



# e invest

The power sector investment challenge:  
**100 Billion** per year and counting



Eurelectric represents the interests of the electricity industry in Europe. Our work covers all major issues affecting our sector. Our members represent the electricity industry in over 30 European countries.

We cover the entire industry from electricity generation and markets to distribution networks and customer issues. We also have affiliates active on several other continents and business associates from a wide variety of sectors with a direct interest in the electricity industry.

#### **We stand for**

The vision of the European power sector is to enable and sustain:

- A vibrant competitive European economy, reliably powered by clean, carbon-neutral energy
- A smart, energy efficient and truly sustainable society for all citizens of Europe

We are committed to lead a cost-effective energy transition by:

**investing** in clean power generation and transition-enabling solutions, to reduce emissions and actively pursue efforts to become carbon-neutral well before mid-century, taking into account different starting points and commercial availability of key transition technologies;

**transforming** the energy system to make it more responsive, resilient and efficient. This includes increased use of renewable energy, digitalisation, demand side response and reinforcement of grids so they can function as platforms and enablers for customers, cities and communities;

**accelerating** the energy transition in other economic sectors by offering competitive electricity as a transformation tool for transport, heating and industry;

**embedding** sustainability in all parts of our value chain and take measures to support the transformation of existing assets towards a zero carbon society;

**innovating** to discover the cutting-edge business models and develop the breakthrough technologies that are indispensable to allow our industry to lead this transition.



Dépôt légal: D/2019/12.105/30

WG Wholesale Market Design & Investment Frameworks  
WG RES & Storage

Contact:  
**Hélène LAVRAY**,  
Senior Advisor - Renewables & Environment - [hlavray@eurelectric.org](mailto:hlavray@eurelectric.org)

**Eurelectric report**  
September 2019



The power sector investment challenge:  
**100 Billion** per year and counting



## Key Messages

### The investment challenge

- Electrification, combined with complete decarbonisation of the power sector, is key to achieving a carbon-neutral EU economy as set out in the European Commission's Long-Term Energy and Climate Strategy. This will require a significant increase of investments in clean generation and storage (towards €100 bn per year<sup>1</sup> over the period), as well as additional grid and infrastructure investments.
- The path and investments required to reach carbon neutrality of the power sector differ from country to country as the EU Member States have different generation mixes, a variety of available resources and market design specificities.
- The electricity sector is ready to play a leading role in these investments and made a pledge to become carbon-neutral well before 2050. In addition, consumers will have to undertake large investments in electrification of households and businesses.
- Overall, an efficient energy transition requires a consistent combination of market design, regulatory framework and energy policies.

### The market and the Clean Energy Package at work

- The whole market framework, including a strong EU Emissions Trading System (ETS) to provide an efficient carbon price signal, must be able to work and provide these investment signals to accelerate the energy transition. Markets, not only policies, should define the supply-demand balance.
- Commitment to a strong and stable ETS is necessary. More generally, a CO<sub>2</sub> price signal is also required to decarbonise transport, heating and other diffuse sectors.
- Political and regulatory risk remains the biggest problem for making long-term investments, including those made by small (including domestic) consumers.
- The Clean Energy Package is a major step forward and it must be effectively implemented. However, while it will improve the functioning of short-term markets, it fails to provide a definitive solution to the problem of providing long-term investment signals to achieve the energy transition cost-effectively. The Governance framework will be key to ensure that Member States are on track to reach the 2030 climate and energy objectives and beyond, while progressing towards a single electricity market.

---

<sup>1</sup> Eurelectric, Decarbonisation Pathways, 2018



## **Investments, both in grids and by customers, combined with efficient regulation, smart tariffs and taxes**

- Considerable investments in transmission and distribution grids are necessary to accommodate the challenges brought by the energy transition and to replace the ageing infrastructure. Efficient regulation is required to incentivise innovation and proactive development of the networks, consistently with the deployment of decarbonised generation.
- Consumers will eventually carry out significant investments to reduce their consumption and switch to electricity. Efficient customer consumption and investment decisions require smart tariffs and adequate allocation of taxes and levies. The deployment of charging infrastructure for electric vehicles presents particular challenges.

## **Investments in generation, demand-side response and storage still require solving technical and market design challenges**

- Renewables are the backbone of the future electricity system: by 2030, they will account for up to 60% of electricity generation in the EU, with over 80% by 2045. To reach these levels, Europe needs to significantly accelerate the pace of renewable development of the past. The Clean Energy Package provides a framework for national measures and for regional cooperation to enable the power sector to deliver on investments in renewables. However, there are still national and local barriers.
- Currently, fossil thermal generation is providing most of the firmness and flexibility, together with nuclear and hydro, but is being phased out. In the future, a system with a large share of variable renewables will require an increase in decarbonised firm and flexible capacity e.g. generation, storage and demand-side response. This is the biggest challenge, both technically and in terms of market design.



# Table of Contents

## Recommendations

<b>1</b>	<b>Focus on resilient and forward looking long-term policies to foster the change towards a generation system based on renewables</b>	<b>1</b>
<b>2</b>	<b>Ensure a level playing field for customers</b>	<b>2</b>
<b>3</b>	<b>Introduce smart network tariffs and smart use of smart meters</b>	<b>2</b>
<b>4</b>	<b>Foster risk-hedging instruments for carbon-neutral generation investments and transition enabling technologies</b>	<b>3</b>
<b>5</b>	<b>Deliver the needed new firm/flexible capacity</b>	<b>3</b>
<b>6</b>	<b>Improve network regulation</b>	<b>4</b>
<b>7</b>	<b>Improve planning tools</b>	<b>4</b>
<b>8</b>	<b>Reach decarbonisation through electrification</b>	<b>5</b>
<b>9</b>	<b>The way forward</b>	<b>6</b>
<b>1</b>	<b>The investment challenge – how to translate the European electricity sector’s climate commitments into reality</b>	<b>7</b>
<b>2</b>	<b>Building the decarbonised electricity system</b>	<b>9</b>
<b>3</b>	<b>Is the current market and regulatory context sufficient to deliver a carbon-neutral power sector while maintaining security of supply?</b>	<b>14</b>
<b>3.1</b>	<b>Carbon price: one step forward</b>	<b>18</b>
<b>3.2</b>	<b>Asymmetric taxes, charges and levies hinder decarbonisation</b>	<b>19</b>
<b>3.3</b>	<b>The deployment of renewables</b>	<b>26</b>
<b>3.4</b>	<b>Delivering firm and flexible carbon-neutral capacity</b>	<b>33</b>
<b>3.5</b>	<b>The legacy generation system</b>	<b>38</b>
<b>3.6</b>	<b>The transmission and distribution grids</b>	<b>44</b>
<b>3.7</b>	<b>The downwards investment spiral</b>	<b>48</b>
<b>5</b>	<b>Does the Clean Energy Package solve this situation?</b>	<b>55</b>



## Recommendations

### **1. Focus on resilient and forward looking long-term policies to foster the change towards a generation system based on renewables**

#### **Implement the CEP and continue working towards an integrated European market through better coordination of national and EU energy policies**

By 2030, electricity generated from renewables is expected to almost double compared to today, raising from 32% of the generation mix today to almost 60% by 2030, and reaching at least 80% by 2045. The CEP is setting a clear path towards a system revolving around a high share of variable renewables. This requires a significant acceleration of the pace of renewables deployment, with a yearly capacity addition superior to what has been achieved so far (see section 3.3).

Focus must be on implementing the CEP and continuously working towards an integrated European market through better coordination of national and EU energy policies and the implementation of the network codes and guidelines already in place. The Governance provisions of the CEP are a solid start, and the development of European and regional adequacy assessments will help. National and regional variations in market design might be inevitable due to differences among countries, but they must be integrated into the European market. Policymakers should allow the markets to work freely, as much as possible unhindered by distortions and interventions, while efforts to streamline authorisation and permitting processes and legal frameworks should continue. Public acceptance issues should be addressed in line with best practice tools.

The European Commission and Member States should guarantee long-term political commitment to continuous and ambitious CO<sub>2</sub> emission reductions towards a carbon-neutral economy by 2050. They should also ensure a strong EU ETS, providing an efficient carbon price signal as the core instrument for decarbonising the ETS sectors.

While these should be the primary objectives of the Commission and Member States, industry will engage with stakeholders to improve public acceptance.





## 2. Ensure a level playing field for customers

### **Stop hindering the potential of electricity through taxes and levies. They should provide efficient and stable signals for decarbonisation and should be harmonised across fuels**

The current tax and tariff system penalises the electricity from the grid, by loading it with enormous burden of taxes and levies, while benefitting the oil and gas sector, where taxes usually do not reflect externalities and do not contribute to the decarbonisation effort (e.g. they do not finance renewables deployment). Distorted tariffs encourage the use of the grid as a fall-back option without payment and provides an incentive to go off-grid. Inefficient electricity tariffs also induce negative distributive effects through cross-subsidisation, creating a “customer divide”. Electricity should be taxed when delivered for consumption, while taxes on generated electricity and distortive tariffs on storage should be removed.

Though it is a responsibility of the Member States, at European level, a revision of the Energy Taxation Directive should reflect the role of electricity in decarbonisation. A shift from unanimity rules to qualified majority vote within the Council of the EU may allow major structural changes.

## 3. Introduce smart network tariffs and smart use of smart meters

### **Make use of smart meters to introduce smart network tariffs that give efficient signals to distributed generation and storage, demand electrification, etc**

Demand side flexibility requires prices and tariffs that signal energy and networks costs, restrictions and needs. Smart meters can now support almost any conceivable scheme, including hourly (or 15 minute) energy prices and grid tariffs. Smart meter technology can support tariffs that are robust and give efficient signals, not only signalling scarcity of energy, but also network congestions.

Smart tariffs should provide efficient frameworks for citizens energy communities (CECs), distributed generation, active customers, demand-side response and electric vehicles. However, a CEC should not be charged less than the sum of its individual members, as long as their behaviour does not change, and an EV owner should not pay more if he/she has a parking spot separated from their home.

The Member States are responsible for extending best practice in network tariff design introduced in the CEP using this mechanism, while the EU Commission should monitor the progress.



## 4. Foster risk-hedging instruments for carbon-neutral generation investments and transition enabling technologies

### **The Member States should consider additional risk-hedging instruments for carbon-neutral generation investments providing long-term price signals**

The energy transition involves significant investments that need efficient risk management, but there are currently not enough instruments and counterparts to trade large volumes in the long-term. Even though industrial customers may need such volumes, their investment visibility is seldom further than 2-3 years, while generators operate with further horizons in mind. Corporate PPAs are expected to play an important role but will not be sufficient to deliver on all the investments needed. Adequate visibility of long-term revenues can however reduce the cost of capital significantly.

The Member States should be working in the framework provided by the CEP, however Eurelectric expects the revision of the Guidelines on State aid for environmental protection and energy (EEAG) to drive the design of long-term risk hedging instruments for carbon-neutral generation investments.

Some Member States already have a positive investment framework, either with or without explicit interventions. However, for those who do not have such an investment framework in place, this could include well-designed renewables auctions and other support schemes, which would have to comply with the CEP and the EEAG.

## 5. Deliver the needed new firm/flexible capacity

### **The Member States should consider capacity markets to deliver new firm/flexible capacity (storage, demand-side response, Power-to-X).**

A mix of technologies, including storage, demand-side response and power-to-x, will deliver the new carbon-neutral firm and flexible capacity. The main justification for firm/flexible capacity is security of supply. However, customers' economic incentives to hedge security of supply risks is questionable, since they may rely on governments to take care of it.

As long as scarcity pricing is not credible in many markets, and where scarcity situations are rare and sudden events, it may be necessary to consider capacity markets as an alternative.

- Capacity markets provide efficient hedging and long-term price signals for technologies that will not deliver much energy.
- They hedge security of supply not for individual consumers, but for the system as a whole.
- They can be instrumental in fostering demand side response, as seen in the United States.

Finally, a capacity market (together with a strong CO<sub>2</sub> price signal) is an efficient way of driving the transition from thermal plants to new carbon-neutral firm capacity.

While the Member States bear the responsibility in order to make maximum use of the strict framework provided by the CEP, the Commission will have to approve any new scheme.



## 6. Improve network regulation

### Improve efficiency and performance incentives in network regulation

The current regulatory approach is coherent with what is required for an established technology and gradual change. It focuses on minimising costs and unnecessary investments. Network deployment follows demand and does not precede it.

However, it usually provides little incentive to innovate, or even to adopt a proactive stance needed to modernise assets, to extend the grid to facilitate renewables deployment, and to contract services instead of investing.

Incentive regulation approaches must be followed to:

- foster the deployment of smart grid technologies and digitalisation;
- extend the network proactively and efficiently to facilitate the integration of new renewables and new loads (EV, etc.);
- facilitate the deployment of local flexibility by shifting from remuneration based on a separate control of investment (CAPEX) and expenses (OPEX) to schemes focusing on the combination of both (the so-called TOTEX), leaving the network operators more flexibility to organise their business. Remuneration should be based on performance, and not only on physical investment.

It is a responsibility of the national regulatory authorities, who should rely on the European knowledge of the Council of European Energy Regulators (CEER) to apply the best practices. CEER could monitor progress in this area.

## 7. Improve planning tools

### Introduce a wider and more realistic set of assumptions in system planning tools

Current tools, such as MAF/SOAF, usually take an optimistic view of the availability and financial viability of current capacity in the mid-term. They frequently ignore political debates such as coal and nuclear phase-out. They tend to neglect investors' point of view and do not incorporate economic conditions for investments. Therefore, they tend to overestimate security of supply.

We need planning tools to analyse the impacts of different policy options on security of supply, emissions and competitiveness, and the CEP provides an adequate framework for this.

We need visibility on national targets and measures (e.g. renewables, efficiency, etc.) and the Governance Regulation has a key role to play.

This is a responsibility of ENTSO-E and Member States, within the framework provided by the CEP, working closely with the Commission.



## 8. Reach decarbonisation through electrification

### Facilitate electrification investments as the key for decarbonisation

Since 2011, the electrification rate of Europe has stabilised around 22% (see Eurelectric Decarbonisation Pathways), while projections for 2050 are 50% and above. Changing the trend quickly requires millions of individual decisions by customers.

The implementation of energy efficiency legislation and, in particular, the Energy Efficiency National Funds, can provide a framework for supporting investments in demand electrification.

For industrial customers, support schemes can be developed when shifting from fossil-fuels based industrial processes to decarbonised solutions. For households and commercial customers, this can be used to promote solutions such as heat pumps, when they are the most efficient. Moderating risks for customers/investors is critical for the social acceptance of electrification.

Future European legal and regulatory initiatives will be useful for this:

- An ambitious review of the Air Quality Directive, in line with the 2030 Climate & Energy objectives, would be an opportunity to deploy electrification solutions in the transport and heating sectors.
- For new buildings and renovations, CO<sub>2</sub> emissions standards should encourage decarbonised solutions (electricity or green gases).

This is a responsibility for the Commission when launching the new legal and regulatory initiatives, and for Member States working closely with it.



## 9. The way forward

The CEP does not address all the critical issues, but there will be no major new EU legislation anytime soon. Therefore, for a number of issues, national solutions are realistic in the mid-term. This will be the case for taxes, smart tariffs, corporate PPAs, renewables support schemes, capacity markets and networks regulation. These national solutions should be subject to some common principles (e.g. polluter pays, efficient distribution of the decarbonisation burden, avoid distorting the dispatch and the wholesale market).

In addition to the above (see 5.8), what will be the next relevant European legislative and regulatory initiatives?

- The Review of the Market Stability Reserve (MSR) should signal the continued EU's commitment to address the oversupply of allowances.
- The revision of the EEAG could offer some room to improve the coordination of markets and public intervention.
- The future framework for sustainable finance must include all the investments in the decarbonisation of the energy system.
- A review of the Water Framework Directive should consider the role of hydropower in providing flexibility/firmness.
- A review of the Alternative Fuels Directive to support the shift to zero-emission mobility.

Regarding existing assets, an efficient market design should drive an efficient replacement of old assets with new ones and enable existing assets to continue their operation when efficient. In any case, freedom to exit the market is a must, as recognised in the CEP.

Any EU funding until 2030 should help achieve a cost-effective energy transition. In particular, it should facilitate a "Just transition" in regions affected by structural changes and on the EU islands, taking into account different starting points and local availability of key transition technologies.

# 1 The investment challenge – how to translate the European electricity sector’s climate commitments into reality

To meet the goals set by the Paris agreement, the EU has committed, by 2030, to at least 40% emissions reduction below the 1990 level, and has further set an aspiration of 80–95% reduction by 2050. Today, roughly three quarters of emissions in Europe come from energy use across economic sectors. The European power sector, represented by Eurelectric, is committed to lead the required energy transition by delivering a cost-effective decarbonisation that will support European competitiveness in the global market place. In its new vision published in 2017<sup>2</sup>, the power sector made a pledge to become carbon-neutral by 2045, considering the different starting points of each European country and the commercial availability of key transition technologies.

There are two main reasons why electrification helps delivering decarbonisation:

- First, most decarbonised energy sources are actually electricity generation sources. Only biomass for direct uses and, to a much lesser extent, solar thermal or geothermal energy for low temperature heat, are decarbonised energy sources not linked to electricity. The technological improvements and cost reductions in renewable technologies such as photovoltaic and wind have been impressive and, even in the most pessimistic projections, are expected to continue in the coming years. Therefore, decarbonised electricity largely based on renewables has become the backbone of the energy transition.
- Second, electrical appliances and processes are often more energy-efficient than their non-electrical alternatives. For instance, an electric car engine or an electric heat pump is at least three to five times more efficient than their non-electric alternatives (a thermal car engine or a natural gas boiler).

Thereby, the power sector will support other sectors in their cost-effective decarbonisation efforts via:

- Mainly and first, direct electrification of energy uses in transport, heating, cooling and industrial processes.
- Second, the so-called indirect electrification: the production of hydrogen (obtained by the electrolysis of water, using electricity to separate hydrogen from oxygen) and synthetic fuels such as methane (produced from carbon and hydrogen, using electricity). These fuels can directly power machines and equipment in processes that cannot efficiently be electrified or, on the longer term, be transformed back into electricity when renewables production is not sufficient.
- Third, the use of electricity to power carbon capture and storage and to produce biofuels.

Eurelectric has completed a comprehensive study to assess the potential contribution of the power sector to economy-wide decarbonisation: Decarbonisation Pathways<sup>3</sup>. It concludes that electrification, coupled with full decarbonisation of the power sector is a direct, effective and efficient way of reaching the decarbonisation objectives for the society as a whole. 80–95% decarbonisation of the energy used in the EU economy requires a strong impulse across a portfolio

---

<sup>2</sup> [Eurelectric. Vision of the European Electricity Industry. 2017](#)

<sup>3</sup> [Eurelectric. Decarbonisation Pathways. 2018](#)

of decarbonisation levers, in which direct electrification of end-uses in buildings, industry and transport will play a significant role. Currently, only approximately 22 % of energy consumption is electrified. For the EU to reach 95% energy emissions reduction by 2050, direct electrification needs to supply close to 60% of final energy consumption. This electricity must be carbon-neutral: by 2030, electricity generated from renewables is expected to almost double compared to today (from 30% of the generation mix today to 55-60% by 2030) and to reach at least 80% by 2045.

This transformation will require massive investments. Therefore, Europe should strive towards an attractive framework for all investments, obviously for renewables, but also for all the other needed technologies (firm/flexible capacity, storage, demand side participation), for transmission and distribution grids and for the electrification of households, commercial, transport and industrial sectors. Investments at wholesale level will take place only if investors have a perspective of reasonable return obtained through market mechanisms (energy, capacity, ancillary services, congestion management, guarantees of origin, auctions, etc.), which is appropriate to the risk they are taking. Investment in electrification, at retail level, will only happen if customers have reliable perspectives of saving money on their energy bills. Finally, investments in grids will depend on an efficient regulatory framework.

