The Costs of Decarbonisation:

System Costs with High Shares of Nuclear and Renewables

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Nuclear Technology Development and Economics

The Costs of Decarbonisation:

System Costs with High Shares of Nuclear and Renewables

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Foreword

In December 2015, 174 countries and the European Union agreed to reduce their greenhouse gas emissions to limit the global average temperature increase to well below 2°C above pre-industrial levels. As electricity generation produces about 40% of the world's CO_2 emissions, this sector will be at the centre of efforts to reduce carbon emissions.

Meeting these ambitious climate goals means reducing the carbon intensity of the electric power sector by as much as a factor of ten. The increasing electrification of industry, transport and buildings will only further reinforce the pivotal role of electricity generation. Thus, it is crucial that the electricity being used comes from clean-energy sources.

Our effort to decarbonise the electric power sector needs to be transformative. Governments must foster vigorous investment in low-carbon technologies. Where hydroelectric power is constrained by natural resource endowments, the main alternatives are solar, wind and nuclear technology.

Given that low carbon power generation technologies typically require massive investments, it is of paramount importance to boost investor confidence. We also need proactive policies to facilitate a "fair transition" for affected businesses and households, particularly in vulnerable regions and communities. No one can be left behind.

It is promising that governments have committed to an ambitious global temperature goal and national actions to limit emissions. But today we are neither on track to achieve our environmental goals nor to execute the related policies in a cost-effective way, which places the well-being of our societies at risk.

This study is timely given the major question facing policymakers today: "how can we achieve our ambitious carbon reduction targets in a cost-effective manner?" Answering this question correctly will help design, develop and deliver better, cost-effective, environmentally-sound policies, for better lives.

Angel Gurría
Secretary-General, OECD

Foreword

The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables deepens and enlarges our work on system costs that began in 2011 with the publication of *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems*. At the time, the very notion of system costs – the idea that in the presence of uncertain and variable electricity generation the total costs are more than the sum of plant-level costs as calculated with the levelised cost of electricity (LCOE) methodology – was somewhat of a novelty. The NEA has been at the vanguard of the analysis of how different low-carbon technologies can work together to achieve ambitious carbon emission reduction targets. In the meantime, mainly due to the addition of significant amounts of variable renewables that have profoundly changed the behaviour and the economics of electricity markets, many others have joined us in this work.

The present study is part of our ongoing work on the different dimensions of cost and financing of nuclear energy that the NEA undertakes, alongside a good number of more technical studies, to support our member countries as they seek to make well-informed decisions about their energy futures. This includes (in addition to our system cost studies) work on: the projected costs of electricity generation at the plant-level undertaken with our sister agency, the International Energy Agency (IEA); the economics and financing of new nuclear power plants; long-term operations; decommissioning and radioactive waste disposal, as well as our recent study on the *Full Costs of Electricity Provision*, which also addresses health, resource and environmental issues.

What we have learned so far is that in the electricity systems of the future, all available low carbon generation options, nuclear energy, wind, solar photovoltaic (PV), hydroelectricity and, perhaps one day, fossil fuels with carbon capture, utilisation and sequestration, will need to work together in order to enable countries to meet their environmental goals in a cost-efficient manner. Plant-level costs do remain, of course important and we fully recognise the great strides that variable renewable energies (VRE), such as wind and solar PV, have achieved in this area in the recent past. If, according to our data, they are not yet fully competitive with nuclear power on that metric except in particularly favourable local circumstances, they soon might be. However, their intrinsic variability and, to a lesser degree, their unpredictability, imply that the costs of the overall system will continue to rise over and above the sum of plant level costs. What nuclear energy and hydroelectricity, as the primary dispatchable low carbon generation options, bring to the equation is the ability to produce at will large amounts of low carbon power predictably according to the requirements of households and industry. For the right decisions to be made in the future by governments and industry, these factors must be understood and addressed.

A cost-effective low carbon system would probably consist of a sizeable share of VRE, an at least equally sizeable share of dispatchable zero carbon technologies such as nuclear energy and hydroelectricity and a residual amount of gas-fired capacity to provide some added flexibility alongside storage, demand side management and the expansion of interconnections. Those of us working in the nuclear energy area are well aware that electricity markets are evolving and that nuclear energy must evolve to meet future requirements. Nuclear energy is well placed to take on these challenges but can also work together with all other forms of low carbon generation, in particular VRE, to achieve the ambitious decarbonisation targets NEA member countries have set for themselves.

William D. Magwood, IV
Director-General, Nuclear Energy Agency

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List of abbreviations and acronyms

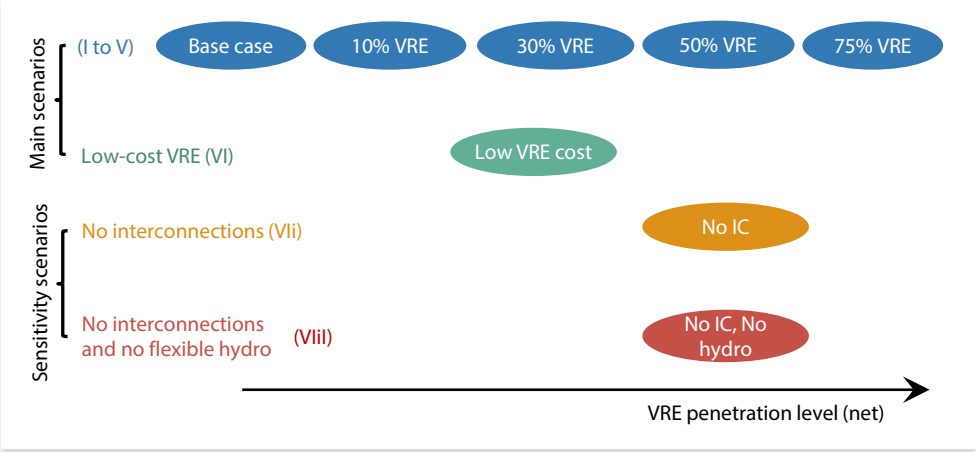
BEIS	Department for Business, Energy and Industrial Strategy (United Kingdom)
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CEE	Central and Eastern Europe
CFD	Contract for difference
CONE	Cost-of-new-entry
CRM	Capacity remuneration mechanism
CWE	Central Western Europe
CWIP	Construction work in progress
DER	Distributed energy resources
DOE	Department of Energy (United States)
DSM	Demand-side management
DSR	Demand-side response
EES	Electric energy storage
FIP	Feed-in premiums
FIT	Feed-in tariffs
GenX	Optimal Electricity Generation Expansion
GDP	Gross domestic product
GW	Gigawatt
IEA	International Energy Agency
ISO	Independent system operator
LCOE	Levelised cost of electricity
LDC	Load duration curve
LP	Linear programming
LTO	Long-term operations
MILP	Mixed-integer linear programmes
MIP	Mixed-integer programming
MIT	Massachusetts Institute of Technology (United States)

MW	Megawatt
MWh	Megawatt-hour
NDC	Nuclear Development Committee (NEA)
NEA	Nuclear Energy Agency
NPP	Nuclear power plant
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
PPA	Power-purchasing agreements
PPP	Polluter pays principle
PV	Photovoltaic
PTC	Production tax credits
RES	Renewable electricity sources
RLDC	Residual load duration curves
SMR	Small modular reactor
T&D	Transmission and distribution
TSO	Transmission system operators
VOLL	Value of lost load
VRE	Variable renewable energy
WACC	Weighted average cost of capital
WPNE	Working Party on Nuclear Energy Economics (NEA)

Executive summary

This study sets out to assess the costs of alternative low-carbon electricity systems capable of achieving strict carbon emission reductions consistent with the aims of the Paris Agreement. It thus compares the total costs of six different scenarios of the electric power sector of a representative OECD country, all of which are consistent with a low-carbon constraint of only 50 gCO_2 per kW, but which contain different shares of nuclear energy and renewable energies, in particular wind and solar photovoltaic (PV). These shares vary between 0% and 75% of total electricity consumption. A low variable renewable energy (VRE) investment cost scenario completes this analysis by assuming significant future cost reductions for VRE. Two sensitivity analyses built around different levels of available flexibility resources (availability of interconnection or flexible hydroelectric resources) complete a suite of altogether eight scenarios allowing a good understanding of the principal drivers of the costs of decarbonisation (see Figure ES1 below). In particular, the study highlights the impacts the variability of wind and solar PV production have on electricity system costs, which appears as costly adjustments to the residual system.

Figure ES1. **Eight scenarios to study the cost of low-carbon electricity systems with 50 gCO_2 per kWh**



The present study not only highlights the costs of achieving ambitious carbon targets but also sets out a policy framework for achieving them in a least-cost manner. The five principal pillars of this framework are 1) setting a robust price for carbon emissions, 2) short-term markets for efficient dispatch and revealing the system value of electricity, 3) regulation for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution, 4) mechanisms to enable long-term investment in low-carbon technologies, including the reform of existing mechanisms and 5) the internalisation of system costs wherever practical and necessary. Achieving radical carbon emission reductions does not come for free. However this study shows that defining the right overall mix of the shares of nuclear energy and renewables as well as setting the right policy framework will allow the achievement of radical climate targets while respecting high standards of the security of electricity supply and overall reasonable costs to electricity consumers.

The context

Under the Paris Agreement, which was concluded in December 2015 and entered into force in November 2016, many OECD countries agreed to aim for a reduction of their greenhouse gas emissions sufficient to hold the increase in the global average temperature to well below 2°C above pre-industrial levels. This implies a major effort to decarbonise their electric power sectors. Holding the increase of global temperatures to 2°C requires limiting greenhouse gas concentrations in the earth's atmosphere to roughly 450 ppm of CO_2-equivalent emissions. This requires a massive effort to decarbonise electricity generation, as the electricity sector is expected to bear the brunt of the effort to reduce emissions during the next three decades. Projections indicate that in order to achieve reductions commensurate with the 2° objective, CO_2 emission from the electric power sectors of OECD countries would need to be reduced by almost 90% by mid-century. The average carbon intensity of the electricity produced in OECD countries of 430 gCO_2 per kWh today would need to be reduced to roughly 50 gCO_2 per kWh by 2050.

This decarbonisation will require a radical restructuring of the electric power sectors of each OECD countries and a truly massive deployment of low-carbon technologies, in particular nuclear energy and renewable energies such as wind and solar PV. Other generation options, including hydropower, are limited in a window of only 25-35 years, which is short given the intrinsic inertia of electricity systems, where power plants and transmission infrastructure frequently have lifetimes of 60 years and more.

Renewable energies have enjoyed in recent years both popular and political support. While average costs per MWh of wind and solar PV are still somewhat higher than those of nuclear energy, the cost gap at the level of plant-level generation costs (as calculated with the levelised cost of electricity (LCOE) methodology as set out in the 2015 OECD study on the *Projected Costs of Generating Electricity)* no longer seems insurmountable. However, as spelled out in the first OECD Nuclear Energy Agency (NEA) study on system costs, *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (2012), VRE technologies such as wind and solar PV cause a number of additional costs to the system, which are referred to as system costs.

The most important categories of the system costs of VREs are increased outlays for distribution and transmission due to their small unit size and distance from load centres, balancing costs to prepare for unpredictable changes in wind speed and solar radiation and, perhaps, most importantly, the costs for organising reliable supplies through the residual system during the hours when wind and sun are not fully available or not available at all. Variability also induces significant changes in the composition of the remainder of dispatchable technologies that ensure round-the-clock security of supply in the power system. When deploying VREs, one observes, in particular, a shift from technologies with high fixed cost, such as nuclear power to more flexible technologies with low fixed cost such as gas-fired power generation. While the latter will be able to better absorb the loss of operating hours due to VRE infeed, the overall costs of the residual system will increase, an effect known as "profile costs". In addition, deploying VREs does not automatically translate into carbon emission reductions. For instance, when nuclear power is substituted by a mix of VREs and gas-fired generation that produces electricity when VREs are not available, overall carbon emissions will increase.

All technologies have system costs. Nuclear, for instance, requires particularly strong network connections and access to reliable cooling sources. However, these costs turn out to be an order of magnitude lower than those imposed by the variability of renewable energies. The key advantage of nuclear power in the economic competition with wind and solar PV is the fact that nuclear power plants are dispatchable, i.e. they can produce large amounts of carbon free baseload power in a reliable and predictable fashion. In the context of the decarbonisation of electricity systems, this poses three important questions:

- What is the optimal mix of nuclear baseload and variable renewables from an economic point of view and what is the added cost of reaching a CO_2 emission target with exogenously imposed shares of renewable generation?
- Are electricity systems that are trying to reach these objectives primarily with large shares of variable renewables technically and, in particular, economically viable?

- What are the key policy instruments for creating frameworks that enable the level of investment in low-carbon generation technologies required to ensure a transition towards deeply decarbonised electricity systems?

The precise answers to these questions depend on a number of qualifying conditions, for instance the amount of flexibility resources available in an electricity system that are spelled out throughout the study using a "greenfield approach", where the system is optimised and costs are minimised without making any assumptions about the existing power generation mix other than the availability of hydroelectric resources. This improves the transparency and readability of the modelling results, and thus their pertinence for policy making in a time frame that spans all the way to 2050.

The defining features of this study and the nature of system costs

Today, system costs are no longer part of an unfamiliar concept but a universally accepted part of electricity system analysis. The first NEA study on system costs, published in 2012, was part of an early wave of studies that were instrumental in introducing and conceptualising the notion of system costs. While the initially developed concepts, as well as the basic methodology of working with residual load curves to assess profile cost, have proven robust, much has changed during the past five years. Among the changes that need to be accounted for are:

- the significant decline in the LCOE costs of renewable energies, in particular for solar PV, as documented in the changes in investment costs reported in the IEA/NEA reports on the *Projected Costs of Generating Electricity* for 2010 and 2015;
- the emergence of a broad and lively literature on the system costs of electricity systems, which includes the emergence of a widely shared methodological framework for assessing profile costs;
- a greater awareness and better understanding by policy makers of the importance of system costs
- a clearer idea of the policy-relevant questions that can be usefully asked and answered by the available conceptual and modelling tools given the present state of knowledge.

From the outset, it was clear that any new study should not simply provide an update of the well-regarded 2012 study. In the present study, great care has been expended to construct a representation of the electricity sector in a manner as complete as possible. In this process, the NEA worked with a team of experienced power system modellers at the Massachusetts Institute of Technology (MIT). NEA modelling of the eight scenarios is thus built on the Optimal Electricity Generation Expansion (GenX) model developed at MIT, which provides the detailed, comprehensive and flexible representation of an integrated electricity system that was required.

The electricity sector model that underlies this study thus includes not only hourly dispatch but also ramping constraints and reserve requirements that preserve both system stability and economic equilibrium. In addition, a carefully selected set of credible flexibility options has been added to the model. They include interconnections with neighbouring countries, a relatively high share of flexible hydroelectric resources, demand-side management (DSM) and several storage options. Both technological and flexibility options are important drivers of total system costs. This holds, in particular, if electricity generation includes a large share of wind and solar PV, since their variability challenges the workings of the system by increasing ramp costs and reserve requirements, and it also increases the demand for different flexibility options.

The defining feature of this modelling effort is the fact that all scenarios include the same stringent carbon constraint of 50 gCO_2 per kWh, which is consistent with a level that the electricity systems of OECD countries must achieve to contribute their share to limit the increase in global mean temperatures to 2°C. In order to allow for economic results that are as general, relevant and transparent as possible (and thus independent of the power generation

mix of a particular country), this study has taken a "greenfield approach". This means that starting with a clean slate the electricity system evolves only as a function of electricity demand throughout the year and the specific costs of different technologies in an optimal fashion as if all plants were built from scratch on a green field. This approach is limited only by the exogenously imposed constraints, i.e. carbon emissions of 50 gCO_2 per kWh and different shares of VRE generation that are specified *ex ante*. Only the share of hydroelectric resources has been set exogenously.

The alternative – using a brownfield approach – would have yielded different results. In function of the existing mix, the results in this volume might help individual countries to better assess the cost of their transitions. However, the results of brownfield modelling would not allow drawing comparable general conclusions about the respective costs of electricity systems with different shares of nuclear and renewables. In particular, for variable renewables such as wind and solar PV, the total system costs are highly dependent on local conditions and the structure of the residual system.

VREs, more specifically wind and solar PV, share some specific characteristics that make their integration into the electricity system particularly challenging. The IEA has identified six technical and economic characteristics that are specific to VRE and are a key element to explain and understand the system costs associated with their integration. The output of VRE is thus:

- Variable: the power output fluctuates with the availability of the resource (wind and solar) and not in function of demand or system needs.
- Uncertain: the amount of power produced cannot be predicted with precision. However, the accuracy of generation forecast increases with approaching the time of delivery.
- Location-constrained: the available renewable resources are not equally good in all locations and cannot be transported. Favourable sites are often far away from load centres.
- Non-synchronous: VRE plants must be connected to the grid via power electronics and are not directly synchronised with the grid.
- Modular: the scale of an individual VRE unit is much smaller than other conventional generators.
- With low variable costs: once built, VRE generate power at little operational cost. The short-run marginal costs of wind and solar PV units are zero.

The concept of system effects, which are heavily driven by these six attributes of VRE, has been conceptualised and explored extensively by the NEA and the IEA, and has benefitted from a significant amount of new research from academia, industry and governments. System effects are often divided into the following four broadly defined categories of profile costs (also referred to as utilisation costs or backup costs by some researchers), balancing costs, grid costs and connection costs.

Profile costs (or utilisation costs) refer to the increase in the generation cost of the overall electricity system in response to the variability of VRE output. They are thus at the heart of the notion of system effects. They capture, in particular, the fact that in most of the cases it is more expensive to provide the residual load in a system with VRE than in an equivalent system where VRE are replaced by dispatchable plants. A different way of looking at the profile costs of VRE is to consider that the electricity generation of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. This decreases value for the system of each additional VRE unit and corresponds to an equivalent increase in profile costs. In addition, the presence of VRE generation generally increases the variability of the residual load, which exhibits steeper and more frequent ramps. This causes an additional burden, also called the flexibility effect, to other dispatchable plants in terms of more start-ups and shutdowns, more frequent cycling and steeper ramping requirements, leading to lower levels of efficiency, an increase in the wear and tear of equipment and higher generation costs.

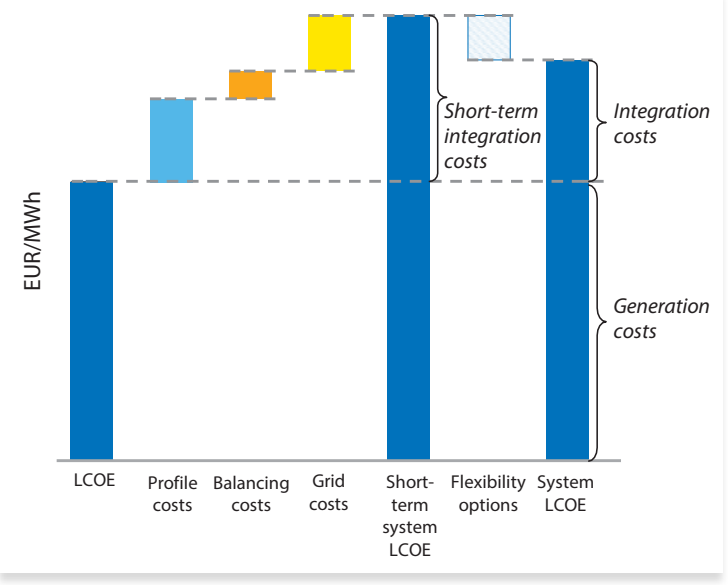
Balancing costs refer to the increasing requirements for ensuring the system stability due to the uncertainty in the power generation (unforeseen plant outages or forecasting errors of generation). In the case of dispatchable plants, the amount and thus the cost of operating reserves are generally given by the largest contingency in terms of the largest unit (or the two largest units) connected to the grid. In case of VRE, balancing costs are essentially related to the uncertainty of their output, which may become important when aggregated over a large capacity. Forecasting errors may require carrying on a higher amount of spinning reserves in the system.

Grid costs reflect the increase in the costs for transmission and distribution due to the distributed nature and locational constraint of VRE generation plants. However, nuclear plants also impose grid costs due to siting requirements for cooling and transmission. Grid costs include the building of new infrastructures (grid extension) as well as increasing the capacity of existing infrastructure (grid reinforcement). In addition, transmission losses tend to increase when electricity is moved over long distances. Distributed solar PV resources may, in particular, require investing in distribution networks to cope with more frequent reverse power flows occurring when local demand is insufficient to consume the electricity generated.

Connection costs consist of the costs of connecting a power plant to the nearest connecting point of the transmission grid. They can be significant especially if distant resources (or resources with a low load factor) have to be connected, as can be the case for offshore wind, or if the technology has more stringent connection requirements as is the case for nuclear power. Connection costs are sometimes integrated within system costs (see NEA, 2012), but are sometimes also included in the LCOE plant-level costs. This reflects commercial realities as different legislative regimes require connection costs either to be borne by plant developers or by the transmission grid operator. In the former case, they are part of the plant-level costs and thus fully internalised, while in the latter case they are externalities to be accounted for in the system costs.

The above list of four cost categories of system costs is not fully exhaustive. The provision of physical inertia, which is implicitly provided by dispatchable plants but not by VRE, is thus emerging as a topic of research. Together, the four categories nonetheless make up the bulk of system costs. Figure ES2 below summarises them.

Figure ES2. **Illustration of system cost**



Source: OECD, 2015.

Modelling results from the NEA system cost study

The NEA study shows that combining explicit targets for VRE technologies and a stringent limit on carbon emissions has important impacts on the composition of the generation mix and its cost. In particular, total generation capacity increases significantly with the deployment of VRE resources. Since the load factor and the capacity credit of VRE is significantly lower than that of conventional thermal power plants, a significantly higher capacity is needed to produce the same amount of electricity. While about 98 GW are installed in the base case scenario without VRE, the deployment of VRE up to penetration levels of 10% and 30% increases the total capacity of the system to 118 and 167 GW, respectively. The total installed capacity would more than double to 220 GW if a VRE penetration level of 50% must be reached. More than 325 GW, i.e. more than three times the peak demand, are needed if VRE generate 75% of the total electricity demand. In other words, as the VRE penetration increases vast excess capacity, thus investment, is needed to meet the same demand. The capacity mix of different generation technologies in the five main scenarios is illustrated in Figure ES3, while their respective electricity generation share is shown in Figure ES4 below.

Figure ES3. **The capacity mix with different shares of VRE**

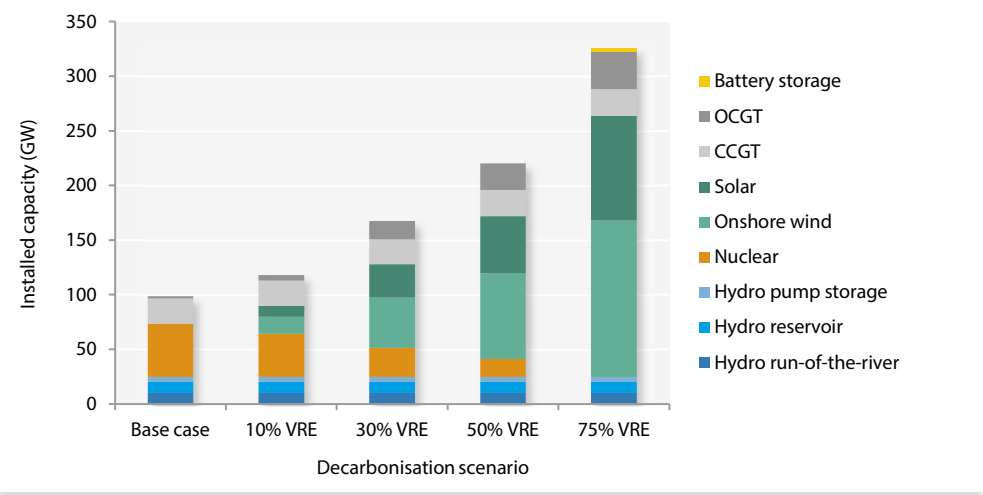
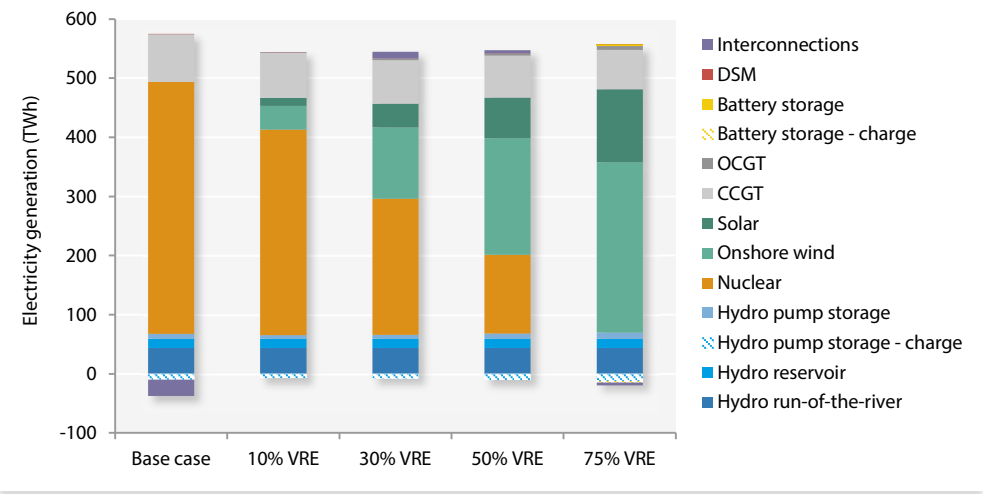


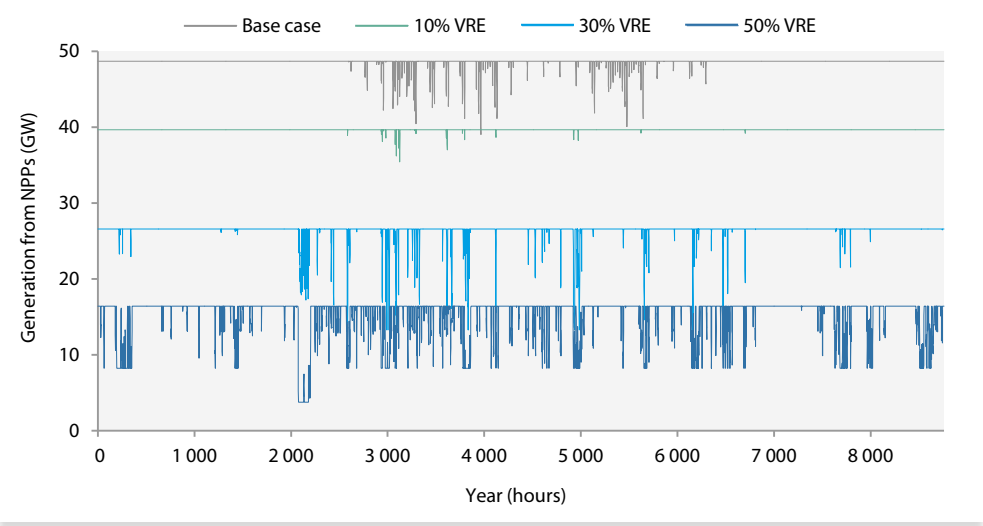
Figure ES4. **Electricity generation share in the main region (main scenarios)**



The integration of VRE changes the long-term structure of the thermal generation mix. The share of fossil-fuelled generation (open cycle gas turbine [OCGT] and combined cycle gas turbines [CCGT]) remains almost constant in all scenarios, as it is limited by the carbon cap. However, the structure of the capacity installed of gas plants and the relative share of generation from OCGT and CCGT changes significantly with the presence of VRE. While the capacity of CCGT power plants is almost constant in all scenarios considered, they are operated at lower load factor in the scenarios with more variable generation. Another important finding is that, under the stringent carbon constraint adopted for this study, coal is never deployed in any of the scenarios considered, despite being cheaper than the other technologies on a pure LCOE basis. In terms of generation, VRE displaces nuclear power almost on a one-to-one basis, which results from the fixed carbon constraint in combination with a fixed amount of hydroelectric resources.

The way in which thermal plants operate also changes significantly, with a reduction of the average load factors and an increase of ramping and load-following requirements. Figure ES5 shows the projected hourly generation pattern of the nuclear fleet for four of the five main scenarios considered (there is no nuclear generation under the 75% VRE). This allows a visualisation of the increased flexibility requirements from nuclear plants, as well as the reduction in nuclear capacity associated with VRE deployment.

Figure ES5. **Projected generation pattern from nuclear power plants**

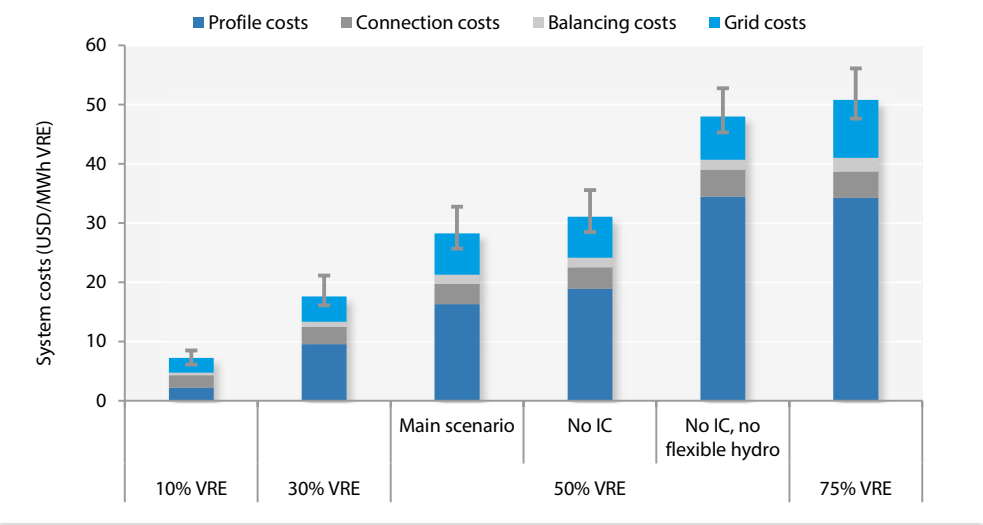


Nuclear capacity progressively decreases with the share of renewables. In the base case scenario with the lowest cost and no VRE, nuclear power is the major source of low-carbon electricity and produces about 75% of the total electricity demand with minimal demand on flexibility. At higher rates of VRE, the demand for nuclear flexibility increases progressively. In the 50% VRE case, nuclear units must ramp up and down by a maximal 30-35% of their installed capacity in one hour.

The changes in the capacity mix, the generation mix and load factors of the different technologies can be captured in the system costs of the different scenarios. Additional grid costs, balancing and connection costs are thus added to the profile costs already implicitly calculated in the different optimised scenarios. As already mentioned, profile costs result from the de-optimisation of the residual system due to the variability of VRE. Total system costs, expressed in USD per unit of net electricity delivered by VRE to the grid are shown in Figure ES6 for the four scenarios of 10%, 30%, 50% and 75% VRE as well as for the two sensitivity scenarios. These system costs must be understood as the increase of the total costs to provide the same service of electricity supply above the costs of the least-cost scenario without any VRE. System costs in the reference system are zero since the issue of variability

does not arise because all the electricity is generated by dispatchable technologies. The figure also provides a breakdown of the total system costs into the four main components. Also, an error bar provides an indication of the uncertainty range deriving from a range of possible assumptions on grid, connection and balancing costs.

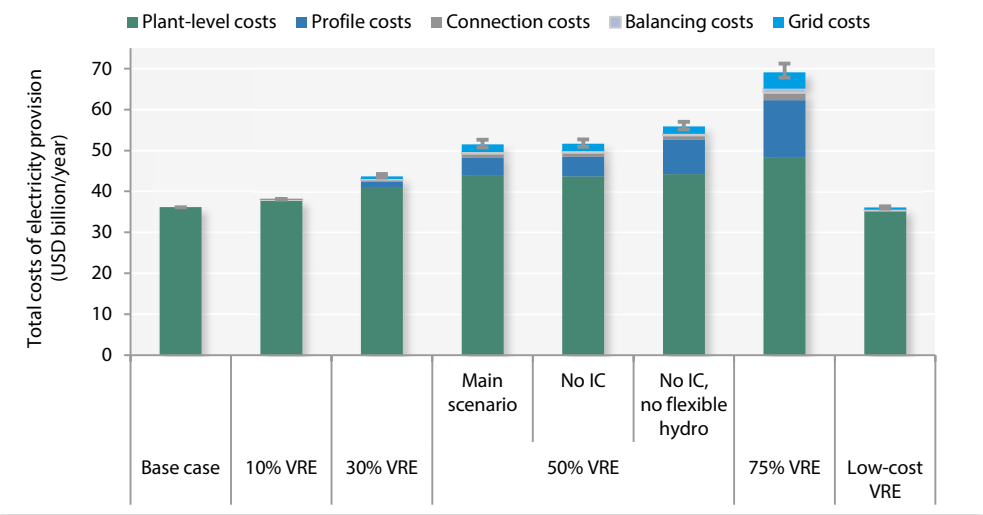
Figure ES6. **System costs per MWh of VRE**



System costs vary between less than USD 10 per MWh of VRE for a share of 10% of wind and solar PV to more than USD 50 per MWh of VRE for a share of 75% of wind and solar PV. Almost as important is the increase of USD 28 per MWh of VRE to almost USD 50 per MWh of VRE, both at a share of 50% of wind and solar PV, as a function of the availability of flexibility in the system in the form of interconnections with neighbouring countries and flexible hydroelectric resources. While such estimates come with some degree of uncertainty, the order of magnitude provides clear indications for policy choices.

Figure ES7. **Total cost of electricity provision including all system costs**

(USD billion per year)

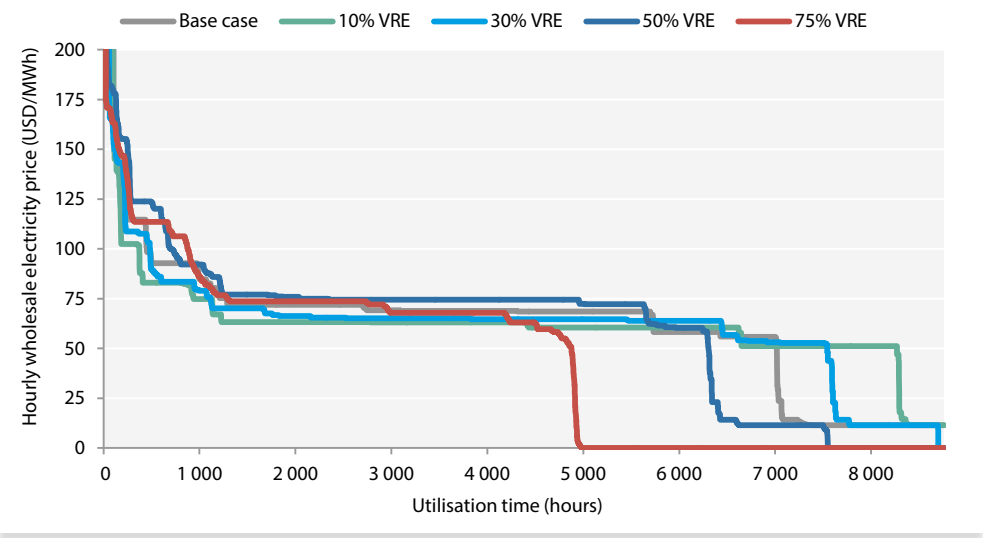


These values need to be compared to the plant-level generation costs of VRE, which range, depending on the scenario, from USD 60 per MWh for onshore wind to up to USD 130 per MWh for solar PV. It should also be noted that the system costs are largely unaffected by any declines in plant-level costs as long as the share of VRE remains exogenously imposed. Indeed, all four components of system costs (balancing, profile, connection and grid costs) increase with the deployment of VRE resources, but at different rates. By adding system costs to the costs of plant-level generation as assessed in LCOE calculations, one can calculate the total system costs of electricity provision for the eight scenarios analysed in this study (see Figure ES7 above).

With 10% of VRE in the electricity mix, total costs increase only about 5% above the costs of a reference system with only conventional dispatchable generators, which in a mid-sized system such as the one modelled corresponds to additional costs of about USD 2 billion per year. At 30% VRE penetration, costs increase by about USD 8 billion per year, i.e. by 21% with respect to the base case. Reaching more ambitious VRE targets leads to considerably higher costs. Total costs increase by more than USD 15 billion per year if 50% of electric energy generation is provided by variable renewable resources, which corresponds to an additional 42% of costs compared to the base case. Reaching a 75% VRE target finally implies almost doubling the costs for electricity provision to almost USD 70 billion per year, representing more than USD 33 billion above the base case.

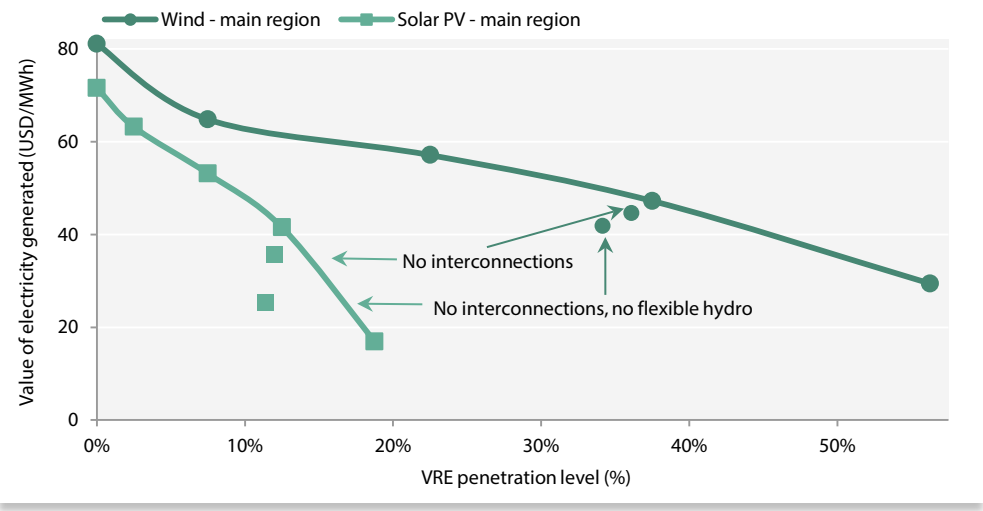
A striking effect of the deployment of low marginal cost variable resources on the electricity market is the appearance of hours with zero prices, a substantial increase in the volatility of electricity prices and the commensurate increase in capital cost (not modelled here). Such zero prices are not observed in the two scenarios with no or low VRE deployment but start appearing for 60 hours per year when VRE reach a penetration level of 30%. The number of occurrences increases dramatically with the VRE penetration level; at 50%, more than 1 200 hours in a year feature zero-price levels, i.e. about 14% of the time. When VREs produce 75% of the demand, zero prices occur during 3 750 hours, i.e. more than 43% of the time (see Figure ES8). Since the model works under a financing constraint, the higher frequency of hours with zero prices is compensated by an increase in the number of hours with high electricity prices, which increases volatility. At 75% VRE penetration, the number of hours with prices above USD 100 per MWh is more than double that at zero or low VRE penetration rate.

Figure ES8. **Price duration curves of wholesale electricity prices in the five main scenarios**



Last but not least, the generation by VRE as a function of the availability of natural resources such as wind speed or solar radiation, is not only more variable than that from dispatchable plants but also more concentrated during a limited number of hours. Periods with high generation are followed by periods with lower or zero output. Because they all respond to the same meteorological conditions, wind turbines and solar PV plants tend to auto-correlate, i.e. produce disproportionally more electricity when other plants of the same type are generating and to produce less when other wind and solar PV plants are also running at lower utilisation rates. In combination with the zero short-run marginal costs of VRE resources, this causes a decrease in the average price received by the electricity generated by VRE as their penetration level increases, a phenomenon often referred to as self-cannibalisation. Figure 48 summarises this effect by showing the average market price received by wind and solar PV generators in the wholesale electricity markets as a function of their share in the electricity mix.

Figure ES9. **The market remuneration received by wind and solar PV as a function of their share in the electricity mix**



The average price received by solar PV and wind resources in the electricity market declines significantly and non-linearly as their penetration level increases, and this price decrease is much steeper for solar PV than for wind as its auto-correlation is higher. The value of the solar PV generation is almost halved even when a penetration rate of only 12.5% is reached. Further deployment of solar PV capacity to a penetration level of 17.5% would further halve its market value to below USD 20 per MWh. Thus, even if the generation costs of solar PV were divided by five, its optimal penetration level would not exceed 17.5%. A similar trend, although less pronounced, is observed for onshore wind, which has a higher load factor than solar PV and whose generation spans over a larger time period. At a penetration level of 22.5%, the value of a megawatt-hour of wind is reduced by 25%. For penetration levels above 30%, the market value of wind electricity is below USD 50 per MWh compared to an average price of all electricity of USD 80 per MWh. Offshore wind with its even higher load factor might show less pronounced declines but was not included in the study as its overall LCOEs were significantly higher than those of competing low-carbon technologies including nuclear.

Last but not least, achieving more ambitious renewable targets also implies that VRE must be curtailed more frequently. Curtailment of VRE generation thus appears at 30% penetration level and increases sharply with their share. At 50% generation share, the curtailment rate of the marginal VRE unit deployed is above 10%. In the scenario featuring a 75% share of VRE generation, about 18% of the total VRE generation must be curtailed, and the curtailment rate of the last unit deployed is above 36%. Curtailment can be understood as an indicator that the system value of VRE is lower than its system costs, i.e. that reducing VRE output during certain hours constitutes the least-cost flexibility option.

Effective policy options to decarbonise the electricity sector

Decarbonising the energy system to achieve the climate goals set by the Paris Agreement represents an enormous challenge for OECD countries. To reduce the carbon intensity of the electric power sector to 50 gCO_2 per kWh, an eighth of the current levels, requires a rapid and radical transformation of the power system with the deployment of low-carbon emitting technologies such as nuclear, hydroelectricity and variable renewables (VRE). In the absence of mechanisms to capture and store the CO_2, this will mean phasing out coal and strictly limiting the use of gas-fired power generation. Given the massive investments that the realisation of this transformation requires, it is of paramount importance to create long-term frameworks that provide stability and confidence for investors in all power generation technologies. This has important implications beyond the electricity sector. Decarbonising the energy sectors and the economies of OECD countries will require an important effort of electrification (see also the IEA *World Energy Outlook 2018*). This concerns, quite obviously, the transportation sector, but also industry and housing. Effective action to reduce carbon emissions and to limit climate change depends on the creation of a robust low-carbon electricity sector.

If OECD policy makers want to achieve such a deeply decarbonised electricity mix they must foster vigorous investment in low-carbon technologies such as nuclear energy, VRE and hydroelectric power. Where hydroelectric power is constrained by natural resource endowments, nuclear and VRE remain the principal options. This is why the modelling in Chapter 3 took a brownfield approach to hydroelectricity, i.e. fixed the amount of available resources *ex ante*, independent of market conditions or VRE deployment. This is a useful starting assumption at the level of generality of this study. It should, however, be mentioned that the generating capacity of existing installations might also be increased under the right economic conditions. The generating capacity of hydroelectric resources might thus be increased, for instance, through the repowering of dams that are currently only used for irrigation (see Tester et al., 2012: p. 623). While the technical potential exists, there are, at the current costs of alternatives, questions about the economic potential (ibid.: 637). The economic costs of leveraging such additional existing hydroelectric resources are highly site-dependent and inversely related to the size of the plant. In particular, small-scale hydro-projects would thus need to be approached in a full cost-perspective that takes all local, regional and global costs and benefits into account.

Whatever their share of hydroelectric resources, all electricity systems of OECD countries relying on deregulated wholesale markets to ensure adequate investments are currently experiencing great stress in advancing towards the twin objectives of rapid decarbonisation and adequate investment in low-carbon technologies. The reasons are, in particular, the relative disadvantages experienced by technologies with high fixed costs in a deregulated market with volatile prices, the lack of robust and reliable carbon prices, and the out-of-market financing of large amounts of variable renewables with little thought on the impacts on the remainder of the electricity system. These shortcomings have made progressive re-regulation a distinct option for the future evolution of the electricity sector of OECD countries.

The risk is that such a return to regulated systems would do more harm than good by losing the efficiency gains brought by liberalisation without a clear roadmap for the road ahead. The alternative is to move towards specific market designs for low-carbon generation based on five distinct pillars: 1) the continuing working of short-term markets for efficient dispatch and the revelation of the true system value of the electricity produced; 2) carbon pricing; 3) frameworks for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution; 4) appropriate mechanisms to foster long-term investment in low-carbon technologies, including the reform of existing support mechanisms; and 5) the internalisation of system costs wherever practical and necessary. While details of electricity market reform will require substantive expert discussion, it is important that policy makers understand the importance of these five pillars, which are required to maintain the appropriate equilibrium between short-term competitive pressures and long-term investment incentives for low-carbon generation.

First, maintain current short-term electricity markets for efficient dispatch. The deregulation of electricity markets did not get everything wrong. Even if there is widespread agreement that deregulated electricity markets have not provided on their own sufficient incentives for investment in low-carbon technologies, there is also recognition that they have been good at using existing assets efficiently. Marginal cost pricing based on short-term variable costs is not ideal to incentivise the construction of technologies with high capital costs. It is, however, the appropriate mechanism to ensure the optimal utilisation of existing resources, i.e. to produce a MWh of electricity at the lowest possible costs at any given moment and to expose generators to the discipline of market prices. Recognising this dichotomy implies combining markets for short-term dispatch with explicit mechanisms to foster investment in low-carbon technologies.

Second, whatever the institutional hurdles and lobbying efforts to prevent it, the most important immediate measure is the introduction of carbon pricing, which would raise electricity prices, reduce greenhouse gases and enhance the competitiveness of low-carbon technologies such as nuclear and VRE. A meaningful level for a carbon price in an emission trading system would mean a price high enough to ensure the following outcomes:

a) make gas competitive against coal and, where pertinent, lignite in the markets of all OECD countries;

b) improve the competitiveness of nuclear power plants against gas-fired plants where construction costs are sufficiently low without any out-of-market support;

c) improve renewable competitiveness against gas-fired generation where meteorological conditions are sufficiently favourable without any out-of-market support;

d) provide the dynamic incentive to invest in the development of new even more cost-effective low-carbon technologies.

The precise level of carbon prices to achieve such outcomes would vary on the relative costs of different technologies in different countries. As an order of magnitude, a carbon price of USD 50 per tonne of CO_2 can be considered sufficient to fulfil the criteria mentioned above. The leverage of fossil fuel-based generators and their stakeholders over political decision making has made effective carbon pricing the exception rather than the rule in OECD countries. Where introduced, however, in countries such as Sweden or the United Kingdom, it has been highly effective in driving decarbonisation. Independent of detailed efficiency considerations, a credible carbon price is a powerful signal in order to shape the expectations of producers, consumers and other stakeholders such as suppliers concerning the long-term evolution of the electricity system. Carbon pricing will produce an overall gain for society. However, it will also produce losses for some stakeholders, in particular, fossil fuel producers and their customers. Appropriate compensation will thus need to be part of any politically sustainable package.

Third, develop long-term frameworks for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution: generation is at the heart of any electricity system, but it is ultimately only a part of it. Any electricity system requires frameworks for the provision of capacity, flexibility, system services and adequate physical infrastructures. While this was always the case, the variability of VREs and new technological developments make these complementary services increasingly important. The importance of flexibility provision is also underlined in the latest edition of the IEA's *World Energy Outlook 2018*. Technological and behavioural changes such as the digitalisation of network management, batteries and demand side management (DSM), as well as, in some cases, decentralising generation and consumption makes for an ever more complex equation to be solved. Short-term markets for flexibility provision, balancing, increased interconnections with neighbouring countries and capacity remuneration mechanisms are all part of this. It is also important to recognise the positive contribution to system stability and inertia of large centralised units such as nuclear power plants or hydroelectric dams and to value them appropriately.

Fourth, create appropriate mechanisms for fostering long-term investment in low-carbon technologies. In creating sustainable low-carbon electricity systems, all low-carbon technologies will need to play a part. However, their high capital intensity requires specific financing solutions as they will not be deployed solely on the basis of marginal cost pricing in

competitive markets. This holds for all low-carbon technologies, but particularly for VREs, which themselves suffer most heavily from the lower prices they induce. Due to different lifetimes, risk profiles and financing structures, individual technologies will also continue to require dedicated, individually designed instruments, even though they all are based on the same principle that investment in high fixed cost technologies requires high levels of price and revenue stability.

On their own, neither carbon pricing nor capacity remuneration for dispatchable low-carbon providers will suffice, although they constitute, in principle, the appropriate instruments for internalising the external effects relating to the public goods of climate protection and security of supply. Capacity remuneration mechanisms (CRMs) designed to provide electricity during the rare hours of extreme peak demand will favour technologies with low fixed capacity costs, usually OCGTs, since they are the only ones willing to invest when expected operating hours are in the double digits. This is why policy makers have to make tough calls on striking the appropriate balance between out-of-market support and exposure to wholesale market prices for low-carbon technologies with high fixed costs such as nuclear and VRE. One the one hand, feed-in tariffs (FITs), long-term power purchase agreements (PPAs), contracts for difference (CFDs), regulated electricity tariffs, feed-in premiums (FIPs) or even direct capital subsidies through, for instance, loan guarantees, are all appropriate instruments to achieve long-term security of supply with low-carbon technologies. FIPs or direct capital subsidies even maintain a link with wholesale market prices, which is important for efficient dispatch and value discovery. Even employing FITs and other instruments that share the central characteristic of a long-term contract guaranteeing a price corresponding to average cost need not mean abandoning competition altogether. Competitive auctions can substitute competition *in* the market with competition *for* the market.

Fifth, internalise system costs, where the previous four pillars have not already done so. Carbon pricing will recognise the environmental attributes of low-carbon generation, while capacity remuneration will recognise dispatchability. In principle, exposure to electricity prices would internalise profile costs, and remunerate each unit of electricity generated at its true value for the system. This theoretically sound principle, however, finds its limitation in the need for long-term price guarantees for low-carbon technologies mentioned above. The important thing is not to add implicit subsidisation to explicit subsidisation.

Together, these five pillars form the basic structure of a design for low-carbon electricity markets allowing for the optimised co-existence between VRE, hydroelectricity and nuclear energy within an effective integrated electricity system that will yield deeply decarbonised electricity systems at least cost and high levels of security of supply, independent of individual cost assumptions or country-specific endowments. Even more importantly, these five pillars allow for the construction of market designs that will be sustainable in the sense that they enable the investments that are necessary for the large-scale deployment of low-carbon technologies required for the rapid and radical transformation of the power system.

It should be emphasised that this framework does not depend on country preference for nuclear, hydro or VRE. All low-carbon technologies have a role to play. Based on the cost assumptions used in the main scenarios, this study shows that a mix relying primarily on nuclear energy is the most cost-effective option to achieve the decarbonisation target of 50 gCO_2 per kWh. In addition, costs rise over-proportionally with the share of VRE forced upon the system. However, these results reflect current best estimates. In particular, a further decline in the costs of VRE generation technologies would lead to integrated systems with sizeable shares of both nuclear and VRE. This is the spirit of Scenario VI, "Cost minimisation with low-cost renewables". With overnight costs for wind and solar PV that are between one third and two thirds lower than in the base case scenarios, it supports the vision of a future electricity mix that is realistic for a broad range of OECD countries. Such a mix integrating both VRE and dispatchable technologies would be composed of four main pillars:

i. a share of 30-40% wind and solar PV;

ii. a larger share of 40%-60% provided by dispatchable low-carbon technologies such as nuclear or, perhaps one day, fossil-fuelled plants with carbon capture, utilisation and storage (CCUS);

iii. the maximum possible amount of low-carbon flexibility resources, including hydro, demand response and grid interconnection;

iv. a progressively decreasing share of highly flexible unabated fossil-fuelled technologies ensuring the availability of residual flexibility.

Between now and 2050, the implicit time horizon of this study, research and development efforts are also likely to reduce the overall cost of power generation. Technologies are likely to be both cheaper and more flexible. Further cost reductions for low-carbon technologies such as nuclear, possibly in the form of small modular reactors (SMRs), VREs and batteries are likely. Largely for intrinsic physical reasons CCUS, for instance, is less likely to be a competitive option, even by 2050, but a decisive breakthrough cannot be excluded. The electricity sector is also likely to be more closely intertwined with other economic sectors due to cogeneration, power-to-gas and the convergence with information and communication technologies.

This study does not claim that the options modelled, their technical performances and their costs will be those eventually realised in 2050 and does not make any predictions about future technology developments. Its objective is to inform policy makers and the wider public about the intrinsic difficulties of achieving ambitious carbon emission reduction objectives with variable generation technologies alone. In practice, the choice of electricity market design generation mix and, in particular, the generation mix is a matter of political choices at the national level. While there is a global effort under way to reduce greenhouse gas emissions and prevent dangerous climate change, specific outcomes will be the result of a broader mix of social and political criteria. Local and regional pollution, system costs, technical reliability and the long-term security of supply will all play into the decision-making process.

A particular role in this process will be played by nuclear power. While it reliably provides large amounts of dispatchable, low-carbon power, it faces questions of social acceptability in a number of OECD countries. Nevertheless, this study shows how nuclear power still remains the economically optimal choice to satisfy stringent carbon constraints despite the economic challenges for nuclear during the changeover between different reactor generations. The reason for nuclear power's cost advantage is not in its plant-level costs. Instead, it resides in its overall costs to the electricity system. Variable renewables have reduced quite impressively their plant-level costs, but their overall costs to the system are not accounted for as their output is clustered during a limited number of high-level hours. All of these factors will come to play in the ultimate choices of each country.

Independent of their individual choices regarding the structure of their electricity mixes, OECD countries should move together to implement the five pillars for the design of low-carbon electricity systems. Technologies and consumer behaviour will continue to change rapidly in coming years. There is, however, a high likelihood that the orientations provided by the five pillars developed above – competitive markets for short-term dispatch, carbon pricing, centralised mechanisms for infrastructure provision, long-term stability for investors in low-carbon capacity and the internalisation of system costs – will remain the appropriate reference for the design of low-carbon electricity systems in the decades to come.

Chapter 1. **Introduction**

1.1. **The context for this study**

In the Paris Agreement, concluded in December 2015 and which entered into force in November 2016, OECD countries agreed to reduce their greenhouse gas emissions sufficiently in order to hold the increase in the global average temperature to well below 2°C above pre-industrial levels. This implies a major effort to decarbonise their electric power sectors. Holding the increase of global temperatures to 2°C requires limiting greenhouse gas concentrations in the earth's atmosphere to roughly 450 ppm of CO_2-equivalent emissions. According to the International Energy Agency (IEA) *World Energy Outlook 2017* this would require a 43% reduction of the world's total annual CO_2 emissions of 32 Gt by 2040 and an even more ambitious 61% reduction of the annual emissions of OECD countries of currently 12 Gt (IEA, 2017: pp. 650-1 and 718-9). While already these figures may look daunting, they pale in comparison to the effort required of the electric power sector both at the global level and at the level of OECD countries.

Although electricity generation currently contributes only about 40% to the CO_2 emissions at the level of both the world and OECD countries, it is expected to bear the brunt of the effort to reduce carbon emissions in order to allow attaining the 450 ppm limit. The fact that electricity is generated by stationary sources, little exposed to international competition except where countries chose to connect their electricity systems, and that low-carbon alternatives for power generation exist in the form of nuclear, hydro and renewable energies explains to some extent the asymmetry between the electric power sector and the rest of the economy when it comes to carbon emission reductions. While electricity is also a merit good and an important input to industrial activity, policy makers have decided that serious decarbonisation will start with the electricity sector. Given the potential to electrify, in a second step, other sectors such as transport, this makes strategic sense. By 2040, global emissions from electricity generation are thus expected to decrease their CO_2 emissions by 73% to 3.6 $GtCO_2$ and at the level of OECD countries by an even more radical 85% to 0.6 $GtCO_2$ during the next 25 years (IEA, 2017: pp. 650-1 and 718-9).

In order to have an idea of the magnitude of the effort, it is useful to regard what these reductions would mean in the carbon intensity of power generation. Today, global power stations emit on average 570 gCO_2 for each kWh they produce. In OECD countries, the carbon intensity is currently 430 gCO_2 per kWh. For reference, this corresponds roughly to the emissions of power plants using combined cycle gas turbines (CCGT). To attain the 450 scenario of the *World Energy Outlook*, the carbon intensity of power generation would need to be reduced to 106 gCO_2 per kWh for the world at large and 53 gCO_2 per kWh for OECD countries. In order to lend some intuition to these numbers, one may imagine that of 20 MWh produced, 19 MWh would need to be produced by low-carbon sources, while one MWh could be produced by a coal-fired power plant. Alternatively, of 20 MWh produced, slightly less than 18 MWh would need to be produced by low-carbon sources, while slightly more than 2 MWh could be produced by a gas-fired power plant.

It is quite obvious that the coming challenge for decarbonising electricity systems is gigantic. It is all the more important to get this right in a manner that compromises neither economic and financial efficiency, nor the security of electricity supply. Options for low-carbon power generation are limited. Hydroelectric resources, which produce 16% of the world's electricity and 13% of electricity in OECD countries are well-proven and usually have favourable costs. However, they are in limited supply, particularly in OECD countries, where their acceptability has also suffered somewhat in recent years due the impacts of hydroelectric installations on local ecosystems. Carbon capture and storage (CCS) faces a number of technical,

financial and social acceptability challenges that make it unlikely that it will play a significant role until 2040. In addition, at least in its initial stages its net contribution to carbon emissions reductions is doubtful as it will be most likely applied in the oil and gas industry for the enhanced recovery of hydrocarbons. For this reason, just like a number of other promising but not yet proven technologies, CCS has not been included in the present analysis.

In order to achieve the deep decarbonisation of the electric power sectors of OECD countries, there exist from a practical point of view currently only two viable options: nuclear energy and renewable energies. Nuclear energy today contributes 18% to the electricity generation of OECD countries. Non-hydro renewables contribute slightly less than 10%. However, the growth of non-hydro renewables has been very strong in recent years and is likely to stay so with rates of around 7% per year in the IEA Sustainable Development scenario consistent with the objectives of the Paris Agreement. Other alternatives are doubtful in a window of only 25-35 years, which is short given the intrinsic inertia of electricity systems, where power plants and transmission infrastructure frequently have lifetimes of 60 years and more.

Renewable energies enjoyed in recent years both popular and political support and play central roles in the energy transitions of OECD countries. By far the most important renewable energies are wind and solar PV, which not only have seen significant steady increases in installed capacity but also impressive reductions in manufacturing and installation costs. While the average costs per MWh of wind and solar PV are still somewhat higher than those of nuclear energy, the gap at the level of plant-level generation costs calculated with the levelised cost of electricity (LCOE) methodology no longer seems insurmountable (see IEA/NEA (2015), *Projected Costs of Generating Electricity 2015*).[1]

This seems to indicate that there are no fundamental reasons to abandon the popular vision that effective decarbonisation and high shares of renewable power generation go hand in hand. However, as spelled out in the first OECD Nuclear Energy Agency (NEA) study on system costs, *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (2012), variable renewable energy (VRE) technologies such as wind and solar PV cause a number of additional costs to the system, which are referred to as system costs.

The most important categories of the system costs of VREs are increased outlays for distribution and transmission due to their small unit size and distance from load centres, balancing costs to prepare for unpredictable changes in wind speed and solar radiation and, perhaps, most importantly the costs for organising reliable supplies through the residual system during the hours when wind and sun are not, or not fully, available. Variability also induces significant changes in the composition of the remainder of dispatchable technologies that ensure round-the-clock security of supply in the power system. When deploying VREs, one observes, in particular, a shift from technologies with high fixed cost such as nuclear to more flexible technologies with low fixed cost such as gas-fired power generation. While the latter will be able to better absorb the loss of operating hours due to VRE infeed, the overall costs of the residual system will increase, an effect known as "profile costs". In addition, deploying VREs does not automatically translate into carbon emission reductions. For instance when nuclear power is substituted by a mix of VREs and gas-fired generation that produces electricity when VREs do not, overall carbon emissions will increase.

All technologies have system costs. Nuclear, for instance, requires particularly strong network connections and access to reliable cooling sources. However, these costs are in fact an order of magnitude lower than those imposed by the variability of renewable energies. The key advantage of nuclear power in the economic competition with wind and solar PV is the fact that nuclear power plants are dispatchable, i.e. they can churn out large amounts of carbon free baseload power in a reliable and predictable fashion.

1. This report works with average cost figures. This is particularly important for low-carbon technologies. For variable renewable energies (VREs) and hydroelectricity, load factors and costs depend heavily on local conditions. In specific locations, plant-level costs of VRE resources are already now lower than those of thermal power plants. In the case of nuclear, favourable construction experiences in Asia contrast with high cost constructions in Europe and the United States.

In the context of the decarbonisation of electricity systems, this poses three important questions:

1. What is the optimal mix of nuclear baseload and variable renewables from an economic point of view and what are the added costs of reaching a CO_2 emission target with exogenously imposed shares of renewable generation?
2. Are electricity systems that are trying to reach these objectives primarily with large shares of variable renewables technically and, in particular, economically viable?
3. What are the key policy instruments to create frameworks enabling the level of investment in low-carbon generation technologies that is required to ensure a transition towards deeply decarbonised electricity systems?

While the precise answers to these questions depend on a number of qualifying conditions that are spelled out in detail in Chapters 2 and 3, these questions, in particular question 1 and question 3, structure also this study. The modelling underlying this study pursues in particular question 1 using a "greenfield approach", where the system is optimised and costs minimised without making any assumptions about the existing power generation mix other than about the availability of hydroelectric resources. This improves the transparency and readability of the modelling results, and thus their pertinence for policy making in a time frame to 2050.

1.2. The nature of the new study on system costs

Today, system costs are no longer an unfamiliar concept but a universally accepted part of electricity system analysis. The first NEA system cost report, published in 2012, was part of an early wave of studies that were instrumental in introducing and conceptualising the notion of system costs. While the initially developed concepts as well as the basic methodology of working with residual load curves to assess profile cost have proven robust, much has changed since then. These changes require a new, more refined and complete approach to the phenomenon of system costs in electricity systems with high shares of variable renewables. Among the changes that need to be accounted for are:

1. the significant decline in the costs of renewable energies, in particular for solar PV, a progress that is documented in the changes in investment costs reported in the IEA/NEA reports on the *Projected Costs of Generating Electricity* for 2010 and 2015;
2. the emergence of a broad and lively literature on the system costs of electricity systems, which includes the emergence of a widely shared methodological framework for assessing profile costs (see Chapter 2 for a comprehensive literature review);
3. a greater awareness and better understanding by policy makers and the general public of the importance of system costs in assessing the overall costs of the energy transitions under way that almost invariably include commitments to high shares of variable renewables;
4. a clearer idea of the policy-relevant questions that can be usefully asked and answered by the available conceptual and modelling tool given the present state of knowledge.

From the outset, it was clear that the new study would not simply provide an update of the successful 2012 study. The latter study illustrated a certain number of key concepts and provided indicative estimates for the level of system costs in six OECD countries. While the levels of magnitude of those estimates have held up well when compared with more recent results, the relative crudeness of the representation of the electricity system is no longer compatible with the methodological standards since adopted. In addition, the 2012 study provided estimates of system costs for different countries, while not taking into account any specific carbon constraints.

This study takes a different approach. First, great care has been taken to construct a representation of the electricity sector in a complete as possible a manner. The electricity sector model that underlies this study thus includes not only hourly dispatch but also ramping constraints and reserve requirements that preserve both system stability and economic equilibrium. In addition, a carefully selected set of credible flexibility options has been added to the model. They include interconnections with neighbouring countries, a relatively high share of flexible hydroelectric resources, demand-side management (DSM) and several storage options. Both technological constraints and flexibility options are important drivers of total system costs. This holds, in particular, if electricity generation includes a large share of wind and solar PV, since the variability of the latter challenges the working of the system by increasing ramp costs and reserve requirements but will also increase the demand for different flexibility options.

Second, this study concentrates on a single representative country in order to be able to develop different decarbonisation scenarios characterised by varying shares of nuclear energy and variable renewables, as well as a small number of well-defined sensitivity analyses. Given that the analysis is based on a "greenfield" approach, country-specific characteristics do not concern a particular generation mix or specific costs assumption for standard technologies but rather the shape of the load curve, the pattern of VRE generation, the availability of hydroelectric resources as well as the interconnection capacity with neighbouring countries. The main scenarios confront the cost of systems with exogenously defined shares of wind and solar PV of 10%, 30%, 50% and 75% with those of a system aiming cost minimisation by means of a carbon tax. Given that a carbon constraint of 50 gCO_2 per kWh is common to all scenarios, the share of nuclear power is an inverse function of the exogenous renewable constraint. The higher the imposed share of VRE, the lower the share of nuclear and vice versa. The results presented in Chapter 3 based on IEA/NEA 2015 conform to intuition: the more important the share of VRE, the more expensive are the total costs of the system. Sensitivity studies test the impact of flexibility options such as interconnections with neighbouring countries and storage or hydroelectric pumped storage on the level of total system costs (see Chapter 3 for full details).

The defining feature of this modelling effort is the fact that all scenarios include the same stringent carbon constraint for the average per CO_2 emissions per kWh of the system. The latter has been set at 50 gCO_2 per kWh. As shown earlier, this corresponds roughly to the level that the electricity systems of OECD countries must achieve to do their share to limit the increase in global mean temperatures to 2°C. The focus of the new analysis is thus on the total costs of electricity system as a function of the share of variable renewables that is imposed as an additional constraint on the system over and above the common carbon constraint of 50 gCO_2 per kWh that ensures consistency with the objectives of the Paris Agreement.

A sufficiently detailed and complete model that could provide estimates credible enough to provide a solid foundation for ensuing policy discussions, was not available to the NEA. A new model could only have been built only with an important investment in time and resources. Given the strong demand for immediate policy-relevant insights on system costs under a stringent carbon constraint, it was decided to look for more immediately realisable options. Following a period of careful research, the NEA decided to work with a team of experienced power system modellers who are also researchers at the Massachusetts Institute of Technology (MIT). NEA modelling was based on the Optimal Electricity Generation Expansion (GenX) model developed at MIT, which provided the sort of detailed, comprehensive and flexible representation of an integrated electricity system that was required. A detailed presentation of the model itself, its solver and its algorithms, as well as the precise constraints and data inputs for each of the eight scenarios modelled is provided in Chapter 3.

The general conceptual approach taken in the new system cost study remains the same as in the original NEA 2012 study. That is, the NEA considers that it is the purpose of an electricity system to satisfy a given load in a technically safe and reliable manner at the lowest economic cost, while at the same time satisfying agreed upon public policy objectives. Two points in this definition merit clarification. First, the notion of "reliability" in the electricity sector is less straightforward than it seems. Since so far electricity cannot be economically stored in large quantities, demand needs to be matched by supply second by second. Systems thus need not only be designed for extreme peak demands, e.g. winters that are colder and summers that are hotter than current records, but the totality of supply also needs to be

technically available in precisely those moments. Even if system operators and customers were willing to spend vast sums on backup capacity that might never be needed, this would be an unrealistic objective. No electricity system can guarantee covering the totality of demand at truly all times. Of course, the systems in most OECD countries are of very high quality and the periods during which a small percentage of demand remains unmet are measured in minutes or a small number of hours at best. Nevertheless, it is useful to remember that security of supply in the electricity sector is ultimately a statistical concept, to the extent that it would not make economic sense in *all* situations generated by random events such as the weather to ensure complete coverage of demand. The value of lost load (VOLL) is not infinite, so at some point it makes economic sense to shed load. Serving all demand at any cost is not necessarily a goal of system operators.

The second point that merits clarification is the fact that demand needs to be met while satisfying "agreed upon policy objectives". First and foremost, this concerns fulfilling the CO_2 emission reduction objective mentioned earlier, which is integrated as a constraint of 50 gCO_2 per kWh into the modelling effort. In addition, it implies, of course, compliance with all environmental and safety regulations as formulated by the relevant authorities. However, there exists one, slightly more controversial public policy objective. Several OECD countries are indeed aiming for given levels of the share of renewable energy in their electricity supply, which regularly means considerably increasing the installed capacity of wind and solar PV. This constraint does not necessarily align with the overall system objective of minimising the total costs of meeting a given level of electricity demand subject to a set of environmental constraints. The question is then, which one of the two objectives has priority? Is the purpose of an electricity system to minimise costs or to accommodate the highest possible share of wind and solar PV?

It is the political process that ultimately must prioritise between these objectives. Determining the electricity generation mix is the prerogative of government. The problem is that the double objectives of CO_2 emission reductions and VRE deployment are intertwined in particularly complex ways. Increases in total system cost due to higher shares of wind and solar depend, for instance, on the correlation between demand on the one hand and variable renewable generation on the other. A GW of solar PV capacity will contribute far more value and security to the system in California, where its maximum generation coincides with peak demand at noon, rather than in France, where peak demand manifests itself during winter evenings, when solar PV generation is absent. The value of VRE generation also depends on the amount of flexibility resources available, which not only comprise storage and demand response but also the available amount of hydroelectric capacity or the size of interconnections with neighbouring countries as part of common balancing or control areas. Long-run equilibrium models such as GenX also need to factor in appropriate hypotheses concerning the technological trajectories for batteries and other forms of non-hydro storage or the ability of established technologies such as nuclear to engage in load-following, i.e. their ability to complement or substitute variable renewable generation whenever needed.

In order to allow for economic results that are as relevant and transparent as possible and that are independent of the power generation mix of a particular country, the modelling effort in this study has taken a "greenfield approach". This means that starting with a clean slate, the electricity system evolves only as a function of electricity demand throughout the year and the specific costs of different technologies in an optimal fashion as if all plants were built from scratch on a green field. This approach is limited only by the exogenously imposed constraints, i.e. carbon emissions of 50 gCO_2 per kWh and different shares of VRE generation that are specified *ex ante*. In addition, the share of hydroelectric resources has been set exogenously, i.e. in a "brownfield approach" in the parlance of energy modellers, as the deployment of the latter does not depend on total generation costs but on the availability of the appropriate natural resources.

The alternative would have been to take a brownfield approach for all technologies and to specify the shares of different dispatchable resources in the residual load curve such as nuclear, coal, gas or batteries. It was a conscious choice of NEA experts in co-operation with the modelling team that this approach would ultimately lead to less meaningful results than the cost-minimising optimal mix based on the respective costs for investment and operations. The common carbon constraint in all scenarios ensures that the arbitrage between the low-

carbon options of nuclear energy and VREs becomes readily apparent. NEA modelling based on the GenX model thus identifies in a precise and transparent manner the contribution of different technologies to the overall system costs under a common carbon constraint.

Last, but not least, this study pursues an economic approach interested in identifying least-cost solutions in a framework of static optimisation. This allows the cost of different generation mixes in a 2050 time frame to be shown in a well-defined and transparent manner. Dynamic approaches plotting different transition pathways or focusing on build rates, construction times and the availability of natural and human resources would have produced alternative insights. No model can replicate the real world; every modelling choice thus implies trade-offs. Rather than settle on descriptive realism, the present study has decided to focus on the transparency of the total system costs and a number of impacts on a carefully represented electricity system given different shares of VRE in the mix.

Due to resource imitations, this modelling effort also did not focus on the technical feasibility of power systems with high shares of VRE. Technical constraints such as ramp rates are minor at 10% or 30% of VRE but might become significant at higher shares. Modelling this would, however, require a temporal resolution below the one-hour steps this model considers. The reader should thus keep in mind that depending on the fast-evolving offer of systems-integration technologies technical feasibility may impose additional constraints. By 2050, the implicit time horizon of this study defined by the emissions objective of 50 gCO_2 per kWh, it is also possible that additional generation technologies are available. Yet consider also that 30 years ago the principal technologies on the market were by and large the same as today, even though performance and cost have changed considerably. Lastly, the electricity sector might be more closely intertwined with other sectors due to cogeneration, power-to-gas and the convergence with information and communication technologies.

The overarching objectives of this study were to assess the relative costs of different low-carbon mixes and technical feasibility, which is not a given in the modelling of integrated electricity systems with an hourly resolution, transparency and policy relevance. It is important to underline that the objective of this study is not to assess what will be the future low-carbon generation mix, nor to provide a quantitative assessment of system costs in specific OECD countries. Needless to say, other efforts, in particular those concentrating on existing systems ("brownfield approach") in a dynamic fashion to study transition effects, will yield complementary results as these discussions continue.

1.3. Dealing with system costs: Policy options

Under reasonable assumptions about the costs of different technologies and the configurations of energy systems, VREs increase the total costs of energy system through two channels. First, according to the assumptions used in this study based primarily on the *Projected Costs of Generating Electricity* (IEA/NEA, 2015) VREs have somewhat higher costs per MWh than other low-carbon technologies[2]. Second, they increase the costs of the remainder of the system by demanding more frequent ramping, the installation of expensive flexibility options and by changing the structure of the residual generation mix towards generation technologies with low fixed costs but higher average costs. This second set of costs constitutes the system costs that are not captured by a simple comparison of generation costs at the plant level (LCOE).

In other words, even as VREs approach in certain favourable conditions the threshold of competitiveness with conventional technologies from an analysis at the plant-level, electricity systems with more than small shares of wind and solar PV will be more costly than systems relying exclusively on dispatchable technologies such as nuclear, hydro, coal or gas.

2. Plant-level generation costs of VRE technologies are also strongly system and location specific, as they depend on resources availability. The strong cost dynamics of VRE may also make for lower LCOE in the future.

These system costs are long-run costs that arise even when the system is in equilibrium. In addition, the integration of large amounts of wind and solar PV capacities usually has a number of additional impacts in the short- and medium run that go beyond the system costs that can be assessed with some level of confidence through energy system modelling. These dynamic adjustment costs are not less "real" than the long-run system costs but cannot be assessed with the same degree of precision. This regards both their impacts on overall economic efficiency as well as their distributional implications for different groups of stakeholders such as investors, electricity consumers or tax payers. Such transitory adjustment costs are not the focus of this report.

The long-run system costs on which this report concentrates, in particular the system costs of variable renewables (VRE), constitute higher costs per MWh for the system as a whole. Yet, these added costs to the provision of electricity are currently not internalised by the technologies that cause them. In other words, variable renewables impose external or social costs on all other participants in the system. This is perhaps most obvious in the case of increased costs for connection, transmission and distribution that arise due to the low geographical density of wind and solar installations and their distance from load centres. These surplus costs are borne by network operators who recoup their outlays through network tariffs, typically a per MWh surcharge on electricity consumed, independent of whether that MWh has been produced by a variable or a conventional source, which raises prices for all electricity in a uniform manner.

Of course also other electricity generation technologies can cause important social or external costs. The NEA study *Full Costs of Electricity Provision* (2018) provides a broad overview of the social costs of different power generation options – for instance in terms of unaccounted for health impacts. The social costs of VRE nevertheless deserve specific attention for two reasons. First of all, they are relatively new and have only of late received systematic attention (see also Chapter 2 of this study). Second, they are of a somewhat intermediate nature between fully accounted for market-based costs at the plant-level and completely uninternalised social costs, external to the economic sphere. Mediated by the electricity grid as well as by electricity markets, they constitute economic and financial impacts that can be assessed with some precision on the different actors of the power system and ultimately electricity consumers.

Long-run systems costs are the primary focus of this report. They are also the easiest to assess with some degree of rigour in conceptual analysis and modelling. Nevertheless, in the real world there also exist a number of additional system costs in the short and medium run. Dynamic adjustment costs can pose additional issues. While they are technically difficult to capture, their magnitude is such that they often dominate public discussion and may, under certain circumstances, amount to serious disruptions of the electricity sectors. The recent deployment of significant new wind and solar PV capacity has meant depressed electricity prices, reduced utilisation rates for existing equipment and declining margins of reliable capacity in many OECD countries. While stable demand and lower fuel costs also have played a role, electricity prices have declined primarily because wind and solar PV have zero short-run marginal costs. This means that in a market with free price formation once VREs have sold their electricity, prices align themselves on the remaining producers with the lowest variable costs – usually hydro, nuclear or lignite. A recent study of the German market, for instance, indicates that hourly wholesale electricity market prices decrease by EUR 1 per MWh for each GWh of wind generation.[3]

Due to the same effect, existing producers of electricity from conventional sources such as coal, gas, hydro and nuclear will also sell less electricity than they used to. This makes it more difficult to recuperate the latter's capital costs. In some cases, revenues are so low that producers will no longer even recuperate the fixed annual costs of operations and maintenance. In these cases, producers will quit the market and prematurely retire their power plants or put

3. See Martin de Lagarde, C. and F. Lantz (2016), "Impact of Variable Renewable Production on Electricity Prices in Germany: A Markov Switching Model", Chaire European Electricity Markets (CEEM) Université Paris-Dauphine, Working Paper 22, www.ceem-dauphine.org/working/en.

them into hibernation if there is a chance that the situation will improve. Supporters of an energy transition focusing on VRE deployment rather than on CO_2 emission reductions occasionally remark that this substitution between electricity produced with conventional sources by electricity from renewable sources is precisely the avowed public policy objective pursued by politicians and supported by their voters.

Box 1.1. Profile costs of VRE and their theoretical internalisation in a long-run free-market equilibrium

Somewhat counter-intuitively, in a perfectly deregulated market without subsidies for any technology and where wholesale electricity prices would be determined freely by supply and demand, the system costs of variable renewables relating to balancing and changes in the residual load curve (profile costs) would be fully internalised. If supply was uncertain, customers would pay less for an MWh of uncertain supply and would thus force renewable suppliers to internalise their balancing costs by providing themselves or purchasing reserves to deliver firm power. Profile costs would be internalised through the declining value factor of variable renewables. This rather technical argument relates to the fact that all wind and solar PV plants tend to produce together during a limited number of hours, a phenomenon also referred to as auto-correlation. The concentration of VRE generation with low variable costs lowers the average revenue of all VRE producers and thus limits their penetration at the economically optimal point. Dispatchable producers instead would earn above average revenues during hours with low renewable generation and thus be compensated for their backup services. System costs for increased expenditures for transmission and distribution would however remain uninternalised even in the case of perfectly functioning electricity markets.

The phenomenon of the declining value factor of renewables can be empirically observed already at relatively low penetration rates of 5% or 10%. It accelerates rapidly at higher rates. It triggers a number of important observations. First, the variability of VRE is not per se an economic problem in an electricity market in equilibrium. It becomes an economic problem if it is coupled with selective out-of-market finance for VRE. Second, the share of VREs in a truly deregulated market with free exit and entry and no selective subsidies will be naturally set at the economically optimal level; this optimal level will be limited, even if the plant-level costs of wind or solar PV should be lower than those of the dispatchable competitors. Third, due to social and political preferences for high VRE shares, one is unlikely to see the end of out-of-market financing of VRE any time soon. This means, fourth, that variability coupled with subsidies will continue to impose externalities on dispatchable producers, required for maintaining system security, which implies the necessity of added policy interventions. This phenomenon is well known from other instances of economic policy making: the unforeseen consequences of a first market intervention require a second market intervention, which brings unforeseen consequences of a new kind and so on. Experts also speak of the “slippery slope” of market interventions.

The argument contains some truth although it forgets that if the primary focus had not been on VRE deployment, the objective of CO_2 emission reduction could have been attained at far lower cost. There are two further issues. First, what are the distributional implications of creating large amounts of “stranded costs” in terms of prematurely retired conventional capacity and how should these costs be dealt with? Is the premature closure of a power plant due to political decisions regarding the electricity mix just an ordinary investor risk or is it a form of silent expropriation? In particular, this issue regards peak demand generators in the short run and nuclear power in the long run. Depending on the normative point of view of the policy maker, one could argue that the costs of satisfying the entry of new capacity that contributes only marginally to system needs should be borne by the newcomers or by the governments that have stipulated their introduction. In contrast, advocates of renewable energy will argue that once the latter’s introduction has become official policy, it is the incumbents that should bear the consequences for being incapable of providing the flexibility that the system requires at low enough cost.

Second, whatever the financial arrangements of the original investors in existing conventional capacity, the dispatchable capacity that exits the market because it no longer earns its keep is frequently still required to provide power during the hours when VREs do not produce. Secure, round-the-clock electricity supply requires backup by dispatchable conventional producers during a limited number of hours. In other words, pushing conventional power capacity out of the markets though the combined effects of lower wholesale market prices and reduced operating hours due to the generation of variable renewables with zero short-run marginal costs increases the risk of electricity supply interruptions. In addition, such conventional power capacity often contributes to the electricity supply in terms of reliability, resilience or diversification, which are all attributes that are not or only incompletely valued in competitive wholesale markets with marginal cost pricing. If markets were able to value these attributes, it would increase revenues for these units and the market would reach an equilibrium with the desired level of reliability. The hard part is defining and appropriately valuing such attributes in a market setting.

These questions arise in the fast-changing context of complex, multi-layered energy transitions. Of course, there exist policy options to deal with the above issues, all of which have their advantages and inconveniencies. Needless to say, in public policy discussions there is very little distinction being made between long-run costs (such as the overall increase in satisfying a given level of demand) and short-run costs (such as ultra-low prices, the premature retirement of existing conventional plants and risks to the security of supply). This is to say that the general situation of the electricity sectors in most OECD countries is not only characterised by evermore obvious challenges but also by a great deal of confusion. This confusion exists not only in policy making and public discussion but extends into expert discussion and theoretical argument.

A principle of modern economics, the "Tinbergen rule", states that successful policy making needs as many instruments as there are policy targets. In the present case there exist two clear policy objectives (a) reducing CO_2 emissions to achieve the objectives of the Paris Agreement and (b) maintaining the security of electricity supply at almost all times. This would require two policy instruments targeted directly at these objectives. First, this would demand a substantive carbon tax. Model results reported in Chapter 3 suggest that even a relatively modest carbon tax in the order of magnitude of USD 50 per tCO_2 could achieve emission reductions in line with a two-degree scenario at least cost. Second, this would require deregulated electricity markets without large amounts of renewable capacity financed out of the market that distorts wholesale market prices below the level of cost recovery.[4] With these two policy measures in place, policy makers could expect electricity markets to deliver the most cost-efficient outcomes. If the two policy measures mentioned would be perceived as sufficiently stable, one would see in all likelihood a substantive increase of nuclear energy as the technology that allows for a least-cost reduction of CO_2 emissions at the system level.

This is straightforward. The snag is that there exists in the majority of OECD countries a third policy objective increasing the share of renewable energies – in particular wind and solar PV in the electricity supply. While popular opinion is convinced that this third objective directly translates into the other two, reality is, as indicated, far more complex. A carbon constraint is not the same thing as a renewable energy objective. When a mix of renewables and fossil fuels substitute for nuclear or hydroelectricity, carbon emissions can be expected to increase. When renewables with out-of-market finance press on the market, prices will fall, investment will stop and security of supply will decrease.

4. There is an ongoing debate whether such deregulated electricity markets can be left to their own devices as energy-only markets or whether they need to be complemented by capacity remuneration mechanisms (CRMs). While it can be shown that energy-only markets are the least-cost solution from a theoretical point of view, they entail a number of "scarcity hours" during which not all of demand will be met and rolling blackouts will allocate scarce electricity. This is frequently perceived as a major inconvenience by consumers and politicians. CRMs finance additional capacity to cover also the needs during the hours with the most extreme peak demand. The necessary funds are generated by an increase in retail tariffs which increase the average cost of generation.

While there can be no argument with democratically legitimised policy objectives, economic analysis must show how the policy equation made of CO_2 emissions reductions, security of supply objectives and renewable energy targets can be solved most efficiently. If carbon taxes were universally accepted, a system could be imagined in which carbon taxes are complemented by a system of capital cost subsidies for VREs. This would interfere less with wholesale market prices than current support schemes aimed at production rather than at capacity.

Most countries have opted for fixed feed-in tariffs (FITs), which isolate VREs from wholesale market prices and de-structure the working of electricity markets with an ever more random price signal. FITs are convenient for investors as risks are fully hedged over the lifetime of the project, but are inconvenient for the remainder of the system. In addition, carbon taxes in the electricity sector have met fierce resistance in many OECD countries. Notable exceptions are Sweden, Finland and the United Kingdom, all three countries with sizeable shares of nuclear energy in their mix. The principle alternative, emission trading, in particular the European Emission Trading System (EU ETS) has a mixed record in establishing a reliable long-term carbon price signal capable of steering investment and dispatch.

