Projected Costs of Generating Electricity

2020 Edition

International Energy Agency

NEA
NUCLEAR ENERGY AGENCY

Projected Costs of Generating Electricity

2020 Edition

INTERNATIONAL ENERGY AGENCY
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– to provide authoritative assessments and to forge common understandings on key issues as input to government decisions on nuclear energy policy and to broader OECD analyses in areas such as energy and the sustainable development of low-carbon economies.

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Foreword

At a moment when the COVID-19 pandemic has not yet subsided, creating the appropriate frameworks for ensuring adequate investment in the power sectors of OECD and non-OECD countries alike is of paramount importance. This is especially relevant at a moment where many governments are initiating targeted stimulus packages to support the economy. Many of these packages include measures to accelerate the countries' clean energy transitions – a shift from carbon-intensive electricity generation to low-carbon technologies, setting all areas of the economy and society on a more sustainable path.

Affordability will be a key consideration in designing those transitions. Decision makers in policy and industry, assisted by modellers and energy experts, will have to chart a way forward in increasingly complex contexts. Doing so will require reliable and relevant information. This is where this joint publication by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA) comes in. *Projected Costs of Generating Electricity – 2020 Edition* is the ninth edition of their joint report on electricity generating costs by the major power generation technologies in 24 different countries.

Any comparison of generation costs today must also consider our rapidly changing power systems. As in previous editions, this edition uses the levelised cost of electricity (LCOE) as a well-established, uniquely transparent and intuitive metric, widely used in policy making, modelling and public discussion. As the shares of wind and solar PV in our power systems grow, the value of the electricity generated by a particular technology in a particular power system also changes. Thus, this report also presents a new complementary metric, the "value-adjusted" LCOE to account for these impacts. In addition, five "boundary chapters" take a step back to discuss different aspects of the evolving electricity systems of today and tomorrow in a broad and dynamic long-term perspective.

Altogether, the different elements of *Projected Costs of Generating Electricity – 2020 Edition* aim at contributing to a sound informational infrastructure for forward-looking decision making in decarbonising energy sectors. In this context, knowing the costs and system value of different electricity generation options and, in particular, of low-carbon generation, is indispensable.

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The lead authors and co-ordinators of this report were Dr Stefan Lorenczik, Electricity Markets Analyst, IEA, and Professor Jan Horst Keppler, Senior Economic Advisor, NEA. Effective managerial oversight was provided by Mr Peter Fraser, Head of the IEA Gas, Coal and Power Markets Division and Dr Sama Bilbao y León, Head of the NEA Division on Nuclear Technology Development and Economics (NTE). Mr Lucas Mir and Mr Gabriel Sousa, both of the NEA, and Ms Sunah Kim, IEA, provided valuable help with the analysis and preparation of the LCOE country data. Mr Brent Wanner, Lead of Power Generation Modelling and Analysis for the IEA World Energy Outlook, wrote Chapter 4 on "The value-adjusted levelised costs of electricity (VALCOE)", with support from Mr Connor Donovan. Dr Lorenczik prepared the "Sensitivity analysis" in Chapter 5.

The IEA and NEA Secretariats would like to acknowledge the essential contribution of the Expert Group on Projected Costs of Generating Electricity (EGC Expert Group), which assisted in the sourcing of data, provided advice on methodological issues and reviewed successive drafts of the report. The EGC Expert Group was effectively chaired by Professor William D'haeseleer from Belgium and co-chaired by Dr Yuhji Matsuo (Japan) and Mr Thomas J. Tarka (United States). The full list of the members of the EGC Expert Group can be found at the end of this publication.

Five "boundary chapters" in Part II of this publication provide context and perspective for the LCOE data presented in Chapter 3. Professor D'haeseleer, Professor Erik Delarue and Mr Tim Mertens (KU Leuven) wrote Chapter 6 on "The levelised cost of storage (LCOS)". Professor Keppler and Dr Klaus Hammes (Swedish Environment Agency) authored Chapter 7 on "Carbon pricing". Dr Michel Berthélemy and Mr Antonio Vaya Soler (NEA) are responsible for Chapter 8, "A Perspective on the costs of existing and new nuclear power plants". Mr Olivier Houvenagel, Dr Cédric Léonard and Dr Thomas Veyrenc (all three of Réseau de Transport d'Electricité [RTE], France) contributed Chapter 9 on "Sector coupling: Understanding how the electricity sector can drive the decarbonisation of the overall economy". Finally, Dr Jose Miguel Bermudez Menendez, Dr Uwe Remme and Mr Taku Hasegawa (IEA) contributed Chapter 10 on "Hydrogen: An opportunity for the power sector."

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Executive summary

Projected Costs of Generating Electricity – 2020 Edition is the ninth report in the series on the levelised costs of generating electricity (LCOE) produced jointly every five years by the International Energy (IEA) and the OECD Nuclear Energy Agency (NEA) under the oversight of the Expert Group on Electricity Generating Costs (EGC Expert Group). It presents the plant-level costs of generating electricity for both baseload electricity generated from fossil fuel and nuclear power stations, and a range of renewable generation – including variable sources such as wind and solar. For the first time, this edition also includes cost data on storage, fuel cells and the long-term operation (LTO) of nuclear power plants. It is a forward-looking study, based on the expected cost provided by participating countries of commissioning these plants in 2025, which assumes moderate carbon costs of USD 30 per tonne of CO_2.

Overall, the report provides in total data for 243 plants in 24 countries.[1] Figure ES.1 provides a synthesis of the different technologies analysed and the range of their LCOEs at plant-level at a real cost of capital cost and a corresponding discount rate of 7%. Given the increasing importance of system considerations for a comprehensive comparison of different technologies, the LCOE analysis is complemented by examples of the IEA's value adjusted levelised costs of generating electricity (VALCOE) measure for selected regions and technologies.

Low-carbon generation is becoming cost competitive

The key insight from this 2020 edition is that the levelised costs of electricity generation of low-carbon generation technologies are falling and are increasingly below the costs of conventional fossil fuel generation. Renewable energy costs have continued to decrease in recent years. With the assumed moderate emission costs of USD 30/tCO_2 their costs are now competitive, in LCOE terms, with dispatchable fossil fuel-based electricity generation in many countries.[2] In particular, this report shows that onshore wind is expected to have, on average, the lowest levelised costs of electricity generation in 2025. Although costs vary strongly from country to country, this is true for a majority of countries (10 out of 14). Also solar PV, if deployed at large scales and under favourable climatic conditions, can be very cost competitive. Offshore wind is experiencing a major cost decrease compared to the previous edition. Whereas five years ago, the median LCOE still exceeded USD 150/MWh, it is now significantly below USD 100/MWh and therefore in a competitive range. Both hydro technologies analyses (run of river and reservoir) can provide competitive alternatives where suitable sites exist, but costs remain very site-specific. The result of IEA's value adjusted LCOE (VALCOE) metric show however, that the system value of variable renewables such as wind and solar decreases as their share in the power supply increases.

1. Participating countries include five non-OECD countries: Brazil, the People's Republic of China (hereafter China), India, Romania, the Russian Federation (hereafter Russia) and South Africa. Romania and Russia are, however, member countries of NEA. Brazil, China and India are association countries of the IEA and key partners of the NEA.

2. The influence of carbon costs on the LCOE of fossil-fuel based generation is analysed in Chapter 5. However, the report does not systematically compare all technology LCOEs for different carbon costs.

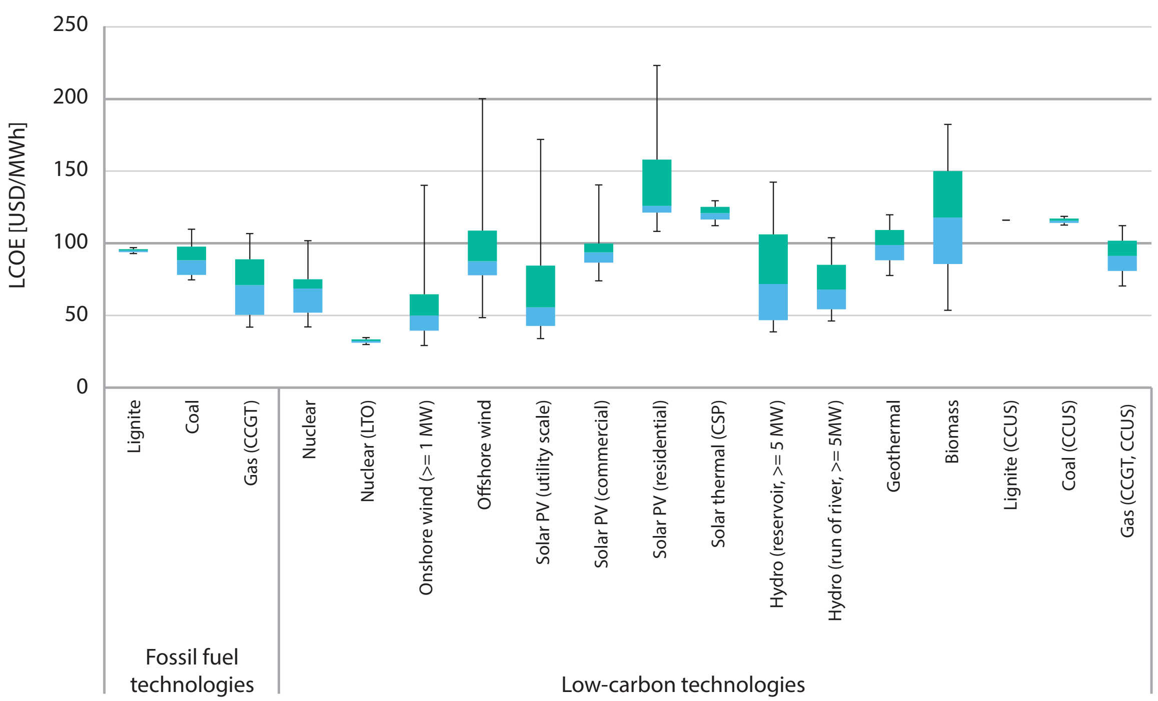
Electricity from new nuclear power plants has lower expected costs in the 2020 edition than in 2015. Again, regional differences are considerable. However, on average, overnight construction costs reflect cost reductions due to learning from first-of-a-kind (FOAK) projects in several OECD countries. LCOE values for nuclear power plants are provided for nth-of-a- kind (NOAK) plants to be completed by 2025 or thereafter.

Nuclear thus remains the dispatchable low-carbon technology with the lowest expected costs in 2025. Only large hydro reservoirs can provide a similar contribution at comparable costs but remain highly dependent on the natural endowments of individual countries. Compared to fossil fuel-based generation, nuclear plants are expected to be more affordable than coal-fired plants. While gas-based combined-cycle gas turbines (CCGTs) are competitive in some regions, their LCOE very much depend on the prices for natural gas and carbon emissions in individual regions. Electricity produced from nuclear long-term operation (LTO) by lifetime extension is highly competitive and remains not only the least cost option for low-carbon generation - when compared to building new power plants - but for all power generation across the board.

Coal- and gas-fired units with carbon capture, utilisation and storage (CCUS), for which only the United States and Australia submitted data, are, at a carbon price of USD 30 per tonne of CO_2, currently not competitive with unmitigated fossil fuel-plants, nuclear energy, and in most regions, variable renewable generation. CCUS-equipped plants would constitute a competitive complement to the power mix only at considerably higher carbon costs.

The LCOE calculations are based on a levelised average lifetime cost approach, using the discounted cash flow (DCF) method. Costs are calculated at the plant level (busbar), and therefore do not include transmission and distribution costs. The LCOE calculations also do not capture other systemic costs or externalities beyond plant-level CO_2 emissions such as, for instance, methane leakage during the extraction and transport of natural gas. This report does however recognise, in particular in Chapter 4, the importance of the system effects of different technologies, most notably the costs induced into the system by the variability of wind and solar PV at higher penetration rates.

Figure ES1: LCOE by technology



Note: Values at 7% discount rate. Box plots indicate maximum, median and minimum values. The boxes indicate the central 50% of values, i.e. the second and the third quartile.

Competitiveness depends on national and local conditions

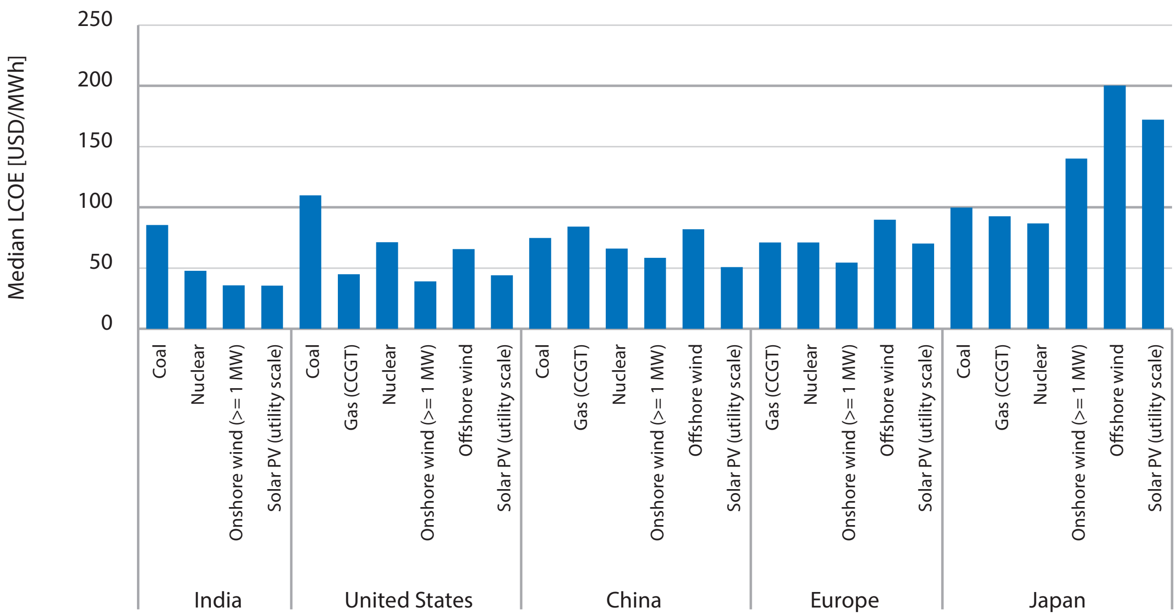
The aggregated data for the 24 countries that provided data for this report does not tell the whole story of levelised generation costs. Due to more or less favourable sites for renewable generation, varying fuel costs and technology maturity, costs for all technologies can vary significantly by country and region. In addition, the *share* of a technology in the total production of an electricity system makes a difference to its value, load factor and average costs.

