level around 30 TWh from 2012. Sweden has been a net exporter or electricity in all years after 2010. To some extent, the numbers indicate that Sweden has become less dependent on imports, more dependent on export opportunities for its increased renewable generation, and more interconnected with neighboring markets including the Baltic countries. Figure 31b shows the net cross-border trade (annual exports minus imports) as a share of electricity production 2007-2016. From 2010, It has varied between 5 and 14 percent.

Figure 31: Annual imports, exports, net trade of electricity (TWh) and net exports as a share of total production in Sweden (in %)

a) Development of import, export and net cross-border trade of electricity in Sweden 2007-2016. TWh



b) Net cross-border electricity trade as a share of total electricity production in Sweden. %



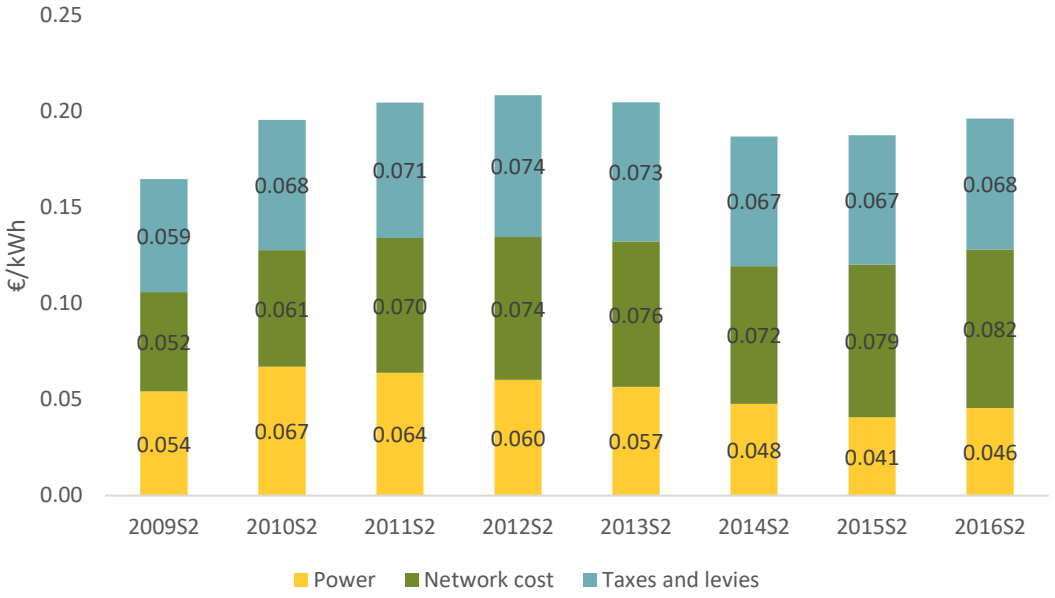
Source: Eurostat (2018)

5.2.4 Retail prices

Figure 32 shows how the average retail electricity price for household consumers developed over from 2009 to 2016. Over the period, the cost per kWh increased, showing the opposite trend of wholesale prices. The main driver for the increase in retail prices has been network costs, but taxes and levies have also increased.

[16] https://www.svk.se/siteassets/om-oss/rapporter/2017/swedish-interconnectors-report-no.-13_rapport.pdf

Figure 32: Development of average retail electricity price for a household consumer with annual consumption between 2 500-5 000 kWh in Sweden

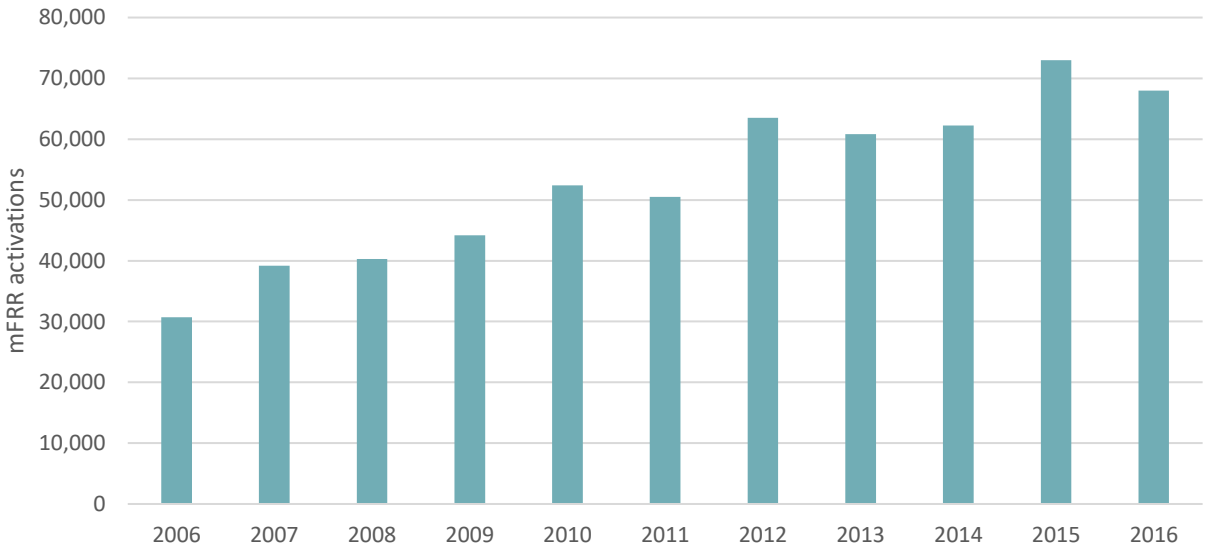


Source: Eurostat (2018)

5.2.5 Electricity system costs

The Swedish TSO, Svenska Kraftnät, writes in their system development plan 2018–2027 that the increasing share of intermittent wind power generation makes the system balancing more complex and demanding. Figure 33 shows the number of activated manual frequency restoration reserves (mFRR) by Svenska Kraftnät in the period 2006–2016. As can be seen, the number more than doubled in the ten-year period preceding 2016. Svenska Kraftnät expects the balancing regulation to become increasingly challenging in light of energy policy targets related to renewable generation, interconnection and market integration in Sweden and the European Union (SvK, 2018).

Figure 33: Number of mFRR activations by Svenska Kraftnät 2006-2016



Source: Svenska Kraftnät (2018). Systemutvecklingsplan 2018-2027

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5.3 Policy developments 2007–2016

5.3.1 Electricity Market design

Congestion management

In Sweden, as in the rest of the Nordic market, structural bottlenecks are mainly handled through market splitting between bidding zones, while bottlenecks within bidding zones are handled by redispatch. Sweden implemented market splitting on November 1st, 2011 by splitting Sweden into four fixed bidding areas. This change in market design followed a complaint by Denmark and an assessment by the European Commission, which had raised concerns regarding the alleged practice of curtailing export capacity between Sweden and Denmark to reduce redispatch in the Swedish grid. In particular, the analysis found that foreign customers in the EU internal market were discriminated by the reduction of interconnector capacity between Sweden and other markets. In response, Sweden aligned its congestion management with the market-splitting mechanism of the Nordic market region and introduced the bidding areas Luleå (SE1), Sundsvall (SE2), Stockholm (SE3) and Malmö (SE4). Prices in the individual bidding zones in the Nordics are determined by production and consumption, and by power transmission to and from adjacent bidding areas.

Price differences mainly occur between the south (bidding areas SE3 and SE4) and the North (bidding areas SE1 and SE2) of Sweden. While Northern Sweden tends to have an electricity surplus, the populous Southern bidding zones normally have a deficit (Svenska Kraftnät, 2017), which is also related to reduced nuclear capacity in the South. Consequently, the electricity tends to flow from the North to the South.

The Swedish wholesale market for electricity is part of an integrated Nordic-Baltic market, Elspot, and is also connected to the European electricity network. The Nordic system operators have jointly managed congestion through implicit auctioning of interconnector capacity on the power exchange Nord Pool. The integrated Nordic market has gradually been increasingly coupled with larger parts of the European market.

Strategic reserves

After the deregulation of the Swedish market in 1996, the capacity margin between supply (and imports) and demand fell by 20 percent to 2000 (IEA, 2013a). As a measure to strengthen security of supply, the Swedish government introduced the Power Reserve Act in 2003, following the shut-down of the 2 GW Barsebäck nuclear power plant. The reserve is a market reserve and not a grid reserve, i.e., it is only to be activated in cases where the market fails to equalize demand and supply. The strategic reserve was established as a temporary measure intended to be phased out by 2011. In 2011, the government decided to extend the strategic reserve, with the intention of gradually phasing it out by 2020 when a market-based mechanism should replace the reserve. The strategic reserve has been further prolonged to 2025.

The peak load power reserve was set to decrease every second year according to the following capacity limits, of which minimum 25 percent needs to be demand reduction:

- 2011-13: 1,750 MW
- 2013-15: 1,500 MW
- 2015-17: 1,250 MW
- 2017-19: 750 MW

According to the act, the Swedish TSO, Svenska Kraftnät, can procure reserves for the winter period between 16 November and 15 March through auctions. Bids from the strategic reserve may only be activated after all commercial bids are activated. Until 2017/2018, activated bids were remunerated at the price of the highest commercial bidder in Elspot plus 0.1 Euro per MWh. Since November 2017, however, the strategic reserve has been priced according to the price cap in the day-ahead market, which is currently 3000 Euro per MWh, in order to reduce the impact on the market. The

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change is in line with future regulations that require clearer price signals and is considered to contribute to more demand response.[17]

According to the energy agreement, there is a need to shift the focus of investments from energy to capacity. This applies to both market design and measures towards generation, transmission and demand.