This complicates matters. Due to the complex effects of variable technologies with zero marginal costs financed through FITs on the one hand and the political difficulties to install carbon taxes on the other, the set of policy options to meet the above – mentioned objectives needs to be enlarged. This concerns, in particular, nuclear power and hydroelectricity, which are currently indispensable if CO_2 emissions objectives are to be met at a reasonable cost. Dispatchable low-carbon power producers such as nuclear in today's real-world electricity markets would indeed benefit from access to the same form of financing as VREs, i.e. receive predictable revenues over the lifetime of a project. This can take the form of FITs, contracts for difference (CFD) or long-term contracts. The legal form is not important as long as revenues per MWh cover the average costs of a project over a sufficiently important share of the lifetime of a generation project.

One would thus evolve towards a system, in which all forms of low-carbon generation would receive some form or other of out-of-market finance. Perhaps this is the price to pay in order to be able to square the triple objective of emission reductions, security of supply and VRE deployment. However, it is also a system in which the information that is contained in wholesale market prices about costs and preferences no longer determines investment and dispatch. In a low-carbon system consistent with a 2°C scenario, in which emissions average 50 gCO_2 per kWh, the amount of energy allocated on the basis of market mechanisms would then become very small, essentially restricted to the remaining gas plants. It would be a system in which investments would primarily be decided by regulators, system operators and policy makers with the well-known risks of regulatory capture, technological inertia and gold-plating, all of which loomed large in the original decision to liberalise electricity markets. At the same time, it would probably be a workable system, meeting the three principal policy objectives.

Chapter 4 will deal with these questions in some more detail on the basis of the scenarios presented in Chapter 3. As mentioned, the modelling scenarios depict long-term equilibrium situations that provide information on the costs of different policy choices. Policy discussions will need to take into account long-term costs as well as the organisation of an orderly transition. However, the modelling scenarios have the merit that they model quite accurately the interplay of the three policy objectives discussed:

1. a common carbon constraint of 50 gCO_2 per kWh;
2. full cost recovery for all technologies (whether this happens though market forces or through appropriate policy instruments, depends on the particular scenario);
3. different shares of electricity produced by wind and solar PV, which, given the common carbon constraint, translate immediately into different shares of nuclear energy.

What these scenarios provide in a consistency and coherence of approach that has yet to be pursued elsewhere is transparency, i.e. the transparency of the costs of different policy choices. Together with the ensuing discussion about policy options in Chapter 4, this report thus pursues the principal objective of OECD policy analysis: allow policy makers to make more informed choices and, ultimately, to implement better policies.

Chapter 2. Literature review of studies on system effects

2.1. Definition and nature of system effects

The electrical power system is one of the largest and most complex infrastructures built by mankind; it is designed to generate, transfer and supply electrical power to final users with a very high degree of reliability. Broadly, it is composed of a generation system consisting of different generation technologies (hydroelectric, fossil, nuclear, solar, wind, etc.), a transmission grid carrying the electricity over long distance at high-voltage, electrical switch yards that transform high-voltage electricity to lower voltage and a distribution grid that brings electricity at low voltage to end-customers. One or several transmission or independent system operators (TSOs and ISOs) assure the efficient operation, stability and safety of the electrical system at regional and national levels. Finally, one or several distribution system operators (DSOs) assure the final stage of electricity power delivery at a local level, from the transmission network to individual consumers. Due to limited cheap bulk storage capabilities of electrical energy in power systems, TSOs and DSOs must still ensure that the electric power generated matches continuously the demand at system level, and that sufficient reserves are always available in case of failure of any large individual component of the system (loss of a transmission line, outage of a generating capacity or disconnection of a large load – this is often referred to as the "N-1" rule). However, in the near to distant future this picture will change, the electrical power flows will become bi-directional, with a mix of generating companies, "pure" consumers, and many dispersed "prosumers" who will inject and withdraw power from the grids. Furthermore, electricity storage might become much cheaper over the coming years. And finally, the N-1 rule requires conceptual adaptation as there will be a multitude of small and large components in the system. Much of the reliability analysis will have to be done stochastically.

All elements of the electrical power system connected to the grid do not operate in isolation but interact dynamically with the other elements and have a direct or indirect impact on all of them. If the analysis is limited to generators, each power plant has its specificities and characteristics: it is able to provide certain services to the system other than pure electricity generation and imposes some constraints and additional requirements to the system as a whole[1]. Broadly speaking, despite their individual differences, all dispatchable technologies share similar features and cause a relatively limited impact on the overall electricity system, mainly thanks due to their easy controllability. On the contrary, variable renewable energies (VREs), more specifically wind and solar photovoltaic (PV) technologies, share some specific characteristics that make their integration into the electricity system more challenging. These characteristics also affect both their capability to system reliability and the economic value of their generation. Not surprisingly, the topic of system effects has gained much interest since VRE technologies have reached sizeable penetration levels in many countries.

1. One could define an "ideal" generator, as one that would not cause any system effects; such power generation unit would have an output fully predictable and perfectly correlated with the load in time and space. Whereas the concept of an "ideal generator" is purely theoretical, it may be nevertheless useful to define and quantify system effects of all "real" generators: see (OECD, 2015) and Section 2.6 for further details.

The IEA (2014) has identified six technical and economic characteristics that are specific to VRE and differentiate them from other dispatchable generation technologies. These characteristics, which are intrinsically linked with their nature, affect the VRE contribution to the power system and are a key element to explain and understand the system costs associated with their integration. The output of VRE is:

1. Variable: The power output fluctuates with the availability of the resource (wind and solar). VRE are non-dispatchable as the power output cannot be adapted to the system's needs[1].
2. Uncertain: The amount of power produced cannot be predicted with precision. However, the accuracy of generation forecast increases with approaching the time of delivery.
3. Location-constrained: The available renewable resources are not equally good in all locations and cannot be transported. Often good sites are in the same region and far away from load centres.
4. Non-synchronous: VRE plants are connected to the grid via power electronics, while conventional generators are synchronised with the grid.
5. Modular: The scale of an individual VRE unit is much smaller than other conventional generators.
6. With low variable costs[2]: Once constructed, VRE can generate power at little cost. In particular, variable generation costs (short-run marginal costs) are close to zero for wind and solar PV units.

The concept of system effects has been recently developed to describe and take into account the interactions between different generation technologies and the infrastructure that constitute the power system, and to capture the impacts of the introduction of each technology on the whole system. System effect analysis also provides a framework for characterising the contribution and economic value of a given generation technology to the overall power system. This concept has been explored extensively and framed by the IEA and the NEA in the recent years (IEA, 2011 and 2014; NEA, 2012; OECD, 2015) and has benefitted from a significant amount of new research from academia, industry and governments.

System effects are often divided into the following three broadly defined categories (a to c), but a fourth category (d – connection costs) is sometimes considered separately:

a) profile costs, also referred to as utilisation costs or backup costs by some authors;

b) balancing costs;

c) grid costs;

d) connection costs.

Profile costs (or utilisation costs) refer to the increase in the cost of the electricity system in response to the variability of VRE output. They capture the fact that in most of the cases it is more expensive to provide the residual load[3] in a system with VRE than in an equivalent system where VRE are replaced by dispatchable plants. Ultimately, profile costs can be seen as the opportunity cost of not having, in the long term, a cheaper conventional generation mix for the residual load.

1. Wind technology can provide some downward services to the system as its generation can be curtailed in case of need. This is a common practice in countries with high penetration level of VRE.
2. Contrary to the previous five characteristics, the low-marginal cost of VRE does not affect the integration potential of VRE from an operational or technical standpoint. However VRE introduction has a profound impact on electricity markets as it shifts the merit order to the right.
3. Residual load or residual demand, sometimes also referred to as "net load" or "net demand" is defined as the instantaneous difference between total electricity demand (or load) and VRE generation.

The integration of VRE changes the temporal structure of the residual load that has to be met by the remaining dispatchable plants: while the peak load may be not changing, there is a trend to have more and more periods where the residual load is low, or even negative. This causes a change in the use of dispatchable generation capacity, with a long-term shift from baseload to more expensive mid-merit and peak generation plants.

A different way of looking at the profile costs of VRE is to consider that the electricity generation of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. Especially at high penetration levels, a given VRE plant is more likely to generate when other VRE plants are also generating. This correlation reduces the average value of each MWh of VRE output as well its contribution to the system.

Several studies (Fripp and Wiser, 2008; Joskow, 2011; Hirth, 2013 and 2015a) have shown using empirical market data or on the basis of numerical simulations that the market remuneration of electricity generated by VRE decreases significantly with their share in electricity generation. This phenomenon reflects the decreasing value for the system of each additional VRE unit and corresponds to an equivalent increase in profile costs. It is possible to establish a link between the profile cost and the market value of a generating technology; under certain hypotheses (e.g. complete and perfect electricity markets) the two perspectives lead to identical results (Ueckerdt et al., 2013b).

In addition, the presence of VRE generation generally increases the variability of the residual load, which exhibits steeper and more frequent ramps. This causes an additional burden to other dispatchable plants in terms of more start-ups/shutdowns, more frequent cycling and steeper ramping requirements. This results in operating conventional generation plants at a lower level of efficiency and to an overall increase in wear and tear of equipment, thus leading to higher generation and system costs. This effect has been reported as the flexibility effect (Hirth et al., 2015b).

Finally, profile costs should also include the effect associated with the low capacity credit of VRE, i.e. the fact that in most cases VRE contribute less than dispatchable plants to satisfy peak demand. However, the ability to fully account for the latter depends on the quality and detail of the methodology and models used for their estimation. The methods commonly used to estimate profile costs are able to capture only partially the costs associated with the low capacity credit of VRE. A complete calculation of the capacity credit of VRE would indeed require complex stochastic modelling of the whole electricity system over a wide range of years and meteorological conditions, which is beyond the capability and scope of most of the tools developed for system effects calculations.

Balancing costs are related to the increasing requirements for ensuring the system stability due to the uncertainty in the power generation (unforeseen plant outages or forecasting errors of generation). In the case of dispatchable plants, the amount and thus the cost of operating reserves are generally given by the larger contingency in terms of the larger unit (or the two largest units) connected to the grid. In the case of VRE, balancing costs are essentially related to the uncertainty of their output, which may become important when aggregated over a large capacity. Forecasting errors may require carrying a higher amount of spinning reserves in the system. In addition, due to the uncertainties in VRE power output, the schedule of other power plants in the system has to be changed more frequently and closer to real time. This may lead to increasing ramping and cycling of conventional power plants, inefficiencies in plant scheduling and to overall higher costs for the system. Sometimes, the variability of VRE within the scheduling interval defined by the markets (one hour or less) is also accounted for in balancing costs. Some studies also include the increased requirements for fast frequency regulation. The ramping up and down incorporated in the "flexibility effect" mentioned earlier, refers to the scheduled behaviour of dispatchable plants. Any non-scheduled behaviour due to forecasting errors is the reason for balancing costs.

The grid costs reflect the effects on the transmission and distribution grid due to the locational constraint of generation plants. While all generation plants may have some siting restrictions, the impacts are more significant for VRE. Because of their geographic location constraints, new interconnections may need to be built or the capacity of the existing transmission infrastructure (grid reinforcement) increased in order to carry the electricity from generation sites to consumers. In addition, transmission losses tend to increase when

electricity has to be moved over long distances. Also, high penetration levels of distributed PV resources may require sizeable investments into the distribution network to cope with more frequent reverse power flows occurring when local demand is insufficient to consume the electricity generated. In general, grid-related costs tend to increase as a result of connecting distant generation units or accommodating distributed resources.

Connection costs are defined as the costs of connecting the power plant to the nearest connecting point of the existing transmission grid. They can be significant especially if distant resources have to be connected. This can be the case for offshore wind, if load factors are low or if the technology has more stringent connection requirements as is the case for nuclear power. Connection costs are sometimes integrated within system costs (NEA, 2012), but more often are not considered as system costs and implicitly included in the levelised cost of electricity (LCOE) as plant-level costs[4]. The difficulty in this assessment is that connection costs are sometimes borne by the plant developer and sometimes paid for by the transmission grid operator. In the former case, they are part of the plant-level costs and thus fully internalised, while in the latter case they are externalities to be accounted for in system costs. In the following analysis, connection costs are not explicitly considered as part of system costs, but it is recommended that they are accounted in economic analysis and that they appear as a component either of plant-level costs or of system costs.

The above characterisation is not fully exhaustive, as there are other aspects that may have a noticeable impact on the electrical system, especially at high shares of variable renewables. For example, the fact that VRE are connected to the grid via power electronics and thus are non-synchronous leads to a reduction of the inertia of the system, although advanced power electronics can mitigate some of this effect.[5] Inertia reduction impacts the ability of the system to restore the target frequency levels after an incident, and thus undermines the overall robustness of the system. While some studies have characterised the dynamics of a system with a high share of non-synchronous resources, there has not been a systematic attempt to quantify its economic impact (EDF, 2015 and IEA, 2014). However, some authors explicitly consider as part of the balancing costs the increasing requirements for fast frequency response due to the reduced system inertia (Strbac et al., 2016). A synthesis of the studies performed on this subject is provided at the end of this chapter.

Finally, it is important to note that the different categories are not independent from one another, but costs can be "shifted" from a category to another. For example, additional investments in the transmission and distribution infrastructure, and thereby higher transmission costs, may lead to a cheaper generation mix and lower balancing costs, thus reducing the two other cost components. Similarly, having more flexible generation is generally more expensive, but allows for a reduction in balancing costs. Because the different system cost categories are not independent of one another, caution is needed when adding up components, in particular if they have been obtained from different modelling exercises.

2.2. Understanding system effects

Before describing in more detail the methodologies used for system effects analysis and quantification, it is important to understand some of their key elements. This section sets out some of the key elements needed to better understand the characteristics and specificities of VRE technologies and what impact they might have on the electricity system.

4. Note however that connections costs are not considered in the LCOE calculations performed in the IEA and NEA joint publication on plant level costs (OECD, 2015).

5. In the medium to far future, it might be possible (although it remains to be proven) that synthetic inertia can do the trick. The inertia issue will be discussed further below in Section 2.6 under the heading "Synchronous vs non-synchronous generation".

Intermittency, variability and uncertainty of VRE: The benefits of geographical diversification

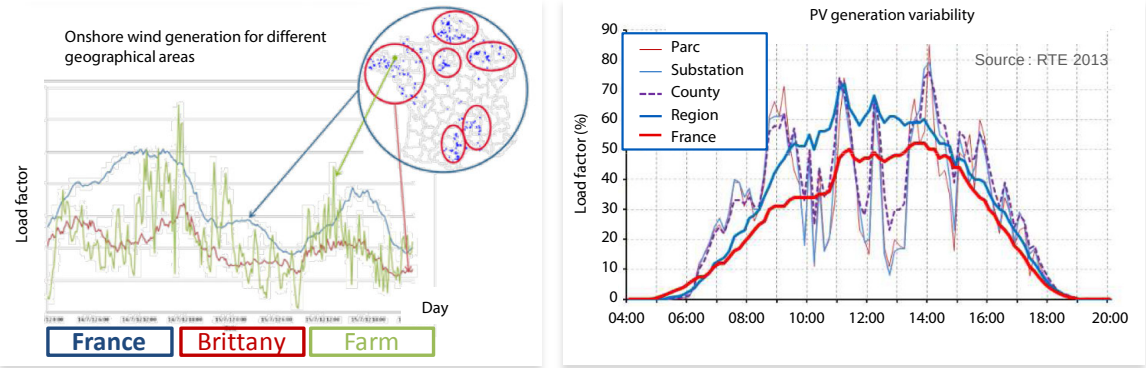
In order to understand the impact of wind and solar PV on the electricity system, it is important to examine the nature of their generation both in terms of their variability and their uncertainty.

The generation from wind and solar PV depends on local meteorological conditions that determine the availability of their primary resources. Changes in VRE generation occur on different time scales: from minute-by-minute variations to seasonal variation to even year-by-year variability. For example, the generation from a solar PV installation can drop from 100% to only 20-30% due to the passage of a cloud at mid-day; similarly, the generation of a wind turbine can suddenly drop to zero for reasons of technical safety when the wind speed exceeds a certain level. All solar PV generators experience a sharp generation increase in the morning, followed by a rapid decrease in the evening. On a different timescale, wind and solar PV resources are more abundant during certain seasons of the year, thus leading to seasonal variability of their generation. For example, when averaged over Europe, the load factor for solar PV is four times higher in summer than in winter, while it is about double in winter than in summer for wind (EDF, 2015). The extent of these variations depends strongly on the region considered: in the United States, average load factors for solar PV are about 70% higher in summer than in winter, while they are about 35% larger in winter than in summer for wind (based on EIA, 2017: Table 6.7.B). On an even longer timescale, the generation from renewable resources varies across different years: wind generation, as well as hydroelectric generation, may significantly differ from a year to the next ("windy" or "wet" years versus "non-windy" or "dry" years). All different types of variability, minute-by-minute, seasonal and year-to-year, have an impact on the system.

If, at the level of an individual plant the generation profile of wind and solar PV is literally "intermittent", with rapid and unpredictable variations, the aggregation of their output over larger geographical areas helps significantly to smooth the generation profile and reduce its variability. The larger and more diverse the geographical region considered, the smoother the resulting generation profile. Due to the geographical diversification of resources, the aggregated load presents less steep upward and downward ramps and appears flattened, with less pronounced peaks and valleys. This is illustrated in Figure 1, which compares the generation of wind and solar PV at different levels of aggregation within France (from individual plants to the country level). In this sense wind and solar PV generation can be considered intermittent at the plant level but variable at the level of a larger system. Clearly, in order to effectively benefit from the geographical diversification of the resources, an appropriate network infrastructure is needed across the area considered.

In addition, but for a different aspect, geographical diversification may have a positive impact by reducing the uncertainty in generation forecasts and thus the amount of reserve capacity required to cover the variations in VRE generation (IEA, 2017b).

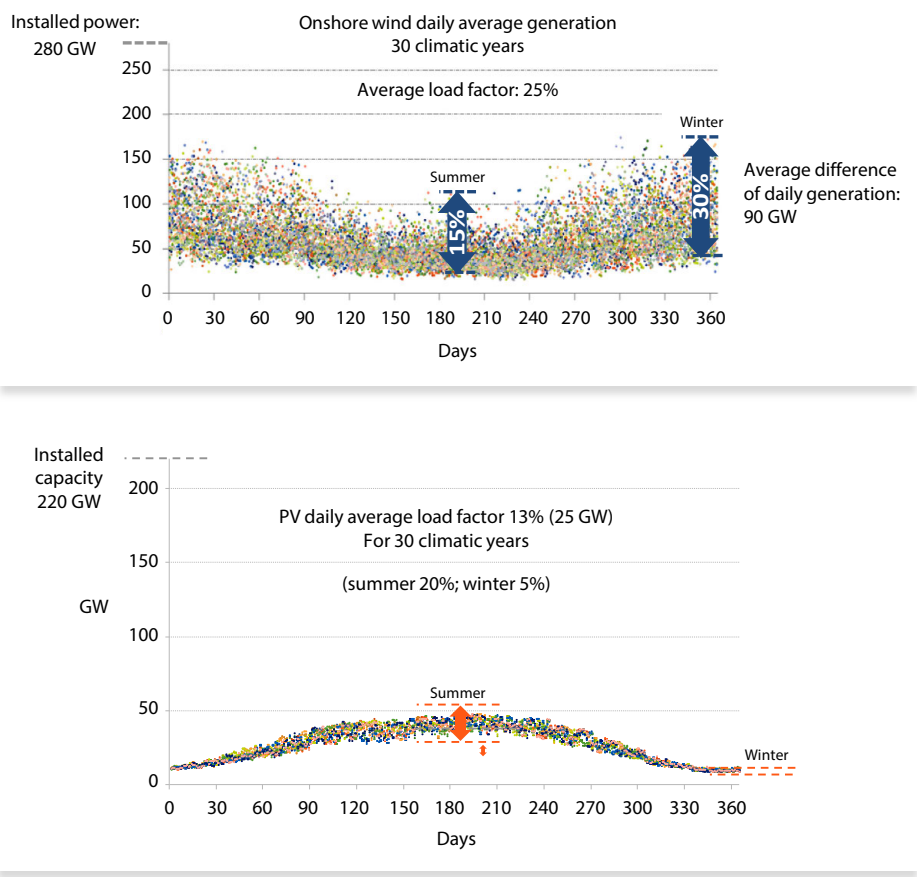
Figure 1. **Wind and solar PV daily generation profile when aggregated at different levels**



Source: EDF, 2015.

However, due to the coupling of climate regimes and meteorological events a significant variability in wind and solar generation persists even if they are aggregated at the level of a continent. Three years ago in 2015, the French utility EDF performed a comprehensive bottom-up study, which allowed characterising the spatial and temporal correlation of VRE resources at the level of the European interconnected system (EDF, 2015). Based on a historical dataset of 30 years of detailed weather observations across Europe, time-series of solar PV, onshore and offshore wind generation have been derived at hourly intervals and with fine geographical granularity. This has allowed a representation of the spatial and temporal correlation of VRE generation across the European continent and to capture the variability across distinct areas as well as across different time scales. Figure 2 shows the simulated onshore wind (upper panel) and solar PV (bottom panel) daily average generation over the 30 climate years considered (each dot represents the average daily generation in one of the 30 years considered). Wind regimes appear often correlated across Europe, leading to a significant variability in aggregated wind generation. For the simulated fleet of 280 GW of installed capacity, wind generation varies between 40 to 170 GW, i.e. by a factor of four, depending on the atmospheric conditions. The data shows also a large seasonal variability, with average load factors varying by a factor of two between 30% in winter and 15% in summer. If aggregated over a large region, solar PV generation features a much lower variability on a daily basis due to atmospheric conditions. However, seasonality of solar PV generation is more significant, with average load factors in summer about four times higher than in winter.

Figure 2. **Wind and solar PV generation in Europe over 30 different years**



Source: EDF, 2015.

The principle of diversification applies not only on a geographic scale but also across different technologies: an appropriate combination of different VRE resources could help to reduce the overall daily and seasonal variability. Taking the results obtained by EDF, wind and solar PV have a different seasonal generation profile in Europe, with a maximum in winter and summer, respectively. Their combined output, therefore, shows a smoother profile than that of individual technologies.

The "variability" of VRE generation has important consequences for the system, especially at high penetration levels. Short-term variability increases balancing requirements and the related costs, as well as having an impact on the structure of the residual generation mix (profile costs). At high penetration levels, large seasonal variability may cause relatively long periods with an excess of VRE generation that must be stored or curtailed, followed by long periods where there is a lack of electricity generation: such systems may require some sort of seasonal storage, the economics of which is extremely challenging. Finally, large year-to-year variability in renewable generation (mainly from wind and hydro resources) may have a significant impact on the level and volatility of electricity prices, with important financial consequences, especially for peak generators.

Finally, the benefits provided by the geographical diversification of VRE resources can also be accompanied by additional costs for the system. As already mentioned, the development of additional transmission and distribution (T&D) infrastructure is needed to fully reap the benefits of geographical diversification. On the other hand, distributing resources more evenly across a region may be more efficient for the system than concentrating them solely in the location with the best resource endowments. The implication is that there is a trade-off between maximising the generation of a wind portfolio, and therefore the profits of the plant developer, and having a smoother output, which may be more favourable for the system as a whole (IEA, 2017b).

Impact on the residual load

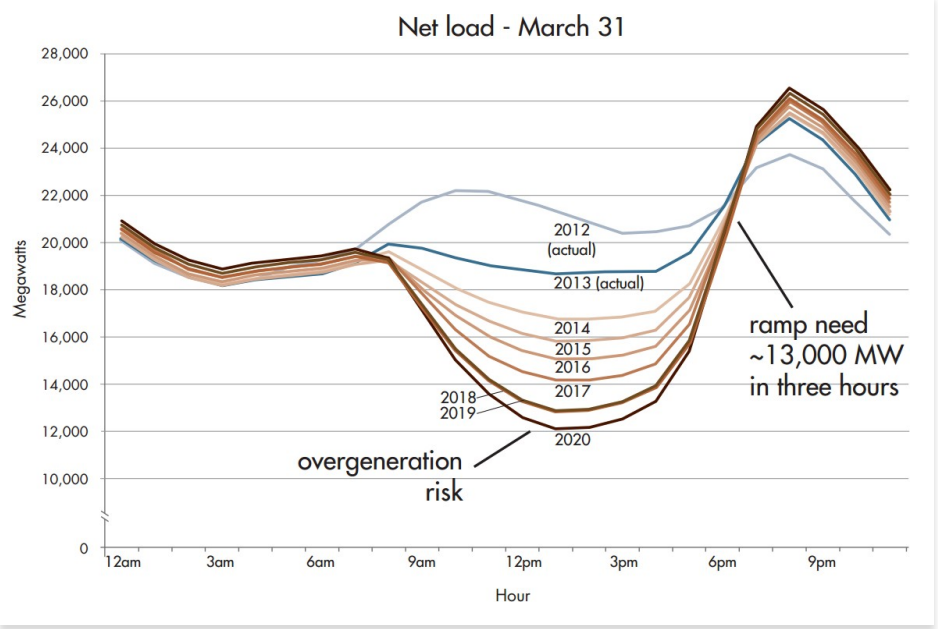
To illustrate the impact that variable resources have on the electricity system it is useful to look at how the residual load changes with VRE deployment. The residual load represents the demand that must be supplied by the rest of the generation system once the generation from VRE resources (and from other near-zero marginal cost generators such as hydro run-of-the-river) has been integrated, i.e. subtracted. Changes in the average level and shape of the residual load indicate clearly the additional requirements faced by conventional generators with increasing deployment of variable resources. A well-known example, which became famous with the nickname of "duck curve", is reproduced in Figure 3. The plot shows the residual load for a representative day in spring in the US state of California CAISO system: the actual data are shown for 2012 and 2013, while projected values are calculated until 2020, as more solar PV variable capacity is progressively added to the system (CAISO, 2013).

With the progressive deployment of VRE resources, in particular solar PV, the residual load decreases sharply around noon, when the generation from solar PV is maximal, while it does not vary significantly in the periods of zero or low solar PV generation. Several conditions emerge that have an impact on grid requirements and on the operations of other generators (DOE, 2017b):

1. shorter and steeper ramping rates (upwards and downwards) when dispatchable generation must be brought online or shut down;
2. risk of over-supply when the residual demand is too low;
3. reduction of the overall inertia of the system with potential consequence for the system stability.[6,7]

6. More complete information on the impact of VRE deployment on the overall reliability of the electricity system is provided in Section 2.6.
7. The degree of residual load "distortion" depends on the future availability of flexibility options. In a combined effort, the system actors could mitigate the distortion by actively applying flexibility measures. See Denholm et al., 2015 and Lazar, 2016.

Figure 3. **The "Duck curve" – residual load in the CAISO system at different solar PV penetration levels**



Source: CAISO, 2013.

Note: Licensed with permission from the California ISO. Any statements, conclusions, summaries or other commentaries expressed herein do not reflect the opinions or endorsement of the California ISO.

Specificities in system effect analysis

The impact of integrating new technologies into an electric power system, and hence the system costs, depend strongly on the characteristics of the system analysed, on the type of generating technologies considered and on its share in generation. While these considerations hold for every technology, their impact is particularly pronounced for variable renewables. Characteristics specific to each power system, such as the shape of electricity load, the correlation between the load and VRE generation profile, the geographical distribution of VRE resources and load, as well as the composition of the existing generation mix and the availability of storage capacity and flexible resources all have a major impact on system costs as well as on the integration potential of VRE.

For example, as already alluded to before, the system costs for solar PV are lower in systems where there is a good match between solar PV generation profile and demand, such as in the Southern regions of Europe and of the United States, where peak load tends to occur in summer at mid-day due to air conditioning. Adding PV capacity to these systems helps to reduce the residual peak load and hence allows for a reduction in installed conventional thermal capacity and expensive electricity generation from thermal plants, which are likely to operate only during peak loads. On the contrary, adding solar PV to systems where the peak load occurs when solar is not producing entails fewer benefits for the system and higher integration costs. This is the case of several countries in the northern part of Europe or of the United States, where the peak load occurs in winter evening hours after sunset. In these cases, PV capacity would reduce neither the needed conventional thermal capacity nor the amount of electricity generation by thermal plants during peak hours.

Similarly, systems with a large amount of flexible resources and storage capacity experience much lower system costs than more inflexible systems. The very high penetration levels of wind energy achieved in Denmark are possible thanks to the large hydro resources present in Norway, which acts like a large-scale battery to smooth the variability of wind output. More generally, significant quantities of flexible hydro resources (dams or pumped storage) are an important enabler for VRE deployment and integration. Also, integration and

system costs are lower if the best VRE resources are geographically close to the main load centres, thus reducing T&D needs. This is the case, at least at low penetration levels, of distributed solar PV resources that generate electricity where it is directly consumed, therefore limiting the use of T&D resources. In many systems, however, the best renewable resources are located far away from the main load centres, therefore requiring the construction of new or the reinforcement of existing transmission infrastructure. This is the case of Germany, where the best wind resources are located in the north of the country, while important loads are located in the south. The significant investments required in new transmission infrastructure face fierce also public resistance. A similar situation can be observed in Chile, which hosts in the extreme north of the country (Atacama Desert) some of the most favourable solar resources worldwide. However, an effective utilisation of these resources needs a complete rethinking of the electric grid of the country and requires important investments in T&D infrastructure to interconnect the solar PV resources in the north with main load centres in the middle of the country and with the main hydro resources located in the extreme south.

Quantitative analyses and empirical experience show that each component of system costs increases substantially with penetration level. These phenomena, particularly prominent in the case of profile costs, hold also for all the other components. For example, while at low penetration levels distributed solar PV resources may reduce requirements at the T&D level, at higher penetration levels they may require an upgrade of the distribution grid to cope with the bi-directional flux of electricity, to and from each individual producer/consumer, which may lead to significant investments in the distribution infrastructure. Said in a different way, the technical challenges and the associated cost to integrate the first 10% of VRE generation in a system are much lower than those needed to increase their penetration level from 30% to 40% in the same system. A literature review and empirical estimates tend to confirm these findings: at low penetration levels system costs are generally low, and in favourable circumstances may even be negative, but they tend to increase significantly to reach values of several tens of USD/MWh_{VRE}[8] at higher VRE penetration levels.

In conclusion, each analysis of system costs is specific to the system assessed, to the level of VRE penetration for which it has been derived and to the boundary conditions considered. Quantitative results cannot, therefore, be easily extrapolated or adapted to other systems and other conditions. However, while numerical results can differ, the main effects and trends observed are more general and common to all system and penetration level.

Short-term and long-term effects

A crucial aspect to be considered when analysing system effects or comparing results from different calculations is the time frame chosen for their assessment. The overall economic impacts on the system arising from the introduction of new generation capacity as well as the impacts on the operation mode and economic profitability of existing assets depend strongly on the time horizon chosen. Most of the studies make the assumption that the integration of new capacity takes place either in an existing system, where a given amount of generation capacity and electrical infrastructure is already present, or in an entirely new system where all the generating capacity and infrastructure has to be built. These two situations are often referred to as “brownfield” vs. “greenfield”, or as “short-term” vs. “long-term” perspectives. However, the choice of a short-term or a long-term approach may lead to very different outcomes on such aspects as the composition of the generation mix, the operations and economic profitability of different generation assets as well as the level and structure of wholesale electricity market prices. Similarly, the time horizon considered affects significantly the costs and benefits arising from the introduction of new capacity.

8. Reported values on system costs (or on each of its components, profile, connection, balancing and transmission costs) are expressed in USD per MWh of VRE generated. To avoid confusion they are indicated as USD/MWh_{VRE} throughout the report.

The electricity demand and the structure of the electricity generation mix are quite inelastic in the short term: existing power plants have long lifetimes and building new capacity and transmission infrastructure may require a considerable lead time and significant upfront investments. In the short-term (or in a brownfield approach) the electricity system is locked in with the existing generation mix and infrastructure, and cannot adapt quickly to the introduction of new technologies. In this perspective, it is implicitly assumed that new generation is introduced into the electricity system almost instantaneously, and without being anticipated by the market. On the contrary, in the long-term, the analysis is situated in the future when both the infrastructure and generation capacity can evolve and adapt to the new market conditions resulting from the introduction of new generation capacity. In these cases, the electricity system is considered as "greenfield", where the whole generation stock and power infrastructure can be replaced and re-optimised. Some studies may also take an intermediate approach, assuming that only a fraction of the existing assets remain in place and/or allowing that existing generation capacity can be retired or mothballed.

These two approaches will inevitably lead to different estimates of system costs and of the system value of introducing a new technology such as VRE. Combining the results from short-term and long-term analysis provides valuable insights to researchers and policy makers. On the one hand, such analyses help to underline and to understand the different phenomena arising from the integration of a new VRE capacity, and in particular the impacts on different generation technologies at various time frames. On the other hand, the short-term and long-term scenarios could be interpreted simply as providing upper and lower limits for a more realistic assessment of system costs and benefits. By how much the "true" system costs will differ in a more realistic situation depends mainly on three factors: the evolution of electricity demand, the system's capital turnover rate relative to the speed of deployment of the new technologies, and the degree to which existing and available assets complement the new entrants. For example, if VRE are introduced very slowly relative to the natural turnover rate of the power system or relative to the change in electricity demand, the system could remain continuously well adapted during the transformation process and system costs would stay at a minimum level (long-term costs). Instead, if VRE are rapidly introduced to a power system with a lower turnover rate and with a stagnant demand, system costs will be higher and close to those of a short-term perspective. Also, if the existing generation assets already provide sufficient flexibility to the system, short-term integration costs will be closer to long-term costs, while this difference will be more significant for more inflexible systems. A more detailed discussion on the level of system adaptation in the short, mid and long-term can be found in (Ueckerdt et al., 2013a) as well as in (NEA, 2012 and OECD, 2015).

Many quantitative studies have shown that the introduction of large shares of VRE resources have a profound impact on the operations and economics of dispatchable power plants, on the optimal structure of the generation mix, as well as on the level and volatility of electricity prices and on carbon emissions. As indicated, these impacts are strongly different in the short and long term.

The short term

In the short term, the introduction of new VRE capacity with low variable costs will cause two different effects:

- a reduction of the load factor of existing generators, which affects mostly those with highest short-run marginal costs (often referred to as the transitory utilisation or compression effect);
- a reduction of the level of wholesale the electricity market prices when VRE are generating (referred to as merit order effect).

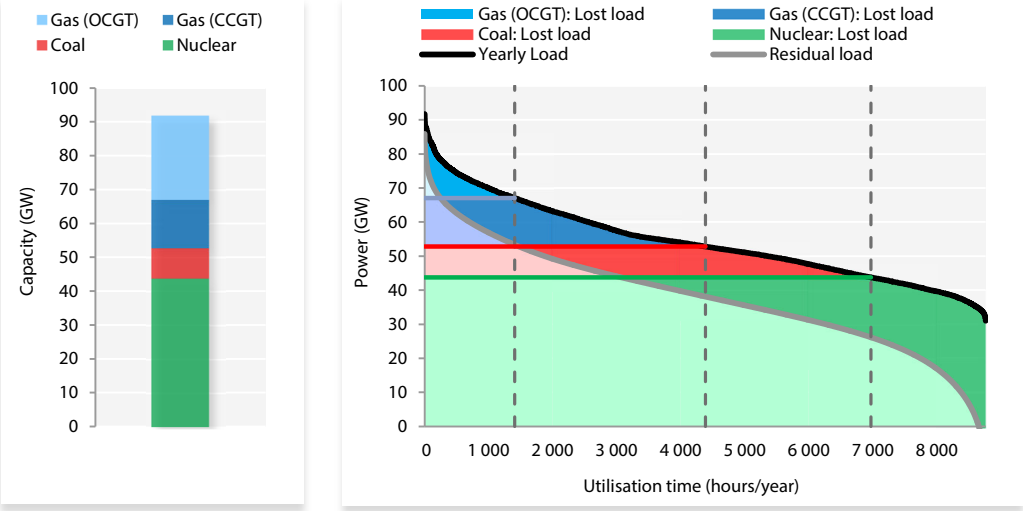
Due to the infeed of low marginal cost electricity from VRE, all existing dispatchable power plants have to reduce their generation levels and operate at reduced load factors. However, not all power plants are equally affected by the deployment of VRE. Indeed, the VREs shift all the generating units to the right in the merit order ranking; the units on the far right of that ranking are mostly affected and not so much the baseload units. Hence, the impact on the load factor of baseload plants is rather limited. On the contrary, peaking plants and to a lesser

extent mid-load plants are the most penalised, with a significant reduction of their maximal utilisation time and of a large share of their electricity generation. This phenomenon is illustrated in Figure 4, which shows the decrease in electricity generated by dispatchable plants after the introduction of a large share of VRE energy (wind at 30% penetration level, in this example). The column on the left-hand side shows the capacity mix of dispatchable technologies, which has been optimised before the introduction of the wind capacity. On the right-hand side, the light coloured area represents the electricity generated by each dispatchable technology after the introduction of wind capacity, while the darker area shows the respective generation lost, which has been replaced by the electricity produced by wind.

The decrease in load factors and generation levels is only one of the two elements affecting existing dispatchable generators. Because of the infeed of low marginal cost electricity, the supply curve shifts to the right, pushing plants with higher marginal costs out of the market: the number of hours in which peak and mid-load technologies are marginal decreases, which results in lower spot and average electricity market prices. This, in turn, reduces the infra-marginal rent for all generation technologies. An illustration of these phenomena is presented in the 2015 edition of *Projected Costs of Generating Electricity* (OECD, 2015: see Figure 10.4).

The combination of reduced load factors and lower average wholesale electricity prices can have a severe impact on the revenues, and consequently on the profitability of existing power generation plants, including the VRE themselves if they operate in a pure market environment. These impacts are particularly severe for technologies with high variable costs such as peakers and mid-merit power plants. The short-term impact on the output of baseload plants is somehow more limited. This may be considered a normal process of technology substitution, typical for a market economy. However, the key issue that the new technologies introduced by out-of-market mechanisms are due to their technical characteristics as imperfect substitutes in terms of the cost and system services delivered.

Figure 4. **Short-term reduction in generation level after the introduction of VRE (wind power at 30% penetration)**



Source: Adapted from NEA, 2012.

Note: based on load data and wind profile for France 2011. Calculation has been performed by scaling the wind generation in 2011 to a level corresponding to a generation share of 30%. This may overestimate the impact of variability.

The long-term

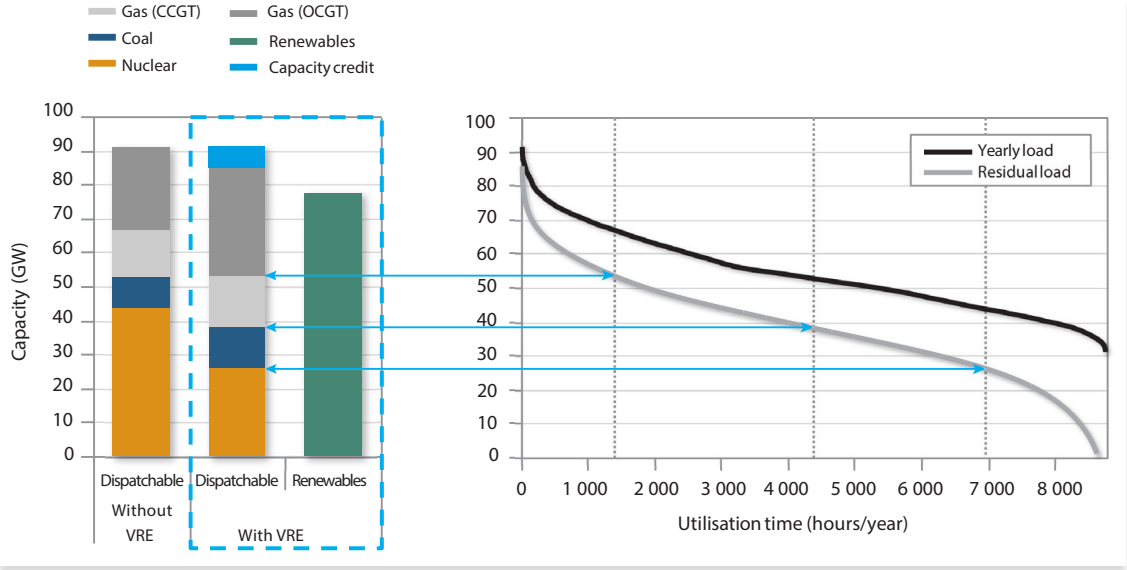
While the economics of peak- and mid-merit plants are challenged mostly by rapid VRE additions mostly in the short and medium term, the long-term impacts in the mainly affect baseload plants. Adding low marginal cost electricity from VRE creates a new residual load

curve that must be satisfied by a different generation mix: a well-documented phenomenon is the shift towards more mid-load and peak power plants, accompanied by a concomitant decrease in baseload capacity.

At very low penetration rates, and if the generation of VRE is well correlated with the electricity demand, the addition of VRE contributes to a flattening of the residual load duration curve (RLDC); in this context, renewable energy substitutes mostly peak- and mid-merit generation plants. However, at higher penetration levels, or if the VRE generation is not well correlated with electricity demand, the residual load curve tends to become steeper. The reason for this is twofold. First, maximum residual load tends to decrease more slowly than the average residual load. As a result, the left side of the curve remains high (scarcity periods of VRE generation). Secondly, minimum residual load tends to decrease faster than average residual load, meaning that the right side drops away more quickly (periods of abundant VRE generation). As the residual load curve becomes steeper, less dispatchable capacity can achieve high load factors. Once allowance is made for adjustments to the generation capacity, the resulting optimal generation mix is likely to contain more peaking and mid-merit plants and less baseload than in the absence of VRE (see also IEA, 2014; NEA, 2012; and Nicolosi, 2012). The long-term effects of the different optimal generation structure to meet the residual load curve are captured by the profile costs discussed in the previous section.

A simple and intuitive way to describe and illustrate the long-term changes in the electricity generation mix is based on the analysis of the annual load duration and of the residual duration curves. This allows, under certain simplifying assumptions, the straightforward determination of the optimal mix of dispatchable generators that would satisfy a given electricity demand at the lowest cost. The impact on the RLDCs and the long-term effects on the optimal generation mix are illustrated in Figure 5 using the approach described above (NEA, 2012). Two situations are compared: a scenario without VRE and a scenario with wind producing 30% of total electricity demand; this example shows the effect on the residual demand and the consequent change in the long-term optimal generation mix, with a shift towards more peaking generation and a reduction in the need for baseload capacity. The bar on the left gives the resulting optimal generation mix for the scenario without wind, and the two bars on the right show the new optimised generation mix in presence of wind generation together with the wind capacity.

Figure 5. **Optimal long-term generation mix with and without VRE (wind 30% penetration level)**



Source: NEA, 2012.

Note: based on load data and wind profile for France 2011. Calculation has been performed by scaling the wind generation in 2011 to a level corresponding to a generation share of 30%. This may overestimate the impact of variability.

While the introduction of low marginal cost electricity generation sources strongly influences the behaviour of electricity market prices in the short term, over the long term the impact on (annual) average wholesale market prices is moderate, unless high penetration levels are reached.

In the long term, the most relevant effects occur at the two extremes of the load duration curve (LDC), which correspond to the hours with the highest and with the lowest wholesale market prices. It has been observed that in the presence of VRE the left side of the RLDC becomes steeper and statistically more subject to variations due to meteorological conditions. This may affect the capability of demand-side measures to intervene effectively and thus have an impact on the number of hours with very high scarcity prices. The other major effect happens at the extreme right side of the LDC, in particular when renewables become the marginal technology (Green and Vasilakos, 2011 and NEA, 2012)[9]. In these periods wholesale electricity prices would decrease from the variable costs of the baseload technology to zero (which reflects the variable cost of VRE) or even negative levels, in presence of subsidies to generation from VRE. VRE are expected to be the marginal technology, and thus have an impact on long-term electricity prices, only when reaching a penetration level of 20-30%, depending on the characteristics of the system and those of the VRE technologies deployed. The number of hours with zero or negative prices increases significantly after reaching this threshold. However, putting aside the more technical arguments discussed above, the fundamental reason for which the impact on the (yearly) average electricity price would be minimal in the long term is that all power plants must be able to recover their costs in the long run, and thus the price curve must allow them to have sufficient infra-marginal rent to cover their fixed costs or otherwise investors would not invest in them in the first place.

However, whereas the long-term average level of electricity prices is expected to not vary significantly with the deployment of renewable resources, it is expected that the volatility of electricity prices would increase substantially in VRE-dominated systems both in an inter-annual and intra-annual perspective. In particular, the level of electricity prices could fluctuate significantly on a year-to-year basis in systems with a significant wind and hydroelectric basis, depending on the yearly generation level of these low marginal cost resources. Indeed, historical evidence shows that, even if averaged over a large region, wind and hydro generation in a single year could be a few tens of percent above the average in favourable “wet” and “windy” years. In contrast, electricity generation could fall well below the average in unfavourable “dry” and “calm” years. If the share of hydroelectric and wind resources is sizeable, the load factor of thermal plants and the level of market revenues from the electricity market could vary significantly on a yearly basis, in particular for mid- and peak-load technologies. Such year-on-year uncertainty in revenues from wholesale electricity markets could have an adverse effect on the overall risk for generating companies, thereby leading to an increase of the cost of capital for all generation plants in the system.

Impact on wholesale electricity markets

During the last decade wholesale electricity markets have experienced unprecedented tensions, which have spurred an intense debate among stakeholders and policy makers in many OECD countries. The major outcome has been a substantial decline of wholesale electricity market prices, in particular in Western Europe and parts of North America. A second factor is the emergence of several hours with very low or even negative prices and, in general, a sharp increase in price volatility. The combination of these aspects and the consequent increase of the electricity market risk is putting severe economic pressures on most generating companies and therefore affecting their ability to take on new investment as well as impairing their overall economic sustainability. In parallel, a significant number of OECD countries, in particular in Western Europe, have experienced the definitive shutdown or mothballing of a large dispatchable generation capacity base on purely economic grounds. The

9. The degree to which this will hold on actual markets depends on whether market agents price-in start-up, ramping and part-load efficiency costs.

premature closure of such capacity, which includes not only flexible gas-fuelled power plants but also more capital-intensive coal or nuclear units, is also raising some concerns as to the reliability of the electricity sector and, more in general, on the security of energy supply. In particular there is an increasingly vigorous debate whether liberalised electricity markets are able to mobilise the sufficient level of investments to maintain in the future the current high reliability levels of the electricity system, in particular in the context of a significant reduction of their carbon intensity. Finally, in Western Europe, the drop in wholesale market prices is coupled with significantly higher retail tariffs paid by final consumers. The increasing wedge between wholesale and retail prices is a source of concern for the future affordability of electricity provision. This section provides a short overview of these three important aspects, looking more specifically at the role played by the large development of low variable cost VRE resources. The situation in the OECD countries of Central and Eastern Europe (CEE) is somewhat different to the extent that subsidies for VREs are substantially less and electricity prices are holding up somewhat better. The exception is the Czech Republic, whose electricity market is closely integrated with those of Germany and Austria.

Many concurrent factors have contributed to the decline in wholesale electricity market prices in North America and Western Europe. Among them are an unexpected stagnation or even decline in electricity demand following the financial crisis in 2008, overinvestment in generation capacity undertaken at the beginning of the century, the large decrease of fuel prices following the development of shale gas in the United States, and, at least until very recently in Europe, the low level of the carbon price.[10] However, the recent fast deployment of VRE resources, driven by direct subsidies and/or mandates and financed mostly by out-of-the-market mechanisms, has been recognised as one of the most important if not the most important driver of these trends. For example, a quantitative ex-post study has shown that the massive deployment of VRE capacity is the single largest driver of the collapse of wholesale market prices in Germany and Sweden between 2008/2010 and 2015 (Hirth, 2016b); more information on this study is provided in Box 2.1. Wiser et al (2017) performed a detailed analysis and an extensive literature review focused on the United States. The main conclusion of this work is that the main factor driving average wholesale electricity prices lower in the US is the decline in natural gas prices, while the impact of VRE deployment has been so far limited. However, there is a broad consensus that higher level of VRE is associated with a decline in electricity market prices, at least in the short term. Wholesale electricity prices decline between 0.10 and 0.80 USD/MWh per a 1% increase of VRE generation share. The study indicates also that the temporal and geographic pattern of wholesale prices has changed in the areas with higher production from VRE such as Texas and California, with higher frequency of negative prices. Box 2.2 provides additional insight and analysis on the topic of negative prices.

Another, more fundamental question is whether, in the context of the decarbonisation of electricity systems, current wholesale electricity markets are capable of delivering attractive long-term risk/return profiles for investors. A stochastic analysis of the wholesale electricity price formation in the UK market has shown that the decarbonisation of power markets is associated with a progressive deterioration of the financial risk/return profile for investors in all generation assets (Munoz and Bunn, 2013). This is fundamentally due to the shift towards a high-capital/low-variable cost structure of the generation mix, which characterises all low-carbon generation options. The progressive increase of the project risk in the power generation sector has implications on the type of investors attracted to such a market, on the required cost of capital and, ultimately, on the total cost of electricity generation.

10. It should be noticed that recently, following a number of policy changes, the price of carbon emissions in Europe has sharply increased to reach a level above EUR 20 per tonne in August 2018.

Box 2.1. The drop in European wholesale electricity prices: Focus on Sweden and Germany[11]

European wholesale electricity prices have dropped by nearly two thirds in real terms since their all-time high in 2008/2010. This had a profound consequence on the electricity markets and has severely affected the profitability and overall sustainability of most European generation companies. Many elements have contributed to this effect: among the most significant factors are the reduction of fossil fuel prices and a drastic decrease of carbon prices in the European market, the deployment of large shares of VRE and the unanticipated stagnation (or decline in some countries) of electricity demand. Indeed, over-optimistic projections on electricity demand growth have led to an excess of investments in generation capacity at the beginning of 2000.

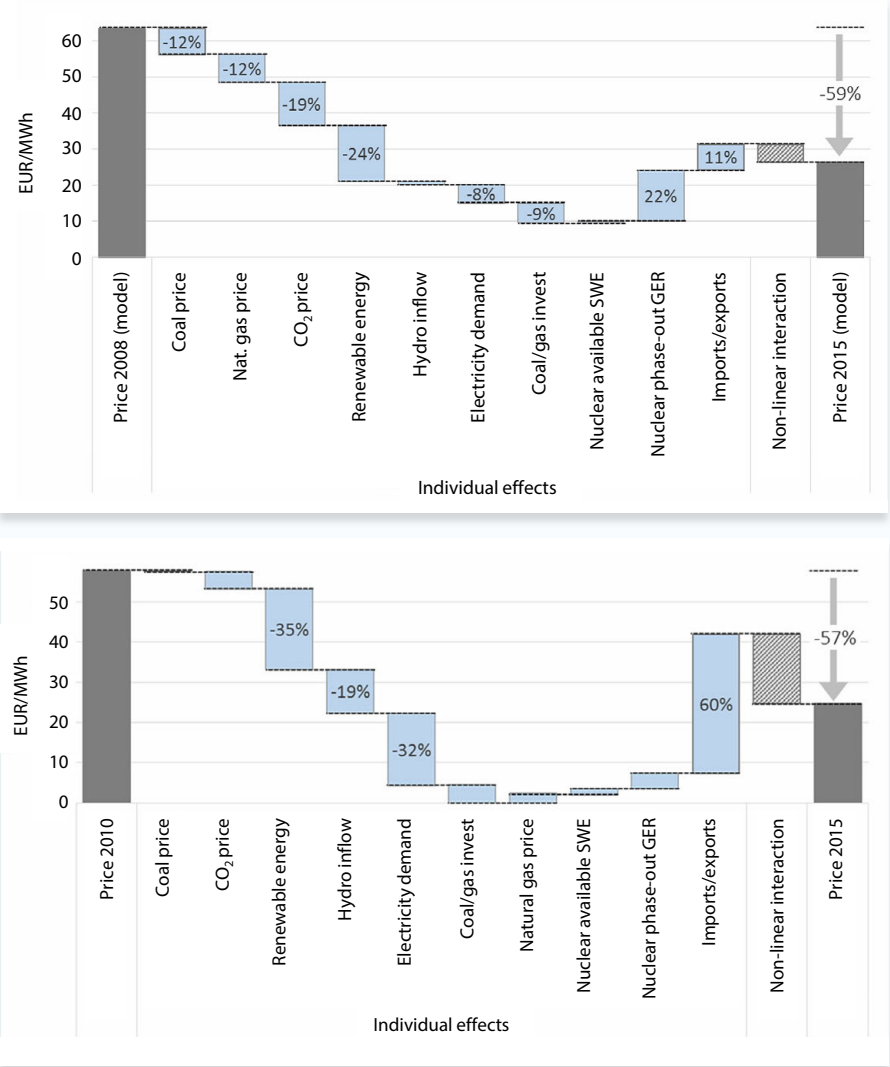
Hirth (2016b) has assessed the impact of ten individual factors on the structure and level of electricity prices in Germany and Sweden between 2008/2010 and 2015. Wholesale electricity prices have declined by 59% in Germany between 2008 and 2015 and by 57% in Sweden between 2010 and 2015. In the same period, the electricity share of VREs has increased by 11% in Germany and by 7.5% in Sweden[12].

In both countries, the deployment of low marginal cost renewable energy has been the largest individual driver for the electricity price decrease: VRE deployment alone would have caused an electricity market price reduction of 24% in Germany and of 35% in Sweden. In Germany, the reduction of coal and gas prices, as well as the collapse of carbon prices also had significant impact on electricity prices; collectively, these factors would have caused a decrease of electricity market prices of roughly 40%. On the contrary, their overall impact on the electricity market prices in Sweden was almost negligible since fossil fuels constitute a much smaller share of electricity generation.[13] Among the other factors that had a downward impact on electricity prices were the reduction in electricity consumption and the additional investments in coal and gas capacity, which contributed to approximately 20% of the price drop in Germany and about 35% in Sweden. The shutdown of eight nuclear units in Germany following the accident in Fukushima had a large impact on electricity prices in the country: the study assessed that this policy intervention has raised electricity prices by 22% in Germany and also had a small impact on Swedish markets. It is worthwhile recalling that electricity prices would have dropped even further without the premature shutdown of eight nuclear units in Germany. The increase of exports to neighbouring countries further supported prices in both markets. Interestingly, the downward effect of VRE addition and the upward effect of nuclear retirements almost balanced out prices in Germany. However, as far as CO_2 emissions are concerned, the nuclear shutdowns were not neutralised in the same manner, as low-carbon nuclear power was substituted by a mix of VRE and fossil fuels. The main results of the study are summarised in Figure B2.1 below.

The quantitative impact of each individual factor varies significantly in the two countries, due to the different characteristics of their respective power systems. An interesting conclusion of this study is that the Swedish power system is more vulnerable to quantity shocks such as the deployment of VRE, and year-to-year variations in demand and supply from low marginal cost sources such as nuclear and hydroelectric power. Price volatility, and hence market risk for investors in power generation, is much higher in markets dominated by high capital cost technologies, such as hydro, nuclear and VRE. This indicates that a transition towards a low-carbon electricity mix is accompanied by a large increase in the electricity market risk. Finally, it is worthwhile recalling that electricity prices would have dropped even further in Europe, without the premature shutdown of eight nuclear units in Germany.

11. The content of this Box is based on Hirth, 2016b.
12. Penetration level of VRE has increased from 7.1% to 18.2% of the indigenous generation in Germany between 2008 and 2015, and from 2.4% to 10.1% in Sweden (source: IEA, 2010, 2012 and 2017a).
13. Fossil fuels contribute to about 60% of the electricity generation in Germany and less than 10% in Sweden.

Figure B2.1. **Decomposition of electricity price changes in Germany (top) and Sweden (bottom)**



Source: Hirth, 2016b.

Similar trends were observed in an earlier study, which quantified the decrease of wholesale market prices induced by the expansion of VRE generation in Germany between 2001 and 2006 (Sensfuss et al., 2008). The reduction in the average electricity price attributable to VRE deployment is estimated to about 1.7 EUR/MWh in 2001 and to 7.8 EUR/MWh in 2006. In the same period, the VRE generation in Germany increased from 18 to 52 TWh.

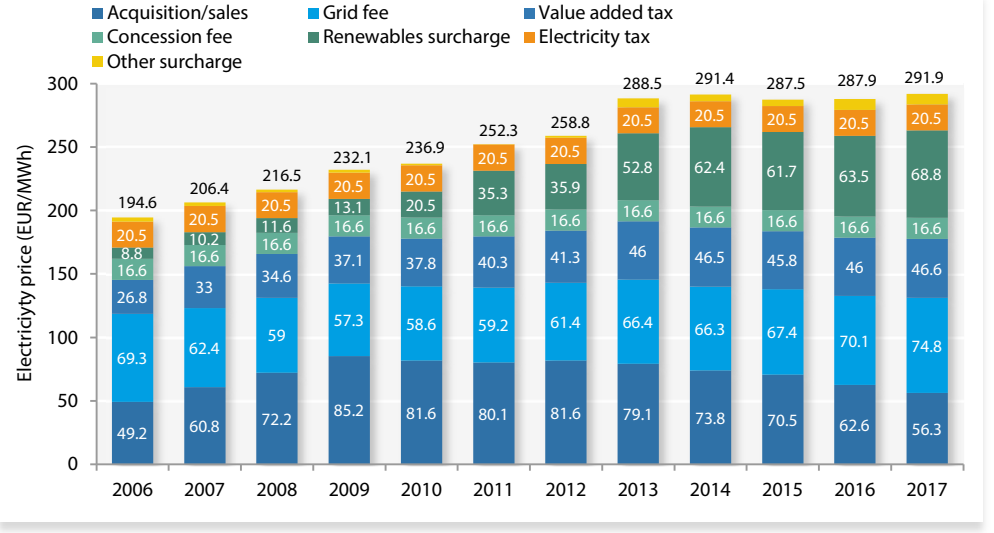
Using a similar methodology, Wiser et al. (2017) shows that reduction of natural gas prices was the most important driver for explaining the wholesale electricity price reductions in California and Texas. Additions of new VRE power plants represent the second contributor factor in California and the third in Texas (the second being the net additions of conventional power plants).

Despite the sharp decline of wholesale electricity prices, in recent years households and industrial consumers of many OECD countries have seen their electricity bills increase. Of course, the cost of electricity generation is only one component in the total cost of electricity: retail rates also include charges for T&D grid; concessions and various local and state taxes; additional charges to support specific policy goals, such as energy efficiency targets; direct or indirect subsidies for renewable energy, etc. In most OECD countries, the reductions in electricity generation wholesale prices have been offset by increasing costs to upgrade the T&D infrastructure and to promote the development of VREs.

Germany constitutes a telling example of this situation. Between 2006 and 2017, over 70 GW of new wind and solar PV plants have been deployed and the penetration level of VRE has increased from 6% to over 22% of the total generation (in terms of TWh). In the same time period, retail prices have increased much more than in other European countries and in the last five years Germany has had the highest electricity prices for households and small businesses, despite having one of the lowest wholesale prices in Europe. Figure 6 shows the evolution of the electricity price for households in Germany between 2006 and 2017 as well as its breakdown into different components. In the last ten years electricity prices for German households have increased by 34%, from EUR 216.5 per MWh in 2008 to EUR 291.6 per MWh in 2017, despite a 30% reduction of power supply wholesale prices. Costs for T&D have increased by EUR 15.6 per MWh, i.e. by 27%. More importantly, the subsidies for renewables have risen more than six-fold, from 11.6 to EUR 68.8 per MWh. In 2017, the surcharge for renewable energy is the second largest component of power costs after grid costs (respectively 24% and 26% of the total), while the cost for power supply constitutes less than 20% of the total.

Figure 6. **Household electricity prices (<3 500 kWh per year) in Germany**

(Households with consumption of less than 3 500 kWh per year, EUR per MWh)



Source: Adapted from BDEW, 2017.

Looking forward, it is hard to imagine that current low wholesale market prices can be sustained in the long term, unless a technological breakthrough materialises or a continuous excess of supply is maintained by continuing the support for VRE technologies. In the coming years electricity market prices must increase to reach the full long-term costs of generation. On the other hand, it is difficult to forecast a reduction in the other components of the electricity bill, which will compensate investments and additional operational costs in T&D as well as long-term commitment to VRE.

Box 2.2. **Electricity markets and negative prices (adapted from OECD, 2015)**

Negative prices in the electricity markets have been traditionally very rare events; however, such events are becoming increasingly frequent in major wholesale electricity markets in North America and in Europe, with hours showing negative electricity prices on day-ahead, intraday and balancing markets. In Germany, the number of hours with negative prices in the day-ahead market has steadily increased from 2012 to 2017 in parallel with the share of VRE generation. In 2012, 56 hours on 15 days with negative prices were observed on the day-ahead market, for an average value of -70.2 EUR/MWh. In 2017, negative prices occurred during 146 hours in Germany for an average value of -26.5 EUR/MWh (Agora, 2018). A recent DOE study reports that real-time markets in the US experienced negative prices in somewhat less than 2% of the time in 2016 (DOE, 2017b). Nevertheless that study also indicates that more frequent negative pricing has been observed in CAISO, and in constrained hubs with large amounts of VRE or relatively inflexible nuclear generation. A comprehensive analysis on the frequency and drivers of negative prices in several hubs in the United States can also be found in Wiser et al. (2017). Overall empirical evidence shows that negative prices occur in situations characterised by (1) a large supply of renewable energies, (2) comparatively low levels of demand and (3) a lack of flexibility in the conventional system (Agora, 2014).

Negative prices reflect a combination of low demand, excess of generation (often coupled with must-run requirements from thermal power plants), sub-optimal support mechanisms for certain technologies, errors in generation forecasts as well as transmission constraints.

The presence of specific policies designed to support the deployment of renewable technologies, such as feed-in tariffs, feed-in premiums, tradable green certificates or production-based tax incentives, contribute to the occurrence of negative power prices in the electricity markets and thus increase the revenue losses of existing generation. Based purely on plant economics, VRE generators would be expected to bid no lower than a very low positive price, reflecting their very low variable cost. However, support policies, which contain a performance-based element, may create an incentive for VRE plant owners to bid below their short-run costs, because they receive revenues on top of achieved market prices. Hence, bids may be below zero (minimum bids are likely to equal short-run cost minus the value of support payments). Depending on the policy context, VRE generators may also enjoy priority dispatch. Where VRE generators have priority dispatch, their operation can run independently of any market price signal. This can lead to more pronounced negative prices (Nicolosi, 2012).

Other technologies may bid at prices well below marginal short-run costs or even at negative prices, as a result of "must-run" levels or from technological limitations such as start-up, shutdown and ramping constraints. A conventional generator may accept to incur in a short-term loss selling electricity below its variable costs if that would allow for a rapid ramping-up when the VRE generators fade – for example, PV electricity when the sun sets. This effect could be reinforced by "take-or-pay" fuel contracts, for example for gas plants.

However, negative price signals can also prove useful. If well implemented, they deliver a signal to all generators that increased flexibility is necessary. Negative price signals are thought, for example, to have encouraged the reduction of must-run levels of coal plants in Denmark.

Short-term and long-term impacts on carbon emissions

One of the main drivers for the deployment of variable renewable technologies is the reduction of carbon emissions from electricity generation. It appears self-evident that deploying low-carbon emission VRE technologies would inevitably reduce the specific carbon emissions from electricity generation. However, the previously cited study from the NEA (2012) shows that the performances of VRE technologies in terms of carbon emission reductions differ significantly in the short term and in the long term. More importantly, in absence of other policy measures specifically targeting carbon emissions, the deployment of VRE alone is not necessarily accompanied by a reduction of carbon emissions in the long term. This outcome depends essentially on the type of technology used as a baseload, and more specifically whether the technology used as baseload is emitting carbon (i.e. coal or gas) or is also low-carbon, such as nuclear or hydroelectric. The deployment of renewables into an

electricity system whose baseload technology emits CO_2, such as coal, will definitively reduce the CO_2 emissions from the electricity sector in both the short- and the long-term. However, this will not hold when the baseload technology displaced by renewables also does not emit CO_2 during generation, as is the case for nuclear energy. In this case, instead, the electricity produced by fossil-fuelled technologies tends to increase, and long-term CO_2 emissions will be generally higher than in the "base case" without VRE (see NEA, 2012 for further details and quantitative estimates).[14]

In the short-term generation from VRE replaces that from other generation sources – baseload, mid-load and peakers – as illustrated in Figure 4. By reducing the electricity generated by mid-merit and peaking plants, which are generally assured by fossil-fuelled technologies, carbon emissions thus decline in the short term. Clearly, these carbon emission reduction are larger if the existing generation mix is carbon intensive (i.e. having coal or lignite as baseload technologies), but they are also observable for systems featuring a low-carbon technologies as baseload. The reduction observed in the short term, however, is unlikely to be confirmed in the long term.

In the long-term the deployment of VRE introduction leads to a complete reconfiguration of the generation system. The deployment of VRE resources lead invariably to a reduction of the capacity and generation share from baseload technology. In the majority of the scenarios, this is accompanied by an increase in the capacity of mid- and peak-load plants and in their generation share. In these cases the combined generation share from VRE and baseload technology is lower than that of baseload alone in a scenario without VRE. The consequent increase in fossil fuel generation mechanically leads to higher carbon emissions with respect to a scenario without VRE.

2.3. Methodological issues, difficulties and modelling choices adopted

The ample scientific research in this area performed in recent years has allowed for a better understanding of the most relevant phenomena to be considered, for a convergence in the methodologies used as well as in the representation of system effects. However, despite the significant progresses achieved, a rigorous and universally accepted definition of system effects and a well-codified methodology for their quantification is still lacking (Agora, 2015; Strbac and Aunedi, 2016; and NEA, 2018). This is a direct consequence of the underlying nature of system effects, the complexity of the phenomena involved and the challenges of performing a detailed modelling of the power system. In this respect, Agora Energiewende (2015) indicates that the outcomes of different analyses may differ substantially not only depending on the specific electrical power system analysed, the share of renewable energy modelled and the perspective taken, but also on different, more subjective features. Which cost elements are included, which methodology and computational tools are adopted and, more importantly, which predictions are taken with regard to the future development, availability and costs of individual technologies within the power system.

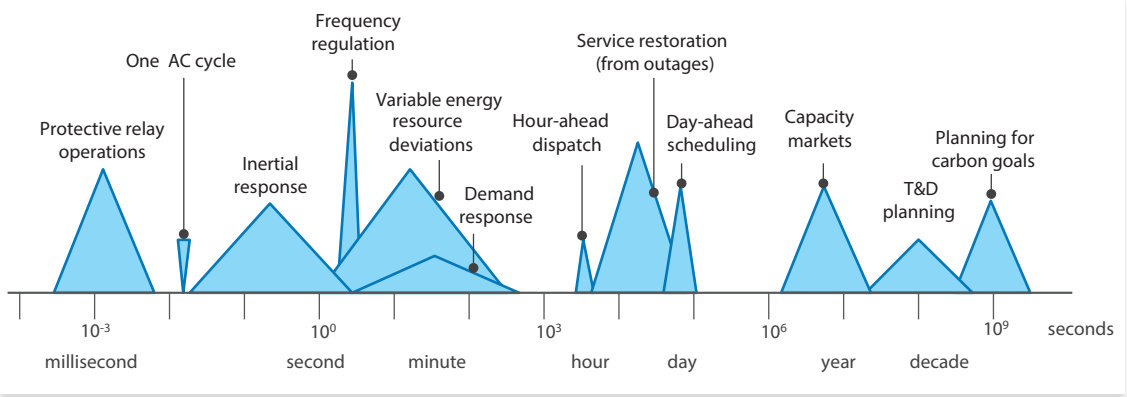
By their nature, system effects cannot be defined nor observed by looking at a single system but can be understood and quantified only by comparing two or more systems, and their quantitative estimation depends on the choice of the reference system ("benchmark"). As an example, the introduction of a given amount of VRE capacity in a given system, for example 10 GW of onshore wind, would cause a change in that electricity system in the long term: more transmission would be needed (or a different structure of the transmission grid) as well as a different generation mix, more adapted to accommodate the characteristics of wind generation. The quantification of system effects due to the introduction of these 10 GW is possible only by comparing the new generation system with the "benchmark" system, in

14. This discussion focuses on markets without CO_2 emission penalties or the like. In the EU, because of the EU-wide ETS, the explanation given here may apply locally (in certain countries) but the overall CO_2 emissions within the EU are unaffected by these effects because of the imposed cap.

which the 10 GW of wind energy have not been exogenously imposed. How the "benchmark" system is defined and how the system with wind energy is constructed and optimised are key aspects in any quantitative evaluation of system effects (additional discussions can be found in OECD, 2015). From a different perspective, the definition and quantification of system effects is simply a re-allocation of the cost difference between two systems and their attribution to different cost components.

These conceptual considerations must be complemented by the necessary conventions on how to model a large interconnected electrical grid. Ideally, calculations of system effects would require the simultaneous optimisation of the T&D networks together with that of the electricity generation system, with a time frame going from the short-term operational constraint in a range of few dozens of minutes to the long-term investment planning on new generating capacities and on T&D infrastructure (see Figure 7 for an illustration). The numerical capabilities of existing tools, of course, do not allow such comprehensive calculations and existing power system models can represent only some aspects of the whole system and are therefore able to capture only limited impact groups at once. Different models will help to solve different questions. For instance, some models are able to assess impacts on the transmission or distribution grid, while others may be able to assess the impact on balancing, on reserve requirements or on profile costs. This is all that is required in order to develop meaningful and policy-relevant conclusions.

Figure 7. **Electricity system operation and investment time scales**



Source: DOE, 2017a.

The models used in electric power generation optimisation aim to find the long-term optimal generation mix that meets a given electricity load at minimal cost, subject to a set of various technical, economic and environmental constraints. Most of the models currently in use fall into the two following categories:

- models based on LDCs (usually known as "screening curves");
- unit commitment and capacity planning models, formulated as linear programming (LP) or including some non-linearity (i.e. mixed-integer linear programmes [MILPs], dynamic programming, etc.).

Other numerical tools have been developed to address complex problems related to the generation expansion in a competitive environment, or the investment and unit commitment decisions under uncertainty. However, these more complex models will not be further addressed in this study.

Models based on LDCs have been used for decades as a simple and efficient tool for power system analysis and generation optimisation. Such methods are based on the analysis of the LDC, which is an approximation of the electricity load, generally over one year, obtained by ordering it from the highest to the lowest value. This information is then combined with the

economic characteristics of available generation capacities to derive the mix that satisfies the LDC (and hence the electricity load) at the minimal cost. While originally conceived for the analysis of systems composed by traditional, dispatchable power plants, they have been successfully adapted to a system with VRE. In these cases, a given VRE capacity is exogenously imposed into the system and the procedure described above is applied to the residual load, i.e. the electricity load minus the low marginal cost VRE generation[15]. This allows determining the cost-efficient mix of non-VRE dispatchable power plants, and thus constitutes the optimal mix in conjunction with the amount of VRE capacity exogenously given. Examples of application of this methodology are provided in Figure 4, Figure 5 and Figure 10.

Due to their simplicity, these models allow multiple calculations to be performed, taking into account the year-to-year variability of the load as well as different meteorological patterns. These models therefore incorporate the stochastic variability of VRE generation. On the other hand, by construction load duration and RLDCs lose the sequential temporal information of load, as well as that of generation from VRE and dispatchable plants. This hinders the capability of such methods to represent all the dynamic aspects of the system. For instance, these models are unable to correctly represent short-term and long-term storage, hydroelectric resources[16] as well as different forms of demand-side flexibility. In addition, it is not possible to represent correctly some aspects of the operational constraints of dispatchable generation and the associated costs. Another important challenge of these methods is their inability to model power exchanges between multiple regions, since the LDCs of different regions are not synchronous in time[17]. These models are designed to represent only a single region system, with the implicit hypothesis that all different zones within the system are perfectly interconnected (this approach is often described as a *copper plate*). Additional information on the limitations of methodologies based on LDCs and on the possible numerical improvement can be found in the work of Falko Ueckerdt, Cedric De Jonghe and Carlos Batlle (Ueckerdt et al., 2015; De Jonghe, 2011; and Batlle and Rodilla, 2013).

Unit commitment and capacity planning models based on total cost optimisation allow overcoming most, if not all of the shortcomings and limitations described above. At least in theory, such models can represent all the detailed constraints and requirements of the electric system (operating reserves requirements, for example) as well as those of individual power plants (indivisibility of units, minimum stable output levels, minimal up and down times, efficiency losses at part-load, ramping constraints and start-up costs). More importantly, these models allow for an explicit representation of all forms of storage and demand-side management (DSM)[18]. Generally, this is done assuming a perfect foresight of future demand and generation from variable sources such as hydro and VRE; this differs significantly with real-system operation in practice. From a spatial perspective, any system can be subdivided in an arbitrary number of separate regions, each of them treated as a copper plate. Then, it is possible to calculate the power flows among different interconnected regions, as well as to optimise the size of the interconnections to minimise the total costs of electricity generation within the system.

However, the size and numerical complexity of a unit commitment and capacity expansion model increase substantially with the number of variables considered and with the degree of modelling details required. For instance, a full MILP formulation with endogenous investments, a multi-region approach and a year-time representation with hourly resolution is numerically intractable even with the most advanced computational capacity available today. Depending on

15. Hence the name "residual load duration curve".
16. This includes reservoir and pump-based hydro, while run-of-the-river resources can be easily modelled.
17. Interconnection between two separate systems cannot be represented with these models, due to the loss of time dimension implicit in the load duration approach. Two consecutive points in an LDC are not necessarily close in time, and the same point in two different LDCs may also correspond to different times in a year.
18. Many models use an inelastic demand, but some models offer the possibility to include some form of demand flexibility.

the objectives of the research, some of the constraints imposed must be relaxed in order to reduce the complexity of the problem and to achieve a numerical solution in a reasonable time. Typical simplifications used are to limit the number of regions considered, to reduce the temporal size of the problem by analysing only some representative hours, days or weeks within a year, to cluster some generation units or to relax some of the generator constraints. An alternative to effectively simplifying large problems is to reduce the number of binary variables or to avoid them, thus relaxing the integer constraint. However, these techniques inevitably introduce some inaccuracies that should be carefully controlled (see Palmintier, 2012 and 2014; Abujarad et al., 2017 and Villavicencio, 2017 for further details).

Given the time required for a simulation, calculations are often limited to a single region, with a reduced time period, and assuming a given unique generation pattern from VRE and from run-of-the-river "fatal" hydro resources. For example, in the calculations performed for the present study, a unit commitment and capacity planning model is used. It has been decided to represent a two-region system with a single interconnection of fixed capacity, explicitly model a wide range of technologies including storage options and demand response, and to fully describe a whole year with an hourly resolution. This has necessitated relaxing some of the operational constraints of dispatchable generation as well as some integer constraints of the problem, thus allowing the deployment of units of fractional capacity.

Given the continuous progresses in computing power and the large body of knowledge accumulated in recent years, unit commitment and capacity planning models are becoming the reference tool for electricity system modelling and optimisation.

2.4. Representing system costs

Two different approaches have been adopted in the literature to represent and quantify the system costs of different generation technologies: the system cost approach and the system value approach. Essentially each approach aims to ease the comparison of different generation technologies by directly or indirectly complementing the information on pure generation costs with the additional costs or benefits arising from their integration into the wider electricity system (system effect analysis). A schematic description of the two approaches is provided in Figure 8. For a more complete discussion on this approach, the reader could refer to the bibliography of this Chapter (Ueckerdt et al., 2013a and 21013b; Hirth, 2015a, 2015b and 2015c; OECD, 2015 and IEA, 2016).

In a system cost approach, the different components of system costs (profile costs, balancing costs and grid costs) are added, or subtracted if negative, to the pure cost of generation, often expressed by the LCOE. The resulting metric, referred to as "system LCOE" by some researchers, allows for a direct comparison across different generation technologies. The system LCOE is often represented as a function of the penetration level, as this has a significant impact on the system costs component. By comparing the system LCOE of two or more technologies, it is possible to rank them in term of overall economic efficiency, and determine which one brings more benefits to the system.

As seen in the previous sections, the definition of system costs intrinsically implies the comparison of two different systems; their calculation therefore requires the definition of a comparison benchmark technology. The choice of a different benchmark leads to different quantitative estimates of system costs. This reflects the pure nature of system costs, which measure the opportunity costs (or benefits) of building a given technology instead of the benchmark. It is not the absolute level of system costs that carries analytical value or practical interest, but rather the difference in system costs between two technologies. System costs of different technologies can therefore be directly compared as long as the same benchmark is used.

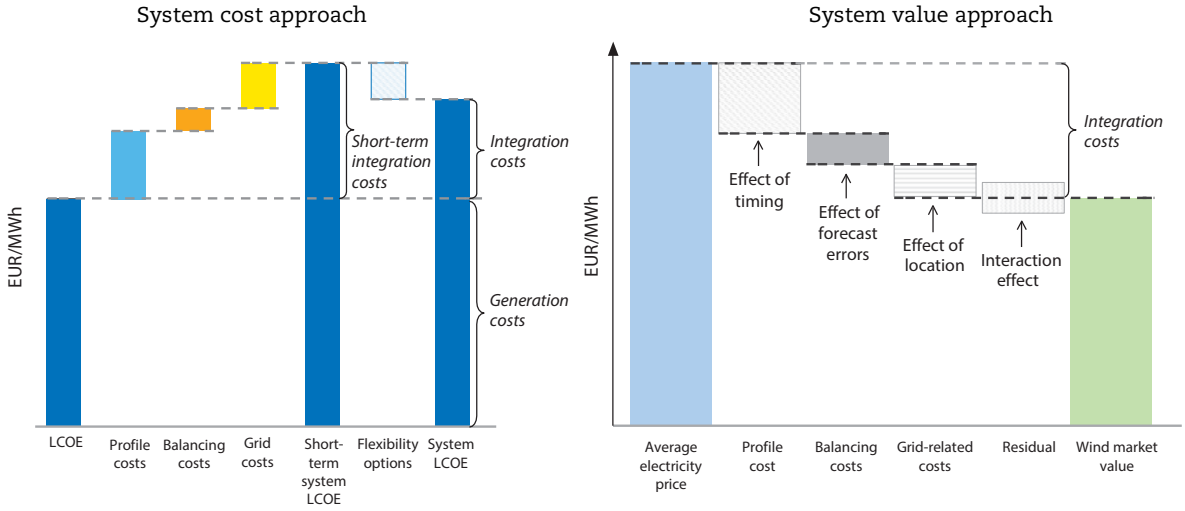
Two different benchmarks have been commonly used in the literature: a flat output profile (flat bloc) or an "ideal generator" in which the generation profile is perfectly correlated with demand. The latter choice presents some methodological advantages: i) it is simpler to calculate as the cost of the residual system declines at a constant rate with the share of

generation and ii) its application is straightforward whatever the generation share. The drawbacks of this choice are the higher level of abstraction and the system-dependency of the benchmark. On the other hand, the choice of a flat bloc is more intuitive and closer to the generation profile of a baseload dispatchable technology. However, it presents some difficulties as the cost of the residual system will not decrease at a constant rate as the share of the technology rises. This choice presents also some methodological difficulties at high penetration levels, i.e. when the capacity of the flat band exceeds the minimal load of the system.

The system value approach aims to calculate the benefits of deploying a given technology into the system, and subsequently to compare it with the generation costs of that technology. In a first step, benefits for the systems are calculated as the difference between the costs of the initial system minus that of the residual system after the introduction of that technology. Benefits include the savings from variable and fixed costs of generation technologies no longer needed as well as the positive or negative impacts in term of grid costs and balancing needs. In a second step the net benefits, expressed per unit of electricity generated, are then compared with the total long-term generation costs of that technology, i.e. the LCOE. This approach thus helps to identify whether the introduction of a given technology is economically beneficial for a system (system value > LCOE) or not (LCOE > system value). The comparison of the system value and generation costs of various technologies also provides a basis for ranking them and for selecting the most efficient for a given system.

Ultimately both approaches convey the same information and should lead to equivalent outcomes in term of deployment of the optimal generation mix (at least in the case of fully competitive markets in long-term equilibrium).

Figure 8. **Illustration of system cost and system value approaches**



Source: OECD, 2015

2.5. **Main studies and quantitative estimates available**

Although studies on system effects as an economically relevant phenomenon are relatively recent, a sufficiently rich literature is building on this topic. However, because of the intrinsic complexity of such analysis, most of the studies focus on only one or two components of system costs, and, as far as can be seen, a complete and comprehensive analysis of the system effects has yet to be performed. Also, many studies analyse and describe the impacts of large VRE penetration on the system but do not explicitly calculate system costs.

Among the relatively few studies that covered a broad spectrum of system costs can be underlined the work at the OECD by the IEA and NEA (OECD, 2015; IEA, 2011 and 2014; NEA, 2012), the comprehensive wind and solar PV integration study undertaken by Agora Energiewende (2015), a very detailed study at the European level by the French utility EDF (EDF, 2015), a study on the future power system in Belgium by the University of Leuven (Delarue et al., 2016), several studies published by Lion Hirth and Falko Ueckerdt (Hirth, 2013, 2015a, 2015b, 2015c, 2015d, 2016a and 2016b; Ueckerdt et al., 2013a and 2013b) and at the Imperial College (Strbac et al., 2015 and 2016).[19]

Almost all studies focus on the system costs associated with the introduction of VRE, and only minimal attention has been given to those associated with dispatchable technologies. The only research on this aspect was undertaken by the NEA (2012), in which the system costs of different conventional power plants was compared with those of VRE. Also, the large majority of recent studies focus on the impacts on generation mix (profile cost) or on the value of VRE generation, while research on impacts on T&D infrastructure or on balancing costs is more limited.

A survey of the literature shows a wide range of results, which underlines the difficulties of such undertakings. In particular, it should be kept in mind that quantitative results are influenced by many factors and assumptions, which may significantly differ among studies:

i. different power systems are assessed, with different shares of flexible hydropower plants;

ii. different levels of VRE penetration;

iii. different assumptions on the development, availability and cost of technologies in the future: in particular assumptions on available storage technologies, smart grids and demand response deployment;

iv. cost assessments are made in a long-term or on a short-term perspective, with different assumptions on the ability of the power system to adapt;

v. a different definition for each system cost component;

vi. different models with a different degree of complexity and different predictive capacity;

vii. different frameworks for the analysis.

However, despite these difficulties, the most recent estimates of the different system effects categories are below.

Grid costs

A major analytical effort has recently been performed in the United States and in several European countries to estimate the costs of T&D expansion associated with the deployment of VRE, with a particular focus on onshore wind.

Integration studies have been performed for the three interconnected systems in the United States, for a penetration level of VRE of about 30% (NREL, 2015). Additional grid costs are estimated within a range of USD 2 to 6 per MWh_{VRE} for PJM (GE Energy, 2012), at about USD 9 per MWh_{VRE} for the Eastern electricity system (Corbus et al., 2011), and at about USD 2 per MWh_{VRE} for the Western electricity system (Lew et al., 2013).

AGORA (2015) has quantified the additional costs for T&D in Germany based on three studies performed by the German network operator Consentec and a consulting company under the Federal Ministry for Economic Affairs and Energy. According to these three studies, transmission costs increase by about EUR 5 per MWh_{VRE} for onshore wind and solar PV, and by

19. Many studies covering only partial effects are mentioned in the following subsections.

about EUR 30 per MWh_{VRE} for offshore wind. Additional distribution costs have been evaluated in a range of EUR 6 to 14 per MWh_{VRE}.[20]

Other studies have been performed for individual countries in the European Union: in Ireland, additional costs for transmission have been evaluated in a range of EUR 2 to 10 per MWh_{VRE} for penetration rates of 16% and 59% (IEA, 2011). Holttinen et al. (2011) report values between EUR 2 and 7 per MWh_{VRE} for penetration levels below 40%. Costs from several European countries show an average value of EUR 7 per MWh_{VRE}, with large difference between the countries analysed (KEMA, 2014). Grid costs for Belgium have been estimated at about EUR 3 per MWh_{VRE} by the University of Leuven (KU Leuven) for VRE penetration levels between 19% and 35% (Delarue et al., 2016).