Whereas renewables are very competitive in most countries participating in this report, the data provided for *Projected Costs of Generating Electricity – 2020 Edition* shows that they still have higher costs than fossil fuel- or nuclear-based generation in some countries (in this report: Japan, Korea and Russia). Also within countries, different locational conditions can lead to differences in generation costs at the subnational and local level. In Europe, both onshore and offshore wind as well as utility scale solar installations are competitive to gas and new nuclear energy.

In the United States, gas-fired power plants benefit from the expected low fuel prices in the region, although fuel price assumptions are, in general, uncertain. Nevertheless, in terms of the LCOE of the median plant, onshore wind and utility scale solar PV are, assuming emission costs of USD 30/tCO_2, the least cost options. Natural gas CCGTs are followed by offshore wind, nuclear new build and, finally, coal.

In China and India, variable renewables are having the lowest expected levelised generation costs: utility scale solar PV and onshore wind are the least-cost options in both countries. Nuclear energy is also competitive, showing that both countries have promising options to transition out of their currently still highly carbon-intensive electricity generation.

Figure ES2: Median technology costs by region

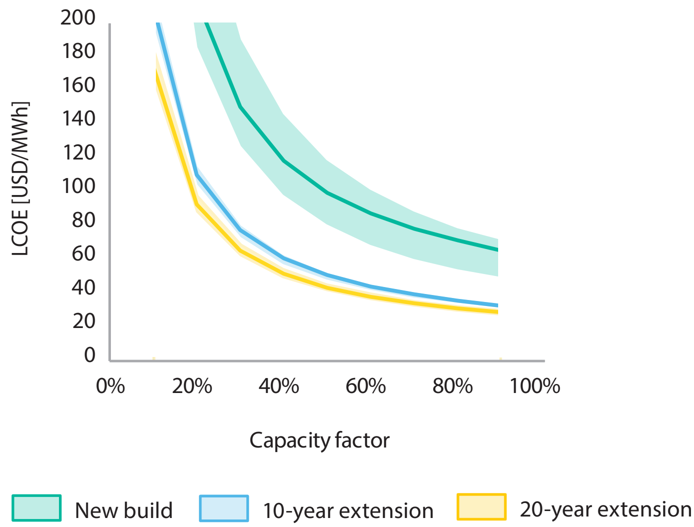


Note: Values at 7% discount rate.

Lifetime extensions of nuclear plants can be very cost effective

Beyond investments in new sites (greenfield projects), this report includes levelised cost estimates for the long-term operation of nuclear plants (LTO) – representing extensive refurbishments to enable a secure operation beyond the originally intended lifetime. The report shows that this brownfield investment, i.e. making use of the existing facilities and infrastructure, significantly reduces costs compared to building new greenfield plants. Even at lower utilisation rates, a potential scenario for nuclear units in systems with high shares of variable renewables, costs are below those of new investments in other low-carbon technologies. Other low-carbon technologies with long lifetimes, in particular hydroelectric plants, could be similarly attractive for such LTO investments but no cost data was submitted.

Figure ES3: Costs for nuclear new build and lifetime extension of existing plants



Note: Values at 7% discount rate. Lines indicate median values, areas the 50% central region.

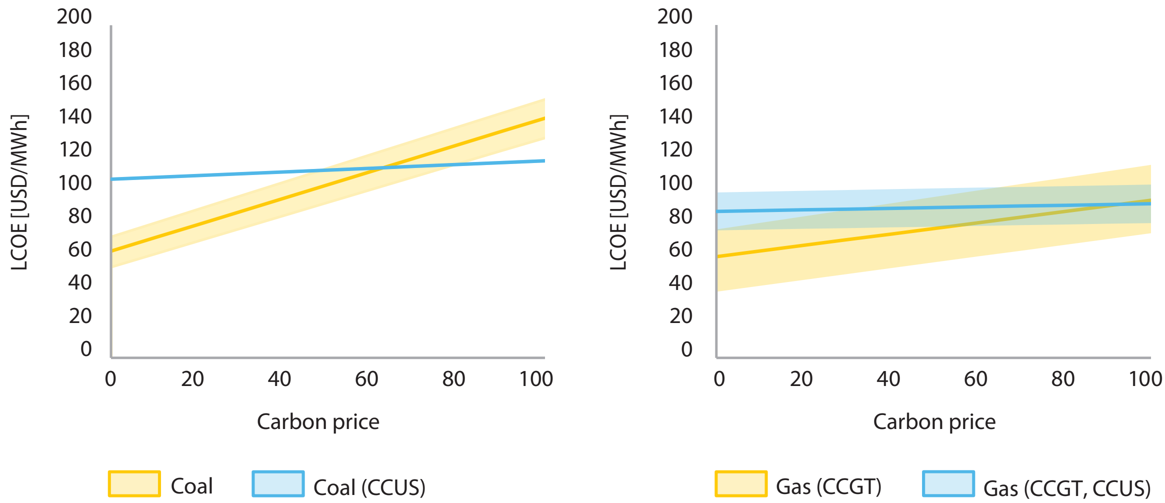
Carbon capture technologies could be a viable option with higher carbon costs

In the default case with emission costs of USD 30/tCO_2, equipping coal and gas plants with a CCUS is, due to the higher investment costs of CCUS equipment and the reduced thermal efficiency, more expensive than unmitigated fossil fuel-based electricity.

With higher emission costs however, the picture could change. For coal power plants, due to the fuel's relatively high carbon content, CCUS units become competitive at around USD 50 to 60 per tCO_2. For gas-fired CCGTs, only carbon prices above USD 100/tCO_2 would make plants with CCUS competitive. At such high carbon prices, renewables, hydroelectricity or nuclear are likely to constitute the least-cost options to ensure low-carbon electricity.

Although the necessary carbon price levels required for triggering a cost advantage of CCUS plants exceed the majority of today's prices, they are still relatively low compared to existing estimates of the social cost of carbon. Although the estimates carry great uncertainties, global social costs could exceed USD 100 per tCO_2 (Nordhaus, 2017). Thus, if flexible low-carbon generation is needed, competitive alternatives are lacking and affordable fossil resources are available, CCUS may become an option. Depending on national circumstances, with sufficiently high carbon prices, CCUS could be a possible complement in certain low-carbon power mixes.

Figure ES4: LCOE with and without CCUS for various carbon prices



Note: Values at 7% discount rate. Lines indicate median values, areas the 50% central region.

Technologies have to fit into the market

To enhance the comparability of costs between regions and markets, it was necessary to harmonise certain assumptions. Therefore, in the base cases of our analyses we assume an 85% capacity factor for nuclear, coal and CCGT plants as well as a 7% discount rate. Depending on the individual market, these parameters can differ significantly, based on the existing technology mix as well as the market environment.

With increasing shares of renewable generation for example, baseload plants may lose market share and have to content themselves with satisfying the residual demand. This is why this report includes also estimates for 50% load factors for dispatchable baseload technologies such as gas, coal and nuclear. In practice, load factors are country and system specific, but capacity factors of this magnitude are not uncommon, both in OECD and non-OECD countries.[3] Depending on their position in the merit order, technologies will be affected differently. In the United States, with its low gas prices, for instance, coal units will typically be dispatched last, and will have lower capacity factors.

The results show that, due to their relatively low investment costs and in many regions moderate variable costs, gas-fired CCGTs are well suited for handling different generation levels. Nuclear units on the other hand, due to high investment costs, require high utilisation rates.

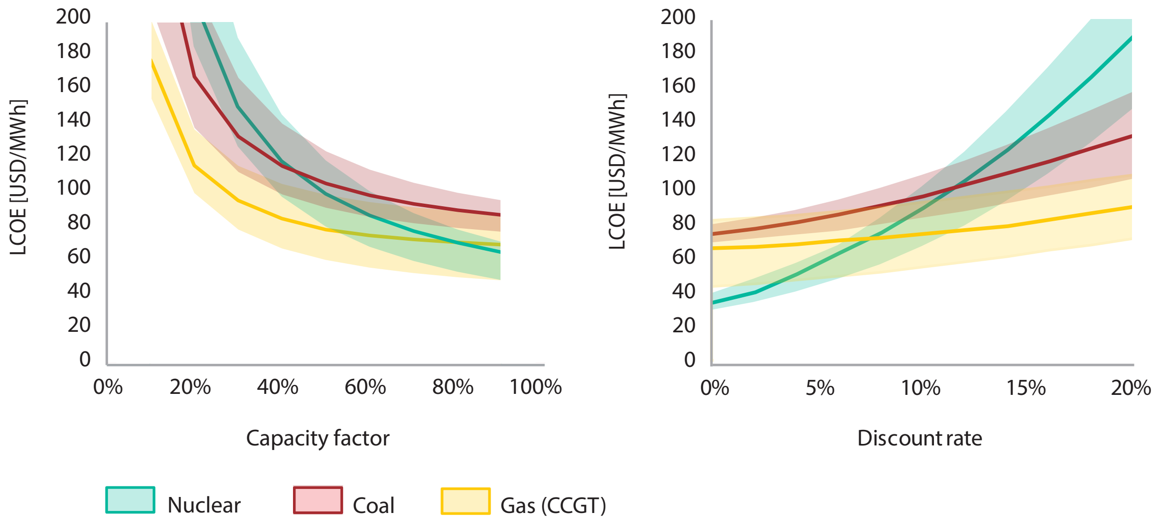
A key determinant of competitiveness is the discount rate, which corresponds in the LCOE methodology to the cost of capital. In its central case, this report assumes a uniform discount rate of 7% for all technologies and countries. In practice, the discount rate reflects, among others, opportunity costs of investment as well as different kinds of risk and uncertainty, for example regarding political and regulatory developments, the market design, the system development and future investment and fuel costs. Furthermore, in the real world the question of who bears the risk is important: Government support, in the form of price guarantees for example, would shift the risk from the investor to the public. Long-term power purchasing agreements would allow sharing the

3. With very high shares of variable renewables, also for example wind and solar PV might have to be curtailed, depending on the available flexibility options. Their load factors would then be below their theoretical maximum that would increase the reported LCOE values.

risk between project developers and electricity buyers. Although the overall risk remains the same, the investment would thus become cheaper from an investor perspective. Such factors, which can be important at the level of an individual project, do not appear explicitly in the LCOE numbers provided in this report, which does not include considerations of contractual structure or market intervention.

The more capital-intensive a technology, the more sensitive its LCOE are to changes in the discount rate. Among baseload plants, this means that in particular the costs of nuclear new build depend on the discount rate. With a low discount rate of 3%, reflecting a stable market environment with high investment security, the LCOE of new nuclear plants is lower than for new coal and gas plant. With higher discount rates at 7% or 10%, which would reflect riskier economic environments, the costs of a newly built nuclear plant would exceed those of fossil fuel-based plants.

Figure ES5: Sensitivity of LCOE of baseload plants to capacity factor (left) **and discount rate** (right)



Note: Values at 7% discount rate. Lines indicate median values, areas the 50% central region.

System costs are important to show the full picture

The LCOE is a well known and, thanks to its relative simplicity and transparency, well understood metric for comparing different generation technologies. The common assumptions made in this report – for example assuming identical capacity factors for gas, coal and nuclear plants across regions – ensures that cost differences can be clearly identified. However, this approach neglects the differences in individual systems and markets that considerably influence the competitive position of technologies. These system-specific characteristics interact with the technical and economic characteristics of different technologies, i.e. their variability, dispatchability, response time, cost structure and place in the merit order. This also includes the fact that not all units are dispatched to the same extent across technologies and markets, or that revenues in many markets are determined by fluctuating prices and not, as assumed in the LCOE analysis, by a stable price over a technology's lifetime.

More importantly, the LCOE metric applies to the level of the individual plant and does not address the value that different generation technology options add to the electricity system at different levels of penetration. The electricity generation of variable renewables of a particular type is correlated and not reliably available at all times. The simultaneity of generation, which is not necessarily correlated with demand, reduces the value of generation. The lack of reliability requires either dispatchable back-up or, alternatively, flexibility options such as storage or demand response to ensure security of supply at all times. Additionally, potentially rapid changes in variable renewable generation need to be balanced. To understand this impact and to ensure that a given demand is satisfied with low-carbon electricity at least cost, electricity system-level analysis is required (see IEA, 2019 and NEA, 2019). Overall, this means that LCOE increasingly needs to be contextualised by other analyses in order to obtain a meaningful picture of the relative competitiveness of different electricity generating technologies.

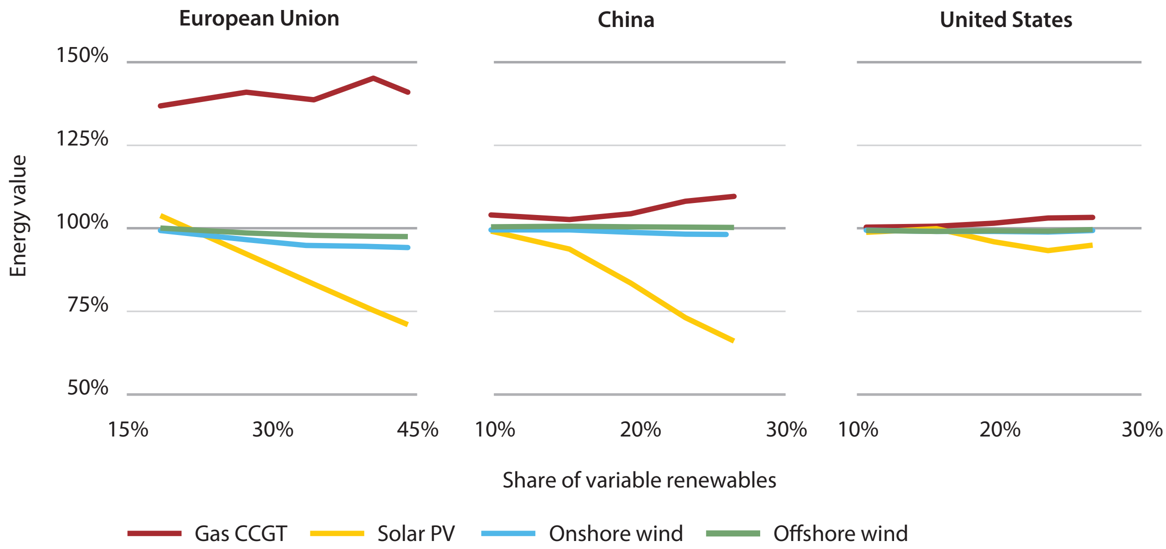
In order to complement the LCOE approach and enable a more system specific cost comparison, the IEA has developed a methodology to adjust the costs by a system value component known as the value adjusted LCOE (VALCOE). It modifies the LCOE of an individual technology in a particular electricity system according to its contribution to enabling all aspects of securely operating the system. Crucially, the calculated results reflect the value in existing, i.e. brownfield systems and their possible future development.