5.3.2 Energy Policies

Renewable energy targets

Sweden reached its 2020 target of 50 percent renewable energy of total energy consumption already in 2012 and in 2016 the share was 54 percent.

As part of the energy agreement in 2016, the Swedish Riksdag (parliament) agreed to set a target of 100 percent renewable electricity production by 2040.

The energy commission expects that renewable capacity will be further expanded, and that Sweden will remain a net exporter of renewable electricity for a long time. The output from both hydro, biomass and wind can be increased.

Support for renewables - Elcertificate scheme

In 2003, the Swedish government introduced a green certificate scheme, the Elcertificate scheme. This market-based support system for renewable electricity production grants an electricity certificate for each MWh produced from new renewable resources. To create a demand for Elcertificates, electricity suppliers have an annual quota obligation to hold electricity certificates corresponding to a specific share of their sale and use of electricity during the previous years. Eligible generators thus receive additional income from selling the certificates, which makes it more profitable to invest in renewable electricity production, while the cost is passed on to end-users.

Since its introduction, the Elcertificate system has been prolonged several times and the target has been expanded. From 1st January 2012, Norway joined the certificate system under a common target of 26.4 TWh, allowing generators in both Norway and Sweden to trade Elcertificates across national borders. While Norway and Sweden initially decided on financing 13.2 TWh each under the common 2020 target, Sweden decided in 2016 to raise its target by an additional 2 TWh, bringing the total target to 28.4 TWh. Until 2016, a major share of renewable electricity production supported by the system had been allocated to Swedish producers.

In June 2017, the Swedish parliament decided to prolong the system to 2030 with the objective of increasing the production by a further 18 TWh, while Norway decided to not prolong its participation in the scheme.

The price of electricity certificates has varied since the system was established in 2003, peaking at SEK 350 in 2008.

Ambiguous nuclear policy

Sweden's nuclear policy has shifted back and forth in the past few years. For several decades prior to 2010, Sweden's energy policy targeted a phase-out of the nuclear power programme, which was sparked by the nuclear accident at Three Mile Island in 1980. In June 2010, however, the Riksdag voted to repeal a decision from 1980 to phase out nuclear power by 2010. According to the legislation from 2010, new nuclear reactors may replace the ten existing reactors as they retire, granted that they are constructed in the same locations.

However, tough market conditions owing to low power prices and increased costs have triggered an early decommissioning of several reactors in Sweden. In 2014, the new government proposed to

[17] Svenska Kraftnät. (2018). System Development Plan 2018-2027. Retrieved from: https://www.svk.se/siteassets/om-oss/rapporter/2018/svenska-kraftnat-system-development-plan-2018-2027.pdf

raise the nuclear capacity tax by 17 percent from 2015 (THEMA Consulting, 2015). In the following year, E.on announced that it would decommission the Oskarshamn nuclear power plant by 2017, stating that the company did not find it “financially viable” to invest in either continued operation of the plant after 2020 or the necessary upgrades to keep the unit operational until then (THEMA Consulting, 2015). In the same year, Vattenfall also announced that it would decommission the reactors Ringhals 2 and Ringhals 1 by 2019 and 2020 respectively, instead of 2025 as originally planned, due to expectations of low prices and increased production costs in the years to come.

According to the energy agreement (2016), the phase-out act was removed and new investments on existing sites are allowed. The principle that nuclear power should not be subsidized remains and investments need to be carried out in order to meet future radiation security standards. On the other hand, the tax on installed thermal power is phased out. The conservative party, Moderaterna, has advocated a strategy for a fossil-free energy sector rather than a renewable energy sector in order to keep nuclear power in the system.

5.3.3 Climate Policies

In 2009, the Swedish Government declared its target to reduce Sweden’s greenhouse gas emissions from non-ETS sectors by 40 percent in 2020 relative to 1990-levels. Two thirds were set to be achieved through domestic emission reductions while one-third would be achieved by investments in other EU Member States or through flexible mechanisms (e.g. through joint implementation projects or the clean development mechanism–CDM).

Sweden has implemented CO_2 taxation since 1991 in addition to a previously existing tax on fossil fuels. According to the IEA, Sweden has the world’s highest CO_2 tax in the non ETS sector and households/services. In 2009, the Riksdag decided to increase efforts to steer decarbonisation via a CO_2 tax reform limiting exemptions for energy-intensive industry and other emissions outside the EU-ETS. Taxes on heating fuels were reformed too to better reflect their impact on emissions.

Table 2: Overview of the changes introduced by Sweden's 2011 CO_2 tax reform

Area of use	Changes in 2011 (decided by Riksdag in 2009)
Households and services	100 % energy tax based on energy content (€ 0.008/kWh); 100 % CO_2 tax
Industry outside EU-ETS and agriculture	30 % energy tax (€0.0025/kWh); 30 % CO_2 tax, rising to 60 % from 2015
Installations within the EU-ETS	Industry: 30 % energy tax (€0.0025/kWh); 0 % CO_2 tax Heat production in CHP: 30 % energy tax (€0.0025/kWh); 7 % CO_2 tax, falling to 0 % from 2013; Other heat plants: 100 % energy tax; 94 % CO_2 tax

Source: IEA (2013, p. 34). Energy Policies of IEA Countries–2013 Review.

Sweden further enacted a new Climate Policy Framework in 2017, with the objective of achieving zero net emissions by 2045, also extending GHG emission reduction targets to non-ETS sectors (reduction of more than 63 percent by 2030 and 75 percent by 2040 compared to 1990 levels). It also contains a target for reduction of transport-related emissions by 70 percent by 2030 compared to 2010 levels. The parliament is expected to adopt an action plan outlining specific measures to attain the set objectives.

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6 GERMANY

6.1 Summary

Both demand and generation of electricity remained more or less unchanged year-on-year from 2007 to 2016. Consumption fell briefly during the financial crisis in 2009, but quickly recovered. While overall generation did not change much, Germany saw a considerable change in the power mix, with a 40% reduction in nuclear power generation being counterweighted by a strong growth in wind and solar power.

Germany has been a net exporter of electricity throughout the period 2007–2016. However, the increasing imbalance between generation in the North and demand in the South combined with limited transmission infrastructure leaves Northern regions oversupplied while demand centres in the South and the West face an electricity deficit. This trend has been exacerbated in the period between 2009 and 2016.

Despite the reduction in wholesale prices, end-user prices have increased due to grid costs and renewable energy support. The numbers indicate that prices would have increased even more were it not for the relatively low coal and CO_2 prices in the period.

The ambitious *Energiewende* policy led to massive costs to develop solar PV and wind generation. However, the decision to phase out nuclear power has also had a significant impact on the German capacity mix. The simultaneous phase-out of nuclear capacity that would otherwise have been a low-carbon complement to support a rapid decarbonisation complicated the agenda and ultimately led to de facto the same level of coal generation in the market in 2016 than in 2007.

A feed-in tariff support scheme that decoupled renewable energy producers entirely from developments on the wholesale market, did however erode the economics of gas power plants, illustrated by the changes in the price structure and the falling capacity factors in the period after 2010. Although gas plants would constitute a flexible generation source ideally suited to react to the intermittency of renewables, the design of the subsidy regime and a massive growth of renewables diminished their profitability. The situation was exacerbated by the relative increase in gas prices and the low CO_2 price in the period. Coal power plants were thus the generation source favoured by the merit order and hence, CO_2 intensity of the German power sector has declined much slower than in other EU countries, e.g. the UK.

The introduction of a contingency and a capacity reserve in the German power market can be seen as a consequence of energy policies not catching up with market developments. Security of supply, cost considerations as well as sustainability and innovation were mentioned as the main arguments for the introduction of market design measures in the *electricity market 2.0* strategy. However, due to the former mainly relying on coal power generation, the approach has to be questioned when other, more sustainable measures to ensure security of supply might in fact exist.

The nuclear phase-out ahead of the coal phase-out puts Germany in a tight spot concerning its decarbonisation targets. Inner German grid expansion is delayed and cannot alleviate loop flows due to excess wind power in the north and a lack of firm capacity in the south. The price zone split with Austria has, for the moment, given Germany some time to deal with its internal bottlenecks. The EU Commission, however, might have tools at hand to demand an inner-German price zone split eventually if the situation does not improve. The politically sanctioned nuclear moratorium and the proposed coal phase out trajectory does not simplify the task for the country. Additional pressure comes from a large share of renewable energies not responding to price signals on the wholesale market and affecting the economics of gas power plants and biomass generation.

Transforming the EEG subsidy from a feed-in tariff to a marked-linked premium and introducing auctions to lower the levels of payments to RES generators was a step in the right direction. In light of its ambitious CO_2 reduction targets (-40 % by 2020 compared to 1990 levels), further steps will certainly be needed to achieve the set objectives.