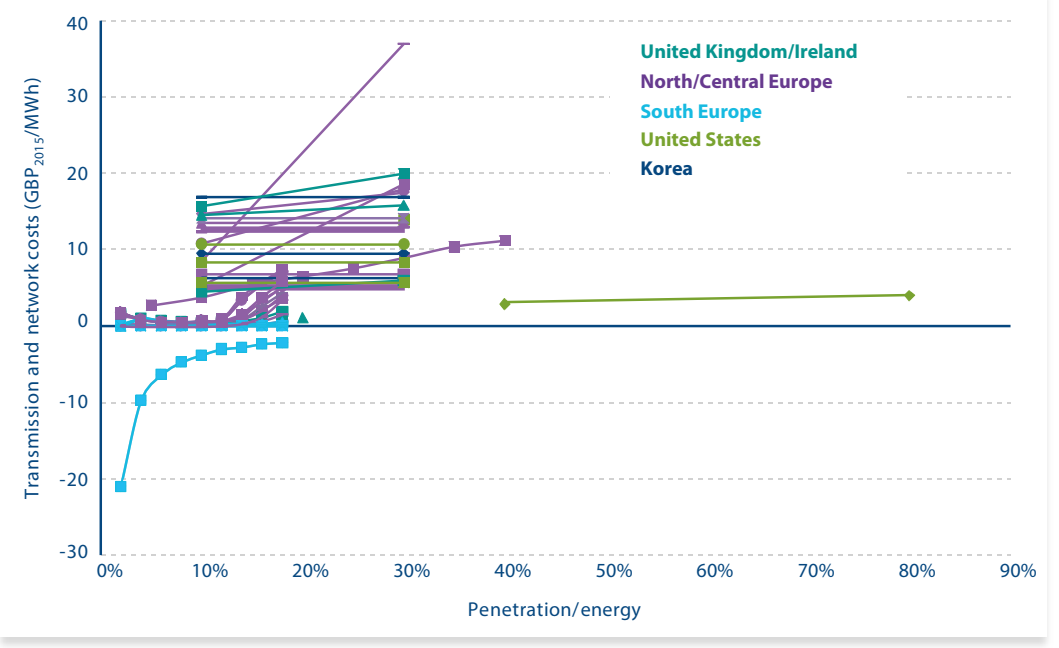
With respect to solar PV, the PV Parity Project assessed additional transmission costs at EUR 0.5 per MWh_{VRE} for 2020 that will increase to EUR 3 per MWh_{VRE} by 2030 with the increased penetration level. Reinforcing distribution network for accommodating more distributed PV resources would cost about EUR 9 per MWh_{VRE} by 2030 (PV Parity, 2013).

A study by the UK Energy Research Centre (UKERC, 2017) has collected from a variety of literature results over 250 data point on T&D costs associated with VRE deployment. The authors conclude that, with the exception of some outliers,

> "costs are in a range of GBP 5-20 per MWh, for penetration levels up to 30%. There is a grouping of very low costs (well below GBP 5 per MWh) up to a penetration level of around 15%, although many of these are from an analysis which was focused on distribution system costs."

T&D costs from this literature review are plotted in Figure 9.

Figure 9. **Transmission and grid costs as a function of VRE generation share**



Source: UKERC, 2017.

20. If not otherwise indicated, this study provides economic costs, benefits and prices in USD. However, when quoting existing studies using EUR or GBP, the original quotations are maintained. In mid-2018, EUR 1 equated to USD 1.18 and GBP 1 equated to USD 1.32.

In conclusion, quantitative estimates available on grid costs are characterised by large variations, reflecting the characteristics of each individual system, the different penetration levels analysed and whether distribution costs have been included, as well as specific methodological assumptions. However, available estimates lie in a broad range from a few USD per MWh_{VRE} up to USD 25-30 per MWh_{VRE}.

Connection costs

Connection costs, i.e. the cost of connecting a power plant to the nearest connecting point of the existing high-voltage power grid, are only seldom considered in studies of system costs, as these costs are often borne by the plant developer and thus integrated into plant-level costs. However, there are situations in which connection costs are paid by the transmission operator and thus become part of system costs. Also, connection costs are not integrated in the LCOE methodology developed by the NEA and IEA. For completeness, estimations of NEA (2012) are reported and discussed below.

Connection costs are strongly project specific and therefore exhibit a large variability across countries and among different projects within a country. However, their impact may be substantial, especially if distant resources have to be connected to the grid. In general, connection costs are higher for wind and large-scale solar PV projects[21], owing to their lower load factors and their distance from the grid network. Higher costs are expected for offshore wind, reflecting the additional complexity of connecting resources by underground cables. With respect to dispatchable technologies, nuclear power has the highest costs, mainly due to the need for two physically independent connections to the grid for safety reasons. Estimates of the NEA study, averaged over different countries, are of the order of USD 0.5 per MWh for gas power, USD 1 per MWh for coal, USD 2 per MWh for nuclear, USD 6 per MWh_{VRE} for onshore wind, USD 14 per MWh_{VRE} for solar PV and about USD 20 per MWh_{VRE} for offshore wind.

Balancing costs

While the definition of balancing costs is relatively straightforward, there are differences across different studies with respect to the elements that are accounted for and the methodologies used: i) some studies include the cost of holding balancing reserves, while others do not, ii) the definition of "short-term" varies across the studies and iii) some studies use the current market price for imbalances, while others rely on modelling data. Only a few studies have assessed the costs associated with the increased wear and tear of conventional power plants due to additional cycling.

Literature estimates for balancing costs for wind power range from USD 1 to 7 per MWh_{VRE}, depending on the penetration level and system context (Hirth, 2013 and Holttinen, 2011). In thermal-based systems, more recent estimates of balancing costs are in the range of EUR 2 to 6 per MWh_{VRE} (Hirth et al., 2015b and Holttinen, 2013), while these costs are significantly lower, i.e. less than EUR 1 per MWh_{VRE}, in a system with high hydro capacity. However, Agora (2015) notes that studies that assess balancing costs based on market data find in general higher balancing costs than those that are based on models; this reflects the fact that the price that generators pay today for imbalances are often not reflective of costs. For example, balancing costs for wind in Austria were estimated at EUR 11 per MWh_{VRE}, based on market data (e3 consult, 2014). The KU Leuven has assessed balancing costs in Belgium and Central Western Europe (CWE) for different VRE penetration levels (from 19% to 35% of solar PV and wind energy). Estimates of balancing costs lie in a range of EUR 2.1 and 4.7 per MWh_{VRE} in Belgium and between EUR 1.4 and 3.6 per MWh_{VRE} in CWE (Delarue et al., 2016).

There is a much less published research on solar PV balancing costs, but current estimates are much lower than that for wind: the PV Parity study (2013) estimates the balancing costs for solar PV in the range of EUR 0.5 to 1 per MWh_{VRE}. Finally, the increased wear and tear

21. Connection costs do not apply to distributed residential solar PV, but only to large solar infrastructure.

associated with more frequent and deeper conventional power plant cycling was the focus of an integration study conducted by the National Renewable Energy Laboratory in the United States (Lew et al., 2013). The study concluded that increased plant cycling contributed a very low additional cost, between USD 0.1 and 0.7 per MWh of VRE generation at a penetration level of 33%.

An EDF study shows that the deployment of large shares of VRE (40% of penetration level in Europe) increases significantly the exposure of the residual load to climatic conditions and their associated uncertainty. Thus, the system requires a significantly higher level of operating margins in order to ensure the same level of grid reliability. The study, however, does not provide a quantification of the associated costs (EDF, 2015; more details on this aspect are provided in Section 2.6 below).

Despite being a dispatchable technology, whose output is, short of a technical accident, predictable, some balancing costs must also be attributed to nuclear energy. These costs, which are below EUR 1 per MWh_{VRE}, are explained by the fact that nuclear power plants constitute the installations with the largest capacity. Electricity systems must always maintain cycling reserves according to the N-1 criterion, which means that the system must be able to continue supplying the full load, even if one plant trips. Logically, these cycling reserves are calibrated on the largest plant in the system, which happens to be nuclear. With smaller reactors, the balancing costs of nuclear, while not very high to being with, would be even smaller.

In conclusion, the most recent estimates for balancing costs lie in a range of EUR 2 to 6 per MWh_{VRE} for wind power in thermal systems, while costs for solar PV and wind power in hydro-based systems are much lower, less than EUR 1 per MWh_{VRE}.

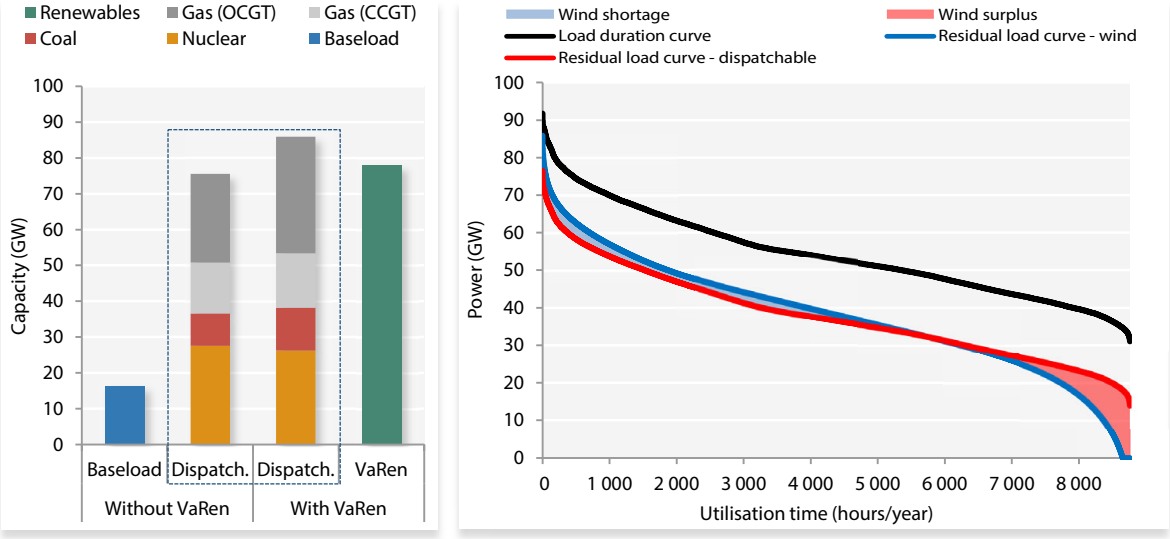
Profile costs and the value of VRE generation

In recent years there has been a significant effort to understand, capture and quantify the impacts that the introduction of VRE has on the residual load, on the generation mix and on the security of supply. In the long term, the deployment of VRE induces a significant change in the structure of the conventional generation mix, with a larger overall capacity needed and a shift from baseload technology towards peakers and mid-load capacity. In terms of electricity generated, the share of baseload generation is reduced and replaced by peak and mid-merit plants. This effect is illustrated in Figure 10, where the residual load for a system with a given capacity of VRE (wind at 30% penetration level in blue) is compared with that of system where the same amount of energy is provided by baseload capacity (30% of demand, in red): the difference between those two curves constitute the heart of profile costs. In most cases, the cost providing the residual load is higher in a system with VRE than in a system without VRE, and this cost increases markedly with their penetration level.

While there is a broad consensus about the impact of VRE introduction, the quantification of profile costs requires a significant modelling effort and results are sensitive to the establishment of a large number of parameters and assumptions. Also, the quality and precision of computational tools used have an impact on the results. For example, methods based on residual load duration curves are unable to adequately take into account the storage capacity present in the system and the potentials for DSM, thus implicitly overestimating profile costs. Furthermore, these models cannot correctly describe the technical limitations on the flexibility of all conventional power plants or take into account their associated costs; this leads to an underestimation of profile costs. These limitations are overcome, at least partially, by using more complex modelling tools, based on dispatch and unit commitment models.

Also, most studies attempt to evaluate the declining value of VRE generation with penetration level, expressed often as a fraction of the value of baseload generation, while only a few studies directly assess profile costs. As previously indicated, these two metrics essentially describe the same effect, and the findings of the different studies are coherent in this respect. However it is not straightforward to translate an estimate of “value” of VRE generation in terms of “profile costs” and vice versa.

Figure 10. **Comparison of residual load duration curves with and without VRE**



Source: Based on NEA, 2012.

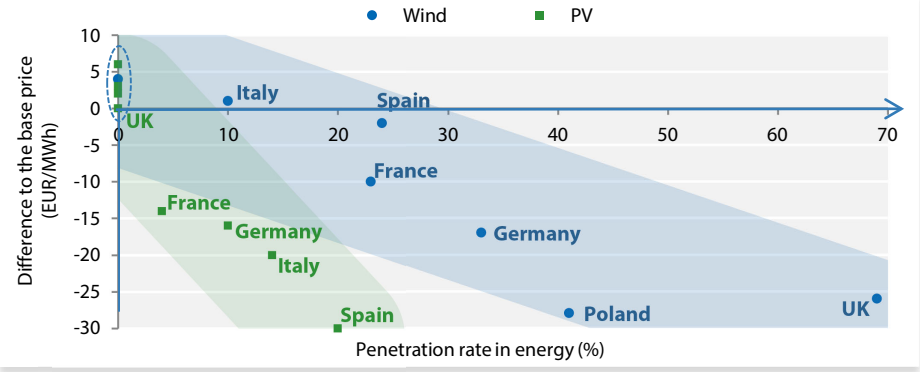
Few estimates of profile costs are available in the literature, but all suggest that they are considerable, especially at high VRE penetration levels: the NEA and IEA provided very similar estimates for wind power using a model based on residual load duration curve; values lie in a range of 4 and 10 USD/MWh_{VRE} at 10% and 30% penetration levels (IEA, 2014 and NEA, 2012). The results for solar PV show a wider range, maybe reflecting the analysis of different systems: for the two penetration levels of 10% and 30%, IEA estimates are in the range of 4 and 15 USD/MWh_{VRE}, while the NEA results lie in a range of USD 13 to 26 per MWh_{VRE}. Other estimates of profile costs have been obtained using a dispatch model (Hirth, 2013), or derived from a literature survey (Ueckerdt et al., 2013). At very low penetration levels (a few percent of demand) marginal profile costs are small and could be positive or negative depending on the correlation between wind generation and demand. For wind power at 30% penetration level, marginal profile costs are estimated at about 30 EUR/MWh_{VRE} for Germany and between EUR 14 and 35 per MWh_{VRE} for North Western Europe. Overall, a broad survey of about 30 studies of profile costs estimates long-term profile costs to be between EUR 15 and 25 per MWh_{VRE}, for wind at 30% penetration level (Hirth, 2013). In the case of solar PV, most of the studies directly calculated the value of solar generation without directly assessing its profile costs. The University of Leuven (Delarue et al., 2016) has estimated profile costs in a range of EUR 3.3 and 8.4 per MWh_{VRE} for Belgium and between EUR 6.5 and 12.6 per MWh_{VRE} for CWE, assuming a combined solar PV and wind penetration rate between 19% and 35%.

Many studies[22] express the same concept by introducing the concept of "value of VRE energy" relative to a baseload technology: it is expressed either in relative terms, as the ratio of the market price seen by VRE and the average price seen by a baseload technology, or in absolute terms, as the difference between these two prices (an example of the latter is shown in Figure 11). The market value of VRE represents the total remuneration that a VRE power plant receives from the market assuming that the electricity price is the cost of the marginal technology called upon. Under the hypothesis of a perfect market, this price represents the value to the system of the electricity generated. For the first unit of electricity produced by VRE, the market value can be higher or lower than the electricity base price, depending on the correlation between VRE generation and demand; this correlation is in general positive for

22. For instance one could look at: Fripp et al. (2008), Gilmore et al. (2014), MIT (2015), Clò et al. (2015), Green and Léautier (2015), Levin and Botterud (2015), Sivaram and Kann (2016), Denholm et al. (2016), Hirth (2016a), Welisch et al. (2016), Winkler et al. (2016).

solar PV, since normally electricity demand is higher during the day when solar PV is generating. However, the market value of VRE decreases quickly with the scale of their deployment. This effect is caused by the fact that a VRE generator is likely to produce when other VRE generators are also generating, thus reducing the value of electricity. Conversely, electricity prices tend to be higher when VRE are not producing, since there is less electricity supply in the market. All studies surveyed show that the market value of VRE decreases significantly with penetration level and such decrease is more significant for solar PV than for wind power since solar PV generation is concentrated around a few hours in the day.

Figure 11. **VRE value in comparison to base price per country**



Source: EDF, 2015.

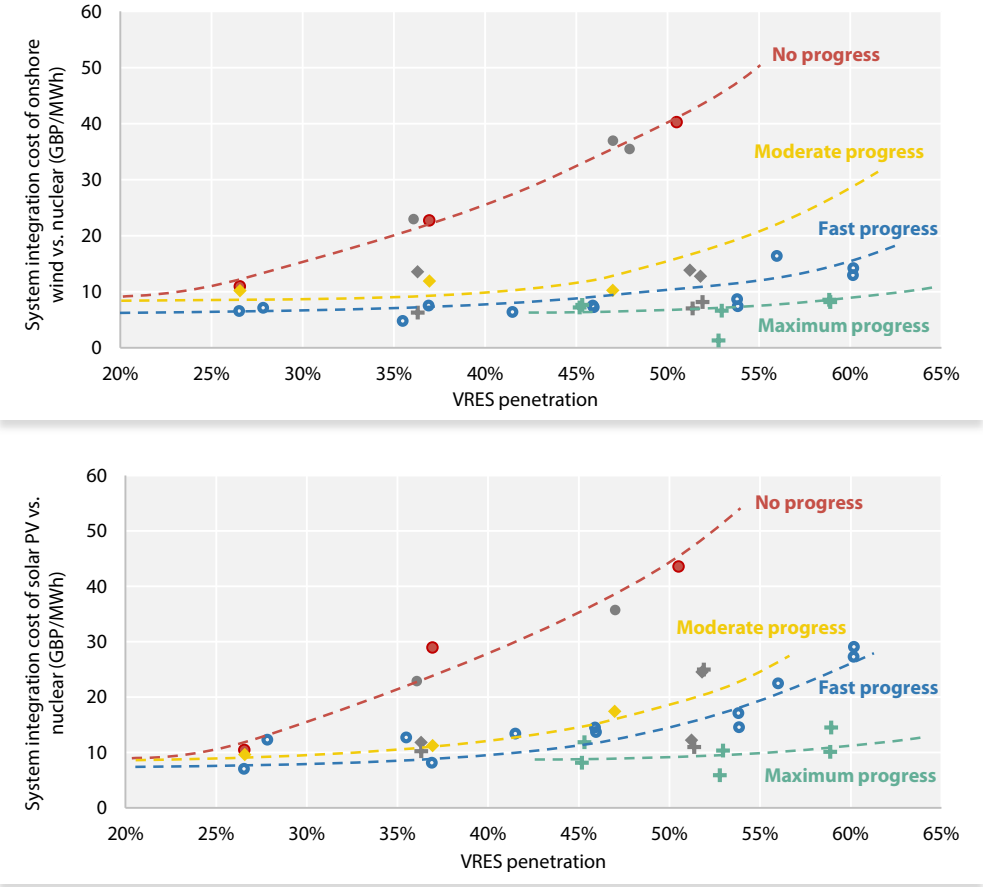
Note: The chart shows the difference between the yearly baseload price, calculated as the time-average system marginal cost, and the market revenue of wind and solar PV.

A thorough study has been performed by the French utility EDF (2015) to analyse the technical and economic implications of introducing 40% of VRE at the scale of Europe. Results confirm that the difference with baseload price is low for the first MW of wind energy or solar PV installed, ranging between +6 and -1 EUR/MWh$_{VRE}$ depending on individual countries characteristics. On the contrary, this gap becomes important if a broad European target of 40% of VRE is achieved. Country-specific trends for solar PV and wind are illustrated in Figure 11. Similar results have been shown in Hirth (2013) by modelling several countries in Continental Europe (France, Germany, Belgium, the Netherlands and Poland). The value factor for wind power, initially about 10% above the market price, decreases significantly, reaching 65% of the baseload price at 30% penetration level. These numerical findings are backed by a review of literature studies and by an analysis of historical data in different European markets. More recent analysis shows that the value factor loss is slightly less pronounced for more flexible systems, with significant hydro resources (Hirth, 2016a). Higher drops are featured for solar PV, for which the value factor decreases more dramatically, reaching about 60% of baseload costs at a penetration level of 15% (Hirth, 2015c). Quantitative analysis performed within the present study confirms this trend (see Chapter 3): in a highly flexible system, the value factor for onshore wind reaches about 80% and 70% of baseload at 30% and 40% penetration level, respectively. Solar PV reaches 60% of baseload price at 12.5% penetration and the value sharply drops to 30% when 20% penetration level is reached.

A comprehensive study of the integration costs (system costs) of VRE in the United Kingdom was undertaken by Imperial College London in 2016 (Strbac and Aunedi, 2016). With respect to other research mentioned above, this study reports the total system cost associated with VRE, obtained as the sum of the three components identified above. Also, the study reports marginal system cost, calculated with respect to a system where the last (marginal) unit of VRE is replaced by nuclear. Results are provided for a reference scenario, with different

deployment levels of VRE (corresponding to different targeted years and carbon intensity levels of the system). In these reference scenarios, system costs for onshore and offshore wind vary in a range of USD 10 and 16 per MWh[23], for a combined generation share of 13% and 40%, respectively. For solar PV, system costs are in a range of USD 13 and 19 per MWh, for a penetration level varying between 2.5% and 5.5%. The study indicates that a key parameter for the level of system costs is the availability of flexibility in the system, in terms of new storage capacity, additional interconnections or demand-side response. Several scenarios with different levels of flexibility are therefore compared to the reference case in 2030. System integration costs vary in a wide range: for onshore wind they vary between 54 USD/MWh_{VRE} (no flexibility) and 9.7 USD/MWh_{VRE} (maximal flexibility), compared to a level of 10.1 USD/MWh_{VRE} in the reference case. For offshore wind system costs are in the range of USD 65 and 7.5 per MWh_{VRE}, compared to a reference value of 10.5 USD/MWh_{VRE}. Finally, for solar PV system costs are estimated between USD 59 and 11 per MWh_{VRE}, compared to 19 USD/MWh_{VRE} in the reference scenario. The results of the Imperial College London study on system costs are summarised in Figure 12 for onshore wind and solar PV.

Figure 12. **System costs for wind (up) and solar PV (bottom) as a function of penetration level and progress on flexibility**



Source: Strbac and Aunedi, 2016.

Note: The different colours represent the different assumptions about the level of flexibility in the system; from "No progress" to "Maximum progress".

23. The original results have been converted in USD using an exchange rate of 1.35 USD/GBP.

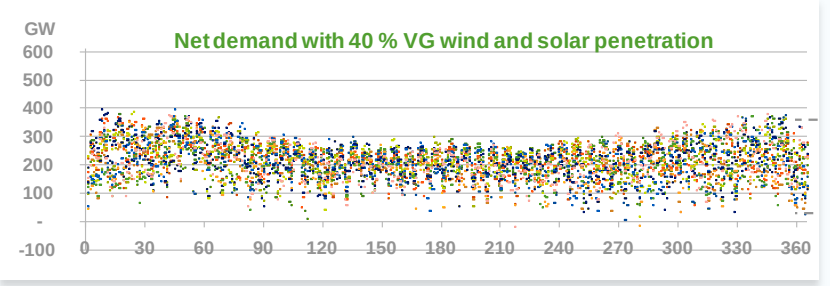
Box 2.3. Residual load becomes more weather-dependent and shows a significant year-to-year variability

Even when aggregated at a continental scale, VRE generation varies significantly in different time scales: variations in a very short time scales, daily and seasonal variability as well as inter-annual variability, i.e. change in yearly electricity generation across different years. An illustration of these phenomena for Europe was provided in Section 2.2 (see Figure 2). If significant penetration levels of VRE are sought, the variability of VRE generation has a direct impact on the residual load, which becomes also more and more variable, less predictable and dependent on climate conditions. This accrued variability and dependence has also important impacts at different time scales.

The EDF study has analysed the variation of VRE generation, and the related variations in residual demand, for the European system for a VRE penetration level of 40% over a sample of 30 years (EDF, 2015). Large short-term variations in the residual electricity demand occur more frequently, and their maximal extent is larger with respect to the demand. The study assessed a doubling of the occurrences of upward hourly variations in excess of 20 GW and of the occurrences of downwards variations in excess of -10 GW. Extremely hourly variations above 70 GW that do not occur in demand can be observed in residual demand. The electricity generated by VRE at the European level may vary by 5 TWh across different climate years, depending on weather conditions. This variation is equivalent to a daily power change of about 200 GW, i.e. 90% of the residual electricity demand (Figure below). By comparison, the maximal difference in electricity demand across the years due to the temperature is no more than 2 TWh in winter, and of about 0.7 TWh when averaged across the entire year.

The deployment of a large share of VRE significantly increases the dependence of the residual load on the climatic conditions as well as its associated short-term uncertainty and predictability in the medium term. The study concludes that the system will require a significant increase of operating margins to face this challenge, but it does not quantify its economic impacts.

Inter-annual variability of residual demand (average daily demand, GW)



Source: EDF, 2015.

The intra-annual variability of electricity generation by VRE and other RES (renewable electricity sources) has also a direct impact on the level of electricity wholesale market prices and on the revenue volatility for all generators. For instance, in a given year the annual generation from wind can vary by ±15-20% compared to the average level. Similarly, the generation level of hydro resources varies significantly across the years, depending on the level of precipitations occurred ("wet" vs. a "dry" year). In a "wet" year with abundant wind generation, average electricity prices are pushed downward and all generators will have lower revenues from electricity market sales. Conversely, prices and revenues will be higher in a year with reduced generation from low marginal cost wind and hydro capacity. The magnitude of these effects increases with the cumulative deployment of wind and hydro resources. While these phenomena tend to compensate in different meteorological years, there is an increase on revenue volatility, and hence, on the investment risk perceived by market participants. Some quantitative estimates of these effects are available (NEA, 2012: appendix 7.B).

Adequacy of the generation system and the concept of capacity credit

The adequacy of an electricity system measures the ability to satisfy future demand at all times, taking into account the fluctuations of demand and supply and reasonably expected outages of the system components, and projected construction and retirement of generating capacity. Each component of an electric system cannot be guaranteed to be available all the time, as power plants and other equipment undergo maintenance periods and there is always the risk of a technical failure in one or several system's components. Therefore, in practice, no power system can guarantee to be able to serve all requested load in all circumstances. To remain within acceptable economic limits, most power systems operate with a targeted level of reliability, which will reflect an acceptable probability that some amount of load will not be served during some periods. With respect to generation capacity, all power systems, therefore, maintain a total amount of capacity exceeding the expected maximal level of demand by a given fraction, referred as a reserve margin.

With respect to generation plants, the capacity credit is often used to measure the relative amount of load that can be reliably ensured by the power plant. The capacity credit of a power plant is defined as the additional load that can be served following the deployment of an additional unit of a specific generation technology to the system while maintaining the same level of reliability (Keane et al., 2011). In practice, however, the effective calculation of the capacity credit of a plant is a very complex undertaking which requires the use of advanced stochastic modelling and a detailed description of the entire electricity system.

The capacity credit is generally expressed as a percentage of the nominal power plant capacity: a capacity credit of 60% for a power plant of 500 MW means that, statistically, the plant can assure the system a firm capacity of 300 MW. Intuitively (and simplistically) it can be seen as the capability of a power plant to be available when the system needs it most, i.e. generally when the load is highest. Again, in a very schematic way and neglecting the ancillary services, one can see each generator contributing two main services to the system: the electricity produced during a reference time period, a year for example, and available capacity when the system needs it most. The load factor is a direct measure of the first service, while the capacity credit measures each plant contribution to the second, i.e. its ability to generate when most needed. In this respect, the ratio between the capacity credit and the load factor is a more meaningful metric for comparing different generation technologies.

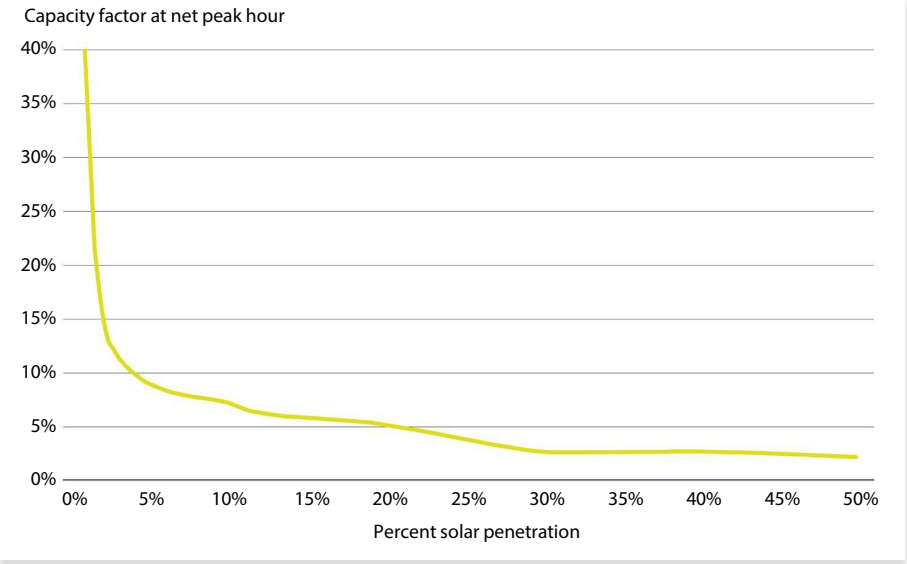
In general, the capacity credit for dispatchable plants is of the same order of magnitude or higher than the maximal achievable load factor (sometimes referred as availability factor): this is because planned outages are normally scheduled during periods of weak electricity demand, while keeping plants available during periods of high demand. But, the load factor of dispatchable plants varies strongly depending on their role in the overall electricity system: it is high for baseload plants and may be very low for peaking plants. In this respect, the ratio between capacity credit and load factor is an indication of the role of a plant in the system. A higher value indicates a peaking plant, which is able to provide the power when needed: the role of such plant is mostly to ensure the "capacity" to the system. A value close to one indicates a baseload plant, for which the main service to the system is the electricity generated.

Compared to dispatchable technologies, the capacity credit of VRE and its ratio to the load factor varies in a much wider range, reflecting the different contribution to the system adequacy and the different services it can provide to the system. In general, the level of capacity credit of additional VRE capacity depends on several parameters such as their correlation with periods of peak (net) electricity load, their generation variability and the level of targeted security of supply.

At very low penetration rates, the capacity credit of VRE varies across in a wide range, mostly reflecting the correlation of their output with peak demand. While capacity credits for wind plants are usually close to their load factor, those for solar PV can vary in a wider range. For solar PV, it is reported to be as high as 38% (PJM, 2010) in extremely favourable cases, and may be close to zero if the output is low or even zero at times of peak demand (for instance when peak demand occurs in the evening). Reported capacity credit values for wind power vary in a wide range from 40% of installed capacity to 5%, depending on penetration level and power system (Holttinen, 2013). The German federal network agency (Bundesnetzagentur) attributes a capacity credit of zero to solar PV in its reliability calculations.

VREs have the peculiar characteristic that their capacity credit decreases with their penetration level since any new VRE capacity added to the system tends to have a lower capacity credit than existing plants. The capacity credit of this additional VRE depends on whether its output coincides with times of peak residual load[24]. The critical point is this: the higher the level of VRE in the system, the higher the instances of peak residual load occurring when wind power or solar PV generation is low. Because additional VRE generation is correlated with existing VRE output, adding more to the system will do little to increase output during these hours. Thus, the capacity credit of VRE decreases with the penetration level, reflecting the increased correlation with its own generation[25]. The reduction of capacity credit with penetration level is much steeper for solar PV than for wind as, after a certain penetration level, any additional increase of solar PV capacity has no effect in reducing the residual peak load. Figure 13 provides an illustration of this phenomenon for solar PV in ERCOT[26] (Electric Reliability Council of Texas), where there is a very good correlation between peak demand and solar PV generation.

Figure 13. **Marginal capacity credit of solar PV in the ERCOT market in function of its share in the electricity mix**



Source: DOE, 2017b.

In conclusion, precisely due to their variability, VREs have a far lower capacity credit than dispatchable technologies, especially at high penetration levels. Thus VRE tend to have a much lower contribution to system adequacy than dispatchable plants, since only a fraction of their potential output is certain to be available at times of peak demand. As a result, other resources are needed in the system to compensate for the lower contribution to adequacy and

24. When VRE deployment is just starting, load and residual load are the same. However, at growing penetration, the capacity credit of additional VRE generation is determined by its contribution during peak residual load, which can occur at a different time than peak load itself. The reasons for this is that at high shares of VRE, periods of capacity scarcity tend to be increasingly driven by the absence of VRE generation rather than by the level of electricity demand.
25. A graphical explanation of this phenomenon is provided in (OECD, 2015: p. 176; NEA, 2012: p. 112 and IEA, 2014: p. 75)
26. ERCOT (Electric Reliability Council of Texas) is an independent system operator in Texas (United States) serving more than 25 million customers.

to maintain the targeted reliability level of the system. This is also shown by the analysis of the ratio between capacity credit and load factor, which is generally much lower than one for VRE, indicating that VRE contribute to the system more in terms of electricity generation than in term of firm capacity.

Box 2.4. Cost of flexible operation in thermal power plants[27]

Several studies of VRE integration and empirical observation have shown that deployment of VRE is inevitably accompanied by increasing flexibility needs from the electricity system and additional cycling requirements from conventional, thermal-based power units. These requirements increase substantially with the penetration level of VRE: as the residual load becomes more and more variable and less predictable, more reserve requirements are needed. A more flexible operation from thermal plants means more frequent and steeper power gradients, an increase in the number of shutdowns and start-ups and a more frequent operation at part-load or a power levels where the energy conversion efficiency is below the optimal. However, the technical and economic implications of more flexible operations are not extensively discussed in the scientific literature, and only a few studies have assessed the costs associated with the increased wear and tear of conventional power plants due to additional cycling. These costs are only sometimes incorporated in the economic analysis (and when included, they are only partially).

Cycling has a damaging effect on units. When a power unit varies its output, various components are subject to stresses and strains which may cause damage. During the shutdown and start-up of a plant, the boiler, steam lines, turbine and auxiliary components go through large thermal and pressure stresses, which increases the failure rate of the most exposed components, in particular high-temperature components subject to creep-fatigue interaction. Shorter component life expectancies will result in more frequent forced outages, additional maintenance costs to replace components and may lead to a shorter than expected plant lifespans. These effects may not be noticed immediately by the plant operator and may not be attributed to cycling. The DOE report (2017b) notes that these effects may impact the financial viability of generators and that the failure to recognise the full costs of cycling may lead to sub-optimal unit commitment and dispatch decisions. In addition, cycling imposes other "direct" costs to the plant operator, but these costs are generally well known and reflected in unit commitment decisions. The direct start-up costs, i.e. the costs for additional fuel, carbon emissions and auxiliary services associated with each start-up. In addition, operating at power level outside the range for which the plant has been designed and optimised has a negative impact on its thermal efficiency, which increases fuel costs and carbon emissions.

While sufficient information is available on the technical cycling data of thermal power plants (see for example NEA, 2011 and Van den Bergh, 2015), less information is publicly available on the economic costs of cycling. A comprehensive analysis based on the operational experience of several hundred plants in the United States has been performed by Intertek APTECH for the US National Renewable Energy Laboratory to assess the cycling costs for different types of coal and gas plants (NREL, 2012)[28]. The cost estimates show a large variation depending on the type and size of the plant, on its age, whether the plant was designed for more flexible operations or as baseload, and on the operation and maintenance (O&M) history and procedure. Also, (DOE, 2017b) indicates that it is possible to retrofit a power plant to improve its cycling capabilities. Much fewer data are available for nuclear, as these plants are designed for baseload operations and are allowed to operate in a cycling mode in only a few countries. However, in some countries nuclear units were designed to operate in a flexible manner and their flexibility performances are close to those of coal plants. From an economic viewpoint, different studies have observed a reduction between 0.7% and 1.8% in the availability rate of nuclear plants operated in a load-following mode, while no statistically significant effect was observed on fuel failure rates or on the main components (NEA, 2011 and 2012).

27. The contents of this box is based on (Van den Bergh, 2015; NREL, 2012; Lew, 2013 and DOE, 2017b)
28. This analysis provides for low-bound and high-bound estimated of cycling costs, but unfortunately only the former set of data is publicly available.

Box 2.4. **Cost of flexible operation in thermal power plants** *(cont'd)*

Very few studies have attempted to evaluate the costs associated with increased wear and tear of conventional plants due to the integration of VRE. An integration study conducted by the National Renewable Energy Laboratory in the United States has concluded that deploying VRE at 33% penetration level leads to an increase of cycling cost of s between 13% and 24%. However, increased plant cycling added a very low overall additional cost: at a penetration level of 13%, the additional cost was estimated to be between USD 0.4 and 1.0 per MWh_{VRE} of VRE generation. Surprisingly, at a higher VRE penetration level of 33%, specific integration cost decreases to a USD 0.1-0.4 per MWh_{VRE} range (Lew et al., 2013).

2.6. Impact on the reliability of the electricity system

The introduction of VRE plants into the electricity mix and the consequent evolution of the generation mix, together with the evolution of consumer electricity usage patterns, has an impact on the operational procedures to guarantee the reliability of the electricity system. While operators have so far kept up with all those factors by improving and modernising the grid and the way in which it is operated, there is a growing concern that the impacts of high penetration levels of VRE may have on the overall reliability of the system. Among the main factors that have improved the grid resilience[29], there are the development of more IT and analysis capabilities, the improvement of the forecasting tools for VRE generation predictions, the adaptation of better integration codes and requirements for VRE, and the improvements in electricity markets.

The reliability of the electricity system may be defined as its capability to satisfy the electricity demand at all times with a high level of continuity and quality. The concept of reliability operates at different time scales and encompasses the concepts of security and adequacy of the system. System security (also referred to as operating reliability) is the ability to withstand sudden short-term disturbances such as operational transmission failures, unanticipated losses of generating units, changes in load conditions and other contingencies, as well as human errors. System adequacy looks at the ability of a system to satisfy the load in a much longer timescale, taking into account projected demand, the planned retirement of old infrastructure and construction of new assets. It comprises both the ability to generate the power required by customers (referred to as generating adequacy) and that of transporting it to the actual customer load points (transmission adequacy).

Much work has been recently devoted to analyse the overall reliability and resilience of future electricity systems which are characterised by a rapid expansion of variable renewable resources. This is a very important and highly technical issue, for which much work has been published and is currently ongoing (see for instance Delarue et al., 2016; DOE, 2017b; EDF, 2015; IEA, 2014 and 2016; Shakoor et al., 2017; and Strbac et al., 2012 and 2015). Some of these aspects are discussed below, with the simple purpose of clarifying these issues and without any attempt to monetise them.

Synchronous vs. non-synchronous generation

All thermal power plants and some other renewable resources share a similar basic principle; they convert mechanical rotational energy, originated from different sources, into electricity, and are connected to the grid via a direct electro-mechanical interface. Every generator within

29. The Institute of Electrical and Electronics Engineers (IEEE) uses the following working definition for the "resilience" of the electric power system: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event" (IEEE, 2018).

the same synchronous system rotates at the same speed, which corresponds to the frequency of the system (50 or 60 Hz in OECD countries). For these reasons, these technologies are indicated as "synchronous" technologies. The heavy rotating components connected to the shaft of the synchronous generator (rotors, turbines and other masses) store a large amount of kinetic energy and thus collectively provide physical inertia to the system[30]. On the contrary, wind and solar PV instead are connected to the system via power electronic convertors or invertors. They are referred to as "non-synchronous" technologies to differentiate them from conventional "synchronous" technologies. The lack of direct electro-mechanical interface with the system limits the ability of non-synchronous technologies to provide important services to the system, such as inertia and reactive power[31, 32].

The total inertia present in a system directly affects its dynamic robustness. The amount of energy required to change the speed of rotating parts, and hence the frequency of the synchronous system, is directly proportional to their mass (and the square of their radius), i.e. to their inertia. As a consequence, the same in balance in electricity demand and supply will have a greater impact on the frequency of a system with low inertia than a system with higher inertia. Thus inertia helps to keep the grid frequency at a stable level, as it slows the rate of frequency drop after a major grid event (disconnection or trip of a large generator), and provides more time to restore frequency at its required level. Symmetrically, it limits the frequency spike following a disconnection of a large load. More detailed information on the importance of inertia in power systems and other relevant metrics can be found in the bibliography of this chapter (Thielens and Van Hertem, 2016; Eto et al., 2010 and 2018).

The deployment of VRE resources directly reduces the natural or intrinsic system inertia, with possible adverse consequences on the overall dynamic robustness of the system. While the large electricity systems of most OECD countries have today a sufficient level of inertia to integrate low to moderate levels of VRE resources without impairing the system's reliability, the question of the overall robustness of the system becomes more important when the overall inertia is low, i.e. for a smaller system, when the electricity demand is low and when the instantaneous penetration level of VRE is high. A study by the French utility EDF (EDF, 2015) has shown that a large well-interconnected synchronous system such as Europe is sufficiently robust to accommodate a significant share of non-synchronous resources, up to 40% of VRE penetration. However, dynamic simulations have shown that the reference incident leads to a frequency drop which violates the current security limits of 49.2 Hz in 25% of circumstances; in about 1% of the scenarios analysed, the reference incident leads to a frequency drop below 49 Hz, triggering load shedding. The study concludes that the most critical periods for frequency stability are those when demand is low, even at moderate instantaneous penetration levels of VRE. On the contrary, fewer problems are observed during periods of high demand even at substantially higher levels of instantaneous VRE penetration.

Similar conclusions were reported by the IEA (IEA, 2014) citing two studies for Ireland and Germany (Eirgrid/SONI, 2010 and Consentec, 2012). In 2010, the Irish system could manage up to 50% of instantaneous non-synchronous generation, including wind generation and net imports from DC interconnection[33]. However the study indicated a level of 75% of instantaneous penetration could be achieved with changes to the system infrastructure and operational policies. The German study found that a minimal amount of conventional generation was needed in the German system as a number of system services were only provided by

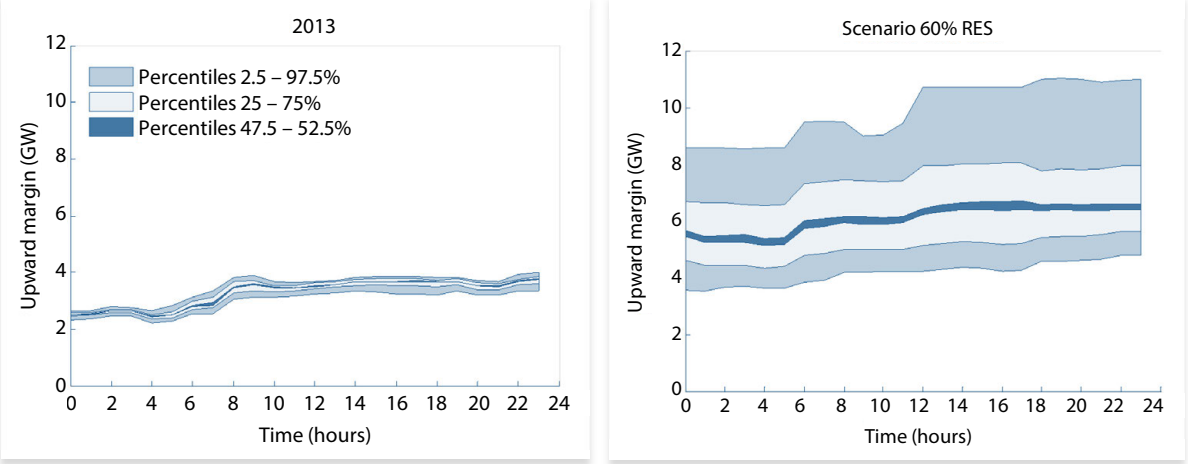
30. Note that also electricity demand may contribute to some inertia to the system, as spinning masses of motors may store some kinetic energy as well.
31. As already mentioned above, it might be possible in the future that synthetic inertia can help. See Kroposki et al. (2017) and Ackermann et al. (2017) for recent developments and long-term aspirations.
32. Note that Direct Current (DC) lines are unable to provide inertia services and behave as non-synchronous resources; the HVDC converter stations are capable of providing reactive power control.
33. Currently, the system in Ireland limits the level of non-synchronous generation below 65%, but tests at 65% have started in November 2017 (Eirgrid/SONI, 2018).

conventional generation[34]. The minimal conventional capacity reported varied between 4-8 GW and 12 and 16 GW depending upon the amount of load and wind generation. A common conclusion of all these studies is that all VRE resources must contribute to the provision of ancillary services, frequency regulation and to new services such as synthetic inertia are required to reach higher VRE penetration levels.

VRE generation forecasts and balancing requirements at high VRE generation share

Many studies conclude that improving the accuracy in forecasting solar PV and wind generation has a major role to play in reducing the requirements for the operating margins and operating reserves needed to maintain the balance between electricity demand and supply in the short term. Solar PV and wind generation forecasts become increasingly more accurate the closer they are to the time of delivery: forecasting uncertainties are therefore significantly lower in an intraday horizon (i.e. few hours before the delivery) than on a day ahead or a few days before the delivery. Also, the aggregation of forecasts over a larger area, at a national scale for example, tends to be more accurate than prediction at a site generation level or if aggregated over a smaller area. For instance, EDF reckons that the VRE forecasting error at the level of a site is 3 to 4 times higher than that at the level of France (EDF, 2015). Many studies have also observed that the use of improved and more sophisticated meteorological tools and the experience gained in VRE generation forecasts has sensibly reduced VRE generation forecasting errors in recent years.

Figure 14. **Day-ahead upward operating margin for France in a typical summer day**



Source: EDF, 2015.

EDF has shown that integrating a large share of VRE in the European system requires a significant increase in the level of upward and downward reserves, due to the uncertainty in solar PV and wind generation (EDF, 2015). In France, reaching a 30% share of VRE would increase the level of operating reserves by a factor of three or four compared to the current level. This trend is illustrated in Figure 14 above, which compares the upward operating reserves required in the current system (left) to that would be needed in a system with 60% RES (right). A similar trend is observed when analysing downward reserves. Operating reserves

34. In the meantime, in some places (e.g. in Germany the shutdown NPP Bibilis-A) "older" synchronous electrical generator machines (alternators) are now operated as zero-load synchronous motors for the sake of providing classical mechanical inertia. They are then referred to as "synchronous condensers" (whereby they can also assist in reactive power control for voltage stability). See for example (Deecke, 2015).

in systems with low VRE deployment are due to the uncertainties on demand and hydroelectric generation as well as on generation outages. In scenarios with higher VRE shares, the level of operating margins and reserves are related mostly to the generation share of VRE. However, despite assessing the increased operating reserves requirements linked to the VRE generation share, the study does not quantify the additional costs associated.

2.7. Role of storage and other flexibility options[35]

There is little disagreement among experts that flexibility is an essential element to managing the variability of solar PV and wind resources, and that significant investments in flexible resources are needed in order to reach a significant share of VRE in the generation mix. System-wide flexibility has been defined as "… the ability to adjust generation and consumption in the presence of network constraints to maintain a secure system operation for reliable services to consumers" (Shakoor et al., 2017). This general definition however hides the fact that different energy system constellations might have very different flexibility needs over different time frames. Recent work from the Imperial College of London indicates that "the system integration costs of low-carbon technologies will significantly depend on the level of system flexibility" and that "very significant costs savings can be made by increasing the flexibility of the electric power sector" (Strbac et al., 2015 and 2016) (a quantitative representation of these effects is provided in Figure 12). A DOE study recognises that "a grid with higher levels of VRE and more dynamic customer loads will need more of the services that energy storage can provide by acting on both the supply and demand side, including energy, capacity, energy management, backup power, load levelling and essential reliability services, over periods from seconds to hours or days" (DOE, 2017b).

Flexibility needs cover a wide time range spanning from fractions of a second, minutes and hours to days, weeks, seasons or even years. According to their technical abilities and cost profiles, in particular the ratio of fixed to variable costs, different technologies will be employed to answer different flexibility needs. A nuclear power plant is unlikely to bid on the balancing market where power needs to be provided in a 15' or 30' time frame, but it can very well adjust its output to demand variations over the day or the week. The IEA has identified six different time scales to characterise different flexibility services and requirements (IEA, 2018), which can be grouped into three broader categories:

1. Short-term flexibility, with a timescale ranging from sub-seconds to hours. It broadly covers different issues for the electricity system: i) system stability, i.e. the ability to reduce the frequency drop following a large disturbance from the demand or the supply and to re-establish the desired frequency level, ii) the ability to address short-term fluctuations on the demand/supply balance and iii) manage ramps in the load as well as in the supply from VRE resources.
2. Medium-term flexibility, which is related to the determination of operating scheduling of the generation resources on a time frame going from hours (hourly markets) to days (day-ahead market).
3. Long-term flexibility: It addresses the issue of longer periods of surplus or deficit of generation (from hydroelectric resources and VRE) and demand, due to particular weather conditions. Particular weather conditions can have a strong impact on both demand (heating or cooling) and generation from VRE in a time scale of several days to months. On a longer timescale seasonal or even inter-annual variations are also observed in demand level or in generation from hydroelectric resources and VRE.

35. Manuel Villavicencio, from Université Paris Dauphine has largely contributed to this section. In the present context, the flexibility has been dealt with at a level consistent with the modelling requirements of this study. For further in-depths discussions, in particular on the contributions of storage and the increased ramping ability of nuclear power plants to the flexibility resources at the system level see also de Sisternes et al. (2016) and Jenkins et al. (2018).

Broadly speaking, five different technological options are identified as potential sources of flexibility and system services:

- Flexibility from the conventional power plants: Conventional generation currently provides the majority of flexibility and system services in the power systems of all OECD countries. Conventional technologies are constantly improving their operation characteristics in terms of achieving faster and larger power output swings, operating at lower minimal stable power levels and allowing for shorter start times. Additional flexibility from the conventional generation mix can be achieved by shifting the investments towards more flexible technologies. Additional information on power plant flexibility can be found in the work of the IEA (IEA, 2018).
- Network development and cross-border or interstate interconnections: The creation of a larger electricity system as well as grid digitalisation has a direct benefit of less correlated demand and generation infeed from renewables, thus leading to a flatter and less variable residual load. A larger system also benefits from mutualising ancillary services and backup resources.
- Electric energy storage (EES) technologies: A few storage mechanisms, such as pumped hydroelectric storage and thermal energy storage, are used in the traditional electricity system to shift energy demand from peak to off-peak periods, thus levelling the residual load seen by conventional plants. Electricity storage has also contributed substantially to balancing the system, providing ancillary services and network management. Electricity storage technologies can provide multiple services to the system, ranging from very short to very long timescales such as seasonal storage (IEA, 2018). Today, it is mainly composed of pumped hydro storage units. But, the promising cost declines due to learning effects of different types of batteries, compressed-air energy storage and fuel cells, open emerging prospects for energy storage on the next years. The scale of the facility and their sitting location are important parameters differentiating EES technologies on different categories like bulk, distributed, or even behind-the-meter. There is a growing consensus among researchers that even at current capital costs levels, EES can break even if they are properly rewarded for the multiple services they provide to the system (World Energy Council, 2016)[36].
- Demand-side response (DSR): DSR is the capacity of users to adapt or redistribute their consumption in response to changes in the state of the system. These DSR schemes have a significant potential to provide different types of flexibility services across multiple time frames and system sectors, from providing primary frequency response to facilitating network congestion management (Shakoor et al., 2017). Flexibility from DSR programmes is mainly distributed, with a certain degree of concentration in the case of industrial consumers capable of rescheduling generation processes.[37] The effective deployment of demand-side flexibility requires the development of advanced metering infrastructure and communications. It might be market-based by the introduction of dynamic rates, so informing customers of price changes some time in advance of consumption, or incentive-based, enabled by penalties or rebates on prices during specific moments. Another category often mentioned is the so-called "sector coupling" (referring to coupling the electric power system with the heating sector and/or the transportation sector). However, this is actually nothing more than a particular sort of demand management/response application.
- Operational flexibility from VRE: This category include curtailable and/or controllable renewable energy generation, that may be coupled with on-site storage capacity (e.g. PV + batteries installations), and able to follow a control signal dynamically

36. Further details on the cost and economic comparison of EES technologies can be found in: (Luo et al., 2015; Schmidt et al., 2017; Zakeri and Syri, 2015).
37. For a more comprehensive description of demand response programs the authors refer to: (Alstone et al., 2017) and (Faruqui et al., 2009).

through power system electronic and IT devices. State of the art VRE technologies can provide multiple services to the system; these include fast frequency response, upward and downward ramping and operating reserves (IEA, 2018).

2.8. Cost of electricity generation and carbon reduction targets

From a conceptual viewpoint, there is little doubt that imposing a new or more stringent constraints onto a system designed to provide a good or a service tends to increase the cost for providing that good or service. In the case of electrical power systems, imposing a new or a stricter carbon emission target will inevitably increase the costs of providing electricity to customers[38, 39]. Moreover, it is also logical to expect that the marginal costs associated with decarbonisation increase over-proportionally with the degree of decarbonisation targeted, as the most cost-effective measures are implemented first, and increasing decarbonisation goals require the adoption of more costly and often more technically challenging measures. In other words, reducing the carbon content from 100 to 50 g/kWh will be more expensive and technically challenging than achieving the same reduction from 400 to 350 g/kWh. This holds particularly true if decarbonisation is done by means of VRE rather than by means of nuclear power. The cost of the system effects of VRE increases in fact over-proportionally with their share in the system.

An MIT study has analysed a range of possible decarbonisation scenarios in the United States as a function of different carbon emission targets and of a different set of available low-carbon power generation technologies available (Sepulveda, 2016 and MIT, 2018). The study considers two power systems within the US, ERCOT and ISO-NE (Electric Reliability Council of Texas and ISO New England) which have different characteristics in terms of load curves and heat demand, hydro resource availability, as well as VRE potentials and generation profiles. Different carbon constraints were imposed on each system: from a target of 400 g per tonne of CO_2, close to the US pledges for COP21, to 1 g per tonne of CO_2, with intermediate targets fixed at 300, 200, 100, 50 and 15 gCO_2/kWh of. Finally, two different sets of technology pathways are considered: the first set of pathways rely exclusively on renewable technologies (wind, solar and hydro resources) as well as on battery storage, while in the second set nuclear power is added to these low-carbon sources. The generation mix is completed by fossil fuel plants (OCGT and CCGT) which are deployed to the extent allowed by the carbon constraint imposed. For each of these two pathways, additional scenarios were created by considering the participation of demand resources into the system (DSM and demand response) as additional sources of flexibility in the system[40].

38. Introducing a new carbon price, in form of a carbon tax for example, automatically increases the generation costs from fossil plants and inevitably leads to higher electricity costs in the short-term. On the long-term the generation mix will shift toward less carbon intensive technologies and will reach a new equilibrium which minimises the electricity generation costs under the new carbon price level. However, in the long-term generation costs will be higher than those in a system without a carbon price but the system will emit less CO_2.

39. Note that the discussion here is limited to the cost of providing electricity to customers. Reducing carbon emission by an appropriate CO_2 price could provide additional side benefits to society, e.g., through the recycling of tax revenues in terms of added investment or the reduction of other taxes. In other words, the social benefits of a carbon price set at the correct level would outweigh its economic costs (see also Chapter 4).

40. A total of 560 cases were analysed in the report, but the discussion here is limited to a subset of them. The generation mix of each scenario is optimised using a green-field approach where all technologies are deployed to their optimal level, with the exception of the available hydro resources which are given exogenously. Calculations are performed by the GenX model which uses a MILP methodology (see Chapter 3 for further details of this tool) and share the same cost assumptions for all technologies in all scenarios considered.

The main findings of this study can be summarised as the following:

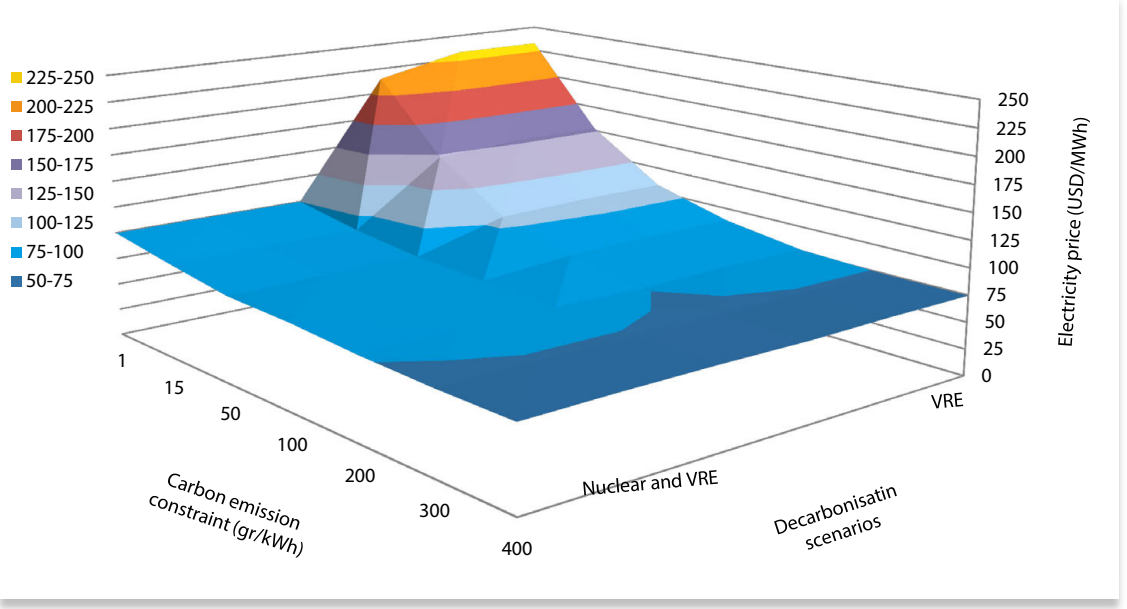
i. the average cost of electricity increases as the carbon constraint becomes more stringent, but this increase depends strongly on the technology path followed;

ii. the structure of the optimal generation mix varies significantly depending on the power system considered and changes drastically as the decarbonisation target becomes more binding; and

iii. the share of nuclear energy in the optimal mix increases as the carbon constraint becomes more stringent.

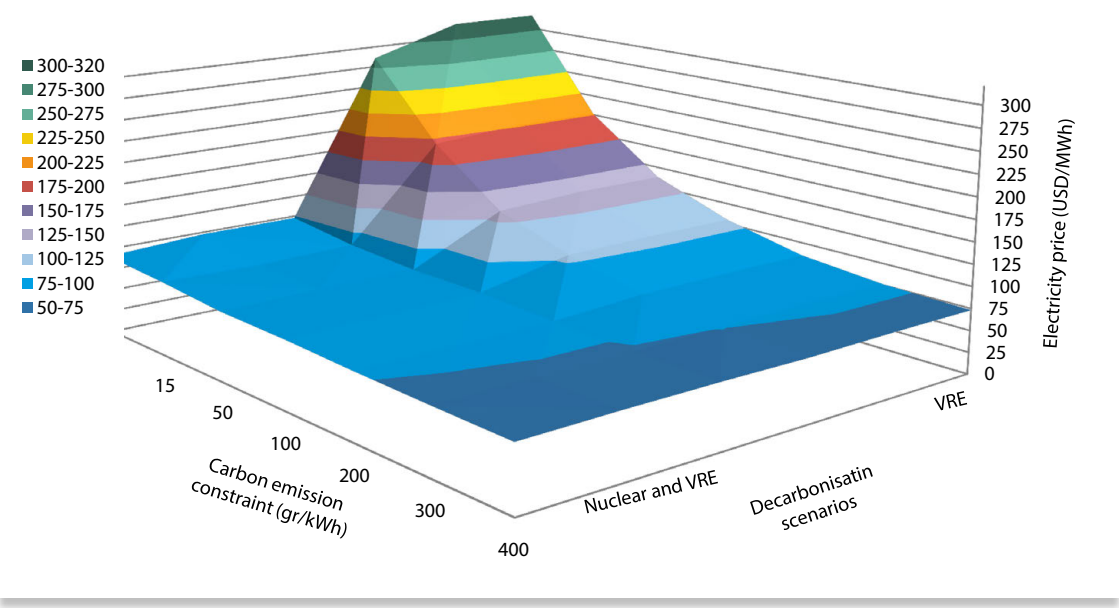
If relatively less ambitious decarbonisation targets are sought (roughly up to 200 gCO_2/kWh) the costs of electricity generation are similar in the two power systems and almost independent of the decarbonisation path chosen. However, while generation costs increase almost linearly with more astringent carbon emissions if nuclear power is allowed into the mix (an increase of 28-35% in generation costs is observed to reduce carbon intensity up to 15 gCO_2/kWh), the generation costs increase over-proportionally if only VRE are allowed. In the latter case, generation costs increase by 2-2.7 fold to achieve the same carbon intensity, as can be observed in Figure 15 and Figure 16. These figures show the generation costs for three scenarios based on VRE, to the right on the x-axis (labelled as "Decarbonisation scenarios"), and for three scenarios with nuclear and VRE, to the left on the x-axis. When very low-carbon intensity levels are pursued with only the use of VRE resources, the generation costs are significantly higher in ISO-NE than in ERCOT, indicating that the specificities of individual systems become more dominant. However, the differences between the two power systems are much smaller if nuclear power is added to the mix.

Figure 15. **Average price of electricity as function of pathways and emissions intensity targets (ERCOT)**



Source: Based on Sepulveda, 2016.

Figure 16. **Average price of electricity as function of pathways and emissions intensity targets (ISO-NE)**



Source: Based on Sepulveda, 2016.

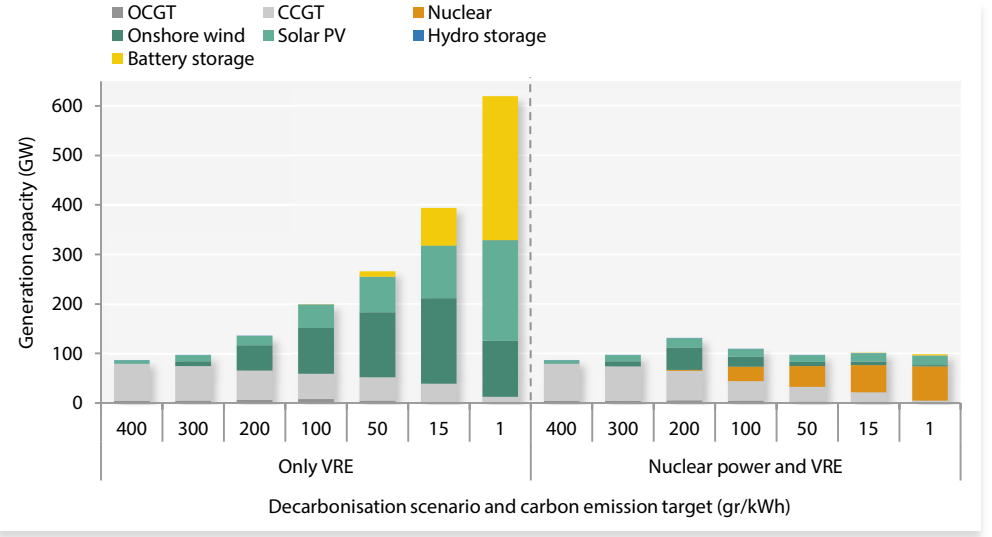
Finally, it is interesting to look at the evolution of carbon abatement costs, i.e. the costs of avoiding the emission of 1 tonne of CO_2, as the carbon emission constraint becomes stricter. In all scenarios considered, carbon abatement costs increase over-proportionally as carbon emission becomes stricter, but are one order of magnitude lower when nuclear power is added to the generation mix compared to when only VRE are considered. In the latter case, carbon abatement costs are of the order of 400-600 USD/t CO_2 when carbon intensity is reduced from 100 to 50 g/kWh. When further reducing the carbon intensity from 50 to 15 g/kWh, carbon abatement costs increase by about a factor of three in a range of 1 200-1 800 USD/tCO_2. Reducing further the carbon intensity to 1 g/kWh leads to carbon abatement costs above 5 000 USD/tCO_2.[41] As indicated, carbon abatement costs are about one order of magnitude lower if nuclear power is considered: from 30 USD/tCO_2 to about 200 USD/tCO_2 and 300-700 USD/tCO_2, for the three decarbonisation intervals considered above.

The second aspect underlined by the MIT study is the change in the structure of the optimal generation mix as the carbon intensity of the power system is progressively reduced (see Figure 17 and Figure 18). The carbon emission constraint of 400 gCO_2/kWh is met in ISO-NE by a combination of gas-fuelled power plants and available hydro resources, while in ERCOT a limited capacity of VRE is installed together with the existing hydro and gas plants. As the system is required to reduce its carbon intensity, fossil fuel generation is progressively replaced by low-carbon technologies. If only RES are allowed, the capacity of VRE and storage increases over-proportionally with the carbon constraint. In both power systems, wind energy is deployed first and starts with a higher share, but is progressively replaced by solar PV as the system is further decarbonised. A similar trend among the two VRE technologies is observed when nuclear power is also considered as an alternative. In ERCOT, due to favourable locational resources, VREs are deployed first: for a carbon constraint of 200 gCO_2/kWh, the optimal generation mix leads to very high capacity of wind and a significant capacity of solar

41. It is highly unlikely that such very stringent carbon intensity targets could be achieved without technological breakthroughs (not modelled in the MIT study).

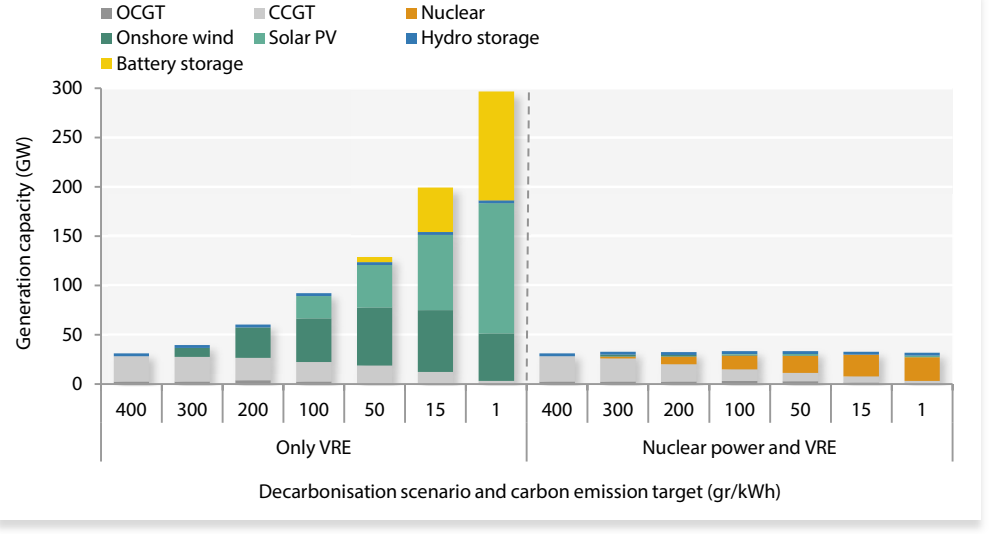
PV, while the capacity of nuclear is relatively low. In these cases a sufficient share of CCGT allows the flexibility needed to integrate more variable and cheaper wind resources. However, imposing stricter emissions constraints changes the mix drastically, with nuclear displacing both gas and wind energy, while the capacity of solar is approximately constant. On the contrary, in ISO-NE nuclear power is the most competitive low-carbon source and provides most of the capacity in the system, whatever is the targeted carbon intensity. In this system, wind and solar PV deployment is limited to few GW, and wind is substituted by solar PV for stricter carbon targets.

Figure 17. **Optimal capacity mix for the two main pathways as a function of the carbon target (ERCOT)**



Source: Based on Sepulveda, 2016.

Figure 18. **Optimal capacity mix for the two main pathways as a function of the carbon target (ISO-NE)**



Source: Based on Sepulveda, 2016.

While the main quantitative results of the study (total cost of electricity generation, optimal generation mix) inevitably depends on the specific characteristic of the power system represented and on the cost assumptions adopted, the trends observed comparing both scenarios provide more general and valuable insights.

In particular, the study concludes that

> "… diversity of energy sources drives down total costs of energy in a low-carbon system, whereas taking options off the table – such as nuclear – creates extra costs to society".

Also, it indicates that

> "… the impacts of decarbonisation targets on the optimal investment policies are not linear and some targets may yield a share of a particular technology e.g. wind, that under a more stringent target may not be present in the optimal mix".

It is therefore important that decarbonisation policies are not based on pre-specified shares of low-carbon resources in the mix, but rather on ambitious CO_2 reduction goals and a pre-specified agenda. A CO_2 price (or a carbon market) is sought as the optimal policy option for an efficient decarbonisation; however, in absence of CO_2 markets, support mechanism should promote all types of low-carbon resources allowing for efficient adaptation among them.

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Chapter 3. **Modelling results**

3.1. **Background and objectives**

In December 2015 all OECD countries signed the Paris Agreement on climate change. The agreement sets the ambitious goal, although only being an "intention" at this moment, to limit the increase in global average temperature by the end of this century to well below 2°C above pre-industrial levels. Signatory countries have expressed willingness to rapidly reduce the emissions level to a point in which zero net carbon emissions are achieved by the middle of this century. Achieving such ambitious carbon emission reductions has a major impact on the entire energy sector and requires a radical transformation of the electric power sectors towards a low-carbon generation mix. Several low-carbon technologies are available today to progressively decarbonise the electric power generation sector and allow for different pathways to achieve the emission targets of OECD countries.

In order to illustrate a possible pathway compatible with the environmental goals of the Paris Agreement, the IEA has developed in the 2017 edition of the World Energy Outlook a decarbonisation scenario, termed the "*Sustainable Development Scenario*" (IEA, 2017). According to this scenario, the carbon emission intensity of the electric power sector has to fall from the current levels of 540 g/kWh to 100 g/kWh by 2040. A deeper reduction is required from OECD countries: carbon intensity has to be reduced by a factor of eight by 2040, from 400 g/kWh to about 54 g/kWh.

This study focuses on the implications associated with such decarbonisation of the electric power system in OECD countries. The main objective of the present work is to analyse the technical characteristics and economic costs associated with different decarbonisation strategies characterised by different shares of VRE leading to the same carbon emissions and to the same level of reliability of the electricity generation power system. This study therefore considers different scenarios of VRE deployment, with VRE generation shares, i.e. wind and solar photovoltaic (PV), varying from 0% to 75% of the total electricity generation and imposes on each scenario the same stringent carbon constraint of 50 g/kWh.

When analysing deep decarbonisation scenarios, a key element is the carbon intensity level of the electric power system, as the resulting generation mix and the total cost of electricity provision are very sensitive to this parameter, in particular when the VRE generation share becomes significant (see also Section 8 in Chapter 2). A same strict carbon emission constraint of 50 g/kWh is applied to all case studies considered in the present study. This carbon intensity level corresponds roughly to the upper projections by the IEA for the OECD countries in the 2040-2050 period.[1] The NEA secretariat, and delegates attending NEA meetings[2] all consider the Working Party on Nuclear Energy Economics (WPNE) and the

1. In the 2017 World Energy Outlook (WEO), the IEA indicates a level of carbon emissions of 54 g/kWh for OECD countries in the "*Sustainable Development Scenario*". Note that the WEO limits its analysis of the power sector to 2040, and it can be reasonably assumed a more stringent limit would apply in 2050. In another series of publications (Energy Technology Perspectives), the IEA put forward a carbon intensity of 25 g/kWh in 2050 if the climate targets of 2°C increase were to be respected (IEA, 2015).
2. Delegates attending meetings of the Working Party on Nuclear Energy Economics and the Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle.

Nuclear Development Committee (NDC) have considered that the choice of such somehow less stringent target would provide more realistic and meaningful information for member countries taking into account the uncertainties in the practical implementation of the Paris Agreement, as well as the enormous challenges associated with such a radical transformation of the electric power sector.

The study considers a large, well-interconnected power system, with a significant endowment in flexible hydroelectric resources (run-of-the-river, reservoir and pumped) as a representative system for most OECD countries. However, two additional case studies represent an isolated system without interconnections with neighbouring countries and a system with no flexible hydroelectric resources. These sensitivity scenarios allow additional insight into the role that these sources of flexibility may have in the integration of large shares of VRE. Also, they allow representing a system that shares some similarities with that of other OECD countries.

The quantitative analysis is conducted in a long-term perspective, i.e. assuming that the electric power system is a green field. The approach chosen reflects the long-term focus of the analysis which looks at the energy mix indicatively in the 2040-2050 time frame, and allows an unbiased and "pure" comparison of different low-carbon generation options[1]. The generation mix is therefore optimised to satisfy the same load at minimal cost by deploying the most cost-effective generation mix under the common carbon emissions constraint and the amount of VRE exogenously imposed. The only exception to this approach is the amount of hydroelectric resources, which are given for all scenarios. This reflects the situation of most OECD countries, where most of the commercially viable hydro resources have been already tapped and there is limited room for further capacity increments. The present study provides therefore a "snapshot" of the future power system under a stringent carbon constraint in a situation of long-term equilibrium. Describing or optimising the dynamic transition between the current and the future target generation mix is beyond the scope of this study.

In term of system costs, the present analysis concentrates on the profile costs (utilisation costs) but is able to model and capture some components of balancing costs. In particular, it considers the added costs of increased reserve requirements, which are a function of the share of VRE and their flexibility needs. No direct attempt has been made to capture either connection costs or transmission and distribution (T&D) grid costs in this modelling work, since each region is considered as a single node. Nevertheless, some estimates for the T&D and connection costs are taken from the literature and added to the cost of electricity provision, in order to obtain a more complete evaluation of the whole system costs.

It is important to underline that the objective of this study is not to assess what will be the future low-carbon generation mix, nor to provide a quantitative assessment of system costs in a specific OECD country. As discussed in the previous chapters, power system and system effects analyses depend strongly on the characteristics of the power system considered, on the technical and economic characteristics of power generators and flexibility sources available in the future, as well as on the quality and detail of modelling performed. The objective of the study is rather to underline the most relevant impacts associated with a deep decarbonisation of the electric power system, to provide an order of magnitude of the long-term costs of electricity provision under realistic cost assumptions and to compare, under the same set of assumptions and conditions, the main characteristics and impacts of different strategies for decarbonisation.

Section 3.2 gives an overview of the different scenarios analysed and provides a brief description of the power system represented as well as of the main modelling assumptions. Further information is provided in the annexes to this chapter.

1. Considering some brown-field resources could have given an advantage to the technologies already present in the generation mix.

The quantitative results and the most important findings of this modelling exercise are given in Sections 3.3 to 3.5, which look at the different technical and economic aspects of VRE integration.

Section 3.3 covers essentially the technical aspects associated with different deployment levels of VRE resources: the impacts on the residual electricity load and on the composition of the generation mix that covers it at minimal cost. Other important impacts on the operations of thermal power plants as well as on the VRE are also discussed. In particular, the impacts and flexibility requirements of nuclear and other thermal plants are discussed, together with the required curtailment of generation from VRE.

Section 3.4 focuses on the main economic aspects: the cost of electricity generation and electricity provision. It presents the total costs for electricity generation in the two main regions considered and the generation costs increases associated with VRE deployment. Such cost increases are then subdivided into different components in order to understand the main drivers and to assess the profile costs of VRE. Finally, these results are complemented with estimates of balancing and T&D costs from the literature in order to provide a reliable estimate of the total cost of electricity provision and of the total system costs for all scenarios analysed.

Section 3.5 looks primarily at the long-term implications on the electricity markets associated with a transition towards electric power systems dominated by VRE and other low-carbon sources. In particular it analyses the requirements in terms of the capital intensity of the generation mix and the long-term effects on the level and structure of electricity prices. All these factors change the overall electricity market risk faced by investors in the electric power generation sector and constitute a policy-relevant side effect of the decarbonisation. Finally, the decline of the market value of PV and onshore wind resources with their penetration level is examined.

Conclusions are drawn in Section 3.6. Additional information is given in the annexes of this chapter. Annexes 3.A1 and 3.A2 provide further details on the characteristics of the power system modelled and on the economic assumptions taken, as well as a more complete description of the modelling tools used in this study. Annex 3.A3 provides descriptions of each of the eight scenarios modelled in the present study. These include basic information on the generation mix such as installed capacity, electric energy generation share, cost of electricity generation as well as level and structure of long-term wholesale electricity market prices. Annexes 3.A4 and 3.A5 provide complementary information for the second region considered in this study in terms of electric power generation costs and market value of VRE and hydroelectric resources.

3.2. Overview of the scenarios and main modelling assumptions

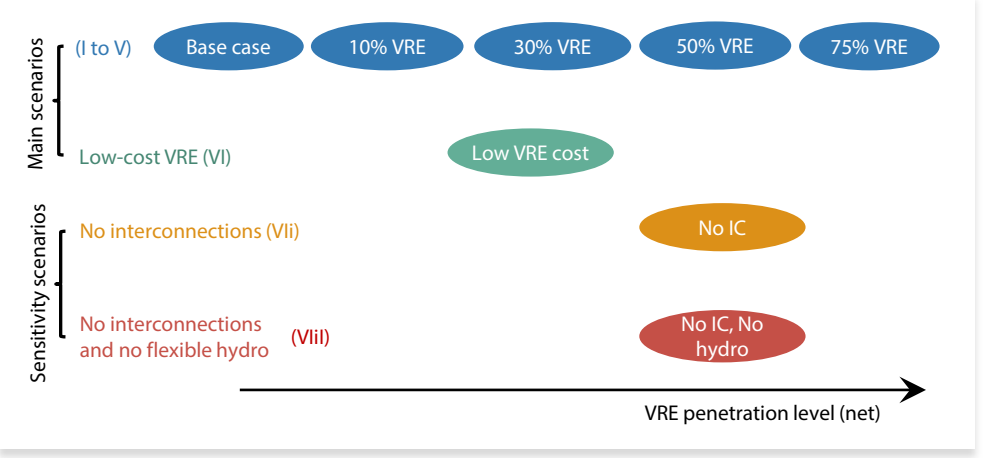
A total of eight different case studies are analysed in the framework of the present work: six main scenarios, five of which (I through V) are characterised by different levels of VRE exogenously imposed on the system (0%, 10%, 30%, 50% and 75%), and a low VRE investment cost scenario, designated as Scenario VI, which assumes significant future cost reductions for VRE. The latter scenario does not impose an a-priori VRE share, but allows the VRE to be deployed endogenously in the generation mix. Two sensitivity scenarios, (VII and VII) represent an isolated system characterised by different degrees of flexible hydroelectric resources, featuring the same VRE capacity as in the 50% VRE scenario. These case studies should be considered as an exploratory exercise to better understand the different aspects of integrating VRE in the electricity system.

All the six main scenarios represent a two-region system, where a main region is interconnected with a second region of the same size. Region 2 differs from the main region with respect to some important characteristics such as the shape of the load curve, the patterns of VRE generation and the availability of hydroelectric resources. The two sensitivity scenarios (VII and VIII) represent an isolated system, constituted only by the main region.

All scenarios model the least-cost electricity mix over the 8 760 hours of a full year under a common carbon constraint and with different shares of VRE in a logic of linear optimisation. While assumptions (see below) reflect a 2050 horizon, no dynamics were modelled in order to provide maximum transparency and provide clear options for policy makers.

An overview of the eight case studies analysed is schematically given in Figure 19. More detail for each scenario is provided in the following pages and in Annex 3.A3. The name of each scenario as well as the acronym used in figures and tables is given in Table 1

Figure 19. **Overview of the eight case studies**



Scenario I: Cost minimisation – base case

In the "cost minimisation" scenario, also referred to as "base case", only hydro resources are exogenously imposed in the two regions, while the rest of the generation mix is determined endogenously to satisfy the electricity load at a minimal cost. This scenario represents therefore the least-cost solution for achieving the carbon emission level targeted and is the basis for comparison of all other case studies in this report. Contrary to other scenarios, where emissions are capped, the required level of carbon emissions is obtained by imposing the same implicit carbon price in the two regions[2].

Under the cost assumptions adopted in this study, the generation mix is constituted only by dispatchable technologies, without the deployment of VRE capacity. The reason for this choice is not to represent the generation mix of the future, as there are almost no OECD countries without exogenously imposed VRE shares, but rather to have a "benchmark" scenario from which to calculate the system costs and to calculate the additional costs associated with exogenously imposing VRE capacity targets. In particular, it is important to recall that having a scenario with only dispatchable technologies is indispensable when calculating the profile costs of VRE. As mentioned in Chapter 2, system effects can be defined and quantified only by comparing a system with a reference or "benchmark" system; the present base case scenario (without VRE) therefore represents the benchmark to evaluate the profile costs associated with the variability of VRE generation.

2. As a first approximation, imposing an "appropriate" carbon price gives the same results as capping the carbon emission to a given level. However, the choice of imposing a carbon price is computationally more demanding, as it requires some numerical iteration before achieving the carbon emission level targeted. In return, it allows obtaining the level of carbon price required; while this information is not available if a carbon emission level is fixed in the calculation. This is the main reason for the different option adopted in the base case compared with the other scenarios.

Scenarios II to V: Wind and solar PV cases

In the four main scenarios II to V, termed respectively "10%, 30%, 50% and 75% wind and solar PV cases", the same hydroelectric resources and a progressively increasing amount of wind and solar PV resources are imposed exogenously in each of the two regions. Wind and solar PV resources achieve an annual net generation share of respectively 10%, 30%, 50% and 75% in each of the two regions. Only the electricity effectively provided by VRE to the grid is accounted for, without taking into consideration the electricity curtailed.[3] It is also assumed that wind generates 75% of the total generation from VRE, while the remaining is generated by solar PV. Offshore wind remained in principle an option, however on the basis of the 2015 cost figures it was never cost-competitive. Given important progress in this area, updated cost figures might lead to different results. The capacity and dispatch of thermal power plants and battery storage is calculated endogenously by the system to minimise the total generation costs while meeting the target carbon emission constraints in the two regions.

Scenario VI: Cost minimisation with low-cost renewables

This scenario, termed "Cost minimisation with low-cost renewables" adopts significant cost reductions in both solar PV and wind technologies. Only hydro resources are exogenously given in both regions, while the remaining generation mix is optimised to minimise the generation costs, under the same carbon constraint in both regions.

In this scenario, the pure generation cost of solar PV and wind is significantly lower than that of the other low-carbon generation sources leading to their widespread deployment in the system. Their optimal capacity is now *endogenously* determined so that the marginal value of each technology equates to its generation cost. Under the hypothesis on generation costs taken, it turns out that the VRE achieve an average generation share of about 35% (with actual 15% penetration in the main region and 50% in region 2).

Scenario VII: 50% wind and solar PV, no interconnections, and scenario VIII: 50% wind and solar PV, no interconnections and no flexible hydroelectricity

These two sensitivity scenarios represent an isolated electricity system, without exchanges with the neighbouring region. In both cases the electricity system is therefore constituted only by the main region (region 1). For completeness, a second set of calculations has also been performed for the neighbouring region (region 2) also considered as an isolated system. The VRE capacity exogenously imposed in that region is the same as for the scenario IV, where VRE provided 50% of the net total demand for electricity. In scenario VII, region 1 has the same hydroelectric resources as in the previous scenarios (I to V). In scenario VIII, only "fatal" run-of-the-river hydroelectric capacity is present, but no flexible hydroelectric resources (reservoir-based or pumped hydroelectric) are available. All other assumptions and hypothesis are equivalent to those taken in the main scenarios. As in the other cases, the combination of generation plant and battery capacity and dispatch are optimised to minimise the generation costs while respecting the carbon emission constraint of 50 g/kWh.

These two sensitivity scenarios address the issue of having less flexible options in the system to ease the integration of VRE, in terms of no interconnection capacity with neighbouring countries and an absence of flexible hydroelectric resources. The results of these two scenarios are meant to be compared with those of the main scenario IV, since they all share the same amount of solar PV and wind resources.

3. Electricity generated by VRE has to be curtailed when VRE generation exceeds the demand (including potential for storage) and the power cannot be transferred to the neighbouring region, either because interconnections are saturated or because the other region faces also similar challenges. VRE could also be curtailed if shutting down or reducing the power output of thermal generation plants would result in higher costs for the system (due to ramping constraints or start-up costs).