The results illustrate that a technology's plant-level generating costs can vary significantly from its value to the system. The importance of taking this into account is especially striking when considering variable renewables: solar PV units show a high correlation in the output of individual plants resulting, in the analysed scenarios, in a significant reduction of the generation value with increasing shares. Curtailment during hours of high production is an additional issue and may in practice reduce load factors and increase LCOE compared to reported values. This would be taken into account in the system analysis. By contrast, the output of wind plants is less correlated among individual units and thus its loss in value is less even as its share increases. At current levels of capacity, the impact of correlation is still limited in many markets, but it may rise if ambitious renewable targets are realised and relative shares increase. Technologies with high variable costs (such as high-flexibility open-cycle gas turbines), that produce only during a few hours with very high prices, provide on average a higher value (per unit of generation) to the system. Baseload plants, typically CCGTs (an exception is Europe, where they are mostly operating during hours with high residual load), coal and nuclear, that produce reliably over a high number of hours provide a value similar to the system average.

The results reported in Figure ES6 provide sample results of IEA's VALCOE analysis for the European Union, China and the United States. While covering these large geographical regions, the model does not take into account grid bottlenecks or cross-border flows but instead assumes full integration across areas. Results thus potentially underestimate the flexibility constraints of future systems. The VALCOE measure provides an innovative approach to capture the complexities of system analysis in a single metric. Values depend not only on the overall share of variable renewables, but also on the costs of complementary resources such as energy storage or interconnections and the costs of competing technologies. Contrary to many other system analysis that simulate future system developments assuming long-run cost optimality, the scenario underlying the VALCOE calculations tries to replicate real-world systems. Future work will systematise and refine current results.

Assessing the system contribution of different generation technologies provides a more complete picture of their economic costs. However, in order to obtain a measure of their full costs to society, the impacts on human health (both through air pollution and through major accidents), the environment, employment, the availability of natural resources and the security of supply need to be included (see, for instance, NEA 2018).

Figure ES6: Energy value by technology and region relative to average wholesale electricity price in the Stated Policy scenario



Source: IEA (2019).

Storage is becoming more important

Increasing shares of variable renewables in the energy mix increase the volatility of electricity prices and therefore improve the profitability of flexibility and balancing options. At the same time, sinking investment costs, for example for battery units, are already making short-term battery storage an economically attractive option in some niche applications (e.g. ancillary services markets). As more volatile electricity prices make inter-temporal arbitrage more attractive, storage could become an attractive alternative to peaking units such as open-cycle gas turbines, thus increasing its importance in the coming years. For the first time, a report of the *Projected Costs of Generating Electricity* series thus includes cost data for storage provided by participating countries.

Storage could complement variable renewable generation to improve the alignment of, for example, wind and solar PV generation with electricity demand. In future low-carbon systems, a mix of multiple flexibility options, for example storage, demand flexibility and flexible low-carbon output from, for instance, nuclear and hydro plants is likely to provide minimal cost solutions.

To better understand the future of storage, its role in energy systems is scrutinised repeatedly throughout the report. Expected cost data for 2025 form the basis for further analysis, followed by a thorough discussion about options for measuring the competitiveness of storage through enhancing the LCOE methodology to come up with a levelised cost of storage (see Chapter 8). One important insight is that storage refers to a continuum of technologies with different ratios of energy to capacity (E/P) as well as different costs, load factors and economic roles in the complex system interactions of modern electricity systems.

Additional perspectives

Five "boundary chapters", free-standing articles contributed by experts in the respective areas, complement the report - considering wider issues related to the costs of electricity generation and broadening the scope of the core analysis.

The 2020 edition of the *Projected Costs of Generating Electricity* series is the first to include data on the cost of storage based on the methodology of the levelised costs of storage (LCOS). Chapter 6, a contribution from researchers at the Department of Mechanical Engineering at KU Leuven, shows how to calculate the LCOS according to transparent and robust protocols – accounting for the differences between storage technologies.

Chapter 7 constitutes a synthesis of the state of knowledge about the impacts of carbon pricing in the electricity sector. The collaboration by researchers from the NEA and the Swedish Environmental Agency provides an overview of current carbon pricing initiatives and their impacts on the economy, carbon emissions, electricity prices and distribution. It analyses potential advantages of allocating carbon emission cost to taxpayers rather than to electricity consumers.

As identified in the 2019 IEA report *Nuclear Power in a Clean Energy System* and confirmed in this report, life extension of existing nuclear power plants can be a highly cost effective investment opportunity for low-carbon generation. Chapter 8, authored by the NEA, presents an up-to-date view of the potential role of nuclear energy in decarbonised electricity systems. It highlights the cost advantages of lifetime extensions (LTO), potentially significant cost reductions for new constructions after gaining experience with new designs and the potential of small modular reactors (SMRs).

To reduce energy-related emissions, it is not sufficient to decarbonise the electricity sector, but electricity also has to replace fossil fuels in other end-use sectors. Chapter 9 is a contribution by the French electricity TSO (transmission system operator) RTE on the transformation of the overall energy sector through electrification and sector coupling. It concentrates on the impacts of the increasing penetration of electric vehicles, industrial hydrogen use and energy efficiency measures in residential heating on electricity demand and supply in France and Europe until 2035 – stressing the increasing need for comprehensive system analyses.

Chapter 10, a contribution by the IEA, presents a detailed discussion of hydrogen as a potential key element in the transition towards a clean, secure and affordable future energy system, further strengthening the need to adopt a system perspective. Based on the 2019 IEA report *The Future of Hydrogen: Seizing Today's Opportunities*, the chapter highlights the critical role of the power sector in the realisation of the new emerging opportunity, but also potential barriers and necessary next steps. It concludes the five boundary chapters taking a broad, forward-looking approach to a changing energy world.

Conclusions

This ninth edition of *Projected Costs of Generating Electricity* focuses on the cost of electricity generation from a wide set of technologies in a large range of countries. Inevitably, regional, national and local conditions have their importance. Nevertheless, the increasing competitiveness of low-carbon technologies for electricity generation remains the key insight of this report. This holds both for variable renewables such as wind and solar PV, as well as flexible low-carbon generators such as hydro and nuclear energy (including LTO). Even at a modest carbon price of USD 30 per tonne of CO_2, unmitigated coal is no longer competitive. Gas-fired electricity generation remains competitive in some markets, especially OECD North America, due to very low gas prices. CCUS would require considerably higher carbon prices than those seen in most markets today to become competitive.

The report also considers for the first time in some depth the costs of the system effects of different generating options, most notably the variability of wind and solar PV. Such system analysis will become increasingly important as their penetration in the electricity systems of OECD and non-OECD countries increases. Logically, the costs of storage are also included for the first time. Lastly, this report provides a perspective on the coming electrification of sectors such as transport, hydrogen or heat production, which will integrate electricity generation with the wider economy in new and important ways. The chances are that these latter two aspects will play an even greater role in future editions of the *Projected Costs of Generating Electricity*.

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Part 1

Methodology and data on the levelised costs of electricity (LCOE)

Introduction and context

Projected Costs of Generating Electricity – 2020 Edition is the ninth edition of the report on electricity generating costs published jointly every five years by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA). It is also referred to at times as the report on Electricity Generating Costs (EGC). As with previous editions, this report relies on the direct contributions on generation cost data from the governments of both OECD and non-OECD countries, which in turn consulted widely with national experts and industry organisations. This data is then vetted and processed according to a common methodology by the EGC Expert Group (EGC EG), composed of experts from government, academia and industry. The EGC Expert Group provides advice on methodology and data as well as on the content and format of the final report. Over the years, the *Projected Cost* series of reports on electricity generating costs has become a widely used tool for policymakers, modellers and experts, as well as the interested public, to inform discussions about the economics of power generation.

The core of this edition of this *Projected Costs* report are the detailed data tables in Chapter 3 that indicate the levelised cost of electricity (LCOE) and its components for different power generation technologies in different OECD countries. These LCOE figures have been computed on the basis of the inputs received from participating countries and a common methodology that is identical for all technologies and countries. Chapter 2 presents in detail the methodology, conventions and assumptions underlying the LCOE analysis as they have been validated by the EGC Expert Group.

The set of countries included in the 2020 edition is broadly consistent with that of the 2015 and 2010 editions. As usual, the IEA and NEA jointly invited representatives of OECD countries, and a select group of non-OECD countries, to submit data for inclusion in this report. Countries participate on a voluntary basis, and while some countries elected not to submit data this time, a number of additional countries that did not do so in previous editions participated in this edition. The resulting dataset offers a diversity of both countries and technologies that is broadly representative of the costs of electric power generation today. For the first time, a *Projected Cost* report also includes cost data on fuel cells and storage technologies in form of the levelised cost of storage (LCOS). In total, the EGC 2020 report contains data for 243 power plants with different generating technologies from 24 countries to be commissioned in 2025 (see Table 1.1 below).

The overall structure of the data received for this 2020 edition is comparable with the previous 2015 edition. The relative shares of submissions for the different technologies remain roughly stable. As in previous editions, there are more than 20 submissions for power plants based on natural gas, solar PV, onshore wind and hydroelectricity. Similarly, there are more than ten submissions for coal-fired power plants and combined heat and power (CHP) plants.

However, the 2020 edition contains now 26 entries for offshore wind plants, compared to only 12 in 2015, which reflects its status as an important additional asset in the progress towards carbon neutrality. Cost data for eight storage installations is included for the first time, reflecting its contribution to the provision of flexibility and balancing services in the presence of increasing supply from variable wind and solar PV plants. Lastly, cost estimates for four nuclear LTO projects, i.e. the lifetime extension of existing plants that have reached the end of their originally scheduled operating lifetimes, are included for the first time (see Chapter 10 for a detailed discussion of the underlying data). In principle, comparable LTO projects exist also for other technologies, in particular large hydroelectric installations. However, participating countries did not provide LTO data for other technologies.

Table 1.1: Summary of responses by country and technology

Country	Natural gas	Coal	Nuclear	LTO	Solar PV	Solar thermal	Onshore wind	Offshore wind	Hydro	CHP	Storage	Other	TOTAL
Australia	3	4			1	1	1	1			1		**12**
Austria					1		1		1				**3**
Belgium	6				4		4	2					**16**
Canada	3				2		1				1		**7**
Denmark					4		1	2		7	2		**16**
Finland							1				1		**2**
France			1	1	3		1	1				3	**10**
Germany									1				**1**
Hungary					4								**4**
Italy	2				7		14		15	1	1	6	**46**
Japan	1	1	1		2		1	1	1				**8**
Korea	2	1	1		2		1	1					**8**
Mexico	3												**3**
Netherlands					3		1						**4**
Norway					1		1		2			1	**5**
Romania	1									2			**3**
Russia			1				2						**3**
Slovak Republic			1							2			**3**
Sweden				1			1						**2**
Switzerland				1									**1**
United States	2	8	1	1	15	3	10	14	8			2	**64**
Non-OECD countries													
Brazil	2	1			1		1		1			1	**7**
China	1	1	1		1		1	1					**6**
India		2	1		1		1		1		2	1	**9**
TOTAL	**26**	**18**	**8**	**4**	**52**	**4**	**44**	**23**	**30**	**12**	**8**	**14**	**243**

* Data for China and India was drawn from various publicly available sources. Romania and Russia are members of the OECD Nuclear Energy Agency only.

Beyond LCOE

The levelised costs of electricity (LCOE) constitute an important reference for policy making and modelling. Historically, the LCOE concept was developed in order to help choose between different dispatchable baseload technologies in regulated systems. The authors of this report and the members of the EGC Expert Group are aware that LCOE, just as other metrics, has specific strengths and limitations as an indicator of competitiveness in today's electricity markets. For example, as operators earn a complex mix of revenues in volatile energy and flexibility markets, the risk and hence the cost may differ for an investor even for technologies with identical LCOE. Developing a cost indicator for combined heat and power (CHP) plants remains challenging for any metric, as it needs to allocate costs to two different value streams and thus the value of heat can have a large influence on final LCOE figures. Nevertheless, the simplicity, transparency and intuitive appeal of the LCOE concept ensure that it remains a widely used metric by a large range of stakeholders in policy discussions, for modelling purposes or for communicating with the wider public.

The driver for a new approach, such as the one outlined in Chapter 4, is the recognition of the growing share of variable renewable energy (VRE) technologies such as wind and solar PV in today's power systems and the impact they will have on the value of the electricity produced. Most of today's generation investment globally is in solar PV and wind power and this is anticipated to continue. In the Stated Policies Scenario of the 2019 *World Energy Outlook* (IEA, 2019a), which reflects the impacts of implemented and announced government policies and evolution of the costs of energy technologies, wind and solar PV together provide over half of the growth in electricity supply, raising their share from 7% in 2018 to 24% in 2040. In the more environmentally ambitious Sustainable Development Scenario, which is consistent with limiting the temperature rise to 2 100 to 1.8°C with a 66% probability or a 50% chance of a 1.65°C stabilisation, the gains by wind and solar PV are even more striking: rising to 40% of the global electricity supply by 2040.

As the share of variable renewable energy generation (VRE) increases, their contribution to the system – and their costs – will go beyond the energy they produce. Their advent requires taking into account the system contribution or system costs of different technology as an indispensable complement for a full picture of the costs and value of any given technology. The integration of VRE results in more complex interdependencies. The cost of each technology thus depends on the specific system to which it is being added (see Box 1.1).

Box 1.1

System costs of VREs

When considering the costs of generation at the level of the electricity system, this report pursues a three-pronged strategy to complement the basic LCOE figures: (1) system costs analysis, (2) sensitivity analyses and (3) boundary issues.

First, regarding system costs analysis, a number of studies including Hirth, Ueckerdt and Edenhofer (2015), IEA (2011) and (2016), MIT (2018) or NEA (2012) and (2019) have assessed the costs at the level of the system rather than at the level of the plant of different technologies. The key parameter here is the variability of a resource in function of meteorological conditions or, conversely, its ability to provide power at will at any given moment according to demand. Quite obviously, this concerns primarily variable renewable resources such as wind and solar PV. Other things equal and, in particular, at identical levels of security of electricity supply, the more variable a resource and the less correlated with demand its output, the higher are the additional *profile* costs that it imposes on the system as a whole. In most reference systems, offshore wind thus generates less system costs than onshore wind, whose system costs in return are somewhat lower than those of solar PV. At the same time, if variable output correlates well with demand, e.g. if peak solar PV production at noon coincides with peak demand and its capacity is modest, its output can decrease system costs.