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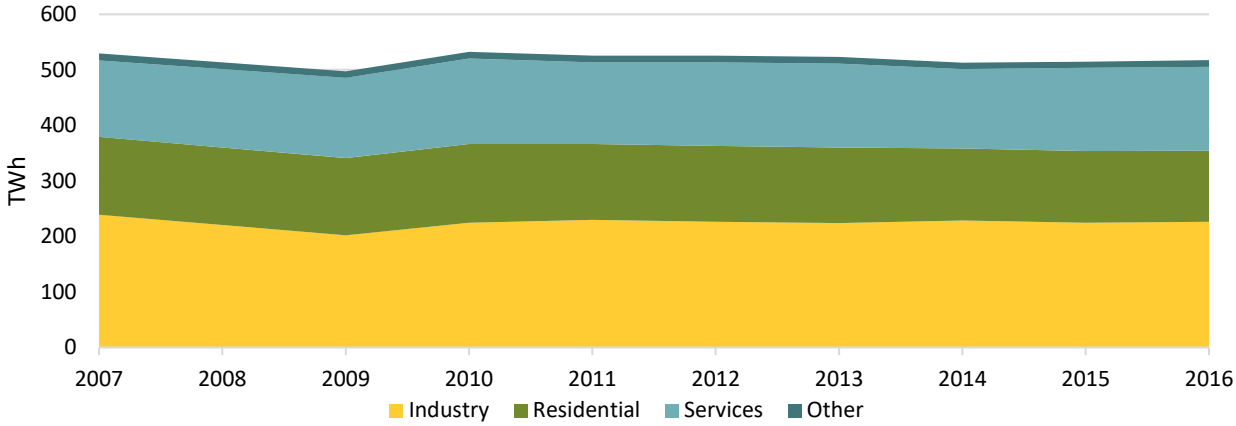
6.2 Market developments 2007–2016

6.2.1 Demand

Electricity demand in Germany hardly changed year-on-year from 2007 to 2016, falling merely by 2 percent or 12 TWh. Consumption fell briefly during the financial crisis in 2009, but quickly recovered. Industrial electricity consumption has historically made up a considerable share of the total electricity consumption in Germany. With the industry's share of total consumption making up 44 percent in 2016, Germany is among the countries in the EU with the highest share of electricity consumption by the industry sector.

Figure 34 shows electricity consumption per sector in Germany from 2007 to 2016. German electricity consumption decreased by about 2 percent (12 TWh) between 2007 and 2016, mostly driven by strong demand decline from households (-9 %) and industry (-5 %). Consumption in the services sector, on the other hand, rose by 10 percent.

Figure 34: Electricity consumption development 2007–2016 in Germany (in TWh)



Source: Eurostat (2018)

Germany reaches its peak demand in the winter when electricity used for heating is at its highest. Compared to the seasonal demand patterns in the Nordic countries, Germany has a flatter demand profile throughout the year as a lower share of the heating sector is electrified and the winter is generally warmer.

6.2.2 Generation and capacity

Figure 35 shows the electricity generation mix for Germany 2007–2016. Total generation was almost unchanged year-on-year with on a 1 percent increase (6 TWh), due to strong growth in solar (+35 TWh) and wind (+39 TWh) being balanced out by a 40 percent fall in nuclear power generation (50 TWh) and a 12 percent (-35 TWh) decline for coal/lignite.

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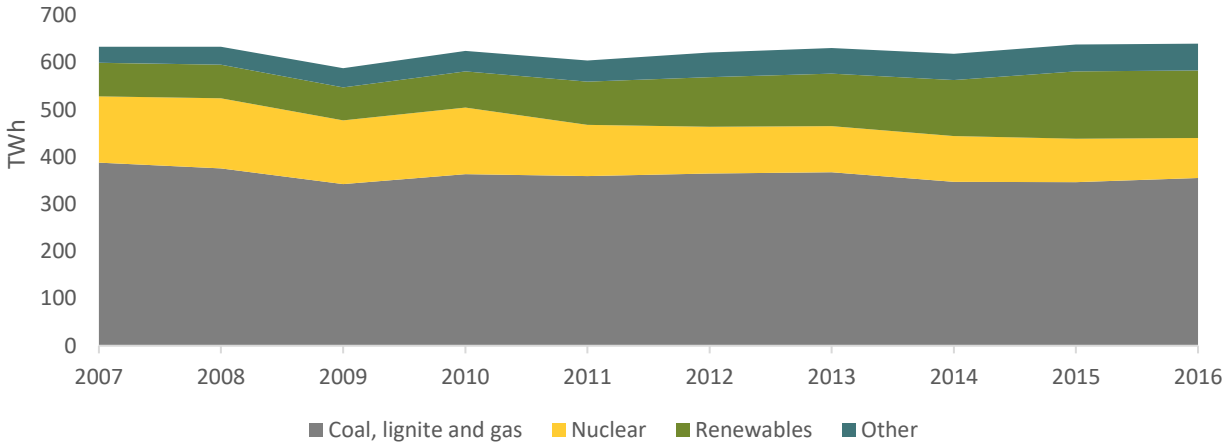
Figure 35: Electricity generation mix in Germany 2007–2016 (in TWh)

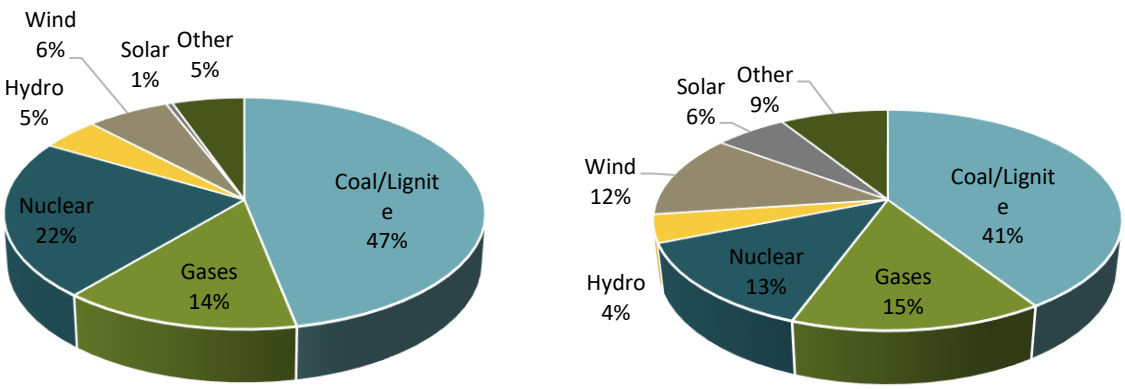


Source: Eurostat (2018)

The share of fossil fuel in the power mix remains almost unchanged, with coal, lignite and gas constituting 61 percent in 2007 and 56 percent in 2016 as seen in Figure 36. Thus, emission intensity of the power sector has decreased from 521.7 gCO_2/kWh in 2007 to 440.8 gCO_2/kWh in 2016 over the observed period (European Environment Agency, 2018). Nuclear generation fell from 22 to 13 percent, while wind and solar grew from 7 to 18 percent.

Figure 36: Electricity generation mix in Germany 2007 and 2016 (in %)

a) Electricity generation mix in Germany 2007 *b) Electricity generation mix in Germany 2016*



Source: Eurostat (2018)

Total installed capacity increased by 52 percent (69 GW), driven mainly by solar and wind expansion (+37 GW and +27 GW). The only technology that saw a drop in installed capacity was nuclear power (-10 GW), where almost half of the capacity was removed from the market after the Fukushima catastrophe, depicted in Figure 37. An increase in gas power capacity (+8 GW) partly made up for the reduction in nuclear capacity. Gas power also has the ability to shoulder the volatility of

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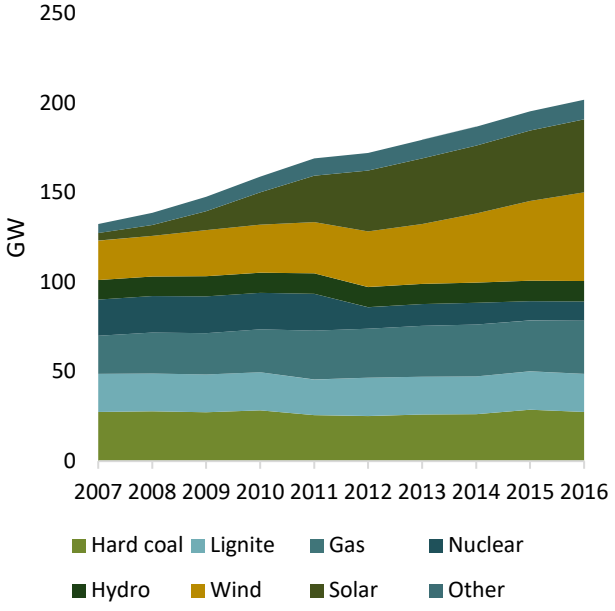
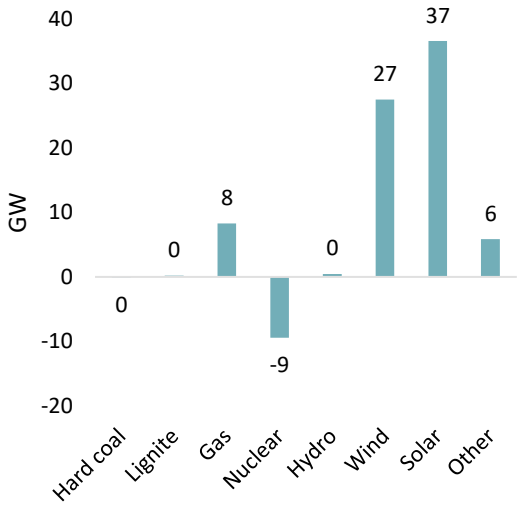
generation of wind and solar power. Hardly any changes in the installed coal and lignite capacity occurred.