The greater the risks for investors, the higher the cost of capital and, consequently, the overall cost of the energy transition. However, it is neither possible, nor efficient, to avoid all risk for investors. The principle is that risks should be borne by the party best able to mitigate them. Therefore, a balance is needed: to keep the energy transition affordable for consumers the market design must provide sufficient long-term visibility for investors, while letting them exposed to the risks they can manage. There are different ways of providing this visibility, which this report will explore.

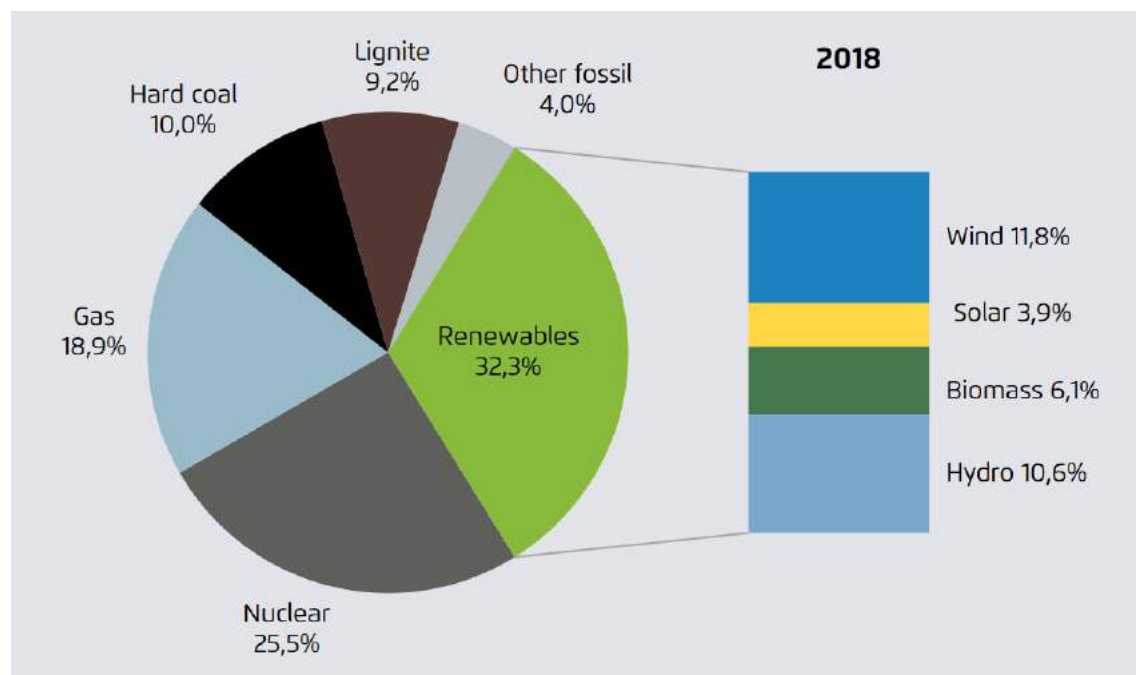
The e-invest project has the objective of providing recommendations for a policy and market investment framework that enables the transition to carbon neutrality.

## 2 Building the decarbonised electricity system

Decarbonisation is more advanced in the electricity industry than in the remaining energy or, more generally, economic sectors. The European electricity industry is strongly committed to a carbon-neutral future.

In 2018, carbon-neutral energy sources already represented close to 60% of the electricity generation mix of the EU, with 32% of renewables and 25% of nuclear.

**Figure 1** – EU electricity generation mix in EU 28 (2018)

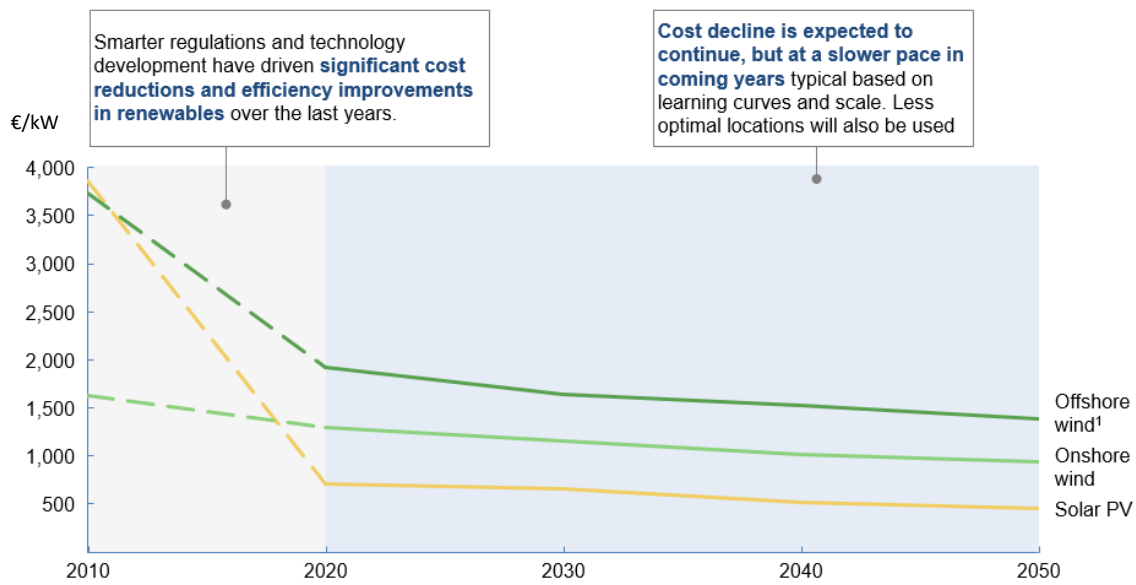


Source: [Agora Energiewende/Sandbag. The European power sector in 2018](#)

In parallel, massive investments and technological improvements, underpinned mainly by subsidies, have facilitated a cycle of dramatic cost reductions in renewables technologies. There are further potential cost reductions driven by innovation, massive capacity deployment foreseen and competition.



Figure 2 – Renewables cost reductions

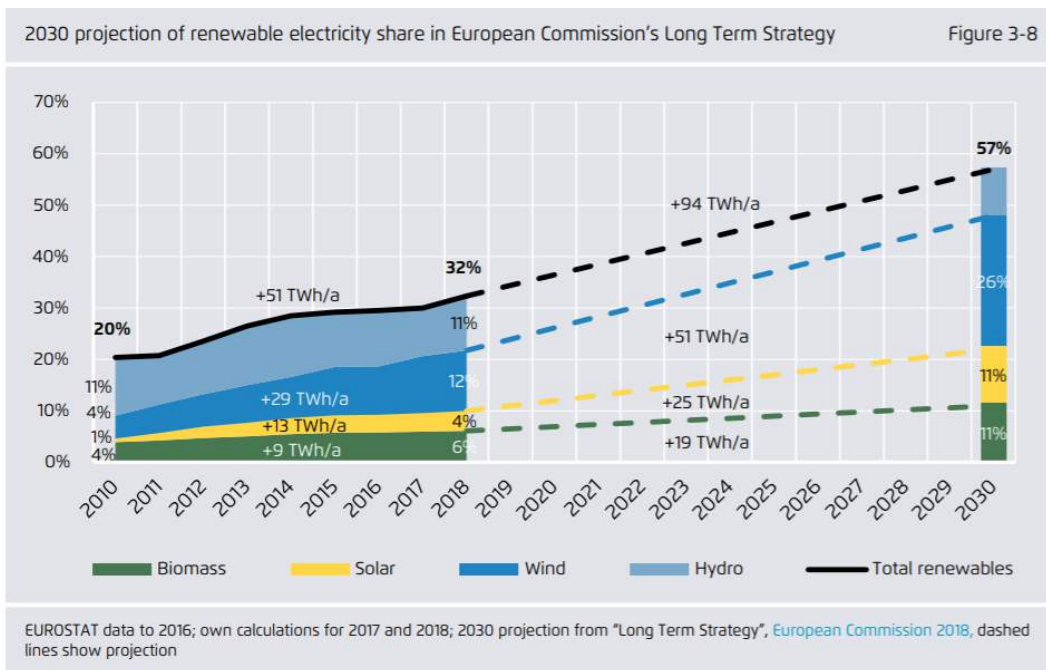


1 It refers to shallow water  
 SOURCE: IRENA ("Renewable Power Generation Costs in 2017") for historical data; ASSET Project ("Technology pathways in decarbonisation scenarios") and Danish Energy Agency (Technology Data for Energy Plants for Electricity and District heating generation) for future projections

Source: [Eurelectric, Decarbonisation Pathways, 2018](#)

According to the European Commission’s Long-Term Strategy, in order to meet Europe’s 2030 targets of at least 32% renewables and 32.5% energy efficiency, the share of renewables in the electricity generation mix must increase to 57% compared to 32% today.

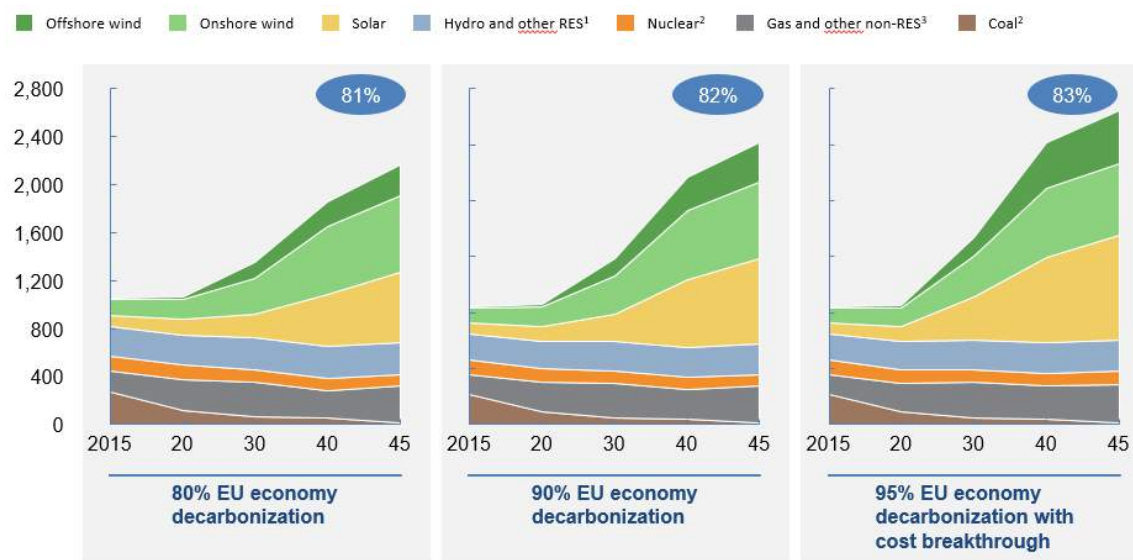
Figure 3 – 2030 Projection of EU renewable power generation



Source: [Agora Energiewende/Sandbag, The European power sector in 2018](#)

Eurelectric's Decarbonisation Pathways study shows that in a carbon-neutral power sector, renewables will account for roughly 80% of the total installed capacity and generation by 2045. This clearly requires a significant acceleration of the pace of renewables development of the recent past.

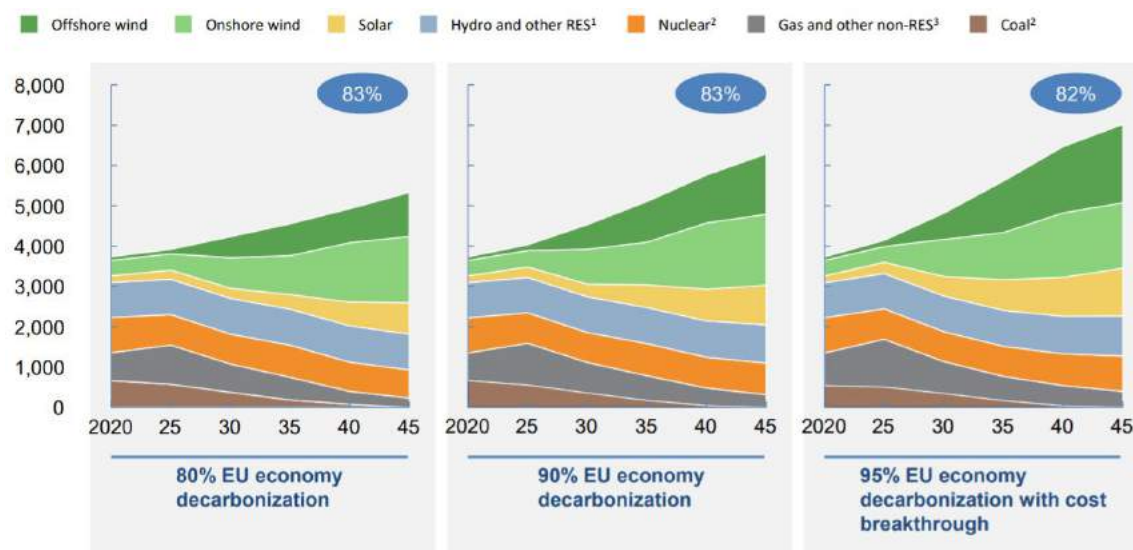
**Figure 4** – Capacity evolution by fuel in the EU electricity mix between 2015 and 2045 in EU 28, GW



1 Includes also small amounts of geothermal, biomass and biogas  
 2 National policies on nuclear and coal phase out have been reflected  
 3 Up to 15% of gas capacity with CCS and other non-renewables  
 SOURCE: 2015 capacity from Enerdata

Source: [Eurelectric, Decarbonisation pathways, 2018](#)

**Figure 5** – Generation by fuel type between 2020 and 2045 in EU 28, TWh



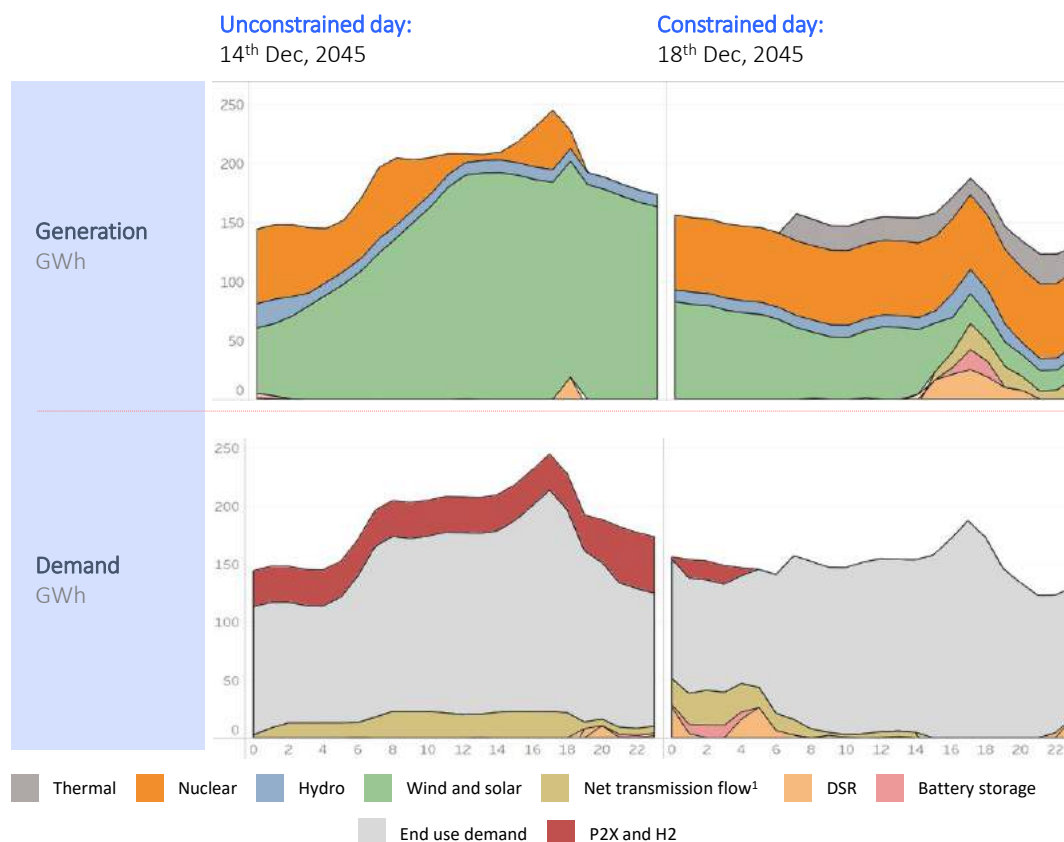
Source: [Eurelectric, Decarbonisation pathways, 2018](#)

Therefore, massive penetration of renewable generation (in most countries, wind and photovoltaic) will be the foundation of the carbon-neutral electricity system of the future. However, wind and solar

will not alone be sufficient for a decarbonised power system: because of the impact that variable renewables (wind, solar) have on system stability and the gradual closure of the thermal generation that is currently providing firmness and flexibility, the system will require new flexible and firm resources. There are different options for this: the already available technologies of dispatchable carbon-neutral generation (e.g. hydropower, nuclear, biomass), largely used today; in the future, thermal assets with green gas or CCS –although the future of this technology in the power sector is very uncertain; short-term storage (batteries, thermal), long-term storage (pumped-hydro storage, power-to-hydrogen, power-to-gas) as well as flexible demand. The scale of this challenge is usually underestimated (see section 3.4). Some of these technologies are not yet fully mature and scalable, so efficient and flexible gas-fired generation has a role to play during the transition period, and possibly in the longer-term if green gas is developed.

In such a system, the availability of variable renewables will be the key feature to manage. For example, on a day with little renewables output, flexible and firm assets have to be dispatched to meet the demand. Figure 6 shows two different days in a high variable renewables electricity system. During a “constrained day”, when there is a very low renewables output, all flexibility options are used during the most constrained hour. During an “unconstrained day”, electricity generation from wind and solar is high and there is little need for dispatchable resources even with a higher demand. The surplus electricity can be stored, exported or used through demand upwards flexibility or to produce power-to-X.

**Figure 6** – Example of the use of flexibility resources to match supply and demand when renewable production is low



Source: [Eurelectric, Decarbonisation pathways, 2018](#)

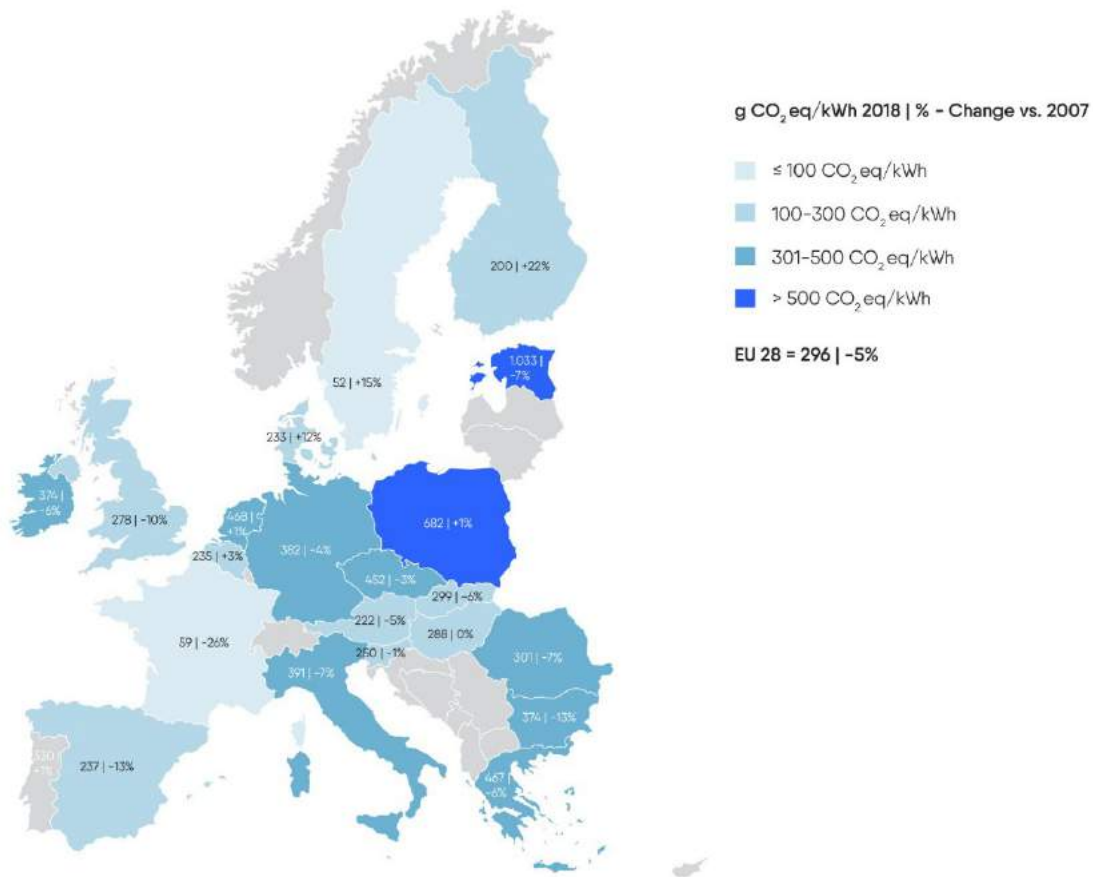
On top of these needs of renewables and firm/flexible capacity, the carbon-neutral electricity system will be more decentralised, and will rely much more than now on investments carried out by customers. In addition, it will require strong and modern networks: investments will be needed to extend and digitise the transmission and distribution grids.