Table 1. **Brief description of the eight case studies and short identifiers**

	Number	Name of scenario	Identifier
Main scenarios	I	Cost minimisation	*Base case*
	II	10% wind and solar PV	*10% VRE*
	III	30% wind and solar PV	*30% VRE*
	IV	50% wind and solar PV	*50% VRE*
	V	75% wind and solar PV	*75% VRE*
	VI	Cost minimisation with low-cost renewables	*Low VRE cost*
Sensitivity scenarios	VII	50% wind and solar PV, no interconnections	*No intc*
	VIII	50% wind and solar PV, no Interconnections no flexible hydroelectricity	*No intc, no flexible hydro*

Characteristics of the electric power system modelled

The system represented in this study is composed of two separate large regions (main region and region 2) Both regions have the same yearly electricity demand of 537 TWh which corresponds roughly to the expected annual demand of a country the size of France in 2050. The two regions are linked through an interconnection with 7.2 GW of capacity, which represents about 12% of the average demand in each region. As commonly done in this type of modelling work due to computational tractability of the optimisation problem, the transmission and distribution systems within each region are not modelled, thus implicitly considering each region as a "copper plate" without transmission losses. Under this assumption, the electricity is carried from the point of generation to each load without losses and without congestion. A schematic representation of the power system modelled is provided in Figure 20 together with a short description of its main characteristics. Additional, more detailed information is provided in an annex to this chapter.

The hourly input data for load as well as the realised load factors of solar PV, wind farms and run-of-the-river "fatal" hydroelectric resources for the main region are based on real data of the French electric power system in 2015.[4] The capacities of hydroelectric resources were also derived from the currently available resources in France (hydroelectric capacities are the only capacity included as pre-existing brownfield, i.e. exogenous to the modelling, in the mix): this applies to run-of-the-river "fatal" capacities, reservoir-based hydro reserves as well as the pumped hydro capacities. The main reason for choosing the French power system as the starting point for the study is the very good availability of detailed data regarding almost all aspects of the electricity system, courtesy of its transmission system operator RTE. Choosing empirical rather than computer-simulated data is essential to capturing the implicit correlations that may exist between different time-series. Of course, the latter may change between countries.[5]

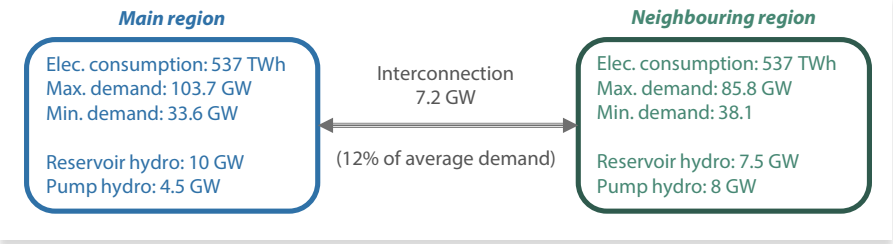
The neighbouring region (region 2) has been re-scaled in order to have the same "size" in terms of average electricity demand as that of the main region. The main characteristics of region 2 have been obtained from the power systems of the countries interconnected with France: Spain, Belgium, Germany, Switzerland, Italy and the United Kingdom, again for reasons of empirical validity. The load and the VRE load factors for renewables have been obtained as a weighted average of the respective country data available. By construction, the

4. The load factors of VRE and hydro resources have also been scaled to reflect the average load factor taken for the cost estimation of these resources, which are representative of values in OECD countries (respectively 30% for onshore wind, 40% for offshore wind, 15% for solar PV and 50% for run-of-the-river hydropower). Realised load factors in France for 2015 were 14.8% for solar PV, 24% for onshore wind and 40% for run-of-the-river hydropower.

5. The fact that France has substantial share of nuclear power in its electricity mix has strictly no impact on the study given that all results are "greenfield scenarios", i.e. constructed *without* any input from existing power generation mix.

profiles of electricity demand and of VRE generation are flatter in region two than those of the main region (see Annex 3.A1 for further information). Similarly, the hydroelectric capacities are based on the real data for those countries.

Figure 20. **Schematic representation of the power system**



Representing a large, well-interconnected power system allows the different daily and load patterns as well as the different regimes of VRE generation across a large area which subject to different climate and meteorological regimes to be taken into account. The system represented is also rich in flexible hydroelectric resources which provide a good degree of flexibility for the integration of VRE. A considerable effort has therefore been devoted to gather consistent "real" data from European TSOs in order to provide a realistic representation of the power system modelled. The realised data implicitly contain and account for the correlations between meteorological conditions, demand level and load factors from VRE and hydro resources across a large geographical area. Accurate data on the "water values", i.e. the amount of water that periodically fills the reservoirs is also essential in order to correctly represent and model hydroelectric storage.

Economics of electricity generation alternatives

A set of generating technologies has been explicitly represented and modelled in this study: dispatchable thermal technologies such as open cycle and combined cycle gas turbines (OCGT and CCGT), coal and nuclear power plants as well as VRE technologies such as solar PV, onshore wind, offshore wind and hydroelectric power. Three different types of hydroelectric facilities are modelled: run-of-the-river plants, impoundment facilities or reservoir-based plants, and pumped storage hydroelectric plants. In term of other options for flexibility, battery storage and demand-side response are explicitly modelled. The study has not included technologies that are currently not deployed on an industrial scale such as carbon capture and storage (CCS), hydrogen or power-to-gas. While there is some likelihood that several new technologies will be part of the electricity mix by the time that carbon emissions have been reduced to 50 gCO_2 per kWh, the aim of the study is not to promote a specific vision of the future but to improve understanding about the inevitable impact of the deployment of variable technologies on the total costs of electricity systems.

Cost data for generation technologies are derived primarily from the last edition of the IEA/NEA *Projected Costs of Electricity Generation: 2015 Edition*, which assesses projected costs for power plants to be built in 2020 in OECD countries (OECD, 2015).[6] The values used in this analysis, as well as the load factors for VRE, are obtained as the average of responses for OECD countries. Fixed costs of generating plants include the annuities of investment costs and fixed operation and maintenance (O&M) expenditures, while variable costs include fuel and variable O&M costs[7]. For all generation options, the annuities of the investments costs are calculated using a real

6. This is the standard OECD reference for generation cost data. A new edition of the report will be prepared in 2019 for publication in 2020.
7. As O&M costs are aggregated into a single value in (OECD, 2015), their repartition into a variable and a fixed component has been performed based on literature data and expert judgement.

discount rate of 7%, which is representative of the cost of capital required by major generation companies in OECD countries. Also, it should be remembered that capital cost varies with the size, the nature and the overall risk of each individual project. For instance, smaller projects with guarantees prices, e.g. VRE with feed-in tariffs (FITs) may require significantly lower rates. The use of a unique discount rate for all technologies does not allow to capture such effects.

Finally, cost assumptions for fossil fuels are based on long-term worldwide projections from the (IEA, 2015a). More specifically a cost of 77 USD/tonne and 9 USD/MMBTU are taken for coal and gas, respectively. In the "low VRE cost" scenario, the costs of VRE have been substantially reduced with respect to the base case scenario: the investment and O&M costs of solar PV have been reduced by 60%, those of offshore wind have been halved and those of onshore wind have been reduced by a third. Battery storage costs are derived from available estimates of Li-Ion, with a cost of 570 USD/kWh. These are average figures, some recent estimates can be as much as 50% lower. Either way, the impact would be very limited due to the low share of storage in all scenarios. The key constraint for using battery storage for riding out demand peaks is not its cost per kWh, which depends largely on the cost at which electricity is bought in the market, but its limited capacity. Storage can be very competitive in the sub-hourly range, i.e. in reserve and balancing markets. However, only very rarely would one resort to storage to respond to a continuous 60 minute load, as would be needed to participate in the day-ahead market that is modelled in this report. Table 2 synthesises the most relevant economic data used in this analysis.

Box 3.1. Investment costs of generation technologies

It must be stressed that the investment cost figures used are "average" costs. There are countries/regions/circumstances where the investment costs are considerably lower; in others they are much higher. For system cost comparison purposes for providing a low-carbon electricity system, it is especially important to qualify the investment cost differences between VRE and nuclear as they are very location and system dependent. To illustrate the point, the table below shows the spread of data provided by different OECD (NEA/IEA) member states and China. Just to consider the most crucial ones for the purposes of this study: the spread for overnight construction cost for nuclear is characterised by a factor of about 3.5; for PV (residential, commercial and large-scale) roughly a factor of about 2-2.5, and for wind offshore and onshore, roughly a factor of about 1.5 and 2.5, respectively.

Summary statistics for different generation technologies

Technology	Number of plants	Net capacity[1] (MWe)				Overnight cost[2] (USD/kWe)			
		Min	Mean	Median	Max	Min	Mean	Median	Max
Natural gas – CCGT	13	350	551	475	900	627	1 021	1 014	1 289
Natural gas – OCGT	4	50	274	240	565	500	708	699	933
Coal	14	605	1 131	772	4 693	813	2 080	2 264	3 067
Nuclear	11	535	1 434	1 300	3 300	1 807	4 249	4 896	6 215
Solar PV – residential	12	0.003	0.007	0.005	0.02	1 867	2 379	2 297	3 366
Solar PV – commercial	14	0.05	0.34	0.22	1.0	728	1 583	1 696	1 977
Solar PV – large	12	1	19.3	2.5	200	937	1 555	1 436	2 563
Solar thermal (CSP)	4	50	135	146	200	3 571	5 964	6 072	8 142
Onshore wind	21	2	38	20	200	1 200	1 911	1 804	2 999
Offshore wind	12	2	275	223	833	3 703	4 985	4 998	5 933
Hydro – small	12	0.4	3.1	2	10	1 369	5 127	5 281	9 400
Hydro – large	16	11	1 093	50	13 050	598	3 492	2 493	8 687
Geothermal	6	6.8	62	27	250	1 493	4 898	5 823	6 625
Biomass and biogas	11	0.2	154	10	900	587	4 447	4 060	8 667
CHP (all types)	19	0.2	5.3	1.1	62	926	4 526	2 926	15 988

1. Net capacity may refer to the unit capacity or to the combined capacity of multiple units on the same site.
2. Overnight cost includes pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).

Source: OECD, 2015

Box 3.1. **Investment costs of generation technologies** *(cont'd)*

For VRE, there is an additional factor of locational differentiation, which also affects the load factor. Again referring to the figures provided to the (OECD, 2015), reported load factors for solar PV range from 10% to 21% (OECD 2015, Table 3.5), while for onshore wind the load factor ranges from 20% to 49% and for offshore from 39% to 48% (OECD, 2015, Table 3.6). All this is clearly reflected by the levelised cost of electricity (LCOE), as is clearly documented in (OECD, 2015).

The authors of this study are fully aware of these investment cost and load factor variations. There are indeed places where conditions for VRE are very favourable, but other circumstances where VRE electric energy generation is very expensive. The same is true for nuclear new build: construction costs will be one of the determining factors as to whether nuclear will enter future generation mixes or not. However, to understand the mechanics of system costs, a particular parameter choice must be made. From a methodological standpoint it is therefore justified to take the average of the reported numbers in *Projected Costs of Generating Electricity* (OECD, 2015). To capture future anticipated cost reductions of VRE, a different scenario with much lower average VRE investment costs is also considered. In any case, these input parameters influence the outcome of the results; they should not be generalised as being applicable everywhere. In some locations/countries/regions, system costs will be (much) lower than computed here; in other cases, they will be (much) higher.

The same cost assumptions and flexibility attributes for all generation and storage technologies are taken in all scenarios. The only exception is the last sensitivity scenario ("low VRE cost"), where the assumptions for the overnight and O&M costs of VRE have been lowered between one third and 60%.

Table 2. **Cost assumptions for generating plants and storage capacities**

Technology	Discount rate (%)	Size (MWe)	Electrical efficiency (%)	Load factor (%)*	Construction time (years)	Lifetime (years)	Overnight cost (incl. contingency) (USD/kW)	Annualised investment costs (USD/MW/year)	Fuel costs (USD/MWh)	O&M costs	
										Fixed (USD/MW/year)	Variable (USD/MWh)
Gas – OCGT	7%	300	38.0%	100%	2	30	700	58 380	80.81	20 000	15.30
Gas – CCGT	7%	500	58.0%	100%	2	30	1 050	87 580	52.94	26 000	3.50
Coal	7%	845	45.0%	100%	4	40	2 200	183 170	21.84	37 000	5.00
Nuclear	7%	1 000	33.0%	100%	7	60	4 700	413 880	10.00	100 000	1.50
Onshore Wind	7%	50		30%	1	25	2 000	171 620	0.00	62 000	0.00
Offshore Wind	7%	250		40%	1	25	5 000	429 050	0.00	175 000	0.00
Solar PV	7%	1		15%	1	25	1 600	137 300	0.00	36 000	0.00
Hydro – run-of-the-river	7%	10		50%	5	80	4 300	347 750	0.00	65 000	0.00
Hydro – reservoir	7%	10		20%	5	80	3 250	262 830	0.00	50 000	0.00
Hydro – pump storage	7%	10		NA	5	80	4 450	359 890	0.00	65 000	0.00
Battery storage	7%	1	90.0%	NA	1	10	1 146	163 164	NA	17 190	0.00
Onshore Wind – low-cost scenario	7%	50		30%	1	25	1 333	114 410	0.00	41 333	0.00
Offshore Wind – low-cost scenario	7%	250		40%	1	25	2 500	214 530	0.00	87 500	0.00
Solar PV – low-cost scenario	7%	50		30%	1	25	640	54 920	0.00	14 400	0.00

* The load factors of different power generation technologies used in economic modelling differ widely among countries as well as according to location and plant. Box 3.1 above spells out the ranges on which the VRE technologies have been based. With regard to dispatchable technologies (Gas-OCGT, Gas-CCGT, coal and nuclear), this study has chosen for modelling purposes a 100% load factor. This is an upper bound. Readers may prefer to make their own judgements based on the specific circumstances of the country and technology in question.

The technical and economic data used to represent the flexibility, i.e. load variations, of thermal plants (nuclear, coal and gas) are set out in Table 3. These figures are based on a combination of literature research and expert judgement. They are also average figures. If in doubt, the more conservative assumption was retained. In particular, this study has taken very conservative assumptions with respect to the flexibility of nuclear power plants, as some of them can ramp down to levels of minimal power of less than 50% at rates as fast as 2% per

minute. In general, however, test runs with the GenX model (Jenkins et al, 2017).suggest that varying the flexibility characteristics of thermal plants does not have a decisive impact on the optimal configuration of the power system. Due its high fixed costs to variable cost ratio, the total number of full load hours is far more important for the economics of a nuclear power plant than the small number of additional hours during which it could substitute for an alternative flexibility option. The limits of using nuclear as a flexible generating resource are set by economics not by technical characteristics.

Demand-side management (DSM) has been also modelled in the study as the possibility to curtail up to a maximum of 4% of the load with a cost of 500 USD/MWh. While new forms of usage such as electric cars might reduce DSM costs, the necessary empirical evidence for such an assumption is still to be gathered. No fixed costs for DSM are assumed. Finally, a value of lost load of 10 000 USD/MWh, and a penalty for not meeting reserve requirement of 5 000 USD/MWh are assumed. All technologies can contribute to reserve requirements in the limits of their respective technical capabilities. These can be considered a proxy for a much finer modelling of the system close to the real time.

Table 3. **Flexibility characteristics and costs of conventional plants**

	Gas-OCGT	Gas-CCGT	Coal	Nuclear
Minimal power (%)	25%	30%	40%	50%
Ramping rate (%Pmax/h)	100%	70%	30%	20%
Minimal up-time (h)	1	4	8	8
Minimal down time (h)	1	6	8	24
Start-up fuel (MBTU/start)	200	700	2 600	NA
Cost of start-up (USD/MW/start)	50	150	250	500

The cost and technical characteristics of different power generation technologies used in the modelling underlying this study correspond to new plants commissioned in 2020. Of course by 2050, these characteristics may change. CCS might make coal a viable option, small modular reactors (SMRs) or innovative large nuclear units might be cheaper and more flexible, the costs of storage and demand response might yet come down. Policy making is, however, the art of the possible. Even long-term policy making must be informed by currently observable empirical facts. The present study informs policy makers about the costs of achieving an ambitious carbon reduction target with different generation mixes of the currently available technologies.

Methodology and tools used

The power system simulation of this study have been performed by a team of experienced power system modellers who are also researchers affiliated with MIT trained at the Massachusetts Institute of Technology (MIT) using GenX[8] The GenX model was developed at MIT and has been used in different MIT publications for a wide range of analyses, including long-term generation and transmission expansion planning as well as short-term operational simulations and optimisation (MIT, 2016 and 2018). It determines investment decisions on electricity resource assets that, if operated optimally, can fulfil the electricity demand of a particular system at minimum cost, subject to defined operational constraint like ramping limits and unit commitment cycling. GenX can also be used to assess the economic feasibility and the economic impact of new technologies (e.g. storage, DSM, distributed energy resources, advanced nuclear), and to determine the equilibrium effect of any given policy, such as carbon caps, carbon taxes or renewables standards (Sepulveda, 2016).

8. The researcher involved in these analyses were Nestor Sepulveda, Fernando de Sisternes and Jesse Jenkins.

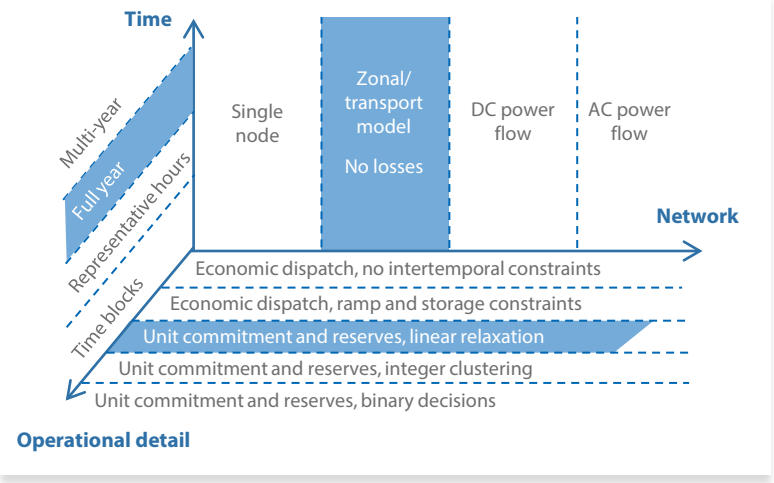
GenX uses mathematical optimisation techniques such as linear programming (LP) and advanced mixed-integer programming to solve for optimal investment and operational decisions. Formally, the model can be divided into two components: a first component where electricity resource building decisions are made (capacity expansion); and a second component incorporating the operational decisions associated with the different electricity resources that have been built in the first stage (unit commitment and economical dispatch). The particularity of GenX is that its cost function includes not only capital cost and variable operating costs, but also the costs of a more intense cycling regime, subject to an array of technical constraints that guarantee the technical feasibility of the modelled system.

Power system analysis presents a dimensionality challenge due to the exponentially-increasing number of decision variables as the time, operational detail and network representations of the model are increased. Figure 21 presents the GenX simulation domain showing the different detail representations for the different modelling dimensions. Going in the simplest case from a single node with economic dispatch but without inter-temporality considerations and using time blocks only, to a full network representation with DC power flow approximation, considering unit commitment and reserves independently for each power plant in a multi-year context. However, it is important to note that not all features can be turned on at same time. Computational limitations entail trade-offs along each dimension, so more detail in one area typically means greater abstraction in other areas. The level of detail used for the simulations performed for this NEA study is shown (in blue) in Figure 21, and more specifically:

- representation of a full year, with hourly intervals;
- two-region model, with interconnections represented as “pipeline" flow constraints, without transmission losses;
- unit commitment operational constraint represented as a linear relaxation;
- explicit representation of reserve requirements.

An additional hypothesis taken in the present study is that the VRE do not enjoy priority of dispatch or an explicit subsidy; VRE curtailment can therefore occur whenever it can contribute to reduce the cost of the system (for example, by avoiding the costs incurred by shutting down a thermal power plant to subsequently starting it up again). Similarly, the VRE are introduced exogenously in the system without an explicit scheme of remuneration above market price: their dispatch is therefore solely based on pure economic considerations and therefore should not occur for prices below their marginal generation costs (which are assumed to be zero).

Figure 21. **GenX dimensionality range and modelling choices adopted**



Further information and more technical insights on the GenX software are provided in Annex 3.A2. The annex describes also the most relevant assumptions[9] adopted to make the problem numerically tractable with current calculation tools, and discusses on a qualitative basis their potential impact on the results.

Main observables and conventions used in the present study

When analysing a complex interconnected power system, subject to a strong carbon constraint and with an imposed share of different brownfield (hydroelectric and VRE) resources, particular care should be taken in appropriately defining and calculating the different metrics used for comparing the different scenarios. There are indeed different ways to calculate important observables such as the cost of electricity generation, or to account for the different characteristics of each individual system. The choice of the metrics used reflects the objective to facilitate the comparability of results across different scenarios.

The most important assumptions and metrics used in the present study are: how the electricity flows across the two regions have been accounted for; how the brownfield resources have been considered; and how the CO_2 emission levels have been taken into account.

When analysing an interconnected system of two or more regions, there are electricity will flow from the region where variable electricity generation costs are lower to the region with higher variable electricity generation costs. The direction of such flows may change several times during a day, depending on the generation resources available and demand patterns in the different interconnected regions. However, the physical (and economic) flows across the regions do not necessarily compensate each other over one year, thus leading to a difference between the electricity generated and consumed in each region. It is therefore possible to define "electricity generated" and "generation costs" in two different ways, depending on which components are accounted for. One possible metric is to aggregate the electricity produced in each region and its costs, regardless of where the electricity has been consumed. Specific electricity generation costs are computed as the total costs of generation divided by the amount of the electricity generated in that region. A second possible metric is to calculate the total generation cost of the electricity consumed in a given region, regardless where the electricity has been produced. The cost of electricity demand in each region is therefore obtained as the total cost of electricity generated in that region, plus the cost of the electricity imported from the other region minus the revenues from electricity exported[10]. The specific cost of demand is calculated as the total cost of demand divided by the total electricity that has been consumed in that region.

In the present study, the latter metric has been consistently used. "Generation costs" in a given region therefore implicitly refers to the generation costs of satisfying the demand in that region.

A second important aspect is whether and how brownfield hydroelectric resources, i.e. hydroelectric run-of-the-river, reservoir and pumped storage, should be accounted for. The hypothesis underlying the present study is that hydroelectric resources are already built and available in the system. Their deployment is the same in seven of the eight scenarios considered.

In the present study, we have therefore not considered the hydroelectric brownfield resources in the cost assessment. Consequently, when calculating the specific cost of electricity demand (expressed in USD/MWh), the total costs are divided by the yearly electricity demand minus the electricity provided by run-of-the-river and reservoir-based hydroelectric resources. Hydroelectric resources constitute essentially a "free" source of

9. The four main assumptions discussed in the annex are: i) Risk-neutrality and perfect market competition, ii) Modelling of transmission and distribution grid, iii) Perfect forecast of future demand and VRE generation and iv) Representation of a single year.

10. The cost of electricity imported (or the value of the electricity exported) in a region is obtained as the quantity imported (or exported) times the specific prices occurring in that region.

flexibility already present in the system. A different approach could have been to explicitly consider the cost and the electricity generated by these brownfield resources. However, considering the costs of such brownfield resources would simply increase by the same amount the cost of electricity generation in all seven scenarios; the comparison of such seven scenarios would therefore been unaffected by including or not including the brownfield hydro resources in the cost assessment. However, this would have made more complex comparing of the scenario where hydroelectric resources are not present with the others.

Finally, due to numerical approximations, the CO_2 target effectively achieved in each scenario may be slightly different from the target level of 50 g/kWh. These imbalances have been corrected by assuming a carbon price of 35 USD/tCO_2, i.e. the carbon price deemed sufficient to achieve the carbon reduction targets in the main region in the base case scenario.[11, 12] These adjustments are negligible in all scenarios, with exception of the base case scenario, where the carbon emissions in region 2 are significantly lower than the target (see Figure 51).

System costs are surplus costs over and above the costs of a reference system. As discussed in Chapter 2, the definition of system costs and their quantitative estimates depend on the choice of the reference system. In this study, system costs associated with VRE are calculated with respect to a reference system constituted only by dispatchable technologies. This assumption allows defining and quantifying the system costs of VRE in the easiest and most straightforward way. It should be noted that the reference system could be also defined as the most economically efficient least-cost system. Under the cost assumptions taken in this study, the reference system is also the economically efficient least-cost system. However, the two reference systems diverge as soon as the plant-level costs of VRE fall below those of nuclear; for instance, under the cost assumptions, considered in the Scenario VI, the least-cost system would have a share of VRE technology.[13]

Some considerations on modelling

Before presenting the insights and main conclusions of this exercise, it is important to underline the limitations of this effort in term of modelling tools as well as the impact of economic and technical assumptions used. Additional considerations can be found on Annex 3.A2. With the exception of hydroelectric resources, which are exogenously given in all scenarios, this study considers the electricity system as a greenfield: the composition of the generation mix and the hourly dispatch of individual plants are optimised to meet the electricity demand at a minimal cost. This choice provides a picture of the generation mix in the 2050 horizon and allows for an unbiased comparison of different low-carbon technologies and decarbonisation strategies. However, such modelling does not provide any information on the possible paths to reach such a long-term generation mix from the status quo. The economic assumptions and technical characteristics of the main generating technologies, storage options and demand-side measures reflect the IEA/NEA projections in OECD countries for 2020 as well as other available estimates. These have an impact on both technical and economic outcomes of the present study. For instance, a drastic reduction in VRE generation costs with respect to those of other low-carbon dispatchable technologies, significant reductions in storage costs or a large-scale development of demand-side flexibility options would all have a significant effect on total generation and system costs.

11. For example, if the CO_2 emissions exceed the targeted level by 1 000 tonnes, the yearly generation costs increase by USD 35 000. Likewise, if carbon emissions are 1 000 tonnes below the specified target, USD 35 000 will be deducted from generation costs.
12. The level of carbon tax needed to achieve a given carbon emission reduction depends strongly on the system assessed, on the cost assumptions used for low-carbon technologies and for CCGT as well as whether a short-term or a long-term perspective is considered. Different assumptions could lead to strong variations in the level of carbon price needed.
13. It should be noted that, under the assumptions taken in this study, the least-cost optimal system is the one that minimises the cost of electricity provision, i.e. the sum of plant-level costs and system costs. In other words, the optimal generation share of VRE is reached when (and if) their lower plant-level costs exactly offset their system costs.

Given the complexity and the large time frame involved in power system optimisation, several simplifications must be made to ensure that calculations can converge in a reasonable time. Among the most relevant assumptions taken in this study are: i) only a single year is considered, with time intervals of one hour, ii) a continental-scale region is treated as a simplified "copper plate" two-region system without a detailed representation of the T&D grid and iii) decisions on the optimal generation mix and power plant dispatch are taken assuming a perfect forecast of future demand as well as of VRE generation. As a consequence of these assumptions, the connection and T&D costs are not accounted for, nor are they integrated into the optimisation process. Limiting the analysis to a single year and assuming a perfect foresight of future demand and renewable generation levels makes the resulting generation mix unlikely to be optimal for a different calendar year or over a longer period. The generation mix may even be unable to guarantee an acceptable level of security of supply for different meteorological years or taking into account the power plant dispatching under uncertainty. In particular, using only one scenario with copper plate assumption and assuming a perfect foresight of future demand and renewable generation is very optimistic especially for the 50% and 75% VRE scenarios: these assumptions inevitably underestimate VRE curtailment and balancing costs, underestimate the security of supply margin, and overestimate the capacity credit of VRE and the value of storage.

More generally, the model is not designed to operate at sub-hourly intervals and therefore is not adapted to provide insights on the overall stability of the system and on security of electricity supply issues. Accounting for these aspects would have inevitably increased the generation costs for all scenarios analysed. These cost increases are expected to be higher in the scenarios with high VRE generation, where uncertainties and yearly variations in the generation/load balance become more significant, thus leading to higher profile costs than those currently assessed. Despite these limitations, which are intrinsic in any numerical modelling, the quantitative analysis allows some valuable technical and economic insights of the integration of low-carbon technologies into an electricity system to be made, and some policy conclusions to be drawn.

3.3. Impacts on the electricity system and on other generators

As discussed in Chapter 2, with the deployment of VRE the shape of the residual load changes and its volatility tends to increase with larger, more frequent and steeper power changes for the remainder of the system. As a consequence, the long-term optimal generation mix shifts towards the deployment of more peakers and more mid-merit power plants at the expense of baseload generation. A more volatile residual load also has an impact on the operating mode of conventional power plants, which are likely to undergo a more frequent ramping and operate at lower load factors. Finally, when VRE reach high penetration levels, their generation must be at times curtailed even for a well-interconnected system with sizeable storage capacity, such as the one considered in the present analysis. This section will discuss some of these issues, based on the evidence from the quantitative modelling work.

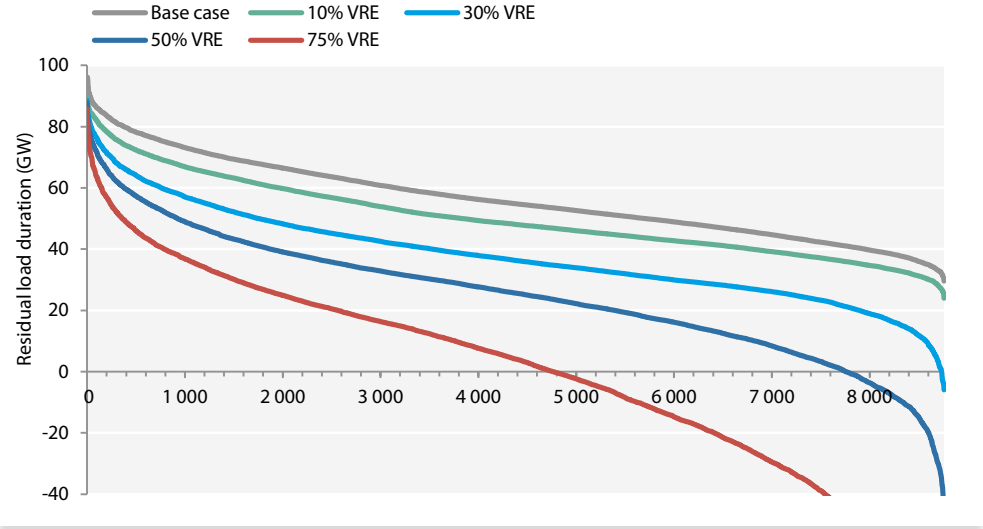
Residual load

Residual load is defined as the total load minus the electricity generated by not dispatchable plants, such as run-of-the river hydroelectric resources and VRE, and has to be covered by the rest of the electricity system, i.e. by an appropriate combination of dispatchable power plants, storage capacities, demand-side measures and by exchanges with neighbouring regions. In this respect, the shape and the predictability of the residual load are two key indicators of the challenges faced by the rest of the electricity system. The flatter and more predictable the residual load, the share of cheaper baseload plants would be larger and the level of operational reserves needed would be smaller.

At 10% penetration level the effect on the residual load duration curve (RLDC) is minimal, owing to the favourable correlation between demand and electricity generation from solar PV and wind resources, as shown in Figure 22. This is reflected by an almost parallel translation

of the load duration curve (LDC) with respect to the base case. Also, neither the residual load variability nor the ramping rates experienced by thermal generation are substantially changed. Hence the integration of the first capacity of VRE resources in the system considered in the present study does not affect the structure of the residual system nor the flexibility requirements from the conventional mix.

Figure 22. **Yearly residual load duration curves for different levels of VRE generation shares**



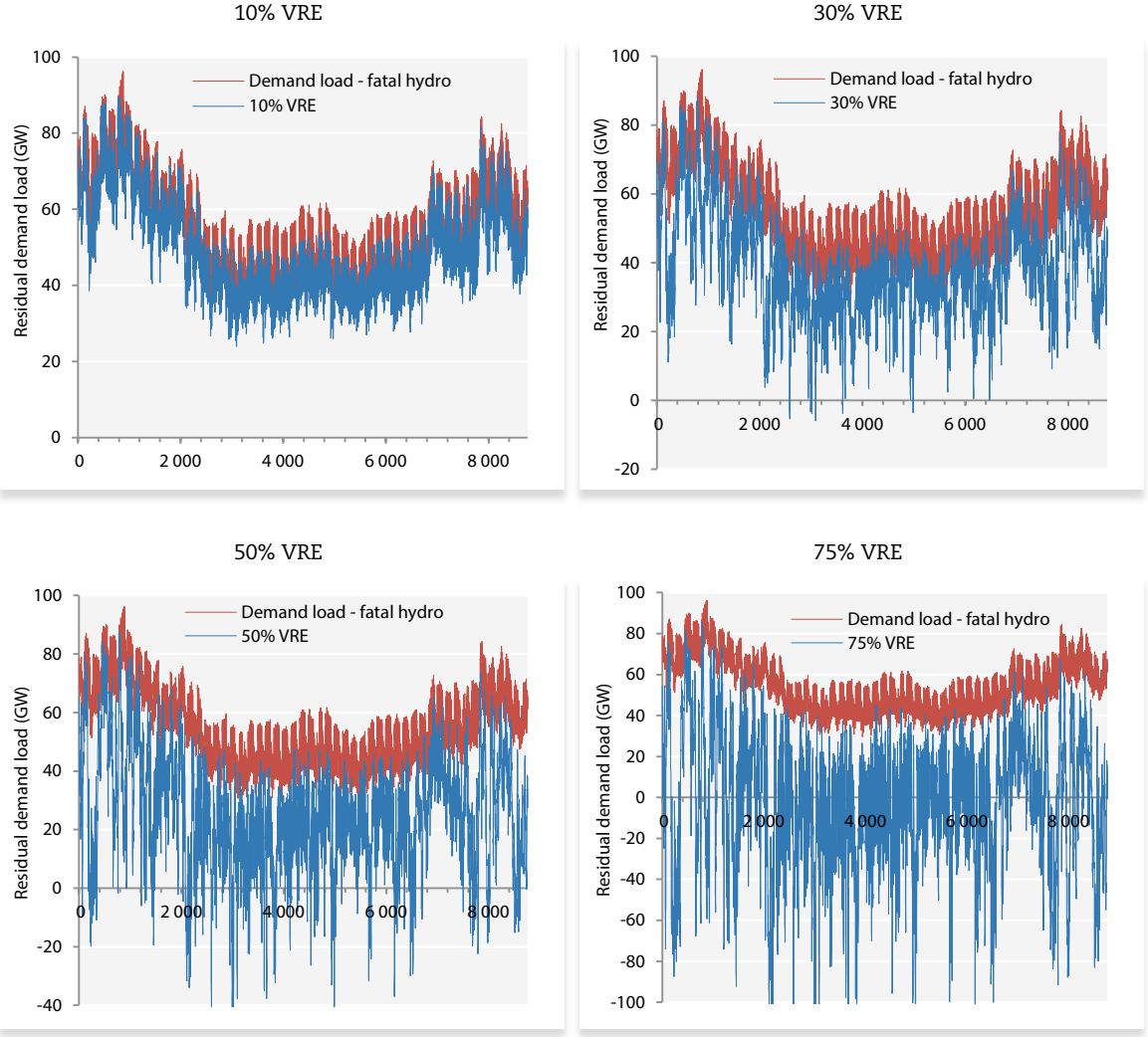
This no longer applies for more ambitious VRE targets. At higher shares of VRE generation the RLDC becomes increasingly steeper, and the generation from VRE resources contributes more to the right end of the curve (periods of low residual demand and high VRE generation, where the value of electricity is lower) than to the left side of the curve (periods of high residual demand and low VRE generation, where the value of electricity is higher). The resulting optimal generation mix is therefore likely to contain more peakers and mid-merit and less baseload generation. The number of hours in which the VRE fully meet the demand increases also with their penetration level; the excess of VRE generation must be curtailed if it cannot be stored or transferred to the interconnected region. Although not visible on the RLDCs shown in Figure 22, the residual load becomes also increasingly volatile and more unpredictable, being dominated by the uncertain VRE generation rather than by the more predictable demand pattern. For instance all indicators of the residual load volatility, either the standard deviation, the maximal amplitude of load changes or the ramp rates, increase substantially with VRE generation share. The combination of a more volatile and more unpredictable residual load raises substantially the requirements for flexibility from the thermal mix together with the challenges in providing it.

When the VRE generation share reaches 50%, there are also more and more occasions in which the electricity produced by VRE and fatal hydro resources exceed the demand, thus causing the residual load to turn negative. On these occasions, if there is no possibility to store the surplus electricity or to transfer it to neighbouring regions, the excess generation must be curtailed[14]. Figure 23 shows the residual load in the main region, obtained as the load minus the generation from "fatal" run-of-the river hydroelectric plants in red. Each of the four plots compares the residual load in the base case scenario (without VRE, thus in red) with that of the four scenarios with imposed VRE capacities, in blue.

14. This aspect will be discussed more in detail in Section 3.

As these plots clearly illustrate, with the deployment of VRE the residual load is lower and becomes increasingly more volatile. The maximal amplitude of residual load variations as well as the gradients of these changes (ramp rates) are also significantly affected. These effects are increasingly severe with higher VRE penetration level and make the balancing of the electricity system by dispatchable generators, storage capacity, exchanges with neighbouring regions and demand-side measures more and more challenging. Another important feature of VRE deployment is that the residual load becomes not only more volatile but also more unpredictable. In particular, especially when the VRE generation share becomes significant, the traditional daily, weekly and seasonal patterns of the load are no longer reflected in the residual load. These are, in turn, dominated by the variability of VRE generation. Under these conditions it becomes increasingly challenging to schedule in advance the periodic outages of thermal power plants for maintenance and, in case of nuclear, refuelling. Also, anticipated planned load reduction when demand is expected to be weaker (during the week end or holidays, for example) may also become increasingly difficult when the VRE share becomes significant. For the same reasons, the optimisation of the operation of flexible hydroelectric resources and other storage capabilities become increasingly challenging.

Figure 23. **Comparison of the residual load at different VRE generation shares**



Note that the figures have a different vertical scale.

Table 4 provides several quantitative indicators which can be used to characterise the variability of the residual load: the average level of the residual load, its standard deviation, the maximal amplitude of changes in the residual load (positive and negative) within a 12 hour interval as well as the maximal positive and negative ramp rates on an hourly time frame are shown. Indicators of variability of the residual demand in the main region are provided for the five main scenarios, together with those for the load, as a term of comparison. Finally, Figure 24 shows the distribution of the ramp rates required from the thermal generation plants in the main region for different VRE penetration levels; by focusing only on thermal plants, the graphs already integrate the reduction in ramp rates due to the beneficial effects of VRE curtailment and of the optimal dispatch of flexible hydroelectric resources, storage capacities and demand-side mechanisms.

Table 4. **Variability of the residual demand in the main region**[15]

	Load	Residual load				
		Base case	10% VRE	30% VRE	50% VRE	75% VRE
Average (GW)	61.3	56.3	50.2	37.9	25.9	9.4
Standard deviation (GW)	13.2	12.7	12.5	14.9	18.4	20.2
Maximal positive amplitude (GW)	25.3	23.4	26.2	38.9	56.8	70.4
Maximal negative amplitude (GW)	-23.6	-22.5	-21.6	-40.4	-53.7	-77.1
Maximal positive ramp rate (GW/h)	5.9	5.7	6.0	9.3	13.3	21.8
Maximal negative ramp rate (GW/h)	-9.7	-8.9	-9.5	-13.6	-17.9	-25.2
Frequency of ramp rates exceeding ± 5 GW/h	6.9%	4.9%	5.2%	10.4%	20.5%	28.7%
Frequency of ramp rates exceeding ± 10 GW/h	0.0%	0.0%	0.0%	0.1%	1.8%	10.3%
Frequency of ramp rates exceeding ± 15 GW/h	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%

Note: The maximal positive (negative) amplitude is calculated as the maximal positive (negative) variation of the residual load within an interval of maximal 12 hours.

In the main region, the integration of "fatal" run-of-the-river hydro resources helps reducing, albeit only slightly, the variability of the demand[16]: all indicators, standard deviation, maximal amplitude in residual load changes and ramp rates, are lower. Interestingly, the overall variability of the residual load is not significantly affected by the introduction of the first 10% of VRE: the maximal amplitude of load variation and maximal ramp rates are only slightly different than those in the base case, while the overall standard deviation actually decreases. This indicates that the deployment of the first 10% of VRE does not have a major impact on the residual load and on the mode of operation of the thermal power generation. Such behaviour may be explained by the good correlation between demand and wind and solar PV generation, which is observed in the two regions represented here (see Table 9 in Annex 3.A1 for more details). However, the variability of the residual load increases markedly when variable renewable resources reach a generation share above 30%. For instance, the standard deviation of the residual demand reaches a value close to its average at 50% VRE penetration. When VRE reach a generation share of 75%, the standard deviation of the residual demand is more than double of the average.

Similar trends are observed when looking at the maximal amplitude of the residual load. The maximal amplitude of the load is roughly 25 GW in both directions: +25.3 GW as maximal load increase and -23.6 GW as maximal load decrease. These values do not change significantly

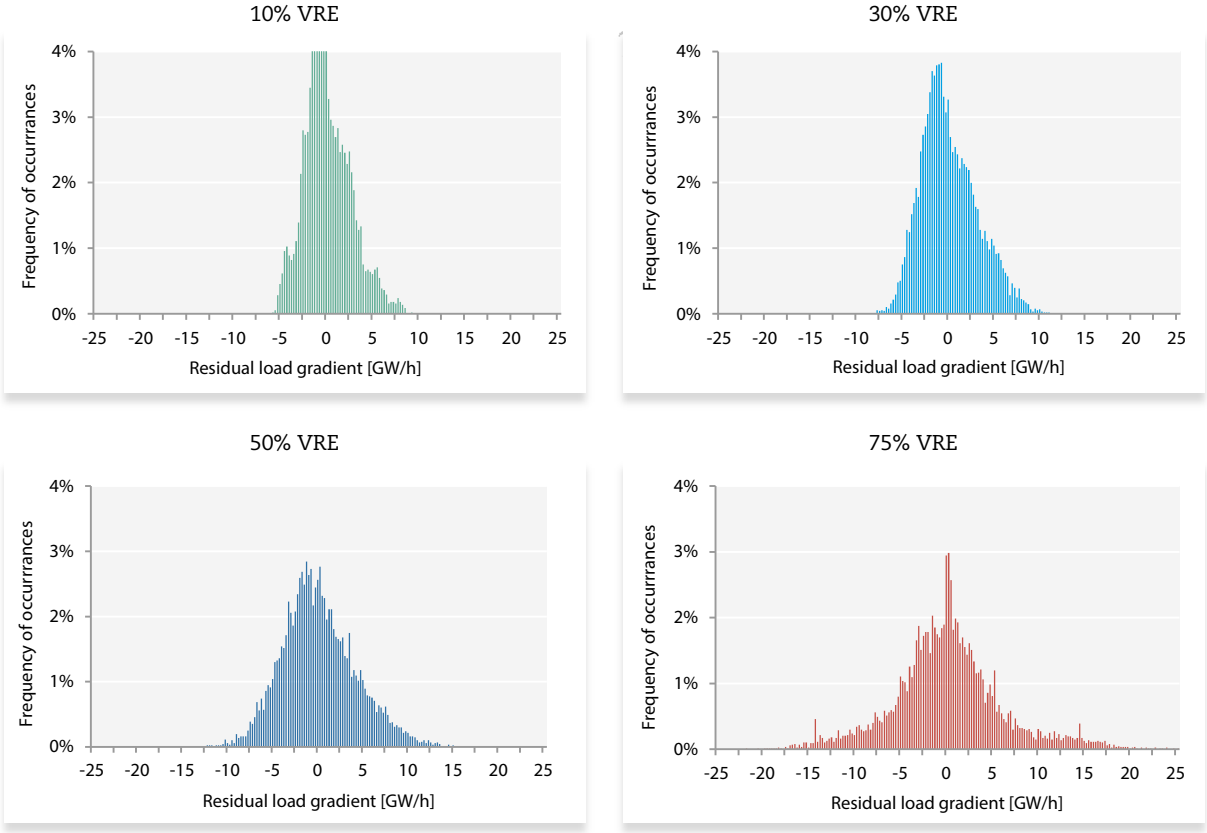
15. Only the net amount of wind and solar PV generation has been taken into account in calculating the residual demand, without accounting for the electricity curtailed; this would have significantly increased the residual demand standard deviation (and reduced its average).

16. In order to see the benefits of the integration of run-of-the-river hydroelectric resources the results of *Load* in Table 4 should be compared with the *Residual load* in the base case scenario, which have been obtained by subtracting the generation of run-of-the-river resources from the load.

after the integration of the "fatal" hydroelectric resources and the first 10% of VRE resources. However, the maximal amplitude of the load increases dramatically when VRE penetration level reaches a value of 30%. The maximal amplitude of the load almost doubles to +39 GW and -40 GW at 30% penetration level, while it reaches a value of roughly 55 GW at 50% VRE penetration. In these circumstances the power system must increase or decrease its generation by a value close to its average load within a few hours. The maximal variations of the residual load that the system must accommodate within a few hours are way above 70 GW (more than 70% of the peak demand) in the last scenario where VRE generate 75% of the total electricity.

The increasing difficulties for balancing the system appears also clearly when comparing the required maximal ramp rates (Table 4) and ramp rates distributions (Figure 24). These metrics characterise the speed at which the power should be decreased or increased (rates of change). The maximal positive hourly gradient of the demand (upward ramping) is in the order of 6 GW/h, while the maximal negative hourly gradient (downward ramping) is about -10 GW/h. Also, the majority of the hourly load variations are within a range of ±5 GW/h, while only 7% of the gradients exceed these values. As already noted, the introduction of fatal hydroelectric resources and of the first VRE capacity slightly reduces these figures. When the VRE reach a penetration level of 30%, maximal ramp rates increase to 9 GW/h and -14 GW/h. Also, in about 10% of instances the gradient observed is larger than ±5 GW/h. At 50% VRE penetration, roughly 20% of the load gradients are larger than ±5 GW/h, and the maximal ramp rate is more than double compared to that of the demand. In about 2% of cases, ramp rates exceed ±10 GW/h. The situation is more extreme when the VRE reach a generation share of 75%: only 70% of the gradients are within ±5 GW/h, while 10% of the time the required ramping exceeds the ±10 GW/h. Maximal ramp rates observed are well above ±20 GW/h.

Figure 24. **Gradient of the residual load (ramp rates) seen by the conventional mix at different VRE generation shares**



Structure of the generation mix and electricity generation shares

The combination of explicit targets for VRE technologies and a stringent limit on carbon emissions has important impacts on the composition of the generation mix as well as on the technology's share of electricity generation. The total generation capacity increases significantly with the deployment of VRE resources. This is essentially due to three separate effects:

i. the load factor of VRE is significantly lower than that of conventional thermal power plants, so a much higher capacity is needed to produce the same amount of electricity than a thermal baseload plant;

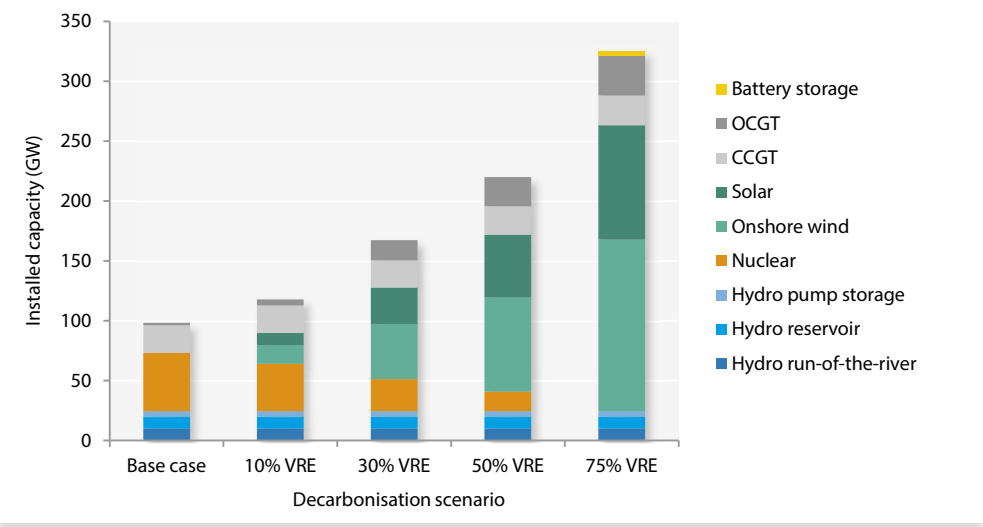
ii. at higher penetration levels, a fraction of the electricity produced by VRE has to be curtailed, thus further reducing the effective load factor;

iii. in general, the capacity credit of VRE[17] is lower than that of conventional thermal plants and decreases substantially with their penetration level. Thus, further addition of VRE capacity reduces only marginally the residual system's capacity needs.

Results from this modelling exercise confirm this trend. While about 98 GW are installed in the base case scenario, the deployment of VRE to a penetration level of 10% and 30% increases the total capacity of the system to 118 and 167 GW, respectively. The total installed capacity would more than double to 220 GW if a VRE penetration level of 50% has to be reached. More than 325 GW, i.e. more than three times the peak demand, are needed if VRE generate 75% of the total electricity demand. The capacity mix of different generation technologies in the five main scenarios is illustrated in Figure 25, while their respective electricity generation share is provided in Figure 26 below[18].

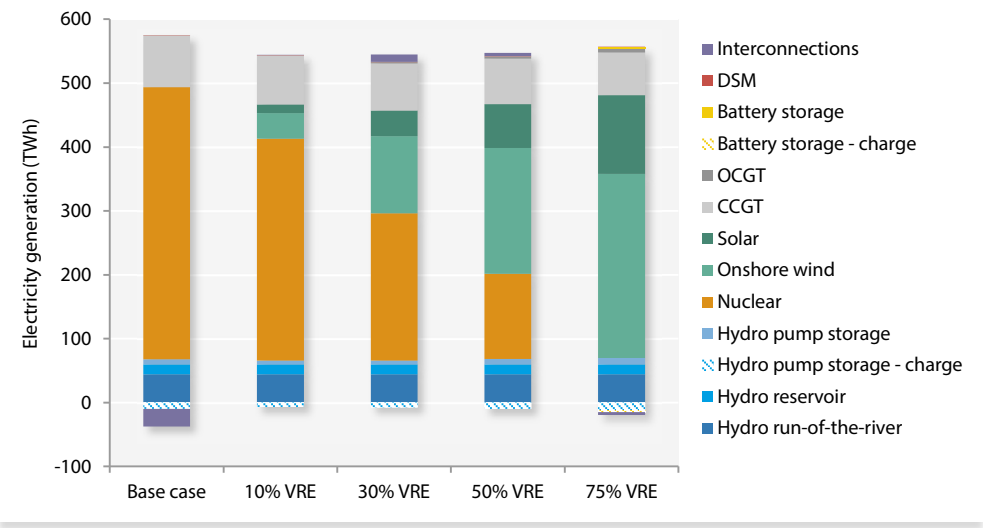
Another important finding of the present study is that, under the stringent carbon constraints adopted, coal is never deployed in any of the scenarios considered, despite being cheaper than the other technologies on a pure Levelised cost of electricity (LCOE) basis. In terms of electricity generation, VRE generation displaces nuclear power almost on a one-to-one basis, which results from the fixed carbon constraint in combination with a fixed amount of hydroelectric resources.

Figure 25. **Capacity mix in the main region (main scenarios)**



17. More precisely, the metric of relevance here is the ratio between capacity credit and load factor.
18. Numerical figures are provided in Annexe 3.A3, Table 12 and Table 13.

Figure 26. **Electricity generation share in the main region (main scenarios)**



The share of fossil-fuelled generation (OCGT and CCGT) remains almost constant in all scenarios, as it is limited by the carbon cap. However, the structure of the capacity of installed gas plants and the relative share of generation from OCGT and CCGT change significantly with the presence of VRE. While the optimal capacity of CCGT power plants is almost constant in all scenarios considered, they are operated at lower load factor in the scenarios with more variable generation. On the contrary, the presence of variable generation increases substantially the required capacity of peaking generation as well as their generation share. For instance the required capacity of OCGT (peakers) in the main region increases from about 2 GW in the base case to 17 GW when the VRE penetration level reaches 30%. At higher VRE penetration levels the system needs about 24 and 33 GW of peaking capacity.

Finally, the way in which thermal plants operate changes significantly with the deployment of variable resources in the system. A reduction of load factors is observed for baseload and mid-merit plants, as well as a strong increase in ramping rates and load-following requirements.

An illustration of the phenomena described above is provided in Figure 27 below. This figure compares the composition of the generation mix of each of the main scenarios with VRE, with that of the base case scenario, which features only dispatchable technologies. In each of the scenarios with VRE, the generation mix is subdivided into two components, *VRE* and residual system, and is compared with the base case scenario, which is also subdivided into two components, equivalent baseload and residual system. In all four cases, the equivalent baseload capacity in the base case scenario provides the same electricity as that generated by VRE; in such way, the two residual systems are equivalent and can be directly compared. These equivalent capacities are plotted in the first (equivalent baseload) and in the fourth (VRE) columns of the graphs. The difference in their installed capacity simply reflect the different load factors of VRE and dispatchable technologies, as well as the curtailment of VRE when needed (effects i. and ii. described above).

The comparison of the residual system in the two middle columns provides important insights on the composition and characteristics of the residual system, i.e. of the optimised mix that ensures the residual load once the VRE generation (or the equivalent generation from baseload) have been integrated. Three important phenomena can be observed:

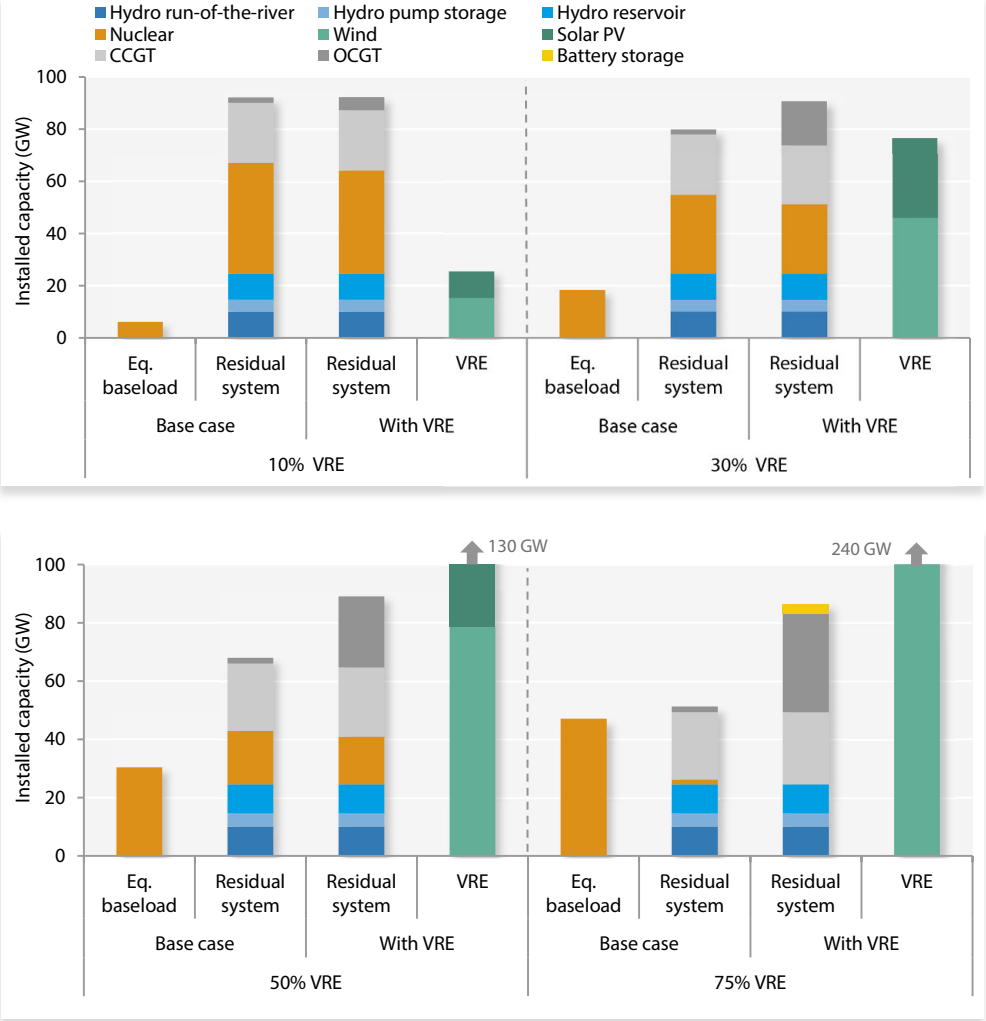
i. the capacity of the residual mix is higher in presence of VRE than in presence of dispatchable baseload; this reflects essentially the lower capacity credit of VRE compared to that of baseload power units;

ii. after the integration of the first 10% of VRE, the deployment of additional variable resources decreases only marginally the total capacity of the residual system;

iii. with increasing generation share of VRE, the composition of the residual mix shifts towards less capital-intensive technologies; in particular the OCGT capacity increases markedly at higher VRE penetration rates.

The graphs clearly illustrate how the capacity of the residual system increases with the generation share of VRE in the system. While the deployment of the first 10% of VRE allows reducing the conventional system from 98 GW to 92 GW, further deployment of VRE does not change significantly the capacity of the conventional mix. At 30% penetration level, the total conventional capacity is limited to only 90 GW, and to 89 GW if VRE reach a penetration level of 50%.

Figure 27. **Breakdown of capacity mix for the main five scenarios**



In terms of electric energy generation, the main effect observed is that VRE generation replaces nuclear power on an almost one-to-one basis. No other major effects are observed, beside the already mentioned shift towards a higher share of OCGT generation with respect to CCGT. This is different from what was observed in *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems* (NEA, 2012) where VRE were substituting nuclear on more than

a one-to-one basis, with the gap being filled with additional generation from fossil fuels. For instance, the 2012 NEA report found that the deployment of 1 TWh of VRE would displace a higher amount of electricity generated by nuclear, with an equivalent increase of electricity generated by fossil fuels. The report concluded that if a low-carbon technology such as (nuclear) was replaced by a combination of low-carbon VRE and fossil fuels; this combination would minimise the cost of electricity generation but would also lead to higher carbon emissions in the long term. A similar outcome is not observed in the present study, as the strict carbon constraint limits the total amount of electricity produced by fossil-fuelled plants.

In the low VRE cost case (Scenario VI), VRE are developed endogenously in the system to reach a generation share of 15% in the main region and roughly 50% in region 2. In terms of electric energy generation, VRE substitute nuclear energy almost on a one-to-one basis (the residual baseload capacity is almost identical in the two scenarios). The other major visible trend is the increase in OCGT capacity and a consequent shift in fossil fuel generation from CCGT to OCGT. These trends are illustrated in Figure 28 and Figure 29 which compare the installed capacity and the generation share in the base case with that of the low VRE cost case.

Figure 28. **Capacity mix in the main region: Scenarios I and VI**

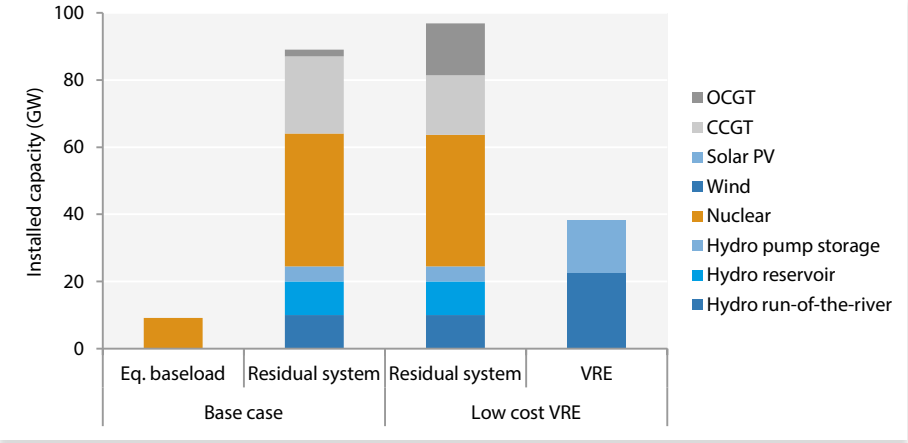
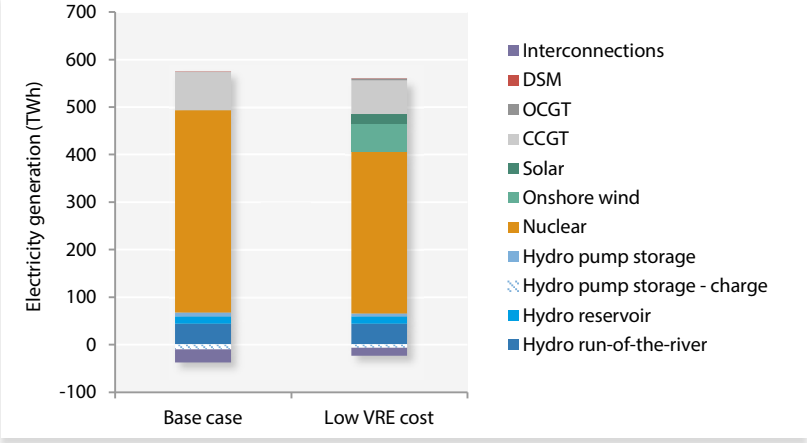


Figure 29. **Electricity generation amounts in the main region: Scenarios I and VI**



The analysis of the three scenarios featuring the same amount of VRE generation capacity (scenarios IV, VII and VIII) provides some insights on the impacts of interconnections and flexible resources on the residual system composition. The resulting capacity mix and electric energy generation amounts are provided in Figures 30 and 31. As expected, the impact on the residual system and the challenges for integrating VRE increase progressively when going from a well-interconnected system with significant flexible hydro resources (50% VRE scenario) to an isolated system (case study VII) and to a system which also does not have flexible hydro resources (case study VIII).

The most relevant effect observed is the increased curtailment of VRE resources and the consequent reduction of the total net electricity generated by VRE. This effect is more severe when the system lacks not only interconnections with a neighbouring region but also flexible hydro capacity that would ease the integration of variable resources. In both scenarios the additional curtailment of VRE generation is compensated by an increase in nuclear generation, which is the cheapest low-carbon technology available for deployment. In comparison with the base case, nuclear capacity increases by 3 GW in scenario VII and by 8 GW in scenario VIII, respectively. In the last scenario, nuclear generation compensates also for the generation lost from reservoir-based hydroelectric plants. Another phenomenon observed is the progressive increase in gas power plants capacity with the increasing challenges faced for the VRE integration. Also, in scenario VIII some storage capacity is endogenously deployed in the system.

Figure 30. **Capacity mix in the main region: scenarios IV, VII and VIII**

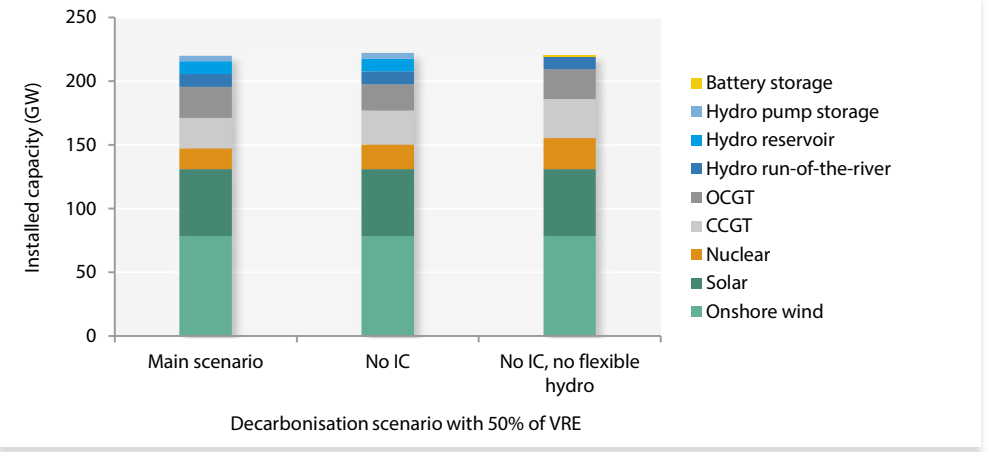
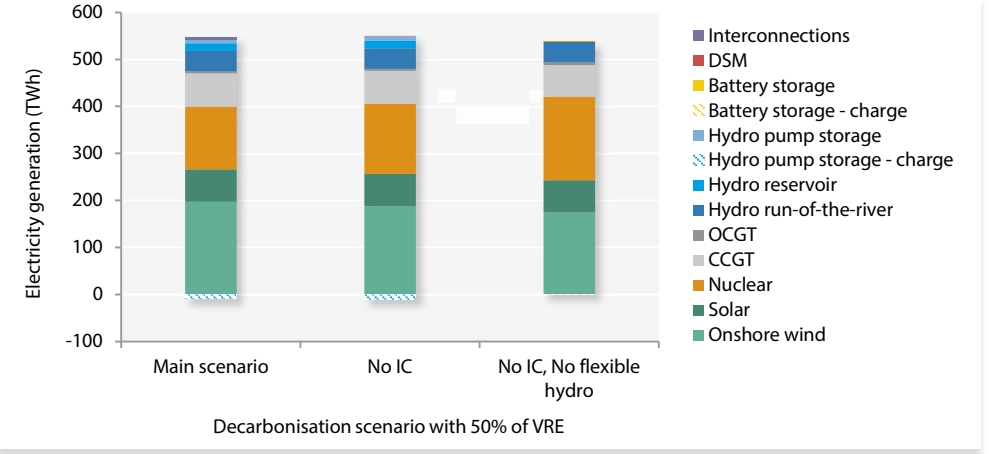


Figure 31. **Electricity generation amounts in the main region: Scenarios IV, VII and VIII**

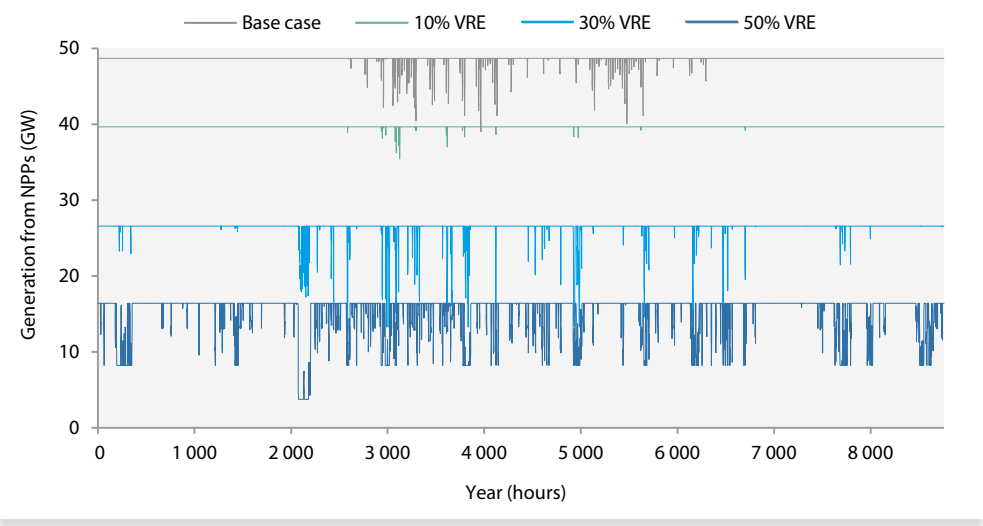


Impact on the operations of nuclear and other thermal power plants

The deployment of variable renewable sources and their integration into the electricity system increases the need for flexibility within the whole electricity system. Part of this additional flexibility is provided by the VRE themselves via the curtailment of their generation, by building additional storage capacity or using more frequently the existing hydroelectric storage reserves available, and by increasing the power exchanges between the two interconnected regions. In particular, the amount of the electricity exchanged with neighbouring regions increases with VRE penetration, as well as the number of hours in which the interconnections operate at full capacity. However, given the investment and operational cost assumptions taken in the present study, the largest source of flexibility in the system is provided by gas-fired and nuclear thermal plants.

As previously discussed, the integration of VRE changes the long-term structure of the thermal generation mix, with a shift towards less capital-intensive and more flexible technologies. However, the way in which thermal plants operate also changes significantly, with a reduction of the average load factors and an increase of ramping and load-following requirements. The present section illustrates how the operational patterns of thermal plants change in conjunction with the deployment of VRE resources. Figure 32 shows the projected hourly generation pattern of the nuclear fleet in the main region for four of the five main scenarios considered (there is no nuclear generation in the scenario with 75% VRE).[19] This representation allows visualising the increased flexibility requirements from nuclear plants, as well as the reduction in nuclear capacity associated with VRE deployment. Similar plots are presented for gas-based technologies (OCGT and CCGT) in Figure 34. In order to improve the readability of the plots the hourly generation patterns for the five main scenarios are plotted as independent graphs one above the other. The use of the same scale allows better visualisation of the differences in term of installed capacity and flexible requirements associated with different VRE generation shares. Finally, Table 5 summarises the most important operational characteristics of different thermal power plants.

Figure 32. **Projected generation pattern from nuclear power plants**



19. The total electricity generated by nuclear power (or any other technology) over one year can be obtained as the integral of the hourly generation curve. Graphically it is represented by the surface between the hourly generation curve and the zero-axis.

Nuclear capacity progressively decreases with the share of renewables, and no nuclear is needed when VRE cover 75% of the total demand, as VRE and hydroelectric power provide a sufficient share of low-carbon generation to achieve the carbon emission target. In the base case scenario, nuclear power is the major source of low-carbon electricity and produces about 75% of the total electricity demand. Some degree of flexibility is required from nuclear power plants towards the middle of the year, when demand declines; however, the impact on amount of load factor is very low, at around 0.2%. The maximal hourly ramping observed is in the range of ±5 GW/h, i.e. about 10% of the total capacity. At low VRE generation shares (such as i.e. 10%), the flexibility requirements from nuclear power decrease even further and nuclear power is operated as baseload throughout almost the entire year; therefore the impact on load factor is negligible. The maximal hourly ramp from nuclear power is almost halved to roughly ±2.5 GW/h. This somehow surprising effect may be related to the good correlation between VRE generation and demand which smooths the residual demand at least at low penetration levels.

When the VRE penetration level reaches between 30% and 50%, nuclear units are required to be more flexible in order to adapt to a more variable residual load. The impact on nuclear generation becomes significant at 50% VRE penetration, with a load factor loss of more than 7%. While the maximal (positive and negative) ramping does not increase much in absolute terms, they have to be assured by a lower nuclear capacity, thus leading to much higher rates. In the 50% VRE case, nuclear units must ramp up and down by a maximal 30-35% of their installed capacity in one hour, and there are about 240 events per year where nuclear units ramp up or down by more than 20% of their maximal capacity. In these scenarios there are also extended periods of generation at the minimal power rate, as can be observed in Figure 32.

Table 5. **Operational behaviour of thermal power plants at different VRE penetration levels**

			Base case	10% VRE	30% VRE	50% VRE	75% VRE
Nuclear	Capacity	GW	48.7	39.7	26.6	16.4	
	Curtailment	%	0.2	0.0	1.1	7.2	
	Maximal positive ramp	GW/h	4.8	2.7	5.3	4.7	
	Maximal negative ramp	GW/h	-4.6	-2.4	-5.3	-6.0	
	Maximal positive ramp	%/h	9.9	7.0	20.0	29.0	
	Maximal negative ramp	%/h	-9.4	-6.0	-20.0	-36.0	
	Average positive ramp rate	GW/h	1.2	0.8	2.0	1.8	
	Average negative ramp rate	GW/h	-1.1	-0.8	-1.7	-1.6	
	Average positive ramp rate	%/h	2.5	2.0	7.6	10.9	
	Average negative ramp rate	%/h	-2.2	-1.9	-6.2	-9.5	
CCGT	Capacity	GW	23.0	23.0	22.7	23.8	24.8
	Average Load factor	%	39.8	37.9	37.0	34.1	30.8
	Maximal positive ramp	GW/h	14.6	15.4	15.9	16.0	17.3
	Maximal negative ramp	GW/h	-7.5	-8.1	-10.0	-12.6	-17.3
	Average positive ramp rate	GW/h	3.6	3.4	3.3	3.5	4.5
	Average negative ramp rate	GW/h	-2.6	-2.3	-2.4	-2.9	-3.8
OCGT	Capacity	GW	2.0	5.1	17.0	24.4	33.8
	Average Load factor	%	3.7	1.1	1.5	1.8	2.2
	Maximal positive ramp	GW/h	1.5	2.1	7.7	11.2	20.7
	Maximal negative ramp	GW/h	-1.7	-1.3	-6.1	-9.8	-17.2
	Average positive ramp rate	GW/h	0.3	0.5	1.9	2.5	3.3
	Average negative ramp rate	GW/h	-0.3	-0.5	-1.6	-2.1	-2.8

Some interesting trends can be observed in the operation of gas-fuelled power plants, (open cycle gas turbines [OCGT] and combined cycle gas turbines [CCGT]). Whereas the optimal capacity of CCGT is almost constant in all scenarios considered, their average load factor, and thus their overall electric energy generation decrease with VRE penetration level. CCGT are also operated more flexibly, with more frequent power cycling and steeper ramps, as can be observed in Figure 33. The most significant impacts on power plant operations are observed for the most flexible thermal plants (OCGT). Their installed capacity increases drastically with penetration level, from 2 GW in the base case to over 30 GW in the 75% VRE scenario, as these peakers must balance an increasingly more volatile residual load. These plants must therefore undergo steeper and steeper ramping rates, as clearly shown in Figure 34.

Figure 33. **Projected generation pattern from gas-fuelled CCGT power plants**

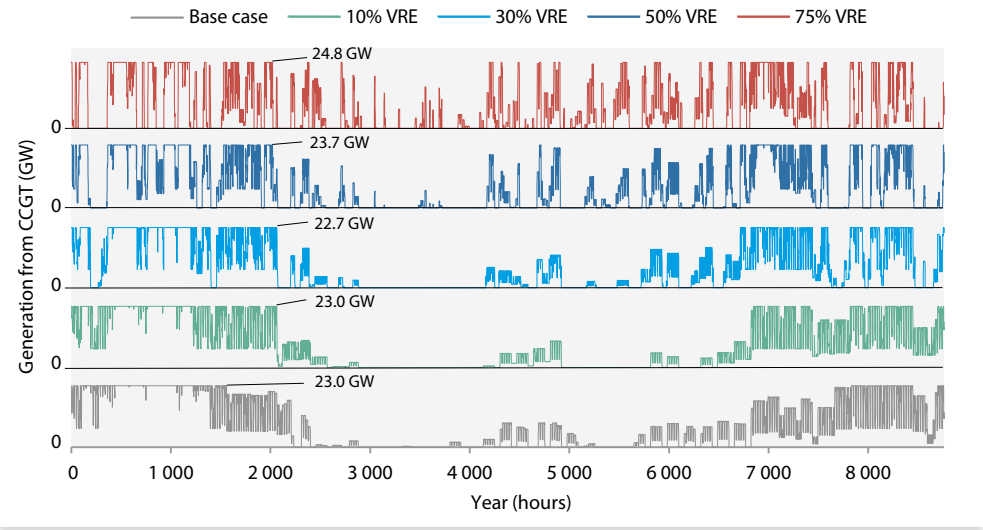
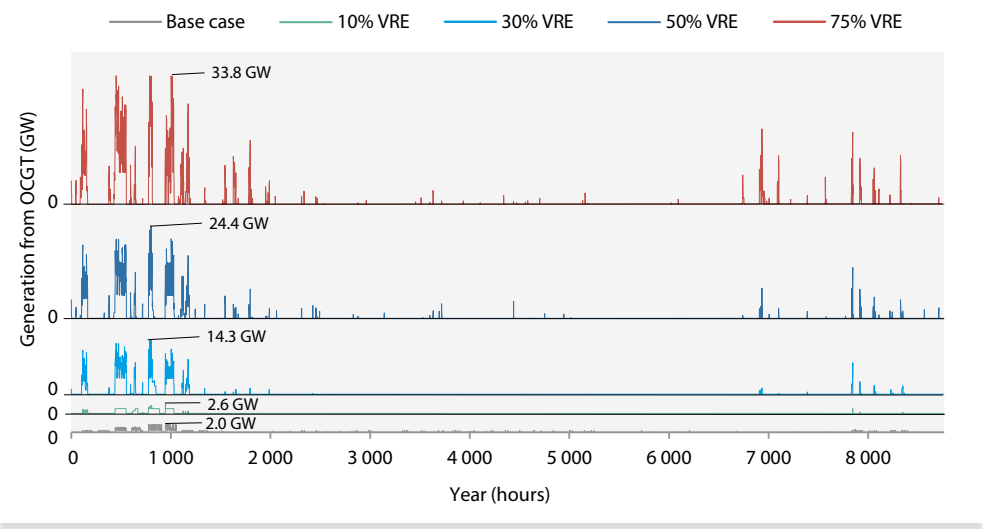


Figure 34. **Projected generation pattern from gas-fuelled OCGT power plants**



Curtailment of VRE resources

When VRE exceed a certain level, there are some periods when the generation from VRE and from other low marginal cost renewables exceeds the capacity of the system to efficiently make use of them. Hence, the only practical option is to curtail part of the VRE generation[20]. Curtailment of variable renewables generation occurs when there is no more capacity in the system to store excess generation, either because the storage resources are already operating at full power or because the storage capacity is already full, and when the electricity cannot be transferred to neighbouring regions because transmission lines are congested or the interconnected regions are already facing a similar problem of excess generation. However, VRE curtailment does not only occur in these circumstances, i.e. when the residual load becomes negative; in most circumstances it is economically more efficient to keep some thermal capacity running even if the wholesale market electricity price is below the marginal cost of generation. This would avoid the higher costs of shutting down and subsequently restarting the unit or to avoid the cost of ramping up and down the unit. These trade-offs are fully accounted for and optimised within the modelling framework adopted for this exercise. There is evidence that the instantaneous penetration of VRE could also be limited by other technical factors linked with the stability and security of the electricity system. However, these complex considerations have not been taken into account in the model and therefore are not reflected in its results: doing so would have led to even higher VRE curtailment and higher costs for the system.

The most relevant data on the curtailment of VRE resources are provided in Table 6: the fraction of the VRE generation curtailed (averaged over the whole capacity installed) and the curtailment fraction of the last VRE unit deployed (marginal value). The table also provides additional information linking the curtailment of VRE resources with the wholesale electricity market prices; it gives the number of hours when VRE are curtailed, when prices are at zero or below and when the residual load becomes negative. Figure 35 visualises the curtailment of VRE generation in the main scenarios, while Figure 36 shows the impact of the absence of flexible hydroelectric resources and its interconnection with VRE curtailment. For each penetration level, the graph shows the electricity that could have been generated from VRE (dashed line), ordered from the maximal to the minimal value, together with the electricity that has effectively been delivered to the grid; the area between the two curves is the electricity curtailed.

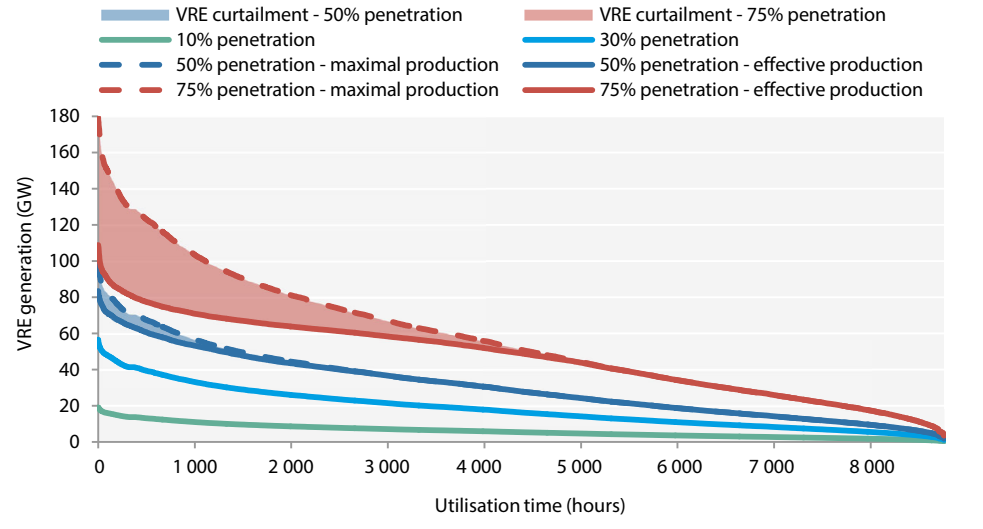
Table 6. **Main quantitative indicators of variable renewable curtailment**

	10% VRE	30% VRE	50% VRE			75% VRE	Low-cost VRE
			Main scenario	No IC	No IC, no flexible hydro		
Fraction of electric energy curtailed from VRE	0.0%	0.1%	3.4%	7.0%	12.0%	18.1%	0.0%
Fraction of electric energy curtailed from the marginal VRE capacity	0.0%	0.6%	10.5%	19.0%	29.0%	35.8%	0.0%
Number of hours when VRE exceeds demand	0	25	1 004	1 004	1 004	3 996	0
Number of hours when market price is zero	0	60	1 204	1 737	2 555	3 744	88
Number of hours when VRE are curtailed	0	51	921	1 667	2 542	3 135	0

20. Note that there is nothing wrong "as such" with curtailment of superfluous electrical power, which is a consequence of the large (over) capacity of VRE that is built in the high VRE scenarios. Cutting electrical power for short times can be a smart way to avoid non-economic oversizing of the electric power system. The amount of energy that is disposed of is small if the curtailment period is short. But the energy "wasted" can become substantial for very high VRE shares of 50% to 75%. In that regard, future systems should pay more attention in the electric power absorption capacity of the entire energy system, whence the ideas of more sector coupling (heating and transportation).

Curtailment of VRE generation[21] is negligible at low deployment levels and starts to appear only when VRE reaches around 30% of electricity generation. No curtailment of VRE occurs in the 10% VRE scenario, while only 0.1% of the total VRE electricity generation needs to be curtailed when VRE reaches a penetration level of 30%. In that scenario, there are only 51 hours per year in which VRE are curtailed. The curtailment of the last VRE unit deployed (marginal curtailment) is 0.6% of its generation. The VRE curtailment rate increases sharply when VRE deployment exceeds this level: at 50% penetration level, average curtailment reaches 3.4% and the marginal curtailment is above 10%. In the scenario featuring a VRE generation share of 75%, about 18% of the total VRE generation must be curtailed, and the curtailment of the last unit deployed is above 36%. Interestingly, no curtailment of VRE is observed in the scenario "low VRE cost", despite the presence of several dozen hours where electricity prices reach a zero level.

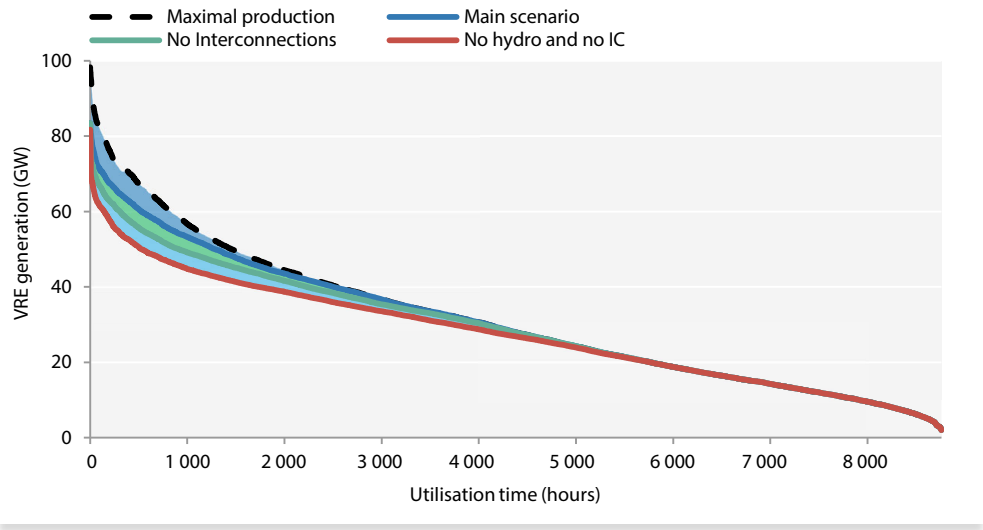
Figure 35. **VRE curtailment – main scenarios**



Finally, the analysis of the three scenarios with 50% of VRE penetration level shows the importance of interconnections and flexible hydro resources on the integration of VRE resources (see Figure 36). The three scenarios have the same wind and solar PV capacity deployed in the main region but they differ with respect to the availability of interconnections (the main region is isolated in both scenarios VII and VIII) and in the availability of flexible hydro resources (no flexible hydro resources are represented in scenario VIII, while in scenario VII the same amount is available as in the scenario IV). With respect to scenario IV, the level of VRE curtailment doubles if interconnections are not available, and increases almost 3.5-fold if flexible hydro is not available. Similar trends are observed for the curtailment rate of the marginal VRE unit deployed, which increases from 10% to 19% and 29%, respectively, as well as for the numbers of hours where VRE curtailment occurs. These results show clearly the importance of having a large well-interconnected system, as well as the impact of local endowment in flexible resources for the integration of VRE.