Figure 37: Development of installed electricity capacity 2007-2016 for Germany

a) Development of installed electricity capacity 2007–2016 for Germany (in GW)



b) Change in installed electricity capacity pr. technology in Germany 2007–2016 (in GW)



Source: Eurostat (2018) & Fraunhofer ISE (2018)

Figure 38 shows the change in the load factor for different generation technologies in Germany 2007–2016. For the total electricity system, the load factor fell by 9 percentage points, mostly due to a large increase in solar and wind capacity, which in general have a lower load factor than conventional power plants due to the intermittency of the energy source.

In addition, the load factors for coal-fired generation fell by 8 percentage points from 2007 to 2016 and gas by 12 percent. In a period of low coal and carbon prices, gas–but also biomass– have been pushed out of the market in hours when renewable generation is high. The falling load factors had major implications for incumbent utilities with large conventional generation assets. Owing to the risk of stranded assets, RWE and E.ON, among other European utilities, put pressure on Member States to introduce Capacity Markets instead of other measures to support security of supply (van der Burg & Whitley, 2016) .

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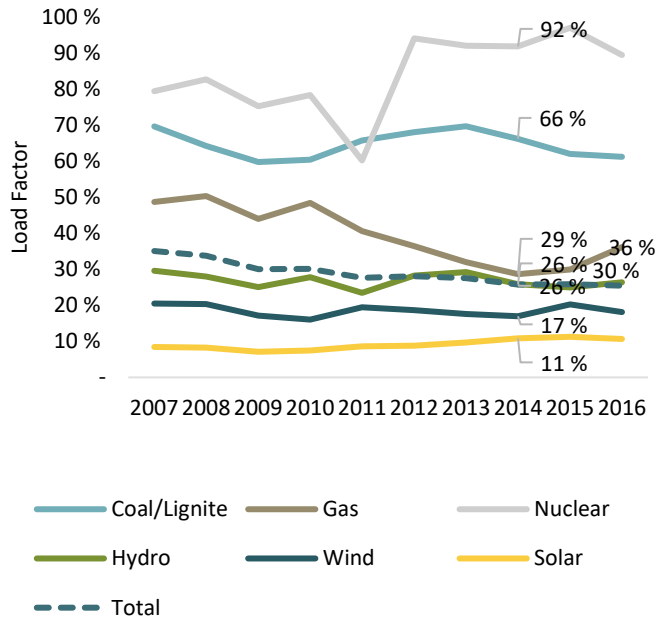
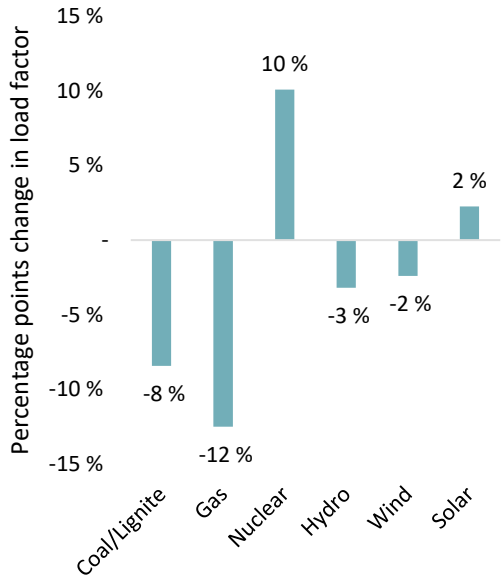
Figure 38: Load factor development for different generation technologies in Germany 2007-2016

a) Load factor development pr. generation technology in Germany 2007-2016.



b) Percentage point change in load factor pr. production technology in Germany 2007-2016



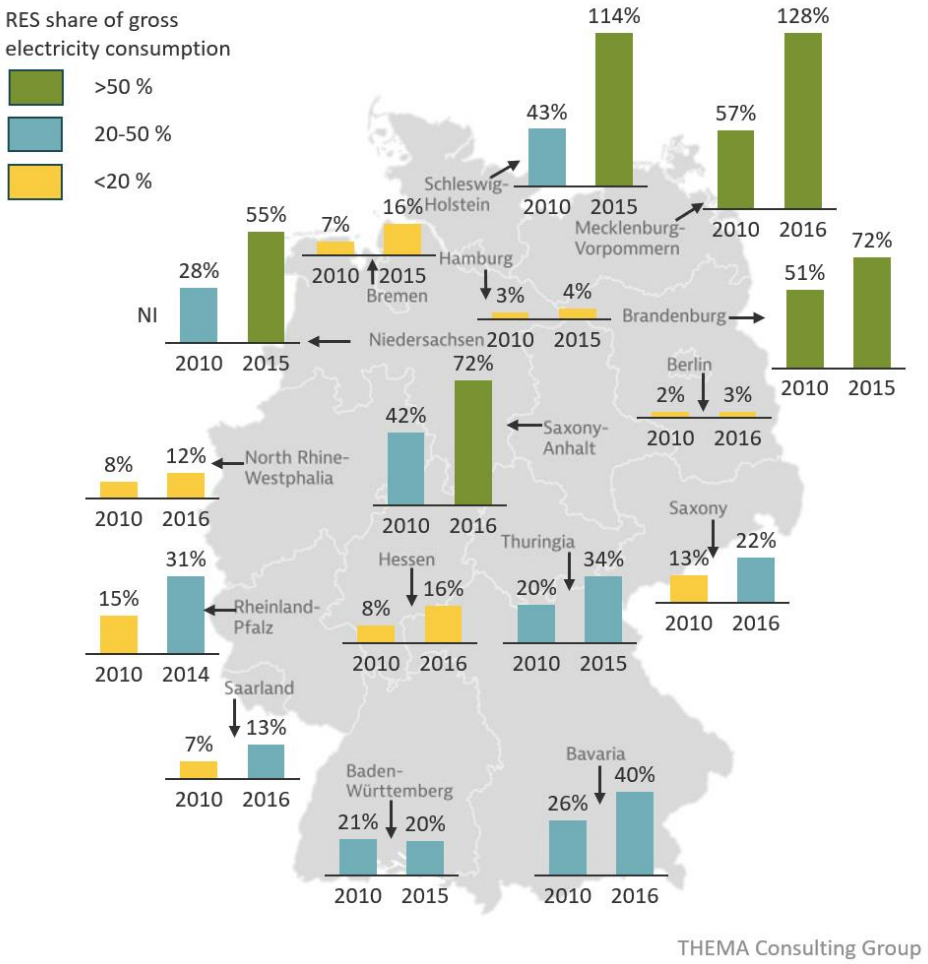
Source: Eurostat 2018

6.2.3 Geographical distribution of renewable energy development

Figure 39 illustrates how the renewable energy share of gross electricity consumption has developed from 2010 to 2014/15/16. As the figure illustrates, the Northern regions of Schleswig-Holstein and Mecklenburg-Vorpommern have seen their renewable energy generation rise above gross electricity consumption, with the RES share jumping to 114 percent and 128 percent respectively in 2015, above all as a result of massive wind power deployment.

Even though additional solar PV and occasionally wind is built in the South, the loss of firm capacity due to the decommissioning of the nuclear power plant portfolio shows the need for more interconnections from the North or a larger share of new gas generation to be built to prevent scarcity episodes. The shutdown of five of the eight nuclear power plants that are due to be shut down between 2017 and 2022 in Baden-Württemberg and Bavaria further underlines the need for alternative solutions to guarantee security of supply.

Figure 39: Renewable energy share of gross electricity consumption per Bundesland in 2010 and 2014/15/16



Source: Data from Föderal Erneuerbar. (https://www.foederal-erneuerbar.de/landesinfo/bundesland/HB/kategorie/top%2010/auswahl/772-anteil_erneuerbarer_/versatz/1/#goto_772)

6.2.4 Cross-border trade

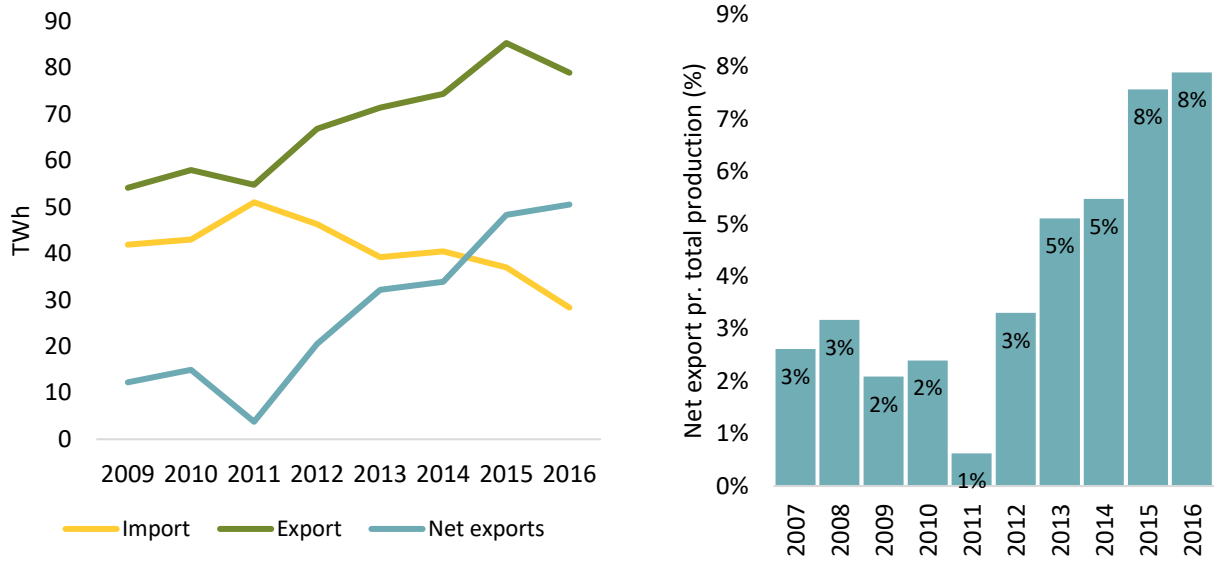
Figure 40 illustrates the development in cross-border electricity trade in Germany 2007–2016. Over the period, exports increased by more than 25 percent, while imports fell by more than a third. This led to net exports more than doubling from less than 3 percent of overall electricity generation to 8 percent. Looking at total traded volume, however, the amount of trade remains almost unchanged.