According to Eurelectric's Decarbonisation Pathways study, the average investment in generation and storage, for the period 2020-2045, necessary to reach a target of 80%-95% decarbonisation of the EU economy, is between €89 and 111 bn per year. We are now developing an assessment of the investment needs in distribution grids.

### 3 Is the current market and regulatory context sufficient to deliver a carbon-neutral power sector while maintaining security of supply?

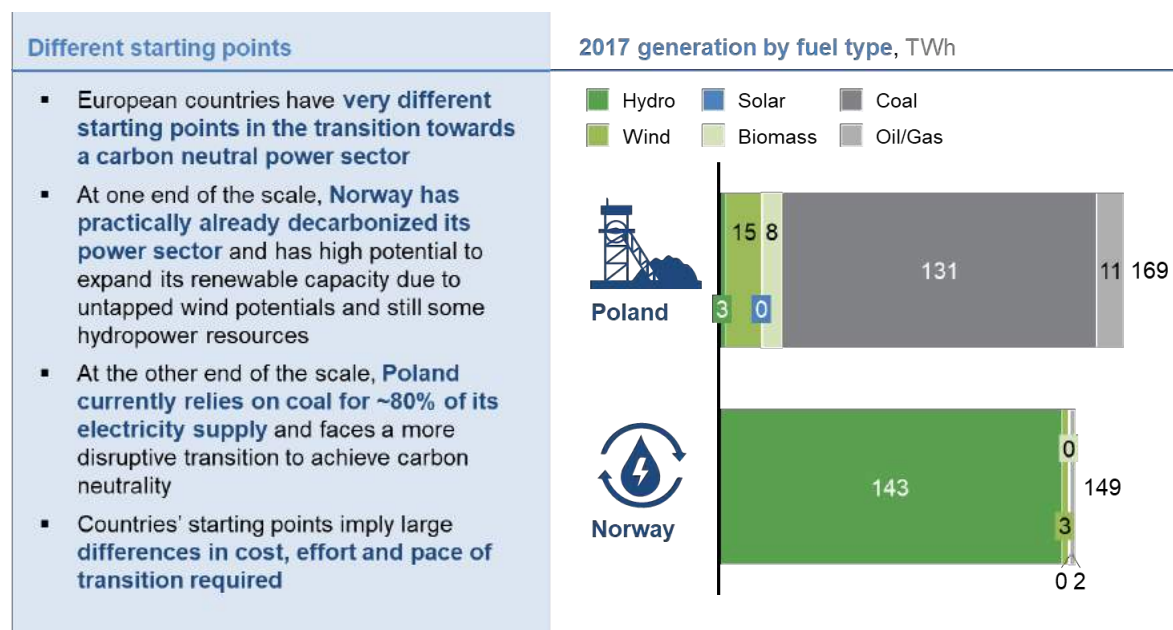
There are clear differences among European countries, such as the availability of natural resources and historic generation mixes with different degrees of decarbonisation. Depending on the region, the political and social tolerance of prices consistent with long-run marginal costs, scarcity prices and volatility in general seem to vary broadly, as well as the acceptance of electricity being a market product. This effectively leads to different degrees of political and/or regulatory interventions, justified to ensure security of supply, to regulate end customer electricity prices or to define what should be the return of investments for energy facilities. This therefore affects the ability of countries to attract investors.

Figure 7 – 2015 carbon intensity of electricity generation (g CO<sub>2</sub>eq/kWh 2018 | %-Change vs. 2007)



Source: [Agora Energiewende/Sandbag, The European power sector in 2018](#)

**Figure 8** – Norway’s power sector is already decarbonised, while Poland relies on coal for 80% of its electricity supply



SOURCE: Enerdata

Source: [Eurelectric. Decarbonisation pathways. 2018](#)

Continued efforts over the years to establish a single European electricity market have brought significant advances. For instance, with the introduction of network codes in the third energy package, progress has been made on the harmonisation of the wholesale market rules, the management of cross-border capacity, the integration of system operation, etc. Nevertheless, there is still a patchwork of energy systems regulated at national level. They include national renewables schemes (feed-in-tariffs, auctions, certificates and Power Purchase Agreements – PPAs); capacity mechanisms (different country-specific schemes approved by the Commission); a number of sectoral schemes (e.g. building efficiency rules, CHP in industries, district heating schemes, mobility plans); as well as different frameworks for generation taxes and fees, grid tariffs and retail price regulation (see box 1), which hinder a European level playing field.

After significant progresses in harmonisation, wholesale markets now successfully coordinate short-term operations and offer mid-term financial hedging possibilities, but are frequently unable to support long-term investments. Market frameworks giving long-term signals, if any, are decided and rolled out at national, not European level. Additionally, many decisions on decommissioning or life-extension of generation are based not on economic, but on political considerations (nuclear and coal phase-out, see box 15, barriers to closure of power plants).

Political and regulatory risks (e.g. interventions in wholesale markets, lack of credibility of scarcity pricing or retroactive measures) are present in many countries and investors cannot hedge them. High and non-manageable risks do result in higher cost of capital, and delays or abandonment of investments and finally higher prices for final customers.

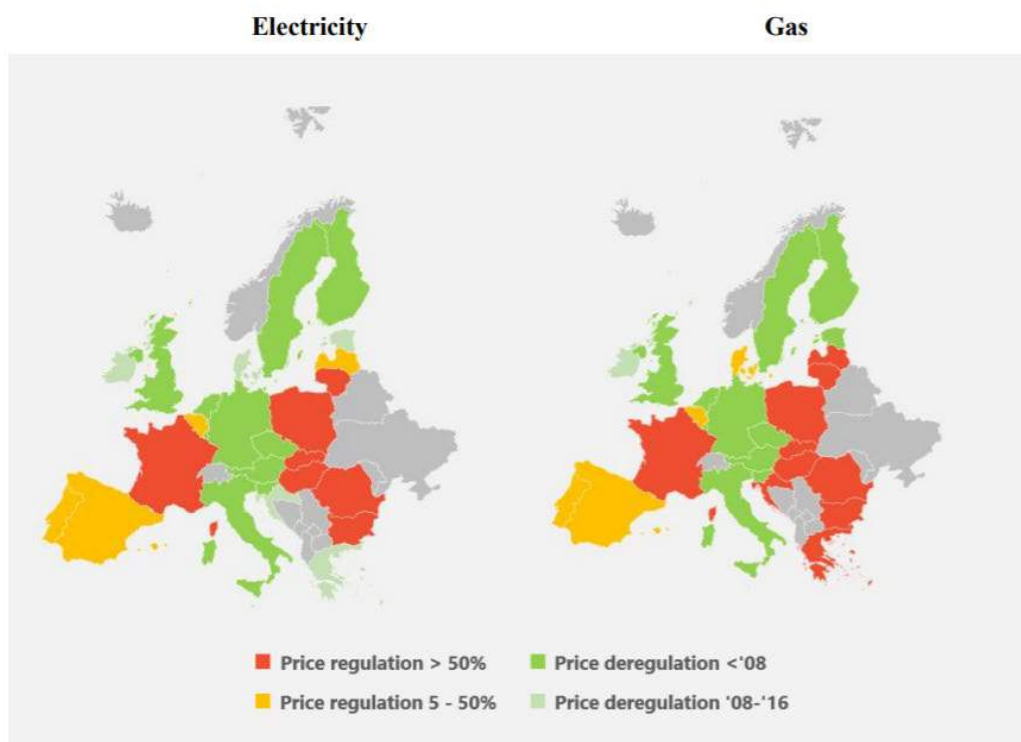
Furthermore, the current planning tools and processes do not provide good visibility in order to evaluate some risks. ENTSO-E, whose role is to anticipate adequacy problems through various

planning tools (Ten-year network development plan (TYNDP)<sup>4</sup>, Mid-Term Adequacy Forecast (MAF) and Seasonal Outlook Adequacy Forecast (SOAF)), have frequently included optimistic assumptions, notably about availability of the current generation fleet and about cross-border exchange capacities in the mid-term (see box 2), probably because of insufficient stakeholders involvement in the process.

Based on the above, Eurelectric raises the question of whether this scenario is the most efficient way to deliver the energy transition while maintaining security of supply. In this section of the report, we will provide a diagnosis on several key elements of the current investment environment.

**Box 1. Retail price regulation is an obstacle to competition among electricity supply companies**

Retail price regulation may reduce the incentive for companies to become more efficient and stifle the development of value-added services, including dynamic pricing. In addition, regulated prices impede consumers from realising the true value of the energy they consume, therefore undermining the potential of demand response. Well-functioning competitive markets are better equipped than top-down regulation to deliver cost-reflective and fair prices to consumers.



**Figure 210 - Household price regulation in EU Member States in 2016**

Source: [European Commission \(2018\) - Energy prices and costs in Europe. Staff Working Document](#)<sup>5</sup>

<sup>4</sup> Article 48 of the Electricity Regulation has long included a requirement for ENTSO-E to “integrate long-term commitments from investors” in the TYNDP.

<sup>5</sup> According to the European Commission staff working document:

- For electricity, Italy and Greece are Member States that are not considered to have regulated prices but have social tariffs. In the case of Italy, the social tariffs constitute an intervention in price setting but it has consistently been applied to only a very small share of households. In the case of Greece, the social tariffs do not constitute an intervention in price setting.

Even countries that have fully liberalised their retail markets can sometimes move backwards: in September 2018, the UK regulator announced the introduction of a price cap until 2023. The perception of retail prices being high has been politically controversial in recent years. Despite increased retail market competition, the Government felt that customers on Standard Variable Tariffs (default tariff if a customer does not select a specific alternative tariff) were insufficiently protected as these tariffs tend to cost more than other tariffs but some of these customers will not switch. The cap applies only on Standard Variable Tariffs and is supposed to ensure that those customers are charged in line with the estimated costs of operating in the UK electricity retail market (wholesale, network and policy costs, and cost to operate). The cap level is reviewed twice a year to reflect the latest estimated costs of supplying electricity and gas.

### [Box 2. The planning tools: MAF and TYNDP 2018](#)

#### [Italy:](#)

In the Mid-term Adequacy Forecast (MAF) 2018, the scenario of grid development assumed by ENTSO-E and the Net Transfer Capacity (NTC) values reported in Italy, seem very optimistic. Regarding cross-border interconnection, it could be due to different assumptions on merchant lines. Concerning the internal capacity between regions, some values are not in line with the Grid Plan issued by Terna (Italian TSO). Additionally, the MAF does not address the economic viability of power plants and the risk of decommissioning.

#### [Spain: The last Ten Year Network Development Plan \(TYNDP\) is very optimistic regarding generation availability.](#)

Two out of three scenarios in the TYNDP assume around 4,000 MW of coal capacity in 2030, while the recently published Integrated National Energy and Climate Plan (INECP) considers between 0 and 1,300 MW.

The TYNDP considers that all the nuclear fleet (more than 7,000 MW) is operational in 2030, while the latest estimate, following the NECP and an agreement between the industry and the government is below half of that amount. The early closure of nuclear plants in Spain has been discussed for a long time.

Finally yet importantly, the TYNDP assumes that the full CCGT fleet is maintained and even expanded in some scenarios. This is quite unrealistic, taking into account that they are far from recovering their full costs, the capacity payment that they currently receive will soon be phased out and there are no perspectives for a new capacity mechanism. The NECP assumes that, in average, CCGT will operate 225 h/year around 2025. In the absence of a capacity market, all market players consider building new CCGT, and even maintaining the current ones, unfeasible.

- 
- For gas, Italy is the only country that is not considered to have regulated prices but has social tariffs. As for electricity, the social tariffs for gas in Italy have consistently applied to only a very small share of households.



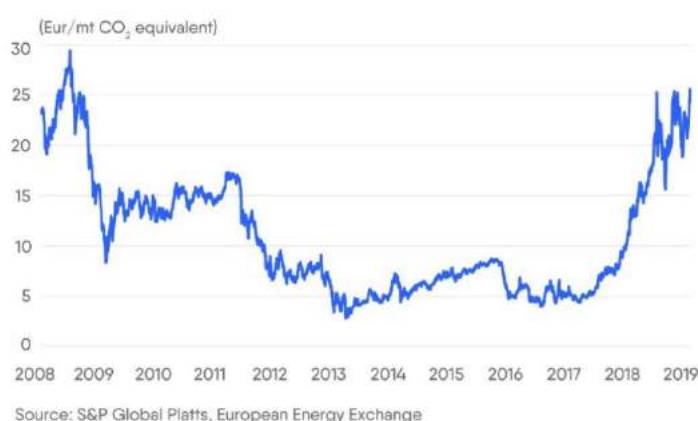
### 3.1 Carbon price: one step forward

A well-functioning emission trading system (ETS) is the cornerstone of a successful and cost-efficient EU energy and climate policy. The EU ETS aims at providing an efficient EU-wide carbon price signal as the core instrument for decarbonising the ETS sectors. A strong ETS price would enable further industrial decarbonisation/electrification, as well as contribute to investments in carbon-neutral generation and transition enabling technologies.

Recent policy action to reform the EU ETS has been successful to some extent, as prices have risen from € 8/t to reach € 29/t in anticipation of a tighter supply in 2019, when the Market Stability Reserve in the EU ETS will remove almost 400 million allowances from the market. Higher CO<sub>2</sub> prices mean that producing electricity from coal becomes less attractive. Depending on the relative prices of gas and coal, the price zone where a change in the merit order occurs is somewhere in the € 20-45/t range<sup>6</sup>. This also makes renewables investment more attractive.

However, many uncertainties remain on commodity prices and on the ETS price. Studies<sup>7 8</sup> suggest that the carbon price could be lower after 2023 than now, when the stability reserve will absorb less allowances in surplus and when energy efficiency, renewables and coal phasing-out are more advanced. We cannot take it for granted that the ETS will then be able to trigger decarbonisation decisions in the power sector, be it in operation (fuel switch) or in investment (competitiveness of renewables).

Figure 9 – CO<sub>2</sub> European Emission Allowances – price chart



Of course, higher ETS prices may trigger political discussion, in particular if they impact electricity intensive industries. For instance, in summer 2018 they created significant political turmoil in some countries (see box 5 on Spain and Portugal). Nevertheless, a carbon price signal, tax or ETS, is the most cost effective tool to reach a given level of decarbonisation. The European strategy is clearly to achieve deep and cost-effective decarbonisation of the economy by 2050. This is why the EU needs both a strong ETS and an effective just transition policy, which protects those parties that may be affected by carbon pricing. In fact, Member States have often introduced support schemes, which are duly checked by the European Commission, according to its Guidelines on State Aid for Environmental Protection and Energy (EEAG), to protect electricity-intensive consumers against this indirect cost of the CO<sub>2</sub> price.

<sup>6</sup> [Montel News](#)

<sup>7</sup> [Refinitiv](#)

<sup>8</sup> [Carbon Tracker](#)

### 3.2 Asymmetric taxes, charges and levies hinder decarbonisation

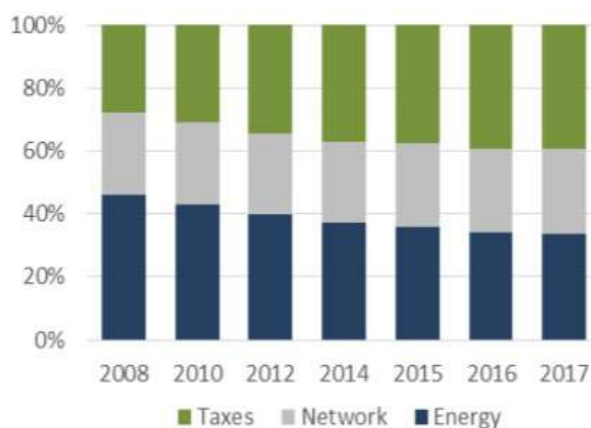
Energy decarbonisation has been almost entirely paid for by the electricity sector and, ultimately, by the consumers of electricity, because of two reasons:

- Electricity generation is subject to the emissions trading scheme, and the price of electricity incorporates the cost of CO<sub>2</sub> emission rights. However, the use of gas and oil for transport, heating and other uses in non-ETS energy sectors does not require paying a price for CO<sub>2</sub> in many European countries: although there is a pan-European EU ETS carbon price, national environmental taxation is usually insufficient for most final non-electric energy consumption.
- Renewable generation is an efficient way to produce carbon-neutral electricity, making electricity easier to decarbonise than oil or gas. Therefore, renewable generation has benefitted from a variety of support schemes. In most European countries, the cost of such schemes has been included in the electricity bill, either explicitly or implicitly, even though renewables targets do not refer to renewable electricity, but to the share of renewables on final energy consumption. This cost is a major component of the taxes, levies and policy support costs incorporated in the electricity bills across the EU.

This means that, despite its key role for the decarbonisation of the European economy, electricity has become artificially expensive versus other energy carriers: electricity bills have increased, not because of the evolution of electricity wholesale prices, but because of these increases in taxes and levies, while the weight of network costs is stable<sup>9</sup>.

End customers will make a growing part of the investment decisions regarding electrification, and the main economic signal they receive is a growing energy bill, composed of energy costs, grid tariffs and taxes/levies. This penalises further investments in electrification, even if electric technologies are increasingly competitive and boost energy efficiency.

**Figure 10** – Evolution of electricity bill components



Source: [European Commission \(2018\) – Energy prices costs in Europe, Staff Working Document](#)

<sup>9</sup> ACER Market Monitoring Report 2017: in 2017, on average, energy costs (contestable charges) represented 35% of the final price while the remaining 65% was formed by the sum of network costs, taxes, levies and other charges, i.e. non-contestable charges. Since 2012 the relative share of the contestable charges has declined from 41% to 35% in 2017, which reflects the decreasing wholesale electricity prices and better market functioning. Contrary, the share of RES charges has increased every year, from 6% in 2012 to 14% in 2017. Network costs remained almost unchanged during the period and VAT and other taxes decreased by 3%.

A particularly relevant category of investment at customer level is charging infrastructure for electric vehicles, which faces significant challenges beyond the common problems posed by the current electricity bill (see box 3).

Additionally, in many countries, taxes and grid tariffs applied to generation distort the wholesale market and increase electricity prices. For instance, different types of generation taxes were adopted or envisaged in Germany (see box 15), Belgium (see box 16), Sweden, Finland, Romania (see box 4), Spain and Portugal (see box 5) and Slovakia (see box 6). In a number of countries, storage is penalised by having to pay grid tariffs and/or taxes on both the energy taken from the network for storage and the energy injected into the grid.