Conversely, the size of the additional costs will also depend on the particular electricity system. Systems with smaller shares of VRE, greater shares of flexible resources, and more interconnections are able to incorporate additional VRE very inexpensively whereas those with high shares and limited or no interconnection will find incremental system costs to be higher. The key point is that the system costs depend on the existing system, and not just the plant-level technology.

(continued Box 1.1)

The central insight of the system costs approach can be summarised as follows: different technologies with different abilities to provide power at any given moment over any desired timeframe have different functions in different integrated electricity systems. LCOE, while it continues to provide uniquely relevant information, no longer allows assessing a technology's costs fully on its own. In particular, LCOE does not say anything about the value a technology brings to the system. Indeed, a technology's full system costs and system contribution depend on the surrounding system, in particular the structure of the overall technology mix, the amount of interconnections as well as the structure and flexibility of demand. Finally, while there still is competition between different technologies there is also an increasing recognition that different technologies are complementary. This holds, in particular, for the low-carbon systems of the future where variable renewables such as wind and solar PV will have to be complemented, in addition to flexibility providers such as storage or demand response, by dispatchable generators such as biofuels, nuclear energy, hydropower, coal- and gas-based generation equipped with CCUS.

The challenge is to translate such system cost considerations into a simple metric similar to the LCOE. As part of its work on the World Energy Model (WEM), which prepares the projections of its annual *World Energy Outlook*, the IEA has developed since 2018 the VALCOE metric. It adjusts LCOE values at the plant-level for the system contribution of a technology and thus provides a more complete picture of its system cost per MWh depending on the technology mix of the systems including the level of VRE penetration. The VALCOE necessarily depends on the system in which a technology is deployed. Currently, estimates exist for China, Europe, India and North America as reported in Chapter 4. With time, advances in system cost analysis, both at the IEA and elsewhere, will increasingly include a broader set of countries and regions. Future editions of *Projected Costs* will undoubtedly contain an even more systematic assessment of the system value and system costs of different generation technologies. An overview of methodological issues in system analysis, including an attempt to unify the different approaches pursued in the current literature, will be prepared jointly by IEA and NEA in collaboration with the EGC EG for publication in 2021.

Second, this report provides in Chapter 5 a comprehensive sensitivity analysis of the LCOE values presented in the data tables of Chapter 3. Such sensitivity analysis constitutes a necessary complement to the reference values derived on the basis of the default assumptions. For reasons of readability, transparency and comparability, it is indispensable to treat the raw cost data received from participating countries according to a common methodology with identical assumptions. The solidity of the methodology and the plausibility of the assumptions both ensured by the IEA and NEA Secretariats and the EGC Expert Group largely constitutes the value added that this series of reports brings to the international debate. Given their importance, already the common data tables differentiate values according to the real discount rates of 3%, 7% and 10% and load factors of 85% and 50% for coal, nuclear and CCGTs as well as 30% and 10% for open-cycle gas turbines (OCGTs).

However, this is not sufficient for fully understanding the economics of electricity generation. Once reference values based on common assumptions are established, it remains necessary to undertake a broader analysis of how LCOE figures vary as soon as the underlying assumptions such as the discount rate, load factors, or fuel costs change over a broad range of possible values. A new graphic display of those variations used for the first time in this report allows a form of representation that is both intuitive and systematic. The web-based version of the *Projected Costs of Generating Electricity – 2020 Edition* includes a LCOE calculator that allows users to complement the published version with results computed with the raw cost data and their own assumptions.

Third, in order to provide further context for the LCOE numbers, similarly to previous editions of the *Projected Costs* series, this report includes in Part II five so-called "boundary chapters". The boundary chapters are five free-standing articles which consider issues relating to the costs of electricity generation costs in a broad and dynamic long-term perspective. The date of commissioning of the plants for which the LCOE are reported in Chapter 3 is supposed to be 2025. This is by and large a realistic timeframe for a power generation project, for which an investment decision is taken today, even if the construction times for different technologies differ considerably and are, on average, somewhat longer for new nuclear or hydroelectricity projects. However even today, energy policymakers and utility executives need to set their sight on far longer time horizons. Investment plans are formulated for a decade ahead or more and energy policy objectives in many OECD countries are referenced with respect to a long-term objective of net carbon neutrality by 2050. The boundary chapters on sector coupling, carbon pricing, the costs of storage, the hydrogen economy, or the evolution of nuclear energy, thus provide added information on trends that will have a bearing on electricity generating costs over the medium- and long-term. They are best thought of as different spotlights on the low-carbon electricity sectors of the future, where changes in technologies, economics, and regulatory frameworks already underway will interact in promising but as of yet still unforeseeable ways.

As mentioned earlier, this 2020 edition of the *Projected Cost* series is the first to include data on the cost of storage based on the methodology of the levelised costs of storage (LCOS). Chapter 6, a contribution from the energy modelling team of the Department of Mechanical Engineering at KU Leuven, shows how to calculate the LCOS according to transparent and robust protocols. The challenge in cost accounting for storage is always that its output, electricity, is also its input, only provided or sourced at different moments. Assumptions about the time profile of charging and discharging electricity are thus decisive for calculating its unit costs per MWh. In addition, there are vast differences between different storage technologies with respect to the trade-offs they present between capacity and energy. Batteries with high capacities for a few seconds or minutes are already widely available on commercial terms. The greater challenge consists in developing and financing storage technologies capable of delivering a sizeable amount of electricity for hours or days. Beyond that, only dispatchable generation will be able to provide the flexibility for variations in variable renewable generation and demand. This chapter provides a widely applicable and easily replicable methodology that is helpful to assess the economic feasibility of different available technological options.

Chapter 7 constitutes a synthesis of the state of knowledge about the impacts of carbon pricing in the electricity sector based both on recent conceptual and empirical research. The collaboration by researchers from the NEA and the Swedish Environmental Agency provides an overview of current carbon pricing initiatives and their impacts on the economy, carbon emissions, electricity prices and distribution. In particular, the article contains not only information on carbon tax regimes and emission trading systems but also on initiatives to support low-carbon generation through per unit subsidies such as the zero emissions credit (ZEC) scheme in the United States. It underlines, in particular, the potential advantages in the political economy of carbon pricing to allocate the costs of carbon emission reductions to tax payers through subsidy schemes rather than to electricity consumers through taxes and higher prices.

In Chapter 8, authors from the NEA report on the potential of nuclear energy to make a decisive contribution to low-carbon electricity generation in the short and long run. As evidenced by the LCOE figures reported in Chapter 3, the existing nuclear fleet continue to be a highly competitive source of dispatchable low-carbon electricity. In the short run, nuclear new build will be complemented by the long-term operations (LTO) of existing plants that have reached the end of their original operating lifetimes. While requiring extensive refurbishments and replacement of some key components, LTO constitutes currently the least-cost option for low-carbon electricity generation. Building on the lessons learnt from recent first-of-a-kind projects important efforts are taking place to significantly reduce the investment costs of the current large-scale Generation III+ reactors in the short run (NEA, 2020). Over the longer run, a new generation of small modular reactors (SMR), with a significant share of factory-produced components and lower financing requirements, hold out further promise to extend, in a complementary way to large reactors, the contribution of nuclear power to low-carbon electricity.

Chapter 9, a contribution from RTE, the French electricity transmission system operator, examines the transformation of the overall energy sector through electrification and sector coupling. Different generation technologies thus interact in order to provide overall least-cost solutions for carbon abatement. It concentrates on the impacts of the increasing penetration of electric vehicles, industrial hydrogen use and energy efficiency measures in residential heating on electricity demand and supply in France and Europe until 2035. Recent advances in detailed energy and electricity sector modelling allow today a far better understanding of how these policy-driven developments will affect the level, structure and flexibility of demand -- and hence the composition and cost of electricity supply. All the aspects of the analysis in Chapter 6 strongly confirm the general insight that drives the thinking behind this edition of the *Projected Costs* series: today's complex electricity systems with large shares of variable renewables require that the analysis of generation costs adopts an ever broader systems approach.

Chapter 10 broadens and deepens the analysis of one of the issues included in the system analysis of Chapter 9: the potential of hydrogen in the low-carbon electricity and energy systems of the future. The advantages of hydrogen, light, of high energy density and producing no emissions other than water vapour during combustion, as a vector for storage and transport in integrated electricity systems are obvious and it is already widely used for industrial purposes today. However, its wider adoption in areas such as transport (in particular trucking and shipping), industrial processes, heating or electricity storage has been held back by the high carbon intensity of the current, still most cost-effective method of hydrogen production, steam methane reforming. Chapter 10, based on the recent IEA publication *The Future of Hydrogen* (IEA, 2019b) explores the potential for hydrogen-based on alternative production methods such as electrolysis using low-carbon electricity from renewables, nuclear and hydroelectricity or biomass conversion. Enjoying strong government support and benefiting from a potential fall in the costs of both low-carbon electricity in several parts of the world and of electrolysers, hydrogen is today at a critical juncture at which it can prove that it is indeed able to make a sizeable contribution to the low-carbon electricity systems of the future.

Overall, the authors and contributors of *Projected Costs of Generating Electricity – 2020 Edition* have made every effort to ensure that also this edition remains the same readily accessible and useful reference on electricity costs for policymakers, modellers and experts as it predecessors. As far as plant-level average cost numbers are concerned, the most interesting new extensions concern offshore wind, storage and nuclear LTO. However, it is also clear that in increasingly complex and time-differentiated electricity systems, different technologies have increasingly different functions and hence very different revenues per MWh. This will further reduce the relevance of direct LCOE comparisons in the long run.

Projected Costs of Generating Electricity – 2020 Edition provides a gradual entry into systems considerations while striving to preserve traditional benefits of transparency and comparability. This process will continue in the same gradual manner based on and methodological conventions and modelling capabilities that still need to be established. Future editions will offer further insights from the fast evolving field of electricity system analysis. In the meantime, the 2020 edition provides an overview of a sector in transition. Most technologies presented here will play their part in the decarbonising and increasingly differentiated electricity systems of the future. Several boundary chapters also indicate that this future will be increasingly electric. The *Projected Costs of Generating Electricity* will continue to accompany the development towards an electric low-carbon future.

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Methodology, conventions and key assumptions

This chapter presents the EGC model used to calculate lifetime (long-run) average levelised costs (LCOE), as well as the methodological conventions and key assumptions to ensure consistency among cost estimates for different countries. The economics and methodology behind the calculation of levelised average lifetime cost for each generating technology are discussed here. However, only a few parameters can be included in any general model, and many factors that have not been taken into account influence costs. Methodological limitations of the LCOE approach are discussed in the context of its extension towards value adjusted levelised cost of electricity (VALCOE) in Chapter 4.

2.1 The levelised cost of electricity (LCOE)

The LCOE is the principal tool for comparing the plant-level unit costs of different baseload technologies over their operating lifetimes. The LCOE indicates the economic costs of a generic technology, not the financial costs of a specific projects in a specific market. Due to the equality between discounted average costs and the stable remuneration over lifetime electricity production, which is at its heart, LCOE is in spirit closer to the costs of electricity production in regulated electricity markets with stable tariffs, for which it was developed, than to the variable prices in deregulated markets. By adjusting the discount rate for the implicit cost of price volatility, the LCOE concept can, in principle, also be applied in the context of deregulated markets.

However, one can identify a number of developments in the operations of today's electricity systems that, to different degrees, limit its immediate applicability. In the regulated markets of the past, the technology with the lowest LCOE really was indeed also the best baseload investment choice. This no longer holds true. First, structural changes in demand and supply, in particular the advent of significant shares of variable renewables with zero short-run marginal costs, but also storage, distributed generation or demand response, challenge the notion of baseload production itself, i.e. technologies with comparable characteristics that predictably produce at high load factors. Second, the complexity of markets with a spectrum of flexibility needs leads to increased "revenue stacking" even for former baseload producers rather than dedicated production for one single (forward) market. Third, in the context of these increased flexibility needs, portfolio effects become increasingly important rather than the technical characteristics of individual units. Fourth, and most importantly, in systems with large shares of variable renewables, one must complement cost considerations with value considerations, or, equivalently, account for costs at the system rather than at the plant level.

As explained more comprehensively in Chapter 4 on VALCOE, a technology's true economic cost will now depend also on its overall share and technical characteristics as well as on the costs and technical characteristics of all other technologies in the system rather than only on the discounted sum of its investment costs and variable costs at the plant-level.

Nevertheless, despite its limitations, well understood by the experts, LCOE has maintained its appeal. It remains a uniquely straightforward, transparent, comparable, and well understood metric. While there is an increasing need to complement it with information, such as provided by VALCOE, on the system contribution of different technologies under different constellations, the LCOE retains its fundamental usefulness as a widely used tool for modelling, policy making and public debate.

The question of discounting

The calculation of the LCOE is based on the equivalence of the present value of the sum of discounted revenues and the present value of the sum of discounted costs. Another way of looking at LCOE is considering it the electricity tariff at which an investor would precisely break even after paying the required rates of return on capital, given the costs incurred over the lifetime of a technology. This equivalence of discounted lifetime revenues and LCOE is based on two important assumptions:

(1) The real discount rate r used for discounting costs and benefits is stable, the same for all technologies and does not vary during the lifetime of the project under consideration. The EGC 2020 edition uses a 3% discount rate (corresponding approximately to the "social cost of capital"), a 7% discount rate (corresponding approximately to the cost of capital of a large utility in a deregulated or restructured market), and a 10% discount rate (corresponding approximately to cost of capital in an environment with relatively higher risks). Nominal discount rates would be higher, reflecting inflation. While in practice the cost of capital, and hence the relevant discount rate, may vary between different technologies, assuming an identical costs of capital for all technologies allows comparing the costs across technologies and across regions.

(2) The electricity tariff, P_{MWh}, is stable and does not to change during the lifetime of the project. All output, at the assumed capacity factor, is sold at this tariff.

With annual discounting, the LCOE calculation begins with Equation (1) expressing the equality between the present value of the sum of discounted revenues and the present value of the sum of discounted costs, including payments to capital providers. The subscript t denotes the year in which the sale of production or the cost disbursement takes place. The summation extends from the start of construction preparation to the end of dismantling, which includes the discounted value at that time of future waste management costs. All variables are real, i.e. net of inflation. On the left-hand side one finds the discounted sum of benefits and on the right-hand side the discounted sum of costs:

$$\sum P_{MWh} * MWh * (1+r)^{-t} = \sum(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t) * (1+r)^{-t} \quad (1)$$

P_{MWh} = The constant lifetime remuneration to the supplier for electricity;

MWh = The amount of electricity produced annually in MWh;

$(1+r)^{-t}$ = The real discount rate corresponding to the cost of capital;

$Capital_t$ = Total capital construction costs in year t;

$O\&M_t$ = Operation and maintenance costs in year t;

$Fuel_t$ = Fuel costs in year t;

$Carbon_t$ = Carbon costs in year t;

D_t = Decommissioning and waste management costs in year t.