There is, however, a significant volume of loop flows between Germany and its neighbours. Due to bottlenecks inside the German bidding price zone, excessive wind production cannot be transported to the South where demand sits. Thus, electricity takes the path of least resistance, the market flow from north to south physically flows across the borders to Poland and France and enters the country again in the South through France, Switzerland, Austria and the Czech Republic. Since these loop flows lead to unwanted grid strain in neighbouring countries, they appeal to Germany to either build North-South transmission lines or split their bidding zone to reflect occurring bottlenecks.

Figure 40: Development of import, export and net cross-border trade of electricity in Germany. (in TWh)

a) Development of import, export and net cross-border trade of electricity in Germany (TWh)

b) Net cross-border electricity trade as a share of total electricity production in Germany (%)

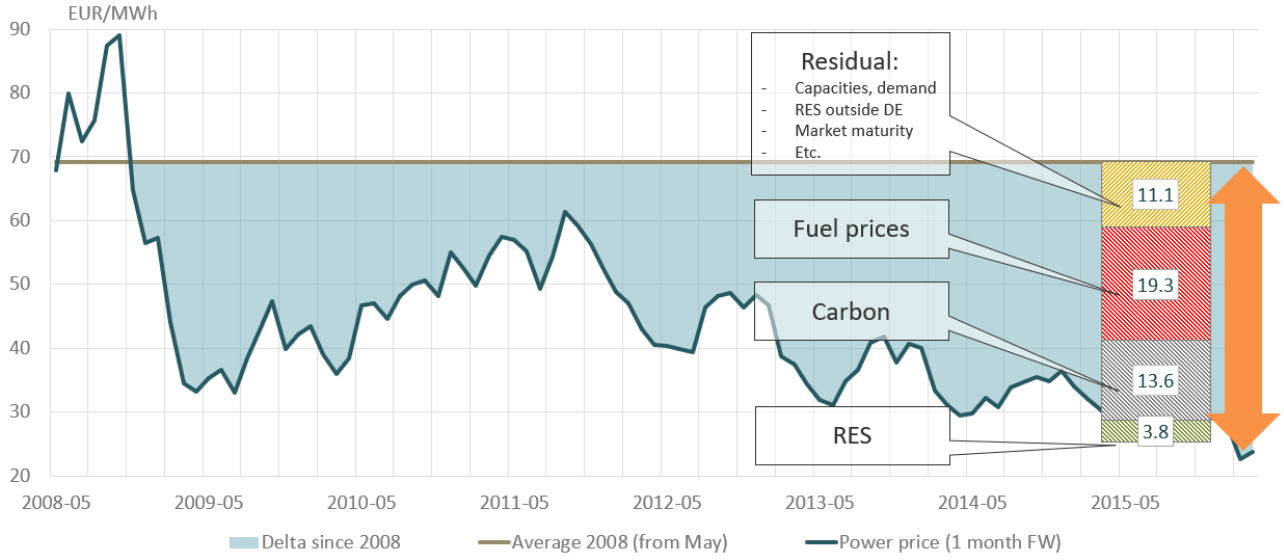


Source: Eurostat (2018)

6.2.5 Retail and wholesale prices

Figure 41 illustrates the relative impact of different price drivers responsible for the fall in wholesale power prices in Germany. In chapter 3, we saw that there was a close relationship between German power prices and short-run marginal costs (SRMC) of coal in the period 2008–2016 when coal was the dominant price-setter. According to an analysis by THEMA (2019), fuel and carbon prices explains 70 percent of the wholesale price change from 2008 to 2015, and the increase in RES generation about 8 percent. The remaining 20 percent or so is explained by developments in demand, capacity mix in surrounding markets and increased market maturity (more efficient trade).

Figure 41: German power prices 2008-2016 decomposed by price driver



Note: Based on "month ahead" contracts. Source: Thema Consulting Group 2019–Workshop Agora Energiewende

The change in the capacity mix has affected the wholesale price structure in Germany, as illustrated in Figure 42. The figure shows the difference of hourly wholesale prices to the average daily price

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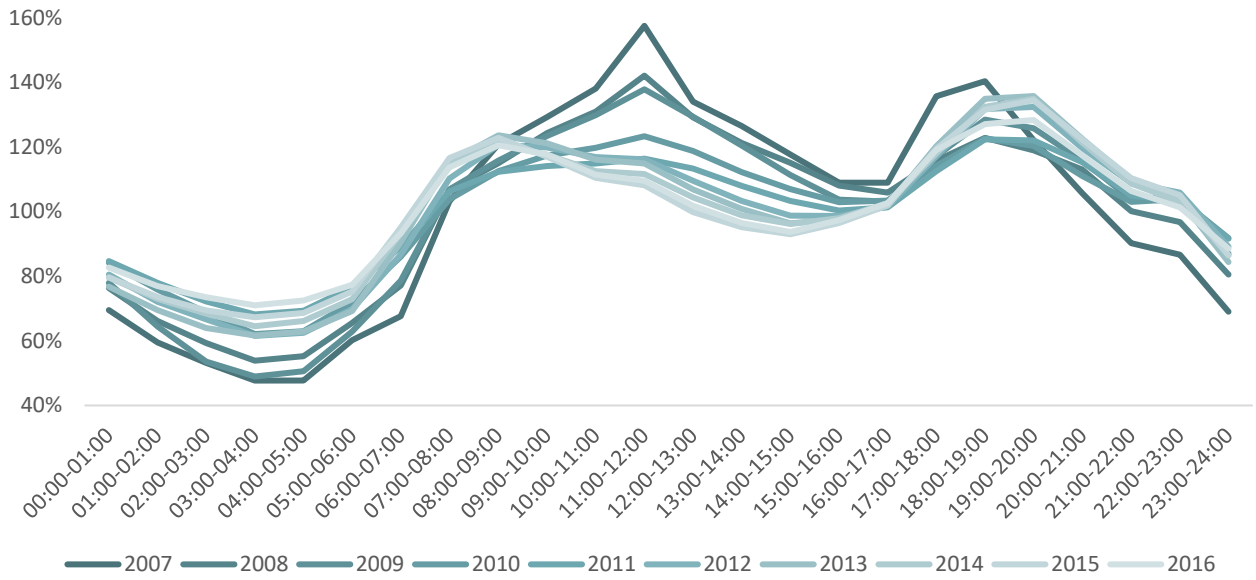
for the respective year. While the influx of solar PV generation is the main explanation for the lower midday peak, less baseload capacity pushes up prices during off-peak periods at night.

Figure 42: Share of average daily wholesale price in Germany, 2007-2016



Source: Montel (2019), THEMA calculations

Figure 43 and Figure 44 show that while wholesale electricity prices fell, retail prices for households increased from 2007 to 2013, due to increasing grid tariffs and especially levies. The fee increase is particularly driven by the EEG surcharge, as end-users finance the Feed-in-Tariff scheme. Greater volumes of RES supported under the EEG framework drove up the EEG levy. Despite a more efficient allocation of subsidies through the introduction of market premia and auctions, costs for the German taxpayer are expected to peak in the early 2020s. However, household prices were roughly stable to slightly decreasing from 2013 to 2016 with increasing grid and EEG costs being offset by lower wholesale electricity prices.