### **Box 3. Charging infrastructures for electric vehicles**

The deployment of a robust recharging infrastructure, both private and public, is essential to foster the uptake of electric vehicles. The unavailability of public infrastructure in particular can be a barrier for the switch from conventional vehicles. In the early phase, investments in charging infrastructure are sometimes supported by public sector funding, as the use of charging points is usually not sufficient to be profitable for private investors. The expected increase in the share of EVs should foster profitable business models for charging services in the mid-term. In the meantime, different demand-driven support mechanisms have been introduced:

- If you live or work in the municipality of **Amsterdam**, and you do not have the option to park your car on site or if there is no public charging point within 300 meters walking distance, there is a procedure to request a public charging station for your area. Source: [Nuon](#)
- Fortum, AspelimRamm –a property developer– and the municipality of **Oslo** have built in the Vulkan neighbourhood, a former industrial area that has been transformed and revitalised, a parking garage with 100 smart charging points for electric cars and 2 high-speed charging stations. Source: [Fortum](#)
- In the **United Kingdom**, the Office for Low Emission Vehicles (OLEV) offers funding of up to 75% towards the cost of installing electric vehicle chargepoints at domestic properties across the UK, through the Electric Vehicle Homecharge Scheme (EVHS). It has also established the Workplace Charging Scheme (WCS), a voucher-based scheme that provides support towards the up-front costs of the purchase and installation of electric vehicle charge-points, for eligible businesses, charities and public sector organisations. Source : [GOV.UK](#) . In London, Source London, the city's largest network of on-street charge points, in partnership with SSE and other stakeholders, launched a “power my street” initiative. It allows Londoners to nominate locations for charge points. People simply have to load a map and pin on the map the location where they would like a charger or they can support an existing nomination. This will help suppliers and local authorities assess where chargers are most necessary. Source: [Power my street](#)
- Across Europe, utilities, the car industry and other stakeholders are collaborating to develop ultra-fast charging networks.

Name	#stations #sites	Partners	Location	Comment
Ionity	400 / ~2,400	BMW, Mercedes, Ford, VW Group (Porsche and Audi)	24 countries	By 2020 Partner with Shell
Ultra-e	25 / ~100	Allego, Audi, BMW, Magna, Renault, Hubject	Netherlands (5), Belgium (4), Germany (12) and Austria (4)	Completion by summer 2018. Sites at average distance of 150-200 km
E-Via Flex-E	14 / ~60	Enel (coordinator), EDF, Enedis, Verbund, Nissan, Renault and Ibil	Italy (8), Spain (4), France (2)	
MEGA-E	39 / 322	Allego	20 countries (Central Europe and Scandinavia)	Focuses on metropolitan areas with e-charging hubs
Central European Ultra Charing	118 / N.A	Verbund (coordinator), CEUC, Enel X, Smatrics, Greenway, OMV	Austria, Czech Republic, Italy, Hungary, Romania, Bulgaria and Slovakia	EU financed 20% of the total cost (€12 mio out of €61 mio)
NEXT-E	30 / N.A	E.ON, MOL, HEP, PETROL, Nissan, BMW	Czech Republic, Slovakia, Croatia, Hungary, Slovenia, and Romania	222 fast (50kW) chargers are also included
E.ONxClever	180 / N.A.	E.ON and Clever	Germany, France, Norway, Sweden, UK, Italy and Denmark	2-6 chargers per station
Instavolt network	N.A. / 200	Instavolt	UK	Equipement from ChargePoint
Fastned network	25	Fastned	Germany, Netherlands, UK	Equipement from ABB. More sites expected
Pivot Power and the National Grid	45 / 100		UK	50 MW battery storage
EnBW	100-1000/ 800	EnBW and OMV	Germany	2 chargers per sites first, cooperation with gas provider OMV, focus on urban areas
Porsche(private)	N.A.			private network, cooperation with gas provider OMV

Source: [Transport & Environment, Roll-out of public EV charging infrastructure in the EUs the chicken and egg dilemma resolved?](#)

- In **Ireland**, one of the front-runner countries in EV deployment, ESB has already rolled out almost 1,100 standard and 70 fast chargers public over the isle of Ireland (Source: [ESB](#)). The Irish government announced it would allocate €20 mio to deploy 50 high-power ESB charging hubs over the country in order to address “range anxiety” and to support the government’s policy that conventional vehicle sales will end by 2030.
- In **Norway**, in 2018 the market share of electric vehicles reached 34% (around 200.000 cars) and is expected to exceed 50% this year. There are already over 10.000 charging points in the country. Source: [InsideEVs](#) and [Norwegian electric car association](#)

#### **[Box 4. Some taxes on generators across the EU](#)**

##### **[Sweden: positive decisions on reducing nuclear and hydropower taxation](#)**

In connection with the debate on the closure of the Barsebäck nuclear power plant in the late 1990s, the government imposed a capacity tax on nuclear power, at SEK 5514 per MWh per month, which resulted in about €3–3.2/MWh potentially produced, penalising nuclear relative to other sources. In the following years it was gradually increased up to €7.5/MWh in 2015. The nuclear industry was then paying about SEK 4.5 bn (i.e. circa €0.42 bn) in tax annually, which represented about one-third of its operating cost. After a long process of appeal through Swedish courts, the European Court of Justice in September 2015 ruled that the tax did comply with EU laws.

The tax put the economic viability of the plants at risk. In 1999 and 2005, two out of ten nuclear power plants were closed, and there were plans to decommission four more units by 2020.

Hydro power plants have been subject to a real estate tax that was approximately 12 times higher per kWh than the equivalent tax applied to any other generation technology.

After months of negotiation, in June 2016 a framework agreement was announced by five political parties, representing 70% of Parliament, on aiming at 100% renewable electricity by 2040, together with phasing out the nuclear tax between 2017 and 2018 and reducing the hydro property tax to a level similar to the one of other generation technologies over a four-year period.

Source: [World Nuclear Association, Nuclear power in Sweden, January 2018](#); [Nuclear Energy Agency, Country profile Sweden](#); [Framework agreement on energy policy](#); [News on Swedish property tax on hydro](#)

##### **[Finland: rejection of windfall tax, but high property tax](#)**

In 2013 the Finnish Parliament passed the Act on Power Plant Tax, known as the Windfall Tax Act. The act was expected to come into force in 2014, and the tax would have targeted hydro, wind and nuclear power plants built prior to 2004. The country’s largest energy company, Fortum Oyj, submitted a complaint to the European Commission and requested clarification on whether the tax treats companies in a similar situation in an equal manner and whether the tax is prohibited state aid to plants excluded from it. In 2014, the Finnish government re-evaluated the controversial tax and eventually decided that it should not be implemented.

In Finland, power plants are subject to a property tax with a higher tax rate (up to 3.1%) than for other industrial properties. As this tax is applied also on wind farms, it hampers market-based wind power investments, as well as reduces the competitiveness of existing power plants in Finland.

Source: [Krogerus](#); [Borenius](#)

### Romania: tax measures

In 2000, Romania adopted a tax on water used by hydro power plants in order to support the development of hydroelectricity: 1% of the total production costs of electricity were to be transferred to Romanian Waters (the institution that manages the waters of the state public domain and the infrastructure of the National System of Water Management), as a fee for the water used in electricity production. However, the tax increased significantly over the years (over 10 times) and is now impacting negatively the activity of hydro power plants operators.

Source: [Energy Policy Group](#)

In December 2018, the Romanian government introduced a package of fiscal measures including a 2 % turnover tax for all energy firms and capped gas and electricity prices for three years for households and some industrial consumers. Following a backlash by investors, a stock-market crash and threats to the country's sovereign-credit assessment, the government backtracked on some of the measures e.g. the 2 % contribution for coal plants and the cap on gas and electricity prices for companies.

Source: [Bloomberg](#)

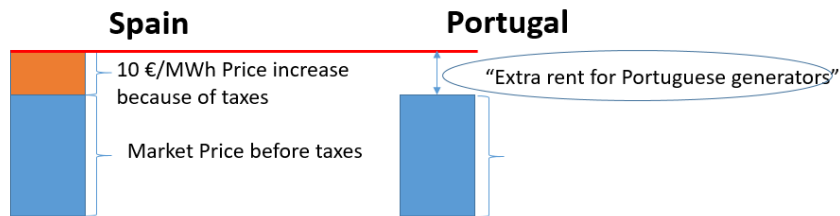
### Box 5. Spain and Portugal: interventions in wholesale markets cause distortions beyond borders and are followed by further interventions

The Spanish electricity system has accumulated (as of today) more than €19 bn of tariff deficit, since the regulated retail prices have not increased over the years to ensure the balance between system revenues and costs. Policy costs such as support to renewables and cogeneration, and compensation to the non-mainland systems have exploded, mostly between 2005 and 2013. One of the reactions of the Spanish Government (besides retroactive cuts in renewables and grids remuneration) was the introduction of several taxes on generation: a general 7% tax on all generation revenues, plus specific taxes on nuclear (€5/MWh), hydropower (25% of revenues), coal (€7/MWh) and gas (€4.8/MWh). The revenues of these taxes are being used to cover the accumulated tariff deficit.

The Portuguese Government has also introduced taxes and charges on generators, namely the so called CESE (applied to the net asset value of energy operators) and the social tariff (which is financed by the generators).

The Spanish taxes have an obvious impact on the wholesale price, since they increase the variable costs of generators. Since Spain and Portugal share a wholesale market, MIBEL, and the price in both countries is the same most of the time, this price increase also affects Portugal.

The Portuguese Government set up a regulatory mechanism to compensate the effect of the Spanish taxes: the so-called “harmonization tariff”. Portuguese generators had to pay an amount, determined ex-post, supposed to compensate the extra revenues caused by higher wholesale prices because of the Spanish generation taxes. This amount was eventually paid to end consumers as rebates in the grid tariffs, so Portuguese end consumers would, in theory, be protected from the price-increasing effect of the Spanish taxes.



### Market prices June - September 2018: even moderate price increases are not politically acceptable



In the summer 2018, price levels were close to €70/MWh, mostly driven by the upward trend in CO<sub>2</sub> prices. Under social and political pressure, among severe criticism of the wholesale market and with the declared aim of reducing wholesale prices (which are directly passed-through to the regulated tariff that most Spanish households pay), on October 3rd, the 7% tax on generators was temporarily suspended and the special tax on gas (marginal technology) was abolished. In 2019, the Portuguese Government also suspended the harmonisation tariff with retroactive effects to October 2018. However, suspension of the 7% tax on generators in Spain ended in April 2019. It is unclear what will happen next in Spain, following the April 2019 elections, and in Portugal.

At the same time, the Coalition agreement for the approval of the 2019 Public Budget between the Government and one of the main opposition parties included the proposal for a claw back of the so-called windfall profits, to be applied to hydro and nuclear power plants. The claw back has not been implemented so far. However, a similar measure was applied between 2006 and 2009.

The draft bill of energy transition and climate change, recently published, intends to give the TSO control of new pumped hydropower storage facilities. This is a very relevant issue: there is a potential of at least 5 GW of new pumped hydropower storage plants in Spain (and more in Portugal), which will be badly needed by the Iberian system given the ambitious renewables targets that both governments have set. However, the regulatory risk of having the operation of the plant controlled by the TSO makes the investments unattractive. In addition, the compatibility of this proposal with recent European legislation is, to say the least, far from clear.

In conclusion, this long sequence of political interventions puts the market at risk and deters investments.

### **Box 6. Slovakia: G-charge improper implementation causes wholesale market distortions**

The “access payment into the electricity grid for electricity generators” (G-charge) was introduced by the Slovak energy regulator as of 1 January 2014, without any prior proper expert debate or justification and without any detailed regulatory impact assessment:

- Electricity generators connected to the transmission network pay charges for the access based on the reserved capacity.
- Electricity generators connected to the distribution network are charged, depending on the reserved capacity, the area and the voltage level.
- Generators qualifying as prosumers also pay the G-charge.

The reserved capacity is based on the technical and commercial conditions of the TSO or DSO, agreed in the connection contract, or on the installed capacity of the generation unit. The G-charge is applicable to all existing as well as new generation plants. Generation units providing exclusively ancillary services and small hydropower plants with up to 5 MW of installed capacity are exempted.

The introduction of the G-charge has created unexpected costs for existing generating units and affected business operations and planning. The total impact on Slovak generators is estimated at €50–60 mio/year.

The value of the G-charge depends on the voltage level and the generation technology. The lowest level is applied to nuclear and coal power plants connected to the transmission grid, at €0.40/MWh and €1.5/MWh respectively. For the distribution network, charges also depend on the time of use of the network. For CCGT and coal they range between €1.5 and 6/MWh. In case of hydropower plants, charges might reach up to €32/MWh, when used for commercial generation only, or even up to €80/MWh, when used primarily for the provision of system services for the TSO.

The G-charge in Slovakia is affecting dispatching decisions of the generators, bid prices, investment planning and the decision to connect/disconnect to the network, especially at distribution level. Since 2014, several large projects at this level were mothballed – the Bratislava CCGT PPC, 220 MW, with charges of €1.5–2.1/MWh, or the Vojany coal power plant, 220 MW, with charges of €6.1/MWh.

The current G-charge in Slovakia results in a number of distortions of the wholesale market and hinders decarbonisation:

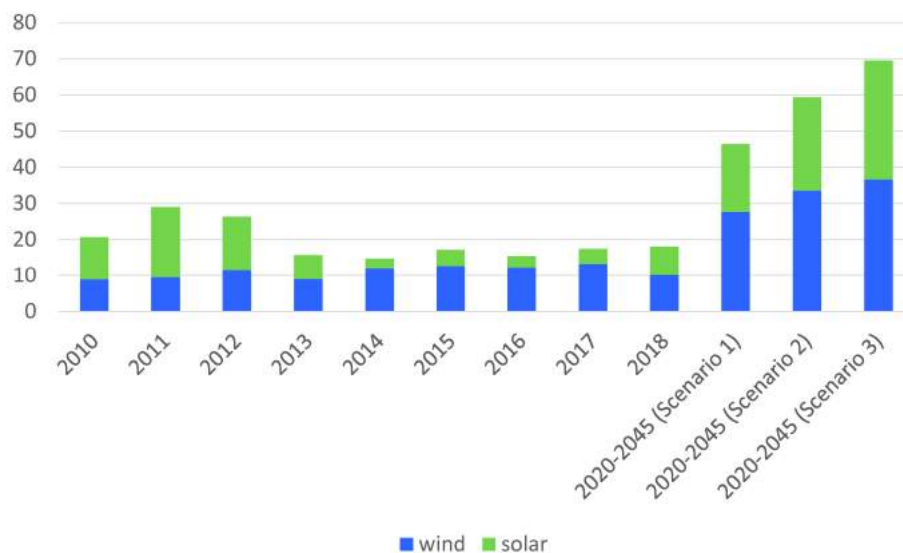
- Discrimination of Slovak generators against competitors from neighboring countries acting on the same wholesale electricity market where no G-charge exists.
- Discrimination between generators in Slovakia acting on the same wholesale electricity market due to quite different G-charges applied at TSO level (€0.5/MWh on average) and DSO level (up to €32/MWh).
- Renewables development is hindered due to the disproportionate G-charge (up to €32 /MWh) against current wholesale electricity price (cca. €50/MWh)
- Undermining of overall system efficiency and decentralized generation due to much higher G-charges at lower voltage levels (up to €32/MWh) vs G-charges at TSO level (€0.5/MWh on average).



### 3.3 The deployment of renewables

By 2030, electricity generated from renewables is expected to almost double compared to today, raising from 32% of the generation mix to almost 60% by 2030, and to reach at least 80% by 2045.

**Figure 11** – Yearly average capacity installation (2010–2018) & Yearly average capacity expected evolution 2020–2045 (GW)



Scenario 1: 80% EU economy decarbonisation; Scenario 2: 90% EU economy decarbonisation; Scenario 3: 95% EU economy decarbonisation with cost breakthrough. [Eurelectric, Decarbonisation pathways, 2018](#)

Source: Eurostat, [Solar Power Europe](#), [Wind Europe](#) and [Eurelectric, Decarbonisation pathways, 2018](#)

This requires a significant acceleration of the pace of renewables build-out: Fig. 11 shows the yearly average capacity build out necessary to decarbonise the power sector compared to the values in recent years.

Up to now, there has been little renewables deployment without national support schemes. Measures such as feed-in tariffs (FITs) and priority of dispatch for the electricity produced from renewables installations have offered high certainty to investors. At the same time, support schemes usually protected renewables generators from any exposure to market signals, giving an incentive to produce even when there was an excess of energy in the system (i.e. renewable resources generating even when market prices do not cover their variable cost or, more precisely, their short-term opportunity cost). This distorted the wholesale market and sometimes led to negative prices.

Today, the significant cost reductions of these technologies, as well as digitalisation and refining of weather forecast tools, maintenance systems and other improvements –achieved and still to be expected– are key developments to allow for considerable progress in market integration.

The EU regulatory framework for renewables has been subject to significant changes since the adoption of the first Renewables Directive in 2009. From 2014 onwards, Member States have been progressively adapting their regulatory frameworks to comply with the conditions set in the EEAG. The key principles set out in the EEAG are now enshrined in the revised Renewables Directive (RED II) adopted in late 2018 and the Electricity Regulation. The use of competitive mechanisms, non-

discrimination and cost-effectiveness are progressively becoming the standard criteria for support schemes based on auctions, if Member States deem them necessary (see box 7). Market integration of renewables generation has also made significant progress, with a growing amount of renewables capacity being subject to balancing responsibility or able to participate in the ancillary services markets.

Lately, there has been significant development of market-based PPAs in some regions (see box 8) and there is potential in other countries, but there are doubts on whether corporate appetite is enough to deliver the required volumes to decarbonise the power sector and meet ambitious targets. As renewables penetration increases across Europe, there is also increased risk of very low, zero or even negative prices at times of high renewables output. One consultancy has estimated that the cumulative merchant risk of such price depression is as much as £200 bn EU-wide by 2030<sup>10</sup>. Some investors could be able to take on this merchant risk whereas others could expect some degree of risk transfer. However, this so-called “cannibalisation” can also be considered a natural market signal that prevents over-construction of a given renewable technology, and protecting investors from this effect would lead to inefficient development.

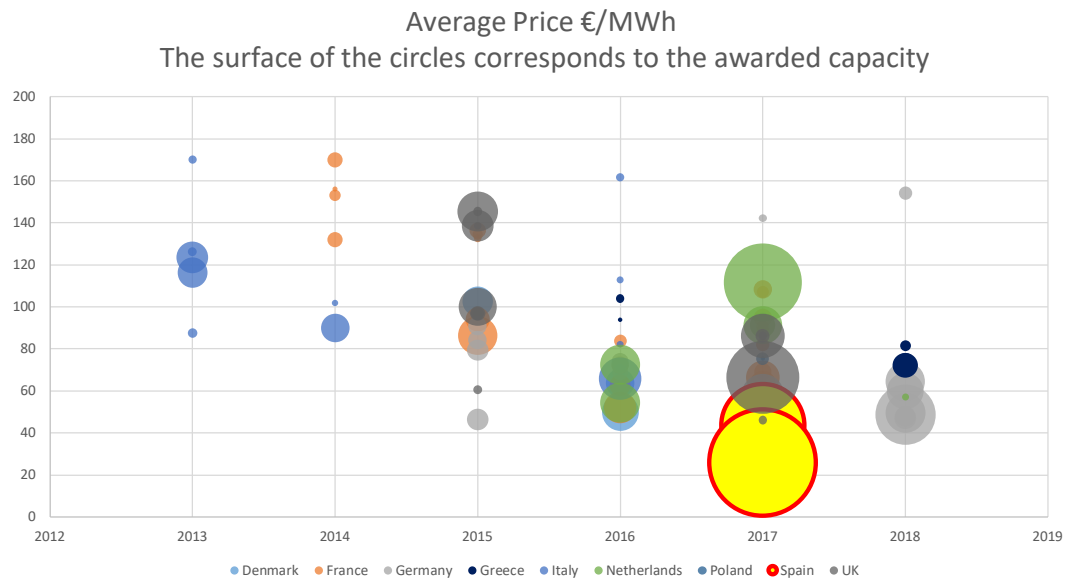
At national level, there are growing difficulties such as coordination of renewables and grid development, taxation, licensing or public acceptance (see box 9). This local acceptance must be taken into account, to develop locally the most suitable solutions taking into account, on one hand the cost-efficiency of the industrial solutions (lines and large turbines) and, on the other hand, the value given by people to the area where they live. RED II contains positive elements to address these issues but there remain national and local challenges.