Because P_{MWh} is a constant over time, it can be brought out of the summation, and Equation (1) can be transformed into

$$LCOE = P_{MWh} = \frac{\sum(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t) * (1+r)^{-t}}{\sum MWh\ (1+r)^{-t}} \quad (2)$$

where this constant. P_{MWh}. is defined as the levelised cost of electricity (LCOE).

Equation (2) is the formula used here to calculate average lifetime levelised costs on the basis of the costs for investment, operation and maintenance, fuel, carbon emissions and decommissioning and dismantling provided by OECD countries and selected non-member countries. (For CHP plants, a heat credit is subtracted from total unit costs to establish the LCOE.) It is also the formula that has been used in previous editions of the EGC series on the cost of generating electricity, and in most other studies on the topic.

Some confusion could arise if Equation (2) were taken out of context. In that equation, it looks as if MWhs are being discounted. Because P_{MWh} is a constant, it can be taken out of the summation of revenues over the plant's lifetime and both sides of Equation (1) can be divided by this summation. It is not the MWhs that are being discounted; it is the revenue from those MWh that is being discounted. Revenue today has more value to the investor/owner/operator than revenue tomorrow. It is not output per se that is discounted, but its economic value. This is standard procedure in cost-benefit accounting.

Calculating the costs of generating electricity

Before presenting the different methodological conventions and default assumptions employed to harmonise the data received from different countries, one major underlying principle must be discussed: this report on *Projected Costs of Generating Electricity* is concerned with the levelised cost of producing baseload electricity at the plant level. While this seems straightforward, it has implications that are frequently less evident.

First, the assumed capacity factors are reasonable consensus assumptions for comparing baseload technologies. They do not reflect the technical capabilities of different technologies. For example, nuclear power plants can operate more than 90% capacity factors in years without refuelling outages, and combined-cycle natural gas turbines (CCGTs) can operate at less than 80% when they are too expensive to compete in the baseload market. For nuclear, coal and CCGTs a standard capacity factor of 85% was chosen. This is higher than the average observed capacity factors in practice, and particularly so for CCGT plants (this report does not consider steam cycle natural gas plants). The reason is that operators may choose to shut them down during baseload periods, when prices are low, owing to their higher marginal costs (for example owing to high natural gas prices).

Second, plant level costs imply that for the LCOE calculation the overall system effects are not taken into account, i.e. the impact of a power plant on the electricity system as a whole. The system effects, however, can potentially have a significant impact. In the case of variable renewable energies for example, they might negatively impact expected revenues at higher shares of penetration.

Finally, this report considers social resource costs: the cost to society to build and operate a given plant, independent of all taxes, subsidies and transfers. For example a tax credit or a faster amortisation schedule can boost the profitability of a given project. Hence, they affect the competitiveness of specific technologies, aside from their social resource cost. Keeping in mind these caveats concerning the nature of the analysis, it is now possible to provide an overview of the more detailed methodological conventions and key numerical assumptions employed to calculate the levelised cost of electricity (LCOE) for different technologies in different countries.

2.2 Methodological conventions and key assumptions

The purpose of these methodological conventions for calculating levelised average lifetime costs with the EGC model is to guarantee comparability of the data received while preserving the country-specific information. Defining them in a satisfactory manner implies finding a careful balance between too much and too little homogenisation.

As an example, different fuel cost assumptions inside a single region such as Europe would blur most other information but reveal little about national conditions for electricity generation costs. At the same time, the important differences in fuel costs between Europe, North America and Asia have to be adequately reflected. Globally harmonised values have thus been used for:

- discount rate;
- technical lifetime;
- load factors of flexible plants;
- carbon price (including carbon emission factors of fuel, except lignite);
- construction duration and expense schedule;
- decommissioning costs and duration.

Regionally differentiated values instead have been used for:

- fuel prices (lignite and bio-fuel costs are project specific; nuclear fuel cycle costs for Japan and Russia reflect national specifications);
- load factors of renewable technologies.

In the light of occasionally incomplete national data, methodological conventions and default assumptions serve to complete and harmonise data. Decisions on methodology were prepared by the IEA and NEA Secretariats and taken in the EGC Expert Group by consensus. What follows is an overview of key assumptions and conventions.

Lifetimes

The EGC harmonised expected lifetimes for each technology across countries are as follows through consensus:

Battery storage:	10 years
Solar PV, onshore and offshore wind:	25 years
Gas-fired power plants:	30 years
Coal-fired power and geothermal plants:	40 years
Nuclear power plants:	60 years
Hydropower plants:	80 years
Additional lifetime after nuclear LTO:	10 or 20 years, depending on regulatory framework

Discount rates

The levelised costs of electricity were calculated for all technologies at 3%, 7% and 10% real discount rates.

Capacity

Wherever the distinction was made in national submissions, net rather than gross capacity was used for calculations. If only gross capacity was provided, net values were deducted using provided or generic own consumption. While this report compares plants of very different sizes, it does not take into account the economies of larger multiple-unit plants. It is estimated that new units built at an existing site may be 10% to 15% cheaper than greenfield projects if they can use, at least partially, existing buildings, auxiliary facilities and infrastructure. Regulatory approvals are also likely to be more straightforward.

Capacity factors

A standard capacity factor of 85% was used for all combined-cycle gas turbines (CCGTs), coal-fired, fuel cells and nuclear plants under the assumption that they operate in baseload. It is clearly understood that many CCGTs are frequently used in mid-load or even peak load rather than in baseload, and that coal-fired power plants habitually only achieve 50-60% load factors in major markets. Nevertheless, the 85% assumption is used as a generic assumption for CCGTs and coal-fired power plants as it allows for the straightforward comparison of the costs of three technologies that could be used as baseload. For OCGTs, a capacity factor of 30% is assumed. However, as capacity factors vary significantly in different markets, we also present results for capacity factors of 50% for flexible coal, nuclear and CCGT gas plants and 10% for OCGTs to illustrate the impact of this change on the LCOE.

For all other technologies, country-specific capacity factors were assumed as they are largely site-specific.

Overnight costs

Overnight construction costs include:

1. direct construction costs plus pre-construction costs, such as site licensing, including the environmental testing;
2. the indirect costs such as engineering and administrative costs that cannot be associated with a specific direct construction cost category, as well as capitalised indirect costs;
3. owners' costs that include any additional expenses incurred by the owners associated with the plant and plant site, but excluding offsite, "beyond the busbar", transmission costs;[1] and
4. contingency to account for changes in overnight cost during construction.

1. Cost information on overnight costs and LCOE pertain explicitly only to costs *before* the busbar, i.e. before connection to the grid. While in some countries, project developers are obliged to pay for connection costs themselves, the latter are not part of the figures reported in this report.

Contingency payments

Contingencies, increased costs resulting from unforeseen technical or regulatory events, are included in the overnight costs. The following conventions have been adopted by the EGC Expert Group if national data was not available:

Nuclear energy (except LTO):	15% of overnight costs
All other technologies:	5% of overnight costs

Construction cost profiles

We assume linear expense schedules for all technologies and the followings constructions lengths:

Non-hydro/-geothermal renewables, fuel cells:	1 year
OCGT power plants:	2 years
CCGT power plants:	3 years
Coal- and biomass-fired power plants:	4 years
Geothermal and hydro plants:	5 years
Nuclear power plants:	7 years (LTO: 2 years)

Investment costs

Investment costs consist of overnight costs plus financing costs (e.g. interest during construction), referred to in Equations (1) and (2) as total capital construction costs.

Annual efficiency losses

Some power plants experience lower electric conversion efficiencies and hence reduced output as their operational lifetime progresses. These losses are usually small and can be disregarded. The only technology where efficiency losses have a systematic effect is solar PV. The study therefore assumes a default value of an annual efficiency loss of 0.5%.

Emission costs

No costs for emissions other than CO_2 (see below) were included in the LCOE calculations of this report. Increasingly strict regulations in OECD and non-OECD countries for emissions such as particulates, NOx and SOx, however, increase the cost of power production primarily from coal and biomass. The degree to which the costs of pollution control equipment is included in overnight capital costs varies from country to country.

Treatment of fixed operations and maintenance costs

Fixed O&M costs were added to each year of operation. Where available, provided national data was used, otherwise default values were used.

Fuel prices

Fuel price assumptions for hard (black) coal and natural gas are comparable with the assumptions used in the STEPS scenario in the *World Energy Outlook 2019* (IEA, 2019).[2] For the heat content of brown coal, national assumptions were used. The prices used are provided in standard commercial units for coal (tonnes, weighted averages adjusted to 6 000 kilocalories per kilogramme) and for natural gas in million British thermal units (MBtu).

Table 2.1: Fuel prices

Region	Hard coal [USD/tonne]	Natural gas [USD/MBtu]
Asia	83	10
Americas	51	3.2
China	88	9.1
Europe	75	8

For Australia, an individual gas price of USD 7.8 per MBtu was selected.

Due to the global coronavirus appearance in the first half of 2020, fuel prices saw significant declines globally early that year. The values assumed for this report were fixed before much of these declines, and therefore may be high relative to expectations at the time of publication. Of course, any view of fuel prices in 2025 will have significant underlying uncertainties. For a discussion on the impact of changes in fuel prices on the LCOE calculation, see Chapter 5.

Costs of the "once-through" nuclear fuel cycle

Many countries provided cost data on different components of the fuel cycle, including the costs of recycling used fuel. However, to increase comparability, cost data was harmonised for all countries except Japan and Russia who indicated specific national values.

For the LCOE calculations, the following fuel prices per generated MWh of electricity were used:

Front-end of nuclear fuel cycle: (mining, enrichment, conditioning)	USD 7 per MWh
Back-end of nuclear fuel cycle: (spent fuel removal, disposal and storage)	USD 2.33 per MWh

Japan provided costs of 8.6 and 5.3 USD/MWh for front-end and back-end cost respectively, Russia 4.0 and 0.9 USD/MWh.

Carbon price

The EGC includes a harmonised carbon price of USD 30 per tonne of CO_2 common to all countries over the lifetime of all technologies. Many countries do not have an explicit carbon price. In these cases, the price can be assumed to be the implicit shadow price of carbon.

2. Recent events, notably a decrease in energy demand following the Covid-19 pandemic, have led to short-term declines in fuel prices. However, given that this report assumes commissioning in 2025 and that plants will only consume fossil fuels from that date onward, there is no need to adjust what is in fact a central estimate for necessarily uncertain long-term price assumptions.

We calculate emission costs based on the carbon content per MWh. For globally traded fuel, data was derived from IPCC (IPPC, 2006, Volume 2, Chapter 2, “Stationary Combustion”, p. 2.16; confirmed by IPCC, 2019).

Decommissioning and residual values

At the end of a plant’s lifetime, decommissioning and waste management costs are linearly spread over the decommissioning period. We assume the following durations:

Nuclear power plants:	10 years
All other technologies:	2 years

The cost of decommissioning is defined as the total cost of dismantling an existing plant and related activities minus any residual value. This report uses the following generic values for the sum of residual value and decommissioning costs:

Nuclear energy:	15% of overnight costs
All other technologies:	5% of overnight costs.

Because of the levelised cost methodology, decommissioning costs become small when discounted over 60 or 80 years, the lifetime of a nuclear plant or hydroelectric plant. In practice, the operator makes annual contributions to a Decommissioning Trust Fund during operations whose sum plus accrued interest will eventually correspond to the estimated total costs of decommissioning. While the amount per MWh figure is small (see LCOE tables in Chapter 3), the long lifetime and the accumulated return on the fund ensure full coverage of the estimated decommissioning costs (see PNNL, 2011). Such generic assumptions inevitably abstract from unanticipated cost inflation or other uncertainties related to expenditures that will take place several decades later.

Heat credit

A CHP device produces two products, electricity and heat, simultaneously. The cost of the expended primary fuel should be allocated partly to the electric energy and partly to the thermal energy. There are several ways of doing this, depending on the individual point of view.

A frequently used approach is to compare the heat produced by a CHP plant to the costs of a dedicated heat production technology. For comparability reasons, a uniform heat price of USD 37.1/ MWh_{th} assuming 90% efficiency was used, which represents the heat production costs of a highly efficient natural gas combustion engine in Europe, which was the only region for which CHP data was received.

Transmission and grid connection costs

Transmission and grid connection costs were disregarded, as the LCOE figures presented in this report exclusively consider plant-level production costs.

Exchange rates

All costs are reported here in 2018 USD terms. Table 2.2 shows the exchange rate used for each national currency unit (NCU) for which a conversion was performed, based on the average 2018 rate as reported by the OECD.

Table 2.2: National currency units per USD (2018 average)

Country	Exchange rate
Australia	1.34
Brazil	3.65
Canada	1.30
China	6.62
Euro area	0.85
Hungary	270.21
India	68.39
Japan	110.42
Korea	1 101
Mexico	19.24
Norway	8.13
Romania	3.94
Russia	62.67

Source: OECD (2020), http://data.oecd.org/conversion/exchange-rates.htm.

2.3 Conclusions

This overview described the conventions and key assumptions adopted for calculating the levelised cost of electricity generation. While individual assumptions can be debated – and several of them have been the subject of extensive discussion in the EGC Expert Group – one should not lose sight of their essential function, which is to render comparable large amounts of heterogeneous data. In fact, only by rendering the data comparable can the specificity of each individual dataset be brought out and assessed. Readers are invited to form their own views. The sensitivity analyses in Chapter 5 and the interactive tools in the web-based version of this report will help them in assessing the impact of different assumptions for different parameters.

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LCOE Values by technology and country

This chapter presents an overview of the technologies included in this report. Section 3.1 includes a summary of overnight and investment costs, capacities, and other relevant technical specifications for all 243 plants in the EGC 2020 report. Sections 3.2, 3.3 and 3.4 provide plant-by-plant cost data including a breakdown of the LCOE cost components, for each plant, separated according to technology. All cost figures are in USD 2018. The assumed commissioning date is 2025.