21. As mentioned above, the model can only capture the VRE curtailment due to economic optimisation, but is unable to capture the curtailment required for other technical reasons.

Figure 36. **VRE curtailment – impact of interconnections and storage**



Note: All three scenarios have the same VRE capacity deployed.

Finally, a comparison of the VRE curtailment rates obtained using two different methodologies (MILP and RLDCs) is provided in Annex 3.A6.

3.4. Costs of electricity generation, profile costs and an estimate of total system costs

Different policy objectives and strategic choices regarding the achievement of carbon emission targets do not only have technical implications with regard to the structure of the generation mix and on the operation of power plants, but they also have far reaching economic implications. Depending on the choice of alternative low-carbon generation options, the total cost for meeting the electricity demand can vary significantly. This section looks at these economic aspects and attempts to estimate the total costs for meeting the electricity demand in the two regions modelled. Throughout this exercise, from the scenarios' definition to the analysis of the results, particular attention has been devoted to assure the comparability across the scenarios selected and among the different low-carbon technologies available.

For each scenario, GenX calculates the economically optimal generation mix which minimises the electricity generation costs under a given set of constraint. The main output of these calculations is the generation cost to meet the electricity demand in each of the two regions considered. The first part of this section reports the results of this modelling exercise. In terms of system costs, the calculations performed capture the pure electricity generation costs, including the costs of cycling conventional power plants, the profile costs and, at least partially, the balancing costs[22]. As each individual region is considered as a copper plate, the reported costs do not account for the expenses related to the T&D infrastructure within the region or for the connection costs between each power plant and the transmission grid.

22. The model used is able to account for the additional reserve requirements associated with a growing share of VRE generation, but not for other components of balancing costs.

In the second part an attempt is made to also include the other components of system costs which were not accounted for in the model used. Therefore the costs of building or reinforcing the T&D infrastructures, the costs of connecting each individual plant to the transmission grid as well as an estimate of the unaccounted balancing costs are assessed based on literature estimates. This allows the evaluation of the total costs of electricity provision in the eight scenarios analysed and the total system costs of VRE to be calculated for different penetration levels.

Electricity generation costs

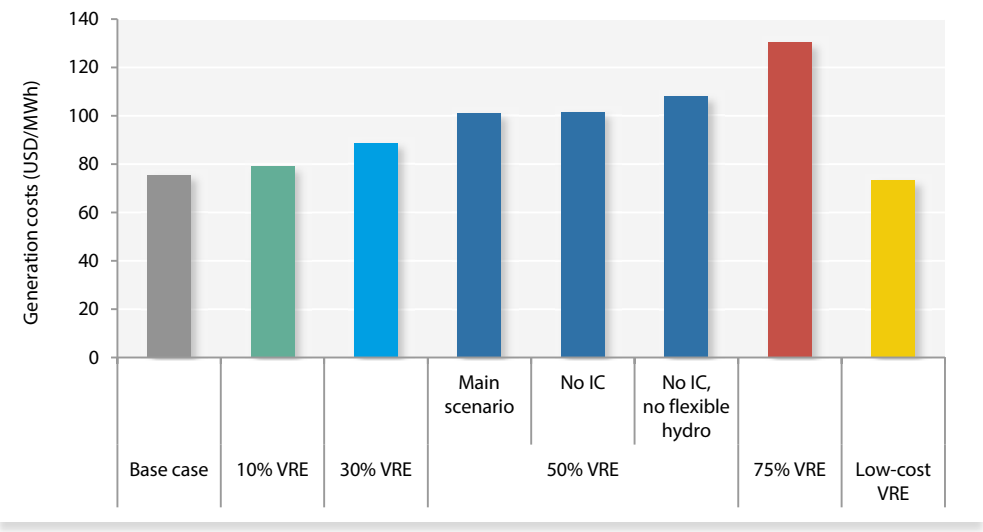
Under the cost assumptions of the present study, the generation mix which satisfies the electricity demand at a minimal cost relies mainly on dispatchable low-carbon generation technologies, such as nuclear and hydroelectric power. An appropriate combination of these two technologies as well as of gas-fuelled power plants allows the carbon emission targets to be met with maximum economic efficiency. The cost of electricity generation increases with the share of VRE in the system. More importantly, this relationship is not linear, with the rate of cost increase growing with the VRE penetration level. This reflects the additional challenges of deploying additional non-dispatchable VRE units into the generation mix and their decreasing value for the system.

While the additional costs are limited at low VRE targets, they increase markedly at higher penetration levels, as shown in Figure 37. Modelling results indicate that electricity generation costs increase by 17% with respect to the base case scenario when a 30% VRE penetration is reached. Achieving higher VRE targets of 50% and 75% of the total electricity generation would increase generation costs by 33% and by more than 70%, respectively. For a mid-sized country as the one represented in this study, additional costs for electricity generation are in the range of a few billion to a few dozen billion USD per year. For instance, if imposing a target of 10% of VRE generation increases the cost of electricity generation in the main region by USD 1.7 billion per year, achieving a higher VRE target of 30% would increase the electricity generation costs by USD 6 billion per year. Reaching even more ambitious VRE targets of 50% and 75%, would impose additional costs to the system equal to USD 12 and 26 billion per year, respectively. These findings are not specific of the main region but are also observed in region 2 modelled, albeit to a slightly lesser extent (additional information on the cost of electricity provision in region 2 are provided in Annex 3.A5).

Significant reductions of VRE generation costs and their deployment at an optimal level, translate into the least electricity generation costs to meet the CO_2 emission constraint of 50 g/kWh. The last main scenario, "low VRE cost" features a steep reduction in the investment and O&M costs from VRE. In comparison with reference values, investment and O&M costs for solar PV are reduced by 60% and these of onshore wind by one third. Under these conditions, VREs are efficiently deployed into the system and reach an optimal penetration level of 34% in the whole system. The availability of cheaper VRE resources and their deployment at the optimal penetration level allows reaching a minimal generation cost in both regions. Compared with the values used in the other scenarios, generation costs are reduced by roughly 3%; this represents a saving of about USD 1 billion per year for each region.

Systems with lower flexible resources, either in the form of interconnections or hydroelectric reservoirs and pumped storage, face more severe challenges to integrate VRE resources and higher costs of electricity provision. The cost increase observed is partially due to the larger curtailment of VRE generation which a more inflexible system is unable to integrate, and partially due to a more expensive residual generation mix. The quantitative results obtained in the two sensitivity scenarios indicate that hydroelectric storage provides a much higher value to the system than the level of interconnections considered in the model. Electricity generation costs in the main region increase by about USD 200 million per year if the system is isolated. On the contrary, the lack of hydroelectric resources raises the yearly generation cost by about USD 4 billion per year. However, caution should be taken when comparing the "value for the system" of interconnections and hydroelectric storage resources, as specific modelling assumptions have a strong impact on their relative benefits.

Figure 37. **Total costs of electricity generation in the main region (USD/MWh)**



From a policy perspective, the quantitative outcomes of the present study support the conclusion that most economically efficient way to achieve the low-carbon emission target is to impose a carbon price (or a cap on carbon emissions) which limits the use of fossil-fuelled generation sources and allows the deployment of the most efficient low-carbon resources. Under a carbon price (or an equivalent carbon cap), all low-carbon resources are deployed at their optimal level in the system, thus maximising their private value as well as the value for the overall system. If an appropriate carbon price is selected, carbon emissions can be reduced to a desired level with minimal economic impact. Under the assumptions taken in the present study, a carbon tax of 35 USD/tonne[23] is deemed sufficient to reach the carbon emission levels set at minimal cost. For this base case scenario, annual power generation costs in the main region correspond to USD 36.1 billion per year, which corresponds to an average cost of electricity generation slightly above 75 USD/MWh[24].

On the contrary, technology-specific mechanisms, as for example setting specific targets for a given subset of low-carbon technologies, may lead to a sub-optimal deployment of these technologies and to higher costs for electricity generation. While the cost increase is relatively modest at 10% VRE penetration level with average generation cost reaching a level of 79 USD/MWh, economic impacts are more significant when VRE deployment becomes more significant. At 30% penetration level average generation costs reach almost 89 USD/MWh, with an increase of about 17% compared with the base case scenario. Achieving even higher VRE penetration level imposes even higher electricity generation costs to the system: they exceed 100 USD/MWh and 130 USD/MWh for penetration levels of 50% and 75% respectively.

23. Recall that the level of carbon tax needed to achieve a given carbon emission reduction depends strongly on the system assessed, on the cost assumptions used for low-carbon technologies and for CCGT as well as whether a short-term or a long-term perspective is considered. Different assumptions could lead to strong variations in the level of carbon price needed. One of the key drivers of the implicit value of CO_2 emissions in the model is the price differential between nuclear generation and CCGT power generation in the provision of baseload power. Translating such modelling results into economic and political reality however requires great caution. Modelling, in particular, assumes that the carbon price would be absolutely certain *forever*, abstracting from uncertainty, transaction costs, adaptation costs or credibility issues.

24. As already indicated in Section 3.2, in order to ease the comparability across scenarios, the cost of electricity generation do not include the costs for brownfield hydroelectric capacity.

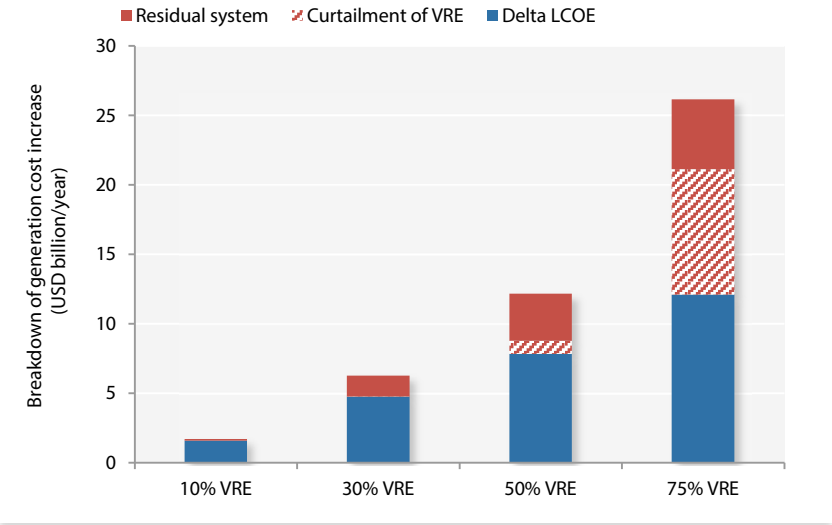
Breakdown of electricity generation costs increases and estimating profile costs

The increase in total electricity generation costs with the deployment of VRE resources is essentially due to three different factors:

1. under the assumptions taken in the present study, lifetime electricity generation costs for wind and solar PV are still higher than those of other low-carbon technologies such as nuclear;
2. curtailment of VRE generation is needed at high penetration level;
3. for all scenarios considered, the cost of meeting the residual load is higher in systems with VRE than for systems with only dispatchable technologies.

The first element pertains to plant-level costs and is captured by metrics such as the LCOE, while the two other elements are both components of profile costs. The absolute value and the extent of each of these factors vary significantly with the VRE generation share, as can be seen in Figure 38. While the difference in plant-level cost is the major factor at low penetration levels, the impact of profile costs becomes progressively more significant with penetration level. At 75% VRE penetration level, the profile cost becomes the largest component of the price increase.

Figure 38. **Breakdown of generation costs increase in the main region (USD billion per year)**



Note: this chart shows the electricity generation cost increase in different scenarios with respect to the base case scenario. As a reference, yearly electricity generation costs in this scenario are around USD 37 billion per year.

The difference in generation costs for the four main scenarios in comparison to these of the base case scenario are shown in Figure 38; the increase in electricity generation cost is subdivided into the three components described above. The first component, indicated as "Delta LCOE" and represented in blue in the figure, shows the cost increase which can be attributed to the difference in plant-level costs between VRE and nuclear plants, i.e. the cheapest alternative low-carbon technology available. It simply reflects the fact that, under the assumptions taken in the present study, the lifetime generation costs of VRE are higher than those of nuclear power[25]. The two other elements, represented in red into the figure,

25. In the last sensitivity scenario, this component becomes negative as the lifetime generation costs from VRE are lower than those of nuclear power.

capture two different components of the profile costs. If the electricity generated from VRE is curtailed, their load factor decreases and thus their cost of (useful) generation increases; this can be viewed as if additional VRE capacity must be built to provide the same effective electricity output to the grid, hence increasing the costs for the system. This second component depends on the curtailment ratio, as well as on the lifetime generation costs of VRE (as measured by their LCOE). It is termed "Curtailment of VRE" and represented by a dashed area in the figure. Finally, the last component captures the fact that the cost of satisfying the residual system is higher in presence of VRE than in presence of dispatchable capacity. This component, indicated as "Residual system" in the figure, is also specific to the system and VRE penetration level analysed. However its cost depends only upon the relative costs of dispatchable generation and storage technologies available; this cost is de facto independent from the generation costs of VRE[26].

At low penetration levels, profile costs are fairly low and the majority of the generation cost increase observed is due to plant-level cost differences between available low-carbon technologies (Delta LCOE). With the increasing penetration level of VRE resources, this trend reverses and the majority of generation cost increase observed can be attributed to profile costs. Also, the cost of curtailment appears only when a certain threshold of VRE is reached and then tends to increase quickly with VRE penetration levels. At the highest penetration level considered this component dominates the profile costs. As a final note, it is important to remember that the profile costs presented above are calculated as average costs between zero and the penetration level considered, and not as the marginal costs characteristic of that penetration level.

The comparison of the three scenarios with 50% VRE allows useful insights into information on the relative benefits of interconnections and flexible hydroelectric resources on the integration of VRE and on their impact on electricity generation costs[27]. As seen in the previous section, curtailment of VRE generation increases significantly when flexible resources are not present in the system. Increases in generation costs for the two sensitivity scenarios with respect to the base case are provided in Table 7.

Table 7. **Generation costs increase for the three scenarios with 50% VRE penetration level (USD million per year)**

		Main region	Region 2	Total
50% VRE	Main scenario	Ref.	Ref.	Ref.
	No Interconnections	220	417	637
	No interconnections, no flexible hydro	4 287	4 207	8 495

As already mentioned, according to the results of this analysis flexible hydro resources play a much more important role in easing the integration of VRE than the availability of interconnections. Without interconnections, generation costs in both regions increase by only USD 600 million per year, whereas the impact of not having flexible hydroelectric resources has been estimated to somehow less than USD 8 billion per year. Interestingly, the generation structure does not vary significantly when comparing the 50% VRE reference scenario with the scenario without interconnections, besides the need for a larger capacity

26. If the LCOE of Variable Renewables is halved the first component of profile cost (dashed in Figure 38) would also be halved, while the second component (plain in the Figure) would remain constant.

27. In the three scenarios analysed, the installed capacity of VRE is the same and is the one which allows reaching a VRE net penetration level of 50% in the "reference" 50% VRE case. This choice allows for a straightforward comparison between the three cases. However the VRE net penetration level differs within the three scenarios, owing to different levels of curtailment. This should be kept in mind when comparing the economics of the three scenarios.

and electricity generation from nuclear to compensate for the increased curtailment of VRE generation. On the other hand, the generation mix changes radically when comparing the scenario without interconnection and without flexible hydro with the other two. Additional nuclear capacity and battery storage is built, and an increase in the utilisation of peaking OCGT capacity is also observed.

While the results discussed above reflect the value of interconnections and storage resources for the system modelled, they also are function of their assumed size of interconnections or flexible hydroelectric capacity. In addition, it should be remembered that the modelling assumptions taken have an opposite impact on the evaluation of such resources. The assumption of perfect foresight (in terms of future demand, future generation from VRE and from hydroelectric run-of-the river plants, future water inflows in the hydroelectric reservoirs and future electricity prices), inherently allows for an optimal usage of these resources and thus maximises their value. In a real-life situation uncertainties about the future would certainly reduce the market value extracted from these resources. On the other hand, the value of an interconnection is strongly influenced by the differences between interconnected regions; the more diverse the demand profile and the generation mix, the more valuable the interconnection. By construction, a greenfield analysis based on the same economic hypothesis for available generation options in the two regions, leads to a quite similar generation mix between the two systems, which in turn reduces the value of the interconnections between them.

Estimation of system costs and of total cost for electricity provision

The model used in this study is designed to assess only two components of the system costs, as they are defined in Chapter 2: profile costs and, at least partially, balancing costs. The model is not tuned to capture the two other components of system costs, i.e. grid costs and connection costs. The two-region model used represents each region as a "copper plate" and therefore lacks the detailed representation of the T&D grid which is needed to provide an estimate of grid costs. Also, the costs for connecting the plant to the transmission grid are not reported in the IEA/NEA report *Projected Cost of Electricity Generation*, from which the economic data used in this study are primarily drawn (OECD, 2015). Connection costs and grid costs are therefore not considered in the optimisation process of the generation mix. The present section attempts to close this gap, thus providing an estimate of system costs as well as a more complete assessment of "total" costs of electricity provision.[28]

In order to obtain an estimate of the system costs, additional grid costs and connection costs as well as the fraction of balancing costs not yet accounted for are added to the profile costs already calculated in the different scenarios[29]. The resulting system costs are shown in Figure 39 for the different scenarios considered, including a breakdown into their four main components. Also, an error bar provides an indication of the uncertainty range deriving from a range of possible assumptions on grid and balancing costs. It should be noted that system costs are expressed in USD per unit of net electricity delivered by VRE to the grid (i.e. whereby the curtailed electrical energy is not accounted for as "useful" end energy in the denominator). It should be remembered that system costs do not reflect the differences in plant-level costs between dispatchable and VRE generation technologies, but indicate the additional costs for the system due to the variable, uncertain and locational constraint output of VRE plants. As

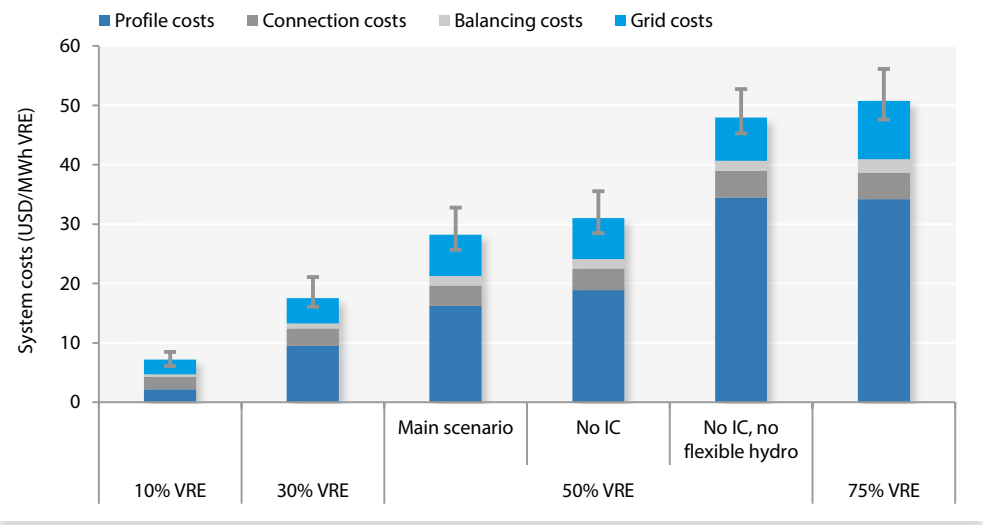
28. The full costs of electricity provision can be subdivided into three broad categories: 1) Plant-level costs, 2) Grid-level system costs and 3) External or social costs. The latter category accounts for the environmental and social costs impacting the well-being of individuals and communities outside the electricity sector (see NEA, 2015). The present study limits the analysis to the electricity system and therefore addresses only the first two components of the full costs of electricity provision described above. With the term "total costs" we refer therefore only to the plant-level costs and to all components of the system costs, either calculated directly by the model or obtained from literature estimates.

29. More details on the specific values used for each cost component, as well as on the methodology used for their quantification are provided in Annex 3.A1.

discussed in Chapter 2, system costs should therefore be considered in conjunction with the plant-level costs, and their value should be compared with the level of plant-level generation costs. By comparison, the IEA/NEA *Projected Costs of Electricity Generation* (OECD, 2015) indicate, for a 7% discount rate, a plant-level cost range of 70 and over 200 USD/MWh for solar PV plants and of 40 and over 100 USD/MWh for onshore wind plants.

Clearly, the resulting estimates of system costs should be considered with great caution. Firstly, the values derived from a literature review imply a certain degree of subjectivity and have a much lower level of firmness than the profile costs obtained from a rigorous modelling exercise. Secondly, the different components of system costs are not independent of each other, but costs can be "shifted" from one component to another. Summing elements obtained from calculations performed with different assumptions and hypothesis therefore demands additional care. Nevertheless, despite these caveats, having an estimation of the system costs, as well as their breakdown in to different categories, provides important insight to the costs associated with the deployment of VRE and should be an important guidance for policy makers.

Figure 39. **Estimation of system costs in the main region (USD per MWh of net VRE generated)**



Note: Plant-level costs and profile costs are computational results; other components of system costs are estimates.

The present analysis confirms the main findings of *Nuclear Energy and Renewables: System Effects in Low-Caron Electricity Systems* (NEA, 2012): system costs are significant, and they increase more than proportionally with the deployment of variable resources. At 10% VRE penetration level, system costs are estimated at about 7 USD/MWh$_{VRE}$. Profile costs, grid costs and connection costs contribute roughly equally to the system costs, while the weight of balancing costs is considerably lower. The level of system costs becomes substantial when the deployment of VRE reaches higher levels: at 30% VRE penetration, system costs more than double, up to 17.5 USD/MWh$_{VRE}$, and they reach 30 USD/MWh$_{VRE}$ at 50% penetration. Higher deployment targets of VRE lead to a staggering value of 50 USD/MWh$_{VRE}$. All four components of system costs increase with the deployment of VRE resources, but at different rates. In particular, the rate of increase of profile costs is much larger than that of the other components of system costs. Thus, profile costs become the dominant component of total system costs at the already moderate deployment levels in place now in some OECD countries: they constitute approximately 50% of the system costs at 30% VRE deployment. At 75% penetration level, they account for about two thirds of the system costs.

Whereas the penetration level of VRE remains the dominant factor, many other characteristics of the electric power system have an impact on the integration potential of variable resources, and hence on the additional costs borne by the electricity system as a whole. The sensitivity analysis allows a closer examination of the role of two sources of flexibility: the presence of interconnections with a neighbouring region and the availability of reservoir or pumped-storage hydroelectric capabilities. Both these sources of flexibility ease the integration of VRE and help to reduce system costs. However, their relative impact on system costs is significantly different. While the system cost of VRE increase is only 10% in an isolated system, the lack of flexible hydroelectric resources has a much more significant impact, with system costs increasing by more than 70%. For instance, at 50% VRE penetration the system costs would increase from 28 USD/MWh_{VRE} for the reference system to 48 USD/MWh_{VRE} for an isolated system without flexible hydroelectric resources. Such levels are close to that observed for the reference system at a much higher VRE penetration level (75% VRE).

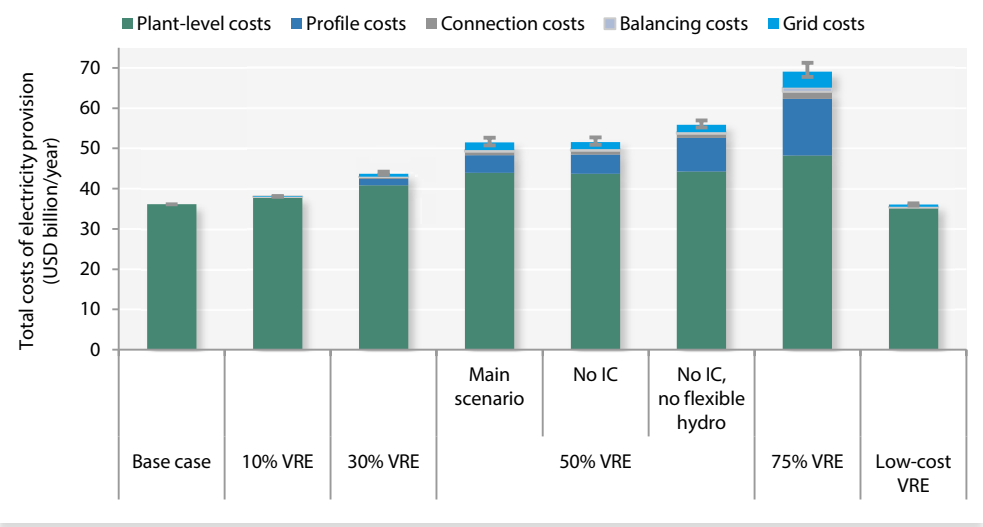
Finally, the assessment of system costs allows to derive the "total" cost of electricity provision, i.e. the cost for generating, transporting and distributing the electricity to each load with a given level of security of supply. This is the most significant metric to compare different options to achieve a predetermined carbon emission target, as it accounts, to the maximum extent possible, the entire costs of providing the same service to all customers. The yearly cost of electricity provisions are plotted in Figure 40 for the eight scenarios analysed in this study: a breakdown of the total cost into different components (plant-level costs, profile costs, grid costs, etc.) allows a visualisation of their order of magnitude and relative importance.

However, while providing a more complete and compelling results, this analysis does not change the main conclusion already discussed:

1. deploying VRE into the system beyond their optimal level increases the total cost of electricity provision;
2. these additional costs increase more than linearly with VRE penetration level.

Figure 40. **Estimation of total cost of electricity provision including all system costs in the main region**

(USD billion per year)



Note: Plant-level costs and profile costs are computational results; other components of system costs are estimates.

With the plant-level cost assumptions adopted in this study, the total costs of electricity provision increase, even for a low level of VRE penetration. In particular, at 10% VRE penetration, total costs are 5% higher than these of a system with only conventional dispatchable generators; for a medium-sized electricity system such as the one modelled, this

corresponds to additional costs of about USD 2 billion per year. At 30% VRE penetration, costs increase by about USD 8 billion per year, i.e. by 21% with respect to the base case. Reaching more ambitious VRE targets leads to much higher costs to the overall electricity system. Total costs increase by more than USD 15 billion per year if 50% of electric energy generation is assured by variable renewable resources, which corresponds to additional costs of 42% compared to the base case. Reaching a 75% VRE target implies almost doubling the costs of electricity provision, up to almost USD 70 billion per year. This represents additional costs of almost USD 33 billion per year with respect to the base case.

Some additional insight can be drawn by analysing the results of the "low VRE cost" scenario, in which VRE provide about 30% of the generation in the two-region system, albeit only 14% in the main region (and about 50% in region 2). As expected, this scenario features the lowest cost of electricity provision of all scenarios analysed. However, despite assuming substantially lower plant-level costs for solar PV and wind than those for alternative dispatchable low-carbon resources, the total cost of electricity provision remains almost unchanged. Comparing the total cost for electricity provision with the base case yields a difference of only USD 100 million per year, i.e. about -0.3% of the total.

This surprising outcome is explained by two important factors. Accounting for profile, connection, balancing and grid costs narrows the gap between plant-level costs of nuclear and the lowered costs of solar PV and onshore wind plants. Even more importantly, not considering some of the system costs in the optimisation process leads to the deployment of wind and solar PV resources far beyond their optimal level. The resulting generation mix is therefore no longer the most efficient once all system costs are accounted for, thus unnecessarily causing higher electricity provision costs. In order to reap the full benefits of low-cost VRE resources, it is important that all system costs are internalised by appropriately allocating them to the technologies that cause them. This would have allowed the deployment of VRE and all available technologies at their optimal level, thus achieving the most economically efficient generation mix. Only then would the generation mix have been the cheapest, thus maximising the welfare for the whole society.

3.5. Electricity wholesale market prices, capital intensity of the generation mix and the value of VRE generation

Achieving a low-carbon system has impacts that go beyond the technical and economic aspects discussed previously. One is a more capital-intensive generation mix, where lifetime electricity generation costs are dominated by investments and variable costs are minimal. As a consequence of this shift towards more capital–intensive technologies, the long-term structure of wholesale electricity prices changes and their volatility increases substantially. Compared to the recent past and the situation today, the increase in the electricity market risk, in turn, means that investors in generating power plants face a higher risk, at least in the energy-only markets which are currently the reference model in many OECD countries[30]. As the model used in this exercise cannot translate the increase in risk profile for each technology into an investment decision, this aspect is now discussed on a qualitative basis only.

This section looks more in detail at three interlinked aspects associated with a low-carbon electricity mix:

i. capital intensity of the power mix;

ii. structure of electricity price and recovery of generation costs;

iii. market value of generation with VRE and other renewable resources.

30. Note that "capacity markets" do exist in parts of the United States (e.g. PJM) and many countries alleviate risks with so-called capacity remuneration mechanisms (CRM), of which capacity markets are an example.

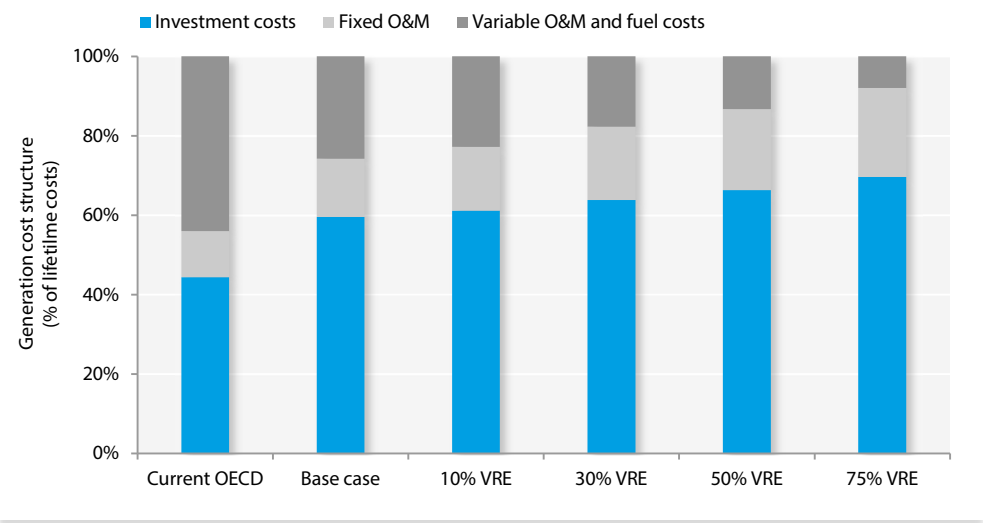
A more capital-intensive generation mix

All low-carbon generation sources, while very heterogeneous in terms of location, size as well as technical and operational characteristics, share a similar economic structure. They are characterised by high investment costs and low variable costs. Total generation costs are thus mostly independent of the electricity output. On the contrary, the cost structure of fossil-fuelled generating technologies is characterised by a much higher share of variable costs, mainly fuel and, where applicable, carbon costs (see Box 3.2 for a detailed discussion of the cost structure of major generating technologies).

Regardless of the specific technologies adopted, a low-carbon generation mix therefore consists of a more capital-intensive mix when compared to the current mix in most OECD countries. This difference is clearly illustrated in Figure 41 and Figure 42, which compare the lifetime generation costs of the various scenarios analysed in this study (all subject to the same imposed carbon constraint of 50 g/kWh) with these of a generation mix representative of that of OECD countries[31]. In low-carbon systems, investments represent 60-70% of the costs, up from the 45% level of the current generation mix in OECD countries. More significantly, the share of variable costs would decrease by a factor of 2 to 5 with respect to the current value. This highlights the challenges and the effort required to reduce the carbon intensity of the power mix from their current levels to 50 g/kWh.

However, specific low-carbon technologies deployed to satisfy the carbon constraint also have a crucial impact on the overall capital structure of the generation mix as well as on the share of variable costs. The share of variable costs varies significantly across different low-carbon scenarios: variable costs progressively decrease when going from a low-carbon system dominated by nuclear power to a system where VRE generate the bulk of the electricity. This decrease is compensated by a corresponding increase in the share of investment and fixed O&M costs. In the base case scenario, variable costs represent 25% of the lifetime generation costs, while in the 75% VRE scenario, variable costs account for less than 10% and investment costs about 70% of the lifetime costs.

Figure 41. **Breakdown of generation costs and comparison with actual mix**



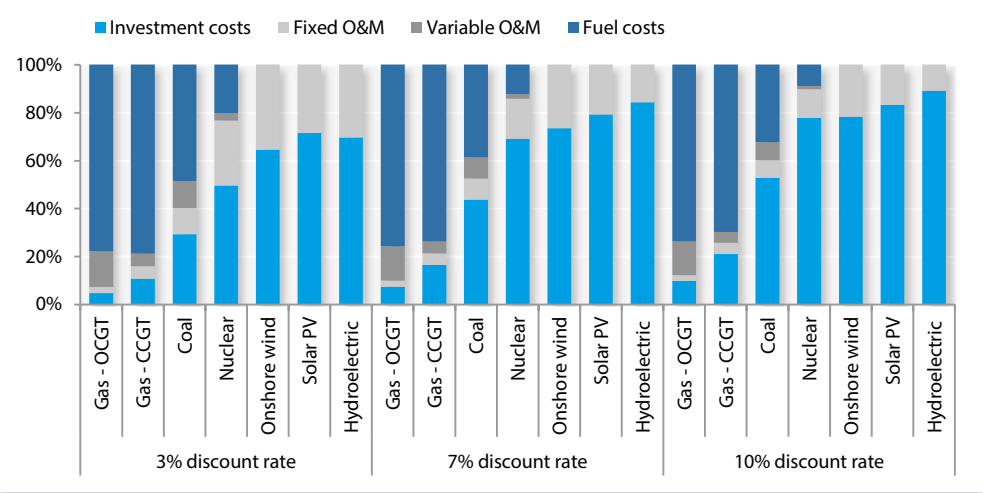
31. For comparison purposes, in 2016 the specific average CO_2 emission of the generation mix in OECD countries was about 400 g/kWh, e.g. eight times the level target level of the present study. The specific emission from electricity generation worldwide reaches about 540 g/kWh, i.e. more than ten times this study's reference (own calculations, based on IEA, 2017).

Box 3.2. **Cost structure of the main generation technologies**

Lifetime generation costs are subdivided into four components: investment costs, fixed and variable O&M costs and fuel costs. Investment costs include the overnight and contingency costs as well as interest accrued during construction. They represent the cash outlays that have been committed until plant completion and before any revenue can be expected from the investment. Fixed O&M costs represent the fixed share of costs which occur on a regular basis independent of the electricity generation level; they include, among others, the cost of the personnel or those for regular maintenance activities. Contrary to investments costs, which can be considered as sunk, these costs are not incurred in case of mothballing the plant. The other two cost components, variable O&M and fuel costs, represent the generation costs directly dependent on the generation level of the unit; these costs do not occur if the plant does not generate.

The cost structure of the main generation technologies is provided in the figure below for three different discount rates, 3%, 7% and 10%. Note that these results are based on *Projected Costs of Generating Electricity* (OECD, 2015) and have been obtained under a common "standardised" load factor of 85% for thermal plants. Also, no carbon cost has been included in Figure B3.2; this would have increased further the variable component of all fossil generation options.

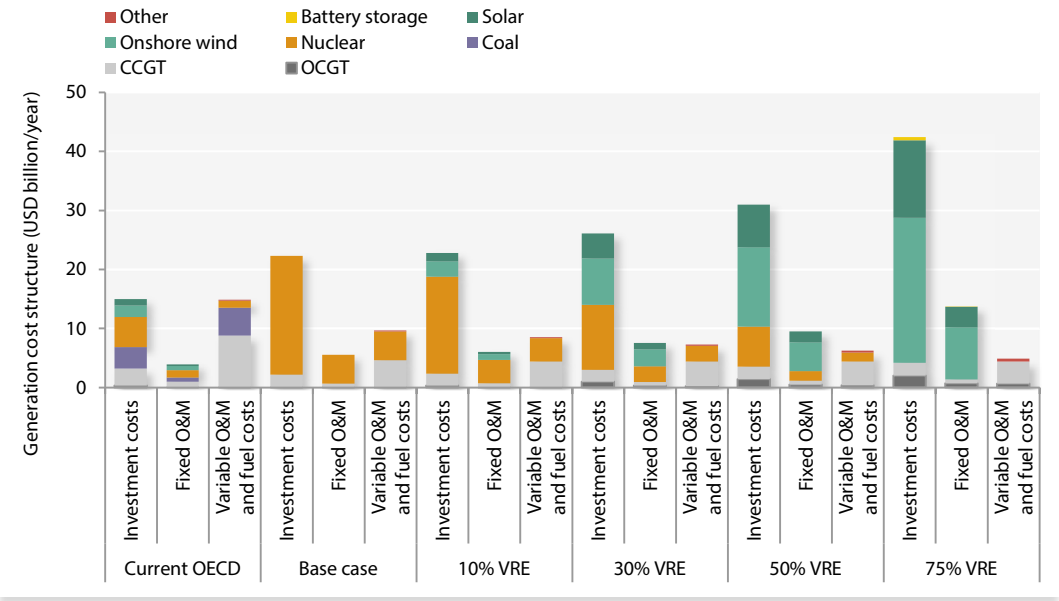
Figure B3.2. **Breakdown of lifetime generation costs for different technologies**



If a real discount rate of 7% is assumed, investment costs represent roughly 70% of the lifetime generation costs of a nuclear power plant; about 17% of the lifetime costs are by fixed O&M costs, while only 14% are variable costs essentially fuel costs. Similar figures are observed for renewable technologies: investment costs represent about 74% of the lifetime generation costs for onshore wind, almost 80% for solar PV and about 85% for hydroelectric power. The remaining lifetime costs of renewable technologies are represented mainly by fixed O&M and are therefore independent of generation levels. For these technologies variable costs are negligible and are commonly set to zero. In contrast, variable costs represent the larger share of fossil-based generation technologies: 48% for coal and almost 80% for CCGT (based on the assumed coal and gas prices in *Projected Costs of Generating Electricity* [OECD, 2015]).

Finally, it is interesting to qualitatively discuss the impact that project risk has on the discount rate and hence on the lifetime generation costs of a power plant. In principle, the discount rate should reflect, among other parameters, the risk of the project being assessed. Higher project risks result in a higher rate at which the expected cash flows from the project should be discounted. For any investment in power generation, this would translate in an increase in lifetime generation costs. Also, the share of investment costs would increase, thus proportionally reducing the share of variable costs (see the 10% discount rate case in Figure B3.2). Conversely, lower project risk allows for of a lower discount rate to be adopted which in turn leads to the opposite trend (see the 3% case).

Figure 42. **Detailed breakdown of generation costs and comparison with actual mix**



In synthesis, with VRE deployment the generation mix becomes not only more expensive but also more capital intensive. In liberalised markets, capital-intensive technologies are more vulnerable to long-term changes in the level of wholesale electricity prices, as they may be unable to recover their (large) capital costs should electricity prices decline with a consequent reduction of infra-marginal rents (see *Nuclear New Build* [NEA, 2015] for a more detailed discussion). Capital-intensive technologies therefore carry a higher risk for investors compared to technologies with lower capital (and higher variable) costs[32]. As a consequence, the transition towards a low-carbon system has important implications for the financial risk faced by investors in the electric power sector. Also, as is discussed in the next paragraphs, this has relevant impacts on the structure and volatility of wholesale electricity market prices[33].

Structure of the electricity price and recovery of generation costs

A more capital-intensive generation mix has noticeable repercussions on electricity markets, and in particular on the level and volatility of wholesale electricity market prices.

Gen X calculates wholesale electricity prices as a function of the variable costs and operational constraints of the marginal technology called upon (i.e. the hourly electricity price is determined as a dual variable of the market clearing constraint); this corresponds to the price formation in competitive wholesale energy-only markets. Before discussing the different results, it should be recalled that in all scenarios beside Scenario VI, VRE and hydroelectric

32. However, it should be noted that these depends on wholesale electricity market designs. This is certainly true in deregulated energy-only markets such as those of many OECD countries, where the large majority of plant revenues come from the sale of electricity. It is less relevant in electricity markets where there are other more stable income sources for the generator. Finally, market designs that shield the power producer from volatility in market prices (by long term price agreements, such as FIT or CFD, or by fixing a remuneration based on cost recovery, as done in fully regulated markets) do not present market risk.

33. Clearly, when looking at the (far) future, technology evolution has an impact on the total cost of electricity provision, as well as on the structure of electricity market prices. The scenario VI, which features a sharp decline in wind and solar PV generation costs, provides some intuition on these aspects.

resources are exogenously imposed on the generation mix, and do not enjoy any direct market support in form of a fixed remuneration (feed-in tariff) or a top-up to the market price (feed-in premium). The most consistent way to represent such a state is by assuming that these technologies have enjoyed a capital support for investment that has allowed them to be deployed at that penetration level. Thus, the dispatch of VRE and hydroelectric resources satisfies a pure economic optimisation. For instance, VRE (and hydro) are curtailed if it is cheaper for the system to do so. For this reason, no negative prices are observed in the modelling results. This is different from the actual experience in many OECD countries where direct support to electricity production from VRE (such as feed-in tariff or feed-in premium) distort natural price formation in the wholesale electricity market and contribute to the appearance of negative prices. If the VRE generators receive a fixed remuneration (FIT) or a fixed contribution in addition to the wholesale market price (FIP), these technologies will continue to operate regardless of the market price or until the market price reaches the same (negative) level as the FIP or FIT.

Electricity wholesale market prices are visualised by their duration curves, obtained by ordering the hourly electricity prices from the highest to the lowest over the course of one year. Figure 44 shows the price duration curve over the year for the five main scenarios while Figure 45 focuses on the most expensive 100 hours in the year, where prices may reach a level of 10 000 USD/MWh (value of lost load – VOLL[34]) and the power supply is interrupted (voluntary or involuntary load shedding and/or rolling blackouts). These two plots allow visualising the difference in the electricity price structure associated with increasing deployment of VRE resources. The most important quantitative data on electricity market prices in the main region are reported in Table 8 for all eight scenarios considered in this study[35]. Finally, Figure 46 compares electricity price duration curves for the three scenarios with the same imposed VRE capacity but with different characteristics in terms of interconnections and the availability of flexible resources.

Table 8. **Electricity market price data in the main region**

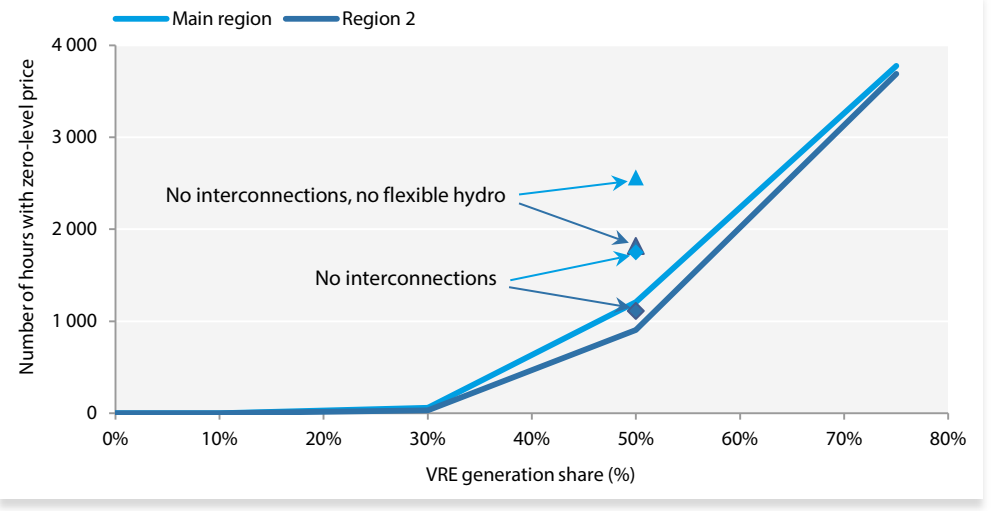
		Main scenarios						Sensitivity scenarios	
		Base case	10% VRE	30% VRE	50% VRE	75% VRE	Low-cost VRE	No IC	No IC, no hydro
Average electricity price	USD/MWh	70.16	70.16	70.13	69.42	53.73	70.11	69.07	68.57
Quantity-weighted electricity price	USD/MWh	79.93	77.19	76.79	75.74	58.71	76.79	76.35	77.02
Standard deviation	USD/MWh	165.01	166.46	230.17	255.17	259.01	211.80	244.59	248.72
Total generation costs (incl. brownfield hydro)	USD/MWh	84.31	87.48	95.97	106.95	133.07	82.39	107.37	105.57
Total generation costs (excl. brownfield hydro)	USD/MWh	75.63	79.19	88.74	101.09	130.47	73.47	101.57	106.58
Loss of load	hours	0	0	3	4	4	1	3	3
Not meeting reserves	hours	8	8	6	6	6	11	8	8
Demand response	hours	95	85	32	18	7	34	9	9
Price above USD 100/MWh	hours	451	373	484	705	877	468	1 030	1 482
Price at zero	hours	0	0	60	1 209	3 777	88	1 745	2 559
Hours with different prices	hours	730	731	1 885	3 364	5 530	2 173	-	-

34. The value of lost load is traditionally defined as the value attributed by consumers to unsupplied energy.
35. The average electricity price is defined as the average of hourly electricity prices over one year. It measures the average price seen by a plant with constant generation output. The quantity-weighted electricity price is the quantity-normalised electricity price over one year. It represents the average cost for meeting the electricity load over one year.

This study finds that the deployment of VRE has a much lower impact on average electricity prices than that reported in the empirical literature summarised in Box 2.1. This is essentially due to the different short-term vs. long-term approaches taken. This study assumes a long-term equilibrium situation where all generators need to recuperate their full costs, including investment costs, or otherwise they will not enter the market. This is different from reality, where historical conventional generators stay in the market even when new VRE enter the market and will leave only if they can no longer recuperate their operating costs. In the short term, VRE entry creates structural over-supply, which pushes down prices.

A striking effect of the deployment of low marginal cost variable resources on the electricity markets is the appearance of hours with zero prices and a substantial increase in the volatility of electricity prices. Zero-electricity prices are not observed in the two scenarios with no or low VRE deployment, and start appearing when VRE reach a penetration level of 30%, albeit only for 60 hours in a year[36]. For the low VRE cost scenario considered, the number of zero-price hours is about 88 hours. The number of occurrences increases dramatically with the VRE penetration level; at 50%, more than 1 200 hours in a year feature zero-price levels, i.e. about 14% of the time. When VRE produce 75% of the demand, zero prices occur during 3 750 hours, i.e. more than 43% of the time. Figure 43 visualises this effect by plotting the number of hours with prices at or below a zero-level price in the two regions as a function of the penetration level of VRE.

Figure 43. **Number of hours with zero-level price in selected scenarios**



The higher frequency of hours with zero prices is compensated by an increase in the number of hours with high electricity prices. For instance, the number of hours in which electricity price is higher than 100 USD/MWh increases substantially when the generation share of VRE exceeds 30%; at 75% VRE penetration the number of hours with prices above 100 USD/MWh is more than double than that at zero or low VRE penetration rate. The volatility of electricity prices increases substantially when VRE are deployed above 30% penetration level, as a direct consequence of this more uneven price distribution (see Figure 44).

36. The penetration level at which this phenomenon appears depends not only by the characteristics of the system but also on the relative fraction of solar PV and wind resources: the results obtained therefore reflect the ratio of solar PV and wind generation taken in this study (solar PV provides ¼ of VRE generation, while the remaining ¾ is produced by onshore wind). In general, for any given VRE penetration level a higher share of solar PV resources would increase the number of hours with zero prices.

Figure 44. **Duration curves of wholesale electricity prices for the five main scenarios**

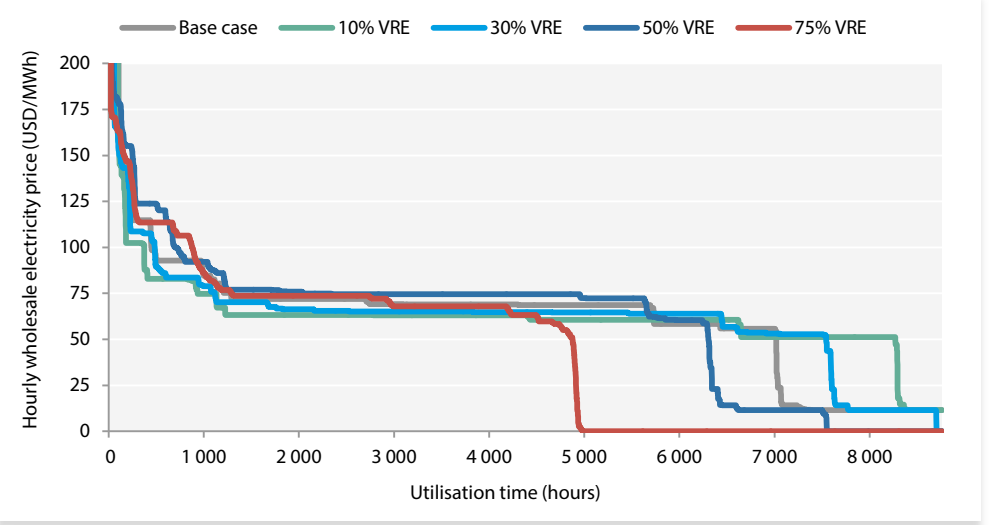
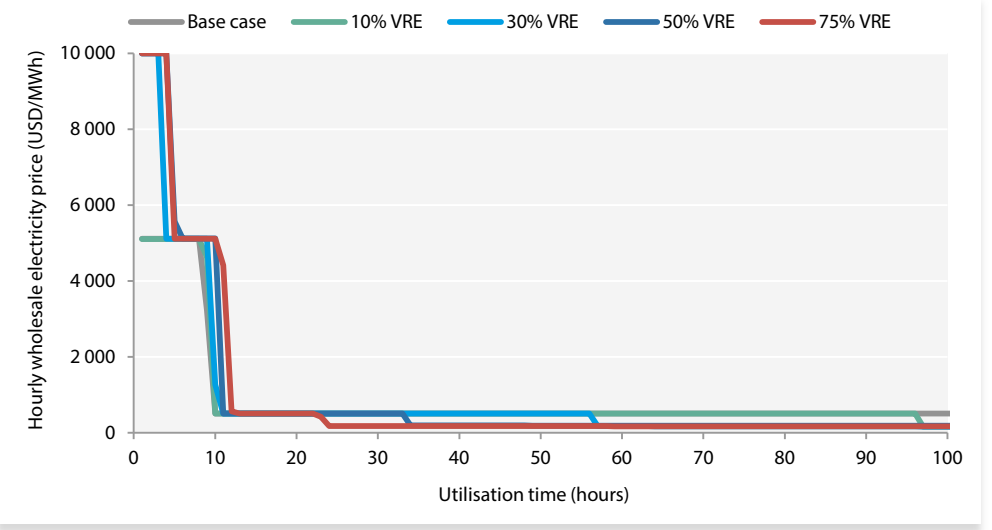


Figure 45. **Duration curves of wholesale electricity prices for the five main scenarios**

(First 100 hours)



Note: Changed scale of ordinates with respect to Figure 44.

The high volatility of electricity wholesale market prices and a reliance on a limited number of hours with high or very high market prices significantly increases the electricity market risk for all generation technologies. Higher market risk would automatically increase the expected rate of return for investors and, by consequence, lead to higher capital costs[37].

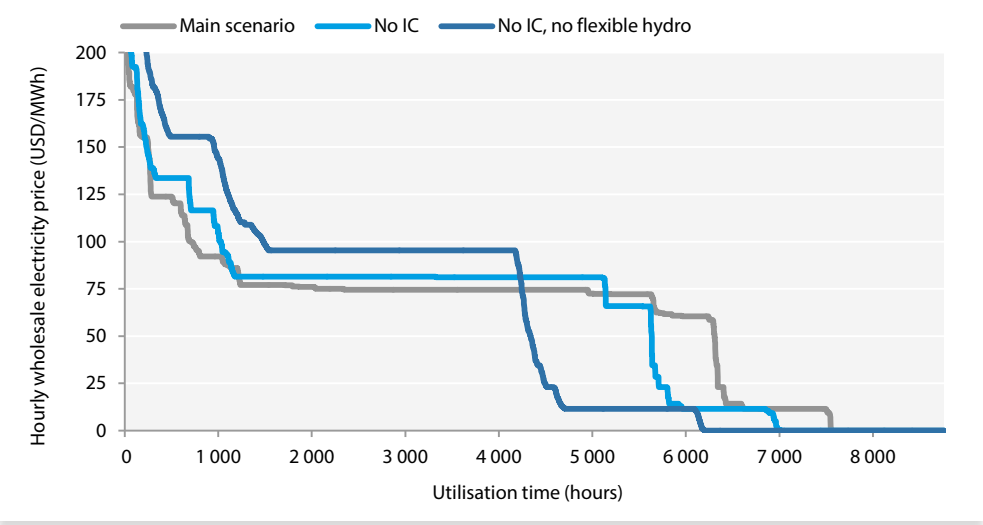
37. This has not been modelled in the present study as the same discount rate of 7% has been applied to all generating technologies in all scenarios considered. Taking into account of the market risk would have increased the generation costs, in particular for the scenarios featuring a large generation share of VRE.

This is particularly relevant for capital-intensive, low-carbon technologies such as VRE or nuclear power, which have a longer payback time and are more sensitive to long-term changes in the level of electricity prices (see *Nuclear New Build* [NEA, 2015] for further information and analysis). Therefore, exposure to wholesale prices where prices are at or below their variable cost of generation for a significant part of the year would have severe negative implications on the ability to finance low-carbon sources such as VRE and nuclear power in energy-only markets. Thus appropriate policy measures are required to accompany energy-only markets in order to ensure adequate investment in low-carbon technologies (see Chapter 5 for a detailed discussion).

As already indicated, the two regions are linked by a relatively large interconnection which allows dispatching the cheapest available technology across the two regions and, ultimately, helps to reduce the total cost of generation across the whole system. As expected, the physical exchanges of electricity between the two regions increase with VRE generation share; this reflects the increasing need for flexibility provided by interconnecting the two systems. Consequently, the number of hours where the interconnections are saturated increases significantly, especially when VRE penetration level exceeds 30%. During these hours, electricity market prices may differ significantly between the two regions. However, when looked at over the whole year, there are no significant differences in the structure of electricity prices between the two interconnected regions. This is to be expected since in each scenario the two regions have the same VRE net generation, are subject to the same carbon constraint and the different power plants available for deployment share the same economic characteristics and generation costs.

Finally, the comparison of the three scenarios with the same VRE capacity (scenarios IV, VII and VIII) allows the benefits of the availability of flexible resources (either from interconnection or hydroelectric reservoir plants) to be highlighted when considering the integration of VRE. In Section 3.3 it was indicated that higher curtailment of VRE resources is observed in a less flexible system. Also, less flexible systems are characterised by higher generation costs, more volatile electricity prices and by higher frequency of low or zero prices than more flexible systems (see Figure 46). For instance, an isolated system features roughly 40% more hours at zero prices than the reference system, while their occurrence more than doubles when hydroelectric flexibility is not also available.

Figure 46. **Duration curves of wholesale electricity prices for the scenarios with 50% VRE (scenarios IV, VII and VIII)**

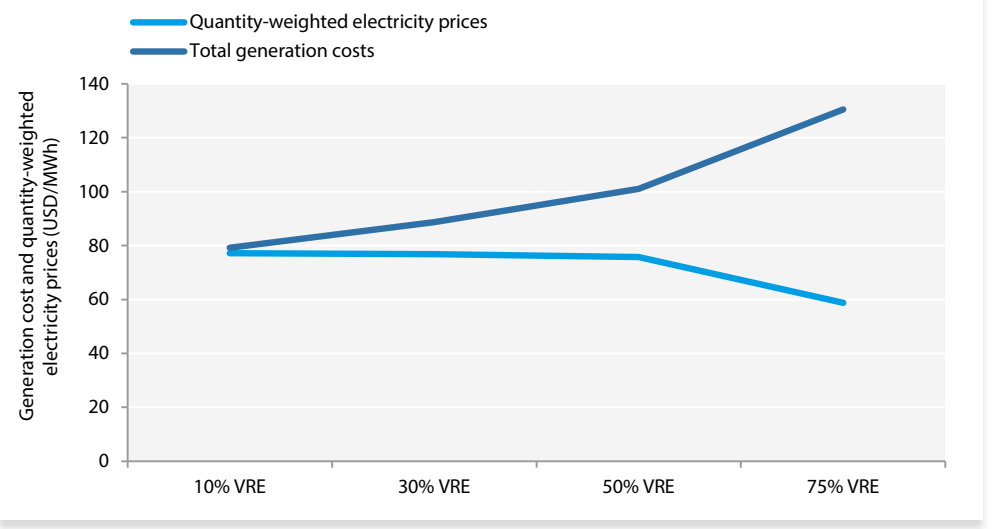


Another important aspect observed in the present study is the increasing gap between electricity generation costs and revenues as the penetration level of VRE increases in the system. Whereas the cost of electricity generation increases substantially with more ambitious VRE targets, the average market price and hence the revenues from the energy-only market follow an opposite trend. The consequence is a growing shortfall of revenues from wholesale markets to cover generation costs. Figure 47 illustrates this trend, showing a comparison between the average generation costs and the (quantity-weighted) average price of electricity in the main region as a function of the penetration level of renewables. For instance, at a 50% VRE penetration level the revenue shortfall is more than 20 USD/MWh, and grows to over 70 USD/MWh or over USD 34 billion per year when VRE reach a penetration level of 75%. At this level, revenues from the markets can cover less than 50% of the generation costs. Investors in generation capacity must therefore rely on out-of-the market mechanisms or specific subsidies to close the gap.

This unsustainable situation is the result of a profound policy contradiction. On the one hand, investors are expected to generate returns on the basis of wholesale market prices alone. This would be possible in a full free-market system based solely on cost and system value. However, this would also be a system with slightly more than 30% of low-cost VREs in Scenario VI and a system with no VREs in all other scenarios. Once VRE targets are exogenously enforced, the system moves away from the economic optimum. In a long-term equilibrium perspective, the divergence between generation costs and wholesale market prices is thus essentially the result of the exogenous deployment of a resource beyond its optimal level; in this case, the revenues from the wholesale electricity market are insufficient to cover generation costs. This is an indication of the larger out-of-the market subsidies required to achieve the targeted VRE generation level, which comes essentially from two concomitant factors:

1. the amount of VRE capacity to be supported increases with their penetration level.
2. the out-of-the market support level needed for a unit of VRE capacity also increases, as the value of the generation from VRE decreases with penetration level[38].

Figure 47. **Average generation costs and quantity-weighted average electricity price**



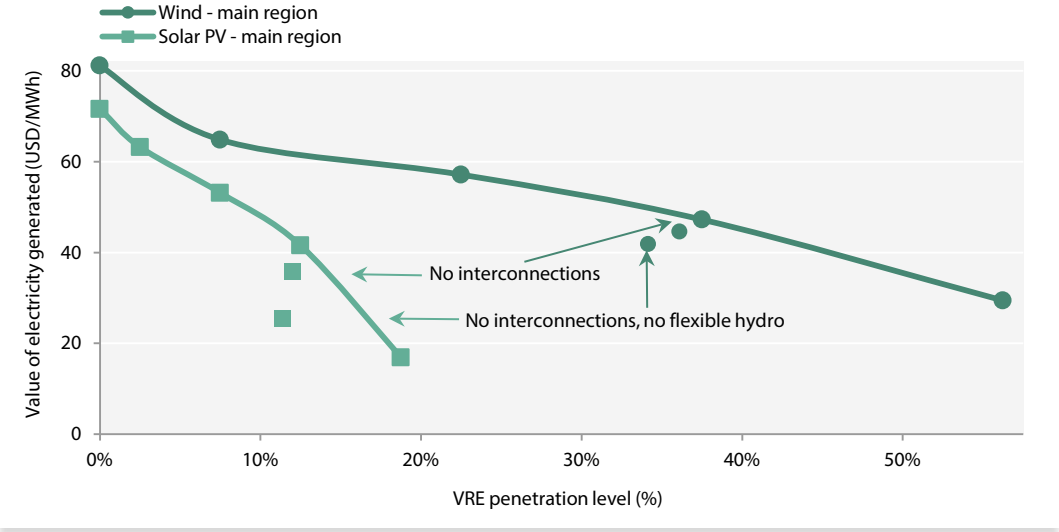
38. This phenomenon is further discussed in the next paragraph.

The declining market value of solar PV and wind generation

VRE generation is linked with the availability of the natural resource, wind speed or solar radiation, which is intrinsically variable and dictated by meteorological conditions. Solar PV and wind plant generation therefore fluctuates and is more stochastic than that from dispatchable plants. Periods of high generation are followed by periods with lower (or even zero) output. In particular, because they all respond to the same meteorological conditions in the broad "surroundings", solar PV and wind turbines tend to produce more electricity when other plants of the same type are generating; similarly, they tend to produce less when the other solar PV and wind turbines also have a lower output. The correlation of the VRE generation with that of other plants of the same type present in the system is the phenomenon behind the decline in the market price of electricity generated by VRE with their penetration level (this is often referred to as the self-cannibalisation effect)[39]. The present study confirms the trend which has also been observed and extensively discussed in the recent scientific literature. The most relevant results of this study are summarised in Figure 48, which plots the market value[40] of solar PV and wind generation as a function of their deployment in the main region.

These graphs provide two types of information. First, they show the pure electricity market price received by a solar PV or wind plant as a function of their penetration level into the system. Second, and perhaps more importantly, they also provide an indication of the optimal deployment level of a variable resource, either solar PV or wind, as a function of its lifetime generation costs. For example, if the market value of solar PV in the main region is equal to 40 USD/MWh at a 12% penetration level, the optimal deployment of solar PV resources with a generation cost of 40 USD/MWh would be exactly 12%.

Figure 48. **The market remuneration (marginal value) of wind and solar PV as a function of their penetration level**



39. A more comprehensive description of these phenomena is given in Chapter 2 (Section 2.5).
40. By market value of VRE generation we refer here to the remuneration that a VRE power plant receives from selling electricity to the wholesale market.

The average price received by solar PV and wind resources in electricity market declines significantly and non-linearly as their penetration level increases, and this decrease is much steeper for solar PV than for wind. Declining prices from electricity markets reflect the lower value for the system of the electricity generated by variable resources. While this phenomenon, i.e. the decrease in the value of generation from a source the higher the quantity generated, is valid for every technology, the magnitude of the decrease is much higher for VRE than for other dispatchable plants[41].

The value of solar PV generation is almost halved (to 41.5 USD/MWh) when a penetration rate of only 12.5% is reached. Further deployment of solar PV capacity to a penetration level of 17.5% would further halve the market value of solar PV generation. In this situation, the market value of electricity generated by solar PV is below 20 USD/MWh. Thus, even if the generation costs of solar PV would be divided by five, their optimal penetration level would not exceed 17.5%. A similar trend, although less pronounced, is observed for onshore wind which has a larger load factor than solar PV and whose generation spans a larger time period. At 22.5% penetration level, the value of each MWh is worth USD 20 less than that of the "same" MWh generated by the first wind turbine in the system; this represents a loss of more than one quarter of its market value. For penetration levels above 30%, the market value of wind electricity is below 50 USD/MWh.

This study demonstrates that the availability of flexible hydroelectric resources and interconnections have a significant impact on the market value and, consequently, on the optimal deployment level of VRE resources. This impact is more pronounced for solar PV resources than for onshore wind power. This sensitivity analysis is performed at a combined VRE penetration level of only 50% (12.5% solar PV and 37.5% onshore wind); the results are plotted in Figure 48. In an isolated system without flexible resources the market value of solar PV is reduced by 40% if compared with the equivalent well-interconnected and more flexible system taken as a reference for this study. An isolated system with the same flexible resources as the reference would see the value of solar PV generation reduced by 15%. The decrease in market value of onshore wind generation can be estimated at -12% and -6%, respectively. The same trend and similar values are observed also when looking at region 2 modelled in this exercise. More details on the results in this second region and an explanation of the trends observed are provided in the annexes, together with a discussion of the market value of brownfield hydroelectric reserves.

The declining market value of the variable resources and their reduced value for the system as their deployment increases have important implications on their ability to be financed in energy-only markets as well as in optimal policy choices. These topics are the heart of Chapter 4 of the present study and are addressed more extensively there.

3.6. Conclusions

Decarbonising the energy system to achieve the long-term climate goals adopted during COP21 represents an enormous challenge for OECD countries. To reach these targets[42], the IEA estimates that by 2040 the carbon intensity of the electric power sector in OECD countries has to be reduced roughly to 50 g/kWh, i.e. by a factor of eight compared to current levels. For a full discussion see "*World Energy Outlook* Sustainable Development Scenario" (IEA, 2017). This requires a rapid and radical transformation of the power system with the deployment of low-carbon emitting technologies such as nuclear, hydroelectric power and variable renewables. In absence of large-scale implementation of mechanisms to capture and store CO_2, this would mean phasing out or limiting the use of fossil fuels.

41. An explanation of this phenomenon is provided in Chapter 2, Section 2.5.

42. This refers to the "intention" for long-term decarbonisation towards a maximum of 2°C and even beyond; not to the short-term actual commitments made in the INDC.

The present study analyses several scenarios of deep decarbonisation achieving the same stringent carbon emission target but characterised by different shares of variable renewable technologies, hydroelectric power and nuclear energy in a large, well-interconnected system, which is representative of that of several OECD countries. The objective has been to provide a cost comparison of different "snapshots" of the possible long-term generation mixes that would meet the carbon emission target of 50 g/kWh. Analysing the scenarios in more detail allows highlights some of the potential technical and economic challenges facing a low-carbon generation system. However, before presenting the insights and main conclusions of this exercise, it is important to underline the limitations of this effort in terms of the modelling tools used as well as the impact of the economic and technical assumptions made.

With the exception of hydroelectric resources, which are exogenously given in all scenarios, this study considers the electricity system as a green field, implicitly taking a long-term perspective: the composition of the generation mix and the hourly dispatch of individual plants are optimised to meet the electricity demand at a minimal cost. This choice provides a picture of the generation mix in the 2050 horizon and allows for an unbiased comparison of different low-carbon technologies and decarbonisation strategies. However, such modelling does not provide any indication on possible paths to reach such long-term generation mix from current power systems. The economic assumptions and technical characteristics of the main generating technologies, storage options and demand-side measures reflect the IEA/NEA projections in OECD countries for 2020 as well as estimates from series of additional sources[43]. These indeed have an impact on both the technical and economic outcomes of the present study, as they strongly depend on the assumed capital costs for nuclear, solar PV and wind (and to a lesser extent on the assumed natural gas prices). For instance, a drastic reduction in VRE generation costs with respect to those of other low-carbon dispatchable technologies, significant reductions in storage costs or large-scale development of demand-side flexibility options would all have significantly changed the outcomes of the present study.

Given the complexity and the large time frame involved in power system optimisation, several simplifications had to be made to ensure that calculations can converge in a reasonable time. Among the major assumptions taken in this study are:

i. only a single year is considered, with time intervals of one hour;

ii. a continental-scale region is treated as a simplified "copper plate" two-region system without a representation of the T&D grid; and

iii. decisions on optimal generation mix and power plant dispatch are taken assuming a perfect forecast of future demand as well as of VRE generation.

As a consequence of these assumptions, the connection and T&D costs are not accounted for nor integrated into the optimisation process. Limiting the analysis to a single year and assuming a perfect foresight of future demand and renewable generation levels makes the resulting generation mix unlikely to be optimal in a different calendar year or for a longer period. The generation mix may be even unable to guarantee an acceptable level of security of supply for different meteorological years or taking into account the power plant dispatching under uncertainty. More generally, the model is not designed to operate at sub-hourly interval and therefore is not adapted to provide insights on the overall stability of the system and on shorter-time security of supply issues. These assumptions inherently underestimate the VRE curtailment and balancing costs, the security of supply margin and overestimate the value of VRE generation and storage capacity. This phenomenon is particularly important in scenarios with high VRE generation share. Accounting for these aspects would have inevitably increased the generation costs for all scenarios analysed. These cost increases are expected to be higher in scenarios with high VRE generation, where uncertainties and yearly variations in the generation/load balance become more significant, thereby leading to higher profile costs than those currently assessed.

43. Such assumptions may therefore be conservative, in particular for VRE and storage technologies.

However, despite these limitations which are intrinsic in any numerical modelling, the quantitative analysis has revealed some valuable technical and economic insights on the integration of low-carbon technologies into an electricity system and from which important policy conclusions can be drawn.

Increasing deployment of VRE has a major impact on the shape, variability and predictability of the electricity system's residual load and hence on the composition of the generation mix which has to provide it. Under the stringent carbon constraint adopted (and without CCS), coal is never deployed in any of the scenarios considered despite being cheaper than the other technologies on a pure cost basis. The share of fossil-fuelled generation (OCGT and CCGT) remains almost constant in all scenarios, as it is limited by the carbon target. However, a progressive shift from CCGTs to less efficient but more flexible OCGTs with lower capital costs can be observed as rising flexibility requirements and reduced load factors favour the deployment of the least capital-intensive gas-fuelled power plants. This typically raises the profile costs and the total system costs of the high VRE scenarios. In term of electricity generation, given the stringent carbon constraint, the main phenomenon observed is that with more ambitious renewable energy targets VRE generation replace nuclear power almost on a one-to-one basis. The total generation capacity increases markedly with VRE deployment: in comparison with the base case, the installed capacity more than doubles in the scenario with 50% VRE generation and trebles in the 75% VRE scenario. This reflects not only the lower load factor achievable by VRE compared to dispatchable baseload plants, but also an increasing curtailment of VRE generation and their low capacity credit, especially at higher generation share. In particular, the OCGT capacity increases significantly with more ambitious VRE targets: while 2 GW are sufficient in the base case, more than 17 GW are deployed at 30% VRE share and about 34 GW are needed when VREs reach a 75% share of electric energy generation.

A more volatile residual load has also an impact on the operations of conventional thermal plants. With a growing share of VRE in the generation mix, thermal plants are likely to undergo more frequent ramping and operate at lower load factors. A consistent reduction in the load factors of traditional baseload and mid-load plants is observed with increasing shares of VRE in the generation mix. For instance, the average load factor of CCGTs is 25% lower in the scenario dominated by VRE than in the base case which relies only on dispatchable low-carbon technologies such as nuclear. The mode of operation and the flexibility requirements from thermal plants depend strongly upon the penetration level of VRE sought. While the first 10% generation share of VRE does not significantly change the variability of the residual load and thus has a minimal impact on the flexibility required from thermal generators, this no longer applies at more ambitious VRE targets. In particular, the mode of operation of nuclear power plants is severely affected: significant flexibility is required from NPPs when the VRE generation share exceeds 30%, and the reduction in achievable load factors becomes more significant. Achieving more ambitious renewable targets also implies that VRE are curtailed more frequently. Curtailment of VRE generation thus appears at 30% penetration level and increases sharply with their increasing share. At 50% generation share, the curtailment rate of the last VRE unit deployed is above 10%. In the scenario featuring a 75% share of VRE generation, about 18% of the total VRE generation must be curtailed, and the curtailment rate of the last unit deployed is above 36%.[44]

Under the cost assumptions of the present study, the generation mix which meets the electricity demand at a minimal cost relies mainly on dispatchable low-carbon generation technologies, such as nuclear power and hydroelectric power. An appropriate combination of these two technologies as well as of gas-fuelled power plants allows meeting the carbon emission targets with maximum economic efficiency. The cost of generating electricity increases with the share of VRE in the system. While the additional costs are limited at low VRE targets, they increase markedly at higher penetration levels; this reflects not only the higher plant-level generation costs for VRE resources, but also the additional challenges of

44. Curtailment could be mitigated by coupling with other sectors such as the heating sector and transportation sector (both of which are a form of demand side management or active demand response).

deploying additional non-dispatchable VRE units into the generation mix and their decreasing value for the system. Modelling results indicate that electricity generation costs increase by 17% with respect to the base case scenario when a 30% VRE penetration is reached. Achieving higher VRE targets of 50% and 75% of the total electricity generation increases generation costs by 33% and by more than 70%, respectively. For a mid-sized country as the one represented in this study, additional costs for electricity generation range from a few to over USD 15 billion per year. If the plant-level generation costs of VRE decrease significantly compared to current levels, VREs will be a component of the optimal generation mix and will be deployed without external intervention. The optimal share of VRE in the generation mix will depend on their relative costs with respect to that of alternative dispatchable low-carbon technologies. The low VRE cost scenario, in which the plant-level cost of VREs is about 20% lower than that of the alternative dispatchable technologies, indicates an optimal penetration level of VRE of about 30% in the two regions combined.

The analysis and discussion of the total costs for electricity provision, as presented above, is only a first step for policy analysts and is of limited value if not complemented with other metrics; this is due to, at least, two reasons. Firstly, results depend strongly on the relative assumptions taken for VRE and other low-carbon technologies, which are, by definition, uncertain when considering such a long-term horizon. Secondly, other important system effects affecting the integration of VRE resources in to the mix and their competitiveness are not appropriately captured by the modelling tools used in this study. This is why electricity provision costs should be complemented with an estimation of VRE system costs, and their evolution at increasing levels of VRE penetration. This is done by complementing the profile and balancing costs quantified in this study with an estimate of the other components of system costs taken from the literature. Thirdly, only limited considerations of flexibility options have been taken into account; adding in more flexibility options (such as sector coupling) could mitigate system costs.

Consistent with the previous NEA study on system effects and the recent scientific literature, this study shows that total system costs are significant, and they increase more than proportionally with the deployment of variable resources. At low penetration levels, total system costs of VRE are fairly limited, being estimated at 7 USD/MWh_{VRE}. Profile costs, grid costs and connection costs contribute roughly equally to the overall system costs, while the weight of balancing costs is substantially lower. The level of system costs becomes substantial when the deployment of VRE reaches higher levels: at 30% VRE penetration, total system costs more than double, up to 17.5 USD/MWh_{VRE}, and they reach 30 USD/MWh_{VRE} at 50% penetration. Higher deployment targets of VRE lead to system costs as high as of 50 USD/MWh_{VRE}. Indeed, all four components of system costs (balancing, profile, connection and grid costs) increase with the deployment of VRE resources, but at different rates. In particular, the rate of increase of profile costs is much larger than that of the other components of system costs. These figures should be compared with the actual plant-level generation costs of nuclear power, which range from USD 40 to 100 per MWh in OECD countries, and of VRE technologies themselves, for which the levelised cost fall into an even wider range, which ranges from USD 40 per MWh up to USD 200 per MWh.

It is vital to understand that the VRE system costs depend strongly upon the country-specific characteristics of the system considered. Systems with lower flexible resources face more severe challenges to integrate VRE resources and higher costs of electricity generation. Assumptions concerning hydroelectricity and interconnections with neighbouring countries are crucial in these cases. For instance, an isolated system without flexible hydroelectric resources at 50% VRE penetration the total system costs almost double from 28 USD/MWh_{VRE} to 48 USD/MWh_{VRE}. This cost increase is partially due to the larger curtailment of VRE generation which a more inflexible system is unable to integrate, and partially due to a more expensive residual generation mix. Closely integrated countries with sufficient interconnection capacity (such as the countries of Western Europe) can thus absorb the variability of VRE more easily than more isolated countries (e.g. Japan or Korea). Countries with large dispatchable hydropower resources such as Austria, Norway or Switzerland are in a similar favourable situation.

Increasing profile costs as the VRE generation share rises and the consequent reduction of the value of VRE generation for the electricity system are reflected by increasingly lower prices received by solar PV and wind resources. The present study confirms that VRE revenues from electricity markets decline significantly and not in a linear fashion as their penetration level increases. This decrease is much steeper for solar PV than for wind. This is due to the auto-correlation of solar PV and wind resources, which tend to produce when other plants of the same type are also producing; this reduces the market value of electricity precisely when VRE are generating. Market revenues for solar PV are thus halved when a penetration rate of only 12.5% is reached. Adding further solar PV capacity to reach a generation share of 17.5% halves again the market value of a MWh produced by solar PV to a value below 20 USD/MWh. A similar trend, although less pronounced, is observed for onshore wind which has higher load factors than solar PV and whose generation profile is better distributed through time. These considerations raise serious questions concerning the optimal deployment level of VRE technologies and the long-term economic sustainability of the support mechanisms which are currently employed for their development.

A low-carbon system has characteristics that go beyond the technical and economic aspects discussed above. First, the system becomes a more capital-intensive generation mix. Compared with the current mix in most OECD countries, where investment and variable costs represent each roughly 45% of the total lifetime costs, investments constitute a 60-70% share of the total costs in low-carbon scenarios, and variable costs are much lower. However, the choice of low-carbon technologies has an impact on the overall capital structure of the generation mix. Variable costs progressively decrease when going from a low-carbon system dominated by nuclear power to a system where VRE ensure the bulk of generation. In the base case, variable costs represent 25% of the lifetime generation costs, while they account for less than 10% of the total cost in the 75% VRE scenario. The second effect is a significant change in the long-term structure of wholesale electricity prices. One of the most striking effects of the deployment of low marginal cost variable resources on the electricity markets is the appearance of hours with zero prices and a substantial increase in the volatility of wholesale electricity prices. Zero-level electricity prices start appearing as soon as VRE reach a penetration level of 30%. The number of occurrences increases dramatically with the deployment of VRE resources; at 50% generation share, more than 1 200 hours in a year feature zero-price levels, i.e. about 14% of the time. When VRE produce 75% of the electricity demand, zero prices occur during 3 750 hours, i.e. more than 43% of the time. The higher frequency of hours with zero prices is compensated for by an increase in the number of hours with high electricity prices. For instance, the number of hours in which electricity price is higher than 100 USD/MWh increases substantially when the VRE generation share exceeds 30%. High electricity prices volatility and the reliance in a limited number of hours with high or very high prices increases significantly the electricity market risk for all generation technologies. Higher market risk automatically increases the expected rate of return from investor and, by consequence, lead to higher cost of capital. This is particularly relevant for capital-intensive, low-carbon technologies such as VRE or nuclear power, which have a longer payback time and are more sensitive to long-term changes in the level of electricity prices.

From a policy perspective, the quantitative outcomes of this study support the conclusion that most economically efficient way to achieve the carbon emission target is to impose a carbon price (or an equivalent carbon cap) which limits the use of fossil-fuelled generation sources and allows the deployment of the most efficient low-carbon resources. Under a carbon constraint, all low-carbon resources can freely compete and are deployed at their optimal level into the system, thus maximising their private value as well as the value for the overall system. With an appropriate carbon constraint, carbon emissions can be reduced to a desired level at minimal cost. In contrast, technology-specific mechanisms, such as setting targets for certain technologies will lead to sub-optimal outcomes and higher costs.

Annex 3.A1. Case studies: Power system and economic assumptions

Model of the power system

Power system analysis requires gathering a sizeable amount of detailed information on electricity systems. Evolution of the electricity demand, load factors of VRE and hydro run-of-the river power plants, water inflows in the reservoirs, size and seasonal availability of interconnections among the different regions simulated are some of the required information. A considerable effort has therefore been devoted to gather consistent and reliable data on the real systems to be modelled, in order to provide a realistic representation of a large, well-interconnected power system as the basis for this modelling exercise. The present study has strongly benefitted from the large amount of information on EU power systems published by the European transmission system operators (TSOs) and utilities.

Much of the input data for the main region (region 1) have been derived from real data of the French power system in 2015, which are published by the French transmission system operator RTE. These data include the load as well as the realised load factors from solar PV, wind farms and run-of-the-river "fatal" hydroelectric resources, which are available with a 30 minute interval. These data have been aggregated to match the hourly interval used in the modelling. The capacities of hydroelectric resources were also derived from the currently available resources in France: this applies to run-of-the-river "fatal" capacities, reservoir-based hydro reserves, as well as the pumped hydro capacities. Overall, region 1 has:

- 10 GW of run-of-the-river hydroelectric capacity;
- 10 GW of reservoir hydroelectric;
- 4.5 GW of pumped hydroelectric capacity.

The "water value", i.e. the amount of water that periodically fills the reservoir, has been aggregated on a weekly interval.

Region 2 is artificially constructed in order to set up an interesting modelling exercise for being able to study the behaviour of the main region. Region 2 reflects the characteristics of the six power systems of the countries interconnected with France: Belgium, Germany, Italy, Spain, Switzerland and the United Kingdom. However, this region has been redesigned (i.e. scaled downwards) to have the same yearly electricity demand as that of the main region. The two regions have therefore the same "size" in electricity terms. The load and the VRE load factors renewables have been obtained as a weighted average of the respective country data available. Similarly, the hydroelectric capacities are based on the real data for those countries. Overall, region 2 has:

- 7.5 GW of run-of-the-river hydroelectric capacity;
- 7.5 GW of reservoir hydroelectric;
- 8 GW of pumped hydroelectric capacity.

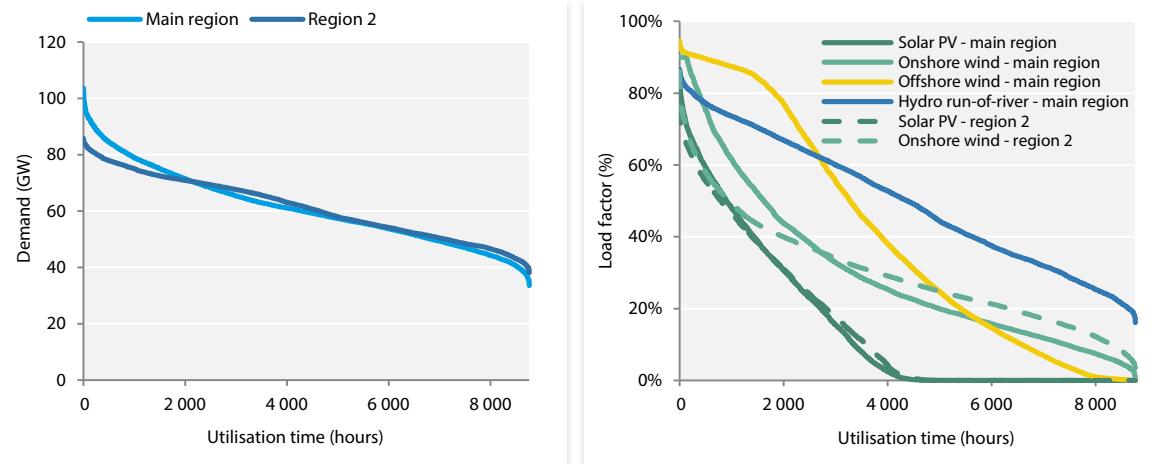
As not all information was available in neighbouring countries, the load factors for hydroelectric resources and "water values" for region 1 have also been applied in region 2.

The demand curve for 2015 has been scaled using a factor of 1.14 to reflect the expected increase in the electricity demand by 2050 in OECD countries (see *World Energy Outlook* [IEA, 2015a]). The load factors of VRE and hydro resources have also been scaled to reflect the *average* load factor taken for the cost estimation of these resources, which are representative

of values in OECD countries (respectively 30% for onshore wind, 40% for offshore wind, 15% for solar PV and 50% for hydro). However, in this process the maximal load factor for each hour was limited to a maximal value of 90% (95% for offshore wind).

Figure 49 shows the load duration curve (left) as well as the load factor distributions (right) in the two regions. As clearly visible in these figures, both the demand and the VRE load factors are much more smoothed in region 2 than that of the main region, due to the their aggregation over a much larger area. This goes some way towards explaining why the uptake of VRE is far more vigorous in region 2 than in region 1 in the least-cost efficiency low-cost renewable scenario (see above).