---

<sup>10</sup> [Aurora. The future of merchant renewables in the European power market](#)

### Box 7. Implementing auctions for market-based support schemes

A growing volume of renewables capacity is receiving support schemes through auction mechanisms that, for the time being, are resulting in lower prices each year.

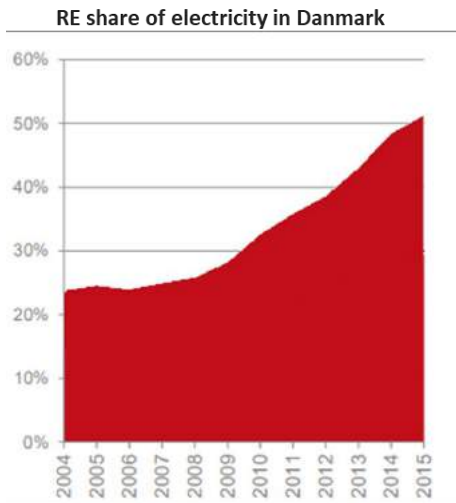


Source: BNEF – as of July 2018 "3Q 2018 Global Auction and Tender Results".

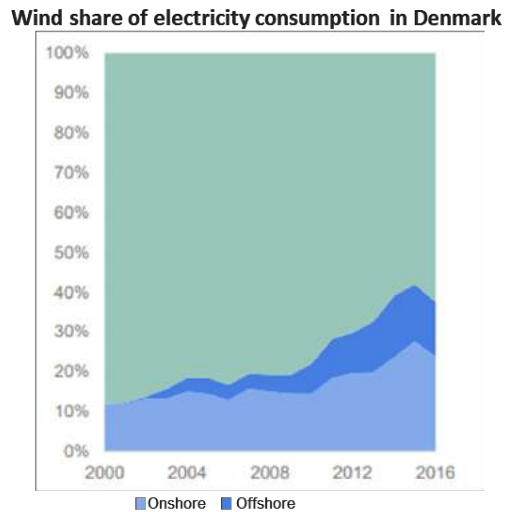
The original source provides data in \$/MWh, converted into €/MWh at 1.14 \$/€. For Spain, the price is the floor price. This is not directly comparable with the prices in other auctions: in Spain the floor is a minimum value, but bidders expect to receive the wholesale price, while in most other auctions, in general, bidders receive the auction price only.

#### Denmark: From feed-in tariffs to competitive tenders

Denmark has shown that high shares of renewables penetration are achievable through a persistent, active and stable energy policy based on ambitious renewable energy goals. Historically, the renewables expansion has largely been a result of successful government subsidy schemes with limited market exposure for – and competition between – renewables producers. Denmark has now entered a new age where renewables investments are driven mainly by competition for the market using a new technology-neutral auction system.



Source: Danish Energy Association 2017



Source: Danish Energy Association 2017

**Denmark introduced technology-neutral auctions for renewable energy in 2018:**

The new mechanism allows developers to offer renewables projects in a centrally coordinated pay-as-bid auction. The projects are evaluated against each other based on objective criteria. Auction winners are granted a 20-year price premium on the market price, but are responsible for selling all production in the market and bear full imbalance responsibility. All the risk related to future market price trends is thus borne by the producer. As a result, the producer faces market conditions and clear price signals which incentivises production where and when the electricity price is high. Support is provided throughout the life of the plant (set at 20 years), and aid is granted for actual production in order to obtain more accurate incentives for maintenance and replacement.

The budget for the first tender was €34 mio, while the second tender will have a budget of €78 mio. In addition, another €537 mio is set aside for further tenders in 2020–2024.

**Breaking records: Results from the first technology-neutral tender in Denmark 2018**

17 projects were submitted, comprising 260 MW onshore wind and 280 MW solar PV and 6 winning projects were selected (see table below including 3 onshore wind projects (165 MW) and 3 solar PV projects (104 MW)). The weighted average price was at €0.0031/kWh.

Winners	Technology	Offered price premium (€/kWh)	Capacity (MW)	Share of budget (%)	Municipality
1- NRGi Wind V A/S	Onshore Wind turbines	0.25	28.8	11.9	Thisted
2- K/S Thorup-Sletten	Onshore Wind turbines	0.27	77.4	33.5	Jammerbugt& Vesthimmerland
3- SE Blue Renewables DK P/S	Onshore Wind turbines	0.33	59.3	32.4	Randers
4- Solar Park Rodby Fjord ApS	Solar PV installation	0.38	60.0	12.7	Lolland
5- Solar Park Naessundvej ApS	Solar PV installation	0.38	30.0	6.3	Morso
6- Better Energy Frederikslund Estate ApS	Solar PV installation	0.40	11.5	3.1	Slagelse

### Spain: Renewables auctions in 2016–2017 based on a revenue floor deliver the largest volumes allocated in Europe

Support to renewable generation in Spain was mostly based on market premium remuneration, and generators were traditionally subject to balancing responsibility. The cost of the scheme was recovered through grid tariffs. The growth of renewables capacity led to a significant increase in cost, and tariffs were not updated accordingly, leading to a large tariff deficit. In 2013 the Government decided to introduce retroactive changes to the remuneration scheme applied to existing plants, to reduce the cost going forward. For several years, development of renewable generation in Spain was paralysed.

The current remuneration scheme is based on incentives allocated through auctions. The methodology provides an efficient dispatch (incentives are paid in €/MW) avoiding distortions in market prices. Producers will refrain from producing when market prices are below their operating costs (since its introduction, zero prices have disappeared). Under the new scheme, plants will not receive incentives unless market price plummets below a floor level (€28-41 /MWh). Below those levels, incentives will ensure investment recovery at a given rate of return. Three recent renewables auctions (April 2016, May and July 2017) were made to achieve 2020 targets. As a result, 8.8 GW of renewables capacity were awarded.

MW	April 16	may-17	July 17	TOTAL
On-shore wind	500	2.980	1.128	4.607
Biomass	200			200
Solar PV		1	4.009	4.010
Others		19		19
<b>Total</b>	<b>700</b>	<b>3.000</b>	<b>5.137</b>	<b>8.837</b>

## Box 8. The development of PPAs

### Finland: Political and stakeholder commitment to energy-only has enabled investments in market-based wind power and firm/flexible biomass and hydropower

One last tender took place at the end of 2018 for 1.4 TWh, and future projects are expected to develop without auctions or support schemes.

Harjavalta  
hydropower  
plant extension  
72 MW → 110 MW  
(commissioned  
in 2016)



Subsidy-free wind power:  
In total 340 MW to be commissioned in 2019

- 190 MW with PPA contract for Google
- 107 MW to be owned by IKEA
- 21 MW by TuuliWatti Oy (St1 oil company and S Group retail cooperative)
- 21 MW to be built by Energiequelle GmbH

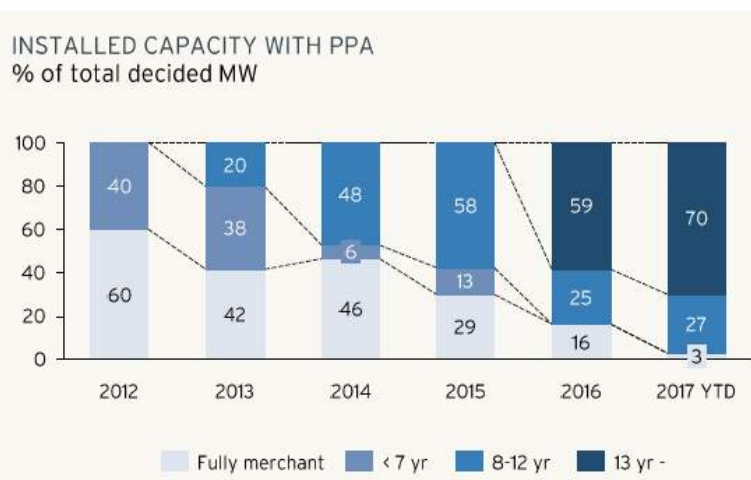


Sources: [www.alstom.com](http://www.alstom.com), [www.lansisuomenvoima.fi](http://www.lansisuomenvoima.fi), [www.metsafibre.com](http://www.metsafibre.com), [www.blog.google](http://www.blog.google), [www.ox2.com](http://www.ox2.com), Finnish Wind Power Association

### Norway and Sweden: PPAs increasing role and renewables projects less dependent on green certificates

Norway and Sweden have shared a green certificate system (Elcert) since 2012. Sweden previously had its own national system in place since 2003. This has delivered a large volume of renewable capacity. Plants remuneration was based on their market revenues and the green certificate price. Over the years, the average plant size increased significantly.

In the last decade, a growing amount of capacity has negotiated PPAs with different counterparts.



## Box 9. Difficulties with renewables development

### UK: large scale onshore wind and solar prevented from competing in the auctions

Onshore wind and solar PV projects above 5MW were originally able to compete for Contracts for Difference (CfD) within an 'established technology' pot auction, the first of which was held in 2015 and delivered cost reductions.

The Conservative Party manifesto for the 2015 General Election contained a commitment to stop subsidising onshore wind. Since that election, the UK government has not held any CfD auctions for established technologies, effectively preventing onshore wind and solar PV from delivering the cheapest new low carbon power to customers.

Since 2015 no subsidy-free onshore wind or solar PV of substantial scale have reached financial close.

The UK government has opted against recommencing the auction for established technologies despite analysis from consultants that projects would be successful without requiring net payments from consumers under the CfD over the lifetime of the project.

### Germany and France 2018 auctions undersubscribed

The results of recent wind auctions in Germany and France have both come back undersubscribed.

In May 2018, in **Germany**, 670 MW of onshore wind capacity was on offer but only 363 MW won a contract. However, 900 MW of projects were actually approved for the auction and had a permit. Unfortunately, because of legal challenges to these permits, many chose to avoid penalties for non-delivery and refrained from bidding.

Similarly, in **France** in September 2018, of the 500 MW available only 118 MW were awarded. This follows a December 2017 court decision that leaves open the responsibility for environmental permits needed to build new installations. Over a year later, the French government had not clarified which would be the authorities in charge of issuing these permits.

### Italy: hydroelectric power plants

The Iren Group has subjected to revamping two run-of-river hydroelectric power plants located in the Susa Valley. The main objectives of the project are the exploitation of still unused water resources, in a context in which European objectives provide for an increase in energy production from renewable energy sources; and the enhancement of the territory and synergies with local entities (the initiative will generate important resources able to guarantee the growth of the municipalities involved in the project in the future).

The main technical-economic details of the project are the following:

- flowing water systems
- installed power ~15 MW
- energy production ~35 GWh
- total cost of investments ~€20 mio

In addition to the normal profitability of the investment (linked to the sale of the energy produced), the project is also admitted to benefit of public incentives governed by Ministerial Decree 23 June 2016 “Incentives for electricity produced from renewable sources other than photovoltaics”. The aforementioned Decree represents the latest official reference in the field of energy incentives produced by renewables. The Italian legislation on public tenders for the reassignment of expired concessions and concession fees creates uncertainty regarding the future awarding of hydroelectric concessions and the correct management of the assets. Moreover, the ongoing revision of the legislation on public incentives for electricity produced from renewables raises concerns about the business case for this specific project. The project was accepted under the incentive scheme defined by the previous Renewables Decree and it may not benefit from the scheme under the new Renewables Decree.

### 3.4 Delivering firm and flexible carbon-neutral capacity

To support this changing generation system based on variable renewables, carbon-neutral firmness and flexibility is essential. The development of this new capacity is certainly a major technical and economic challenge, but there is a surprising lack of awareness about it.

For short-term, daily flexibility, either solutions are already available or there are promising emerging technologies. Demand-side management (see Fig 12), hydropower storage (with natural inflow and/or pumping) and batteries – if the current cost reduction projections become real, and probably including the large-scale use of the batteries of electric vehicles – are able to provide fast flexibility (ramps, balancing, etc.) and guarantee firmness.

Figure 12 – Role of demand side response in the future power system



Source: [Eurelectric, Decarbonisation pathways, 2018](#)



The potential for additional hydropower, which would be needed to replace the existing thermal fleet, is constrained economically, environmentally and socially in the European Union. However, there are opportunities for retrofitting and optimising existing facilities and systems. For instance, in Spain there is potential for increasing the current pumped hydropower capacity by 5,000 MW with relatively small investment, but the current market does not pay for this and the projects are not moving forward. New technologies such as batteries are more expensive, so their feasibility would be even more difficult in the current environment.

Long-term flexibility (from more than a few low wind days to seasonal) is considerably more challenging, as shown in box 10. Hydropower storage (with natural inflow and/or pumping, see box 11) is the only proven solution, but hydro resources are not available everywhere and there is not much room for further large-scale development in the European Union, due to a limited economically, socially and environmentally feasible additional potential. In some regions, nuclear and off-shore wind can contribute firmness and flexibility in this time horizon. The technical and economic cases for other solutions are not established yet (e.g. hydrogen and power-to-gas or power-to-liquids, see box 12). The recent study “Towards fossil free Energy in 2050” by the European Climate Foundation finds that there is a substantial need for installing gas turbines running on hydrogen to balance out the decarbonized power system in 2050. In any case, the eventual efficient mix of firm and flexible resources is uncertain, as it depends on technology and cost evolution – i.e. it would be a mistake to make long-term decision too early.

As long as the long-term flexibility challenge is not solved, gas-fired power plants will play a role to enable a cost-efficient transition, according to the generation mix of each region. Their role may evolve on the road to 2050 depending on the development of green gases.

#### **Box 10. The challenge of storage**

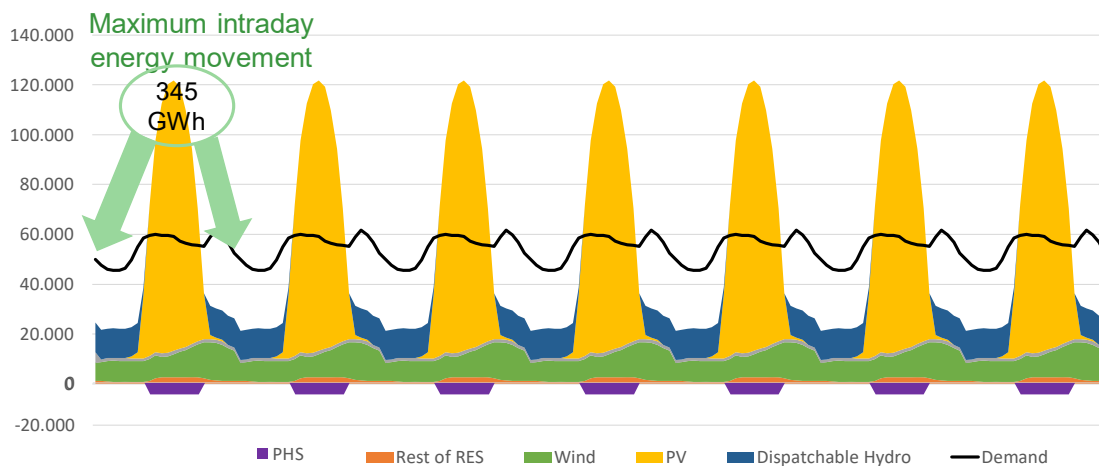
Storage will play a very relevant role in any electricity system dominated by variable renewables, delivering firmness, flexibility and minimizing renewables spillage. However, the exact nature of this role is not always well-understood, and storage is sometimes presented as the silver bullet of the decarbonised power system. We try to illustrate the volume of the storage challenge using a simplified simulation of a fully decarbonised power system in a European country in 2050:

- Total demand is 470 TWh, with 70 GW peak demand. Seasonal patterns are similar to those of today.
- There is a significant presence of hydropower and pumped hydropower storage (35% of the peak demand).
- There are 190 GW of variable renewables (roughly one third wind capacity and two thirds photovoltaic generation, this being a combination that minimises spillage).
- There is no thermal or nuclear generation.
- New storage capacity (beyond the existing hydropower) provides the remaining necessary firm and flexible capacity.

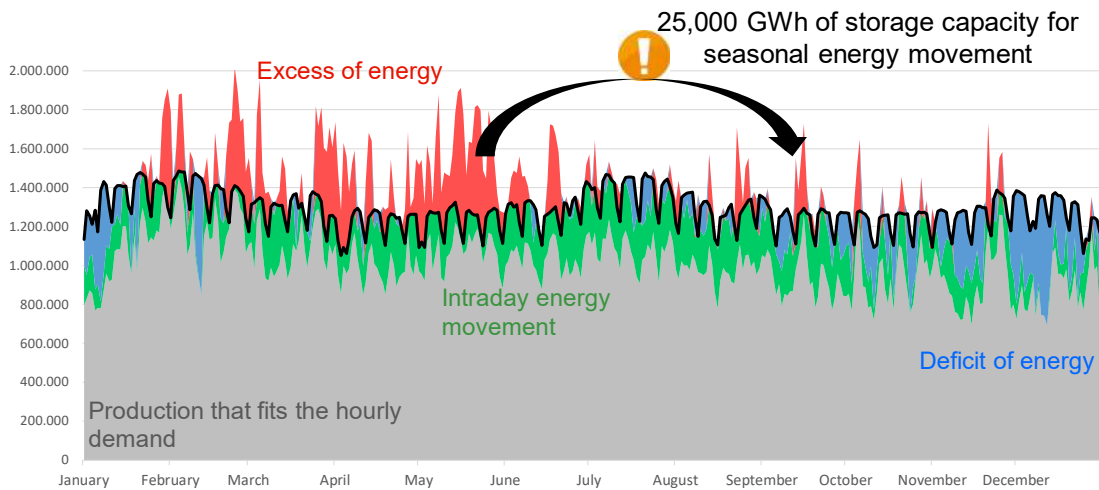
The purpose of this example is not to present a precise forecast of a generation mix, but just to illustrate the relative sizes of the daily and seasonal challenges.

The following figure shows the hourly demand and production in a week with maximum intraday movement of energy, in March 2050. There is a significant photovoltaic production in the sunny

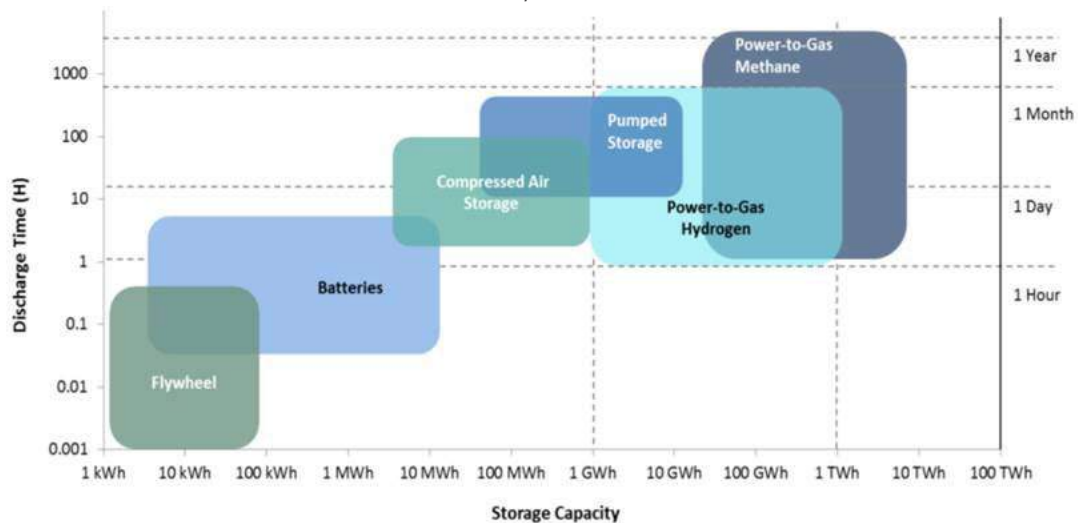
hours of the day, well above demand, while production in the early morning and the evening is below demand. The maximum daily excess of photovoltaic production found by the model is 345 GWh. This means that such an amount of additional storage capacity would be needed in the example system to balance the daily photovoltaic production. This is a significant volume: the global yearly production capacity of batteries in 2016 was 28 GWh and it is expected to be 174 GWh in 2020. However, considering the growth rate of battery production capacity in recent years and the fact that these are the needs for 2050, 31 years from now, after the closure of all the existing thermal capacity, it can be considered to be feasible. Obviously, there could be other complementary ways of providing this daily balance, such as demand-side response, new pumped hydropower storage, new thermal capacity with green gases or CCS, etc. The objective of this exercise is not to determine the right combination, but just to assess the volume of the challenge.