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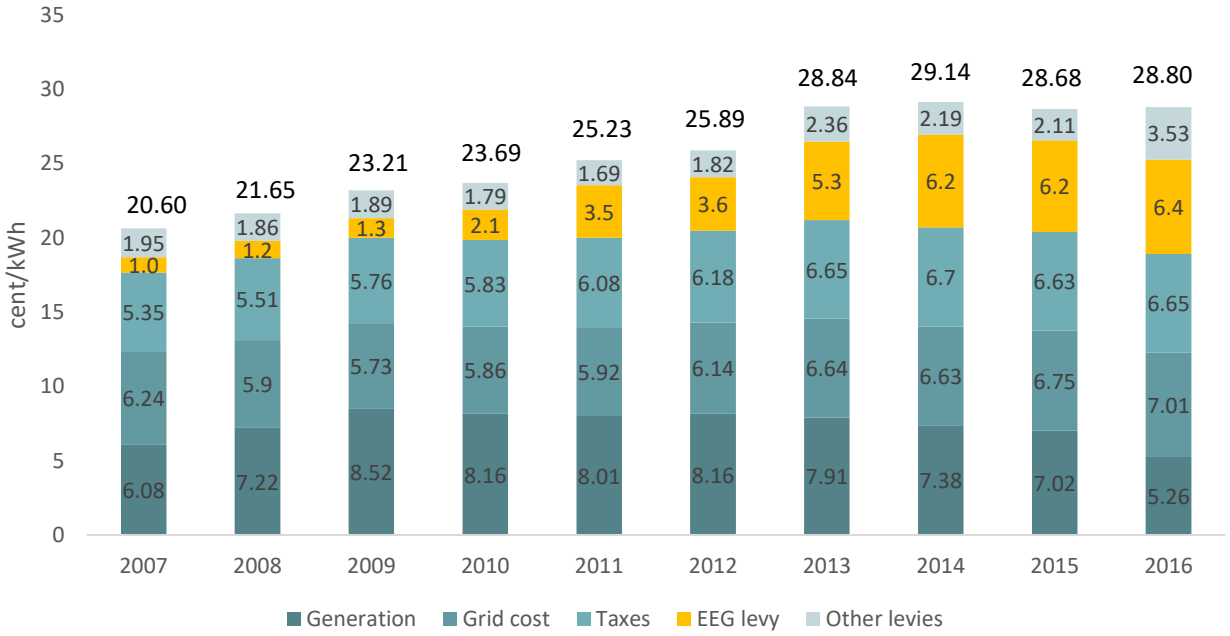
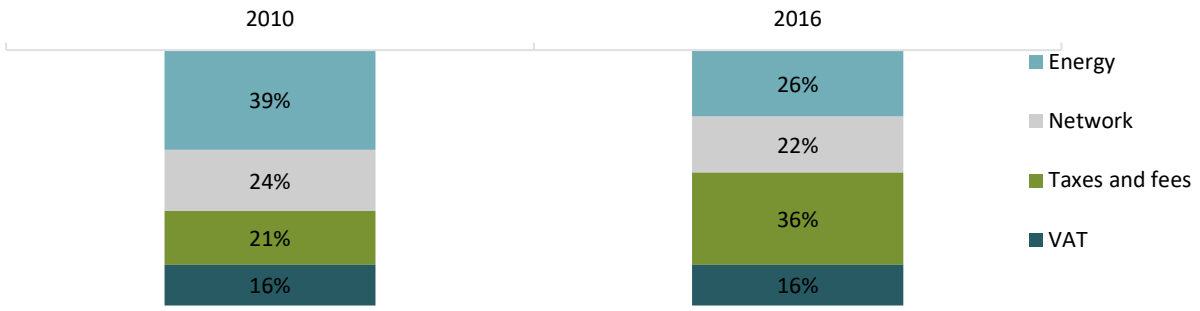
Figure 43: Retail electricity price development for households in Germany with an annual consumption of 2500–5000 kWh (in cent/kWh, nominal)



Source: BDEW (2017). Erneuerbare Energien und das EEG: Zahlen, Fakten, Grafiken (2017)

Figure 44: Breakdown of household electricity cost in 2010 and 2016 for Berlin



Source: ACER Market Monitoring Report 2011 and 2016

There are huge variations in the charges paid by different industrial end-users. Many industrial consumers are eligible for several exemptions such as cuts in the EEG charge, taxes and network tariffs. Some industries hardly pay any mark-ups at all on the wholesale price, see Figure 45. These favourable conditions make German power prices for heavy industry some of the cheapest in Europe while they remain above average for medium-sized industry (Fraunhofer ISI & Ecofys, 2015).

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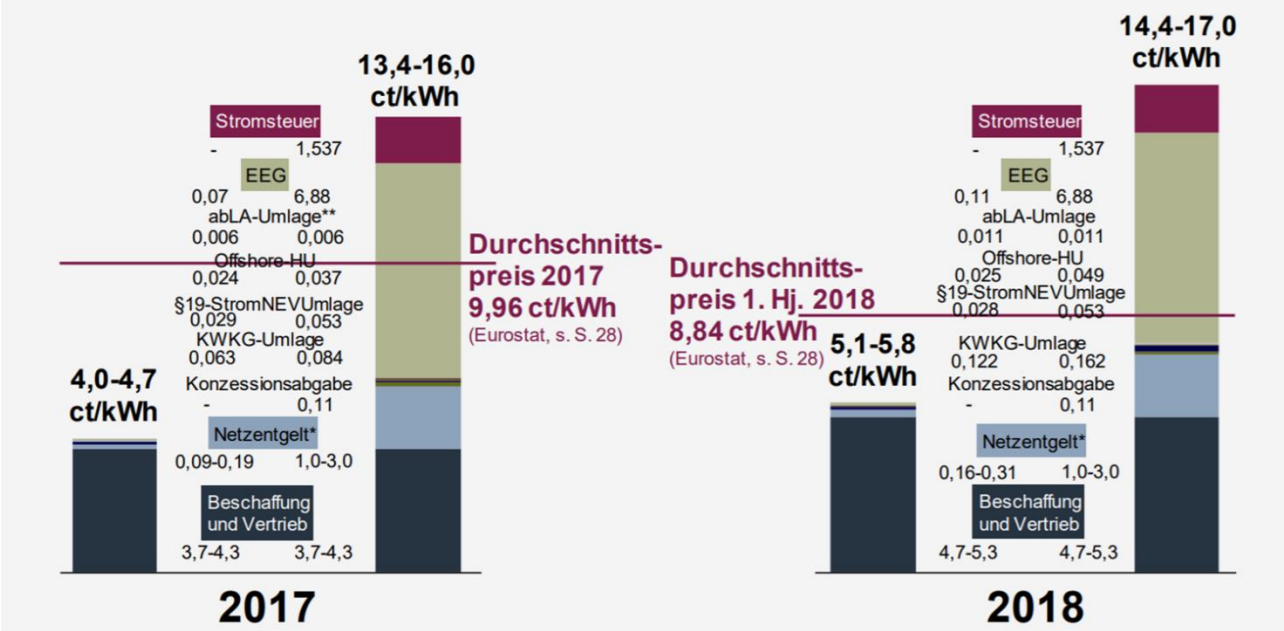
Figure 45: Min-max-variation in power prices for industry in Germany in 2017 and 2018

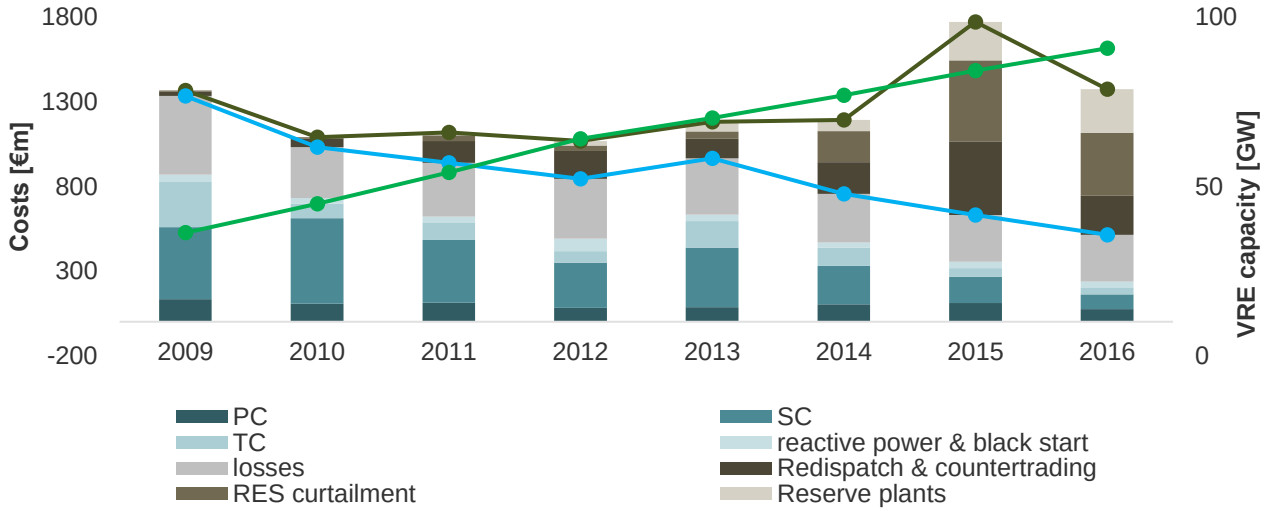


Source: BDEW

6.2.6 Electricity system costs

Figure 46 shows the development of different components of the electricity system operation cost 2009–2016 as compiled by (Joos & Staffell, 2018). As the share of intermittent renewable energy sources has increased, the congestion costs fell, but this was more than made up for by an increase in other system operation costs, most notably redispatch and countertrading costs, curtailment costs and compensation to plants in market reserve. In total, comparing the system operation costs in 2009 and 2016, the increase is however moderate. According to Figure 43, German grid costs have increased, but this is apparently not mainly explained by an increase in system costs.