3.1 Overview and summary statistics

Table 3.1 presents the size and overnight cost statistics for the various technologies included in *Projected Costs of Generating Electricity – 2020 Edition*. For the calculation of mean and median values, to weigh the values for each country equally, median cases for each country were selected in case multiple datasets for the same technology exist. Otherwise, no weighing was performed (all figures in this report follow this approach). As not all countries provided data for each technology, results should not be mistaken for (capacity-weighted) averages over all countries.

Table 3.1: Summary statistics for different generating technologies

Technology	Number of plants / countries	Net capacity (MWe)				Overnight costs (USD/kWe)			
		Min	Mean	Median	Max	Min	Mean	Median	Max
ACAES	1 / 1	250	250	250	250	1 695	1 695	1 695	1 695
Lithium-ion battery	4 / 4	1.0	7.5	2.0	19	452	932	655	1 967
Biomass	4 / 3	0.42	18	25	30	833	2 501	1 095	6 545
Biomass (CHP)	5 / 2	0.42	130	130	358	2 538	4 689	4 689	6 545
Coal	11 / 6	138	693	722	954	800	1 897	1 785	4 382
Coal (CCUS)	4 / 2	499	641	641	650	4 490	4 572	4 572	5 991
Coal (CHP)	1 / 1	700	700	700	700	2 240	2 240	2 240	2 240
Fuel cell	4 / 2	0.003	0.20	0.20	15	2 361	4 715	4 715	6 492
Gas (CCGT)	16 / 11	471	762	743	1 372	254	823	955	1 109
Gas (CCGT, CCUS)	2 / 2	437	541	541	646	2 412	2 619	2 619	2 826
Gas (CCGT, CHP)	2 / 2	5.80	253	253	500	1 024	1 092	1 092	1 160
Gas (OCGT/int. comb.)	8 / 5	100	464	500	980	325	630	668	1 141
Gas (OCGT/int. comb., CHP)	3 / 3	35.90	119	125	195	330	707	684	1 107
Geothermal	6 / 2	5	19	19	40	3 851	6 647	6 647	10 959
Hydro (reservoir, >= 5 MW)	4 / 4	11.95	58	23	175	1 899	3 319	2 778	5 819
Hydro (reservoir, < 5 MW)	1 / 1	0.32	0.32	0.32	0.32	3 966	3 966	3 966	3 966
Hydro (run of river, >= 5 MW)	7 / 4	5	85	44	248	2 326	3 557	3 026	6 681
Hydro (run of river, < 5 MW)	18 / 4	0.02	2.54	3.00	4.80	956	3 507	2 801	7 484
Lignite	2 / 2	709	805	805	900	2 189	2 973	2 973	3 756
Lignite (CCUS)	1 / 1	570	570	570	570	6 891	6 891	6 891	6 891
Lignite (CHP)	1 / 1	2 900	2 900	2 900	2 900	1 015	1 015	1 015	1 015
Nuclear	8 / 8	950	1 234	1 137	1 650	2 157	3 606	3 370	6 920

(continued Table 3.1)

Technology	Number of plants / countries	Net capacity (MWe)				Overnight costs (USD/kWe)			
		Min	Mean	Median	Max	Min	Mean	Median	Max
Nuclear (LTO)	4 / 4	1 000	1 000	1 000	1 000	391	504	497	629
Pumped storage	3 / 3	175	458	200	1 000	563	1 962	897	4 426
Solar PV (floating)	1 / 1	8	8	8	8	860	860	860	860
Solar PV (utility scale)	21 / 14	0.83	26	20	100	534	995	923	2 006
Solar PV (commercial)	15 / 8	0.05	0.25	0.24	0.50	846	1 065	1 085	1 357
Solar PV (residential)	15 / 8	0.004	0.01	0.01	0.02	719	1 583	1 653	2 597
Solar thermal (CSP)	4 / 2	100	125	125	150	5 238	5 857	5 857	6 475
Offshore wind	23 / 8	11.25	186	100	600	1 721	2 876	2 740	4 039
Onshore wind (>= 1 MW)	33 / 18	1	58	40	280	877	1 391	1 439	3 022
Onshore wind (< 1 MW)	11 / 1	0.01	0.19	0.19	0.90	1 782	2 852	2 852	5 539

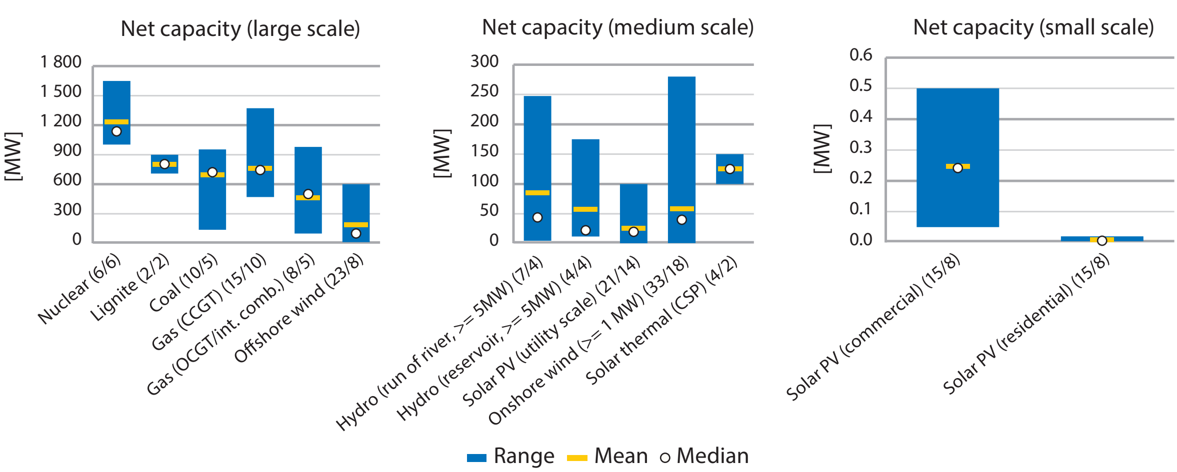
Note: CHP = combined heat and power. CCUS = carbon capture. utilisation and storage. CCGT = Combined cycle gas turbine. OCGT = Open cycle gas turbine. LTO = long-term operation. CSP = concentrated solar power. ACAES = Adiabatic compressed air energy storage.

The EGC 2020 dataset includes a wide range of generating technologies, including natural gas-fired generation (both combined-cycle gas turbines [CCGTs], and open-cycle gas turbines [OCGTs]), coal-fired generation, nuclear plants, solar photovoltaic (of varying sizes) and concentrated solar power (CSP), onshore and offshore wind, geothermal, biomass, and combined heat and power (based on a variety of fuel types).

The main drivers for the costs of generating electricity are typically the construction, fuel (including expenses for CO_2 emissions) as well as operation and maintenance costs. All these factors are influenced by the size of the individual units, with economies of scale typically reducing costs at larger scale. Despite the very modular nature of solar PV and wind turbines, costs can typically be reduced by building wind or and solar farms. In case of renewables, costs can typically be reduced by constructing wind or solar farms. The following figures illustrate to what extent some of these key parameters vary in the provided data (limited to technologies with data from at least two to three countries).

Figure 3.1 illustrates capacity ranges grouped by size. The values illustrate that technologies vary considerably with respect to capacity. Only nuclear new builds have been provided with at least 1 GW of capacity. Especially wind installations come in very different sizes, ranging from single turbines with below 1 MW to farms of 200 MW. Similarly, offshore installations range from 11 to 600 MW (especially for offshore wind, larger projects exist, for example Hornsea One with 1.2 GW which is due to be inaugurated in 2020). For utility scale solar PV, data for farms with up to 100 MW total capacity was provided.

Figure 3.1: Range of capacity

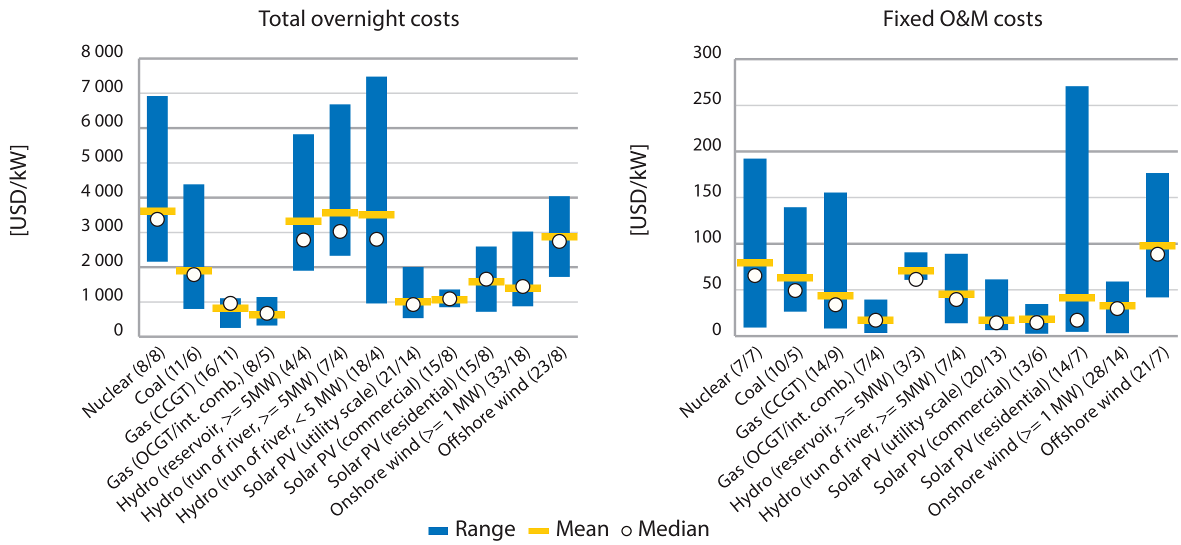


Note: Values in brackets indicate total number of data points and number of countries.

Overnight investment costs vary significantly (see Figure 3.2). Even relatively mature coal- and gas-fired technologies show large differences – depending on the technology specifics, unit size and the individual country. The same is true for annual fixed O&M costs.

The load factors illustrate the range of use cases for different power plants (here the expected values as they were submitted are shown, in the subsequent LCOE calculations the load factors are normalised to enhance comparability). Whereas nuclear and coal plants are used for baseload operation, gas-fired OCGTs are typically peak load plants – CCGTs cover a wider range from mid- to baseload operation.

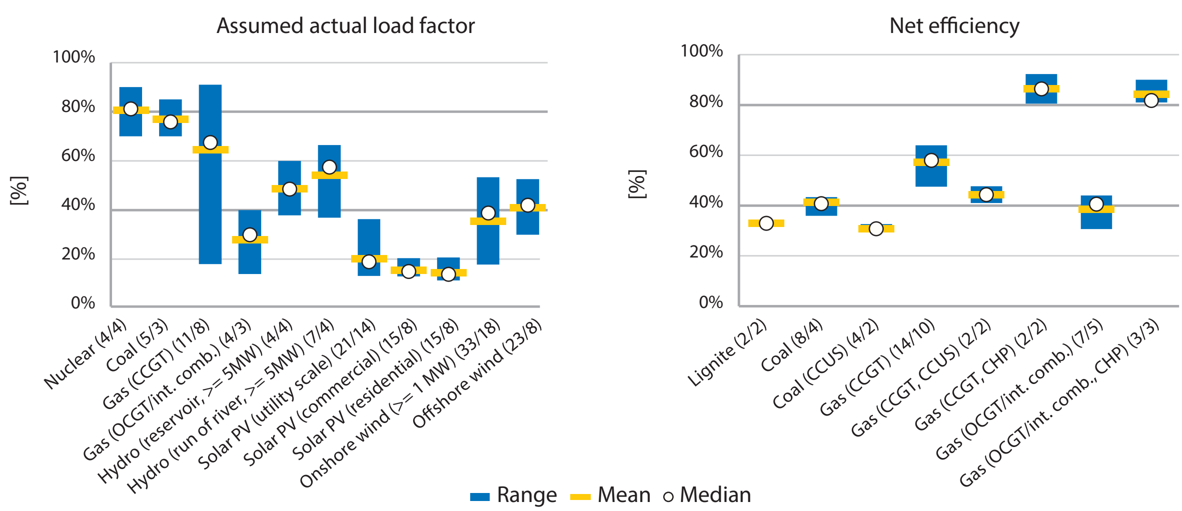
Figure 3.2: Range of overnight and fixed O&M costs



Note: Values in brackets indicate total number of data points and number of countries.

The efficiency of power plants determines fuel costs and emission intensity of electricity generation. Provided values are rather similar within each technology group. Fossil fuel plants with CCUS are on average 10% (coal) and 14% (gas CCGT) less efficient than without capturing CO_2. CHP technologies, which additionally to electricity generation make use of the resulting heat, reach significantly higher total efficiency values than electricity only plants. Even OCGTs, in terms of efficiency in a clear disadvantage compared to CCGTs, reach in conjunction with heat production on average an 84% overall efficiency.

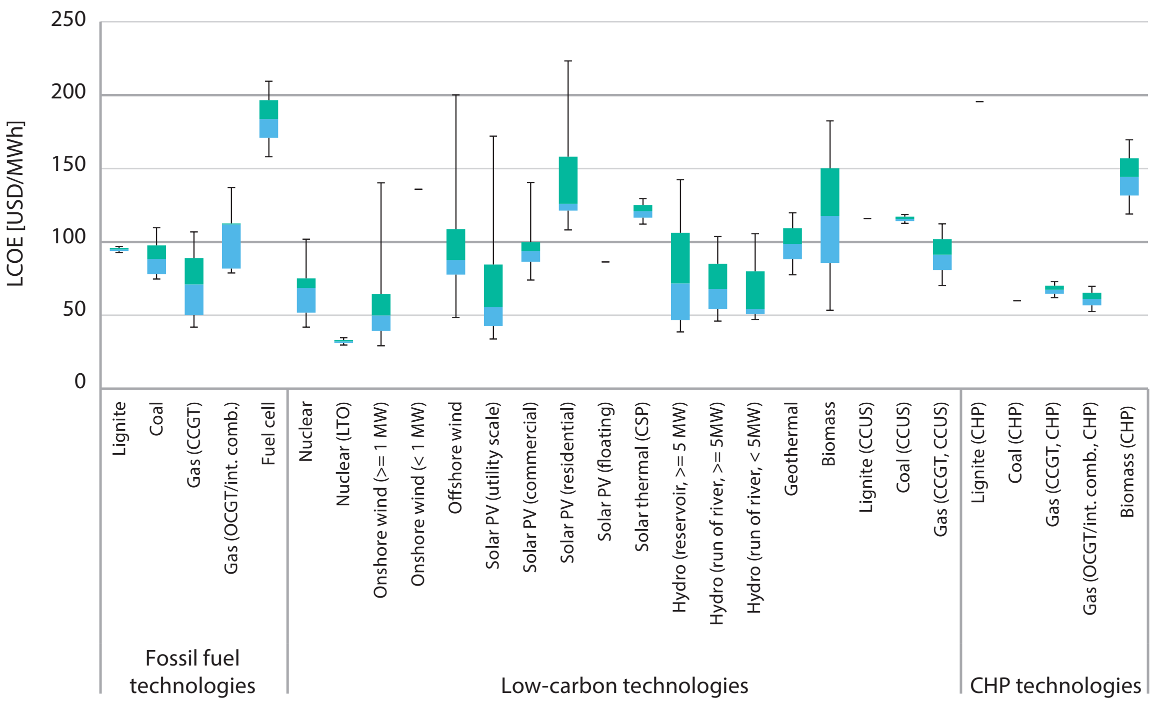
Figure 3.3: Range of assumed load factors and net efficiency



Note: Values in brackets indicate total number of data points and number of countries.