However, this would not be enough to maintain security of supply in such a system. If we simulate the whole year, instead of one week, the picture is quite different. Because of the seasonal patterns of demand (high demand in winter and summer, because of heating and cooling; low demand in spring and autumn), and renewable production (higher hydro and wind production in spring, higher photovoltaic production in spring and summer), there is a structural deficit of energy in winter and a structural excess in spring. In this example, the model foresees the need for 25,000 GWh of new storage capacity, 72 times more than the capacity needed for intraday storage. Obviously, other factors could affect these needs. For instance, new nuclear or off-shore wind capacity could provide, in some regions, additional capacity with a high degree of firmness. In any case, the conclusion is that the seasonal challenge is significantly larger than the daily challenge.



This volume certainly looks far from feasible with battery technology. While batteries will be crucial for short-term/daily balancing, a broad set of storage options will have to be developed to face the seasonal challenge at European scale. The following figure illustrates that, among a variety of storage technologies, some should be able to cope with these seasonal needs, by storing large amounts of energy for months. However, for the time being, pumped hydropower storage is the only available technology capable of such feature, and its potential is limited. This seasonal balance cannot be solved by demand-response, since it would involve shifting demand for months, not for hours or even days. Power-to-hydrogen or power-to-gas seem promising, but we do not know whether and, if so, when, they will become affordable.



Source: [European Commission \(2017\). Energy storage – the role of electricity. Staff Working Document](#)

### [Box 11. Greece, pumped hydropower storage](#)

The project “Amfilochia” promoted by Terna Energy S.A. (no relationship with the Italian TSO) has been selected as Project of Common Interest under the code name PCI 3.24. This project supports the implementation of the North– South electricity interconnections in Central Eastern and South Eastern Europe (NSI East Electricity priority corridor of EU Regulation). Its study has been co-funded by the European Union through the Initiative “Connecting Europe Facility”, it has already been licensed by the Regulatory Authority of Energy and it has also received temporary

terms of connection by the Independent Transmission Operator of Greece. Moreover, the Project has been classified as a Strategic Investment by the Greek Authorities and has been incorporated in the related procedures under the Law 3894/2010.

However, the viability of the project is threatened, since the expected wholesale electricity market revenues are not sufficient to cover its fixed and variable costs.

### **Box 12. Germany power-to-gas**

Power-to-gas is a key technology of sector coupling. It is currently the only application that can link the sectors of electricity, industry, heat and transport with each other and also provide a seasonal energy storage capacity. The large-scale use of power-to-gas is not yet realistic for technical and economic reasons. The aim must therefore be to create conditions over the next decade that will enable the power-to-gas technology to develop in an economically viable way.

The problem is that large-scale plants are not yet competitive, but will probably have to be available on a large scale relatively soon.

German electricity TSO, Amprion, and gas TSO, Open Grid Europe, intend to build the country's first 100 MW power-to-gas facility, which should start operation in 2023 at Lingen. They presented the project to the Madrid Forum in October 2018. In particular, the two TSOs are justifying this investment to reduce curtailment of wind generation in the north-west part of Germany.

Source: [Amprion](#)

According to [Reuters](#), they will soon apply for a permit.

If approved by the regulator as proposed by the two TSOs, this investment would be treated as a regulated asset, and grid fees would be increased in order to recover the estimated cost of €150 mio.

In the debate about the future of sector coupling, there are voices who favour the treatment of these facilities as regulated assets owned by the electricity or gas TSOs. In principle, all power-to-gas plants should be operated in the market. Any specific project must therefore further that goal, and should not endanger the level playing field in the electricity sector for providing flexibility. Additionally, it must not undermine unbundling rules between generation and transmission network operations and ownership. Against this background, every project intended to support the market launch of power-to-gas must be carefully examined, so as not to jeopardise subsequent competitive development.

### 3.5 The legacy generation system

The role of existing assets (thermal generation, hydro and nuclear) in the energy transition is often overlooked while they will have to contribute to the flexibility and reliability of a system which will increasingly and predominantly rely on variable renewables. Fig. 13 shows that different sources of dispatchable resources are required to maintain the system in balance during the transition, and in a fully carbon-neutral power system.

A smart use of the existing assets can drastically reduce the transition costs, while still reducing emissions. Even if thermal plants produce less and less energy (and thus less and less emissions), they can contribute with flexibility and firmness and complement/compete with other sources of flexibility such as demand side response and battery storage, which are becoming more and more competitive and available. Similarly, hydropower plants will be increasingly valuable as providers of flexibility and large-scale storage, allowing variable renewables integration<sup>11</sup>.

Hydro resources can remain stable over the period and make a significant contribution to achieving carbon neutrality. Today, hydro accounts for around 10% of electricity and around one third of renewable electricity in Europe and its role should not be overlooked. Hydro is a carbon free, flexible and firm renewable. It provides different degrees of firmness and flexibility (run-of-river, reservoir, pumped storage) and hydro pumped storage currently provides the only large-scale storage solution that can deliver long-term storage, seasonal or even multi-annual. However, there is not much room for large-scale development of additional capacity in the European Union as the economically, socially and environmentally feasible potential is limited. However, there is room for retrofitting and optimising of existing facilities and hydropower systems.

Nuclear produces today 25% of the electricity in Europe. In line with the IPCC report, the Commission's long-term strategy outline and Eurelectric's Decarbonisation Pathways, nuclear installed capacity should remain stable over the period.

The role of fossil fuel plants will completely shift. It is clear that coal and lignite will be phased out by 2045, and much earlier in a number of countries, but some of these assets can still play a role as back-up capacity with very limited production. According to the Eurelectric analysis, gas-fired power plants would represent 12-14% of the total installed capacity and a significant part of the dispatchable capacity by 2045 (see Fig. 13), but they would only generate 5% of electricity<sup>12</sup>, with biogas playing a role as a clean fuel<sup>13</sup>.

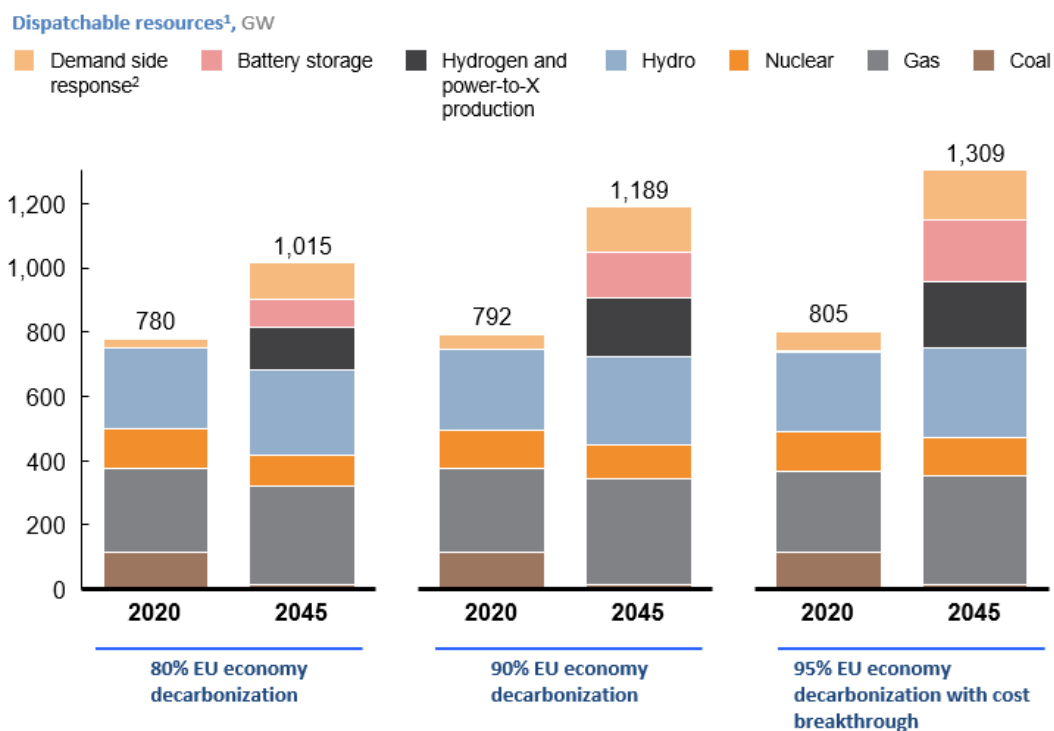
---

<sup>11</sup> [Eurelectric & VGB. Hydropower Fact sheets. 2018](#)

<sup>12</sup> [Eurelectric. Decarbonisation Pathways](#)

<sup>13</sup> [Eurelectric. Decarbonisation Pathways](#)

**Figure 13** – Different sources of dispatchable resources, GW



<sup>1</sup> District heating that is coupled with power sector is not included in this analysis  
<sup>2</sup> DSR flexibility is provided by hour to hour load shifting in transportation, buildings and heating

Source: [Eurelectric, Decarbonisation pathways, 2018](https://www.eurelectric.eu/decarbonisation-pathways)

The delivery of energy from fossil-fuelled generation is lower than what was expected when the investment decision was taken. This thermal generation will be even lower in the future<sup>14</sup>. In spite of this situation, thermal plants are still required to deliver reliability and flexibility, to maintain system adequacy. Nevertheless, the energy and ancillary services markets do not pay the full cost of system adequacy, and firmness –which is one of the most valuable outputs of these facilities– is not paid for in most markets. Therefore, the ability to maintain the needed assets ready to produce when required in a high renewables system is at risk. On the other hand, governments sometimes forbid the decommissioning of these assets, based on security of supply considerations. They may therefore become a heavy burden for their owners as less hours of operation and non-existent scarcity or simply high prices lead to revenue shortage, especially in situations where closure is not an option (see box 14).

The situation is sometimes made worse by the capture of revenues through new taxes and levies on nuclear, hydro or coal (there have been examples of such taxes in Spain, Belgium, Germany, Sweden and Finland, see boxes 4, 5, 15 and 16).

<sup>14</sup> This diagnosis and future evolution prospects can be extended to combined heat and power facilities. Historically, industrial cogeneration has been supported based on its high efficiency compared to individual thermal power plants and heat facilities providing a comparable bundle of electricity and heat. However, in an increasingly renewable electricity system, the supply of mostly renewable electricity from the network and heat from a state-of-the-art gas boiler can compare favourably with cogeneration from the point of view of emissions and consumption of fossil fuels. This can lead industrial cogeneration (unless fuelled by biomass, biogas or biofuels) to face similar challenges to other thermal generators.

In an energy-only market, firmness is meant to be remunerated by very high and very infrequent scarcity prices. In many countries, these prices are lacking. Even if according to ACER<sup>15</sup>, there is currently a reappearance of price spikes in some countries and a “potential of energy-only markets to allow generators to cover their fixed costs”, when these price spikes appeared, several Member States took “unilateral decisions to limit electricity exports” (see box 13).

Sometimes regulation caps maximum prices at a low level, avoiding true scarcity pricing. In many cases there are no formal prohibitions, but high prices cause political and social turmoil and threats or actual market intervention (see boxes 5 and 13).

The market could at least partly self-correct through decommissioning or mothballing, but governments frequently restrict this, leading to artificial over-capacity. These restrictions are explained by concerns regarding security of supply, or because the closure of existing plants would have a significant social impact in some regions. Hence the key role of a “Just transition” rather than an ad hoc prevention of plant closures. Local solutions are sometimes implemented, as in Germany, where profitable coal plants are paid to close to reduce emissions (see box 15). However, within an Internal Energy Market (IEM) framework, there are no common rules on decommissioning or mothballing. The situation is especially critical regarding nuclear, considering that 50 out of 126 reactors in the EU should apply for new operating authorisations within the next 10 years<sup>16</sup>.

In countries such as France, the United Kingdom or Poland, this issue has started to be addressed, with a capacity market putting a value on firmness (see box 21).

#### **[Box 13. Unilateral measures in South-East Europe during a cold spell \(January 2017\)](#)**

During the first half of January 2017, South East Europe experienced an unusual cold spell. Day-ahead power prices generally reflected scarcity but, because the imbalance between the available capacity and the surging demand was expected to increase, several States announced measures that would prove costly for cross-border electricity trading and day ahead market prices. In particular, Bulgaria introduced a ban on exports for 27 days, even though in practice Bulgaria was not tight during most of these days. This resulted in loss of exports for Bulgaria and a substantial divergence between Bulgarian day ahead prices from the prices in Romania, Greece and Hungary. Similarly, Greece implemented restriction measures when consumption was at the highest, but also during days when it was lower. In both countries, these exceptional measures were applied well beyond what was needed during days of extreme weather conditions.

Source: Platts, EU Electricity Markets in January and February 2017. Understanding the impact of the cold spell and the special measures introduced in select Member States and concerned Energy Community Contracting Parties, 20 December 2017.

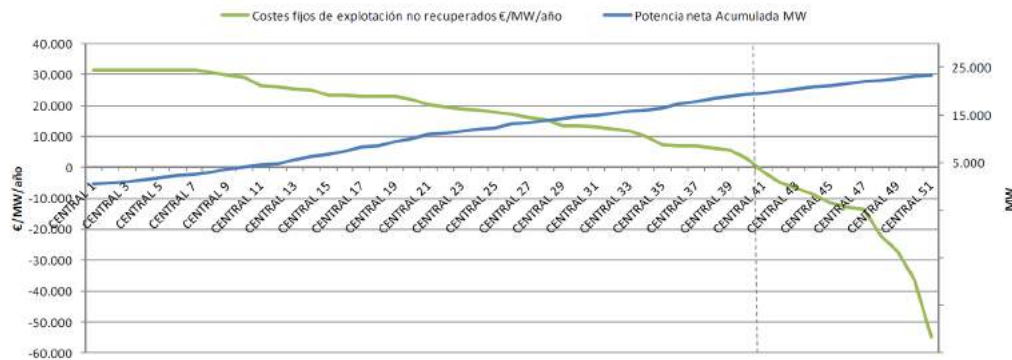
---

<sup>15</sup> [ACER \(2017\), Markets Monitoring Report](#)

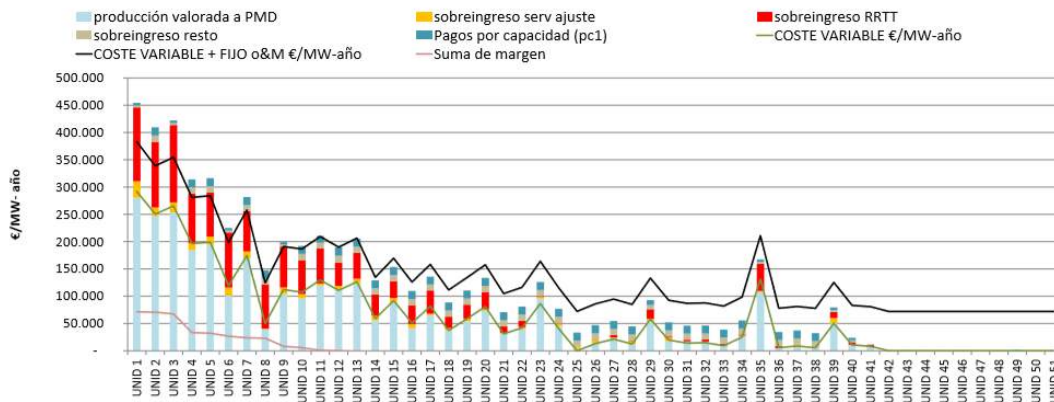
<sup>16</sup> [Fortum For Energy blog](#)

### Box 14. The situation of CCGT in Spain

The following figure summarises an analysis of the recovery of fixed operational costs of CCGTs carried out by the regulator in 2012, showing the majority of plants are not able to recover their fixed operational costs despite receiving a capacity payment (the so-called “investment incentive” and “availability incentive”).



In 2015, the regulator got to a similar conclusion even with an even larger proportion of existing CCGTs not recovering their fixed operational costs – see figure below.



Source: CNMC, “Informe de Supervisión del Mercado Peninsular de Producción de Energía Eléctrica. AÑO 2015”; gráfico 79.

The recently published draft Spanish National Energy and Climate Plan (NECP) expects the CCGT to operate 225 hours/year in 2025 and 1400 hours/year in 2030, despite assuming the decommissioning of 90–100% of the 11,000 MW of coal capacity and 57% of the 7,400 MW of nuclear capacity. The CCGT plants are considered necessary to maintain security of supply, by delivering firmness and flexibility, and the NECP assumes that they will continue to operate into the 2030s. However, if they are unable to recover their costs in the current conditions, and they are expected to operate even less hours, they are unlikely to stay financially viable, especially as capacity payments are being phased-out.



### [Box 15. German case: nuclear, coal and lignite phase out](#)

#### **Moratorium and nuclear phase out**

In 2002, Germany limited the operational lifetime of nuclear reactors to 32 years. Instead of establishing an exact date for the complete phase-out, the plan allocated an amount of electricity to be produced by each plant. The last plant would be decommissioned by 2022 and new nuclear power plants were banned. However, in 2009, another decision extended the lifespan of seven nuclear plants by 8 years and of ten plants by 14 years. In 2011, after the Fukushima (Japan) nuclear incident, the government decided to immediately close eight plants and limit the operation of the remaining plants to 2022. A tax on nuclear fuels was also applied between 2011 and 2016.

#### **Germany: German tax on nuclear fuel**

“Germany had in place a tax on nuclear fuel (fissile uranium and plutonium) between 2011 and 2016. The tax was introduced to make extensions to the lives of nuclear power plants less profitable for operators in the face of the planned postponement of the phase-out of nuclear power in the country (i.e. to reduce windfall profits). (...) The tax rate was € 145/g of nuclear fuel, which translates to a tax of approximately € 7.3 to € 15.8 per MWh of electricity generated. The revenues (which amounted to a total of around € 5.8 bn for the period 2011–2015<sup>17</sup>) were paid into the general budget. The tax is no longer in place since 2017”<sup>17</sup>. On 7 June 2017, the Federal Constitutional Court ruled that the fuel tax did not comply with the German constitution and that taxes collected had to be repaid.

#### **Lignite and coal phase-out**

In November 2015, the German government and three companies (RWE, Vattenfall and Mibrag) agreed to put 2.7 GW of lignite-fired power capacity into reserve. The new government elected in 2017 agreed in its coalition agreement to put in place an end date for coal power and measures towards meeting its 2020 climate target. It established a “Coal commission” which recently decided a coal phase-out by 2038.

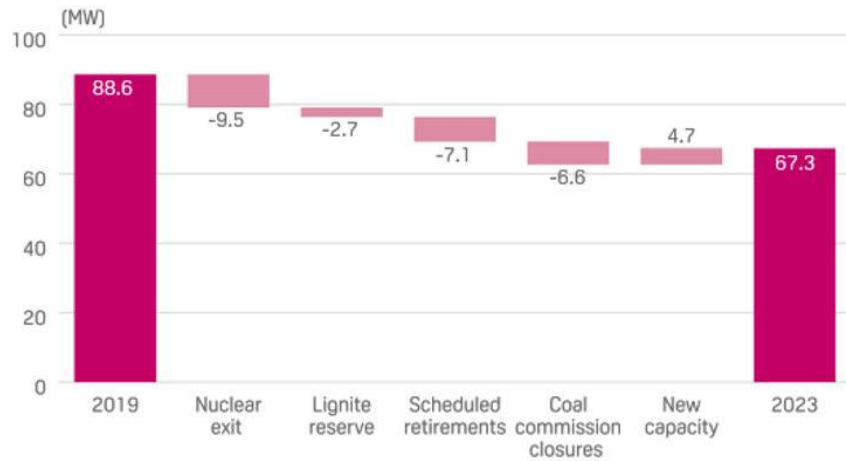
#### **[German power overcapacity to disappear by 2023 as 26 GW close](#)**

According to the German association BDEW<sup>18</sup>, Germany’s conventional generation will decrease from currently 88.6 GW to 67.3 GW by 2023, due to the closure of 26 GW (including 9.5 GW from the nuclear exit, 2.7 GW lignite and 7.1 GW of other retirements) and an addition of 4.7GW new secured capacity expected online by 2023.