Figure 49. **Load duration curves and RES load factor distributions in the two regions**



Finally, it is interesting to calculate the correlation coefficient between the generation from renewable resources and the electricity demand. Indeed, the correlation between RES generation and electricity demand provides an indication of the value of the electricity generated. The more the RES generation is correlated with the electricity load, the more valuable for the system is the RES generation and the higher is the market value of the electricity produced by RES. Table 9 provides the correlation coefficient between RES generation and electricity demand in the two regions considered[1]. In 2015 the correlation coefficient between solar PV and load is close to zero (but positive) in France, indicating that the value of the first MW[2] of solar PV installed on the region should be closer to the average price of electricity. This reflects the characteristics of the French electricity demand, which peaks in the late afternoon winter time, when solar PV generation is minimal. The correlation coefficient is much higher in region 2, thus reflecting a better correlation with demand in neighbouring regions. Opposite trends are observed for wind, where generation is better correlated with demand in the main region. Hence, the market value of wind is expected to be higher than that of solar PV in the main region, while the opposite holds for region 2 (calculated market values for the main region are provided in Figure 48). It should be noted that the correlation coefficient between demand and VRE load factor, especially for wind power, may change from year to year depending on specific meteorological conditions. The above considerations are thus valid only for 2015.

1. The "correlation coefficient" is defined such that $-1 \leq R \leq 1$, whereby R=0.99 is almost perfect correlation, R=-0.99 is perfect anti-correlation and R near 0 means that there is no correlation.
2. The market value of electricity produced by solar PV and wind decreases with their penetration level. The results indicated in Table 9 are therefore indicative of the value of the first MW of VRE installed.

Table 9. **Correlation between renewable generation and demand in the two regions considered**

	Solar PV	Wind onshore	Hydro run-of-the-river
Main region	0.015	0.223	0.355
Region 2	0.372	0.097	0.276

Assumptions on other components of system costs

This section provides the data and assumptions used to estimate the components of system costs that could not be captured by the modelling work performed within this study: connection costs, balancing costs and grid costs, i.e. T&D costs.

Connection costs, i.e. the costs for connecting the power plant to the nearest point of the high-voltage or medium-voltage transmission grid, are not accounted for in the IEA/NEA estimates of plant-level costs used in this exercise and therefore are not part of the optimisation process of the generation mix. The estimates of connection costs used in this study are based upon the data from *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (NEA, 2012) and are expressed as a fraction of the investment costs of each generation plant. Note that OCGT and hydroelectric pumped storage plants have the same annualised connection costs as those of CCGT plants and hydroelectric reservoir, respectively. These data and the resulting annualised investment costs for each generating technology are summarised in Table 10 below. The component "connection costs" is calculated for each scenario in the following way: for each scenario the cost of connecting all power plants in the generation mix is calculated by multiplying the installed capacity of each power plant type by its specific connection cost, drawn for each technology from the literature. The "connection cost" component of the system costs is then obtained by calculating the difference between the total connection costs of each individual scenario and those of the base case, divided by the net amount of electricity produced by VRE.

Table 10. **Plant-level data used for calculating the connection costs**

	Fraction of investment costs (%)	Annualised cost (USD/MW/year)
OCGT	-	4 530
CCGT	5%	4 530
Nuclear	5%	20 694
Wind	8%	13 730
Solar PV	5%	7 350
Hydro run-of-the-river	5%	16 185
Hydro reservoir	5%	12 233
Hydro pump storage	-	12 233

Source: NEA, 2012.

Data for balancing and grid costs are derived from the information available in the public literature and are summarised in Table 11. It should be noted that the model used in the optimisation of the generation mix accounts for the uncertainty of VRE generation by adapting the required level of reserves as a function of the VRE penetration level. Balancing costs are therefore already accounted for, although only partially, in the calculation of profile costs. For this reason, 50% of the balancing costs found in the literature and reported in Table 11 are effectively used in the assessment of total system costs.

Most of the reported data concern low or mid-penetration levels (generally from a few percent up to 30%-40% of wind or solar PV penetration), and a few quantitative estimates are available for VRE penetration levels beyond 50%. The data used for a penetration levels of 10%, 30% and 50% represent the (lower-end) spectrum of results found in the literature, while the values at 75% are obtained as a linear extrapolation.

Table 11. **Estimates for grid and balancing costs**

	Penetration level (%)	Grid costs (USD/MWh$_{VRE}$)	Balancing costs (USD/MWh$_{VRE}$)	
			Literature	Used
Wind	10%	3	1.0	0.5
	30%	5	2.0	1.0
	50%	8	4.0	2.0
	75%	11	6.0	3.0
Solar PV	10%	1	0.5	0.25
	30%	2	1.0	0.5
	50%	4	1.0	0.5
	75%	7	1.5	0.75

Source: NEA estimated based on literature (see Chapter 2).

Note on balancing costs: The left column shows the reference values reported in the literature review, the right column the value used in the calculation (50% of the reference value).

The additional costs for T&D networks to accommodate significant amounts of decentralised and variable renewable energies such as wind and solar PV requires further systematic study. The figures underlying the analysis in this report remain largely based on *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (NEA, 2012), which was based on a meta-analysis of the available literature. Newer estimates indicate that network costs in systems with high shares of VRE might indeed be very large. A recent study (Berthélemy et al., 2018) summarising work by a modelling group around Pantelis Capros of TU Athens thus indicates that in France reducing the share of electricity by nuclear power plants to 50% as early as 2030 would imply investment costs for grid expansion of around EUR 90 billion during the decade 2030-2040, which would *exceed* the costs of new generating capacity over the same decade.

Annex 3.A2. Details of the modelling tools used and impacts of modelling assumptions

This annex provides some background information and details on the mathematical tools used in this study as well as the most relevant numerical simplifications that have been used in order to make the problem numerically tractable with current calculation tools.

The first part of this annex provides a more complete description of the GenX (Optimal Electricity Generation Expansion) model that has been used to perform the quantitative analysis in this study. In the second part of the annex the more significant assumptions implicitly or explicitly considered are described and potential qualitatively impact on the results discussed.

GenX simulation tool

GenX is a power system simulation model developed by researchers at the Institute for Data, Systems, and Societies of the Massachusetts Institute of Technology (MIT). GenX focuses on the operation and planning of electrical power systems and is used in a wide range of planning and operational situations. These include long-term generation and transmission expansion planning, and short-term operational simulations. It determines investment decisions on electricity resource assets that, if operated optimally, can fulfil the electricity load of a particular system at minimum cost, subject to defined operational constraints such as ramping and cycling. By changing certain parameters, the tool can also model the effect of different energy policies, such as carbon prices, carbon emission targets, renewable standards network tariffs, subsidies, and other policy or regulatory decisions on the equilibrium capacity mix. Like other, similar tools for power system analysis, GenX makes the implicit assumption of perfect market competition and risk-neutral agents.

From a centralised planning perspective, this model can help to determine the future investments that will be needed to supply future electricity demand at minimum cost. In the context of liberalised markets, the model can be used by regulators for indicative electric power system planning in order to establish a long-term vision of where efficient markets with increasing penetration of low-carbon generation, storage and demand-side resources would lead.

The model has been designed to carry out the following types of analyses:

1. the optimal expansion plan (centralised utility or decision maker);
2. the optimal investments (independent power producers);
3. the economic feasibility and the economic impact of new technologies (e.g. storage, demand-side management [DSM], distributed energy resources [DERs], VRE, advanced nuclear);
4. determine the equilibrium effect of any given policy (carbon caps, carbon taxes, renewables standards).

Model description

The GenX model was developed at MIT to improve classical methods by incorporating operational flexibility, inter-temporality and network representation in power system analyses. At the same time, the model development has been motivated by the need to

expand from electricity generation capacity expansion to electricity resources capacity expansion, including options such as DERs, combined heat and power systems, demand-side resources and energy storage as well as new technology designs.

GenX uses mathematical optimisation techniques such as linear programming (LP), and mixed-integer programming to solve for optimal investment and operational decisions. LP studies the case in which the objective function f(x) is linear and the constraints are specified using only linear equalities and inequalities. Mixed-integer programming (MIP) studies linear programmes in which some or all variables are constrained to take on integer values, creating a much more difficult problem than regular LP problems.

The GenX formulation tractably includes the operational details of thermal units and unit commitment constraints in capacity planning optimisation on a multi-zonal multi-level framework, while subject to renewable mandates and CO_2 emissions constraints; thereby allowing interaction between the electricity and heat markets.

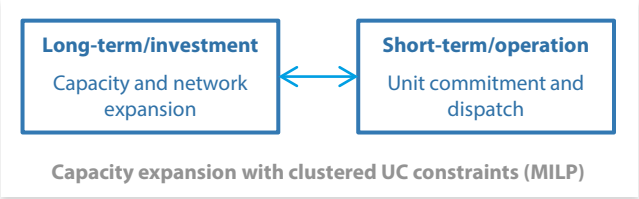
The formulation developed uses technological systems that are currently under development, generation unit clustering, and T&D power flow approximations to tractably co-optimise seven interlinked power systems decision layers:

- capacity expansion planning;
- optimal generation dispatch;
- T&D power flows;
- T&D expansion;
- operating reserves requirements;
- clustered unit commitment operations;
- interactions between electricity and heat markets.

This formulation makes it possible to model operational flexibility impacts on capacity planning in a single, monolithic optimisation problem that otherwise would have been necessary to solve in different, separated stages (Palmintier, 2013 and Sisternes, 2014). At the same time, it is possible to model network interactions, and to model heat-electricity market synergies within regions.

Formally, the model can be divided into two components: a first component where electricity resource building decisions are made (capacity expansion); and a second component incorporating the operational decisions associated with the different electricity resources that have been built in the first stage (unit commitment and economical dispatch); see Figure 50. The particularity of GenX is that its cost function includes not only capital cost and variable operating costs, but also the costs of a more intense cycling regime, subject to an array of technical constraints that guarantee the technical feasibility of the modelled system.

Figure 50. **Schematic representation of the GenX model**



Available centralised generation resources include: combined cycle gas turbines, open cycle gas combustion turbines, pulverised coal, nuclear, wind, solar PV and hydroelectric resources. Other possible centralised generation resources include geothermal, biomass, solar thermal, pumped hydro storage and possible thermal storage for solar thermal or nuclear

units. Eligible DERs include: solar PV, electrochemical storage, thermal storage, flexible demands and batteries. Capacities can be imposed exogenously to the system (brownfield development) as well as can be determined endogenously by the model (greenfield approach).

The capacity of all generating units and DERs is represented as a continuous decision variable, except for large thermal units, which may be represented as integer plant clusters by region if desired (Palmintier, 2013). Units of incremental capacity for all DERs, large-scale wind and solar, and open cycle gas turbines (OCGTs) are all small enough that this abstraction is minor, while larger thermal units can be represented as integer clusters if the discrete nature (or lumpiness) of these investment decisions is considered important. Operational decisions for generating units and DERs are continuous decisions, with the exception of cycling decisions for large thermal units, which can be represented as either continuous decisions or integer decisions (e.g. how many units within each cluster of similar plants to turn on or off) as desired. Integer clustering of similar plants entails the simplifying assumption that all plants within a cluster are identical and that all committed units within a cluster are operating at the same power output level. Treating commitment decisions as continuous variables further relaxes the problem and allows commitment of fractions of a plant. Both options introduce modest approximation errors but significantly improve computational performance, enabling greater detail in other features, such as network complexity. Since on/off decisions for individual DERs and even OCGTs are fast and occur in small increments, representing them as continuous decisions is also a minor approximation.

Capacity investment and operational decisions are indexed across each node or region in the system, enabling the model to select the optimal location of capacity investments and operations in each location. Thus the model balances the different economies of scale at different voltage levels on the one hand, with the differential impacts or benefits of location at different regions or voltage levels on the other – a key advantage over other models.

Power flows between regions and voltage levels are modelled as simple transmission flows. Maximum power flows across these interfaces capture key network constraints. Losses are a function of power flows between voltage levels or regions, implemented as a piecewise linear approximation of quadratic resistive losses. Distribution network reinforcement costs associated with changes in peak power injections or withdrawals at each node are represented as linear or piecewise linear functions parameterised by experiments and optimal power flow modelling.

Reserve requirements are modelled as day-ahead commitments of capacity to regulation and spinning/non-spinning contingency reserves, to capture the commitment of capacity necessary to robustly resolve short-term uncertainty in load and renewable energy forecasts and power plant or transmission network failures.

The time interval evaluated in this methodology is one year, divided into one-hour periods and representing a future year (e.g. 2050). In that sense, the formulation is static because its objective is not to determine when investments should take place over time, but rather to produce a snapshot of the minimum-cost generation capacity mix under some pre-specified future conditions.

The dimensionality challenge

Capacity expansion analysis presents a dimensionality challenge due to the exponentially-increasing number of decision variables as the time, operational detail and network representations of the model are increased. Figure 21 presents the GenX simulation domain showing the different detail representations for the different modelling dimensions. Going from, in the simplest case, a single node with economic dispatch but without inter-temporality considerations and using time blocks only to a full network representation with AC power flow calculations and considering unit commitment and reserves independently for each power plant in a multi-year context.

It is worth noting that not all features can be turned on at same time. Computational limitations entail trade-offs along each dimension, so more detail in one area typically means greater abstraction in others. The configurable characteristic of the model allows the selection of the most relevant features for each specific project.

Description of some calculation assumptions and their impact on results

This section provides additional details on some assumptions used in this study to make the problem numerically tractable with current calculation tools: i) Risk-neutrality and perfect market competition, ii) Modelling of T&D grid, iii) Perfect forecast of future demand and VRE generation and iv) Representation of a single year.

Risk-neutral agent – perfect market competition

Annualised investment costs for all technologies considered in the present study are calculated using a common real discount rate of 7%. This value can be considered as a good proxy of capital costs for generating companies in OECD countries. The same discount rate is used for all generating and storage technologies; this implicitly assumes that the level of risk is the same for all investments in generation, is constant throughout the lifetime of a generator and does not change with each scenario analysed. Such an approach, also referred to as "risk-neutral agent", is commonly adopted in most analyses of the electricity system seen in the research literature.

However, this discount rate captures only some of the elements considered by generating companies in the investment process. When assessing the financial feasibility of a project, the expected cash flows should be discounted using an appropriate rate that takes into account not only the cost of capital for the company undertaking the project (the weighted average cost of capital [WACC], for example) but also the level of risk of the specific project and its correlation with company's existing assets and liabilities. This specific risk depends on the technology and, within a given technology, changes considerably with each phase of the project. For instance, there is a little doubt that a nuclear power project faces a much higher financial risk than a CCGT in the construction phase, owing to the significant uncertainties on the overall overnight costs and on the duration of the construction. By contrast, the good operational track record of most NPPs, combined with lower marginal costs means that market revenues from an NPP are less volatile than those of a CCGT, thus implying a lower risk to this technology during the operational phase.

As seen in the results, the level and volatility of electricity prices, and consequently the market risk for all generating technologies, changes significantly depending on the scenario analysed. However, the discount rate has not been adjusted to reflect such change in the level of financial risk. Also, no attempt was made to evaluate how different policies aimed at curbing carbon emissions may shift the risk from the electric power producer to other entities and thereby affecting the discount rate that should be applied to each generation technology. For example, granting a specific technology a fixed price for its electricity generation (e.g. by means of a long-term contract, perhaps obtained competitively through auctions) would significantly lower its market risk and should be thus reflected in a lower discount rate.

Finally, decisions on investments and power plant dispatch are modelled assuming perfect market competition, without considering possible market manipulation from different actors.

Modelling transmission and distribution grids

The single-node approach, often referred to as a "copper plate approach" is commonly used in economic analysis and optimisation of power systems. Transmission and distribution grids are not modelled, implicitly assuming that the electricity can be transferred from generators to customers without physical limitations, bottlenecks or losses.

The present study refines this approach by considering two separate regions, which are linked by an interconnection of a given net transfer capacity. Power exchanges between the two regions are limited by the maximal capacity of the interconnections, and no transmission losses are considered between the two regions. Each region is represented as a single node, without transmission constraints or losses; and a copper plate approach is thus taken within each region.

Taking into account the geographical distribution of both generation and load within each region would have added another constraint into the optimisation process and thus have led to higher generation costs in all scenarios. The level of these constraints and the additional costs are likely to be higher for the scenarios featuring high shares of VRE for the following two reasons:

1. the electricity is more likely to be transported over longer distances as the location, which maximises VRE generation, is not necessarily close to the load centres. Transmission losses are therefore more significant in scenarios with high levels of VRE resources.
2. the geographical concentration of VRE resources and the fact that their generation tends to be highly correlated in the same geographical areas means that the risk of congestion in the transmission grid increases with VRE penetration levels[1].

Perfect forecast

The optimisation of the generation mix and the operational dispatch of all resources are based on a predictability and perfect foresight of the future load, on the future generation levels of VRE, as well as of the operation of all other power units. Commitment of all generation resources and the charging/discharging patterns of storage capabilities are therefore optimised ex-post and provide the maximal value for the system. This is clearly different from real-world experience where operational decisions are made under uncertainty and with limited knowledge of the future, which inevitably leads to non-optimal choices and to a sub-optimal use of resources – in particular for storage plants. Considering this effect, and thus modelling choices and optimisation strategies taken under uncertainty, would definitively increase generation costs in all scenarios; most likely, the scenarios characterised by higher uncertainties on the residual demand and by a larger use of storage capabilities, such as those with a larger share of VRE, would see their costs increase proportionally.

Only one year – no stochastic representation of inter-annual variability

The generation mix has been optimised based on the data collected for a single year, 2015; the data used includes the level and shape of electricity demand, the realised generation or load factors from renewable resources such as wind, solar PV and hydroelectric run-of-the-river resources, water inflows for hydroelectric reservoirs, etc. A different set of input data, derived from a different year for example, would lead to different outcomes in terms of optimal generation mix as well as in generation costs. A more robust assessment of the optimal generation mix would have required the analysis of hundreds of representative scenarios encompassing several years of different demand patterns, and for each year dozens of different scenarios representing the stochastic variability from variable resources. This kind of analysis, however, would be incompatible with the limits of current calculation tools as well as with the available resources for this study.

These limitations should be kept in mind when interpreting the outcomes presented here. Considering a larger sample of years in terms of load and different regimes for variable resources would have led to a different optimal generation mix and to an increase of generation costs for all scenarios. The resulting generation mix would be more robust, i.e. capable to satisfy the demand over a wider range of possible situations, but not optimal for each specific year. Clearly the difference in the overall generation structure and the cost increase are likely to be more significant for the scenarios featuring prominent levels of VRE, whose generation may vary substantially across different calendar years. However, the

1. The needs in terms of grid reinforcement associated with VRE deployment are mostly captured by grid costs, i.e. by the cost of building and operating a larger and more complex transmission and distribution grid. However, there is also an impact on the generation structure, which should be captured and integrated in the profile costs.

simpler approach taken for this study still captures most of the relevant phenomena associated with the integration of variable resources and allows for a consistent comparison of different scenarios.

A quantitative estimate of these effects has been done by Nagl et al. (2013). The study compares the optimal generation mix and the total generation costs of a system optimised under a deterministic or a stochastic representation of the RES generation pattern. The authors conclude that, compared to a deterministic analysis, taking into account the stochastic availability of RES resources increases the total costs of generation and, symmetrically, reduces the value of electricity generated by RES. The increase in total generation costs is almost linear until the penetration level of renewables reaches a value of 70%, after which it becomes more significant[2].

2 A cost increase of 1.6 EUR/MWh (i.e. about 2.2% of the total generation cost) is reported for a RES penetration level of 50%. At 80% RES penetration level, the cost difference is estimated at 3.6 EUR/MWh, or 4% of the total generation costs, to reach a value of 14.2 EUR/MWh, i.e. 12.3% of the generation costs, when a 95% target of RES generation is achieved.

Annex 3.A3. Scenario by scenario summary

This annex provides a more detailed description of each one of the eight scenarios modelled, as well as a synthesis of the most relevant individual results. Table 12 and Table 13 provide detailed information on the installed capacity and electricity generation for the eight scenarios considered.

Table 12. **Installed capacity in the eight scenarios (GW)**

		Base case	10% VRE	30% VRE	50% VRE	75% VRE	Low VRE cost	No IC	No IC, no hydro
Main region	OCGT	2.0	5.1	17.0	24.4	33.8	15.5	20.6	23.3
	CCGT	23.0	23.0	22.7	23.8	24.8	17.7	26.5	30.8
	Nuclear	48.7	39.7	26.6	16.4	0.0	39.2	19.4	24.3
	Onshore wind	0.0	15.3	46.0	78.5	143.3	22.7	78.5	78.5
	Solar	0.0	10.2	30.6	52.3	95.5	15.6	52.3	52.3
	Hydro run-of-the-river	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Hydro reservoir	10.0	10.0	10.0	10.0	10.0	10.0	10.0	0.0
	Hydro pump storage	4.5	4.5	4.5	4.5	4.5	4.5	4.5	0.0
	Battery storage	0.0	0.0	0.0	0.0	3.3	0.0	0.0	1.4
	Total	**98.2**	**117.8**	**167.3**	**219.9**	**325.2**	**135.2**	**222.0**	**220.6**
Region 2	OCGT	11.4	12.2	13.0	17.3	24.2	16.5	15.8	19.3
	CCGT	8.3	13.3	13.5	15.5	18.7	18.2	18.3	23.3
	Nuclear	51.7	41.9	31.5	19.7	0.0	14.6	18.1	22.2
	Onshore wind	0.0	15.3	46.0	78.5	143.3	81.4	78.5	78.5
	Solar	0.0	10.2	30.6	52.3	95.5	50.9	52.3	52.3
	Hydro run-of-the-river	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
	Hydro reservoir	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0.0
	Hydro pump storage	8.0	8.0	8.0	8.0	8.0	8.0	8.0	0.0
	Battery storage	0.0	0.0	0.0	0.0	0.3	0.0	0.0	1.5
	Total	**94.2**	**115.9**	**157.5**	**206.2**	**304.9**	**204.5**	**206.0**	**204.6**

Table 13. **Electricity generation in the eight scenarios (TWh)**

		Base case	10% VRE	30% VRE	50% VRE	75% VRE	Low VRE cost	No IC	No IC, no hydro
Main region	OCGT	0.6	0.5	2.3	3.9	6.4	4.1	4.5	5.7
	CCGT	80.3	76.3	73.5	71.0	66.8	70.7	70.0	67.6
	Nuclear	425.6	347.4	230.3	133.3	0.0	340.2	149.0	177.7
	Onshore wind	0.0	40.3	120.6	197.0	287.8	59.5	187.3	174.0
	Solar	0.0	13.4	40.3	68.8	123.3	20.6	68.6	68.1
	Hydro run-of-the-river	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8
	Hydro reservoir	15.8	15.8	15.8	15.8	15.8	15.8	15.8	0.0
	Hydro pump storage	8.2	5.8	6.1	8.3	10.2	5.5	9.5	0.0
	Hydro pump storage – charge	-10.1	-7.2	-7.6	-10.2	-12.6	-6.8	-11.8	0.0
	Battery storage	0.0	0.0	0.0	0.0	2.2	0.0	0.0	1.1
	Battery storage – charge	0.0	0.0	0.0	0.0	-2.3	0.0	0.0	-1.2
	DSM	0.2	0.3	0.2	0.1	0.1	0.1	0.1	0.1
	Interconnections	-27.5	0.5	11.5	5.2	-4.6	-16.6	-	-
	Total	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**
Region 2	OCGT	1.3	2.4	3.4	4.3	6.3	1.8	2.6	5.0
	CCGT	22.7	73.3	71.7	70.3	67.0	74.1	72.9	68.6
	Nuclear	444.5	365.9	270.2	158.3	0.0	122.9	148.3	167.8
	Onshore wind	0.0	40.3	120.8	199.1	293.8	212.5	202.9	194.1
	Solar	0.0	13.4	40.3	68.8	124.4	66.8	68.8	68.8
	Hydro run-of-the-river	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6
	Hydro reservoir	11.8	11.8	11.8	11.8	11.8	11.8	11.8	-
	Hydro pump storage	15.8	10.8	10.4	13.0	15.7	10.5	13.3	-
	Hydro pump storage – charge	-19.5	-13.3	-12.9	-16.1	-19.4	-13.0	-16.4	-
	Battery storage	0.0	0.0	0.0	0.0	0.2	0.0	0.0	1.3
	Battery storage – charge	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	-1.4
	DSM	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Interconnections	27.5	-0.5	-11.5	-5.2	4.6	16.6	-	-
	Total	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**	**536.9**

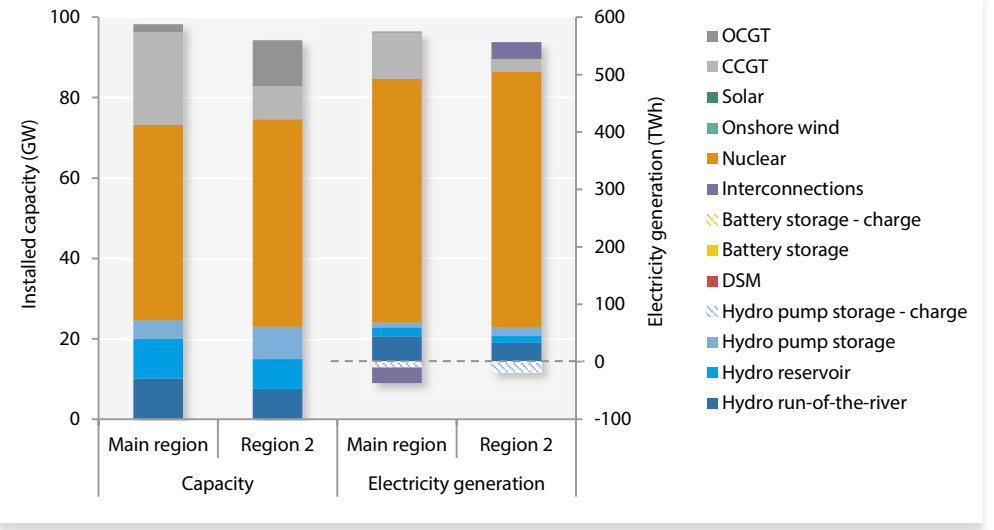
Scenario I: Cost minimisation (base case)

In the "cost minimisation" scenario, only brownfield hydroelectric resources are exogenously given in the system: 24.5 GW of hydroelectric plants are deployed in the main region (10 GW of run-of-the-river, 10 GW of reservoir-based and 4.5 GW of pump-hydro), while about 23 GW are available in region 2, with a larger share of flexible hydroelectric plants. As in all main scenarios, the two regions are linked by an interconnection of 7.2 GW capacity, which corresponds to 12% of the average demand of each region. The rest of the generation mix in both regions is determined endogenously with the objective of satisfying the electricity demand and the carbon constraint at a minimal cost, without imposing a target or having any restrictions on the use of any specific technology. By construction, this scenario has the lowest cost of electricity generation and constitutes therefore the reference to which all other scenarios are compared. The carbon emission intensity of 50 g/kWh is achieved by imposing a carbon price common to

the two regions. A value of 35 USD/tonne, obtained iteratively, is sufficient to achieve the target carbon emission level in the main region. However, this assumption leads to a somehow lower level of carbon emissions in region 2[1,2]. From a policy perspective, this choice represents the adoption of the same carbon price in the two regions modelled, together with a redistribution of the full amount of these revenues to electricity consumers.

Under the cost assumptions of the present study, the optimal generation mix turns out to be a combination of nuclear units, hydroelectric power plants and gas-fuelled generation plants (OCGT and CCGT), without deployment of VRE or coal power. The stringent carbon constraint used in this study means that coal power plants are never deployed in any of the scenarios analysed. The total capacity of the generation mix in the main region is slightly below 100 GW, while that of region 2 is of about 94 GW. In the main region, about 49 GW of nuclear power are built, and 25 GW of gas-fuelled plants, mostly CCGTs. In terms of electricity generation, nuclear power provides about 75% of the electricity generated in the main region and hydroelectric power about 11%; these two technologies together ensure the totality of low-carbon generation in the main region. The remaining electricity generation is provided by a combination of OCGT and CCGT gas-fuelled power plants. Over the whole year, 38 TWh of electricity are exchanged between the two regions through the interconnections, mostly going from the main region to region 2. The electricity price differs between the two regions in only 730 hours during the year, indicating that interconnections are saturated only in 8% of the hours modelled. The composition of the generation mix, the breakdown of electricity generation and the electricity exchanges between the two regions for this scenario are provided in Figure 51.

Figure 51. **Base case – capacity mix and electricity generation share**



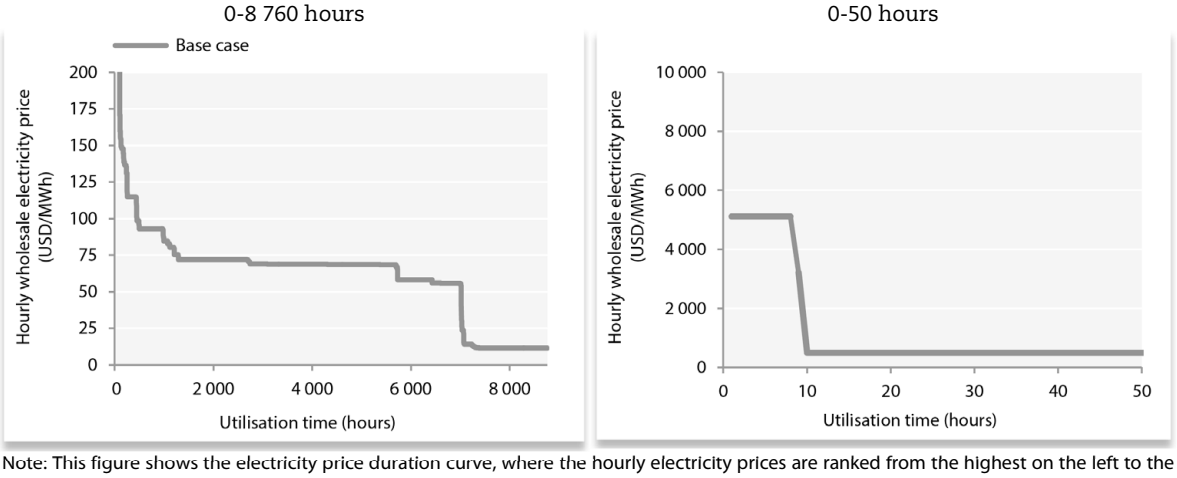
1. The level of carbon emissions in a given system depends not only on the carbon price imposed and on the economics of available generation technologies but also on the shape of the load curve and the availability of interconnections. To obtain the same emission levels in both regions, a different carbon price should be imposed in each region.
2. Most of the comparison across different scenarios performed in this study is limited to the main region; for a better comparability of the results, it was therefore important that the carbon intensity in this region was kept constant across all case studies.

Due to the large share of nuclear power in the electricity generation, nuclear units have to operate with some flexibility, especially during the months around summer, when the electricity demand is lowest. However, even in these conditions the generation lost by nuclear units amounts to only 0.2% of the maximal generation achievable. Combined cycle gas turbines (CCGT) are operated at an average load factor close to 40%, while OCGT are used only to cover peak demand and to provide flexibility to the system; their average load factor is about 4%.

As already indicated, this scenario is characterised by the lowest electricity generation costs of the seven scenarios which share the same input cost assumptions for all available technologies. The total generation costs for the electricity consumed in the main region amount to USD 36.1 billion per year[3]; these costs comprise all variable and fixed O&M costs, fuel costs as well as the yearly component of investments costs, calculated assuming a discount rate of 7% in real terms. It will be shown below that in all scenarios the overall generation costs in region 2 are slightly lower than those in the main region. This is due to a flatter shape of the electricity demand and a larger share of flexible hydroelectric resources in that region.

In this scenario, there are no situations in which the electricity demand is not satisfied (no occurrence of loss of load), but in some occasions the system is unable to ensure the required reserve margin, indicating that the system may be unable to cope with unforeseen events. Voluntary curtailment of demand, via demand-side response mechanisms is active for about 100 hours a year. During these periods some selected and agreeing consumers can be disconnected from the electricity supply. The quantity-weighted wholesale electricity market price is about 80 USD/MWh; the electricity price duration curve for this scenario is provided in Figure 52.

Figure 52. **Base case – electricity prices duration curve**



Note: This figure shows the electricity price duration curve, where the hourly electricity prices are ranked from the highest on the left to the lowest values on the right. The graph on the right shows a zoom of the first 50 hours, where electricity prices are highest. A series of similar figures is provided for the other seven scenarios, comparing the electricity price duration curve of each scenario with that of the base case.

Scenario II: 10% wind and solar PV (10% VRE)

In the "10% VRE" scenario a combination of solar PV and onshore wind capacity is exogenously deployed in each region so that the net generation from VRE resources covers 10% of the electricity demand. Solar PV is set to provide one quarter of the total generation from variable renewable resources, while onshore wind ensures the remaining 75%. The same amount of

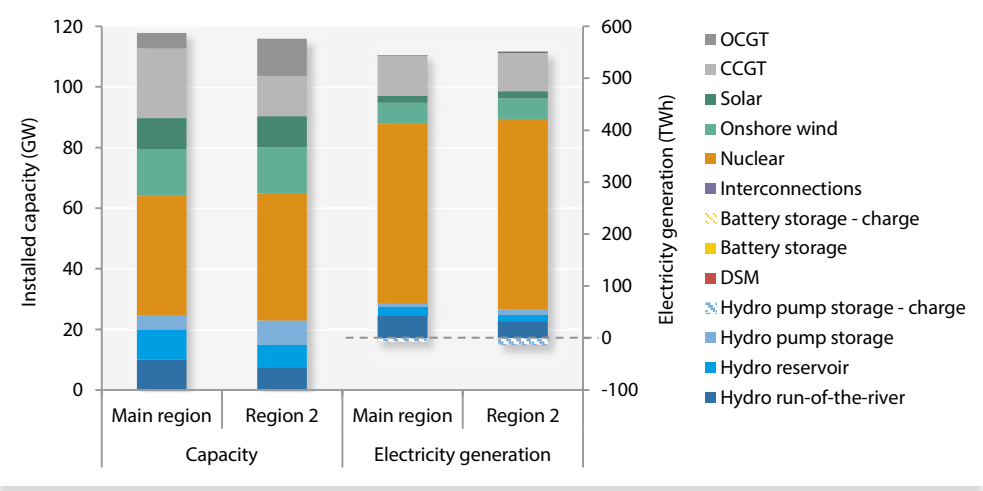
3. Note that for this scenario, as well as for all other cases, the cost estimate does not consider the contribution of brownfield hydroelectric resources (nor the amount of electricity generated by these resources).

brownfield hydroelectric capacity as in the base case scenario is also exogenously imposed in each region: 24.5 GW in the main region and about 22 GW in region 2. The rest of the generation mix is determined endogenously to meet the electricity demand in each region at a minimal cost, without having any restrictions over the use of any specific technology. Unlike in the base case, where an appropriate carbon tax is imposed in both regions, in this scenario the targeted carbon intensity level of 50 g/kWh is achieved by capping the carbon emissions in both regions modelled[4].

The generation mix is constituted by a combination of nuclear power, hydroelectric power, VRE and gas-fuelled power plants (CCGT and OCGT). The total generation capacity increases slightly in comparison to the base case to a total capacity of 118 GW in the main region; the total capacity deployed in region 2 is set at a slightly lower level of 116 GW. Ten gigawatts of solar PV and 15 GW of onshore wind capacity are built in each region to satisfy the 10% VRE generation target. About 40 GW of nuclear power and 28 GW of gas-fuelled plants are deployed in the main region. In terms of electricity generation, nuclear power assures 65% of the electricity produced in the main region while renewable resources, i.e. hydroelectric power and VREs, generate about 21% of the total electricity generation. The remaining electricity generation is assured by gas-fuelled power plants. About 30 TWh of electricity is exchanged between the two regions; physical exchanges are balanced between the two regions, without significant differences in the import/export physical flows. Wholesale electricity prices are identical in the two regions during 731 hours, indicating that interconnections are saturated only for about 8% of the time; this result is similar to that of the base case; integrating a 10% generation share of VRE does not pose therefore many difficulties to the system and that available interconnections are sufficient. The composition of the generation mix, the breakdown of electricity generation for this scenario and the electricity import/export between the two regions are provided in Figure 53.

In this scenario, the flexibility required from nuclear power is minimal, and nuclear units operate at the maximal possible output almost the entire year. Combined cycle gas turbines achieve an average load factor of 38%, below that observed in the base case, while OCGT operate very flexibly, with a load factor slightly above 1%. Due to the low generation share of solar PV and wind, no curtailment of their generation is needed.

Figure 53. **10% VRE case – capacity mix and electricity generation share**

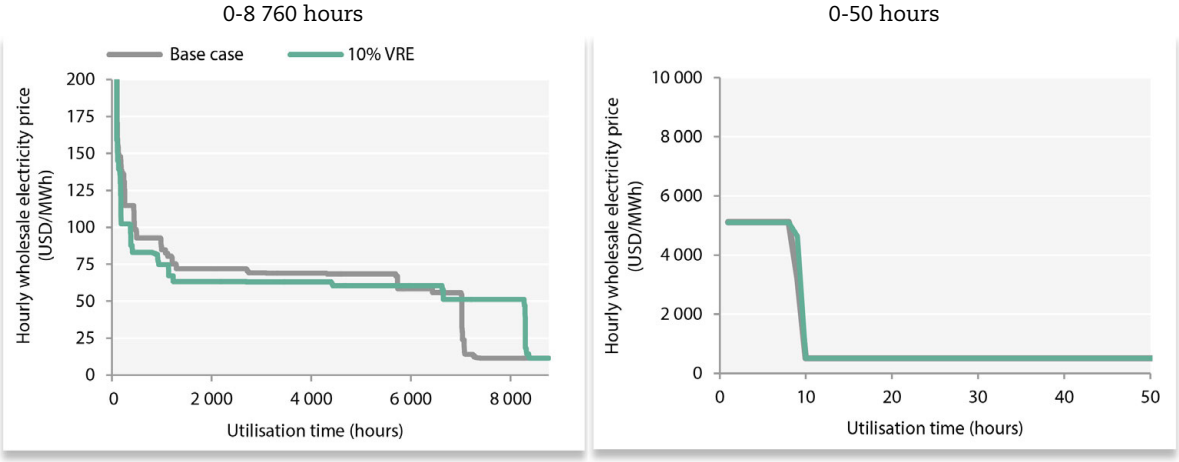


4. Capping the carbon emissions to a given level, which is common to all the scenarios that follow, is equivalent to imposing an appropriate carbon price on each of the two regions, providing that the revenues from the carbon emissions are redistributed to electricity consumers. From a policy perspective, this choice represents the adoption of an emission trading scheme with the total carbon emissions limited to the desired level.

Total generation costs for meeting the demand in the main region amounts to USD 37.8 billion per year, which corresponds to an average cost of electricity generation of about 79 USD/MWh. In comparison to the base case, electricity generation cost increases by about 5%, i.e. by USD 1.7 billion per year. Most of this cost increase is caused by higher VRE generation cost in comparison to those of other dispatchable low-carbon technologies, while profile costs play a smaller role. For the assumed 10% VRE penetration rate, average profile costs are estimated at about USD 2 per MWh of net VRE generation.

With respect to electricity markets, the introduction of a 10% VRE generation share in the generation mix has a minimal impact on the electricity system. As in the base case, there are no occurrences where the electricity demand is not satisfied, and during 8 hours per year the system is unable to ensure the required reserve margin. Voluntary demand curtailment occurs during less than 90 hours per year, slightly less than in the reference system. Electricity prices are lower than those of the base case for most of the duration curve, and become higher only on the right part of the curve. These trends are illustrated in Figure 54, which compares the electricity price duration curve of this scenario (in green) with that of the base case scenario (in grey). Quantity-weighted electricity prices are at about 77 USD/MWh, lower than in the base case. Finally, it is interesting to look at the revenues of VRE technologies at this penetration level. The average market remuneration from onshore wind generation is estimated at 65 USD/MWh in the main region, while that for solar is of 63 USD/MWh; the value for the system of VRE resources is about 10% lower than that of a fully-dispatchable technology.

Figure 54. **10% VRE case – electricity prices duration curve**

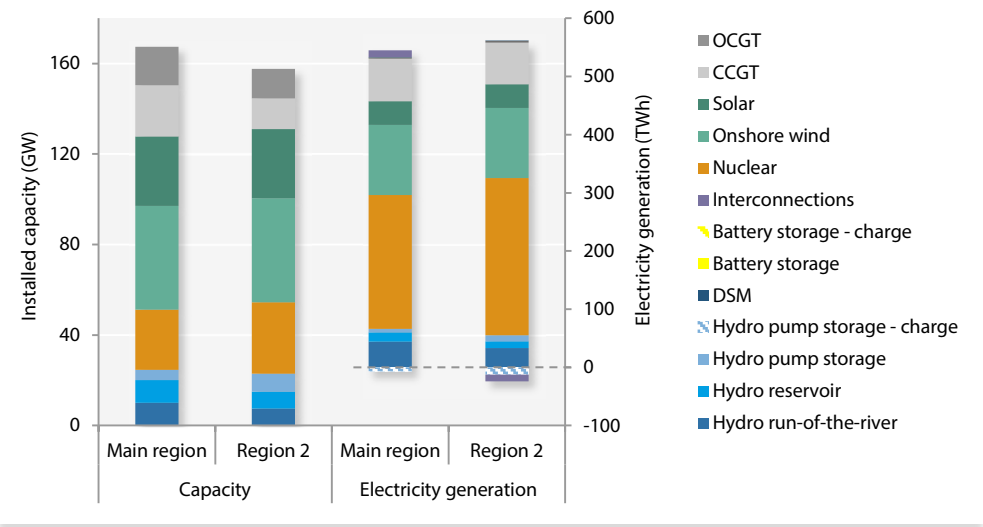


Scenario III: 30% wind and solar PV (30% VRE)

In the "30% VRE" scenario a combination of solar PV and onshore wind capacity is exogenously deployed in each region so that the net generation from VRE resources covers 30% of the electricity demand. Since some of the electricity generated by wind and solar PV resources is curtailed, the installed capacity of onshore wind and solar PV is determined iteratively in each region to ensure that these resources contribute effectively to 30% of the total demand. Again, solar PV is required to provide one quarter of the total generation from variable renewable resources, while onshore wind ensures the remaining 75%. The same amount of hydroelectric capacity as in the base case scenario is also exogenously imposed in each region: 24.5 GW in the main region and about 22 GW in region 2. The rest of the generation mix is determined endogenously to meet the electricity demand in each region at a minimal cost and without having any restrictions over the use of any specific technology. As in the previous scenario, the targeted carbon intensity level of 50 g/kWh is achieved by capping the carbon emissions in both regions modelled.

The generation mix is a combination of nuclear power, hydroelectric power, VRE and gas-fuelled power plants (CCGT and OCGT). About 30 GW of solar PV and 46 GW of onshore wind are built in the main region. The total installed capacity of nuclear power is at 26 GW in the main region, while a somewhat higher nuclear capacity is built in region 2. The overall capacity of gas-fuelled power plants increases markedly with respect to the previous two scenarios, up to about 40 GW; this trend is essentially due to an increase of peaking OCGT plants, from the 2-5 GW in the previous scenarios to 17 GW, while the total capacity of CCGT stays approximately constant at 23 GW. As a consequence, the total capacity installed in the main region reaches 167 GW, about 70% more than in the base case. In terms of electricity generation, nuclear power assures 43% of the electricity produced in the main region, VREs 30%, hydroelectric power 11%, while the remaining electricity generation is assured by gas-fuelled power plants. Physical exchanges of electricity between the two regions reach 37 TWh per year, with the main region importing about 24 TWh of electricity and exporting roughly 13 TWh. With respect to the previous scenarios, the number of hours when interconnections are saturated increases to about 1 900 hours, i.e. more than 20% of the time. The composition of the generation mix, the breakdown of electricity generation for this scenario and the electricity exchanges between the two regions are provided in Figure 55.

Figure 55. **30% VRE case – capacity mix and electricity generation share**

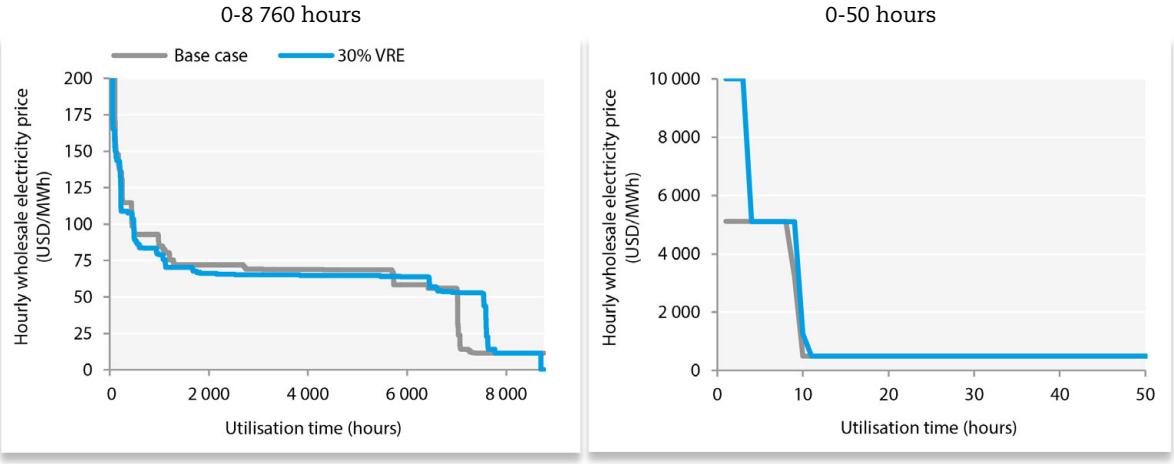


When the penetration level of VRE resources reaches 30%, more variability is observed in the residual demand and the operations of thermal power plants is affected more visibly than in the previous scenarios. Nuclear units have to be operated more flexibly, with more frequent cycling and steeper ramps; as a consequence, the generation from nuclear units is 1% below than their maximal possible output. Gas-fuelled power plants are also impacted: the average load factor of CCGT is about 8% lower than in the base case (37%), while that of OCGT is at 1.5%. During some hours in the year, electricity from VRE sources cannot be fully used by the system and wind and solar generation need to be curtailed. However, curtailment represents only 0.1% of the VRE total generation.

The total costs of electricity generation in the main region exceed USD 42 billion per year, or about 89 USD/MWh, while prices fall. Generation costs increase by 18% with respect to the cost-optimal base case, which represents an additional yearly cost of over USD 6 billion. About three quarters of the increase in electricity generation costs can be attributed to the different plant-level costs of VRE and nuclear. However, at 30% VRE generation share profile costs become significant and exceed USD 1.5 billion per year. Average profile costs for VRE are estimated at about USD 10 per MWh of electricity generated by VRE.

In this scenario, electricity generation is insufficient to meet the demand during three hours per year, thus leading to involuntary power supply interruptions to some costumers ("rolling blackouts" or "enforced load shedding") or, in some unfavourable scenarios, to a total blackout. The system is also unable to meet the required reserve margins during 6 hours per year. Voluntary load shedding occurs during about 40 hours per year, much less than in the scenarios with lower VRE penetration rates. This indicates that the residual load becomes steeper during the hours where residual demand is highest (left side of the load duration curve). Electricity prices are lower than those of the base case for most of the time, and zero-level prices are observed, albeit only for 60 hours per year (see Figure 56). Increasing shares of VRE in the generation mix slightly drives down quantity-weighted electricity prices to 76.8 USD/MWh. Finally, with an increasing VRE share of the mix, the market value of VRE generation decreases further: average market remuneration from onshore wind generation is estimated at 57 USD/MWh in the main region, while that for solar PV is of 53 USD/MWh. The value of variable generation sources is therefore about 20-25% lower than that of fully-dispatchable baseload technologies.

Figure 56. **30% VRE case – electricity prices duration curve**



Scenario IV: 50% wind and solar PV (50% VRE)

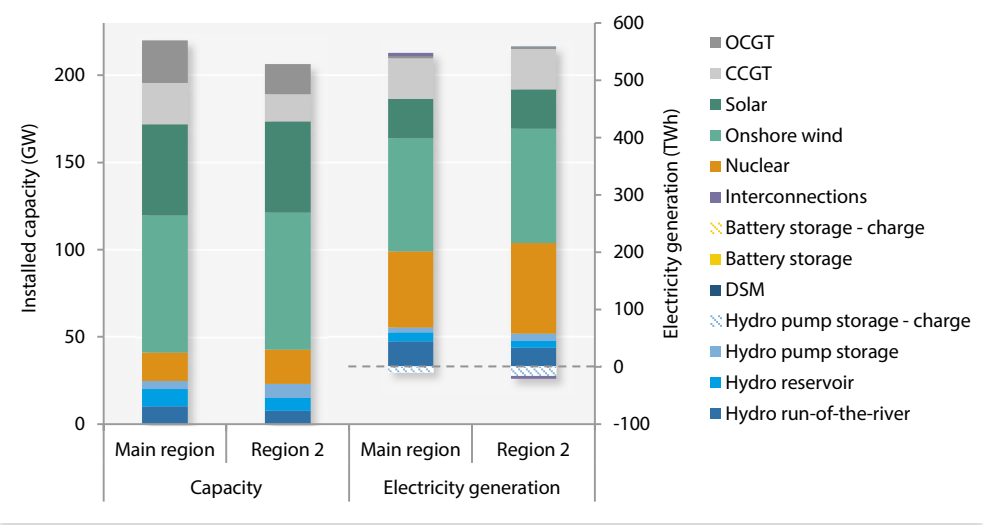
A combination of solar PV and onshore wind capacity is exogenously deployed in each region so that the net generation (i.e. without accounting for the electricity curtailed) from VRE resources covers 50% of electricity demand; as before, solar PV provides 25% of the total generation from variable renewable resources, while onshore wind assures the remaining 75%. The same amount of hydroelectric capacity as in the base case scenario is also exogenously imposed in each region: 24.5 GW in the main region and about 22 GW in region 2. The rest of the generation mix is determined endogenously to meet the electricity demand in each region at a minimal cost. As in the previous scenarios, the targeted carbon intensity level of 50 g/kWh is achieved by capping the carbon emissions in both regions modelled.

Over 50 GW of solar PV and 78 GW of onshore wind are built in the main region as well as in region 2. Due to the higher generation from low-carbon VRE sources, the nuclear capacity deployed in the main region decreases to 16 GW. The total installed capacity of gas-fuelled power plants increases significantly with respect to the previous scenarios, up to 47 GW. As noted in the previous cases, this trend is essentially due to the increased deployment of more flexible, less capital-intensive peaking plants, which are suitable for operating at lower load factors. The total capacity of OCGT plants reaches 24 GW in the main region, slightly above the capacity of the more fuel-efficient CCGT. The large reliance on VREs which operate at a lower load factor than dispatchable technology and the increased requirements from peaking capacity (which in turn is due to the lower capacity credit of VRE), cause a sharp

increase in the total capacity of both regions. The total capacity installed in the main region reaches 220 GW, more than twice that required in the base case. Electricity generation is dominated by VREs, which provide 50% of the electricity produced in both regions, while nuclear and hydroelectric power provide the remaining low-carbon generation, with a share of 25% and 11%, respectively. Gas-fuelled power plants contribute to the remaining 14% of the total generation. It is interesting to note that the generation share from gas-fuelled power plants diminishes with respect to the previous scenarios, as the generation shifts from more efficient CCGT plants to more carbon-emitting OCGTs which emit more carbon dioxide per unit of power generated. In this scenario, physical exchanges of electricity between the two regions exceed 45 TWh over the whole year; the main region imports about 25 TWh of electricity from the neighbouring region, while the exports total roughly 20 TWh. With a growing share of VRE generation in the two regions, interconnections are saturated more often, for about 3 400 hours per year i.e. about 40% of the time. The composition of the generation mix, the breakdown of electricity generation and the electricity exchanges between the two regions for this scenario are provided in Figure 57.

At 50% VRE penetration level, the impact on the generation profile and on the operating performances of thermal power plants becomes significant. Nuclear units need to be operated very flexibly across the entire year, with frequent and steep ramping; overall the load factor of nuclear units is reduced by 7%. Also CCGTs operate at a significantly lower load factor than in previous scenarios (34%); this represents a reduction of 20% compared to the base case. These thermal units are also subject to more frequent and deeper cycling. There are also more and more periods in which the electricity generated by VRE cannot be efficiently used in the system: 3.4% of the average generation from wind and solar PV resources is curtailed. If one looks at the last unit deployed in the system, curtailment rate is above 10%.

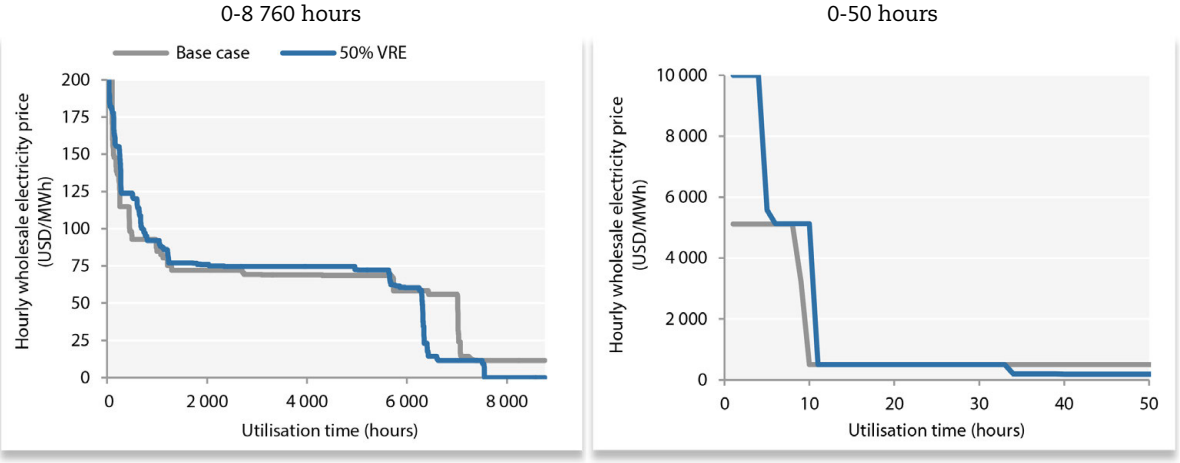
Figure 57. **50% VRE case – capacity mix and electricity generation share**



Reaching a 50% VRE generation share entails significant additional costs for the electricity generation with respect to the cost-optimal base case. Total electricity generation costs reach USD 48 billion per year, i.e. over 100 USD/MWh in the main region. Electricity generation costs increase by more than 33% compared to the base case. For the medium-sized country modelled in this study this represents an additional cost of over USD 12 billion per year. While differences in the plant-level costs of VRE and those of nuclear plants still constitute the main factors causing this cost increase, profile costs become more and more significant. They are quantified at about USD 4.3 billion, i.e. about USD 16 per MWh of electricity generated by VRE.

During 4 hours per year, the generation system is unable to fully meet electricity demand, thus causing an involuntary disconnection of some customers (blackout) or even blackouts. The system is also unable to meet the required reserve margins during 6 hours per year. Voluntary disconnection of customers is reduced to less than 30 hours per year; this phenomenon reflects a steeper and steeper residual load duration curve as the VRE penetration level increases. The most striking phenomena observed in this scenario is the sharp increase of hours with zero-electricity prices, which occurs more than 1 200 hours per year, i.e. about 14% of the time. This phenomenon is balanced by a significant increase of electricity prices above 100 USD/MWh in comparison with scenarios with a lower VRE share, as can be observed in Figure 58. Despite the large increase in total generation costs, the quantity-weighted electricity price continues to decrease, to about 75 USD/MWh. This is particularly relevant for VRE resources: the average market remuneration from onshore wind generation is estimated at 47 USD/MWh in the main region, about 40% lower than that of the first unit of capacity deployed in the system. For solar PV, the drop in value is even more significant: average remuneration from the market is of 41 USD/MWh, which represents a drop of almost 50% in comparison to the value of the first unit deployed in the system. At this penetration level, the market value of onshore wind generation is only 70% of that of a fully-dispatchable baseload technology, while that of solar PV is only 60%.

Figure 58. **50% VRE case – electricity prices duration curve**



Scenario V: 75% wind and solar PV (75% VRE)

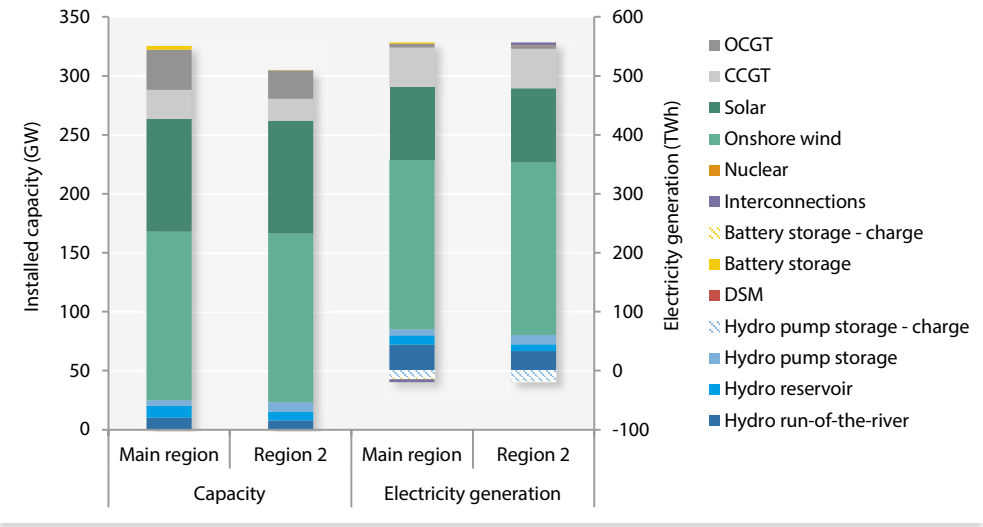
A combination of solar PV and onshore wind capacity is exogenously deployed in each region so that the net generation from VRE resources covers 75% of the electricity demand; solar PV provides one quarter of the total generation from variable renewable resources, while onshore wind ensures the remaining three quarters. The installed capacity of onshore wind and solar PV is determined iteratively in each region to account only for the electricity effectively provided to the grid (net generation). The same brownfield hydroelectric resources are deployed in both regions as in the previous scenarios, and the same optimisation process is followed to obtain the optimal generation mix in both regions. Also, as in the previous scenarios, the targeted carbon intensity level of 50 g/kWh is achieved by capping the carbon emissions in both regions modelled.

A total VRE capacity of 238 GW (more specifically 95 GW of solar PV and 140 GW of onshore wind) is built in the main region to achieve a VRE generation share of 75%. Together with the brownfield hydroelectric resources present in the system, renewable energy sources provide a sufficient level of low-carbon generation to meet the carbon intensity target, and no nuclear is built in the system. The total capacity of gas-fuelled power plants increases substantially with respect to the previous scenario, up to almost 60 GW, i.e. about 60% of the

maximal demand. Thus, 34 GW of OCGT and 24 GW of CCGT are built in the main region. However, gas-fuelled power plants operate at a much lower load factor than in the previous scenarios. Finally, more than 3.3 GW of battery storage are part of the optimal electricity mix, as they help to manage a more variable residual load. The total installed capacity of this more extreme scenario reaches 325 GW, i.e. more than three times the capacity required in the base case. Electricity generation is mostly ensured by RES sources, which provide about 86% of the total generation. Gas-fuelled power plants assure the remaining electricity generation. With respect to other scenarios, the combined share of gas-fuelled generation decreases even further, as the generation shifts from more efficient CCGT to OCGT. Overall, the generation from gas-fuelled plants is 6% lower than in scenarios with lower VRE penetration, i.e. the base case and the "10% VRE". At high levels of VRE generation the physical exchanges of electricity reach 52 TWh, the highest level of all scenarios modelled. Every year the main region imports about 28 TWh of electricity from its neighbours and exports about 24 TWh. In this scenario, the interconnection capacity is saturated for more than 5 500 hours, roughly two thirds of the time. The composition of the generation mix, the breakdown of electricity generation and the electricity exchanges between the two regions for this scenario are provided in Figure 59.

When VRE generates 75% of total electricity the residual demand becomes extremely volatile, with a severe impact on the operating mode of thermal power plants. Combined cycle gas turbines must be operated extremely flexibly, with very frequent and deep cycling; during the most demanding hours, more than 75% of the total capacity installed must be ramped up or down within only hours. Over the entire year, CCGT units reach an average load factor of only 31%, by far the lowest observed in this analysis and 25% lower than that experienced in the base case. The large capacity of OCGT is operated with an average load factor of 2.2% but during periods when prices are high enough to allow them to remain in the system. Also, in this scenario, more than 18% of the generation from wind and solar PV resources cannot be effectively used in the system and must be curtailed. More significantly, more than one third of the electricity generated by the marginal VRE resource must be curtailed.

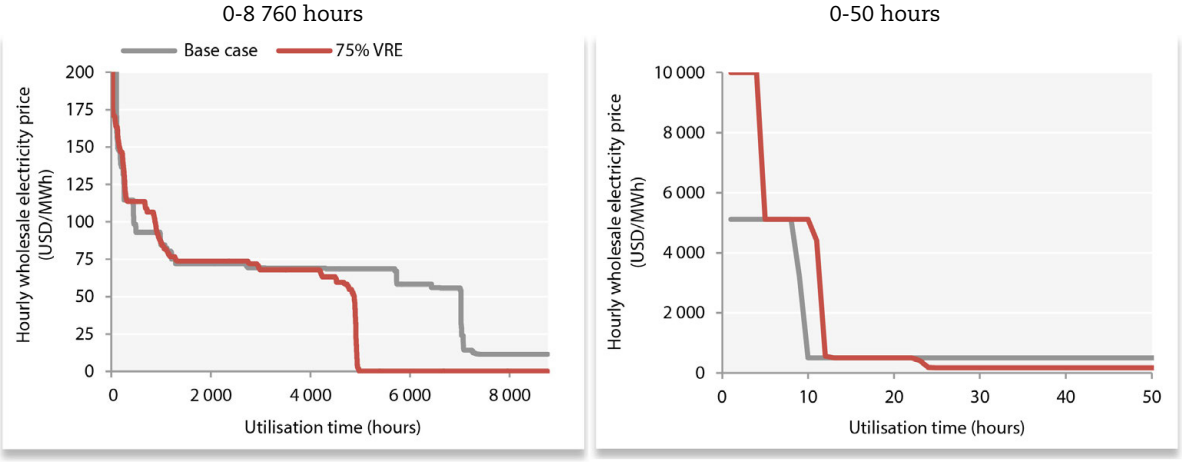
Figure 59. **75% VRE case – capacity mix and electricity generation share**



The challenges for integrating such large share of VRE into the system are reflected by the very high costs of electricity provision in the system. In the main region electricity generation costs exceeds USD 62 billion, i.e. about 130 USD/MWh. Electricity generation costs increase by more than 70% compared to the base case, with additional costs exceeding USD 26 billion per year. Profile costs, which are evaluated at more than USD 14 billion, constitute the major cause of these additional costs, driven by the significant curtailment of VRE generation. Profile costs at 75% VRE penetration level can be estimated at about 35 USD/MWh of VRE generation.

As in the previous scenario, at 75% VRE generation share the system is unable to meet the electricity demand during 4 hours per year, thus leading to rolling load shedding and potential full-fledged blackouts in the system; also reserve requirements are not meet during 6 hours per year. Voluntary disconnection of customers via demand-side measures occurs less than 20 hours per year. At such high levels of VRE, the structure of electricity prices becomes bimodal, with about 3 800 hours at zero-price level and about 900 hours where electricity market price exceeds 100 USD/MWh. The electricity price duration curve for this scenario is provided in Figure 60, together with that of the base case. The quantity-weighted electricity price is below 60 USD/MWh, the lowest of all scenarios considered. The annual average remuneration from the wholesale market for onshore wind generation is estimated at 29 USD/MWh in the main region, about two thirds lower than that of the first unit of capacity deployed in the system. For solar PV, the drop in value is even more significant: average remuneration from the market is of 17 USD/MWh, which represents a quarter of the value of the first unit deployed in the system. The value of wind sources is therefore only half of that of fully-dispatchable baseload technologies, while that of solar PV is only 30%.

Figure 60. **75% VRE case – electricity prices duration curve**



Scenario VI: Cost minimisation with low-cost renewables (low VRE cost)

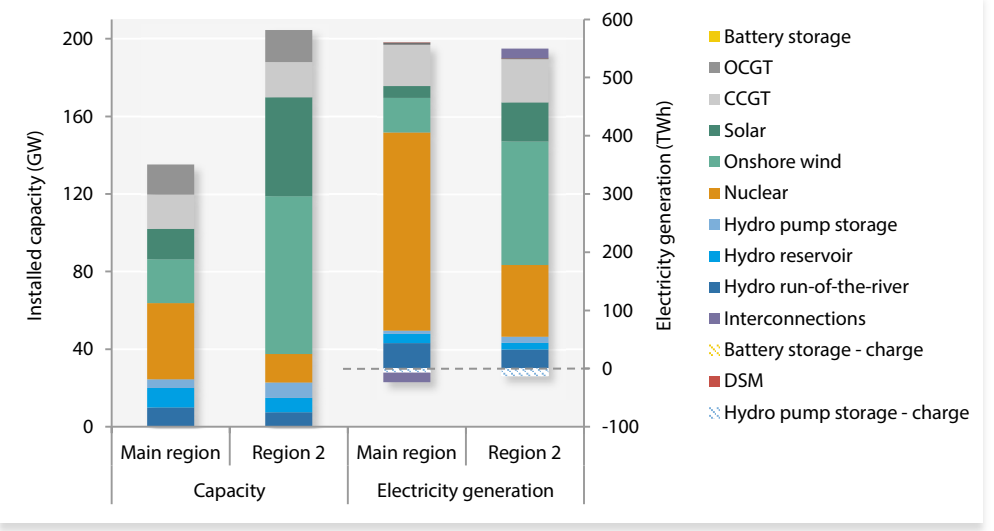
The "low VRE cost" scenario features a significant reduction in the costs of VRE technologies: compared with the other scenarios, investment and O&M costs decline by 60% for solar PV, are halved for offshore wind and are reduced by a third for onshore wind. Under these revised assumptions, long-term generation costs of VRE technologies fall well below these of other low-carbon dispatchable technologies. Investments in onshore wind and solar PV are therefore possible without external support and these resources are deployed "naturally" (or endogenously) in the system up to their optimal level. Beside the different costs assumptions for VRE, this scenario shares all the characteristics of the reference base case scenario: only brownfield hydroelectric resources are exogenously given in the system, while all other technologies are deployed without any limitation or specific target. Also, as in all the main scenarios, the two regions are linked by an interconnection which allows electricity exchanges between the two regions. In both regions carbon emissions are capped at 50 g/kWh and the generation mix is optimised to meet demand at a minimal cost. With the revised cost assumptions for VRE, this scenario would be expected to feature the lowest generation costs of all scenarios considered.

Two very different outcomes are observed in the two regions: while the generation of low-carbon electricity in the main region is mainly assured by nuclear power, in region 2 a majority of low-carbon generation is provided by VREs. In the main region, the larger share of electricity generation is assured by nuclear with 61%, while VREs provide 14% of the

generation and hydro 11%. In region 2, VREs generate over half of the electricity demand, nuclear contributes 23% and hydroelectric power 8%. The share of gas-fuelled plants is 14% in both regions. This somewhat surprising difference between the two regions is confirmed even after thorough analysis. The principal reason is probably that Scenario VI is together with scenario I the least constrained scenarios, which means that cost differences have a far larger impact than in the other scenarios. Even slight differences in the load curve and in the VRE load profile thus lead to different outcomes between the two regions, given the presence of a large interconnection capacity. In term of "natural" or "optimal" generation of VRE resources, a figure of 35%, obtained as an average of the VRE generation share in the two regions, is most likely to be representative for such system.

In term of installed capacity, 39 GW of nuclear are deployed in the main region, together with 23 GW of onshore wind and 16 GW of solar PV. In region 2, instead, the capacity is dominated by VREs (81 GW of onshore wind and 51 GW of solar PV), while the nuclear capacity is limited to 15 GW. The capacity of gas-fuelled power plants is similar in both regions, at about 34 GW. Owing to these differences, the total capacity installed in the main region reaches 135 GW, while that in region 2 is of about 205 GW. Over the whole year, about 43 TWh of electricity are exchanged between the two regions through the interconnections, mostly going from the main region to region 2 (13 TWh exports and 30 TWh imports). The electricity price differs between the two regions only in about 2 200 hours, indicating that interconnections are saturated about 25% of the hours modelled. The composition of the generation mix, the breakdown of electricity generation and the electricity exchanges between regions for this scenario are provided in Figure 61 below.

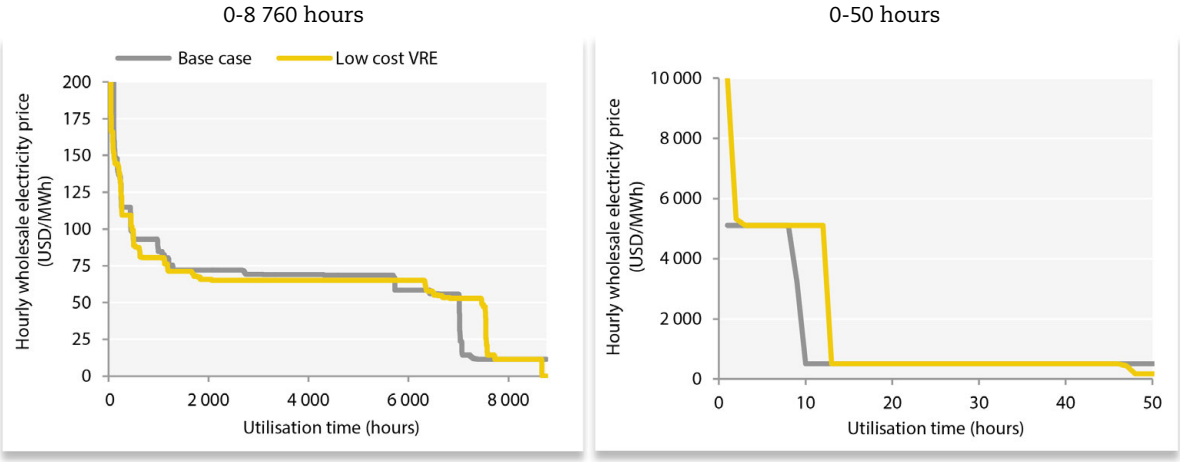
Figure 61. **Low VRE cost – capacity mix and electricity generation share**



Flexibility requirements from thermal power plants in the main region are similar to those observed in the 30% VRE scenario. Nuclear units are operated with a similar degree of flexibility, and the nuclear generation is 1.1% below the maximum possible output. No curtailment of VRE generation is observed in the main region. This scenario features the lowest generation costs of all scenarios considered, due to the significant reduction in generation costs for VRE technologies and their deployment to an economic optimum in the system. Pure electricity generation costs are about 3% lower than in the base case: they total USD 35 billion per year in the main region, which represents a unit cost of about 73 USD/MWh. For a mid-sized country as the one modelled in this study, this represents a cost reduction of approximately USD 1 billion per year.

In this scenario, electricity generation is insufficient to meet the demand during only one hour per year, thus leading to involuntary power supply interruptions to some costumers (blackouts) or, in some unfavourable scenarios, to a complete blackout. The system is also unable to meet the required reserve margins during 11 hours per year. Voluntary curtailment occurs during about 45 hours per year. The structure of electricity prices as well as the quantity-weighted electricity price are similar to those of the 30% VRE scenario, which feature a similar VRE deployment level: there are almost 90 hours a year with electricity price of zero, and high electricity prices occur for more than 460 hours (see Figure 62 which compares the electricity price duration curve of this scenario with that of the base case). Finally, as VRE are deployed endogenously in the system, the average market remuneration from these resources equates their respective lifetime generation costs, i.e. 53 USD/MWh for solar PV and 60 USD/MWh for onshore wind. The value of wind generation is about 85% of that of fully-dispatchable baseload technologies, while that of solar PV is 75%.

Figure 62. **Low VRE cost – electricity prices duration curve**



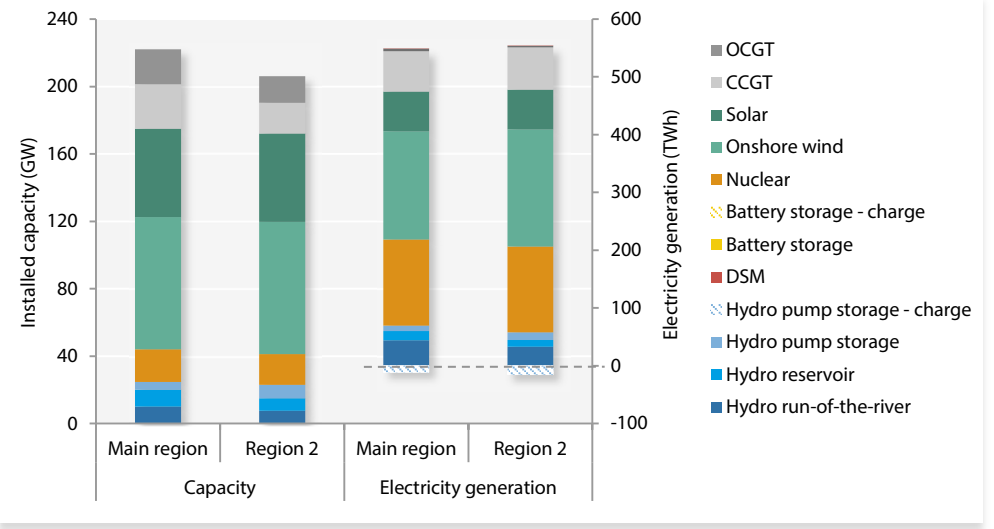
Scenario VII: 50% wind and solar PV – no interconnections (no IC)

This scenario aims at representing an isolated system with no possibility of electricity exchanges with neighbouring regions. Together with the other scenario featuring a 50% share of VRE, it provides some insight to the technical and economic impacts of deploying significant VRE generation share without the flexibility provided by interconnections. This scenario has therefore the same characteristics of the "50% VRE scenario", i.e. the same brownfield hydroelectric capacity and the same amount of VRE capacity in both regions. The only difference between this scenario and the "50% VRE" is that the absence of interconnections prevents the possible exchanges of electricity between the two regions. As in all scenarios considered, the optimal generation mix is determined endogenously to meet the electricity demand in each region at a minimal cost and simultaneously meeting the carbon intensity constraint of 50 g/kWh in both regions.

The same VRE capacity as in the "50% VRE" scenario is deployed in both regions, i.e. 50 GW of solar PV and 78 GW of onshore wind power. However, with respect to the "50% VRE" scenario, the curtailment of VRE resources increases in both regions as the lack of interconnections prevents transferring the excess of VRE generation in one region to the other. The effective (net) generation share of VRE is therefore lower than in the "50% VRE scenario". As a consequence, a larger nuclear capacity is needed to cover this gap in low-carbon generation; the total nuclear capacity in the main regions increases by 3 GW to a total of 19 GW. In the main region over 46 GW of gas-fuelled power plants are built: 20.5 GW of OCGT and 25.5 GW of CCGT. Overall, total generation capacity is not significantly different compared to the reference "50% VRE" scenario, totalling 222 GW. In terms of electricity generation, the

main phenomenon observed is a decrease of VRE share to 47.5%, due to a higher curtailment rate. Nuclear power thus increases its share up to 28% to fill this gap. Gas-fuelled power plants contribute to the remaining 14% of the total generation. The composition of the generation mix and the breakdown of electricity generation for this scenario are provided in Figure 63.

Figure 63. **50% VRE, no interconnections – capacity mix and electricity generation share**



The lack of flexibility provided by interconnections has severe implications on load factors and operating performances of all power plants in the system, including renewables. In particular, the average load factor of mid- and baseload thermal power plants declines significantly with respect to a well-interconnected system. The load factor losses of nuclear power reach 12%, in comparison to a value of 7% in a well-interconnected system. Similarly, CCGT power plants operate at a load factor of 30%, about 16% lower than in the main scenario. The curtailment of VRE resources becomes also increasingly frequent: the curtailment rate of VRE generation doubles to 7%, as well as that of the marginal VRE unit deployed, which reaches a value of 19%.

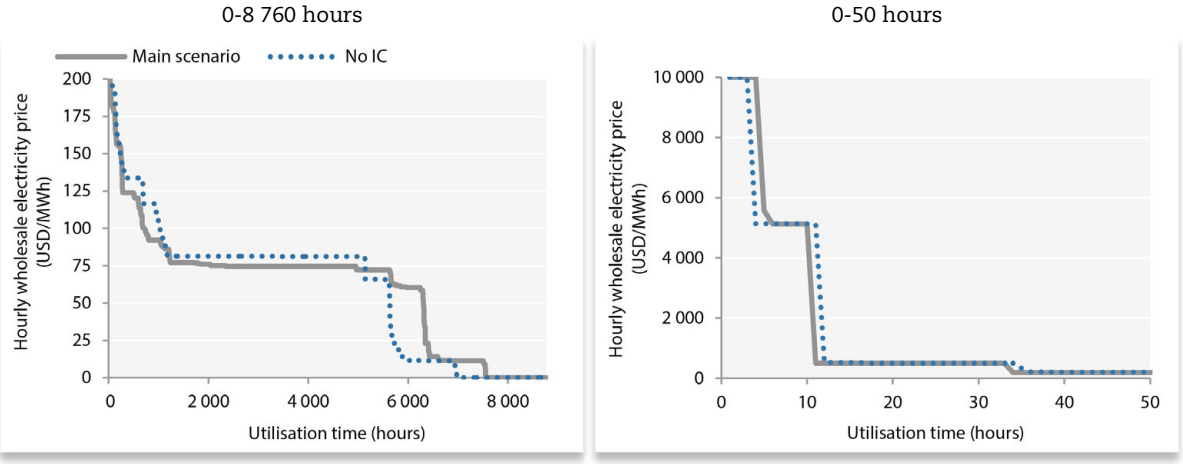
Total generation costs in this scenario are higher than these of the main "50% VRE" scenario, where interconnections exist between the two regions. Electricity generation cost totals USD 48.5 billion per year in the main region, which gives a unit cost of more than 101 USD/MWh. When comparing the results with the main" 50% VRE" case, the cost difference is limited to only USD 200 million per year, and is mainly due to increased curtailment of VRE resources[5]. This requires investments in additional nuclear capacity. Profile costs in this scenario are estimated 19 USD/MWh of electricity generated by VRE.

In this scenario, the power system is unable to meet the demand during 3 hours per year, while reserve margins are not met for eight hours a year. These figures are similar to those observed in the main "50% VRE" scenario. With respect to this scenario, the number of hours where demand-side measures intervene, with the voluntary disconnection of up to 4 GW demand, is reduced to 20 hours per year. The lack of flexibility provided by interconnections

5. It should be noted that the wind and solar PV capacity deployed in each of the three "50% VRE" scenarios is the same. However the net generation share from VRE is different, as the curtailment rate of VRE increases with the lack of flexible resources in the system. Achieving the same net VRE share of 50% in the two sensitivity scenarios would have significantly increased the total generation cost and thus widen the gap with the main "50% VRE" scenario.

increases not only the electricity generation costs, but also quantity-weighted electricity prices, albeit only marginally. However, the distribution of wholesale electricity prices becomes increasingly skewed. The occurrence of zero-level wholesale prices increases by 40% to 1 200 hours per year, while there are more than 1 000 hours per year with price above 100 USD/MWh. Figure 64 shows the duration curve of electricity prices in comparison with that of the main "50% VRE" scenario. Finally, the lack of interconnections reduces the value for the system of VRE generation and hence the remuneration received by the market. The average market remuneration from onshore wind generation is estimated at 46 USD/MWh in the main region, about 5% lower than that of the well-interconnected reference system. For solar PV, the drop in value is even more significant: the average market price is of 36 USD/MWh, about 15% lower than that of the reference system.

Figure 64. **50% VRE, no interconnections – electricity prices duration curve**



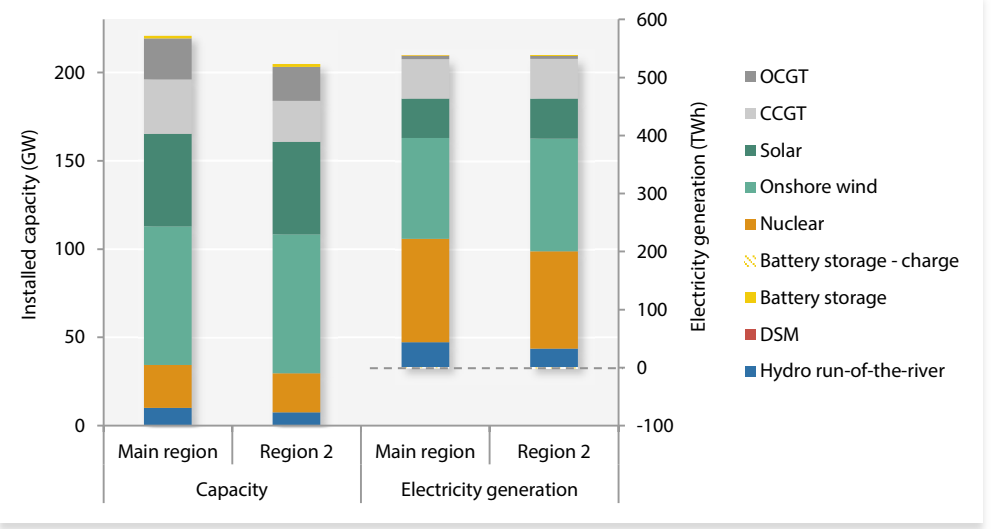
Scenario VIII: 50% wind and solar PV – no interconnections, no flexible hydro (no IC, no hydro)

This scenario represents a system with the least potential for flexible resources: it is an isolated system, without interconnections with other systems, and does not have a potential for developing any flexible hydroelectric resource. The technical challenges and economic costs of reaching a 50% VRE generation share are therefore higher than these in the two scenarios described above. Both regions feature the same amount of VRE and run-of-the river hydroelectric resources as in the previous scenarios; however, flexible hydroelectric resources are available in neither of the two regions considered, and no interconnection exists between the two regions. As in all scenarios considered, the optimal generation mix is determined endogenously to meet the electricity demand in each region at a minimal cost and simultaneously meeting the carbon intensity constraint of 50 g/kWh in both regions.

The same VRE and hydroelectric run-of-the river capacity as in the "50% VRE" scenario is deployed in both region, i.e. 50 GW of solar PV, 78 GW of onshore wind power and 10 GW of run-of-the river hydroelectric power. With respect to scenarios IV and VII, the generation of low-carbon electricity from renewable resources is reduced: the curtailment of VRE generation is more significant and hydroelectric reservoir resources are not present in the system. As a consequence, over 24 GW of nuclear power are built in the main region, significantly more than in scenarios IV and VII. Also, unlike in the two other cases, more than 1 GW of batteries is deployed as they somehow "substitute" the flexibility from hydroelectric power no longer available in this system. Overall, despite having a different structure, total generation capacity is similar to the two other scenarios, totalling 221 GW. In term of electricity generation, the VRE share is reduced to 45%, due to more significant VRE curtailment, and that of

hydroelectric resources to 8%, as hydroelectric reservoir resources are not present. The share of gas-fuelled power plants decreases slightly compared to the other two scenarios. Nuclear power generation increases therefore significantly, contributing to one third of the total generation. The composition of the generation mix and the breakdown of electricity generation for this scenario are provided in Figure 65 below.