Figure 46: Socialised annual electricity system operation costs in Germany from 2009-2016



Source: Joos and Staffell (2018)

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6.3 Policy developments 2009–2016

6.3.1 Electricity Market design

In 2015, the White Paper *An electricity market for Germany's energy transition* was published (BMWI, 2015). The White Paper advocates a so-called 2.0 version of the electricity market based on the (energy only) Target model but backed by a capacity reserve, as opposed to introducing a capacity market. The three main arguments for choosing a capacity reserve were that it would ensure security of supply, be cheaper than a capacity market and enable innovation and sustainability.

Capacity mechanisms

The predicted supply squeeze in the South, stemming from lagging grid developments and the nuclear phase-out, has prompted Germany to introduce several capacity mechanisms to ensure security of supply.

In 2015, as part of the "Climate Action Programme 2020", Germany agreed to place 2.7 GW of lignite-fired power generation capacity in a "security contingency" (Sicherheitsbereitschaft) reserve. The reserve was intended to ensure that Germany would preserve energy security while reaching its emissions reduction target of 40 percent by 2020 relative to 1990 levels. The government initially intended to impose a climate levy on fossil-fired generation but instead opted for the reserve solution after opposition from utilities, trade unions and several politicians. Eight lignite power plants were to stepwise join the reserve in the period 2016-2019, before being decommissioned after four years of participation, with the last plant to be closed in October 2023. The operators would be compensated for foregone profits. The European Commission approved the contingency reserve under the state aid rules in 2016. While the mechanism was framed as a measure to limit emissions from the power sector, there are mixed opinions on whether it was in fact necessary or merely a way of subsidizing domestic lignite generation in the presence of alternative measures such as pushing interconnection, prioritization of flexible generation, more demand response or incentivizing renewables to be more responsible for meeting demand.

In addition to the contingency reserve, Germany considered the need to establish a strategic capacity reserve that would be activated if markets do not clear. In 2018, the European Commission approved the German capacity reserve under the state aid rules. Tendering registration for the reserve was opened in September 2019 and closes December 1st, 2019. The reserve is set to be implemented from winter 2020/2021 and cover a two-year period before another tendering process starts. Power supply, demand-side aggregators and storage facilities are eligible for participation. The reserve capacity is determined by the German Transmission System Operators, and initially capped at 2 GW. After 2020, the reserve is allowed to increase to about 5 GW, representing 5 percent of current peak load. Capacity in the reserve would not participate in power markets and only be used when all market-based options in the power market are exhausted. Following an in-depth investigation from the Commission, Germany agreed to modify the reserve to include demand response participation.

Congestion management

According to the German Ministry of Economic Affairs and Industry, grid investments are lagging behind in Germany due to technical difficulties and public acceptance issues, causing TSOs to handle congestions through redispatch and restrictions on cross-border capacity. The urgency is substantiated by a recently adopted law together with a government program to push for faster grid development. Costs for the provision of redispatch and curtailment increased significantly from below 100 million EUR in 2010 to above 800 million EUR in 2015.

In 2013, Germany established a network reserve (Netzreserve) to have sufficient capacities for redispatch to solve grid congestion between North and South Germany. The network reserve, which mainly consists of power plants in Southern Germany, is kept available for redispatch. It serves to ensure security of supply and grid reliability until the internal transmission network is sufficiently strengthened or the capacity is replaced by alternative technologies. As a measure under the 2015

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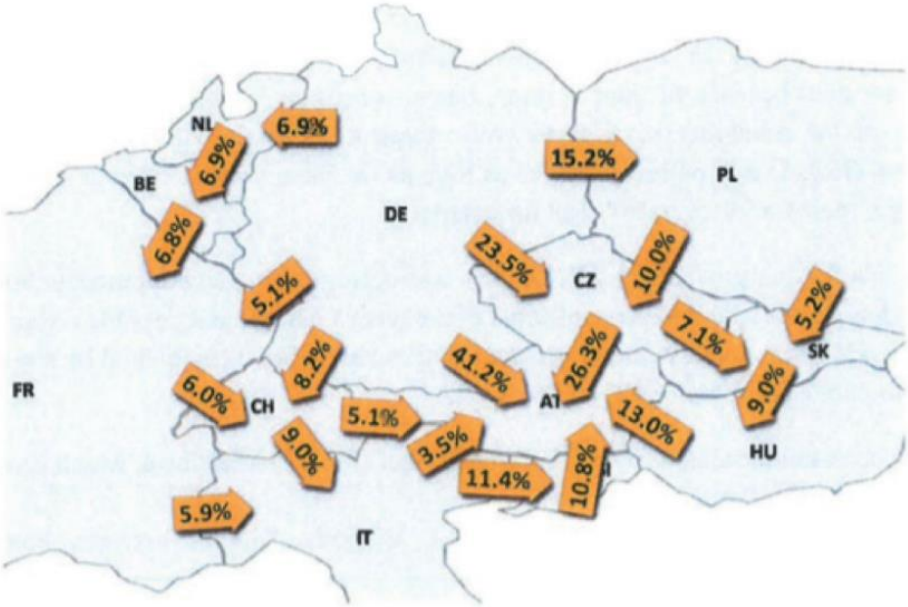
White Paper, the network reserve was prolonged beyond 31 December 2017. The grid reserve is due to expire in 2023 when the most important grid expansions are set to be finalized. As of now, delays look increasingly likely and a further extension could therefore soon be announced. Like the capacity reserve, power plants in the grid reserve cannot be traded in the electricity market. The providers are remunerated for their capacity on standby and activated by the grid operators who pass the costs on to grid consumers through grid tariffs.

From 2001 to 2018, Germany and Austria constituted one common bidding zone, created as part of a wider plan to integrate European energy markets. The common German-Austrian bidding zone came under increased pressure as it allegedly created loop flow problems in neighboring countries. The loop flows partly stem from a lack of transmission capacity between the strong renewable supply in northern Germany and the demand-heavy industrial south. The disrupting loop flows led to complaints from Poland, the Czech Republic, Slovakia and Hungary, which fueled debates on splitting the common bidding zone into two or more bidding zones. Often, physical energy flowed from Germany via Poland, the Czech Republic, Slovakia and Hungary in the east or via the Benelux countries and France to Switzerland to the west as can be seen in Figure 47. A decoupled price in Austria would effectively eliminate loop flows to Austria but could remain for the delivery of power from Northern Germany to the South if transmission bottlenecks in Germany occur. The measure can thus only serve as an interim step to maintain the political stipulation of a single bidding zone for Germany.

Figure 47: Physical flow distribution following a commercial trade from Germany to Austria



Source: ACER (2015)

The Austrian government and Austria's market regulator (E-control) heavily opposed the split, as Austrian consumers profited from lower prices when renewable penetration from Germany in the common bidding zone was high. In contrast, the German and European regulatory authorities, the German Federal Network Agency and ACER called for a split, and in 2017 Germany and Austria agreed to split the bidding zones by 1st October 2018 (E-control, 2018). In In Figure 48, the price premium for Austrian power, especially during winter, can be easily observed. Since the split, times of high wind output with depressed prices in Germany do not automatically evoke lower Austrian prices anymore.

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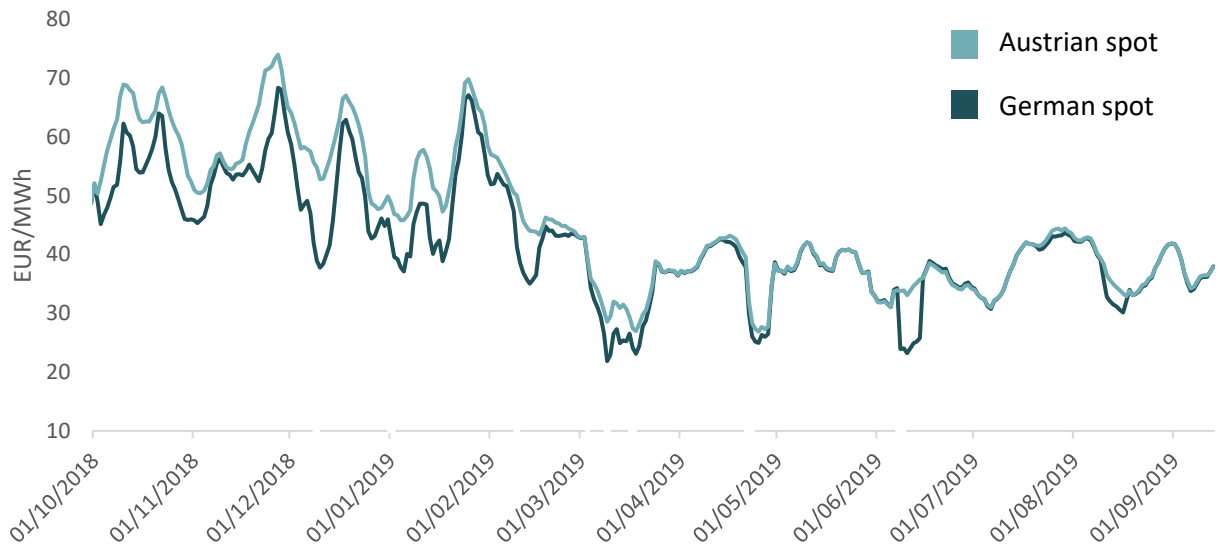
Figure 48: Development of weekly average spot prices in Austria and Germany



Source: Montel (2019)

While German authorities supported splitting the common bidding zone into one German and one Austrian bidding zone, they refused to split Germany further into one Northern and one Southern bidding zones. They have been particularly concerned about the potentially large price differences that would arise between the North and South, with the industrial South facing higher prices in the event of a market split (DIW, 2015). In November 2017, the Federal Cabinet approved an amendment to the Electricity Network Access Ordinance, which enshrined that the transmission system operators will not have the power to split Germany into several bidding zones (Federal Ministry for Economic Affairs and Energy, 2017).