---

<sup>17</sup> [Green Budget Europe, The Ex'tax Project, Institute for European Environmental Policy, Cambridge Econometrics \(2018\): Aligning Fiscal Policy with the Circular Economy Roadmap in Finland.](#)

<sup>18</sup> [BDEW.](#)



Source: BDEW

### [Box 16. Belgium case: targeted profit-shaving and no consistent nor stable long-term vision for investors](#)

An 85 TWh market with firm reliable capacity split between nuclear units and CCGTs. Coal-fired units were closed or reconverted to biomass units. A nuclear phase-out was announced in 2003.

#### **1990s: Investment in a first wave of 7 CCGTs**

#### **2003: Law on nuclear phase-out (~5.9GW), while nuclear generation represents ~55%-60% of Belgian electricity generation**

Nuclear power stations to close after 40 years of operation, unless such shutdowns compromise security of supply. This meant that Doel 1, Doel 2 and Tihange 1 would shut down in 2015 and that the full phase-out would be completed over 2023-25.

#### **Mid-2000s: Investment in a second wave of 3 CCGTs – Commercial operation over 2009-2012**

#### **2008: Introduction of a specific flat tax on nuclear generation, targeted at so-called “windfall profits”**

A yearly nuclear tax was introduced in 2008 as a reaction to previously rising market prices, producing high margins on nuclear generation, most of it came after the facts and went on when operating margins had quasi-disappeared altogether...

Starting from €~250 mio (2008-11), it more than doubled afterwards (€~500 mio, average 2012-2014 on ~46TWh of nominal generation). After 2015, with the lifetime extension of three nuclear units, the nuclear tax has decreased gradually in exchange of a 40% profit sharing, with a floor of €150 mio.

#### **2010s: Adverse evolution of prices causes investments to stall ahead of slightly adapted nuclear phase-out**

In 2012, the government decided to keep Tihange 1 operating longer (+10 years). In mid-2015, the Nuclear Withdrawal Act was amended, allowing also Doel 1 and 2 to remain operational until 2025. These lifetime extensions had poor economic merits; this was compensated by a reduction of the nuclear tax.

Adverse evolution of prices has led to the cancellation of CCGT investments (e.g. Visé, 2x450 MW), the downgrade of several CCGT units to open-cycle (OCGT) mode, the announced closure of several other CCGTs, and the cancellation of a proposed extension of the pumped hydropower storage site of Coe (which was expected to increase its capacity by 600MW).

Concerns regarding security of supply triggered the setup of a strategic reserve in order to postpone the closure of 20-year old CCGTs.

**The lack of long-term visibility for investors and of an appropriate market design has forced existing CCGTs to revert (OCGT conversion) or even to exit the market (full decommissioning, expected closure, etc.) and projects not to materialise, even in the context of an announced nuclear phase-out.**

#### **2020s: Expected introduction of a capacity market**

Over almost 15 years, no additional investment has been made to anticipate the closure of the nuclear units and to fill the associated “firm” capacity gap.

In order to ensure security of supply and to avoid increasing further the dependence of Belgium on electricity imports, a capacity market based on reliability options is being planned to address the forthcoming gap in generation.

**Concerns of security of supply are now emerging, because of traditionally high dependence on imports that tend to become less reliable (decreasing firm export margins in neighbouring countries). This happens even without a clear perception of the implications of likely phase-out schemes of firm capacity in Central Western Europe (CWE) and increasing (correlated) intermittent generation.**

## **3.6 The transmission and distribution grids**

Networks currently face a number of challenges. First, the commercial use of the existing network capacity must be improved, as it is frequently suboptimal. The full implementation of the Capacity Allocation and Congestion Management (CACM) guidelines is necessary.

The development of interconnectors is slow and costly, and more expensive options, such as underground or undersea cables, are sometimes preferred to circumvent public opposition. Network development at national level is in no better shape as it faces similar public acceptance difficulties. This creates a risk of European fragmentation and difficulties for renewables integration, since renewables frequently grow at distribution level and in places that were not considered when planning the network years ago.

Current network regulation is adequate for an established technology in a stable environment. It is mostly focused on minimising costs and unnecessary investments, and grid development usually follows demand, it does not precede it. Only a few countries, such as the United Kingdom or Italy (see boxes 17 and 18), have started moving towards new regulatory schemes that go beyond controlling costs and investments to incentivise output, looking at deliverables of the grid companies such as customer satisfaction, carbon-neutral generation connected to the grid, conditions for new connections, treatment of vulnerable customers, etc.

However, all across Europe there will be needs to modernise, upgrade and extend the transmission and distribution networks for the energy transition. The grid will have to accommodate new demand, as electrification progresses. This will include new electric equipment in industry, services and households, as well as the growing presence of electric vehicles. A significant part of the new renewable generation will be connected to the distribution grid, and distributed generation will turn previously passive distribution networks that were only used for transporting electricity, into grids that can also export energy.

The new distribution network will have to be operated in a much more dynamic way, due to the changing nature of electricity flows. The grid will move from accommodating only “downstream” flows, from centralised generation plants to end consumers, to dynamic flows that can also move “upstream” towards the transmission level. This will require a much more flexible use of the network assets (the smart grid concept). The development of flexibility platforms where grid operators can buy from market parties’ flexibility, storage, etc. will be necessary to optimise the use of the existing networks.

Considerable investments in networks will be needed to accommodate these challenges and to upgrade the infrastructure to the new requirements while maintaining the current high quality of services<sup>19</sup>. The European Commission’s Long-Term Strategy estimates the average investment need for power grids in the 2021–2030 horizon between €60 and 110 bn per year. Eurelectric is starting a detailed assessment of the investment needs in the European distribution grids (see box 19). Obviously, adequate regulation will have to ensure that this development is cost-efficient (in particular, in terms of coordination with renewables generation development) to avoid increasing the customer bills.

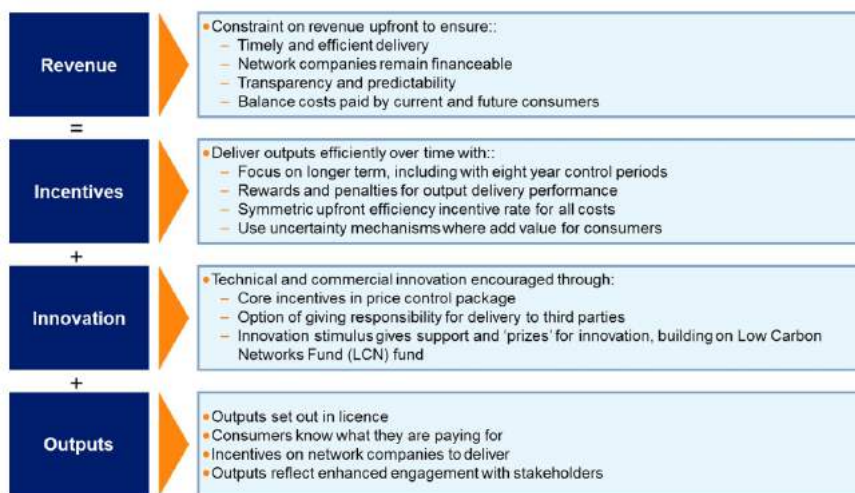
#### **Box 17: RIIO**

RIIO is the UK regulator Ofgem’s framework for setting distribution price controls. As the regulator, Ofgem must ensure that distribution and transmission investment is delivered at a fair price for consumers. To help achieve this, Ofgem developed RIIO (Revenue=Incentives+ Innovation +Outputs) – a performance based model for setting the network companies’ price controls, which lasts eight years. RIIO is designed to encourage network companies to:

- Put stakeholders at the heart of their decision making process.
- Invest efficiently to ensure continued safe and reliable services.
- Innovate to reduce network costs for current and future consumers.
- Play a full role in delivering a low carbon economy and wider environmental objectives.

---

<sup>19</sup> [Eurelectric & EY, Where does change start if the future is already decided, 2019](#)



Source: Pöyry

Under RIIO, Ofgem asks companies to submit well-justified business plans detailing how they intend to meet the RIIO framework objectives. The process starts with the publication of a strategy document in which Ofgem sets out the framework against which the companies will develop their plans. RIIO places a strong emphasis on stakeholder engagement and companies must get stakeholders' input and demonstrate how this has been used to develop their plans. There are separate RIIO frameworks for electricity transmission, distribution and gas transmission and distribution. For electricity distribution, RIIO-ED1 applies to the 6 GB electricity distribution network operators and defines a set of incentives based on their performance against key outputs for consumers:

- Customer satisfaction with network operators;
- Customer interruptions and minutes lost;
- Average time to connect to the network;
- Undergrounding of overhead lines;
- Return on regulatory equity;
- Expenditure vs allowance;
- Estimated network costs per domestic customer.

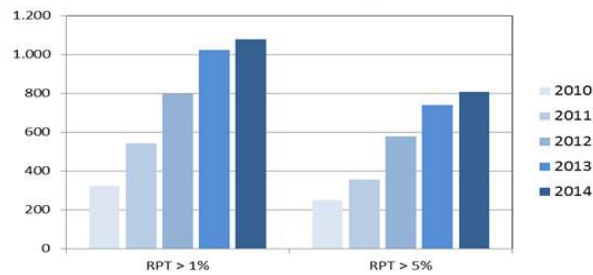
Source: [Ofgem](#)

### **Box 18. Italy: a virtuous path towards output based network regulation**

In the last decade, massive renewables and distributed generation penetration has been changing the main features of the distribution system, with great impact on its operation:

- Dramatic increase in the total number of power plants (~20x) and decrease of average size thereof (roughly down by 95%)
- Changing energy flow patterns, with distribution network increasingly exporting energy to transmission (>25% of HV/MV substations with reverse power flow for >5% of time).

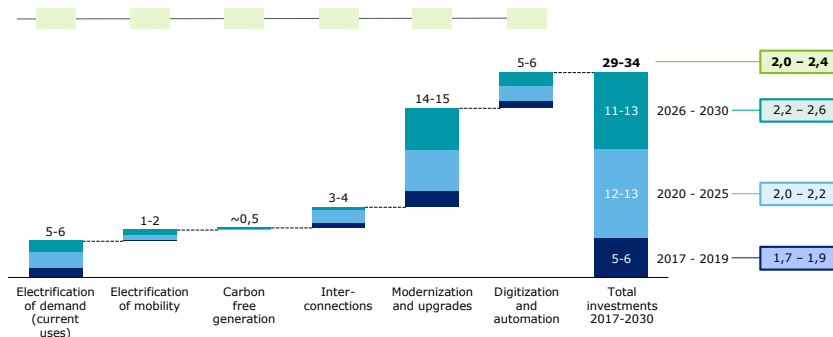
**Reverse Power-flow Time (RPT) in Italy**  
 [number of Primary Substation with RPT > x% of the year]  
 source: Enel Distrib.; total number of PSs: around 3.200



- The “Fit and forget” approach has so far ensured a smooth renewables and system development, but now the grid faces new challenges due to further electrification and decentralisation.
- The Italian Regulatory Authority has promoted since 2010 a forward looking path to transform networks towards “smart distribution systems”:
- First phase: launch of six pilot projects to test technologies and functionalities. The projects cover the introduction of ICT and automation technologies in areas such as voltage regulation, local dispatching of distributed resources, monitoring and automation of low voltage and medium voltage grids, diagnosis of network equipment, fault detection, integration of storage and electric mobility, smart info for final customers, etc.
- Thanks to these projects, the Italian Regulatory Authority analysed each new smart functionality with a cost-benefit analysis and decided to implement the selective development of meaningful outputs (e.g. voltage control on MV network and resilience) with well-calibrated metrics to promote the most efficient solutions.
- The evolution of network regulation should complement traditional input-based approach with new incentives to smart and efficient ways to manage distribution networks, ensuring cost-reflectivity, efficient cost allocation and innovation.

**Box 19. An assessment of the grid investment needs in Spain**

All the Spanish DSOs, together with the TSO, Red Eléctrica de España, have commissioned Deloitte to carry out an assessment of the investment needs of the Spanish transmission and distribution grids in the context of the energy transition. This graph summarises the required investments:



In the case of Spain, these investments are not above the historic trend of network investments, although their nature is somehow different, with “less copper and steel and more silicon”. The analysis foresees that grid tariffs will go down by 10% in the 2030 horizon, because of the increase in demand derived from electrification.

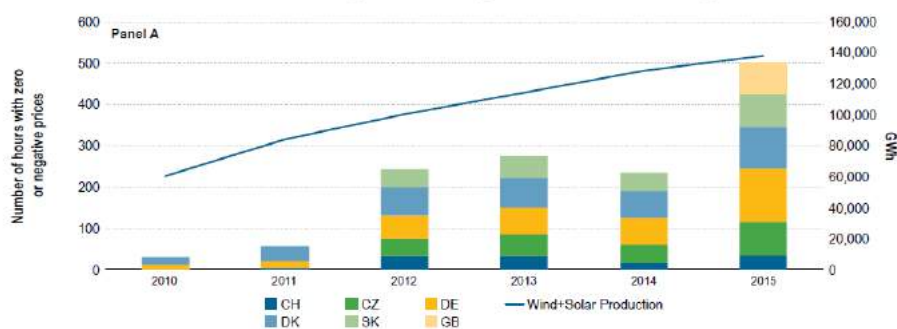
### 3.7 The downwards investment spiral

Across Europe, merchant investments in electricity generation and storage assets are generally not attractive, and this affects particularly the necessary new carbon-neutral firm and flexible capacity. This is down to a number of reasons (see also box 20).

First, short-term prices are generally reflecting mainly the variable costs (in the system marginal prices), and scarcity prices do not happen, are not allowed to happen, or are not sufficient to give the right incentives. Second, the excess of firm generation capacity in a number of European countries is rapidly disappearing as thermal and nuclear capacities are being decommissioned<sup>20</sup>. At the same time, a large amount of renewable capacity, which is mostly isolated from market prices because of feed-in-tariffs and similar support schemes, maintains short-term prices low and can even lead to zero or negative wholesale prices (see Figure 14), although this is gradually changing as support schemes are increasingly adapted to the market.

**Figure 14** – Frequency of zero or negative wholesale prices in a selection of European countries

**Figure 3:** Frequency of zero or negative wholesale prices in a selection of European countries and the quantity of electricity produced from intermittent generation (wind and solar, in combination with run-of-river in the case of the Iberian market) – 2010–2015 (number of hours and GWh)



Source: [ACER/CEER \(2016\) Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015](#)

New assets present an increasing share of fixed and investment costs, compared to variable costs (growing CAPEX/OPEX ratio). When they operate less or at lower prices than expected at the moment of the investment decision, these assets with larger investment costs are more exposed to resulting in significant stranded asset value. On the contrary, assets with a lower share of fixed and investment costs present less risks, since a bigger fraction of their total costs are incurred only when they operate (with a market price above their variable costs).

There is a lack of counterparties for long-term risk hedging, leading to the absence of long-term price signals. Markets usually offer good hedging opportunities to hedge price risks from one year to three/five years. Customers are rarely interested in hedging price risks beyond these time horizons, since their budget cycle does not typically go that far.

<sup>20</sup> According to the Joint Research Center (JRC), between now and 2025, the installed capacity of coal-fired power plants in the EU will drop from 150 GW to 105 GW. On top of this, a further decrease of 55 GW is expected by 2030. Source: [JRC \(2018\), EU coal regions: opportunities and challenges ahead](#)

The justification for entering into contracts of longer duration could be to hedge security of supply risks: this would make it possible for a customer to secure long-term supply and for a generator to hedge its construction risk. However, consumers have little incentive to secure long-term supply risks, since they believe that the State will take care of this risk. In practice, this risk is mutualised, since customers are curtailed based on technical criteria rather than based on their individual contractual position, due to regulatory or technical limitations. This can make security of supply a public good: if at the end of the day, even if adequacy problems arise, the State is not going to leave unhedged customers without supply. Capacity markets are a possible solution for this (see box 21).

Finally, there are significant political and regulatory risks that, by their very nature, cannot be hedged.

These market and regulatory situations are compounded by the fact that the development of carbon-neutral firm and flexible capacity still present significant technical and economic challenges: a new family of storage or firm technologies, maybe based on power-to-hydrogen or power-to-gas, is still needed to replace the existing thermal fleet.

Renewable generation faces similar problems. However, European legislation has offered a framework for the development of national support schemes that provided long-term stable price signals. Additionally, some renewable generation is benefitting from PPAs of long duration, because a growing number of customers are interested in sourcing renewable energy, frequently for strategic or corporate social responsibility reasons. However, it is still unclear whether the demand of these customers will be sufficient to back all the necessary development of new renewables.

On the other hand, renewables also face their own difficulties. In the recent past, the uncontrolled growth of the cost of support schemes has made them financially unsustainable and has led in some countries to retroactive changes that have deteriorated the risk profile of this industry. Additionally, they particularly suffer due to the inefficient and slow development of the grid.

The demand side of investments also has challenges to overcome. An inefficient and biased tariff structure, overcharged with taxes and levies, makes electricity expensive and dis-incentivises electrification in favour of fossil alternatives. Artificially high retail prices send an inefficient signal for self-generation (and possibly inefficient future self-storage): customers have a strong signal to leave the system, to avoid their share of the costs that overburden the electricity bill.

All this slows down necessary investments and put the energy transition at risk (see box 22). Therefore, policy makers conclude that the market framework is failing and they enact even more ad hoc measures, further increasing uncertainty for active consumers and market players. This creates a vicious circle where interventions lead to more uncertainty.



### **Box 20. Risks and investments**

Investors and market participants face both risks (prices, volumes, operations...) and uncertainties (regulations, shifts in national climate policies, price caps...). An investor will decide to invest when the expected return corresponds to the risks and uncertainties of the business.

The efficient policy is to allocate each risk/uncertainty to the agent best placed to manage it. That is, each agent should be “shielded” as far as possible from the impact of the factors it cannot manage. This means roughly that companies and investors are best placed to face market and operational risks, and regulators and governments should deal with regulatory and political uncertainties.

Market risks, the easiest to hedge, are seldom fully hedged. Some exposures are hedged, others are kept in portfolio – either because no market instrument exists for perfect hedging or because a profit opportunity exists that can be captured by keeping the position open. Similarly, insurable risks are usually only partially insured. It is usually sensible to insure against catastrophic events, while it is often more cost-effective to self-insure against high frequency, low-severity events.

It is neither possible nor efficient to avoid all risks but, while risks can be at least partially hedged, uncertainties cannot. For instance, feed-in-tariffs or fixed price regulated PPAs for certain technologies reduce companies’ market risk and lower the cost of capital. On the other hand, they may increase the risks borne by customers, distort wholesale prices and expose the investors to increased regulatory uncertainty.

Assets’ revenues are mainly based on short-term prices: energy prices ( $\leq 3$  years ahead, including ETS signals); balancing services ( $\leq 1$  year ahead); and, to a lesser extent, guarantees of origin ( $\leq 1$  year ahead). Beyond these time horizons, asset operators can reasonably expect to collect revenues in the future but with significant uncertainty, which is reflected in a higher cost of capital. Hence long-term visibility on future revenues leads to lower cost of capital<sup>21</sup>. However, lower risk for the generators does not automatically lead to a more efficient risk allocation and lower cost for the consumer.

### **Box 21. Capacity markets**

Several reasons are usually cited to justify capacity markets.

First of all, security of supply. Customers do not have an incentive to hedge security of supply risks, since they assume that the State will ensure resource adequacy (or even more simply, that adequacy is a given). Experience shows that when adequacy problems arise, customers are curtailed based on security criteria applied by the TSO, whatever their contractual position.

---

<sup>21</sup> According to “UK Electricity Market Reform and the energy transition: emerging lessons”; M Grubb & D Newbery, MIT CEEPR Working Paper, 2018-004, February 2018, adequate visibility of long-term revenues can reduce the cost of capital significantly, up to 3 p.p.