Due to the indicated differences in input values also the LCOE of different electricity generation technologies vary significantly depending on the country, the technology and the properties of individual plants. It is thus not meaningful to point out a single power plant type, which would outcompete the others in terms of average costs. This is in particular true for renewable technologies, especially wind turbines and photovoltaics, whose costs are very much location dependent. Therefore, they are frequently tailored to individual requirements: not only are PV installations differing in size, from household rooftop installation and floating panels to utility scale open space PV installations, but also wind turbines range from being installed in small-scale individual units to large wind farms. The same holds true for hydro units, being connected to small streams or large rivers, in the form of run of river or reservoir. Figure 3.4 illustrates this range of technological options for generating electricity and associated costs.

Figure 3.4: Overview of LCOE values



Note: Values at 7% discount rate. Box plots indicate maximum. median and minimum values. The boxes indicate the central 50% of values, i.e. the second and the third quartile.

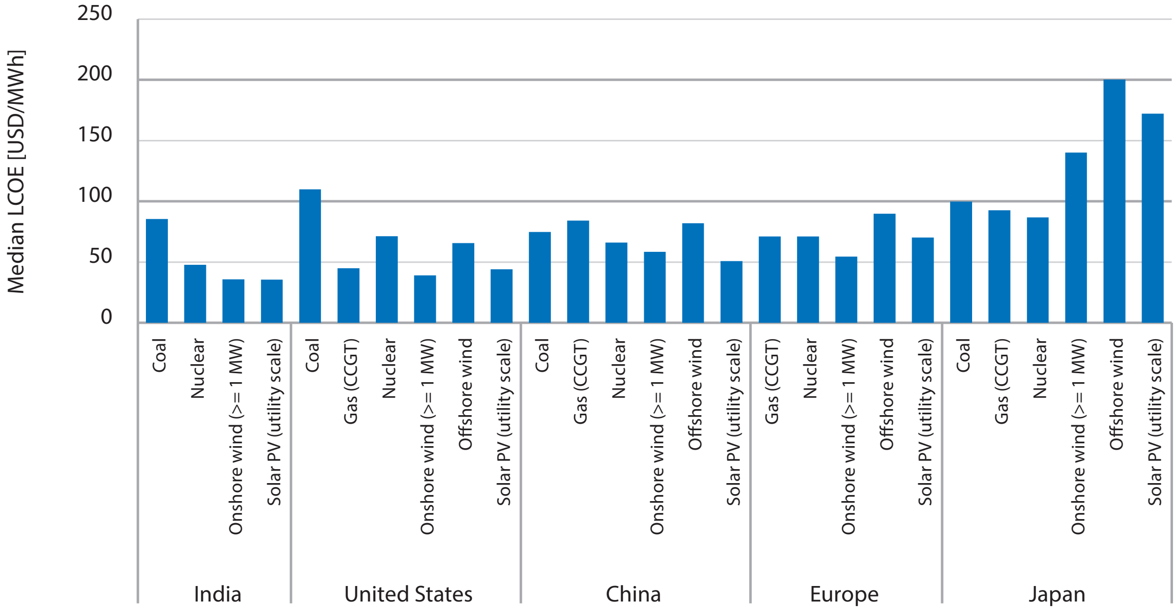
The multitude of categories also illustrates the diversity of options on the thermal technology side: several fuel categories are paired with technology options like CHP, CCUS and different turbine types. One of the most striking results is the large range of LCOE values for renewable technologies. Although utility-size power plants often have plant-level costs that are comparable to conventional power plants, smaller plants can still be several times more expensive.

The aggregated data for the 24 countries that provided data for this report does not tell the whole story of levelised generation costs. Due to more or less favourable sites for renewable generation, varying fuel costs and technology maturity, costs for all technologies can vary significantly by country and region. In addition, the *share* of a technology in the total production of an electricity system makes a difference to its value, load factor and average costs.

Whereas renewables are very competitive in most countries participating in this report, the data provided for this report shows that they still have higher costs than fossil fuel- or nuclear-based generation in some countries (in this report Japan, Korea and Russia). Also within countries, different locational conditions can lead to differences in generation costs at the subnational and local level. In Europe, both onshore and offshore wind as well as utility scale solar installations are competitive to gas and nuclear energy.

In the United States, gas-fired power plants benefit from the expected low fuel prices in the region, although fuel price assumptions are in general uncertain. Nevertheless, in terms of the LCOE of the median plant, onshore wind and utility scale solar PV are, assuming emission costs of USD 30/tCO_2, the least cost options. Natural gas CCGTs are followed by offshore wind, nuclear new build and, finally, coal.

Figure 3.5: Median technology costs by region



Note: Values at 7% cost of capital.

In China and India, variable renewables are having the lowest expected levelised generation costs: utility scale solar PV and onshore wind are the least-cost options in both countries. Nuclear energy is also competitive, showing that both countries have promising options to transition out of their currently still highly carbon-intensive electricity generation.

3.2 Technology-by-technology data on overnight and investment costs

Tables 3.2 to 3.9 present data on overnight costs and investment costs at discount rate of 3%, 7%, and 10%. Since some submissions displayed only very minor differences, only 231 of the 243 power plants, for which data was submitted, were included in the following tables. Units showing the range of values were selected in case multiple similar datasets were provided by single countries. All data is included in the accompanying downloadable files. The overnight cost includes pre-construction (owner's), construction (engineering, procurement, and construction) and contingency costs, but not interest during construction (IDC). The latter is instead included in the investment costs. All values for solar PV (as for the rest) are expressed on an alternating current (AC) basis.

Table 3.2a: Combined-cycle gas turbine (CCGT) generating technology

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Australia	CCGT	506	48%	955	998	1 058	1 105
	CCGT (CCUS)	437	41%	2 826	2 955	3 133	3 271
Belgium	CCGT	500	60%	767	802	850	888
	CCGT	500	64%	1 009	1 055	1 119	1 168
	CCGT	500	58%	974	1 018	1 079	1 127
Canada	CCGT	471	57%	1 058	1 106	1 173	1 224
Italy	CCGT	790	60%	590	617	654	683
Japan	CCGT	1 372	56%	1 109	1 160	1 229	1 283
Korea	CCGT	491	56%	1 107	1 158	1 228	1 281
	CCGT	982	59%	838	877	929	970
Mexico	CCGT	503	51%	669	700	742	775
	CCGT	785	60%	667	698	740	772
	CCGT	835	58%	466	488	517	540
Romania	CCGT	750	58%	254	265	281	294
United States	CCGT	727	59%	952	995	1 055	1 102
	CCGT (CCUS)	646	48%	2 412	2 522	2 674	2 791
Non-OECD countries							
Brazil	CCGT	980	58%	958	1 002	1 062	1 108
China	CCGT	475	58%	560	586	621	648

Table 3.2b: Open-cycle gas turbine (OCGT) generating technology

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Autralia	OCGT	537	31%	668	688	715	736
Belgium	OCGT	350	40%	531	547	569	585
	OCGT	500	41%	670	691	718	738
	OCGT	500	38%	590	608	632	650
Canada	OCGT	100	41%	1 141	1 175	1 221	1 256
	OCGT	243	40%	518	533	554	570
Italy	OCGT	130	37%	325	334	348	357
Non-OECD countries							
Brazil	OCGT	980	44%	739	761	791	814

Table 3.3: Coal-fired generating technologies

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
						7%	10%
Australia	Supercritical pulverised	722	40%	2 433	2 583	2 794	2 961
	Supercritical pulverised (CCUS)	633	30%	4 490	4 766	5 155	5 463
	Supercritical pulverised (lignite)	709	32%	3 756	3 987	4 312	4 571
	Supercritical pulverised (lignite. CCUS)	570	21%	6 891	7 315	7 912	8 386
Japan	Ultra-supercritical	749	41%	2 419	2 568	2 777	2 943
Korea	Ultra-supercritical	954	43%	1 151	1 221	1 321	1 400
United States	Pulverised	138	36%	4 382	4 651	5 031	5 332
	Pulverised	140	36%	3 447	3 659	3 958	4 195
	Pulverised	650	40%	2 478	2 630	2 845	3 015
	Pulverised (CCUS)	650	31%	4 604	4 887	5 286	5 603
	Supercritical pulverised	650	42%	2 582	2 741	2 965	3 142
	Supercritical pulverised (CCUS)	650	33%	4 654	4 940	5 344	5 663
	Ultra-supercritical	641	43%	4 157	4 413	4 773	5 059
	Other coal (CCUS)	499	31%	5 991	6 359	6 879	7 290
Non-OECD countries							
Brazil	Other coal (lignite)	900	34%	2 189	2 324	2 514	2 664
China	Ultra-supercritical	347	45%	800	849	919	974
India	Ultra-supercritical	400	45%	1 148	1 218	1 318	1 397
	Ultra-supercritical	400	45%	1 111	1 179	1 276	1 352

Table 3.4a: Nuclear generating technologies – New build

Country	Technology	Net capacity (MWe)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
				3%	7%	10%
France	EPR	1 650	4 013	4 459	5 132	5 705
Japan	ALWR	1 152	3 963	4 402	5 068	5 633
Korea	ALWR	1 377	2 157	2 396	2 759	3 066
Russia	VVER	1 122	2 271	2 523	2 904	3 228
Slovak Republic	Other nuclear	1 004	6 920	7 688	8 850	9 837
United States	LWR	1 100	4 250	4 721	5 435	6 041
Non-OECD countries						
China	LWR	950	2 500	2 777	3 197	3 554
India	LWR	950	2 778	3 086	3 552	3 949

Table 3.4b: Nuclear generating technologies – Long-Term Operation (LTO)

Country	Technology	Net capacity (MWe)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
				3%	7%	10%
Switzerland	LTO	1 000	550	567	589	606
France	LTO	1 000	629	648	673	693
Sweden	LTO	1 000	444	457	475	489
United States	LTO	1 000	391	403	419	431

Table 3.5: Solar generating technologies								
Country	Technology	Net capacity* (MWe)	Capacity factor (%)	Annual efficiency loss (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
						3%	7%	10%
Austria	Solar PV (residential)	0.02	11%	0.5%	719	730	744	754
Australia	Solar PV (utility scale)	100	28%	0.5%	882	895	912	925
	Solar thermal (CSP)	150	47%	0.0%	5 238	5 316	5 419	5 494
Belgium**	Solar PV (residential)	0.01	13%	0.5%	1 841	1 869	1 905	1 931
	Solar PV (residential)	0.01	12%	0.5%	1 346	1 366	1 392	1 411
	Solar PV (residential)	0.01	13%	0.5%	1 009	1 024	1 043	1 058
	Solar PV (utility scale)	1.00	13%	0.5%	992	1 006	1 026	1 040
Canada	Solar PV (utility scale)	20	25%	0.5%	1 354	1 375	1 401	1 421
	Solar PV (utility scale)	20	19%	0.5%	1 264	1 283	1 308	1 326
Denmark	Solar PV (residential)	0.01	12%	0.5%	1 176	1 194	1 217	1 234
	Solar PV (commercial)	0.10	13%	0.5%	847	860	876	889
	Solar PV (utility scale)	8	16%	0.5%	534	542	553	561
	Solar PV (utility scale)	8	18%	0.5%	623	632	645	654
France	Solar PV (residential)	0.01	18%	0.5%	1 700	1 725	1 758	1 783
	Solar PV (commercial)	0.50	18%	0.5%	850	863	879	891
	Solar PV (utility scale)	25	24%	0.5%	708	719	733	743
Hungary	Solar PV (residential)	0.004	15%	0.5%	1 901	1 929	1 966	1 994
	Solar PV (commercial)	0.05	14%	0.5%	1 297	1 316	1 341	1 360
	Solar PV (commercial)	0.50	14%	0.5%	1 075	1 091	1 112	1 127
	Solar PV (utility scale)	20	14%	0.5%	964	978	997	1 011
Italy**	Solar PV (commercial)	0.08	20%	0.5%	1 306	1 325	1 350	1 369
	Solar PV (commercial)	0.21	17%	0.5%	907	920	938	951
	Solar PV (commercial)	0.42	20%	0.5%	1 210	1 228	1 252	1 269
	Solar PV (residential)	0.004	20%	0.5%	1 846	1 873	1 909	1 936
	Solar PV (residential)	0.01	17%	0.5%	1 368	1 389	1 415	1 435
	Solar PV (utility scale)	0.83	20%	0.5%	827	840	856	868
	Solar PV (utility scale)	0.83	27%	0.5%	836	849	865	877
Japan	Solar PV (residential)	0.004	12%	0.5%	2 333	2 367	2 413	2 447
	Solar PV (utility scale)	2	14%	0.5%	2 006	2 036	2 075	2 104
Korea	Solar PV (commercial)	0.10	15%	0.5%	1 240	1 259	1 283	1 301
	Solar PV (utility scale)	2.97	15%	0.5%	1 226	1 244	1 268	1 286
Netherlands	Solar PV (floating)	8	14%	0.5%	860	873	890	902
	Solar PV (commercial)	0.20	14%	0.5%	846	858	875	887
	Solar PV (utility scale)	8	14%	0.5%	807	819	835	847
Norway	Solar PV (commercial)	0.30	10%	0.5%	984	998	1 018	1 032
United States	Solar PV (residential)	0.01	14%	0.5%	1 884	1 913	1 949	1 976
	Solar PV (residential)	0.01	16%	0.5%	1 884	1 913	1 949	1 976
	Solar PV (residential)***	0.01	17%	0.5%	1 884	1 913	1 949	1 976
	Solar PV (residential)	0.01	19%	0.5%	2 597	2 635	2 686	2 723
	Solar PV (residential)	0.01	21%	0.5%	2 597	2 635	2 686	2 723
	Solar PV (commercial)	0.30	13%	0.5%	1 357	1 377	1 403	1 423
	Solar PV (commercial)	0.30	15%	0.5%	1 357	1 377	1 403	1 423
	Solar PV (commercial)***	0.30	16%	0.5%	1 357	1 377	1 403	1 423
	Solar PV (commercial)	0.30	19%	0.5%	1 357	1 377	1 403	1 423
	Solar PV (commercial)	0.30	20%	0.5%	1 357	1 377	1 403	1 423
	Solar PV (utility scale)	100	23%	0.5%	1 072	1 088	1 109	1 124
	Solar PV (utility scale)	100	26%	0.5%	1 072	1 088	1 109	1 124
	Solar PV (utility scale)***	100	28%	0.5%	1 072	1 088	1 109	1 124
	Solar PV (utility scale)	100	33%	0.5%	1 072	1 088	1 109	1 124
	Solar PV (utility scale)	100	36%	0.5%	1 072	1 088	1 109	1 124
	Solar thermal (CSP)	100	50%	0.0%	6 475	6 571	6 698	6 791
	Solar thermal (CSP)	100	61%	0.0%	6 475	6 571	6 698	6 791
	Solar thermal (CSP)***	100	64%	0.0%	6 475	6 571	6 698	6 791

(continued Table 3.5)

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Annual efficiency loss (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
						3%	7%	10%
Non-OECD countries								
Brazil	Solar PV (utility scale)	25	31%	0.5%	1 197	1 215	1 239	1 256
China	Solar PV (utility scale)	20	18%	0.5%	730	741	756	766
India	Solar PV (utility scale)	35	20%	0.5%	629	638	650	659

* All values represent AC capacity.
** A generic sizing factor of 1.2 was used to convert peak DC capacity into peak AC capacity.
*** Indicated as reference datasets by the providing country.