6.3.2 Energy policies

In 2009, the Coalition Agreement between the Christian Democrats (CDU/CSU) and Liberal Democrats (FDP) pledged to present a new energy concept in 2010 for clean, reliable and affordable energy supply.

In September 2010, the German government adopted ambitious energy policies further enshrining the Energiewende as a pivotal objective by laying the foundation for a long-term energy transition towards 2050 with renewable energy as its cornerstone. The policy included the following targets:

- Cutting CO_2-emissions relative to 1990-levels by 40 percent by 2020 and 95 percent by 2050
- Increasing the share of renewable energy in gross energy consumption to 18 percent by 2020, 30 percent by 2030 and 60 percent by 2050
- Increasing the share of renewable energy in gross electricity consumption to 35 percent by 2020 and 80 percent by 2050
- Reducing electricity consumption 50 percent below 2008 levels by 2050

The energy policy built on the Integrated Energy and Climate Programme of 2007 but differed from previous nuclear policies by allowing prolonged lifetimes for nuclear plants.

Ruling out nuclear energy as a bridging technology after the Fukushima catastrophe resulted in the adoption of a second package of measures to accelerate the energy transition.

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Renewable energy support - from Feed-in tariffs to Feed-in premiums

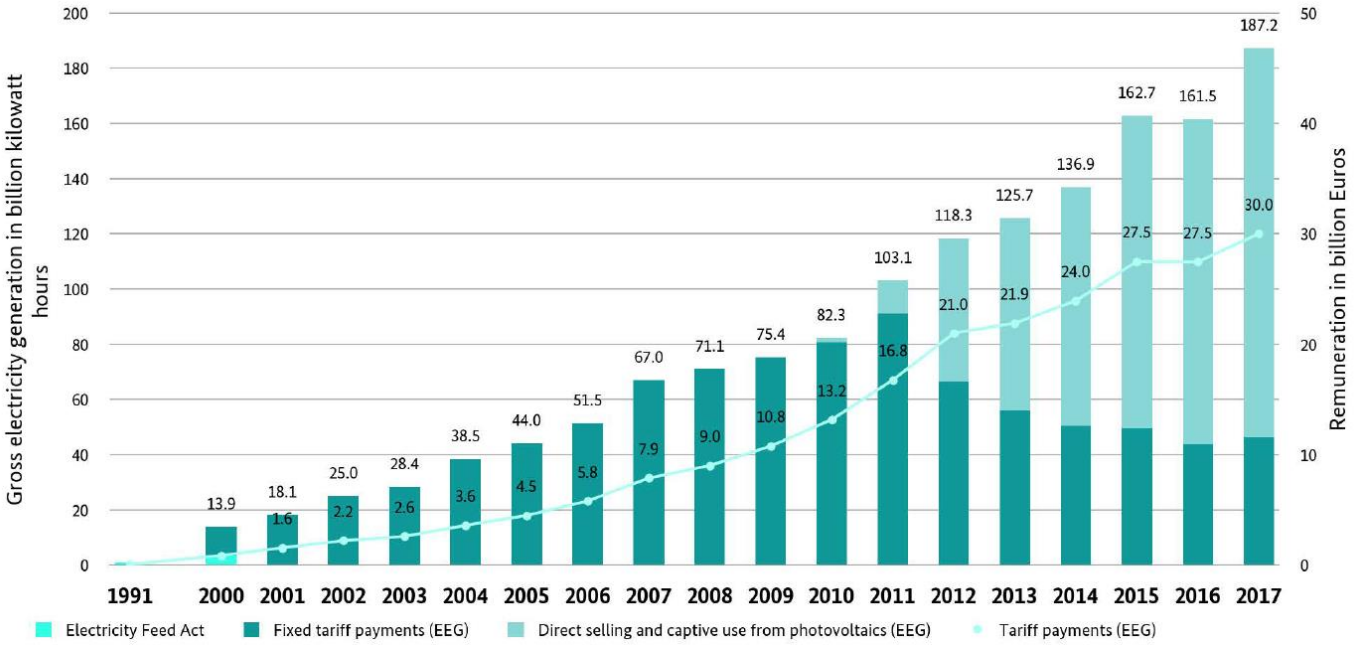
Support for renewable energy already started in 1991, when Germany introduced an electricity feed-in law known as Stromeinspeisungsgesetz, obligating utilities to purchase electricity from certain renewable energy sources. The growth in renewables under the scheme was limited, however, with the share of renewable energy increasing by 0.33 percent per year in the period 1991-2000 (Rutten, 2014).

The substantial growth in renewable energy in Germany has largely been driven by subsequent legislation, i.e., the Renewable Energy Sources Act or EEG (Erneuerbare Energien Gesetz), which first came into force in 2000 and has been revised several times since. The initial EEG act entitled producers generating electricity from solar, wind, hydro and biomass to fixed remuneration for each kWh of electricity for a duration of 20 years. The EEG serves as the key policy instrument for the Energiewende (Energy Transition) (Leiren and Reimer, 2017).

The comprehensive energy strategy, issued by the German government in September 2010, designated renewable energy as the backbone of its future energy mix. The revised energy package from 2011, after Fukushima, consists of seven acts and one ordinance, and contains measures to support renewable energy and grid expansion, promote energy efficiency, fund the reforms and phase out nuclear.

In 2012, the EEG was further modified with the aim to create stronger exposure to market signals. A market premium scheme was introduced as an alternative to fixed feed-in tariffs. The amendment served to limit the costs of the support mechanisms. Figure 49 illustrates the development in generation (left axis) and remuneration (right axis) in 1991 and from 2000 to 2017. Electricity generation from renewable energy sources with remuneration under the EEG has increased from around 10 TWh in 2000 to 188 TWh in 2017. With the revised remuneration system introduced for PV in 2010 and 2011 before the complete overhaul of the EEG in 2012, generation remunerated through fixed FiTs diminished and over time, more and more new facilities received subsidies that gave incentives based on market prices. This led to smaller relative growth but also capped government spending on the Energiewende.

Figure 49: Feed-in and fees under the Electricity Feed Act and the Renewable Energy Sources Act (EEG)



Source: Federal Ministry for Economic Affairs and Energy (2017). Development of Renewable Energy Sources in Germany 2017. Retrieved from: https://www.erneuerbare-energien.de/EE/Redaktion/DE/Downloads/development-of-renewable-energy-sources-in-germany-2017.pdf?__blob=publicationFile&v=17

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Nuclear power phase-out

Germany began using nuclear power commercially in the 1960s but has faced large opposition from the public in several waves since the early 1970s. While Germany enacted a law to phase out nuclear power in 2002, Merkel's government announced plants to reverse the law and grant lifetime extensions to nuclear power plants in 2010. In response to the Fukushima nuclear disaster in March 2011, the German parliament reversed the decision and agreed to shut down eight nuclear power plants immediately and phase out the remaining nine by 2022 (Leiren and Reimer, 2017). Nuclear power was thus removed as a bridging technology from Germany's energy policy (IEA, 2013).

Coal phase-out

In 2007, the Federal Government and the hard-coal mining trade union reached an agreement to phase out hard coal mining by the end of 2018. At the time, this decision was mostly based on economic considerations, since coal imports consistently undercut domestic hard coal prices. The sector thus had to be heavily subsidized to be able to stay in business (Frondel et al., 2007). A support package for the affected regions was introduced to alleviate the impact on the local economies and help former coal miners to retrain and find new jobs.

In a further step, following the Paris Climate Accords in 2015, Germany's grand coalition government could not agree on certain energy and climate policies, and thus agreed to appoint an independent commission made up of experts from the industry and environmental groups, the concerned ministries and regions to negotiate a phasing out of coal power generation and give recommendations on how to best achieve this. In January 2019, the "coal commission" proposed to shut all coal power plants by 2038 the latest, potentially by 2035 if the circumstances in the power and labour markets as well as favourable economic factors would allow it. (WSB Kommission, 2019).

6.3.3 Climate Policies

In 2007, the German government set greenhouse gas reduction targets of 40 percent by 2020, compared to 1990 levels. 3 years later, as part of the Energy Concept policy package, targets for GHG reductions were set to 55 percent by 2030, 70 percent by 2040 and 80–95 percent in 2050, all compared to 1990 levels.

In support of the new laws and targets of 2010, Germany implemented the Energy and Climate Fund, which should be built up using revenues from nuclear power (around 20 %) and the auctioning of emission allowances under the EU-ETS (the remaining approx. 80 %). After the Fukushima incident and the subsequent decision to phase out nuclear power, the funding structure was reformed to make up for missing revenues from the sector. It was decided to use all auctioning revenues from EU-ETS allowances instead. The IEA (2013) estimated that almost 10 bn. EUR would be available for energy efficient building refurbishment, advancing electric transportation, international climate and environmental protection and other energy efficiency purposes during the period of 2013 to 2016.

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