Figure 65. **50% VRE, no interconnections, no flexible hydro-capacity mix and electricity generation share**



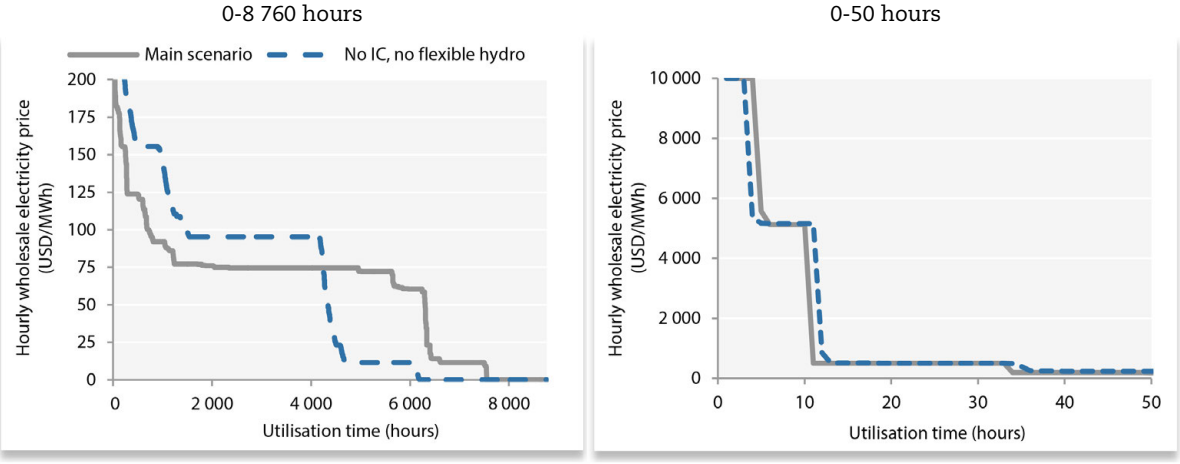
The absence of interconnections and flexible hydroelectric resources exacerbates the flexibility requirements from thermal power plants. These plants are increasingly operated to provide "system services" rather than pure electricity to the system. This is reflected by higher ramping constraints and increasingly low load factors for nuclear and CCGT power plants. Modulation of nuclear generation becomes more significant in comparison to the other scenarios: the load factor losses for nuclear reach 16%, with a significant impact on its economics. Mid-load plants such as CCGTs are even more significantly affected: the average load factor from CCGT reach only 25%, compared with a value of 34% in the main "50% VRE" scenario and a value of 40% in the base case without intermittent generation. A more inflexible system is also less suited to integrate the variable generation from renewable energy: over 12% of the total VRE generation is curtailed, and the curtailment rate of marginal unit reaches 30%.

Total generation costs in the main region exceed USD 52 billion per year, which corresponds to a unit cost of about 107 USD/MWh. In comparison with the base case, electricity generation costs increases by almost 10% in the main region; for the medium size country modelled in this region this represents an additional cost of about USD 4.3 billion per year. These additional costs are partly due to the increased curtailment of VRE resources and partly to a significant change into the generation mix. The additional challenges of integrating VRE in an isolated system lacking flexible hydroelectric resources translate into very high profile costs (34.5 USD/MWh of renewable generation). The profile costs in this scenario are almost double than those of the two other scenarios with 50% VRE share.

In this scenario, the power system is unable to meet the demand during 3 hours per year, while reserve margins are not met for eight hours a year. The number of hours where demand-side measures intervene, with the voluntary disconnection of up to 4 GW demand, is reduced to 20 hours per year. These figures are equivalent to those observed in the previous scenario without interconnection but with hydroelectric flexible resources. In contrast, the lack of flexibility in the system has a large impact on the structure of electricity prices, as can be observed in Figure 66. In comparison with the main "50% VRE" scenario, the number of hours

with zero-level electricity prices doubles, up to over 2 500 hours per year, i.e. 30% of the time. The number of hours with high electricity prices (above 100 USD/MWh) also doubles, up to 1 450 hours per year. Quantity-weighted electricity prices are also slightly higher than those of the two comparable scenarios, up to a level of 77 USD/MWh. The lack of interconnections and flexible hydroelectric resources reduces the value for the system of VRE generation and hence the remuneration from electricity sales. The average markets remuneration from onshore wind generation is estimated at 42 USD/MWh in the main region, about 10% less than that of the main "50% VRE" system. For solar PV, the value drop is even more significant: average remuneration from the market is of 25 USD/MWh, which represent a reduction of almost 40%.

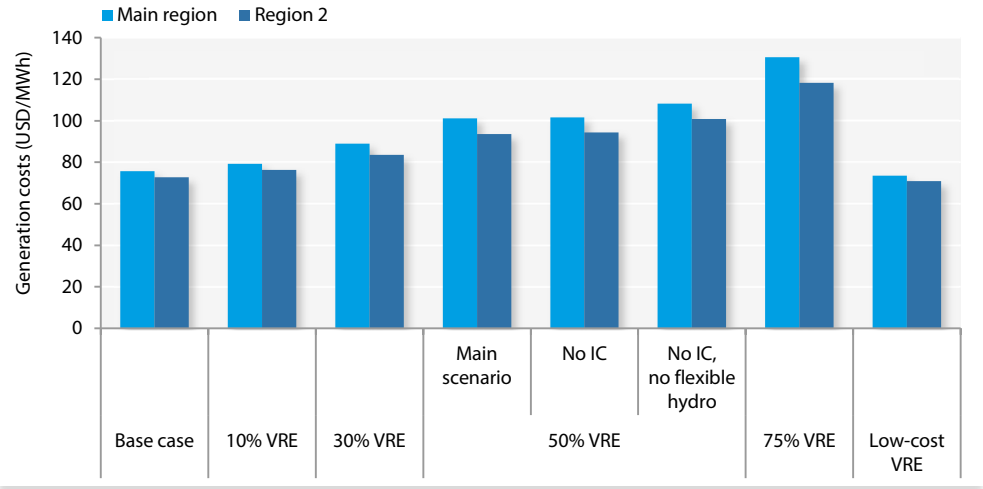
Figure 66. **50% VRE, no interconnections, no flexible hydro: Electricity price duration curve**



Annex 3.A4. Electricity generation costs and value of VRE resources in region 2

Region 2 features the same trends as in the main region, with a significant increase in total generation costs with VRE deployment. However, total generation costs are consistently lower in region 2, as shown in Figure 67. Also total generation costs increase at a rate somehow lower than those in the main region. These phenomena reflect the specificities of the two interconnected systems analysed; more specifically, region 2 benefits from a smoother electricity demand profile and from a relatively larger brownfield capacity of flexible hydroelectric resources, in particular pump hydroelectric storage (the main region has 10 GW of hydroelectric reservoir capacity and 4.5 GW of hydroelectric pumped storage; the capacities in region 2 are of 7.5 GW and 8 GW, respectively).

Figure 67. **Annualised costs of generation in the two regions (USD billion per year)**

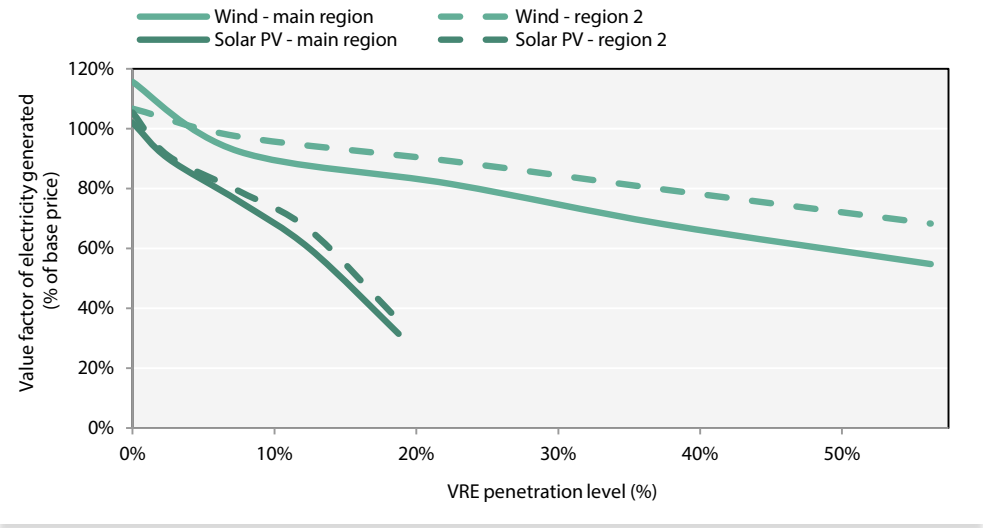


Value of solar PV and onshore wind in region 2

Figure 68 provides additional and complementary information on the value of VRE generation: data are plotted for the two regions considered in the present study, and are no longer expressed in term of USD/MWh but rather as a fraction of the electricity base price (value factor). The base price, i.e. the time-average of wholesale electricity price, represents the price seen by a hypothetical baseload technology working at a constant output continuously over the year; in a system in long-term equilibrium under perfect market conditions the base price is linked to the generation costs of the baseload technology.

The value factor representation emphasises that the role and the competitiveness of a technology in a system depends not only on its own technical and economic characteristics but also on these of alternative generation options. Indeed for all technologies, the relevant metric is the value factor, which is calculated as the ratio between their generation value and base price.

Figure 68. **Value factor of wind and solar PV in the two regions**



The value of the first unit of onshore wind and solar PV depends on the relation between the electricity demand and the generation profile of the variable resource and is therefore strongly dependent on the specific characteristics of the system considered. For smaller penetration levels, the wind and solar PV value factors are above unity in both regions considered in the present study, and the wind value factor is higher than that of solar PV. This means that VRE should be deployed in the system even if they are (slightly) more expensive than baseload generation on a pure LCOE basis.

The results for the two regions also confirm that the value of VRE generation and its evolution over different penetration levels depends strongly on the system considered. In particular it may be observed that the decrease in value of both solar PV and wind resources is less pronounced in region two than in the main region. The main reason behind this trend is that the load factors for wind and solar in region two have been calculated over a larger area (including Belgium, Germany, Italy, Spain, Switzerland and the United Kingdom) and therefore benefits from a larger diversification of meteorological conditions (see for instance the respective load factor distributions plotted in Figure 49).

Annex 3.A5. Value of brownfield hydroelectric resources

Finally, it is interesting to look at the market value of the electricity generated by brownfield hydroelectric resources at varying levels of VRE in the system. Results for the three main types of hydroelectric resources, run-of-the river, reservoir-based and pumped hydro are reported in Table 14 for the two main regions modelled. The market value of each technology is calculated as the average value of its generation (in USD/MWh). For the pumped resources, both the average prices when charging and when producing are provided, together with their price difference, which has been corrected to take into account the efficiency losses in the conversion process.

As expected, the market value, and thus the contribution to the system, of "fatal" run-of-the river resources decreases, albeit only slightly, with the penetration level of VRE. This phenomenon is linked with the positive correlation between the generation of VRE and that of run-of-the-river resources, which is stronger in the region two than in the main region. However, more significantly, the value of run-of-the-river generation drops substantially when VRE generation reaches 75% of electricity demand. This loss in value reflects the drop in the time-averaged electricity price which was discussed in the previous sections.

Table 14. **Value of brownfield hydroelectric resources (USD/MWh)**

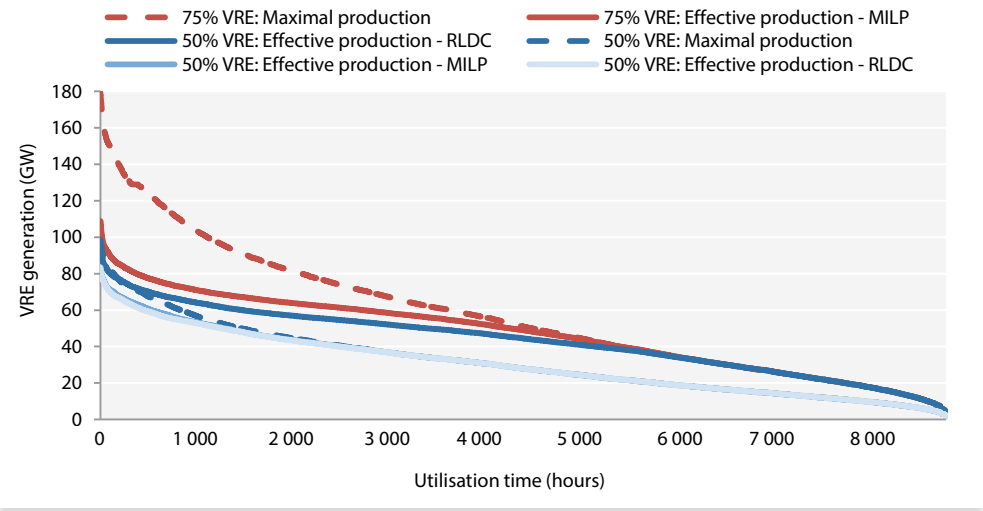
			Base case	10% VRE	30% VRE	50% VRE	75% VRE	Low-cost VRE
Run-of-the-river hydroelectric	Main region		75.8	75.5	74.4	74.1	58.0	73.8
	Region 2		75.8	75.5	74.3	73.8	54.9	73.5
Reservoir hydroelectric	Main region		131.4	121.8	129.8	146.2	144.5	129.5
	Region 2		131.3	121.5	128.7	141.9	137.5	132.2
Pumped storage hydroelectric	Main region	Discharge	117.3	122.7	131.7	127.9	118.0	137.7
		Charge	35.3	44.4	33.9	20.5	8.4	32.6
		Difference	58.5	53.8	71.4	81.9	86.0	77.5
	Region 2	Discharge	113.8	123.9	133.7	133.0	119.2	136.2
		Charge	37.7	45.1	35.4	21.9	8.1	31.1
		Difference	53.3	54.0	71.6	84.5	87.2	77.8

In contrast, the value of flexible hydroelectric resources is expected to steadily increase with the deployment of VRE, as the system needs additional flexibility to balance the variability of VRE resources. This is observed for pumped hydro resources, with the price differential between revenues from generation and costs for charging is constantly increasing with the deployment of VRE (except for the vow penetration shares of 10%). Indeed, at low VRE penetration level the value of generation from hydroelectric reservoir declines by 10% in both regions considered to then increase again at higher VRE penetration levels. While the good correlation between VRE and demand, and the consequent flatter residual load curve may help to understand this result, it is more surprising that the value of reservoir-based hydroelectric generation is similar in the base case and in the 30% VRE scenarios. At higher VRE deployment, the value of flexible hydro resources increases by about 10%, despite the reduction in average electricity wholesale market prices.

Annex 3.A6. Comparison of methodology: Residual load duration curves vs MILP

As discussed in Chapter 2, modelling the electricity system is a complex undertaking which requires the adoption of sophisticated tools. Most of the recent publications in this area rely on capacity planning and unit commitment models which are formulated as mixed-integer linear programmes (MILP). GenX, the tool used for the present study, falls in to such a category of numerical tools. While these models constitute the current reference for such analyses, it may be interesting to compare some of the results of this study with those that would have been obtained using a less sophisticated representation of the electricity system based on residual load duration curves (RLDC). In this context, the curtailment of VRE resources and their value factor have been calculated for the main region using a RLDC method. The results are presented in the following figures: Figure 69 compares the curtailment of VRE in the main region for the two penetration levels of 50% and 75%, while Figure 70 shows the value factor of solar PV and onshore wind at different penetration levels.

Figure 69. **Curtailment of VRE using MILP and RLDC modelling approaches**



Calculations based on the method of RLDC are much simpler and require much lower numerical resources than models based on MILP. On the other hand, as a consequence of the much simpler and less sophisticated representation of the electric power system, methods based on the RLDC are unable to correctly represent some of the characteristics of the system, in particular:

i. storage reserves, including flexible hydroelectric capacities: these plants are either not modelled or their modelled dispatch is based on their realised generation;

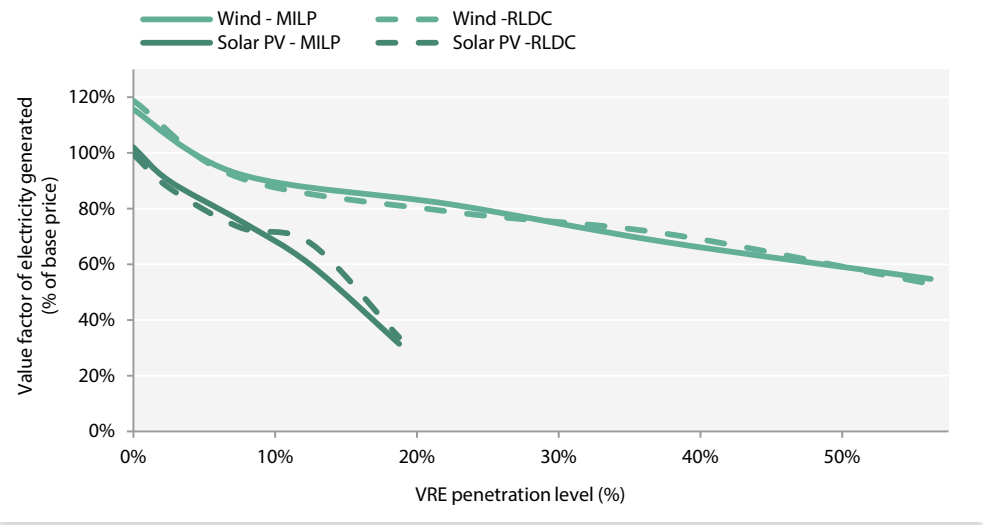
ii. interconnections and electricity flows between two regions: in most of the cases RLDC models solely a single region represented as a copper plate;

iii. operational constraints of all generation capacities are not represented; it is therefore implicitly assumed that all power plants modelled have infinite flexibility.

In comparison to a MILP formulation, the first two elements tend to underestimate the flexibility present in the system which increases the challenges for VRE integration; this simplified approach suggests a larger curtailment of VRE resources and a lower market price for VRE generation (and thus a lower value factor). On the other hand, not taking into account the operational constraints of thermal power plants reduces the integration challenge and therefore has an opposite effect on the two observables analysed here.

With respect to the VRE curtailment, it is interesting to observe that, in the 50% VRE scenario, these "shortcomings" compensate each other, and the estimated level of VRE curtailment is very similar using the two models. The error increases at higher VRE penetration levels, with the methods based on RLDC suggesting a larger curtailment rate of VRE than that obtained with more accurate simulations based on MILP. Interestingly and more surprisingly, the value factors of VRE are very similar when obtained with the MILP and the RLDC approaches: quantitative results are similar and show the same downward trend. Clearly, compensation between different effects also plays a major role in explaining such a convergence of results.

Figure 70. **Value factor of wind and PV generation in the main region**



The results shown above should not be interpreted as a suggestion to adopt one modelling technique over another, nor should they be viewed as a rigorous benchmark of the two methodologies. These conclusions are valid only for the observables analysed here (VRE curtailment and their value factor), do not necessarily apply to other characteristics of the system and may be not be valid for other systems. There are also many other aspects that can be analysed only with a MILP calculation but are not accessible via a RLDC approach. However, the methods based on RLDC curves appear sufficiently robust to provide reliable results, at least as a first approximation.

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Chapter 4. Policy options to internalise system costs

4.1. Introduction

The preceding chapters have shown that under the assumptions of this study the costs of an electricity system over and above plant-level costs constitute a sizeable share of its total costs. Both, system costs, (the sum of increased outlays for transmission and distribution (T&D), balancing costs) and profile costs, as well as the costs of the system as a whole, will, other things being equal, increase with the exogenously imposed share of variable renewables (VRE) in electricity generation. Independent of preferences for particular generating technologies, be they nuclear power or renewable energies, there exists today a broad consensus among experts that system costs are too large to be ignored by policy makers and that appropriate instruments need to be implemented. Such policy instruments have two main functions, first, to minimise the system costs associated with a given amount of VRE capacity and, second, to allocate them among different stakeholders in a manner that appropriately reflects national distributional arrangements. "Internalising" system costs must thus be understood in the broad sense of consciously integrating them into the structural design of a well-working electricity system, rather than in the narrow sense of explicitly making pay a specific group of stakeholders.

When dealing with system costs, it is necessary to account for the normative reference framework in which the debate takes place. In particular, the critical question of who should pay for system costs is difficult to answer. General principles such as "impute costs to those who cause them" are of little help in a context as economically and politically complex as a modern electricity system. Two things are important in this context. First, system costs depend not only on the amount of VRE capacity installed in a given country, but also on the electricity systems of interconnected neighbouring countries. The higher the share of flexible resources such as hydroelectricity or demand response, for instance, the lower will be the system costs.

Financial incentives also play a major role. For instance, an important part of VRE system costs are the profile costs relating to the need for additional investments in dispatchable capacity required to ensure the security of supply. These are fully internalised in a pure market system without any subsidies.[1] The price mechanism in fact ensures that VREs will receive lower revenue for their output and thus limit their deployment (see Section 4.5 for details). Profile costs, however, become a significant externality once VREs are supported through out-of-market mechanisms such as feed-in tariffs (FITs).

Second, the responsibility for system costs depends on the normative framework that is chosen to judge the costs of an electricity system. Such normative references have been changing significantly in recent years in a number of OECD countries, both explicitly and implicitly. The traditional normative reference for judging the performance of an electricity system was cost minimisation in the process of satisfying a given load at high levels of security of supply without any technological restrictions. Another, more recent normative reference is cost minimisation in the process of satisfying the same load while respecting at the same time a carbon constraint with the help of low-carbon technologies. A third reference, which has gained in importance in recent years, is to minimise costs while satisfying the same load with a given share of VRE resources.

1. As stated previously, internalisation takes place through the adaptation of the residual generation mix and is ultimately paid for by electricity consumers. However, they will be compensated through the now overall lower generation costs. The sub-optimality of the existence of profile costs at the system level thus no longer subsists.

In the first case, and to some extent in the second case, increased system costs would, when using a methodological framework of static optimisation, indeed be imputable to newly introduced VRE. This would, in particular, be the case if VRE were introduced into an existing system that was fully capable of satisfying electricity demand on its own working under an identical or even more stringent carbon constraint. In the third case, however, given the policy commitment to satisfy a portion of demand with VRE, the allocation of responsibility and costs is not so straightforward. The ability or inability of conventional sources to provide the newly required flexibility is, in this case, a parameter of the electricity system as a whole. System costs above plant-level costs in the attainment of a given output level of electricity can thus no longer be attributed to a single technology but become, for instance, a function of the flexibility of dispatchable generators. This is, for instance, the general approach taken by several of the studies on system integration by the International Energy Agency (IEA).[1]

The work of the OECD Nuclear Energy Agency (NEA) is instead based on the assumption that the normative reference for a modern electricity system should be the minimisation of costs while reliably satisfying a given demand for electricity and respecting strict carbon emission reduction objectives. In conformity with the intention formulated in the Paris Agreement to limit the increase in global mean temperatures to below 2°C, the modelling results presented in Chapter 3 were calibrated on a carbon emission reduction target of 50 g/kWh. Ultimately, the question of allocating system costs cannot be separated from the policy question of whether the priority for OECD countries should be the reduction of greenhouse gas emissions, which in the electricity sector means primarily carbon emissions, or whether it should be increasing the share of renewables and, in particular, variable renewables (VRE) such wind and solar photovoltaic (PV), in electricity generation.

Studying the process of internalising system costs in an economically and politically sustainable manner thus involves analysing three different issues. First there is the indispensable first step of identifying and measuring system costs. Together with *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (NEA, 2012), the present study is part of this effort. Chapters 2 and 3 have synthesised a large amount of information on this issue, which this chapter will build on. Second, there is the central question of devising new policy instruments capable of addressing directly the issue of system costs. Other than a strong societal long-term commitment to emission reductions, this requires decisions on cost allocation as a function of the distributional arrangements and the normative reference framework that a country has chosen to work with. Third, there is the question of reforming and optimising existing policy instruments such as the support measures for particular technologies. If badly designed, the latter can increase system costs even without making progress towards their declared policy objective.

When addressing all three issues, distinctions between short and long-run impacts need to be carefully drawn. With economic development and policy making taking place in continuous time and with the parameters of the electricity system undergoing a period of particularly fast change, this is not always easy. The distinction is, however, required to ensure that economic analysis remains pertinent to economic policy making. While for methodological reasons economics focusses naturally on long-term equilibria, political decision-making, equally naturally, focused on the short-term impacts that drive the policy process. This does not mean that one cannot inform the other, but it means that the limits of abstract arguments and the reciprocal impacts of both spheres need to be thoroughly understood.

The following analysis is thus geared towards establishing a policy framework that takes economic optimality and cost minimisation within the constraints set by clearly defined public policy objectives. In some ways, this means accepting the results of competitive markets as a benchmark. Competitive electricity markets are today indeed the starting point for policy discussions in the electricity sector of most OECD countries. However, the importance of public

1. See for instance IEA (2014), *The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems*, OECD IEA, Paris; IEA (2016), *Next generation Wind and Solar Power: From cost to value*, OECD IEA, Paris; IEA (2017b), *Getting Wind and Sun onto the Grid: A Manual for Policy Makers*, OECD IEA, Paris; or IEA (2018), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility*, OECD IEA, Paris.

policy objectives such as greenhouse gas emission reductions and the security of supply as well as the particular characteristics of low-carbon technologies imply that policy frameworks for low-carbon electricity systems will always need to link markets with non-market elements. This means that in practice OECD countries will proceed in a differentiated manner in implementing market solutions to foster low-carbon electricity markets. Starkly simplifying this could mean combining decentralised markets for the short-term dispatch of energy with centralised auctions or long-term contracts to finance of investment. The following discussion thus holds a balance between insisting on the necessity to frame policy discussions in the electricity sector in a framework of economic optimality on the one and recognising on the other hand that this may require a set of solutions going beyond classical market models based exclusively on bilateral contracts between producers and consumers.

Chapter 4 thus has the following structure. Section 4.2 will briefly provide an overview of the current state of electricity markets as a starting point for further discussion. Section 4.3 will discuss the efficiency and distributional implications of first-best policy instruments such as carbon pricing and emission trading that would minimise the total costs of electricity generation, including system costs. Section 4.4 will consider instruments such as capacity remuneration mechanisms that are introduced to remediate or to moderate the impacts of prior policy instruments such as dedicated support for selected technologies. Section 4.5 will look more broadly at the need for reforming the design of electricity markets operating with large shares of low-carbon technologies. Section 4.6 will focus on nuclear energy and the project of the NEA to make system costs analysis useful for assessing the impacts of current policies on nuclear new build and long-term operations in the coming decades. Section 4.7 will set out the report's conclusions.

4.2. Deregulated electricity markets and the investment challenge

Electricity is a special commodity. In particular, cannot be stored in great quantities at economically attractive costs, except to some extent in countries with large amounts of hydropower. Since demand fluctuates over the course of the day, the week and the year but is very inflexible at any given moment, this means that the electricity supply needs to be adjusted second by second. This is done by using a mix of generation technologies with different cost structures for different numbers of hours throughout the year. Technologies with high fixed cost (CAPEX) and low variable costs (OPEX) such as nuclear will thus run a high a number of hours as baseload, while technologies with low fixed costs and high variable costs such as gas turbines or diesel generators will run only during the hours of maximum demand as peak load.

The theory of optimal electricity system design was developed during the 1950s. Implementing the optimised designs was left either to public monopolies or to regulators, who specified system needs and remunerated producers with regulated tariffs that were set according to their levelised costs of electricity (LCOE). While such electricity systems were prone to overinvestment ("gold-plating") and organisational slack, they also guaranteed over more than two decades high levels of security of supply and allowed investment in capital-intensive, technologically complex technologies such as nuclear power.

The 1980s and 1990s not only saw a general enthusiasm for market liberalisation in OECD countries but also the development of a new technology, associated with the appropriate infrastructures, that proved crucial for the deregulation of electricity markets. The combined cycle gas turbine (CCGT) had not only relatively low fixed costs, the recovery of the exhaust heat from the gas turbine reduced also its fuel costs per MWh and allowed, if gas prices were sufficiently low, to compete over an increasing number of hours against coal and nuclear as a mid-merit technology. This made the vision of a competitive, self-sustaining electricity wholesale market far more realistic. This is due to the fact that under competition prices are equal to short-run marginal costs. If marginal costs, i.e. the variable costs of the marginal technology, are high and capital costs are low, then wholesale market prices will cover a high share of the total costs of all generation technologies (with the exception of the marginal plant), including low variable cost technologies and nuclear. A mix of, say, diesel generators and nuclear might in theory arrive at the same result but would have far more volatile prices.

Theorists also showed that the independent decisions of decentralised profit-maximising competitive producers can closely replicate the economically optimal system configuration devised by the algorithms used by the former monopolies. The introduction of competition for electric power generation, usually combined with the unbundling of vertically integrated monopolies, i.e. the separation of generation from T&D, began in the 1980s and gained momentum throughout the 1990s in OECD countries.

Scarcity pricing, the security of supply and the investment challenge

Independent of the generation mix, all competitive markets for electricity need to cover a share of fixed costs through "scarcity hours". This means that during a limited number of hours per year supply will not cover demand. During those hours, when voluntary demand response is exhausted, some customer groups will alternately be disconnected for some minutes in a process referred to as "rolling blackouts". As customers scramble to cover their needs, the result is very high prices which are referred to as the value of lost load (VOLL) and are measured in the thousands of USD. Scarcity pricing implies a deliberately accepted and limited degradation of the security of electricity supply. An efficient system will keep the number of scarcity hours to the absolute minimum. France, for instance, designs its system on the basis of the assumption that there will be three hours of scarcity per year. The upside is that the revenue during scarcity hours will cover the fixed capital costs for all generators. Designing a system that would cover the totality of demand during truly *all* hours, such as that during a winter with record cold temperatures could also prove to be very costly.

The need to recur to scarcity pricing is a function of the difficulty to store electricity and the overall high short-term inelasticity of the demand for electricity. Sufficient amounts of cost-effective storage or customers wiling to reduce their consumption voluntarily during peak hours would do away with the need for VOLL pricing during scarcity hours. Some of the most interesting developments in electricity markets currently take place in these areas and affect the way electricity systems work. In several countries this can already be observed. Norway, for instance, whose entire electricity supply is provided by hydropower, and which works like storage, does not need to resort to VOLL pricing. More generally, however, such storage and demand response is not yet sufficiently pervasive to fundamentally alter the conceptual approach taken to the working of electricity markets.

This means scarcity pricing is still required to make ends meet for electricity generation investors. This difficulty is that there is a disconnection between what theorists and investors would like to see which is different again from what other stakeholders would like to see. In the real world, scarcity pricing is frowned upon by politicians and consumers even if it is supported by theory. Their doubts are understandable. Scarcity hours imply an inherently risky situation, both from a technical as well as from an economic point of view. The progressive disconnection and reconnection of selected customer groups by network operators, while usually well managed, always include a small but non-negligible risk of degenerating into a full-blown blackout. From an economic point of view, the unpredictable nature of the number of scarcity hours increases the uncertainty of revenues and profits. Due to the interconnected nature of the economy, scarcity hours also generate security of supply externalities that affect the customers and partners of disconnected consumers over and beyond the VOLL.[2]

So far, theory has rarely been put to the test. While many markets have experienced price peaks in the hundreds and thousands of USD or EUR, high numbers of scarcity hours with involuntary demand interruptions in the electricity markets of OECD countries have usually been avoided. During the small number of scarcity hours recorded, rolling blackouts have been handled competently. In the recent past, this was mainly due to the fact that after decades of regulation, electricity systems were operating with large overcapacity. To the extent that

2. See also Keppler, J.H. (2017), "Rationales for capacity remuneration mechanisms: Security of supply externalities and asymmetric investment incentives", *Energy Policy*, Vol. 105, pp. 562-570.

capacity margins tightened, politicians and regulators have introduced different measures of capacity support to stabilise them. In the future, storage and demand response might provide some additional room for manoeuvre. There exists nevertheless a deep-running paradox in the current electricity markets of OECD markets: while designed to work only with a certain number of scarcity hours, regulators do everything to anticipate them and to avoid their materialisation. On the one hand, this is a good thing for the security of supply. On the other, it means that investors lack the vital complement of revenues that is supposed to stem from scarcity pricing.

Despite such adjustments (some would argue because of them) deregulated electricity markets face a fundamental challenge to incentivise long-term investment in new generation capacity. Price volatility, which implies additional investor risk and thus a higher cost of capital, brings an additional challenge but the phenomenon is broader. The transposition of the theoretical blueprint of deregulation with free price formation into practice has given rise to a series of experiments with different adaptations of the system. At the time, the implicit assumptions of theorists and policy makers were, first, that adequate capacity would be provided with the help of deep and liquid forward markets and that, second, consumers were willing to live with the risk of a limited number of scarcity hours per year. Neither assumption held true but adjustments helped systems to scrape through – albeit without providing a stable long-term framework.

Neither theorists nor policy makers foresaw how important would be the investment challenge in the case of capital-intensive low-carbon technologies such as nuclear, hydro or renewables, where investors crave long-term price stability. The challenge is almost impossible to overcome in the current low price environment that defines the electricity markets in OECD countries. Prices have indeed been reduced far below the replacement cost of generating capacity due to the following five factors that have severely challenged the deregulated wholesale market model and have transformed the debate on market liberalisation:

1. the deployment of large amounts of VREs, essentially wind and solar PV, financed outside of electricity markets leading to higher than economically efficient capacity levels;
2. the need to decarbonise electricity generation in a market essentially designed for fossil fuel technologies;
3. the rapid decline of gas prices, in particular in OECD North America, due to low-cost shale gas reserves as well as a global decline in coal prices;
4. the absence of a reliable long-term price signal on carbon emissions, which would stabilise electricity prices (see also Section 4.3);[3]
5. electricity demand in OECD countries that, depending on country, is flattening, stagnating or declining, although longer term scenarios indicate new growth as economies electrify.

Taken together, these five factors have created a situation in electricity wholesale markets that is very different from the one for which they were originally designed. The most important result is a sharp decline in average electricity prices. While all five factors contribute to this result, a special role is played by the VREs, which have zero short-run marginal costs. Technically speaking, VREs push the load curve to the right and thus demand meets supply at lower prices. Of course, this does not mean that the costs of electricity generation either at the level of the generator or at the level of the system have fallen. Most VRE capacity would not be on the market without the availability of guaranteed feed-in tariffs

3. The rise of CO_2 prices in the European Emission Trading System (EU ETS), widely seen as a global bellwether, in summer 2018 to above EUR 20 per tCO_2, is an encouraging sign. However, the fact that prices only slightly exceeded EUR 5 per tCO_2 for the better part of the preceding six years shows that such prices will need to acquire long-term credibility before they will factored into investment decisions.

(FITs) or production tax credits.[4] In countries with large amounts of VREs, one can observe an increasing gap between the wholesale market prices received by producers and the retail tariffs paid by consumers an issue taken up in some of the literature discussed in Chapter 2. As the latter usually include the cost of subsidies, they provide some indication for total costs. However at the same time, it is no longer possible to invest in firm dispatchable generation capacity, in particular low-carbon capacity, based on wholesale market prices.

As average prices decline, price volatility increases as periods of very low or even negative prices, when VRE generation is high, alternate with periods of high prices when VRE generation is low. While there will be some adjustments as dispatchable capacity leaves the market, high shares of renewables will keep average prices low also in the long-term. For risk-averse investors, decreased average prices and increased price volatility are a major disincentive. With the exception of some investment in gas turbines in the United States, investment in any new generating technology without out-of-market support has come to a halt.in the electricity markets of OECD countries.

The situation does not only affect investment in new capacity but also the operations of existing capacity. In Europe, about 30 GW of gas-fired generating capacity have been closed and "mothballed" because operators were no longer recovering the fixed operating costs of the plant. In the United States, several utilities producing nuclear power that had received regulatory clearance for long-term operations (LTO) beyond the originally scheduled technical design lifetime of their plants abandoned that option due to the unfavourable market outlook. Such early closures or non-extensions of dispatchable capacity can pose a threat to the security of electricity supply, as VREs due to their variability and non-dispatchability only very imperfectly substitute for dispatchable capacity in terms of providing round-the-clock availability of electricity. The economics of storage and hydropower facilities are also strongly degraded as solar PV generation decreases electricity prices during the day. This decreases the spread between prices during the day and during the night. Storage providers however rely on this spread to earn the necessary profits by alternating between selling and buying electricity for discharge and recharge.

Deregulated electricity markets and decarbonisation

The long-term system costs of VRE have, of course, been extensively discussed in Chapters 2 and 3 of this study. In the short run, one can also observe the additional effect that carbon emissions have a tendency to increase in countries where nuclear capacity is retired, either for economic or for political reasons, and is substituted by a mix of VRE and fossil fuel generation.[5] Given the low prices prevailing in most markets, until the recent rise of CO_2 prices one of the few profitable technologies were lignite plants, whose fuel costs, as long as carbon emissions are neither priced or abated, can be below those of a nuclear plant. In the set up chosen for this study, the long-run carbon emissions in all eight scenarios have by construction identical carbon emissions that are achieved by different mixes of nuclear power, VRE, hydroelectric and conventional thermal power plants. Flexibility is provided by a combination of hydroelectric reservoirs, modulation of nuclear and thermal plants output, VRE curtailment, interconnections with adjacent markets and small amounts of batteries, voluntary demand response and involuntary scarcity.

In order to better understand the current situation, it is helpful to recall that the liberalised electricity markets of most OECD countries were implemented following decades of regulation that had generated significant excess amounts of capacity. Some reduction in capacity was thus not automatically considered undesirable. At the same time, policy makers expected that

4. Exceptions exist for onshore wind in Colorado and Texas, for solar PV in Chile and most recently for an offshore wind project in Europe. While this is an area to be watched closely, VRE projects with *average* costs are still very much dependent on out-of-market support.

5. It should be noted, however, that under cap and trade emission trading systems overall CO_2 emissions are set by the original cap rather than by the decisions of generators.

prices during normal operating hours would be aligned to the variable costs of gas-fired power plants as the marginal technology, leaving comfortable infra-marginal rents to coal and nuclear plants. Remaining fixed costs were expected to be recovered during scarcity hours or through modest amounts of monopoly power.

While climate change had already began to emerge as an important policy issue in the 1990s when market liberalisation was first implemented, it was widely assumed that carbon pricing as the first-best solution for internalising the external effects of greenhouse gases would deal with the issue in an efficient manner. The question of whether specific market designs would be needed to bring investment in low-carbon technologies in the absence of carbon pricing did not even arise. While the issues of the non-storability of electricity, strict marginal cost pricing and the short-term inelasticity of demand were fully understood and reflected in market designs, little thought was given to the specific impact these designs would have on low-carbon technologies. In addition, no one anticipated the shocks electricity market investors experienced in the wake of the economic crisis with the advent of significant amounts of renewables with zero short-run marginal costs and ultra-low gas prices in the United States.

Such uncertainty, which today is priced into the rates of return on capital demanded by chastened investors, largely explains why the costs of capital are still high in electricity markets even in a macroeconomic environment of ultra-low interest rates. High costs of capital are particularly damaging for low-carbon technologies due to their high ratio of fixed costs to variable costs. This holds for nuclear, just as for hydroelectricity or renewables. The higher the uncertainty and the higher the costs of capital, the more investors will lean towards fossil fuel-based technologies such as coal and gas. Current electricity wholesale markets in OECD countries with marginal cost pricing and high price uncertainty thus not only pose a general challenge to investment but, in the absence of carbon pricing, also provide the wrong incentives to decarbonise electricity generation. Deregulated energy-only markets without carbon pricing are not technology-neutral but discriminate against high fixed cost, low-carbon technologies.

As shown in Chapter 3, variable renewables such as wind and solar PV are additionally affected in liberalised markets by the decline in the value of their output as their share in the electricity supply increases – due to the concentration of their output during a limited number of hours when their joint production induces lower than average prices. The exceptional support for VREs in the form of often generous feed-in tariffs (FITs) in Europe and Japan or in the form of production tax credits (PTCs) in the United States has so far masked this effect. In addition, this effect really only manifests itself at shares of at least 10% of wind and solar PV in the electricity mix, which is not the case in all OECD countries. However to the extent that following further cost reductions VREs are considered a mainstream option that will need to stand on its own merits, the question of its ability to earn its keep will become an intrinsic part of discussions about the design of future electricity markets.

There is thus a triple incentive to engage in the search for new, economically and environmentally sustainable, electricity market designs. First, consumers and policy makers were never comfortable with the concept put forward by theorists that in the absence of large amounts of voluntary demand response a limited number of scarcity hours would need to come a routine feature of modern electricity systems. Under this assumption, standard market designs by construction do not allow for levels of investment that would guarantee satisfying demand at all times. Second, to the extent the first-best solution of carbon pricing is currently politically unpalatable, decarbonisation will require a change in the working of electricity markets in order to provide a level playing field for low-carbon technologies with high fixed capital costs. Third, if societies opt for VREs in varying proportions independent of other considerations such as cost or carbon emissions, their integration in a non-discriminatory manner in today's electricity markets will only become increasingly more difficult as their share rises.

Were the theorists wrong?

Does the need for new electricity market designs mean that the theorists who designed the current electricity systems were wrong? The answer requires some discussion. While detractors would squarely lay current problems in generating sufficient market-financed low-carbon investment at their door, things are not quite so simple. First, deregulated electricity markets have worked well in organising hourly dispatch and are also quite effective in organising sub-hourly flexibility provision up to the last quarter-hour before delivery when network operators working through specialised balancing markets take over. David Newbery, the doyen of European electricity market economists, asserts that electricity markets are very good at "sweating" existing assets. Second, many observers had underestimated the difficulty of deregulated markets in providing incentives for investment. While macroeconomic circumstances and the evolution of demand were unfavourable, the complete and utter breakdown of all market-based investment points towards a structural rather than a cyclical phenomenon.

Third and most importantly, current markets are being asked to solve problems for which they were never designed. This is primarily due to the fact that energy policy making in OECD countries is fraught with deep-seated inconsistencies. Markets are thus asked to solve contradictions that are unconnected to deregulation as such. One the one hand, drastic carbon emission reductions are an official policy objective in nearly all OECD countries. One other hand, the two most effective options to achieve those objectives, carbon pricing and, as long as costs can be controlled, nuclear energy often lack the policy support required for widespread implementation. With the exception of Sweden and the United Kingdom, deregulated energy-only markets have not been combined with a credible long-term carbon price signal. While Sweden is a special case due to its integration into the Nordpool electricity market and thereby benefitting from large amounts of Norwegian hydropower, the United Kingdom constitutes an interesting test case.[6] It is no coincidence that it is also the only OECD country where several projects for new nuclear reactors are under discussion.

In the absence of radical policy change, the challenges facing deregulated electricity markets will become even more daunting. Even on a conceptual level, a fully market-based system with a high share of existing renewables would imply a substantial number of hours with zero prices, a considerable share of gas-fired power and very high price volatility. Even with increased average prices, market-based investment in new low-carbon capacity nuclear, VRE or hydro will remain a major challenge. Only very substantial carbon taxes with iron-clad guarantees ensuring their long-term application could redress such a situation. Such a solution, however, is not at the centre of current policy discussions.

Thorough discussions without ideological preconceptions, about future electricity market design are thus a necessary part of the realisation of any long-term deep decarbonisation scenario. Models are very good at organising and optimising large amounts of technical and commercial data but obviously cannot solve the policy contradictions that real-world markets have to work around. The following three sections will discuss carbon pricing, the tweaking of existing energy-only markets and the provision of dedicated long-term arrangements for low-carbon technologies as the three most promising avenues for sustained carbon reductions in markets with the high levels of security of supply that electricity customers in all OECD countries have rightly come to expect.

6. Again, given that European countries operate under a common emissions cap, the UK carbon price floor does not affect overall emissions. Nevertheless, the latter has lasting impacts on the structure of the UK energy sector.

4.3. Carbon pricing as a first-best policy instrument for cost-effective emission reductions

Economic distortions and system costs are not an inevitable side effect of a decarbonising electricity system. They arise as objectives and instruments are added to existing systems with little concern for clear prioritisation or overall coherence. In the absence of unequivocal political mandates, long drawn-out institutional processes of great complexity (of which the UN-led COP-process is a prime example) substitute for effective policy frameworks. It also makes the process susceptible to lobbying from different stakeholders. On this point, the current situation does not tend to favour effective decarbonisation.

More broadly and contrary to frequent declarations of intent, climate change concerns and objectives to reduce greenhouse gas emissions have so far failed to effectively restructure energy markets. Current policy making throughout the OECD mostly aims for CO_2 emission reductions in an indirect rather than in a direct fashion. Rather than directly avoiding emissions, indirect routes have been chosen. Frequently, the primary policy driver is increasing the share of renewables for its own sake rather than reducing carbon emissions. Proponents argue that emission reductions will eventually follow. However, this largely depends on the existing electricity generation mix. Substituting nuclear energy with VRE, for instance, will inevitably increase carbon emission (see Figure 73 below) Given the large amount of political capital invested in greenhouse gas emissions reductions, surprisingly few policy measures have been introduced that tackle the issue directly.

In this situation, it is important not to be side tracked by the arguments of the lobbies that are an inevitable part of energy policy making. There exists a straightforward, feasible and effective option to reduce greenhouse gases, which is pricing them at the point of emission. In particular, pricing carbon, which is the most important, best measured and most systematically documented greenhouse gas, could be introduced rapidly and with limited transaction costs. This is consistent with the general principle that external effects or social costs such as climate change are best dealt with through appropriate per-unit charges, as proposed by the British economist Arthur Pigou as early as 1920. Carbon pricing is not only the most cost-efficient manner to reduce emissions in a perspective of static optimisation, but also provides dynamic incentives for the development of low-carbon technologies over time.[7]

The simplest option is a straightforward carbon tax levied at the point of emission and set at a meaningful level. Carbon emission trading is an interesting alternative with a number of advantages and drawbacks that are discussed below. A meaningful level would mean a price high enough that could be reasonably expected to ensure the following outcomes:

1. make gas competitive against coal and, where pertinent, lignite in the markets of all OECD countries;
2. improve the competitiveness of nuclear power plants against gas-fired plants where construction costs are sufficiently low without any out-of-market support;
3. improve renewable competitiveness against gas-fired generation where meteorological conditions are sufficiently favourable without any out-of-market support;
4. provide the dynamic incentive to invest in the development of new even more cost-effective low-carbon technologies.

The precise level of carbon prices to achieve such outcomes would vary according to the relative costs of different technologies in different countries. As an order of magnitude, a carbon price of USD 50 per tonne of CO_2 can be considered sufficient to fulfil the above criteria. Publications based on simple LCOE comparisons such as *Aligning Policies for a Low-carbon Economy* (OECD/IEA/NEA/ITF, 2015) would suggest that even slightly lower carbon prices would

7. Such "price-induced technological change" was first theorised by John Hicks in his *Theory of Wages* in 1932. For a contemporary survey of the issue see Acemoglu (2001).

be sufficient. However, including carbon adders to LCOE calculations only partially deals with the issue of competitiveness under real market conditions. For instance, effective carbon pricing would also need to reflect the fact that the high capital intensity of low-carbon technologies exposes them over-proportionately to the wholesale price volatility that is intrinsic to deregulated electricity markets.[8] As mentioned above, such volatility is likely to increase with the share of VRE in the electricity supply.

The great advantage of striving towards a low-carbon electricity supply with the help of carbon pricing is that the latter is in principle perfectly compatible with the functioning of existing energy-only wholesale markets. If prices are high enough to overcome the intrinsic disadvantage of low-carbon technologies in a free-market environment, there is no need for re-regulation, out-of-market support or other forms of interference with natural market operations. Competition, with free exit and entry into the market, will continue on the basis of the decentralised decisions of private enterprises. In addition, a carbon tax can be applied uniformly across *all* sectors of the economy including heating and transport, which further enhances the efficiency of the effort to reduce greenhouse gas emissions.

As long as VRE does not receive any out-of-market support in the form of FIPs, FITs or capital subsidies, carbon pricing would contribute to an electricity system without any uninternalised system costs. In fact, the declining market value of VRE generation as a consequence of additional capacity producing during the same hours as previously installed capacity would ensure that VRE investment only takes place at a level that is optimal both for investors *and* for the system as a whole, as long as VRE receives no out-of-market support.[9]

In summary, carbon pricing is transparent, efficient and simple. It remains the most straightforward solution to addressing the issue of climate change. It may even offer scope for some macroeconomic benefits, as government revenues garnered through carbon taxes might be used to reduce other levies such as income or excise taxes and thereby allow for additional economic efficiency gains. Last but not least, carbon pricing will also have positive dynamic effects in "future-proofing" an economy, by giving incentives for the development of new low-carbon technologies with economic and commercial potential in a future that will, more likely than not, operate under some form of carbon constraint.

Obstacles to carbon pricing: Distribution and credibility

The points made in the preceding section beg the obvious question, "If carbon pricing has these important advantages, why has it not yet been introduced in a far more systematic manner?" The two main answers are (1) the distributional impacts; and (2) the long-term credibility of carbon prices. Distribution is arguably the biggest stumbling block. Greenhouse gas emissions are hard-wired into modern economies. Producing goods, moving, heating, electricity, agriculture, all emit greenhouse gases. Coal, oil and gas were fundamental drivers of economic growth throughout the 20th century. In the electric power sector only hydropower and nuclear energy were capable of producing electricity without carbon emissions. Pricing carbon would thus negatively affect powerful stakeholders with historic claims for public consideration. Even if official discourses in OECD countries have, with few exceptions,

8. There is an interesting conceptual argument here: as exposure to wholesale market prices would internalise the part of the system costs of VRE that constitute a technical externality and thus a suboptimal constellation. The variability of now optimised VRE production would still cause an adaptation of the residual load curve (and thus under a formal perspective a system cost), but this remaining impact would now no longer constitute an externality.

9. Strictly speaking, the absence of out-of-market support for VRE would only internalise their profile costs. System costs for additional outlays for the transmission and distribution grids as well as for balancing would not be affected. The latter could, however, be appropriately internalised through nodal pricing (i.e. pricing network capacity in function of local congestions) and self-balancing obligations. With appropriate measures it is thus theoretically possible to create a competitive electricity system, in which all system costs are fully internalised and the total costs of the system are minimised.

irreversibly integrated climate change concerns, concrete policy making can still run up against myriads of social and "technical" objections, in particular if a broad aversion against new fiscal measures is mobilised.[10]

The distributional impacts of carbon pricing are of two sorts. First, there is the obvious shift of economic activity from high carbon producers to low-carbon producers. To the extent that this reduces carbon emissions, this is precisely the desired outcome. Electricity generation is, of course, the most important sector in which such a shift would be observed. The interesting question is to what extent such a shift would be equivalent with large losses for investors in high carbon, i.e. fossil fuel-based generation. The answer depends on whether carbon pricing is done in a manner that allocates the rent that is contained in the right to emit greenhouse gas emissions to existing producers or to the government.

The notion of rent is crucial in this context. Rent is the economic return from an asset that is provided for free by nature, that is obtained by chance, or that is taken by force. Typically, a rent-generating asset cannot be reproduced by human effort. To the extent that emitting carbon is economically valuable, and the history of industrial development shows that this is the case, it generates rent for the emitters, or if the latter operate in competitive markets, their customers. In other words, in an electric power sector based on fossil fuels all electricity consumers gain due to the environmental rent that come with the right to emit large amounts of carbon at no cost.

The threat of climate change now requires a radical reduction of emissions. This means that emitting carbon can no longer be costless. If the chosen policy instrument is carbon pricing, this has two highly relevant consequences.[11] First, the overall amount of environmental rent is reduced, i.e. other things equal, electricity will become more costly. Almost more politically relevant is the second consequence, namely that due to carbon pricing the environmental rent will become explicitly monetised and will appear as such in the accounts of companies that emit carbon or that receive, buy or sell rights to emit carbon. This makes carbon pricing a major distributional issue.

The imposition of a carbon price, say in form of a tax in order to simplify matters, in particular, implies an important transfer of wealth that is measured in billions of USD from carbon-emitting companies and their customers to the government and society in general. Some may welcome such a shift. However, the importance of that shift and the break that it constitutes with historical precedent, when for many decades carbon rents were implicitly allocated to the fossil fuel sector, is profound. Much work on carbon pricing concentrates only on its marginal effects, i.e. the shift in generation from fossil fuel-based producers to low-carbon producers such as nuclear, hydro and renewables. While this is important, limiting analysis to this aspect will overlook the *infra-marginal* effects on the wealth and financial health of fossil fuel producers.[12] Under a carbon tax, the latter will not only have to reduce output, which is normal and desired, but will also have to pay for the emissions on the remaining output, an additional wealth transfer that translates into a decline of company value. Last but not least, investors will experience a loss in the residual value of their assets in the ground such as coal mines or gas reservoirs.

10. For further discussion of these issues see OECD/IEA/NEA/ITF (2015), *Aligning Policies for a Low-carbon Economy*, OECD Publishing, Paris.

11. Impacts of alternative instruments such as technical standards are equivalent but manifest themselves in a somewhat more implicit manner. In addition, it can be shown that they will not be cost-minimising, although differences in terms of efficiency are of a second-order.

12. Infra-marginal rent refers to the benefits derived from a scarce, rent-producing asset, on units other than the marginal one. A carbon price equating costs to the market for electricity at the margin would reduce the amount of overall emissions a fossil fuel-based generator could make and thus reduce the overall amount of his rent. He would still derive a benefit from the remaining (infra-marginal) emissions, he is still allowed to make. It makes a large difference to his wealth, and his rent, in fact, whether he receives these emissions for free or is obliged tax.

In an emission trading scheme, distributional impacts would largely depend on whether, allowances would be given away for free, proportional to existing emissions ("grandfathering"), or would need to be bought through auctions. Grandfathering would imply leaving a large part of the environmental rent to historic emitters. The obligation to acquire emission permits through an auction instead would have, assuming certainty and perfect information, the same distributional impacts as a carbon tax. The environmental impacts of carbon pricing would be independent of these distributional choices. The discussion on emission trading systems below will take up these issues in more detail.

In the electricity sector, an additional option to introduce carbon pricing while neutralising the most severe distributional impacts is to switch from taxing fossil fuel-based, carbon-emitting generators to subsidising low-carbon generators. While not consistent with the polluter pays principle (PPP), this can be a successful tactic if fiscal instruments are politically unfeasible. Several states in the United States such as Connecticut, Illinois, New Jersey, New York, Ohio and Pennsylvania have thus introduced *zero emission credits* (ZECs), a form of production tax credit aimed at low-carbon generators, to support nuclear power as well as renewable energies.

The second distributional impact of note stemming from the introduction of a carbon price concerns the trade-off between economic output measured in terms of GDP and overall well-being a notion that would now include in addition to GDP, environmental integrity, i.e. the absence or limitation of climate change. This impact should be quite obvious. Nevertheless, it is frequently misunderstood even by proponents of the imposition of economic instruments for reducing greenhouse gas emissions.

Other things being equal, imposing a levy on any economic activity will reduce the output of that activity. Depending on the use of the revenues thus generated as well as on overall fiscal policy this will affect GDP positively or negatively. The precise economic impacts are difficult to determine *ex ante*. In the electricity sector, for instance, replacing unabated coal plants emitting large amounts of CO_2 with low-carbon nuclear plants as the most cost-effective low-carbon generation option could slightly increase overall generation costs. However, such potential economic losses are more than offset by improvements in environmental integrity in the form of future avoided costs triggered by climate change in the form of violent storms, droughts, floods and thus improvements in overall future well-being.

If carbon pricing takes place by means of a tax or an auctioning of emission allowances and revenues from carbon pricing flow back into the economy through increased government expenditure or reduced general taxes, then the above-mentioned GDP impacts will be second order and may even be positive. From an economic perspective, revenue neutrality at the level of the government budget, i.e. giving back revenues from carbon pricing in the form of tax reductions, should be part and parcel of introducing any carbon pricing scheme. Any attempts to reclaim these revenues for other worthy issues should be resisted. Although intuitively appealing, investments in energy efficiency or new energy technologies should be decided on their own merits and not consider scarce public funds as a free additional resource.

The final efficiency effects will depend on the relative impacts of the loss in output in the sectors experiencing the increase in the carbon tax and the sectors experiencing gains due to the reduction of other taxes such as pay roll or corporate taxes. This is not the place to discuss the finer points of revenue recycling.[13] However as a general point, if employment is a public policy objective, then using carbon pricing as an additional lever to reduce pay roll contributions is a particularly sound economic strategy.

At the level of the individual country, carbon pricing implies thus a trade-off between carbon-intensive sectors, which in many OECD countries includes electricity generation, and the general public benefitting from reduced climate change risks, associated improvements in air quality and, under revenue neutrality, the reduction of other taxes. Such trade-offs not

13. See for instance, OECD/IEA/NEA/ITF (2015), *Aligning Policies for a Low-carbon Economy*, for an introduction to the current literature on green tax reform.

only exist between different groups inside an individual country but may also exist between countries. Climate change is a global externality. While uncertainties are large, there is indeed a small possibility that pricing carbon in an individual country may induce a minor reduction of its GDP. However, if the carbon price is set at an appropriate level, global welfare will unambiguously increase due to overall reduction in climate change risks. This is why it is so important that the largest possible of number of countries participate in the global effort to reduce emissions. If a carbon tax is chosen to advance that effort, each country would of course retain the resulting fiscal revenues on its own.

However, the inability to capture the welfare benefits of climate action fully at the national level is possibly the most important reason why OECD countries have had such difficulty implementing carbon pricing as a first-best policy measure to combat climate change. The logical answer is, of course, to agree on carbon pricing in the framework of regional or, even better, global agreements which would ensure reciprocal benefits between countries. Since carbon emissions are a linear function of the amounts of fossil fuels being consumed, carbon taxes do not require a high degree of institutional sophistication and can be levied straightforwardly on the underlying fuels themselves. They are thus an easy measure to implement, even in countries with only rudimentarily developed fiscal systems, which would struggle to raise revenues in other ways.

For distributional reasons at the intra-country level, such a global agreement would need to begin with a rather low level of carbon price, say USD 5 or 10 per tCO_2. While this would in most regions not be sufficient to make low-carbon technologies competitive against coal and gas in the electricity sector, it would at least force fossil fuel plants to operate in a more efficient manner. It would also provide the right incentive to capture the "low hanging fruits" in terms of technological change and spur new technological development in the right direction. Depending on regional gas prices, even low-carbon taxes could be sufficient to tip the choice between coal- and gas-fired power generation. In any case, a carbon tax would provide a top-up for any low-carbon project introduced for other reasons, such as the reduction of local and regional emissions.

Concerns about international competitiveness and shifts of carbon-intensive production to countries without carbon taxes, so-called carbon leakage, can be dealt with by way of border tax adjustments, i.e. forcing imports to acquit their embodied carbon at the point of entry. The international trading system does not yet universally recognise embodied carbon as the basis for border tax adjustments, but if emissions reductions are to be pursued in earnest, either all countries need to adopt comparable carbon prices or import tariffs must be appropriately adjusted. Climate change is a global externality and free-riding must be systematically discouraged.

There can thus be made a coherent economic case for carbon taxes that provides answers to all concerns about economic efficiency. However, the negative distributional impact on the carbon-intensive sectors of the economy continues to constitute a major barrier. This can lead to questions about the long-term sustainability of a carbon pricing regime. The more uncertain the long-term existence of a carbon price, the less will be its impact on investment. While operations, i.e. dispatch in the electricity sector will be effective immediately without any regard to the incentive measures employed, investment will be highly sensitive to the perceived duration of any carbon price. This impact comes over and above the impact of uncertainty about electricity prices.

The impact of uncertainty about carbon prices on the decisions of investors in low-carbon technologies is a direct function of the longevity of the assets they are investing in. A nuclear power plant from the beginning of planning to decommissioning will have a lifetime of 100 years. It will have an operational life during which carbon pricing will make a difference of 60 years or more. Not all periods during the future lifetime of a yet-to-be-built nuclear plant have the same weight in the original investment decision. Due to a preference for the present and temporal discounting, the profitability of years that are still far away will weigh less than years closer to the moment of decision. This means that the expected revenues stemming from the sale of electricity during the first 30 or 40 years of operations will be decisive for the investment to be made. Investments in renewable energies have somewhat shorter lifetimes but investors will also need to form revenue expectations for the next 20 years.

Obviously, these time frames are far longer than the typical duration of governments in OECD countries. Several electoral cycles will play out during the operation of a power plant, each one risking to undo any carbon pricing policies implemented by the government in place at the moment any investment decisions are made. Such uncertainty lowers the economic value of any carbon price below the average price that can be reasonably expected to prevail over the lifetime of the investment. This means that the proponents of carbon pricing must give serious thought to the question of how they can assure inter-temporal consistency. Binding international agreements, cross-party consensus or inscription into constitutional frameworks are options with different degrees of severity. Of course, those opposed to carbon pricing will use any attempt to interfere with deep-seated structures of the political system as an additional argument to advocate abstention from *any* form of carbon pricing, short- or long-term. In democratic societies, it ultimately pertains to the voters, knowledgeable of the consequences of their choices, to decide on carbon pricing and its persistence through time.

In politics, of course, nothing is truly permanent. However, climate change is a unique long-term challenge that in a very slow and indirect manner is shaping perceptions and behaviour. Once climatic changes have fed through into indisputable social costs, voters and politicians will want to react decisively. All available evidence suggests that such a belated response will be more costly and less effective than immediate action. Nevertheless, once the political tipping point has been reached, it will be good to remember that in a market economy pricing carbon is the most rapid and cost-effective solution to lower emissions.

Carbon emission trading as an alternative to carbon taxes

Carbon emission trading has a number of advantages and drawbacks when compared with straightforward carbon taxes. Its two key advantages are the certainty it provides concerning environmental outcomes by fixing the amount of tonnes of carbon emitted and, more importantly, the ability to modulate the distribution of the environmental rent between low-carbon generators and fossil fuel-based generators. If forcing emitters to acquire their permits has distributional impacts similar to a carbon tax, radically reducing their rent and their benefits compared to the historical situation *ex ante*. Providing emitters their allowances at no cost reduces their rents much less compared to current levels. The key drawback of emission trading consists in the institutional complexities of setting it up, which can easily translate into a lack of transparency, and the uncertain carbon price that is inherent in carbon trading can create added uncertainty for investors.

Carbon trading ultimately is a quantity-based instrument, which sets prices only in an indirect manner. The government chooses the appropriate level of emission allowances, distributes them to different carbon emitters, and lets the market find the appropriate price. It is important to keep in mind that even if the market price varies as a function of the different parameters determining the value of emission allowances, such as electricity demand or abatement costs, the overall quantity of emissions will not be affected.

In many instances, the environmentally-relevant quantity of emissions is decisive. Holding the emissions of potentially toxic pollutants in the water or in the air below the levels at which negative impacts on health and the environment would result are a key focus of environmental policy making. However, this may not be the relevant logic to apply when addressing the issue of climate change, which is characterised by large uncertainties and long time-lags. As mentioned above, the challenge of climate change must be confronted in a medium-term, dynamic perspective. The impact of a precise target in terms of annual emissions in an individual country or region is minimal for the concentration of CO_2 in the atmosphere and the resulting impacts from a changing climate. Instead it is important is to move the industrial structure of the productive system and, in particular, the technology mix of the electricity sector towards a low-carbon trajectory.

As has already been noted, investors are risk-averse and their enthusiasm to invest in low-carbon technologies will depend strongly on the reliability of their estimates of revenue and profit. The latter, however, depend strongly on the stability of the carbon price, whereas the stability of a particular national or regional objective is of limited interest. If the policy priority

is to sustain investment in low-carbon technologies to generate a sufficiently strong dynamic for the evolution of these technologies, then ensuring the stability of the carbon price over time is far more important than the stability of annual emissions in any given trading zone.

Other than the unpredictable level of the carbon price, emission trading systems have the disadvantage of being considerably more complicated to set up and to administer than a simple carbon tax. Exchanges must be created, carbon traders must be employed, rules for the allocation of emission allowances must be negotiated, implemented and adjusted, anxious small and medium-sized enterprises require expert advice and so forth. Final outcomes will depend on constant political adjustments and tinkering with the rules as much as on demand, or new technological developments.

The world's largest and longest-standing carbon trading system, the EU ETS, is a case in point. In November 2017, the European Union adopted yet another reform aiming to deal with chronically low prices. Its original provisions for the 2020-2030 period included reducing the amount of annually allocated emissions by 2.2% and by increasing the allowances placed in a market stability reserve, i.e. temporarily withdrawn from the market. Furthermore, *unused* excess allowances can also be retired. Anticipation and implementation of these reforms have led to a fourfold increase in European carbon prices from around EUR 5 per tCO_2 in June 2017 to more than EUR 20 per tCO_2 in August 2018. However, the complexity of the detailed rules and horse trading between member countries has led to a lack of transparency and considerable uncertainty.

In particular, the transferability of emission allowances from one year to the next, the so-called carbon banking, continues to pose an issue. While in theory such added flexibility promises an increase in inter-temporal efficiency, in practice it confuses investors and regulators further as the true demand and supply balance for emission allowances is more difficult to ascertain. The proposal to install "central banks" for carbon to regularly manipulate prices through the periodic injection or resorption of emission allowances into the market would push the logic of the political management of a quantity instrument in order to obtain desired price levels to the point of absurdity At one point or another a choice has to be made between a potentially complex quantity instrument allowing to mitigate any distributional impacts or a straightforward price instrument in the form of a carbon tax.

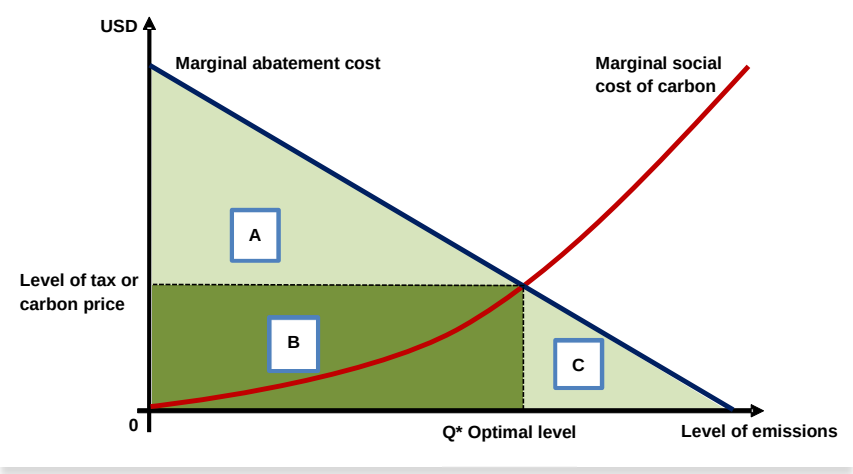
A variation on ensuring suitable price levels is the establishment of "floors" or "corridors", i.e. minimum price levels or price bands. This implies either, again, constant adjustments of the quantity of emitted allowances or the risk of speculation against price limits that no longer correspond to the fundamentals of supply and demand. In short, emission trading systems have great difficulties in ensuring predictable carbon prices. Emission trading should thus only be chosen as the preferred from of carbon pricing if this handicap is outweighed by a major benefit.

The major benefit of carbon emission trading, which is often not sufficiently recognised, is its ability to modulate the distribution of the environmental rent contained in carbon emission permits between low-carbon producers, fossil fuel-based producers and the general public, represented by the government. Such modulation can be crucial for the political sustainability of a sufficiently high carbon price established by carbon trading. As discussed above, the right to emit carbon is economically valuable under all circumstances for fossil fuel-based generators and their customers. It constitutes an economic rent that, in the standard textbook case and in the absence of carbon pricing, becomes part of the consumer surplus of electricity consumers. Imposing a carbon tax or instituting an emission trading system monetises this rent at a level corresponding to billions of USD. A tax or a trading system where allowances are auctioned and need to be bought by emitters will capture that rent and transfer it from fossil fuel producers and their customers to the government.

The graph below sketches the basic distributional impacts for both the imposition of a carbon tax and the creation of an emissions trading system. In the situation *ex ante* with emissions that are limited only by the fact that at one point or another, emitters no longer see any benefit in burning an additional unit of fossil fuel, carbon emitters and their customers benefit from the totality of the carbon rent. The latter is equivalent to the economically valuable right to emit carbon at no cost and corresponds in Figure 71 to the sum of the areas *A*, *B* and *C*. Imposing a carbon tax would reduce the environmental rent to area *A*, whereby an

amount equivalent to area *B* would go to the government levying the tax. Under the simplifying assumptions of full information and certainty the distributional implications of a carbon trading system with emission allowances being auctioned off by the government would be strictly identical. Things are different in the case of trading systems with "grandfathering", where emission allowances are given away for free based on historic emissions. In this case, emitters and their customers would benefit from the rent corresponding to areas *A* and *B*.

Figure 71. **Comparing the distributional impacts of a carbon tax with those of auctioning and grandfathering in an emission trading system**



In all cases, area *C* would be lost for economic activity. Of course, this loss would be more than outweighed by the environmental, social and economic benefits of the damage avoided costs due to reduced carbon emissions. The catch is that benefits will probably be widely distributed, while the costs may be concentrated in certain industries, say, electro-intensive steel production. In political economy terms this provides a strong incentive to the latter to engage in determined lobbying against carbon pricing, while transaction costs impede the vast majority of recipients who reap only comparatively shallow benefits to engage in effective action.

Things are more complicated when a carbon tax or emissions trading is applied to the electricity sector with a mix of high carbon and low-carbon operators as well as its particular structure of revenue generation that is built around the generation of infra-marginal rents depending on the differentials of the operators' variable costs.

Currently, the European Emission Trading System (EU ETS), the world's longest-standing and best-known trading system, which will also be used for illustration in the ensuing discussion, covers around 2 billion tonnes of CO_2 per year, of which around 1 billion tonnes are allocated to the electricity sector. To have an order-of-magnitude idea of the monetised resource rents corresponding to these amounts, it suffices to multiply them with the carbon price. The latter has varied since 2005, when the EU ETS was created, between EUR 5 and EUR 20 per tCO_2.

Fully understanding the distributional impacts of carbon pricing on electricity generators based on different technologies requires an understanding of the interaction between electricity and carbon markets. With a carbon tax the resource rent is withdrawn and transferred to the government. A trading system with auctioning of emission allowances has

precisely the same impact. The predictability of the carbon price is indeed the major difference between a carbon tax and an auction-based emission trading system.[14] In both cases, fossil fuel-based generators will include the price of carbon emission allowances into the price of the MWh of electricity. This will make electricity produced with fossil fuels more expensive and will shift the mix from high to low-carbon sources, precisely as intended.

The total amount of money transferred from electricity consumers to the government will, of course, be lower than the product of previous consumption and the tax, because of the substitution towards low-carbon electricity. In principle, fossil fuel-based producers will neither gain nor lose in this arrangement as they pass on their higher costs to electricity customers. Economically speaking, the latter will lose some of their consumer surplus. The big winners of carbon taxes or emission trading systems are low-carbon electricity producers such as VRE, hydro and nuclear. Since the tax increases electricity prices while their generation costs have remained unchanged, low-carbon producers earn *additional rent* due to carbon pricing. This rent corresponds to real additional financial revenue, which shows up as additional income in company accounts. In the very long-term, this rent could evaporate through the entry of new low-carbon producers attracted by its availability, in which case the rent would revert to consumers through lower prices.

What about the impacts in instances where carbon allowances are not auctioned but grandfathered, i.e. given away for free based on historic emissions? Somewhat counter-intuitively, switching from auctioning to grandfathering will *not* affect low-carbon producers or electricity customers. In particular, electricity prices will remain the same. This also means that the rents of low-carbon producers, which are equal to the difference between their variable costs and prices, stay the same. A frequently asked question is in this context is "How can electricity prices stay the same? Why doesn't grandfathering produce lower prices, given the carbon allowances are received for free?" The answer is to be found in mode of allocation, which will not affect prices. To the extent that emission permits hold value in the market for carbon emissions, producers will factor their value into their costs and prices *regardless of whether they have initially been bought at an auction or received for free*. Economists speak of the "principle of opportunity cost", i.e. that the economic value of any action chosen must correspond to the economic value of an alternative course of action, if not, one would choose the latter. In other words, using an emission quota in electricity generation must yield an economic benefit equal to selling the same quota on the carbon emissions market.

If prices stay the same, the switch from auctioning to grandfathering nevertheless causes one major shift, which concerns the wealth received by generators based on fossil fuels such as coal and gas. With grandfathering, fossil fuel-based producers also gain additional rents. This is the case, even though the total amount of fossil fuel-based generation will be reduced as their relative variable costs that are imputed into electricity prices increase. Yet this increase in variable costs has already been compensated for by the free emission allowances received. While consumers pay more though higher prices, overall costs have not really increased. Thus fossil fuel-based generators, just as low-carbon generators, will benefit from higher prices for each MWh sold, and with grandfathering their annual generation costs remain unchanged. This can make grandfathering politically provocative. Real additional income for generators is thus paid for by electricity consumers. Needless to say, coal- and gas-based producers will lose substantially from any switch from grandfathering to auctioning. While electricity prices will stay the same, the costs of fossil fuel-fired power plants will go up with concomitant losses in resource rents.[15]

14. Under certainty, the two measures are identical. Under uncertainty, emission trading allows emission quantities to be fixed instead of prices. The question is whether guaranteeing quantities or prices is more important seems quite obvious: most experts will have knowledge of current carbon prices and an opinion about appropriate price levels. Most experts will indeed be hard-pressed to indicate the amount of emissions that is actually covered by the EU ETS or any other trading system.

15. Again this analysis is based on the current generation mix. In the long term, economic theory holds that all rents will evaporate as new competitors enter the industry and all producers, low carbon or fossil, will make zero profits.

Depending on the detailed circumstances, an emission trading scheme with grandfathering may leave fossil fuel-based producers better off than before. Their output will be reduced, but the emission allowances they receive for free constitute a monetisable rent, regardless of their production. Especially inefficient high-cost producers might prefer to sell on their allowances rather than produce for the electricity market. Such shifts happen also internally to the utilities concerned. Production losses are thus to some extent offset by capital gains. That is why grandfathering works like a capital cost subsidy.

Low-carbon producers will, of course, be unequivocally better off regardless of whether emissions are allocated by auctioning or given away for free. In Europe, from 2005, when the EU ETS was first introduced, until 2012 when the system switched from grandfathering to auctioning, both low-carbon producers and fossil fuel-based generators earned sizeable carbon rents. Compared with the situation before the introduction of the EU ETS in 2005, European power producers earned almost EUR 20 billion per year in additional rents due to carbon pricing with grandfathering (see Keppler and Cruciani, 2010). Many observers considered that much of the windfall profits from the pre-2012 period were frittered away due to a combination of a European-wide mergers and acquisition mania and ill-judged foreign investments. While the switch to auctioning did not affect nuclear or hydro, it cost European coal producers more than EUR 7 billion and gas producers more than EUR 3 billion per year. These numbers would have been considerably higher had not carbon prices collapsed in the post-2012 period, partly due to an over-estimation of electricity demand. Since 2013, when carbon prices plunged following the switch from grandfathering to auctioning, the impact of the reduced carbon rents low-carbon generators was indeed superseded by the massive decline of electricity prices due to the growing impact of variable renewables.

The fact that fossil fuel-based generators gain financially when emission trading is combined with a costless allocation of emission allowances has made that many stakeholders, experts and policy makers turn against grandfathering. The inconsistency with the straightforward application of the PPP is an additional factor. While understandable, this reaction is preventing more robust carbon prices than those observed in current emission trading systems and is blocking a quicker transformation of the electricity sectors of OECD countries as well as a more drastic reduction of carbon emissions in their electricity sectors. The current trade-off in terms of political economy in OECD countries combines auctioning with an overly generous allocation of carbon permits. Until 2018, the amount of annual emission allowances in the electricity sector of the European Union was *higher* than actual emissions. The only reason that prices have not collapsed to zero is that emission banking provides some potential value for future use, when the allocation of emissions might be less generous. A recent report by two research organisations on climate policy, Agora Energiewende and Sandbag UK, concludes:

> Despite the rise in EU ETS emissions in 2017, the EU ETS cap is still 9% above actual emissions… For every year since the third EU ETS trading period started in 2013, the cap has been 9 to 11% higher than actual emissions. This shows that the initial EU Commissions' calculations back in 2007 when proposing the rules for the third phase of the EU ETS system were fundamentally flawed, issuing too many certificates for the energy and energy intensive sectors. The consequence is that the EU "cap-and-trade" system is actually not providing a real cap – there is simply no scarcity in the EU ETS… the cumulative EU ETS surplus has now risen to more than 3.3 billion tonnes of CO_2 – almost twice the annual emissions of the entire EU emissions trading system. (Agora and Sandbag, 2018)

The recent reform of the system that will come into force in 2019 goes in the right direction but is unlikely to make a decisive difference. The policy makers' reasoning is understandable: in many OECD countries, fossil fuel-based generation still provides employment and income. The regional concentration of either coal or lignite mining further contributes to its relative political leverage. These are facts that any decision maker will have to deal with. The current compromise – full auctioning of power sector emissions vs. overly generous allocations on order to keep carbon prices low – however comes at the expense of environmental integrity and delays the start of a meaningful low-carbon energy transition.

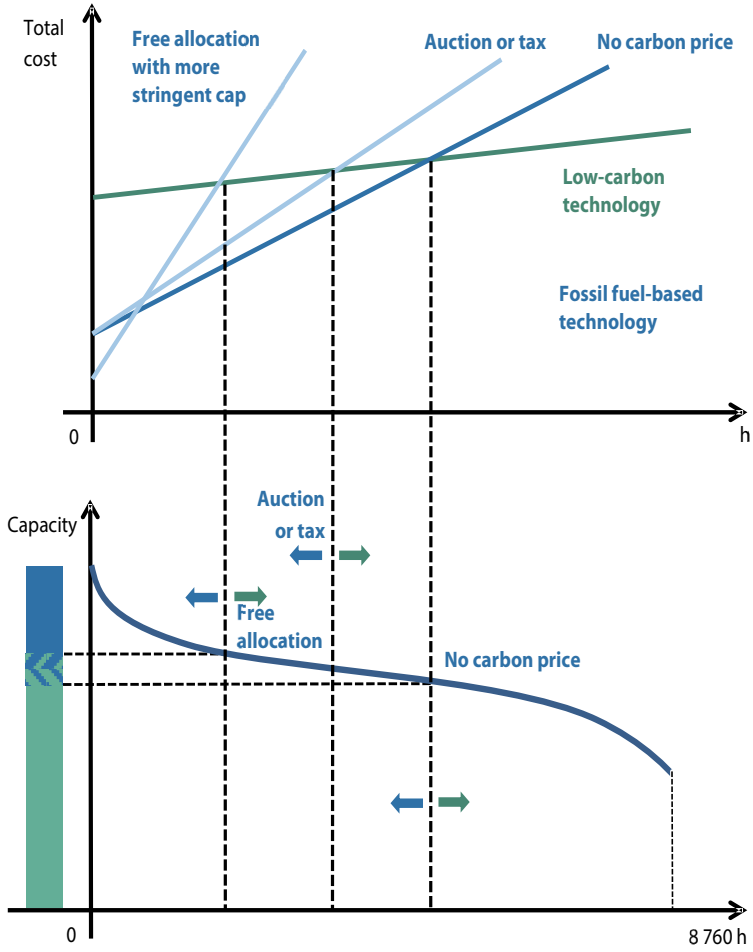
An environmentally and economically superior alternative, in particular in a dynamic perspective, would be to go into the opposite direction, i.e. a return to the grandfathering of emission allowances, as was practised in the EU ETS until 2012 coupled with a significant reduction in the overall number of emission allowances. This is the kind of trade-off likely to be acceptable to the countries relying heavily on coal and gas in their electricity mixes, which in the European context are, for instance, Germany and Poland. Leaving a share of the environmental rent to the investors in fossil fuel-based power plants would open the way to significantly increase the price of carbon and, since the latter is immediately integrated into the variable costs of fossil fuel-based producers, the price of electricity as well. This would have five notable effects:

1. Due to a significantly lower cap, carbon prices would increase and decarbonisation would accelerate as the share of low-carbon electricity in the mix increased and the share of fossil fuel-based electricity decreased. Leaving part of the environmental rent to fossil generators would not impede such a re-alignment since the variable costs of fossil fuel-based electricity would still increase due to higher carbon prices, while the variable costs of low-carbon electricity would remain unchanged. It is competition based on variable costs that determines the relative shares of technologies (see Figure 72 below for a link between relative shares and allocation mechanisms).
2. With higher carbon prices, the environmental rent received by *both* low-carbon and fossil fuel-based producers would increase. This rent would accrue in the form of an annual lump sum transfer to existing operators that is received at the moment of the allocation of emission allowances. It constitutes, in fact, an annual capital subsidy. Given the difficult situation of electricity producers the world over due to the low prices following the influx of VRE with zero marginal costs, this would constitute a welcome contribution to their financial sustainability. Counter-intuitively, such a capital subsidy accruing both to low-carbon and fossil generators would not affect their dispatch. Fossil generators would stay in the market longer than they might otherwise as their fixed operating costs are fully compensated. The carbon rent would also allow more investment in fossil generation than otherwise be the case, but paradoxically this slightly larger capacity would not produce more electricity than with a carbon tax or an auctioning system (see again Figure 72).[16]
3. The capital subsidy implied in the free allocation of emission allowances can be interpreted as a capacity payment, which would allow generation capacity to stay in the market even though the number of hours that it actually produced electricity would not cover fixed operating costs (see also Section 4.4).
4. In a more complete dynamic perspective, the increase in the ratio of the relative costs of fossil fuel-based electricity and the costs of low-carbon electricity due to a strong carbon price constitutes a widely visible signal to develop technologies reducing emissions from fossil generators or increasing the competitiveness of low-carbon generators.
5. Given such widespread benefits, who would the losers be following a switch towards a free allocation of emission allowances coupled with a significant reduction in their total amount? Switching from auctioning to grandfathering implies that the government would no longer earn the monetised rent from the carbon credits. In the context of the EU ETS, with about of one billion tonnes issued to the electricity sector this corresponds to an amount of between five and ten billion euros, a considerable sum, but only a small fraction of total government revenues at the European level. The other "losers" from *any* form of carbon pricing are electricity consumers. Carbon pricing, whether, in the form of a tax or in form of an emission trading system, independent of the fact whether allowances are sold off at an auction or given away

16. These second order losses in economic efficiency confirm that the economic first-best solution remains a carbon tax or an emission trading system with auctioning. However, in the greater scheme of things the political and economic sustainability gained through grandfathering seem, at least in the present situation, promise greater overall advantages.

for free will increase electricity prices. It is thus not the shift from auctioning to grandfathering that affects electricity consumers but the restriction of emission allowances and the resulting increase in carbon prices, which, after all, is the desired and inevitable side effect of reducing carbon emissions. Since all voters are both, electricity consumers and victims of climate change, political honesty requires that the necessity of such trade-offs is explained with the necessary conviction.

Figure 72. **The impact of a switch from auctioning to grandfathering on the relative shares of low-carbon and fossil electricity generation**



In summary, carbon pricing with long-term credibility whether in the form of a carbon tax or an emission trading system remains the first-best measure to ensure the decarbonisation of both the electricity sector and the wider economy. While carbon pricing will necessarily lead to an increase in electricity prices and thus to a decrease of the surplus of electricity consumers, other distributional impacts can be modulated by adopting the appropriate allocation mechanism. While a carbon taxes offer price stability, allocating part or all of the allowances in an emission trading system in a costless manner can ensure the support of fossil producers and their constituencies for carbon pricing during a transition period. Low-carbon generators such as nuclear energy, hydro or renewables will unequivocally improve their competitiveness with all forms of carbon pricing.

4.4. Remunerating dispatchable capacity in markets with high shares of VRE and other ancillary measures

The ability to produce electricity without emitting greenhouse gases in the process is a vital quality of any generating technology aspiring to be part of a sustainable energy future. However, it is not the only one. The ability to deliver electricity predictably and reliably at any moment when consumers it so desire is another. Dispatchability is an essential ingredient of the security of the electricity supply. In particular, the ability to be available during the hours of peak demand in all geographic regions is important in this context. While low-carbon generation and dispatchability are the two most important features of any generating technology, to this can be added a third: flexibility, i.e. the ability to increase or decrease dispatchable load over different time frames, in particular at short notice. Besides the cycling of dispatchable plants, flexibility measures include re-dispatch in T&D systems, storage, demand response or the curtailment of VRE. A particular subset of flexible provision is often referred to as system services and includes all forms of modulating instantaneous power that allow the system operator to stabilise frequency and keep the voltage stable. In addition, the heavy rotating masses associated with the large turbines of dispatchable generation provide physical inertia, which assures the frequency stability of the electricity system.

The provision of sufficient amounts of firm capacity at all times has become an increasingly important issue in the electricity markets of almost all OECD countries. Due to the influx of large amounts of variable renewables and the resulting decline in electricity prices, the economics of conventional dispatchable generators such as nuclear, coal and gas have been strongly degraded. Generators with the highest variable costs were the most vulnerable and gas-fired capacity thus receded in the past five years in key European markets such France, Germany and the United Kingdom. Gas-fired capacity held up better in the United States due to the low costs of shale gas and in Japan due to the need to compensate for electricity generation from nuclear power plants that were halted awaiting safety reviews and the local government permission to restart after the Fukushima Daiichi accident.