Governments can have an interest in using the capacity markets as a hedge against scarcity prices. They want to protect end customers against price peaks. Some designs of capacity markets, such as the so-called reliability options, require contracted capacity to be available at pre-determined prices (the strike price of the options), therefore preventing the appearance of scarcity prices. This is a more effective and less distortive mechanism than a price cap, since the contracted capacities receive the capacity price in exchange for forfeiting the possibility of receiving the scarcity prices.

There are more fundamental arguments that criticize the energy-only market. They point to the discrepancy between the revenues and costs of generators. On the one hand, revenues are based on system marginal prices (essentially variable costs); on the other hand, the generators' costs obviously includes fixed and investment costs. However, this is also the case for most of the other industries: what makes the electricity industry specific (as of today) is the inability to store massively, which can in turn lead to significant price variations which are difficult to forecast. On top of political and regulatory uncertainties, this can make revenues very hard to predict.

Thus, there are good reasons to argue that the energy market is an efficient signal for operation, in particular when all available resources participate in the energy market, but a questionable (or excessively risky) guidance for investment. In a context where there is a need for large investments, this would lead to higher costs. Are marginal prices truly going to solve missing-money issues in a context of energy transition? Will they cover fixed O&M and capital costs, especially in a context of less and less running hours?

Capacity markets are a way of efficiently driving the transition from fossil-fuelled plants to new carbon-neutral firm capacity. Fossil-fuelled plants will gradually become less competitive than carbon-neutral capacity both in the energy/balancing markets and the capacity market, because of the increasing CO<sub>2</sub> price. Capacity markets have also proven effective, for instance in the United States, at facilitating the development of demand-side response.

Different combinations of these reasons have led to the implementation of capacity markets in countries such as the United Kingdom, Ireland, France or Poland. They all share a number of elements:

- The mechanism is used to contract firm capacity, be it generation, storage or demand side response.
- This can be done either through centralised auctions or by direct contracting between generation/storage/demand side response and retailers.
- The contracted capacity undertakes to be available and at the disposal of the system operator in periods of scarcity. These are typically defined by high wholesale prices or by high demand.
- When the contracted capacity is not available when requested by the system operator, it has to pay a penalty.

#### **GB capacity mechanism**

- The GB capacity market is a centrally run reverse auction that takes place between one and four years ahead of the delivery year, for the procurement of a target volume chosen by the government. Winning bidders are paid the £/MW clearing price for the corresponding delivery years. National Grid (GB TSO) issues capacity market warnings, which provide a 4 hour notice period for all obligated providers to start generating or reducing demand. The

system stress event is then determined ex-post with penalties levied where providers have not delivered.

#### **Irish capacity mechanism**

- The scheme has a central buyer – the Single Electricity Market Operator (SEMO), which purchases capacity, through an auction, up to the volume required to ensure security of supply. SEMO buys the capacity from capacity providers (e.g. power plants or demand response operators) in the form of reliability options. The capacity provider that has sold the reliability option will receive a payment i.e. the clearing price of the auction. In return, the capacity provider complies with certain availability obligations and is obliged to pay back 'difference payments' whenever the electricity price on the wholesale market exceeds a certain 'strike price', currently €500/MWh. The market operator finances the option fees through a 'capacity charge' imposed on electricity suppliers. It also makes difference payments to the suppliers in case the wholesale price exceeds the strike price. In theory, prices paid by suppliers are capped at the strike price and capacity providers are ensured a certain and fixed payment.

#### **French capacity mechanism:**

- The scheme is based on a decentralised obligation for consumers to hold capacity certificates covering their demand during peak periods for each delivery year. Generators must certify each unit according to its availability during potential scarcity situations. Demand response operators can select whether they are considered as a negative demand (behind the meter) or certified as available capacity. Capacity certificates can be traded OTC or during market sessions managed by a single market operator, between delivery year -4 and delivery year +2. Since 2019, import capacity is eligible to certification, which allows foreign capacity to participate in the capacity market, and new capacity is eligible to a 7-year contract for difference on capacity price, awarded with a specific auction.

#### **Polish capacity mechanism**

- Polish authorities have designed a capacity market where the Polish TSO, Polskie Sieci Elektroenergetyczne (PSE), will be entrusted to organise centrally-managed auctions to procure the level of capacity required to ensure generation adequacy. To ensure a level playing field between the various potential capacity providers in the capacity market and its technological neutrality, the auctions will be open to all types of capacity, including existing and new generators, demand side response and storage operators, located in Poland or in the control area of neighbouring EU TSOs. Successful bidders will receive a steady payment for the duration of the capacity agreement in return for a commitment to delivering capacity at times of system stress called on by PSE. Financial penalties will apply if beneficiaries do not deliver the amount of energy according to their capacity obligation. The measure will be financed through a levy on electricity supplies.

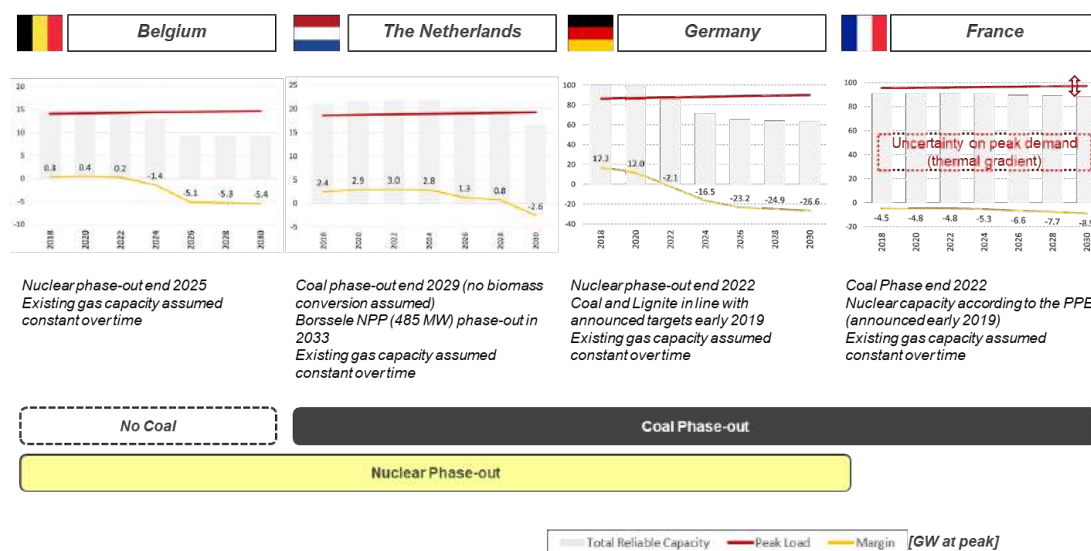
## Box 22. Adequacy outlook for Central Western Europe

### Tractebel study - Outlook on Power Market Adequacy - Central Western Europe (2019)

This analysis is extracted from an up-to-date and European-wide adequacy study<sup>22</sup>, in the context of the Energy Transition that also explicitly addresses the effective use of transmission capacity and the availability of foreign generation capacity.

The outlook on power system adequacy in Central Western Europe (BE, DE, FR, NL) is alarming:

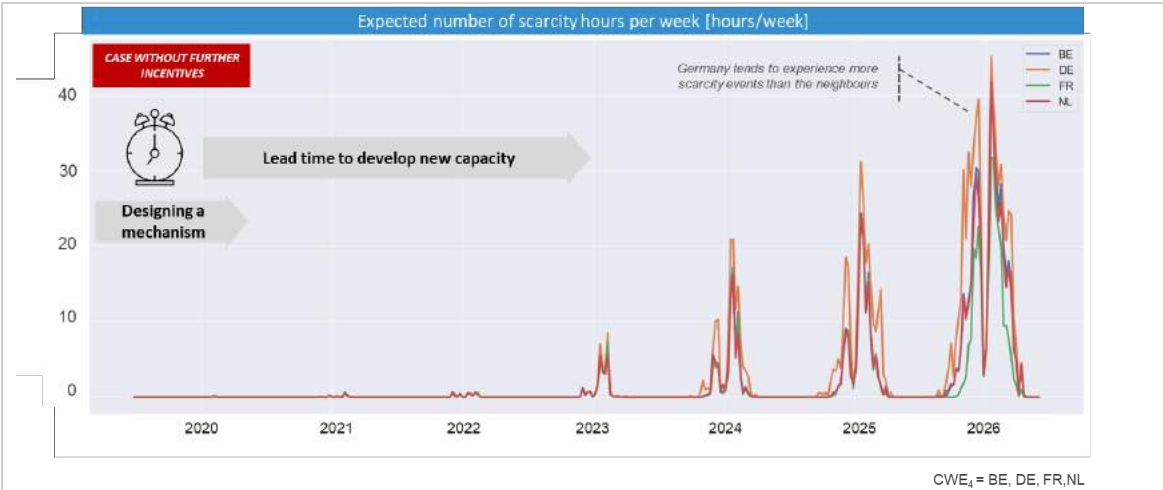
- significant baseload capacity is leaving, driven by implemented or announced nuclear and coal phase-out policies: in the absence of investments in firm capacity, overcapacity in Central-Western Europe is quickly fading away;
- more renewables are needed to meet climate objectives, but also creating flexibility and reliability challenges.



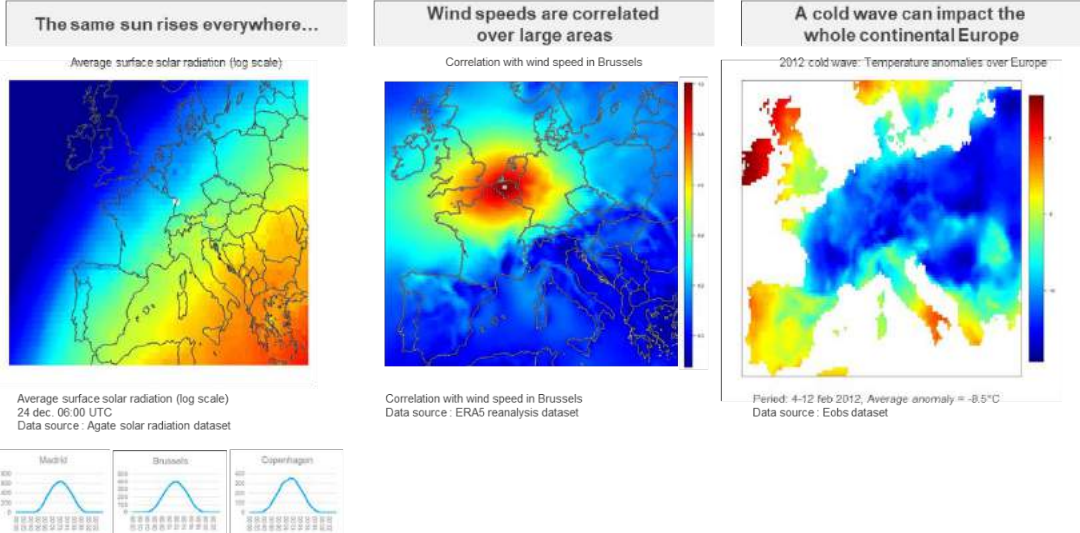
The study strongly indicates that adequacy issues could appear as of winter 2022/23 in the absence of proper anticipation and market framework (e.g. without further incentives to keep existing or to build new reliable capacity).

- in highly interconnected markets, adequacy is a regional concern: all countries considered face adequacy issues simultaneously ;
- hence, it appears that generation rather than transmission is the scarce resource at peak: additional interconnections between the countries will not relieve the situation;
- to share cross-border capacity, coordination between national authorities is thus essential.

<sup>22</sup> Tractebel – Study performed for ENGIE, Outlook on Power Market Adequacy - Central Western Europe, February 2019.



Measures to incentivise investments in firm generation capacity have thus to be taken immediately. This is true for optimising the lifetime of existing capacity, and even more for greenfield development. Indeed, additional variable renewable generation would not solve these adequacy issues: extreme situations of low wind/sun or of higher demand – most relevant for adequacy – are highly correlated across Europe.



**Elia study 2019 – Adequacy and flexibility study for Belgium 2020-2030 (2019)**

In 2019, Elia, Belgium’s TSO, conducted an analysis<sup>23</sup> on the expected capacity shortage in Belgium in 2020-2030, not only because of the nuclear phase-out in Belgium but also the accelerated coal phase-out in neighbouring countries. From 2025, once the nuclear phase-out is completed, there is a structural need for new capacity of up to 3.9 GW. This includes about 1.5 GW related to uncertainties in terms of the availability of generation or interconnection capacity in other countries. Moreover, from 2022-23 onwards, there is an identified structural need for new capacity of more than 1 GW in Belgium due to newly announced generation closures in neighbouring countries.

<sup>23</sup> [Elia – Adequacy and flexibility study for Belgium 2020-2030. June 2019](#)

## 4 Does the Clean Energy Package solve this situation?

At the end of November 2016, the European Commission published the “Clean Energy for all Europeans” package of legislation (CEP) to form the basis of the 2030 EU regulatory framework. It was composed of eight legislative proposals (Energy Performance of Buildings Directive, Renewables Directive, Governance Regulation, Risk-preparedness Regulation, Electricity Directive, Electricity Regulation, ACER Regulation and Energy Efficiency Directive). All these proposals have now been adopted. This is a milestone for the European Union to define an ambitious pathway to decarbonisation, in particular of the electricity sector.

Certainly, the CEP is a major step forward.

On renewables, the EU is now collectively committed to reach a mandatory target of at least 32% by 2030. On the basis of our analysis, this will result in a share of almost 60% for the electricity sector. The CEP fosters market-based instruments, prohibits retroactive measures, facilitates PPAs and ease the integration of renewables in the market (with some exceptions). Although it does not provide an investment framework for renewables at European level, it provides a legal frame for Member States to implement appropriate mechanisms to foster the further deployment of renewables.

The CEP brings clear improvements on the wholesale market. It mandates the removal of caps on wholesale prices, which is a considerable enhancement on the third energy package. The CEP also provides a clear framework for day-ahead, intraday and balancing markets and a reasonable framework for the European adequacy assessment, including the consideration of the economic situation of generation assets when defining planning scenarios. Nevertheless, there are still some provisions of the CEP that will have an uncertain impact, such as articles 14, 15 and 16 of the Electricity Regulation. Will the CEP ensure a more efficient use of interconnection capacity?

The new Electricity Regulation has made significant progress by establishing free market entry and exit (i.e. based exclusively on agents' financial perspectives) as a basic principle of market design, although it remains to be seen how it will be implemented in practice in each Member State.

However, in a world with ever increasing shares of renewables and low variable costs technologies, we need to ensure that energy, flexibility and reliability are properly valued. There are currently inadequate price signals for both closure of existing plants and new investments. The CEP fails to deliver a definitive solution to the problem of providing long-term investment signals to achieve the energy transition cost-effectively while ensuring security of supply.

Indeed, while the CEP acknowledges the role of flexibility, it does not provide a framework to recognise the value of the flexibility and reliability provided by the current thermal fleet while the production of these plants is decreasing and has to decrease even faster. In the same way, the package does not offer any comprehensive alternative to efficiently replace the current thermal fleet with new carbon-neutral flexible/reliable capacity. Therefore, in most markets, with the exception of a few regions in Europe, reliance on the energy-only market will fail to give the appropriate signals for these investments.

Moreover, capacity markets are seen in the CEP as suspicious interventions, not as a market feature. The Clean Energy Package establishes a stop and go approach that does not provide the confidence for the capacity investments needed to ensure security of supply. In order to bridge

this gap, the package could have established alternatives for long-term market design, but it has not.

On networks, a significant contribution is the creation of a new European institutional framework for DSOs: the EU DSO entity. It will facilitate the dialogue between the TSOs and the DSOs and enable a better collaboration between the system operators. On the bright side, the CEP establishes high-level principles for network tariff design and mechanisms to extend best practices in this area, without imposing harmonisation. It also introduces the possibility for the DSOs to contract services to avoid or defer grid investments, and opens the door to DSO-related network codes. All in all, the CEP aims at increasing the role of consumers as actors of flexibility to benefit the operation of the distribution network.

Finally, the CEP maintains regulated tariffs and, above all, fails to address the main problem for final consumers: very high taxes, levies and inefficient grid tariff structure that hinder electrification and, hence, lead to an inefficient decarbonisation process. However, the energy efficiency legislation provides a framework for electrification investments, since they improve efficiency.

Nevertheless, the CEP is a good basis if all its requirements are fully implemented. The new Governance Regulation will be central to the achievement of the CEP objectives, as it ensures that Member States are held to account on their investment framework in order to meet targets. Eurelectric supports this flexible yet robust system, which includes long-term strategy planning for 2050, and opportunities for regional cooperation, while signaling the necessity to assess the impact of national policies on the ETS.

## Table of Figures

<b>Figure 1</b> – EU electricity generation mix in EU 28 (2018)	9
<b>Figure 2</b> – Renewables cost reductions	10
<b>Figure 3</b> – 2030 Projection of EU renewable power generation	10
<b>Figure 4</b> – Capacity evolution by fuel in the EU electricity mix between 2015 and 2045 in EU 28, GW	11
<b>Figure 5</b> – Generation by fuel type between 2020 and 2045 in EU 28, TWh	11
<b>Figure 6</b> – Example of the use of flexibility resources to match supply and demand when renewable production is low	12
<b>Figure 7</b> – 2015 carbon intensity of electricity in different Member States (kg CO <sub>2</sub> /MWh)	14
<b>Figure 8</b> – Norway's power sector is already decarbonized, while Poland relies on coal for 80% of its electricity supply	15
<b>Figure 9</b> – CO <sub>2</sub> European Emission Allowances – price chart	18
<b>Figure 10</b> – Evolution of electricity bill components	19
<b>Figure 11</b> – Yearly capacity installation (2010–2018) & Yearly average capacity expected evolution 2020–2045 (GW)	26
<b>Figure 12</b> – Role of demand side response in the future power system	33
<b>Figure 13</b> – Different sources of dispatchable resources, GW	39
<b>Figure 14</b> – Frequency of zero or negative wholesale prices in a selection of European countries	48

## Table of Boxes

<b>Box 1.</b> Retail price regulation is an obstacle to competition among electricity supply companies	16
<b>Box 2.</b> The planning tools: MAF and TYNDP 2018	17
<b>Box 3.</b> Charging infrastructures for electric vehicles	20
<b>Box 4.</b> Some taxes on generators across the EU	22
<b>Box 5.</b> Spain and Portugal: Interventions in wholesale markets cause distortions beyond borders, and are followed by further interventions	23
<b>Box 6.</b> Slovakia: G-charge improper implementation causes wholesale market distortions	25
<b>Box 7.</b> Implementing auctions for market-based support schemes	28
<b>Box 8.</b> The development of PPAs	31
<b>Box 9.</b> Difficulties with RES development	32
<b>Box 10.</b> The challenge of storage	34
<b>Box 11.</b> Greece, pumped hydropower storage	36
<b>Box 12.</b> Germany power-to-gas	37
<b>Box 13.</b> Unilateral measures in South-East Europe during a cold spell (January 2017)	40
<b>Box 14.</b> The situation of CCGT in Spain	41
<b>Box 15.</b> German case: nuclear, coal and lignite phase out	42
<b>Box 16.</b> Belgium case: targeted profit-shaving and no consistent nor stable long-term vision for investors	43
<b>Box 17.</b> RIIO	45
<b>Box 18.</b> Italy: a virtuous path towards output based network regulation	46
<b>Box 19.</b> An assessment of the grid investment needs in Spain	47
<b>Box 20.</b> Risks and investments	50
<b>Box 21.</b> Capacity markets	50
<b>Box 22.</b> Adequacy outlook for Central Western Europe	53









eurelectric

Union of the Electricity Industry - Eurelectric aisbl  
Boulevard de l'Impératrice, 66 - bte 2 - 1000 Brussels, Belgium  
Tel: + 32 2 515 10 00 - VAT: BE 0462 679 112 • [www.eurelectric.org](http://www.eurelectric.org)  
EU Transparency Register number: 4271427696-87