Existing power plants will be closed and mothballed if current income does not allow compensate for fixed operating and maintenance costs, i.e. the costs for staff to operate the plant and maintaining it in working condition. If incentivising existing plants to remain in the market is difficult, the challenge to attract investment in new capacity is even greater. Except for gas-fired capacity in the United States, conditions in the electricity markets of OECD countries are such that financing new capacity based solely on wholesale market prices is no longer forthcoming. Where new capacity is being built such as in the renewable sector or nuclear, it is based on guaranteed revenues in the form of regulated tariffs, contracts for difference (CFDs), PTCs or a combination of different support mechanisms.

The current low price environment in electricity wholesale markets is reinforced everywhere by the influx of variable renewables such as wind and solar PV with zero marginal costs.[17] In the North American markets low-cost shale gas further increases the downward pressure on prices. That said, not all challenges to investing in power generation capacity are due to renewables or shale gas. These relatively new generation options only intensify a difficulty that is inherent in liberalised electricity markets and that is often referred to as the "missing money" issue. Since one MWh of electricity, once injected into the grid, is indistinguishable and thus not differentiable from another MWh, competition will ensure that prices at all times are equal to the short-run variable costs of the marginal technology. If demand is indeed fully covered at all times, this means that the marginal technology, i.e. the one with the highest variable costs, will never earn more than its variable costs.

17. The latter also distort electricity trading by pushing large amounts of low-cost electricity through the interconnected national systems during hours with strong wind or solar PV production. So far, the out-of-market financing of VRE has not been challenged under WTO rules as an export subsidy. Yet, it is clear that the domestic producers of importing countries undergo large reductions in both load factors and prices.

Of course, technologies with lower variable costs such as nuclear or renewables will earn infra-marginal rent in form of a difference between the price and their variable costs, with which to finance a large portion of their fixed cost. Electricity prices are of course set by the technology, usually gas, with the highest variable costs. Nevertheless, the revenues to pay for the fixed investment costs of the marginal technology, as well as a share of the investment costs of all other technologies in the generation mix will be missing in this case. The investment challenge remains intrinsic to electricity markets, or, in fact, to all markets for non-differentiable and non-storable goods.

Economics teaches us that in this situation generators will no longer invest up to the point at which demand is covered at all times, but will leave a small portion of demand during the highest peak hours unserved. During scarcity hours, whose annual average is measured in the single digits, the fact that some consumers will not be served will let electricity prices rise sharply up to the willingness-to-pay of the last customer. The resulting price is referred to as the value of lost load (VOLL) and is measured in the thousands of USD or EUR. It can be shown that the surplus revenue garnered during those hours will be sufficient to finance the fixed costs of the technology with the lowest capital costs and the highest variable costs, which is, by definition, the marginal provider of electricity during the hours of peak demand.

While VOLL pricing can theoretically be shown to be economically efficient under a certain number of assumptions, neither consumers nor policy makers like the idea of scarcity hours with very high price spikes and portions of demand remaining unserved in the absence of sufficient amounts of voluntary load shedding. Renewables with very low variable costs tend to further increase the familiar challenge of bringing costs and electricity prices into line. Due to the high price volatility that working with scarcity hours implies, VOLL pricing will also increase the average rate of return demanded by investors, which further limits capacity investment at any given electricity price.

Table 15. **Capacity remuneration mechanisms in Europe and the United States**

Country	Capacity remuneration mechanisms (CRM)
Belgium	Strategic reserve (2014); capacity payment being planned
Finland	Strategic reserve
France	Capacity obligation (2016-2017)
Germany	Under consideration
Greece	Capacity payment
Ireland	Capacity payment
Italy	Capacity payment (2015-2017); reliability option for 2018 onwards
Poland	Under consideration
Portugal	Capacity payment between 2010 and 2012; currently suspended
Russia	Capacity payment (under long-term contracts) for new capacity and capacity market auctions for existing capacity
Spain	Capacity payment
Sweden	Strategic reserve
United Kingdom	Northern Ireland: capacity payment Rest of the UK: capacity auction – first auction in 2014 for 2018 deliveries
United States	Capacity auctions in four ISOs PJM, NYISO, ISO-NE and MISO

Source: Timera Energy (2015).

Unsurprisingly, many countries have therefore introduced support schemes for capacity investment that come under the name of capacity remuneration mechanisms (CRMs, see Table 15 for an overview). Further research has also shown that the instinctive aversion of customers and policy makers is grounded in sound economic reasoning. Security of supply externalities, the granularity of generating investment and the risk aversion of investors faced with high but rare peak load prices all lead a situation, in which privately optimal provision of capacity is below the socially optimal one (see also Keppler, 2017).

Capacity mechanisms thus provide top-ups for conventional dispatchable capacity, including gas, coal and nuclear. However, if correctly designed, for instance through an obligation of distributors to meet their capacity obligations at all times, they also incentivise storage and demand response (DR), i.e. the voluntary reduction of electricity consumption during hours of high demand, which can further alleviate the tension in electricity markets during peak hours. The appropriate level of such capacity remuneration depends primarily on the fixed costs of the technology that could solve the capacity problem at the very margin, the so-called cost-of-new-entry (CONE). This, however, is a function of the interplay between a country's capacity needs and the available technologies. France, for instance, may have a capacity issue during only a few hours in a particularly cold winter and might be well served by demand response. Germany, with high shares of wind and solar might require hundreds of hours of additional capacity all year round, so gas-fired turbines might be appropriate. The United Kingdom with the need to replace coal capacity for thousands of baseload hours every year might choose nuclear as an appropriate low-carbon solution.

As an example, the fixed costs of a new open cycle gas turbine used for generation during several dozens of peak hours are about USD 1 000 per kW. With a lifetime of 20 years and abstracting from discounting, an annual payment of USD 50 per kW would thus induce new entry of gas-fired capacity even if it would not expect to make any money in the electricity market outside of hours of extreme peak demand. Such a payment would then be made to *all* dispatchable capacity that is able to commit to be available during peak hours, including coal and nuclear. However, again just for comparison purposes, the resulting revenue of USD 1 000 per kW over 40 years would not be sufficient to build new nuclear power capacity on its own. Needless to say, it would remain highly valuable top-up.[18] Considerations of investor risk magnify these relative impacts. The lower the capital costs, the higher the impact of capacity payments and the greater reduction of investor risk.

There exist a number of mechanisms to administer capacity support. All of them require two decisive prior actions by the system operator that can either be the transmission system operator (TSO) or an independent system operator (ISO). The first step is the definition of an overall capacity objective, which includes periods of extreme peak demand. The second step is the certification of available generation capacity or demand response resources for availability and reliability before it is eligible to participate in the CRM. Once these two preliminary steps have been defined, available mechanisms include:

- Forward reliability markets are the instrument of choice of theorists. They consist of forward auctions, in which electricity suppliers and distributors are obliged to cover themselves for demand peaks by buying drawing rights or call-options on physical capacity offered by generators.
- Fixed capacity payments consist of a simple, administratively determined top-ups to electricity prices that are available indiscriminately to all producers. Such payments are transparent and simple to administer but give no guarantee of attaining the desired capacity target.

18. An equivalent reasoning applies to covering the fixed costs of O&M in order to prevent existing capacity from leaving the market.

- Strategic reserves involve a certain amount of capacity that does not participate in the market but is called upon by the system operator in scarcity hours under precisely defined conditions. Strategic reserves have again the appeal of simplicity and transparency, however, they tend to displace rather than solve the investment issue. Private investors will indeed anticipate the addition of reserves during scarcity hours and thus limit market-financed capacity further.
- Feed-in tariffs (FITs), feed-in premiums (FIPs), power-purchasing agreements (PPAs) and contracts for difference (CFDs) constitute particular forms of long-term power supply contracts guaranteeing a price corresponding to average costs, which includes the costs of capacity. However, because they also remunerate energy, there is a semantic question of whether such mechanisms constitute proper capacity mechanisms. Regardless of definitions, they are an important tool to ensure adequate amounts of dispatchable capacity. The certainty they provide is particularly attractive for low-carbon technologies, which due to their high fixed costs would otherwise be penalised in electricity markets with volatile prices (see *Nuclear New Build: Insight into Financing and Project Management* for an in-depth discussion).

In principle, policy makers thus have an arsenal of measures at their disposal to solve capacity issues. Yet CRMs are no panacea. First of all, they come at a cost to consumers. Pure theory maintains that an energy-only market with scarcity pricing is a first-best optimum. While consumers might well be happy to pay a premium in order to benefit from higher reliability, it is undeniable that ensuring higher levels of security of supply come at a cost.

CRMs are also complex mechanisms that need to be constantly adjusted in function of a country's generation mix, the shape of its load curve and the evolution of the electricity system. In particular, the development of short-term markets for flexibility provision, such as balancing and intraday markets, can interact with the development of capacity markets. One day, increasingly competitive storage solutions or the widespread adoption of demand-side management (DSM) in response to the price signal coming from short-term wholesale markets might even make electricity somewhat less of a non-storable good. In the very long run, this could mean the capacity issue fades into history. Such a situation is, however, still many years away. In the medium and short term, CRMs are both necessary to ensure adequate levels of investment and widely used in a pragmatic manner. Establishing a stable conceptual framework is difficult as capacity issues depend on a great number of rapidly evolving parameters.

Two major issues currently being debated by electricity market experts are whether CRMs should be available only to certain kinds of technologies, i.e. low-carbon technologies, and whether cross-border participation in the capacity mechanisms of neighbouring regions should be allowed or even promoted. Concerning the first question, economic theory rightly advocates choosing for each policy objective the individual policy measure that is best suited to achieve it at least cost. In principle, this would mean a carbon tax to reduce emissions and a capacity mechanism without further conditionality to ensure high levels of security of supply. Profit-maximising investors will ensure the least-cost solution. However, in a policy environment where first-best solutions such as carbon taxes have limited political appeal, it might make sense to use every means available to advance low-carbon alternatives. As it happens, the technologies likely to benefit most from capacity mechanisms are technologies with low fixed costs such as open cycle gas turbines or diesel generators, both of which have comparatively high CO_2 emissions. In such a situation, targeting capacity mechanisms towards dispatchable low-carbon technologies such as hydro or nuclear can be a second-best solution. Ideally, first-best solutions such as unrestricted capacity mechanisms and a carbon price would deliver security of supply and carbon emission reductions at least cost.

Concerning the question of cross-border participation in neighbouring regions the jury is still out. On the one hand, permitting operators from neighbouring regions to bid in national capacity mechanisms can improve efficiency and reduce costs. On the other hand, cross-border participation raises difficult questions of political and regulatory procedures and priorities, as the security of energy supply is largely determined at the national level. How binding would be a generator's contract with a distributor in a neighbouring country or state be if its minister or governor declared a situation of *force majeure* as the home region faces a

blackout? Capacity mechanisms are designed to prepare for and prevent emergency situations. This brings considerations to bear other than standard economic logic. In addition, precisely in an emergency situation, interconnections are most likely to be blocked. So at this stage, the idea of cross-border participation in CRMs seems the result of a political declaration of will rather than the response to a genuine need.

All in all, CRMs do not constitute on their own a royal road towards sustainable low-carbon electricity systems. They constitute, however, an appropriate complementary measure to remunerate the contribution that the reliability of dispatchable generation brings to the working of electricity systems. They would also bring forward low-carbon demand response as well as storage solutions. In a context of deep decarbonisation, which most likely will involve significant amounts of variable renewables such as wind and solar PV, the challenges for investment in dispatchable capacity are bound to increase. Alongside long-term power purchase agreements for low-carbon technologies, capacity mechanisms are thus an indispensable element in the mix of policy measures ensuring the smooth functioning of reliable, low-carbon electricity systems.

4.5. Financing investment in low-carbon electricity generation

Sections 4.3 and 4.4 discussed at length the two principal objectives of today's electricity markets in OECD countries: decarbonising generation and ensuring high levels of security of supply in a cost-effective manner. Making progress towards these two objectives, while continuing to keep costs under control, is the metric by which their performance will be assessed.

The principal challenge for policy makers, market designers and regulators is that the first-best mix of policies suggested by economic theory for achieving these objectives, generalised carbon pricing combined with VOLL pricing during scarcity hours, is unlikely to be implemented in full at least in the short and medium run. The reasons for this unsatisfying state of affairs are due to a complex mix of sociological, political and economic reasons, many of which have been commented on in the previous sections. This does not mean that, in particular, carbon pricing will never be instituted in any form, emission markets in Europe and certain regions of the United States are a case in point. However, in the short run they are unlikely to be employed to the extent and with the determination necessary to provide on their own sufficient incentives to ensure the robust long-term competitiveness of low-carbon technologies that is required for a deep decarbonisation of power generation consistent with limiting rise in global mean temperatures to 2° Celsius.

In most OECD countries, electricity markets will thus need to begin decarbonising their electricity supply with the help of alternative policy measures that will complement, and in some cases substitute, carbon pricing. The objective, of course, remains the same as for the first-best mix of measures mentioned above, i.e. to make low-carbon technologies the preferred choice for investors while ensuring high levels of security of supply. Future low-carbon electricity markets will thus involve, alongside elements of carbon pricing and incentives for adequate dispatchable capacity provision, two interrelated sets of measures:

- Different forms of long-term supply contracts providing price and revenue stability for capital-intensive low-carbon technologies.
- The progressive internalisation of the system costs of different generation technologies in general and of VRE in particular. This will imply also the reform of existing support mechanisms.

These second-best measures will complement carbon pricing boosting low-carbon technologies and capacity remuneration mechanisms supporting investment in dispatchable technologies. Ultimately, sustainable electricity markets for deep decarbonisation will thus be supported by five pillars: 1) the continuing working of short-term markets for efficient dispatch based on variable costs; 2) carbon pricing; 3) frameworks for the adequate provision of capacity, flexibility and infrastructure for T&D; 4) appropriate mechanisms to foster long-

term investment in low-carbon technologies, including the reform of existing support mechanisms; and 5) the internalisation of system costs wherever practical and necessary (a broader discussion of these five pillars follows in the conclusion to this chapter).

The understanding is that these measures will not so much substitute for the working of deregulated electricity markets but complement them. More precisely, short-term dispatch for day-ahead and intraday markets will still be best organised around the competitive submission of supply bids based on variable costs with marginal cost pricing. However, long-term incentives for investing in new capacity or major refurbishments such as lifetime extensions for nuclear plants will most likely be supported by mechanisms where a central authority invites bids for a given amount of capacity that will be remunerated at average costs. This will translate into competition *for* the market rather than *in* the market (see also Finon et al., 2017). The internalisation of the system costs of VREs is an explicit fifth pillar, even though partial internalisation is frequently already a consequence of implementing the four other pillars.

Low-carbon technologies in competitive electricity markets: the challenge of capital intensity

Chapter 3 has shown that decarbonising the electricity generation mix implies a shift from less capital-intensive technologies with high variable costs, in particular fossil fuel-based generators, to more capital-intensive technologies with low variable costs such as nuclear, hydroelectricity, wind and solar PV. With the exception of biomass, low-carbon technologies are all highly capital-intensive.[19] At the same time, Chapter 3 has also shown that price volatility will increase with the share of VRE, alternating hours where prices will be at zero with hours with very high prices in the hundreds or even thousands of USD per MWh. With certain support mechanisms, notably FITs that isolate generators entirely from the feedback from electricity markets, prices can even turn negative, further stoking price volatility.

Price volatility is not limited to variations at the hourly, daily, weekly or seasonal level. The generation from VREs, in particular wind, can change considerably from year to year and thus causes changes in average prices. Furthermore, due to their low variable costs VREs tend to lower the average price level regardless of changes in annual generation. The NEA publication *Nuclear New Build: Insights into Financing and Project Management* (NEA, 2015) has shown how the economic value of capital-intensive technologies is vulnerable to such changes in average price levels. Given that 80% or more of their total lifetime costs are sunk before they produce the first MWh, capital-intensive technologies crucially lack the ability to leave a loss-producing market to limit their exposure and their consequent financial losses. This ability is possessed to a much greater degree by less capital-intensive technologies such as gas-fired power plants. This effect will induce even risk-neutral investors to prefer technologies with relatively lower capital costs in cases where both technologies would have the same levelised cost of producing electricity (LCOE). The effect is, of course, strongly magnified when the habitual risk aversion of investor is taken into account.

In other words, investors in capital-intensive low-carbon technologies, which would face a level playing field if long-term prices were guaranteed, e.g. in the form of a regulated tariff or a long-term supply contract, face additional hurdles as soon as price volatility is introduced. Due to the additional risks implied by high sunk fixed costs, the cost of capital for low-carbon technologies will *ceteris paribus* be higher than the cost of capital for fossil technologies.

The most vulnerable technologies in this respect are the most capital-intensive ones, i.e. wind and solar PV, with nuclear energy and hydroelectricity closely behind. By default, rather than as the result of a coherent strategy based on sound analysis, legislators and

19 Biomass is, in effect, a low-carbon technology only in accounting terms. Burning biomass, of course produces high CO_2 emissions. However, due to the yet to be verified assumption that biomass harvested for electricity or heat production is immediately replanted, statistically one can assume that over their lifecycle the new crops will in fact sequester the same amount of carbon that has been emitted during the combustion of the preceding generation.

regulators have recognised this as far as VRE are concerned and provided a number of technology-specific support mechanisms such as FITs, in particular for wind and solar PV. With very few exceptions due to extremely favourable natural circumstances in niche markets, the low-carbon technologies that are in place today would never have been built without some form of price guarantee. In the past, nuclear power plants also benefitted from such price and revenue stability, primarily in the form of regulated tariffs.[20]

Overall, the argument holds firm: low-carbon technologies in the electricity sector require long-term price stability for their output in order to ensure sustainable levels of capital costs. Support mechanisms for prices and revenues come in different forms. These include feed-in tariffs (FITs), feed-in premiums (FIPs), production tax or zero emission credits (PTCs or ZECs), CFDs, long-term supply contracts (including large-scale auto-generation such as the Finnish Mankala model) or regulated tariffs.[21] They all share the common feature of guaranteeing the revenues of low-carbon providers per unit of output (FIPs, CFDs, supply contracts or tariffs) or of enhancing them (FIPs, ZECs or PTCs). Such measures, which today are a common feature of the electricity markets in most OECD countries, inspire three different reactions from the point of view of economic theory:

- First, such mechanisms are not consistent with the standard textbook model of a market economy with marginal cost pricing in competitive markets. To the extent that these measures directly lower the cost of production as, for instance, in the case of PTCs, they amount to the explicit provision of subsidies. All of these measures provide implicit subsidies as they lower the economic risk and the cost of capital of the technologies concerned. To the extent that revenues are guaranteed without a process of competitive tendering, they might also include a straightforward transfer of wealth from electricity consumers to VRE or, possibly, nuclear producers in the form of rents in cases where the guaranteed revenues exceed the costs of production.
- Second, decarbonising the electricity sector in a pure market framework with marginal cost pricing is theoretically possible but would face (a) a major hurdle, (b) a significant inconvenience and (c) a serious cost for electricity consumers. A pure market framework would imply high and permanent carbon taxes as well as a considerable number of hours of scarcity or hours with high prices set by flexibility providers in the form of demand response or storage. The hurdle is, of course, the political feasibility of a sufficiently high carbon tax. The inconvenience would consist of rolling blackouts associated with scarcity hours if voluntary demand response is exhausted. As mentioned, costs would increase as the high price volatility would increase the cost of capital of investors, in particular for low-carbon technologies with high fixed costs. Deep decarbonisation in a competitive electricity market is a highly unlikely proposition. Even from the point of theory, the search for alternative and complementary measures can thus be justified.
- Third, both practical and theoretical arguments support the proposition that decarbonising electricity generation demands mechanisms that are based on long-term average rather than on short-term marginal costs. However, if this is so, systematic analysis then needs to ensure that mechanisms of the kind mentioned above do indeed deliver carbon emission reductions at least cost. This is where the difficult questions lie. With very few exceptions, (Finland, the United Kingdom and the United States stand out), existing mechanisms providing long-term revenue certainty for low-carbon producers

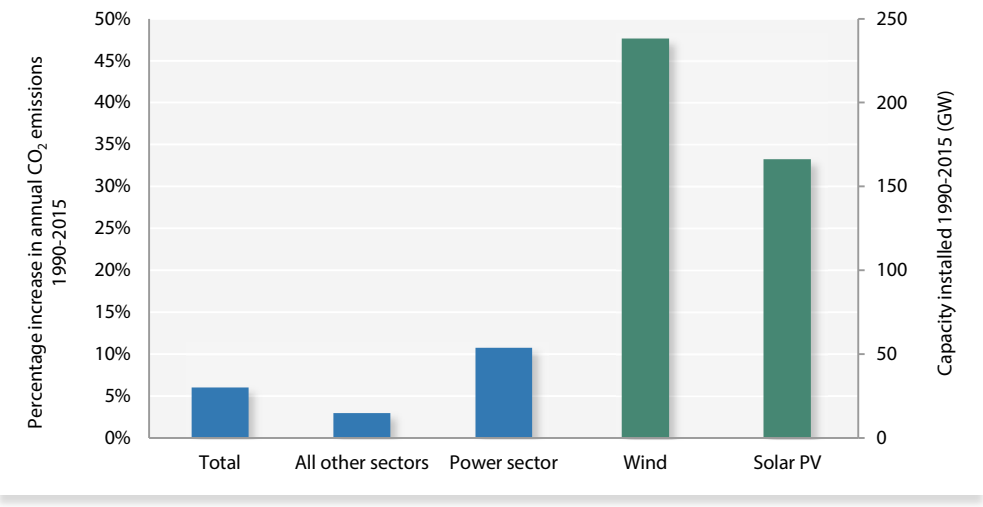
20. The EPR currently under construction in Flamanville (France) will, once completed, be in fact the first and only nuclear power plant constructed without any prior guarantee of stable electricity prices. Using it a as a counter example for the need for long-term price guarantees would, nevertheless, be difficult. One might argue that only the fact that the French government owns more than 80% of its shares allowed EDF, the utility undertaking the project, to proceed.

21. In the Mankala model, the equity holders of a generation project are also its principal consumers. The operating entity will thus sell to them at average costs including a previously agreed return on capital. This provides the project with the certainty that all costs will be fully recovered. It is applied in particular for financing the construction of Finnish nuclear power plants. See *Nuclear New Build: Insight into Financing and Project Management* (NEA, 2015), for more details.

have been tilted towards maximising VRE deployment rather than towards maximising carbon reductions. Support mechanisms have thus been introduced ad hoc in great numbers, un-coordinated and aimed at specific technologies, primarily wind and solar PV. Both, the systemic impacts on the working of the electricity system as well as the impact on CO_2 emissions were neglected in this process. The results of such policy drift are evident. Annual total global CO_2 emissions thus rose by 57% from 1990 until 2015, even as the total annual emissions of OECD countries *increased* 6% over the same period. The failure of current energy policies is even more dramatic if one concentrates on the electricity sector. Despite hundreds of billions of dollars and euros being spent on the deployment of wind turbines and solar panels, CO_2 emissions in the electricity sector grew even faster than over all emissions. Between 1990 and 2015 annual global emissions in the electric power sector grew 77% and 11% in the power sectors of OECD countries (IEA, 2017a). In other words, VRE subsidies accelerated CO_2 emission increases when comparing the electric power sector to other sectors (see Figure 73).

Figure 73. **Less than nothing: Capacity additions of wind and solar PV and CO_2 emission increases**

(OECD, 1990-2015)



Putting the three points together, providing mechanisms for financing investment in low-carbon technologies through the provision of complete or partial revenue certainty outside of marginal cost pricing in competitive markets can be justified. However, such policies need to be undertaken in a systematic manner that is (a) open to all low-carbon technologies and (b) takes into account the systemic impacts of such policies otherwise as spelled out in Chapter 2, selective support for VRE can lead to *increasing* carbon emissions due to the substitution effect in the residual load curve from low-carbon technologies with high fixed costs such as nuclear and hydro towards high carbon technologies with lower fixed costs such as gas, or even coal.

While these effects usually take time to affirm themselves, first indications are clear. In the OECD, electricity generation from wind and solar PV increased between 2000 and 2015 from 30 TWh (out of a total electricity generation of 9 864 TWh) to 749 TWh (in a total of 10 964 TWh). Over the same period, nuclear power decreased from 2 249 TWh to 1 971 TWh. The most striking statistic however is that electricity produced by pumped hydro storage *decreased* over the same period from 72 TWh to 61 TWh. While there is much talk about the need to develop storage in order to accommodate the variability of VRE, economic realities speak a different language. Without some kind of out-of-market support, it is apparently no longer profitable to operate, and even less to develop, pumped hydro storage with its high fixed costs in the presence of increasing amounts of VRE. The compression of the price spread between peak load and baseload generation due to solar PV is an additional factor.

Maximising economic efficiency: Direct capital support for low-carbon technologies

The key point is, of course, finding the appropriate mechanisms that allow for a cost-effective deployment of low-carbon technologies. The most likely method to be implemented in OECD countries is likely to be the competitive auctioning of long-term supply contracts or price premiums, as it requires the least change from the current practices to which regulators, governments and investors have become accustomed to. Before presenting it, one should however pay attention to the provision of direct capital support, which is an economically efficient alternative that possesses real advantages.

The logic is simple: If low-carbon technologies suffer from high risks and high cost of capital, why not directly support investment in them by lowering the cost of capital. Low-carbon technologies could, for instance, benefit from low-cost loans from a carbon fund or from risk guarantees that would kick in if the profitability of a project was in question. The guarantees provided by the tariff reform of the Spanish government in 2014 to ensure a minimum rate of return on the capital invested in renewable projects correspond to this approach. The government could also directly provide lump sum subsidies to low-carbon projects. This would not only lower the cost of capital on the share of the project directly financed by the public but also on the remainder as capital providers would recognise the reduction in risk that comes with the capital subsidy.

The direct provision of support for low-carbon generation projects has one great advantage and one major disadvantage. The advantage is that direct capital support does not interfere with generation decisions and thus the price setting in wholesale electricity markets. Low-carbon technologies will be fully exposed to the working of the markets. For instance, even wind and solar PV installations with their zero short-run marginal costs would stop producing once prices turned negative. Even the reduction in the value of VRE generation due to auto-correlation would be fully brought home. VRE producers would limit themselves to the economically optimal share in the system given their lower capital costs. Direct capital support would thus, in particular, help dispatchable low-carbon technologies such as nuclear and hydro or coal and gas with CCS should that it became an industrial option.

The disadvantage of direct capital support results from precisely the same point as its advantage: the decoupling of the investment decision from decisions of generation and dispatch. Once a plant is built and the capital subsidy consumed, there is little incentive to maximise output beyond selling at, comparatively low, wholesale market prices. In extreme cases, one might imagine plants that are built on the basis of capital subsidies but never connected to the grid. Of course, appropriately structured contracts, e.g. parcelling out the subsidies over several years and linking it to minimum performance requirements would prevent the most blatant abuses. The fact is that compared with long-term price supports, the incentive to maximise generation over the lifetime of the project will be less strong. This is not necessarily a disadvantage from an economic system approach. Dispatchable operators suffering from the compression of their load factors will appreciate the additional space. Reduced generation per GW installed is, however, a disadvantage from the point of view of policy makers interested in maximising the share of VREs in the electricity mix.

The question of capital subsidies either substituting or complementing long-term price support has recently gained new relevance in discussions about nuclear new build. At least two of the potential investors in nuclear new build in the United Kingdom announced in 2018 that their investment decisions would depend on some form of capital support, whether in the form of government taking a sizeable share in the project, loan guarantees or both. Capital cost support has, of course, a long tradition in the nuclear field in the form of direct or indirect government loan guarantees. Direct loan guarantees work much like buying insurance at an advantageous price, while indirect loan guarantees come in the form of public ownership. Whether loan guarantees have been an appropriate form of administering support is a complex question which goes beyond the scope of this report. Let it just be said, that arguments for capital cost support in the construction of nuclear power plants have very little to do with maintaining the integrity of wholesale market operations, where nuclear as a baseload provider is a stable and predictable element of the merit curve. Instead, it is due to the long lead times and the high technical and political risks involved in nuclear new build that capital support is an important element in the decision of any investor pondering participation in a nuclear construction project.

Efficient price support for low-carbon technologies through capacity auctions: Competition for the market rather than in the market

The alternative to providing direct financial support for capital expenditures is to remunerate output with guaranteed prices that reflect average rather than marginal costs. As mentioned, these include feed-in tariffs (FITs), feed-in premiums (FIPs), production tax or zero emission credits (PTCs or ZECs), CFDs, long-term supply contracts or regulated tariffs. While FITs, CFDs, long-term supply contracts or regulated guarantee prices independent of developments in the wholesale market, FIPs, ZECs or PTCs enhance them.

Providing long-term price guarantees does not automatically imply the provision of a subsidy or even the absence of competition. A well-regarded model is the attribution of long-term supply contracts for specific technologies by means of a descending auction. Auctions must specify the "type" of electricity the system operator requires (baseload, peak load, response time, availability etc.). The auctioneer then lowers the price in each round until he only receives bids for the required amount of capacity at the lowest proposed price. Presumably, these will be the most efficient companies. The basic model has been pioneered in the Brazilian electricity sector and was more recently adopted in Germany and in the United Kingdom to contract renewables capacity. It is becoming the model of choice for the allocation of contracts for offshore wind capacity.

This is a process that can be compared to competition on the basis of average costs. The important point is, of course, that such long-term price guarantees must be available to all low-carbon technologies and not just a subset thereof. Depending on the amount of capacity contracted by the regulator, the "missing money" problem is also elegantly solved through such long-term contracts. Most importantly however, auctions remove the suspicion attached to standard fixed-price arrangements that they overpay for the provision of low-carbon electricity. Early feed-in tariff schemes, especially for investors at the household level, were indeed generous when compared with the market costs of solar PV panels – in particular in European countries such as Germany, Italy or Spain. The CFD of GBP 92.50 per MWh attributed to the new Hinkley Point C nuclear power plant to be built by French utility EDF in the United Kingdom, which was also attributed without a competitive tendering process, has come in for similar criticism. With competitive tendering, the argument that providing fixed-price remuneration constitutes a subsidy is much harder to sustain.

The absence of auctions instead has lead at times to over-compensation, akin to a subsidy, due to misinformation or regulatory capture. Appropriate auction mechanisms can squeeze this overt subsidy element quite satisfactorily by appropriate auction mechanisms. Nevertheless, the provision of long-term fixed-price contracts, even if allocated by competitive auction has some drawbacks of its own. These drawbacks are more than outweighed by the need to rebalance the playing field for capital-intensive low-carbon technologies, which are otherwise disadvantaged in deregulated electricity markets; they must nevertheless be clearly understood.

First, it is no longer obvious to which extent dispatch is efficiently provided at marginal cost by operators, who have already received remuneration for their average costs through the long-term contract. In this situation, the privately rational decision is to produce flat out independent of whether this is the socially optimal choice. If short-run marginal costs are truly zero, as for wind and solar PV plants under certain system constellations, private and social optimality coincide. This, however, no longer holds when VRE cover the totality of demand and thus impose additional ramp costs on dispatchable operators. That these costs are real can be seen through the far from anecdotic phenomenon of negative electricity prices, which indicate a situation, in which it is cheaper to pay consumers to take off output rather than to shut down a plant for a small number of hours. Detailed regulatory requirements to curtail VRE generation during certain hours are another expression of the fact that producing electricity all-out for producers receiving guaranteed prices can pose some issues at the system level. A conceptually even more challenging situation, which currently does not yet exist in practice, might arise if technologies with positive variable costs such as nuclear would receive fixed prices for output and technologies with lower variable costs such as renewables would not. In such cases, complex rules for priority dispatch would need to be defined.

Second, while the argument in favour of average cost pricing for low-carbon technologies is overwhelming, there is no doubt that the latter constitutes a divergence from the principle that markets rather than governments should choose the level of capacity as well as the technology mix. Whatever the mechanism chosen, decisions on the level of capacity and investment, as well as the share of low-carbon technologies, will once again be decided upon by a centralised authority. Perhaps this is what governments and voters want. To a significant extent, capacity auctions constitute an updated return to a past of regulated tariffs. As it happens, regulated markets provide precisely the price and revenue stability, which low-carbon technologies require. This may not be a bad thing, as long as the process takes place transparently and fairly and that it is understood that also regulation was not a panacea. After all, the wave of liberalisation in the 1980s and 1990s had been fuelled by very real frustrations with the then existing system of regulation. It had also been promoted by the advent of the combined cycle gas turbine. More than 30 years later, technologies and policy priorities have changed. This just to say that electricity market design is not a field appropriate for ideological grand-standing. Any market design needs to be decided upon after a careful assessment of benefits and costs.

FITs vs. FIPs: Focusing on investment or on system value?

The previous section has essentially focused on the competitive allocation of long-term contacts such as FITs or CFDs. Auctions, however, can also be used to allocate top-ups to existing market prices, so-called feed-in premiums (FIPs). Production tax credits (PTCs) or zero emission credits (ZECs), which constitute the instruments of choice in the United States to support low-carbon technologies, fulfil, in principle, an identical economic function as FIPs. In practice, however, their level is usually determined by regulatory fiat, whereas the level of FIPs is more and more determined by competitive auctions. Top-ups such as FIPs, ZECs or PTCs have the advantage over fixed-price contracts such as FITs inasmuch that they allow wholesale electricity markets with marginal cost pricing to remain the key reference for dispatch decisions, as they allot a fixed supplement to low-carbon technologies for each MWh that they produce.

The fact that wholesale market prices would still steer dispatch and investment is particularly important in electricity systems with large shares of variable renewables. Assessing the comparative impact of FIPs and FITs goes to the heart of the functioning of the electricity system. FIPs distort the functioning a system less than FITs. For instance, it is easy to see that renewable producers with zero short marginal costs will provide power during periods of negative prices only up to the level of the feed-in premium rather than up to the level of the feed-in tariff, which is considerably higher. However, the real value of feed-in premiums lies in the fact that they allow wholesale market prices to reflect the real-system value of different technology options. This is particularly important for variable renewables. The following example might help to illustrate this point.

Consider two competing low-carbon technologies that are eligible for FIPs and that both have the same LCOE. The first technology, perhaps solar PV, concentrates its output during a few hours of the day, the second technology, such as nuclear, produces around the clock. Due to the correlation of the generation of the solar PV plant with the generation of all other solar PV plants, it is likely to produce during hours when electricity prices are comparatively low and more electricity is barely needed. In other words, the system value of its output is comparatively low and it will earn less than the average electricity price. The nuclear plant instead will produce around the clock and earn the average price. This is the normal working of the market.

FIPs come in when the regulator or the system operator call for a given amount of low-carbon capacity to be deployed and ask generators to participate in a competitive tender to see which technology is willing to content itself with the lowest possible FIP, i.e. the lowest possible top-up to wholesale market prices. Staying with this example, the nuclear plant would be able to satisfy itself with a lower FIP to cover its LCOE as the average market price already covers a substantial share of it. The solar PV plant would require higher FIP even though its LCOE is the same, since the prices it earns on the market are lower. In this case, thus the nuclear plant would be retained.

This is the theory. In practice, variable renewable technologies such as solar PV have competed against other renewable technologies such as onshore wind rather than against nuclear power (see for instance the design of the Mexican energy auctions introduced in 2017). Due to the large size and special features of nuclear power, CFDs in the United Kingdom or construction work in progress (CWIP) tariffs in the United States have been allocated on a case-by-case basis rather than through competitive auctions for FITs or FIPs. Of course, the high system value of the electricity provided by dispatchable baseload producers such as nuclear power is recognised in these arrangements. In fact, the difference between a FIT or a FIP for a baseload provider with high load factor such as nuclear relates only to the extent to which expectations about average prices can be locked in. The distinction is vital instead for variable renewables for which generation is clustered during a limited number of high load hours.

In fact, where comparable technologies with different load profiles compete against each other, FIPs have the advantage over FITs of reflecting system value. However, they also have two major disadvantages. The first one is that producers, and to some extent regulators, like the simplicity of FITs. A fixed price for each MWh produced for the next 20 years is a straightforward proposition that every investor understands appreciates. With a FIP, only the top-up will be fixed while total revenues will still depend also on variable electricity prices.

The recent experience of OECD countries shows that the introduction of VRE, as well as decentralisation of electricity generation and consumption, can lead to great uncertainty concerning the level and volatility of electricity prices. This uncertainty will increase the level of the FIP required by generators. In other words, in order to obtain the same leverage in incentivising low-carbon investment, the level of a FIT could be *ceteris paribus* somewhat lower than the sum of a FIP and average expected market prices, with a corresponding benefit for consumers. Of course this effect is offset by the fact that the technologies that are coming through with FIPs, rather than with, say, technology-neutral auctions for FITs, have a higher system value. Ultimately, the choice between FITs and FIPs comes down to the question whether policy makers want to maximise the amount of low-carbon capacity in terms of GW or whether they want to maximise the contribution of low-carbon sources to the electricity supply.

The second disadvantage of FIPs, ZECs or PTCs does not concern economic efficiency but sustainability in terms of political economy. FIPs make the top-up element that is potentially contained in all out-of-market instruments explicit and obvious to see. FITs, CFDs or PPAs can be considered sensible alternative instruments to finance low-carbon technologies with high fixed costs. As has been argued earlier, financing of the latter is far more likely to be forthcoming in a framework based on average cost financing rather than on marginal cost financing – in particular, when competing with gas-fired power plants with far lower fixed costs.

FIPs by working inside the existing wholesale electricity market take a position that is less clear-cut. To some extent, they thus accept the verdict of the market but nevertheless try to (a) internalise the positive externalities of low-carbon technologies and (b) overcome their intrinsic disadvantages in markets with marginal cost pricing. The inability of electricity markets to provide a reliable price signal for long-term investment is here akin to a market failure. It is due to the difficulties of storing electricity as well as the widespread consideration of it as a merit good which motivates a string of strong government interventions. Independent of their intrinsic merit, the double nature of FIPs makes criticism of subsidy provision more likely. From a conceptual point of view the question of whether FIPs or FITs constitute subsidies, i.e. deviations from economic efficiency, is not as clear-cut as it may seem. Both, the internalisation of positive externalities and the correction of market failures increase rather than reduce economic efficiency.

In terms of providing incentives for investment in low-carbon technologies, FIPs work to some extent similarly to carbon pricing by driving a wedge between the profitability of low-carbon and fossil fuel-based producers. In both cases, electricity consumers will pay more for an electricity supply with lower levels of carbon emissions. However, the dynamics, the impacts on the security of supply and the distributional implications are different. In terms of dynamics, a carbon tax would first need to drive out a share of existing high carbon producers and then let scarcity hours and VOLL pricing raise average prices and make investment attractive for nuclear and VRE. With a FIP, investment conditions are more attractive from day

one of its introduction. In terms of the security of electricity supply, FIPs can thus be thought of as providing the missing money to cover demand at all times even during hours of peak demand. This is a service that would be provided in particular by dispatchable low-carbon technologies such as nuclear and hydro.

In distributional terms, FIPs can be thought of as somewhat similar to carbon permit trading with grandfathering, as both arrangements provide additional rents on top of the original wholesale market prices to the operators of low-carbon generators. These rents are paid for in both cases by electricity consumers, either directly through higher prices (carbon permits) or an increase in network and system charges (FIPs). Of course, as mentioned, carbon permits with grandfathering also provide rents to fossil fuel producers, even though they push them down the merit order. Depending on wider-reaching distributional considerations and objectives for the speed of the transition, governments can thus choose one or the other. Needless to say, the two instruments can also be combined. In this case, however, the severity of the carbon constraint will determine the amount of the FIP demanded by low-carbon operators. The stronger the constraint the higher will be electricity prices and the less generous the extra fillip provided by FIPs will need to be.

Whether through FIPs or by direct capital support for the healthy functioning of low-carbon electricity it is vital that low-carbon technologies are supported by instruments that transmit the value of the electricity supplied back to the generator and thus fairly value its contribution to a reliable electricity supply.

4.6. The implications of measuring and internalising system costs for nuclear power: a new NEA project to operationalise the notion of system costs in national energy planning

Nuclear energy is a long-term endeavour in a rapidly changing electricity world. The decision on whether to build new nuclear power plants or to prolong and replace existing ones depends crucially on a clear perception of the needs and constraints of the electric power sector in the coming decades. It is the role of the NEA to assist policy makers in developing a coherent view of the expectations that nuclear energy as a provider of low-carbon electricity will have to meet in tomorrow's power markets. These markets are currently restructuring in response to the large-scale deployment of renewable energies. The latter have enjoyed strong support from both public opinion and governments but are often more expensive and impose a number of additional constraints on the energy system as a whole. In particular, as long as inexpensive storage remains elusive, meeting ambitious emission reduction targets will require deploying dispatchable low-carbon technologies such as nuclear or hydroelectricity alongside variable renewable technologies such as wind and solar PV. It may also require nuclear power plants to participate in the provision of long-term and short-term flexibility and to operate at lower load factors than is the case today.

In this situation, the NEA launched in 2012 an innovative programme to study system costs and the impact of changes in the electricity system on nuclear power. System cost modelling as undertaken by the NEA allows determining the least-cost generation mix and the optimal share of nuclear energy in function of different CO_2 emission reduction and renewable targets. It can also assess the short-term and long-term impacts of different policies on the overall generation mix. The NEA is now making its modelling capability available to interested member countries. While the methodology is general, results will depend strongly on the specific situation of each individual member country.

The great majority of NEA and OECD countries are pursuing ambitious targets in terms of both greenhouse gas emission reductions and the deployment of renewable energy sources – in particular wind and solar PV. These efforts are profoundly reconfiguring the long-term structure of their electricity systems. The variability of the electricity generated by wind and solar PV reduces the working hours of existing plants, mainly nuclear, coal, gas or hydroelectricity, and requires considerably more flexibility ("ramping") from the remainder of the system.

In many OECD countries the rapid deployment of large shares of intermittent solar PV and wind capacity has had a profound impact on the electricity markets, on the value of existing assets and on the profitability of utilities in the short run. In the long run, these pressures will imply a shift from high fixed cost technologies such as nuclear to low fixed cost technologies such as gas turbines. Other things being equal, this would not only increase the total costs of the system but might also increase overall greenhouse gas emissions as nuclear power is substituted by a mix of variable renewables (VRE) and gas-fired power generation. Of course, a robust carbon constraint that is added to the renewables target, whether in the form of a tax, a per-unit emissions limit or an overall quantitative limit, would counteract such a tendency and result in a genuine low-carbon mix constituted mainly by nuclear and VRE. However, even in this case, the variability of VRE generation would force both the operating costs (due to increased ramping and greater reserve and balancing requirements) and the capital costs (due to the profile costs of VRE) of the system as a whole to *increase*.

The presence of a significant share of intermittent resources in the system and the need for new sources of flexibility make the analysis of the electricity system significantly more complex and require the use of advanced modelling tools. Assessing the cost and performance of electricity system as well as the impact and effectiveness of policy measures in the short- and in the long run also requires knowledge and data about a number of country-specific conditions: the endowment of hydroelectric resources, interconnections with neighbouring countries, the development of storage capacity and demand-side response, as well as the generation profile of VRE and its correlation with demand. One corollary of VRE development is the rapid phase-out of coal-fired capacity. To which extent coal is substituted by nuclear or gas depends primarily on the strength of the carbon constraint as well as on the cost and performance of nuclear power plants.

Policy makers are in this context confronted with a number of questions that are difficult to answer without the help of integrated energy system modelling. The most important questions usually are:

- What is the cost of attaining different VRE and carbon targets, either individually or jointly?
- What is the impact of these targets on different technologies, in particular nuclear, and on the overall mix? What will be the load factor for nuclear power and other dispatchable plants?
- To which extent does both the market value generated by a MW of VRE and its contribution to covering demand (capacity credit) decline as the share of VRE in the electricity mix increases?
- What will be the role of storage as well as voluntary and involuntary demand response?
- What is the level and volatility of electricity prices, including hours with zero or negative prices?
- What will be the key inflections points, and the resulting capacity mixes, that define the trajectories running from the current situation to new equilibria?

During the preparation of its studies on the system costs of electricity systems with large shares of renewable energy, the NEA has acquired considerable capability in framing the pertinent policy question, assembling the modelling tools and data as well as preparing methodologically sound and politically relevant answers. The co-operation between NEA and a team of researchers affiliated with MIT in the preparation of the present study has clarified a large number of methodological questions.

In this situation, the NEA is developing a new tool to assist its member countries and other OECD countries in assessing their policy options in the electricity sector. Integrated electricity sector models based on the linear optimisation software GAMS are the tool of choice to model an hourly resolution of annual electricity generation meeting a given demand curve. This type of model resolves jointly for short-term dispatch and for long-term investment in order to establish the optimal least-cost mix given initial conditions, country-specific costs as well as the VRE and CO_2 constraints. The true added value of a the NEA model, named NEA-SC3, lies in

the ability to employ these heavy and sophisticated structures in a manner that allows framing and answering policy-relevant questions on the basis of a well-established methodology and a consistent set of reliable data or on policy-relevant assumptions about future developments.

Based on the framework for analysis developed in this study, the collaboration with member countries offers the perspective to contrast and compare the results presented in particular in Chapter 3 with country-specific results. This will further contribute to the understanding of the implications for the overall costs at the level of the electricity system of different technology choices under stringent CO_2 emission constraints.

4.7. Conclusion: The five pillars of sustainable low-carbon electricity markets

The preceding sections assessed the different solutions that exist to ensure sustained investment in low-carbon technologies such as nuclear energy, VRE and hydroelectricity and to radically decarbonise the electricity sectors of OECD countries. Such solutions must give adequate consideration to environmental performance but also to the reliability and dispatchability of different generation technologies in order to continue to guarantee the security of supply. On their own, the electricity systems of OECD countries relying on deregulated wholesale markets to ensure adequate investments are currently experiencing great stress in meeting the twin objectives of rapid decarbonisation and adequate investment in low-carbon technologies. This is due to a mix of structural issues such as the relative disadvantage experienced by technologies with high fixed costs, the lack of robust and reliable carbon prices, and the out-of-market financing of large amounts of variable renewables without an adequate assessment of the impacts this will bring on the remainder of the electricity system.

These shortcomings have made the progressive re-regulation a distinct option for the future evolution of the electricity sectors of OECD countries. The risk is that this return of the pendulum happens in a similarly haphazard and short-sighted manner as the original deregulation and subsequent out-of-market interventions. There is an alternative. The results of the foregoing analysis allow to be drawn up a blueprint for the design of sustainable low-carbon electricity markets based on five distinct pillars: 1) the continuing working of short-term markets for efficient dispatch based on variable costs; 2) carbon pricing; 3) frameworks for the adequate provision of capacity, flexibility and infrastructures for T&D; 4) appropriate mechanisms to foster long-term investment in low-carbon technologies, including the reform of existing support mechanisms; and 5) the internalisation of system costs wherever practical and necessary. The following paragraphs will briefly summarise the key characteristics of each pillar.

(1) Competitive short-term electricity markets for efficient dispatch: the deregulation of electricity markets did not get everything wrong. Even if there is widespread agreement that deregulated electricity markets have not provided on their own sufficient incentives for investment in low-carbon technologies, there is also recognition that they have been good at using existing assets efficiently. Marginal cost pricing based on short-term variable costs is not ideal to incentivise the construction of technologies with capital costs, it is however the appropriate mechanism to receive a MWh of electricity at the lowest possible costs at any given moment. Recognising this dichotomy implies combining markets for short-term dispatch with explicit mechanisms to foster investment in low-carbon technologies.

The question is to what extent competitive short-term markets can deal with extended periods of zero, or even negative prices. It is obvious that such low price episodes are very detrimental to investment incentives. However, somewhat contrary to intuition, in competitive markets very low or zero wholesale prices are only an expression for the fact that it is cheaper to let generation plants run rather to ramp them down. They are not per se a sign of malfunction. Even in markets where VRE are deployed only up to the economically optimal level, i.e. without out-of-market support, one might observe zero prices, albeit during a relatively small numbers of hours. The price duration curves for Scenario VI are a case a point. It is also to be expected that with the development of flexibility options, storage, demand response or more flexible dispatchable plants, their costs will fall and negative prices will become ever rarer events.

(2) Carbon pricing: the first-best solution for decarbonisation is internalising the carbon externality though appropriately set carbon taxes or emission trading systems. In principle this means sticking with deregulated electricity markets add the carbon price and let the price mechanism do its work. Doubts about the long-term political sustainability of robust carbon taxes as well as the influence of fossil fuel-based generators and their stakeholders have over political decision-making have made effective carbon pricing the exception rather than the rule in OECD countries. Where introduced, such as with the carbon price floor in the United Kingdom, it has been effective in contributing to decarbonisation. Even beyond distributional considerations, carbon pricing does not directly tackle the main challenge of investing in low-carbon generation, which remains high capital intensity and thus vulnerability to changes in electricity prices. In theory, of course, higher carbon prices would eventually feed through into high, more stable electricity prices and more low-carbon investment. In practice it may take a long time for investors to gain confidence that things have definitely changed and complementary measures could substantially accelerate the process (see pillar 4). Independent of detailed efficiency considerations, a credible carbon price is a powerful signal to producers, consumers and stakeholders such as to suppliers concerning the long-term evolution of the electricity system.

(3) Frameworks for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution: generation is at the heart of any electricity system but it is ultimately just a part of it. Any electricity system requires frameworks for the provision of capacity, flexibility, system services and adequate physical infrastructures. This has always held true in every system. However, the variability of VREs and new technological developments make these complementary services increasingly important. CRMs can complement the revenues of dispatchable operators. Flexibility can be provided on short-term balancing and reserve markets either through decentralised trading or through centralised auctions organised by the system operators. Transmission and distribution infrastructure is financed through network charges as negotiated between the regulator and transmission and distribution system operators (TSOs and DSOs).

So far, so good. However technological and behavioural changes such as the digitalisation of network management, batteries and DSM as well as, in some cases, decentralising generation and consumption makes for an ever more complex equation to be solved. Tweaking network performance or increasing interconnections between systems can provide flexibility; storage and localised generation might substitute for additional network investment; co-ordinating local supply and demand equilibria with the national and regional equilibrium is becoming an increasing challenge. It is important for large centralised units such as nuclear power plants or hydroelectric dams, which provide a number of very useful services to the system as a whole, to remain part of this quickly developing landscape in order to ensure that their contribution to overall system performance is maximised, adequately recognised and properly remunerated.

(4) Fostering long-term investment in low-carbon technologies: the challenge shared by all low-carbon technologies to obtain appropriate financing for investment based on wholesale market prices alone requires specific solutions. On their own, neither carbon pricing nor capacity remuneration for dispatchable low-carbon providers will suffice, even though they constitute, in principle, the appropriate instruments for internalising the external effects relating to the public goods of climate protection and security of supply. Carbon pricing for one poses limits in terms of political economy and immediacy of impact. CRMs, for all their usefulness, will have prices set by capacity providers that have comparatively low fixed capacity costs. These are either gas engines or diesel generators. If environmental considerations or sufficiently high carbon prices would preclude these options, DSM is likely to take their place. In either case, the top-up which would go to all capacity providers at peak hours would be very valuable for any nuclear operator. It would however not be sufficient to overcome the challenge of financing the construction of a new nuclear power plant. It should be noted that in several US states the continuing operation of several existing nuclear power plants is only ensured by the capacity payments they receive.

New investment in low-carbon generation therefore requires added mechanisms to provide the certainty required by investors in capital-intensive low-carbon projects. Direct public support for capacity investment is the most straightforward instrument to ensure this but was

long considered incompatible with a broader free-market policy stance. Interestingly, the option of direct government involvement in new build projects has very recently been raised in the context of the UK's nuclear programme. While it is too soon to tell whether this constitutes a successful strategy on a broader scale, it is an interesting development to monitor.

This has left FITs, FIPs, PPAs, CFDs or regulated electricity tariffs as the preferred instruments for financing low-carbon investments. Despite their specific differences, advantages and shortcomings that have been discussed above, they share the central characteristic of constituting a long-term contract guaranteeing a price corresponding to average rather than to marginal costs. This does not necessarily imply a subsidy scheme based on bureaucratic guesswork. Competitive auctions can substitute competition *in* the market with competition *for* the market. However such long-term supply agreements should not shield producers from market price signals. Any *ex ante* cost estimates that form the basis for the capacity requests by system operators must thus include estimates of the system costs and the system value of different generation options.[22]

(5) Internalising system costs: to some extent, the system costs of VREs will be internalised implicitly through the appropriately designed previous four pillars and will not always require explicit and separate action. Carbon pricing will recognise the environmental attributes of low-carbon generation, while capacity remuneration will recognise dispatchability. Appropriately formulated grid codes can take care of balancing requirements. As explained above, appropriate support mechanisms for investment in low-carbon technologies will also allow for the internalisation of profile costs through the market mechanism to the extent that it reflects the correct system value of different VRE technologies.

There exist, however, social costs of VRE that are not indirectly internalised, such as the costs of the reinforcement of T&D networks, or the costs of connection. Due to their decentralised nature, low power density and dependence on favourable natural conditions, the costs for these items tend to be higher for VREs than for other sources of generation. Large generators with steam or hydroelectric turbines also provide inertia to the system as a whole as a positive externality. In the recent past, the political economy of electricity market design in OECD countries has frequently favoured the socialisation of system costs rather than their explicit allocation. In other words, added costs were directly added to consumer bills without apportioning them to renewable producers, which might have affected their competitiveness in the market place.

One needs to be pragmatic here. While the explicit allocation of costs, including all environmental, system and infrastructure costs constitutes a first-best benchmark, it is not always easily attainable. Precisely allocating increased costs for T&D networks to different producers or even different technologies is difficult, uncertain and hence contentious. Socialisation, even if unsatisfactory from a purely theoretical point of view, does make some sense for grid infrastructure costs when taking transaction costs into account. This is different in the case of connection costs which, by their very nature, can be clearly attributed to specific projects, VRE or others. In the name of cost transparency, such costs should always be fully borne by developers. This is already the case in some OECD countries such as France, but not in others, such as Germany.

The internalisation of the system costs of VRE remains thus one of the five pillars for the design of sustainable low-carbon electricity markets. It will, however, need to be pursued in a pragmatic manner that combines indirect allocation, reform of support mechanisms, socialisation and direct allocation. If this sounds complicated, one may reformulate it in the following manner: a larger share of internalisation will need to be reflected in the design of existing or new incentives and a smaller share will need to borne, for pragmatic reasons, as a social cost. Of course, any such efforts will need to be accompanied by an ongoing frank and transparent assessment of all system costs.

22. The recent *Cost of Energy Review* by Dieter Helm (2017) for the UK Department for Business, Energy and Industrial Strategy (BEIS) develops the concept of equivalent firm power (EFP), which is essentially an LCOE adjusted for profile costs, to obtain a like for like system value for each pound spent (Helm, 2017: 47).

Together these five pillars form the basic structure of a sustainable design for low-carbon electricity markets allowing for the productive co-existence and competition between VRE, hydroelectricity and nuclear energy that will yield deeply decarbonised electricity systems at least cost and high levels of security of supply.

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Chapter 5. **Conclusions**

Decarbonising the energy system to achieve the climate goals set by the Paris Agreement represents an enormous challenge for OECD countries. To reach these targets by 2040, the carbon intensity of the electric power sector will have to be reduced to roughly 50 gCO_2 per kWh, an eighth of current levels. This requires a rapid and radical transformation of the power system with the deployment of low-carbon emitting technologies such as nuclear, hydroelectricity and variable renewables (VRE). In the absence of mechanisms to capture and store the CO_2, this will also mean phasing out coal and strictly limiting the use of gas-fired power. Given the massive investments that the realisation of this transformation requires, it is of paramount importance to create long-term frameworks that provide stability and confidence for investors in all power generation technologies.

The great majority of OECD countries are currently pursuing ambitious targets for the share of electricity produced by VRE, in particular wind and solar photovoltaic (PV), as the principal strategy towards achieving a decarbonised electricity system. However, the rapid deployment of large amounts of VRE capacity had profound and largely unforeseen consequences on electricity prices, the value of existing assets and on the profitability of incumbent power companies. This has massively impacted the ability of generators to undertake the necessary investments to implement the radical transformation of the power system that deep decarbonisation requires. The impacts on the power system are likely to be even more significant in the long term, and need to be monitored and understood by governments and policy makers. In 2012, the first OECD Nuclear Energy Agency (NEA) study on the integration of nuclear and renewable energy has contributed to frame the issue of system effects, to develop a coherent methodology for their calculation and has provided the first quantitative estimates in some OECD countries. Since then a significant amount of new research on the topic of system effects has been undertaken by academia, industry and governmental agencies. This study builds upon new studies and new information available and hopes to broaden further the knowledge on this topic.

Key messages of this study

The present study has analysed several scenarios of deep decarbonisation, characterised by different shares of variable renewables, hydroelectric power and nuclear in a large, well-interconnected system, which is representative of that of several OECD member countries. The objective is to provide a cost comparison of different "snapshots" of the possible long-term generation mixes that would meet the carbon emission target of 50 g/kWh. The analysis of these scenarios provides a powerful approach for identifying and highlighting the potential technical and economic challenges of moving towards a low-carbon generation system. Based on the understanding of the challenges, the study also presents an overview of the key policy drivers and tools that could ensure that the electricity systems of OECD countries radically reduce their carbon emissions.

With the exception of hydroelectric resources, which are exogenously given in all scenarios, this study considers the electricity system as a greenfield: the composition of the generation mix and the hourly dispatch of individual plants are optimised to meet the electricity demand at a minimal cost, assuming a perfect foresight of the future demand and renewable electricity source (RES) generation. This choice provides a picture of the generation mix in 2050 and allows for a comparison of different low-carbon technologies and

decarbonisation strategies. The economic assumptions and technical characteristics of the main generating technologies, storage options and demand-side measures reflect the International Energy Agency (IEA)/NEA projections in OECD countries for 2020 as well as estimates from a series of additional sources. Based on the cost assumptions used in the main scenarios of this study, results show that a mix relying primarily on nuclear energy is the most cost-effective option to achieve the decarbonisation target of 50 gCO_2 per kWh. In addition, costs rise over-proportionally with the share of VRE in the system. However, these results reflect current best estimates. In particular, a further decline in the costs of VRE generation technologies, as modelled in Scenario VI, "Cost minimisation with low-cost renewables", would lead to an integrated system with sizeable shares of both nuclear and VRE.

Increasing deployment of VRE capacity has a major impact on the shape, variability and predictability of the residual load, i.e. the load that needs to be covered by conventional, dispatchable generators. Under the stringent carbon constraint of 50 gCO_2 per kWh that is adopted in all the scenarios of this study, results show that coal is no longer deployed in any of the scenarios under consideration although it is cheaper than all other generation technologies on a pure cost basis. The overall share of low-carbon technologies, nuclear (hydro and VRE) remains almost constant in all scenarios. In terms of the electricity generation mix, the principal phenomenon observed is that with more ambitious renewable energy targets, VRE generation replaces nuclear power on an almost one-to-one basis. It should be noted that the share of VRE in the electricity mix is an exogenous constraint imposed in all of the eight different scenarios studied in this report, except the last. In other words, while the share of VRE is fixed *ex ante* in seven of the eight scenarios, the sum of VRE and nuclear is determined by economic optimisation in function of the overall carbon emissions objective.

In function of the predetermined share of VRE, total generation capacity increases markedly; in comparison with the base case, the installed capacity more than doubles in the scenario with 50% VRE generation and trebles in the scenario with 75% VRE generation. This reflects not only the lower load factor achievable by VRE compared to dispatchable baseload plants, but also an increasing curtailment of VRE generation and their low capacity credit, especially at higher generation share. As far as fossil fuel-based generation is concerned, the increasing penetration of variable wind and solar PV, forces a shift from relatively efficient combined cycle gas turbines (CCGT) to open cycle gas turbines (OCGT), which are less efficient but more flexible and have lower capital costs. This is due to the fact that increasing flexibility requirements and reduced load factors favour the deployment of the less capital-intensive dispatchable power plants to satisfy residual load. This change from more efficient plants working a high number of hours to less efficient plants working less hours but having lower capital costs typically raises the profile costs and the total system costs of the high VRE scenarios.

The mode of operation and the flexibility requirements from thermal plants depend strongly upon the penetration level of VRE sought. With a growing share of VRE imposed on the generation mix, conventional thermal plants are likely to undergo more frequent ramping and operate at lower load factors. For instance, the average load factor of CCGTs is 25% lower in the scenario dominated by VREs than in the base case scenario, which relies only in dispatchable low-carbon technologies. In particular, the mode of operation of nuclear power plants is severely affected: significant flexibility is required from NPPs when the VRE generation share exceeds 30%, and modulation of nuclear generation becomes more important, with a reduction on their load factors achievable. Achieving more ambitious renewable targets, however, implies that VRE must also be curtailed more frequently. Curtailment of VRE generation thus appears at 30% penetration level and increases sharply with their increasing share. At 50% generation share, the curtailment rate of the marginal VRE unit deployed is above 10%. In the scenario featuring a 75% share of VRE generation, about 18% of the total VRE generation must be curtailed, and the curtailment rate of the last unit deployed is above 36%.

Under the cost assumptions of the present study, the generation mix which meets the electricity demand at a minimal cost relies mainly on dispatchable low-carbon generation technologies, such as nuclear power and hydroelectric power. An appropriate combination of these two technologies as well as of gas-fuelled power plants means meeting carbon emission targets with maximal economic efficiency. The cost of electricity generation increases with the share of VRE enforced in the system. While the additional costs are limited at low VRE

targets, they increase markedly at higher penetration levels; this reflects not only higher plant-level generation costs for VRE resources, but also additional challenges stemming from the deployment of additional VRE units into the generation mix and their decreasing value for the system. Modelling results indicate that electricity generation costs increase by 17% with respect to the base case scenario when a 30% VRE penetration is reached. Imposing higher VRE targets of 50% and 75% of the total electricity generation increases generation costs by 33% and by more than 70%, respectively. For a mid-sized country such as the one represented in this study, additional costs for electricity generation are in the range from a few to several tens of billion USD per year.

The analysis and discussion of the total costs for electricity provision, as presented above, is only a first step for policy analysts and needs to be complemented with other metrics. This is done by complementing the profile costs quantified in this study with an estimate of the other components of system costs taken from the literature. System costs calculated on the basis of an increase of the unit costs of VRE can be substantial and depend again on the level of penetration. At 10% of electricity generation the system cost of VRE are still limited at 7 USD/MWh_{VRE}. At 30% VRE penetration, total system costs more than double, up to 17.5 USD/MWh_{VRE}, and they reach 30 USD/MWh_{VRE} at 50% penetration. Higher deployment targets of VRE lead to system costs of 50 USD/MWh_{VRE}. These values need to be compared to the plant-level generation costs of VRE, which range, depending on the scenario, from USD 60 per MWh for onshore wind to up to USD 130 per MWh for solar PV. It should also be noted that the system costs are largely unaffected by any declines in plant-level costs as long as the share of VRE remains exogenously imposed. Indeed, all four components of system costs (balancing, profile, connection and grid costs) increase with the deployment of VRE resources, but at different rates. In particular, the rate of increase of profile costs is much larger than that of the other system cost components. It is vital to understand that the VREs' system costs depend strongly upon the country-specific characteristics of the system considered. Systems with lower flexible resources face more severe challenges to integrate VRE resources and higher costs of electricity generation. Assumptions concerning hydroelectricity and interconnections with neighbouring countries are crucial here. For instance, at 50% VRE penetration the total system costs almost double from 28 USD/MWh_{VRE} for the reference system to 48 USD/MWh_{VRE} for an isolated system without flexible hydroelectric resources.

Increasing profile costs with the VRE generation share and the consequent reduction of the value of VRE generation for the electricity system are reflected by increasingly lower prices received by solar PV and wind resources. The present study confirms that VRE revenues from electricity markets decline significantly and non-linearly as their penetration level increases, and this decrease is much steeper for solar PV than for wind. This is due to the auto-correlation of solar PV and wind resources, which tend to produce when other plants of the same type are also producing; this reduces the market value of electricity precisely when VREs are generating. Market revenues for solar PV are thus halved when a penetration rate of only 12.5% is reached. Adding solar PV capacity to reach a generation share of 17.5% again halves the market value of an MWh produced by solar PV to a value below 20 USD/MWh. A similar trend, although less pronounced, is observed for onshore wind which has a higher load factor than solar PV and whose generation profile is better distributed through time. These considerations raise serious questions concerning the optimal deployment level of VRE technologies and the long-term economic sustainability of the support mechanisms that are currently employed for their development.

The transition towards low-carbon systems has impacts that go beyond the technical and economic aspects discussed above. First, the system becomes more capital-intensive. Compared with the current mix in most OECD countries, where investment and variable costs each roughly represent 45% of the total lifetime costs, investments constitute a 60-70% share of the total costs in low-carbon scenarios, and variable costs are much lower. Second, volatility increases. One of the most striking effects of the deployment of low marginal cost variable resources on the electricity markets is the appearance of hours with zero prices and a substantial increase in the volatility of electricity prices. Zero-level electricity prices start appearing as VREs reach a penetration level of 30%. The number of occurrences increases dramatically with the deployment of VRE resources; at 50% generation share, more than 1 200 hours in a year feature zero-price levels, i.e. about 14% of the time. When VREs produce

75% of the demand, zero prices occur during 3 750 hours, i.e. more than 43% of the time. The higher frequency of hours with zero prices is compensated by an increase of the number of hours with high electricity prices. For instance, the number of hours in which electricity price is higher than USD 100 per MWh increases substantially when the generation share of VRE exceeds 30%. High volatility of electricity prices and the reliance on a limited number of hours with high or very high prices significantly increases the electricity market risk for all generation technologies. Higher market risk automatically increases the rate of return that is expected by investors and thus leads to higher capital costs. This threatens to reduce investment in power generation capacity with long-term risks for the security of supply. This reasoning is particularly relevant for low-carbon technologies such as VRE or nuclear power, which, due to their high capital intensity and long payback time, are more sensitive to long-term changes in the level of electricity prices as well as higher capital costs due to increased price volatility and risk.

Effective policy options as a key for decarbonising the electricity sector

What can policy makers do to achieve a deeply decarbonised electricity mix and foster vigorous investment in low-carbon technologies such as nuclear energy, VRE and hydroelectricity in the real world? The electricity systems of OECD countries relying on deregulated wholesale markets to ensure adequate investments are already experiencing great stress in advancing towards the twin objectives of rapid decarbonisation and adequate investment in low-carbon technologies. Responsible are, in particular, the relative disadvantages experienced by technologies with high fixed costs in a deregulated market with volatile prices, the lack of robust and reliable carbon prices, and the out-of-market financing of large amounts of variable renewables with little thought on the impacts on the remainder of the electricity system. These shortcomings have made progressive re-regulation a distinct option for the future evolution of the electricity sector of OECD countries.

The risk is that a full-fledged return to regulated systems would do more harm than good by losing the efficiency gains brought by liberalisation without a clear roadmap for the road ahead. The alternative is to move towards specific market designs for low-carbon generation based on five distinct pillars: 1) the continuing working of short-term markets for efficient dispatch and the revelation of the true system value of the electricity produced; 2) carbon pricing; 3) frameworks for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution (T&D); 4) appropriate mechanisms to foster long-term investment in low-carbon technologies, including the reform of existing support mechanisms; and 5) the internalisation of system costs wherever practical and necessary. While details of electricity market reform will require substantive expert discussion, it is important that policy makers understand the importance of these five pillars, which are required to maintain the appropriate equilibrium between short-term competitive pressures and long-term investment incentives for low-carbon generation.

First, maintain current short-term electricity markets for efficient dispatch. The deregulation of electricity markets did not get everything wrong. Even if there is widespread agreement that deregulated electricity markets have not provided on their own sufficient incentives for investment in low-carbon technologies, there is also recognition that they have succeeded in using existing assets efficiently. Marginal cost pricing based on short-term variable costs is not ideal to incentivise the construction of technologies with high capital costs, it is however the appropriate mechanism to ensure the optimal utilisation of existing resources, i.e. to produce a MWh of electricity at the lowest possible costs at any given moment and to expose generators to the discipline of market prices. Recognising this dichotomy implies combining markets for short-term dispatch with explicit mechanisms to foster investment in low-carbon technologies.

Second, work towards carbon pricing whatever are the institutional hurdles and lobbying efforts to prevent it. The leverage of fossil fuel-based generators and their stakeholders over political decision-making has made effective carbon pricing the exception rather than the rule in OECD countries. Where introduced, however, in countries such as Sweden or the

United Kingdom, it has been highly effective in driving decarbonisation. A credible carbon price is a powerful signal in order to shape the expectations of producers, consumers and other stakeholders such as suppliers concerning the long-term evolution of the electricity system. Carbon pricing will produce an overall gain for society. However, it will also produce losses for some stakeholders, in particular fossil fuel producers and their customers. Compensating them to some extent will need to be part of any politically sustainable package. The quantitative outcomes of this study support the conclusion that the most economically efficient way to achieve the carbon emission target is to impose a carbon price that limits the use of fossil-fuelled generation sources and allows the deployment of the most efficient low-carbon resources. Under a carbon price (or an equivalent carbon cap), all low-carbon resources can freely compete and are deployed at their optimal level into the system, thus maximising their private value as well as the value for the overall system.

Third, develop long-term frameworks for the adequate provision of capacity, flexibility and infrastructures for T&D; generation is at the heart of any electricity system but it is ultimately just a part of it. Any electricity system requires frameworks for the provision of capacity, flexibility, system services and adequate physical infrastructures. While this was always true, the variability of VREs and new technological developments make these complementary services increasingly important. Technological and behavioural changes such as the digitalisation of network management, batteries and demand-side management (DSM), as well as, in some cases, decentralising generation and consumption, makes for an ever more complex equation to be solved. Short-term markets for flexibility provision, balancing, increased interconnections with neighbouring countries and capacity remuneration mechanisms are all part of this. It is also important to recognise the positive contribution to system stability and inertia of large centralised units such as nuclear power plants or hydroelectric dams and to value them appropriately.

Fourth, create appropriate mechanisms for fostering long-term investment in low-carbon technologies. The high capital intensity of low-carbon technologies requires specific financing solutions. On their own, neither carbon pricing nor capacity remuneration for dispatchable low-carbon providers will suffice, although they constitute, in principle, the appropriate instruments for internalising the external effects relating to the public goods of climate protection and security of supply. Security of supply, however, has a double meaning here. On the one hand, it refers to the correct anticipation of long-term needs and the availability of adequate capacity for a variety of demand scenarios. On the other hand, it refers to the ability to provide electricity also during the rare hours of extreme peak demand, for instance cold snaps, in order to avoid blackouts and scarcity pricing. Dedicated capacity remuneration mechanisms (CRM) address the latter issue and will primarily cater to capacity providers that have comparatively low fixed capacity costs, usually OCGTs, since they are the only ones willing to invest when expected operating hours are in the double digits. While the top-up due to CRMs that would go to all capacity providers at peak hours would be valuable for any nuclear operator, it would not be sufficient to overcome the challenge of financing the construction of a new low-carbon capacity, whether nuclear energy, wind or solar PV.

This is why policy makers have to make tough decisions on striking the appropriate balance between out-of-market support and exposure to wholesale market prices for low-carbon technologies with high fixed costs. One the one hand, FITs, PPAs, CFDs, regulated electricity tariffs, FIPs or even direct capital subsidies through, for instance, loan guarantees are all appropriate instruments to achieve long-term security of supply with low-carbon technologies. FIPs or direct capital subsidies even maintain a link with wholesale market prices, which is important for efficient dispatch and value discovery. Even employing FITs and other instruments that share the central characteristic of a long-term contract guaranteeing a price corresponding to average cost need not mean abandoning competition altogether. Competitive auctions can substitute competition *in* the market with competition *for* the market.

In creating sustainable low-carbon electricity systems, all low-carbon technologies will need to play a part and they will not be deployed solely on the basis of marginal cost pricing in competitive markets. This is especially true for VREs, which themselves suffer most heavily from the lower prices they induce. Due to different lifetimes, risk profiles and financing structures, individual technologies will also continue to require dedicated, individually-

designed instruments, even though they all are based on the same principle that investment in high fixed cost technologies requires high levels of price and revenue stability. Such support becomes more indispensable, including for fossil fuel-based generators, in systems with significant shares of VRE supported by selective out-of-market mechanisms, as the latter drive a wedge between electricity generating costs and electricity prices. As the share of VRE increases, market revenues are increasingly insufficient to recuperate generation costs and complementary remuneration mechanisms are required to achieve the desired generation mix.

Fifth, internalise system costs, where the previous four pillars have not already done so. Carbon pricing will recognise the environmental attributes of low-carbon generation, while capacity remuneration will recognise dispatchability. In principle, exposure to electricity prices would internalise profile costs, and remunerate each unit of electricity generated at its true value for the system. This theoretically sound principle, however, finds its limitation in the need for long-term price guarantees for low-carbon technologies mentioned above. The important thing is not to add implicit subsidisation to explicit subsidisation. Appropriately formulated grid codes can thus take care of balancing requirements, and connection costs can be easily allocated to each individual power unit. There exist, however, social costs of VRE that are not indirectly internalised, such as the costs of the reinforcement of T&D networks. Due to their decentralised nature, low power density and dependence on favourable natural conditions, the costs for these items tend to be higher for VREs than for other sources of generation. In the recent past, the political economy of electricity market design in OECD countries has frequently favoured the socialisation of system costs rather than their explicit allocation.

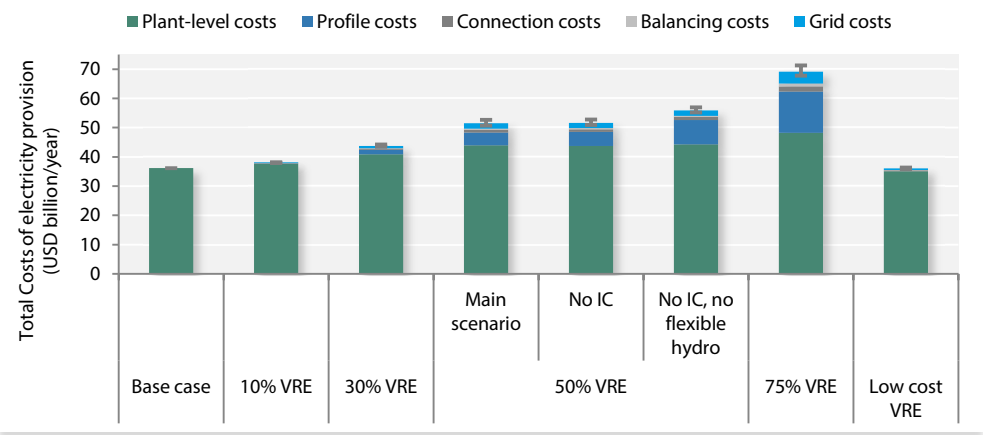
Together these five pillars form the basic structure of a design for low-carbon electricity markets allowing for the optimised co-existence among VRE, hydroelectricity and nuclear energy within an effective integrated electricity system that will yield deeply decarbonised electricity systems at least cost and high levels of security of supply, independent of individual cost assumptions or country-specific endowments. Even more importantly, these five pillars allow for the construction of market designs that will be sustainable in the sense that they enable the investments necessary for the large-scale deployment of low-carbon technologies required for the rapid and radical transformation of the power system.

It should also be emphasised that this framework does not depend on country preference for nuclear, hydro or VRE. This systematic exposition of the building blocks for the creation of cost-effective low-carbon electricity systems is thus entirely compatible with the earlier work by the International Energy Agency (IEA) on system market reform (see, for instance, IEA (2016), *Re-powering Markets: Market design and regulation during the transition to low-carbon power systems*, OECD, Paris). This NEA system cost study presents a general blueprint for what a low-carbon electricity system will look like. It will be up to different OECD countries to decide on the precise mix of nuclear and variable renewables in function of the trade-off between total costs of electricity provision, social and policy preferences.

Under the cost assumptions of this study, the most efficient manner to achieve the ambitious emission objective of 50 gCO_2 per kWh is to rely on nuclear power and hydroelectricity as dispatchable low-carbon generating sources rather than on wind and solar PV. In addition, the total costs of generation increase over-proportionally with the share of variable renewables, a fact for which Figure 74 below provides some insight. However, the development of variable renewable sources such as wind and solar PV is an autonomous policy objective only incidentally related to greenhouse gas emission reductions. The vigorous policies of most OECD countries to promote wind and solar PV, almost regardless of their short- and medium-term impact on carbon emissions (see also Figure 73), has generated a technology transition with a strong dynamic of cost reductions that is likely to continue in the coming years. While choosing the appropriate electricity generation mix is ultimately a political decision, analytical work such as this study indicates the technical and economic boundary conditions of the available options.

Figure 74. **Total electricity generation costs in function of the share of VRE**

(USD billion per year, common emission target of 50 gCO_2 per kWh)



This is the spirit of Scenario VI, "Cost minimisation with low-cost renewables". With overnight costs for wind and solar PV between one third and two thirds lower than in the base case scenarios, it supports the vision of a future electricity mix that is realistic for a broad range of OECD countries. Such a mix integrating both VRE and dispatchable technologies would be composed of four main pillars:

1. a share of 30-40% wind and solar PV;
2. a larger share of 40-60% provided by dispatchable low-carbon technologies such as nuclear or, perhaps fossil-fuelled plants with carbon capture and storage (CCS);
3. the maximum possible amount of low-carbon flexibility resources, including hydro, demand response and grid interconnection; and
4. a progressively decreasing share of highly flexible unabated fossil-fuelled technologies ensuring the availability of residual flexibility.

It should also be recalled that these results are based on a "greenfield" approach. This means the system is optimised without making any assumptions about the existing power generation mix. Taking literally this is, of course, a poor description of reality. At the same time, it greatly improves the transparency and readability of the modelling results, and thus their pertinence for policy making. One should also consider that a carbon emission objective of 50 gCO_2 per kWh automatically implies a long-term time frame for which the year 2050 provides a useful horizon. In the more than three decades until that deadline, the greatest part of the capital stock will turn over, which greatly reduces the relevance of the existing generation mix.

Similarly, one should keep in mind that this study pursues an economic approach to identifying least-cost solutions in a framework of static optimisation. Dynamic approaches plotting different transition pathways or focusing on build rates, construction times and the availability of natural and human resources would have produced different insights. No model can replicate the real world. Every modelling choice thus implies trade-offs. The present study has decided to focus on the transparency of the costs and a number of impacts on a carefully represented electricity system given different shares of VRE in the mix. The overarching objective here was policy relevance.

Between now and 2050, the implicit time horizon of this study, research and development efforts are also likely to reduce the overall cost of power generation. Technologies are likely to be both cheaper and more flexible. Further cost reductions for low-carbon technologies such as nuclear, possibly in the form of small modular reactors (SMRs), VREs and batteries are likely. Largely for intrinsic physical reasons CCS, for instance, is less likely to be a competitive option, even by 2050, but a decisive breakthrough cannot be excluded. The electricity sector is also likely to be more closely intertwined with other economic sectors due to cogeneration, power-to-gas, and the convergence with information and communication technologies.

This report does not claim that the options modelled, their technical performances and costs will be those eventually realised in 2050 and does not make any predictions about future technology developments. Its objective is to educate policy makers and the wider public about the intrinsic difficulties of achieving ambitious carbon emission reduction objectives with variable generation technologies alone. In this effort, the report did not include an analysis of the technical feasibility of power systems with high shares of VRE. Technical constraints such as ramp rates are minor at 10% of VRE, where gradients of more than 5 GW per hours are very rare. This can become very significant at higher shares: with 50% or 75% of VRE in the mix, gradients of up to 20 GW per hour will become necessary several times a week. Modelling such technical constraints with precision would, however, require a temporal resolution below the one-hour steps this model considers. The reader should thus keep in mind that depending on the fast-evolving offer of systems-integration technologies, technical feasibility may impose additional constraints.

Each of the above-mentioned qualifications is a call for further research. Fortunately, as indicated in Chapter 2, an increasingly well-structured research community is establishing meaningful conversations on many of these issues. More work is undoubtedly required and one of the objectives of this report is to draw the attention of policy makers to the need for sustained research funding in this area. The sums involved are, of course, a small fraction of the costs saved by making better informed policy decisions in the electricity sector.

As a first step, a broader range of electricity systems needs to be studied under sets of realistic country-specific assumptions. The NEA initiative presented in Section 4.6 aims to do this. A broader study would help to identify more precisely the key drivers of these complex electricity system models. This would also go some way to establish benchmarks for good modelling practices and thus further structure the ongoing research dialogue in this field. Other priority areas are research on technical constraints in the sub-hourly range as well as on the costs of expanding T&D grids. Alternatives to the long-term greenfield approach concerning the costs of achieving a given carbon target that is pursued in the present study will also need to be explored. Shorter-term transition scenarios, focusing on the very limited empirical impact of VRE deployment on emission reductions, in particular when coupled with fossil fuels to substitute for nuclear power, are of particular high policy interest in this context.

In practice, the choice of electricity market design and, in particular, the generation mix, is a matter of political choices at the national level. While there is a global effort under way to reduce greenhouse gas emissions and prevent dangerous climate change, specific outcomes will be the result of a broader mix of social and political criteria. Local and regional pollution, system costs, technical reliability and the long-term security of supply will all play into the decision-making process. A particular role in this process will be played by nuclear power. While it reliably provides large amounts of dispatchable, low-carbon power, it faces questions of social acceptability in a number of OECD countries. Nevertheless, this study shows how nuclear power still remains the economically optimal choice to satisfy stringent carbon constraints despite the economic challenges it faces during the changeover between different reactor generations. The reason for nuclear power's cost advantage is not in its plant-level costs. Instead, it resides in its overall costs to the electricity system. Variable renewables have reduced quite impressively their plant-level costs, but their overall costs to the system are not accounted for as their output is clustered in a limited number of high-level hours. All of these factors will come to play in the ultimate choices of each country.

Independent of their individual choices regarding the structure of their electricity mixes, OECD countries should move together to implement the five pillars for the design of low-carbon electricity systems set out above. Technologies and consumer behaviour will continue to change rapidly in the coming years. There is, however, a high likelihood that the orientations provided by these five pillars – competitive markets for short-term dispatch, carbon pricing, centralised mechanisms for infrastructure provision, long-term stability for investors in low-carbon capacity and the internalisation of system costs – will remain the appropriate reference for the design of low-carbon electricity systems in the decades to come.

Annex A. List of participants at the WPNE workshop

"Dealing with System Costs in Decarbonising Electricity Systems: Technical Analysis and Policy Options"

Michel Berthelemy	Commissariat à l'Énergie Atomique (CEA), France
Alain Burtin	Électricité de France (EDF), France
Steve Capanna	Department of Energy, United States
Matthew P. Crozat, Co-Chair	Nuclear Energy Institute, United States
Jean-Guy Devezeaux De Lavergne	Commissariat à l'Énergie Atomique (CEA), France
Fernando De Sisternes	Massachusetts Institute of Technology (MIT), United States
Ian Emsley	World Nuclear Association, United Kingdom
Dominique Finon	Centre International de Recherche (CIRED), France
Zbigniew Kubacki	Ministry of Economic Development, Poland
Manki Lee	KAERI, Korea
Yu Nagai	CRIEPI, Japan
Lara Pierpoint	Department of Energy, United States
Tatyana Rakitskaya	Rosatom, Russia
Nestor Sepulveda	MIT, United States
Manuel Villavicencio	Université Paris-Daphine, France
Alfred Voss, Co-Chair	Institute of Energy Economics and the Rational Use, Germany

IAEA

David Shropshire	IAEA

OECD

Marco Cometto	Division of Nuclear Technology Development and Economics, NEA
Jaejoo Ha	Division of Nuclear Technology Development and Economics, NEA
Jan Horst Keppler	Division of Nuclear Technology Development and Economics, NEA
Luis Munuera	Energy Technology Policy Division, IEA

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The Costs of Decarbonisation:

System Costs with High Shares of Nuclear and Renewables

Under the Paris Agreement, OECD countries agreed to aim for a reduction of their greenhouse gas emissions sufficient to hold the increase in the global average temperature to well below 2°C above pre industrial levels. This commitment requires a massive effort to decarbonise energy and electricity generation, a radical restructuring of the electric power sector and the rapid deployment of large amounts of low-carbon generation technologies, in particular nuclear energy and renewable energies such as wind and solar PV.

This study assesses the costs of alternative low-carbon electricity systems capable of achieving strict carbon emission reductions consistent with the aims of the Paris Agreement. It analyses several deep decarbonisation scenarios to reach the same stringent carbon emission target but characterised by different shares of variable renewable technologies, hydroelectric power and nuclear energy.

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