Table 3.6a: Wind generating technology – Onshore

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Austria	Onshore wind (>= 1 MW)	3.00	27%	1 458	1 479	1 508	1 529
Australia	Onshore wind (>= 1 MW)	100	42%	1 432	1 454	1 482	1 502
Belgium	Onshore wind (>= 1 MW)	4.50	25%	1 534	1 557	1 587	1 609
	Onshore wind (>= 1 MW)	5.00	30%	1 475	1 497	1 526	1 547
	Onshore wind (>= 1 MW)	30	28%	1 416	1 438	1 465	1 486
	Onshore wind (>= 1 MW)	30	28%	1 326	1 345	1 371	1 390
Canada	Onshore wind (>= 1 MW)	200	40%	1 361	1 382	1 408	1 428
Denmark	Onshore wind (>= 1 MW)	4.48	40%	918	931	949	962
Finland	Onshore wind (>= 1 MW)	30	40%	1 534	1 557	1 587	1 609
France	Onshore wind (>= 1 MW)	50	38%	1 475	1 497	1 526	1 547
Italy	Onshore wind (< 1 MW)	0.01	17%	5 317	5 396	5 500	5 576
	Onshore wind (< 1 MW)	0.02	32%	5 539	5 621	5 729	5 809
	Onshore wind (< 1 MW)	0.06	20%	4 075	4 136	4 215	4 274
	Onshore wind (< 1 MW)	0.06	33%	4 616	4 685	4 775	4 841
	Onshore wind (< 1 MW)	0.10	31%	3 323	3 373	3 438	3 485
	Onshore wind (< 1 MW)	0.19	18%	2 852	2 895	2 950	2 991
	Onshore wind (< 1 MW)	0.50	33%	2 659	2 698	2 750	2 788
	Onshore wind (< 1 MW)	0.80	32%	1 782	1 809	1 844	1 869
	Onshore wind (< 1 MW)	0.83	30%	2 269	2 302	2 347	2 379
	Onshore wind (< 1 MW)	0.90	48%	2 727	2 767	2 820	2 860
	Onshore wind (< 1 MW)	0.90	43%	2 786	2 827	2 882	2 922
	Onshore wind (>= 1 MW)	1.00	39%	3 022	3 067	3 126	3 169
	Onshore wind (>= 1 MW)	10	37%	1 429	1 450	1 478	1 499
	Onshore wind (>= 1 MW)	20	30%	1 499	1 521	1 551	1 572
Japan	Onshore wind (>= 1 MW)	20	20%	2 282	2 316	2 360	2 393
Korea	Onshore wind (>= 1 MW)	14.85	23%	1 982	2 011	2 050	2 078
Netherlands	Onshore wind (>= 1 MW)	50	48%	1 250	1 269	1 293	1 311
Norway	Onshore wind (>= 1 MW)	130	44%	932	946	964	977
Russia	Onshore wind (>= 1 MW)	60	27%	1 598	1 622	1 653	1 676
	Onshore wind (>= 1 MW)	280	27%	1 472	1 494	1 523	1 544
Sweden	Onshore wind (>= 1 MW)	5	42%	1 098	1 114	1 136	1 151
United States	Onshore wind (>= 1 MW)	100	53%	1 430	1 451	1 479	1 500
	Onshore wind (>= 1 MW)	100	49%	1 338	1 358	1 384	1 404
	Onshore wind (>= 1 MW)	100	47%	1 323	1 343	1 369	1 388
	Onshore wind (>= 1 MW)*	100	45%	1 319	1 339	1 365	1 384
	Onshore wind (>= 1 MW)	100	43%	1 342	1 361	1 388	1 407
	Onshore wind (>= 1 MW)	100	41%	1 523	1 546	1 575	1 597
	Onshore wind (>= 1 MW)	100	37%	1 615	1 639	1 670	1 694
	Onshore wind (>= 1 MW)	100	33%	1 968	1 997	2 035	2 064
	Onshore wind (>= 1 MW)	100	28%	2 180	2 213	2 255	2 287
	Onshore wind (>= 1 MW)	100	18%	2 329	2 364	2 410	2 443

(continued Table 3.6a)

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Non-OECD countries							
Brazil	Onshore wind (>= 1 MW)	30	47%	1 314	1 333	1 359	1 378
China	Onshore wind (>= 1 MW)	50	26%	1 174	1 191	1 214	1 231
India	Onshore wind (>= 1 MW)	65	27%	877	890	907	920

* Indicated as reference datasets by the providing country.

Table 3.6b: Wind generating technology – Offshore

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Australia	Offshore wind	100	51%	3 474	3 526	3 594	3 644
Belgium	Offshore wind	12	39%	2 361	2 396	2 442	2 476
	Offshore wind	50	39%	2 361	2 396	2 442	2 476
Denmark	Offshore wind	11.25	52%	2 012	2 042	2 081	2 110
	Offshore wind	11.5	52%	1 721	1 746	1 780	1 805
France	Offshore wind	500	45%	3 069	3 115	3 175	3 219
Japan	Offshore wind	100	30%	4 039	4 099	4 178	4 236
Korea	Offshore wind	99	30%	3 520	3 572	3 641	3 692
United States	Offshore wind	600	47%	1 952	1 981	2 019	2 047
	Offshore wind	600	46%	1 958	1 987	2 025	2 054
	Offshore wind*	600	46%	2 060	2 091	2 131	2 161
	Offshore wind	600	46%	2 151	2 183	2 225	2 256
	Offshore wind	600	45%	2 189	2 222	2 264	2 296
	Offshore wind	600	39%	2 209	2 242	2 285	2 317
	Offshore wind	600	30%	2 411	2 447	2 494	2 529
	Offshore wind	600	53%	2 410	2 446	2 493	2 528
	Offshore wind	600	51%	2 420	2 456	2 503	2 538
	Offshore wind	600	50%	2 486	2 523	2 572	2 607
	Offshore wind	600	50%	2 577	2 615	2 666	2 703
	Offshore wind	600	47%	2 604	2 643	2 694	2 732
	Offshore wind	600	37%	2 607	2 646	2 697	2 735
	Offshore wind	600	31%	2 864	2 907	2 963	3 004
Non-OECD countries							
China	Offshore wind	50	35%	2 265	2 299	2 343	2 375

* Indicated as reference datasets by the providing country.

Table 3.7a: Other renewable generating technologies – Hydropower

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Austria	Run of river (< 5 MW)	2.2	51%	2 361	2 544	2 809	3 023
Germany	Run of river (>= 5 MW)	24.5	65%	3 000	3 233	3 569	3 842
Italy	Run of river (< 5 MW)	0.02	55%	6 510	7 015	7 745	8 336
	Run of river (< 5 MW)	0.1	34%	3 013	3 247	3 585	3 859
	Run of river (< 5 MW)	0.2	55%	5 503	5 930	6 547	7 047
	Run of river (< 5 MW)	0.25	15%	3 647	3 930	4 339	4 670
	Run of river (< 5 MW)	0.25	8%	3 266	3 520	3 886	4 183
	Run of river (< 5 MW)	0.25	19%	1 592	1 715	1 894	2 039
	Run of river (< 5 MW)	0.5	20%	1 070	1 153	1 273	1 370
	Run of river (< 5 MW)	0.50	15%	3 782	4 075	4 499	4 843
	Run of river (< 5 MW)	0.50	22%	2 398	2 584	2 853	3 071
	Run of river (< 5 MW)	0.7	55%	4 411	4 753	5 248	5 649
	Run of river (< 5 MW)	1	15%	956	1 030	1 137	1 224
	Run of river (< 5 MW)	2.1	50%	3 216	3 466	3 826	4 119
	Run of river (>= 5 MW)	5	37%	3 052	3 289	3 631	3 908
	Reservoir (< 5 MW)	0.32	65%	3 966	4 274	4 719	5 079
	Reservoir (>= 5 MW)	15	38%	3 108	3 349	3 697	3 980
Japan	Reservoir (>= 5 MW)	12	45%	5 819	6 271	6 923	7 452
Norway	Reservoir (>= 5 MW)	30	52%	1 899	2 047	2 260	2 432
	Run of river (< 5 MW)	3.0	47%	1 964	2 117	2 337	2 515
United States	Run of river (< 5 MW)*	4.8	62%	6 383	6 879	7 594	8 175
	Run of river (>= 5 MW)*	82	64%	5 810	6 261	6 912	7 441
	Run of river (< 5 MW)*	4.2	60%	4 275	4 607	5 086	5 475
	Run of river (>= 5 MW)*,**	45	60%	4 031	4 344	4 795	5 162
	Run of river (< 5 MW)	3.7	66%	7 484	8 065	8 904	9 585
	Run of river (>= 5 MW)	44	66%	6 681	7 200	7 949	8 556
	Run of river (< 5 MW)	4.3	62%	6 544	7 052	7 786	8 380
	Run of river (>= 5 MW)**	94	66%	5 891	6 349	7 009	7 544
Non-OECD countries							
Brazil	Run of river (>= 5 MW)	248	50%	2 326	2 507	2 768	2 979
India	Reservoir (>= 5 MW)	175	60%	2 449	2 639	2 914	3 136

* These are projects for powering non-powered dams (NPD). They are thus brownfield projects, for which part of the investment costs have already been amortised.

** Indicated as reference datasets by the providing country.

Table 3.7b: Other renewable generating technologies – Biomass

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Italy	Biomass	0.5	89%	4 605	4 888	5 288	5 604
	Biomass	0.42	89%	6 545	6 948	7 515	7 965
Non-OECD countries							
Brazil	Biomass	25	30%	1 095	1 162	1 257	1 332
India	Biomass	30	85%	833	885	957	1 014

Table 3.7c: Other renewable generating technologies – Geothermal							
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Italy	Geothermal	40	76%	3 851	4 150	4 581	4 932
	Geothermal	15	86%	7 132	7 686	8 485	9 134
	Geothermal	10	86%	9 799	10 560	11 659	12 549
	Geothermal	5	86%	10 959	11 810	13 038	14 034
United States	Geothermal	30	90%	4 120	4 440	4 901	5 276
	Geothermal	25	80%	5 538	5 968	6 588	7 092

Table 3.8: Combined heat and power (CHP) technologies							
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Denmark	Biomass	177	46%	4 013	4 260	4 608	4 884
	Biomass	261	46%	2 715	2 882	3 117	3 304
	Biomass	258	57%	2 951	3 132	3 388	3 591
	Biomass	358	57%	2 538	2 694	2 914	3 088
	Coal (Ultra-supercritical)	700	57%	2 240	2 378	2 572	2 726
	Gas (CCGT)	500	57%	1 024	1 071	1 135	1 185
	Gas (OCGT)	125	46%	684	705	732	753
Italy	Biomass	0.4	89%	6 545	6 948	7 515	7 965
Romania	Pulverised (Lignite)	2 900	50%	1 015	1 077	1 165	1 235
	Gas (OCGT)	195	90%	330	340	353	363
Slovak Republic	Gas (CCGT)	6	70%	1 160	1 213	1 286	1 343
	Gas (OCGT)	36	98%	1 107	1 141	1 186	1 220

Table 3.9: Storage technologies								
Country	Technology	Net capacity (MWe)	Storage capacity (h)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
						3%	7%	10%
Australia	Pumped storage	200	na	15%	897	910	927	940
Canada	ACAES*	250	4	15%	1 695	1 772	1 879	1 961
Denmark	Lithium-ion battery	19	0.33	15%	484	491	501	508
	Pumped storage	1 000	na	15%	4 426	4 492	4 579	4 642
Finland	Lithium-ion battery	1.14	5.26	15%	1 967	1 997	2 035	2 063
Italy	Lithium-ion battery	2	0.5	15%	452	459	468	474
Non-OECD countries								
India	Lithium-ion battery	1	4	15%	826	838	854	866
	Pumped storage	175	na	15%	563	571	582	590

* Adiabatic Compressed Air Energy Storage

Table 3.10: Fuel cells

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
France	Fuel cell	0.003	85%	6 492	6 589	6 715	6 809
	Fuel cell	0.2	85%	5 902	5 990	6 105	6 190
	Fuel cell	15	85%	2 361	2 396	2 442	2 476
Norway	Fuel cell	1	85%	3 529	3 582	3 650	3 701

3.3 Technology-by-technology LCOE data at standard capacity factors

Tables 3.10 to 3.17 present the calculated LCOEs for the power plants included in the EGC 2020 dataset, along with the relevant cost components, calculated at each of the three discount rates (3%, 7% and 10%). The LCOEs for coal, nuclear and CCGT gas plants are all calculated at the same assumed capacity factor of 85%, while the LCOEs for OCGT gas plants are calculated at a capacity factor of 30%.[1] Plant-specific capacity factors were used for all renewable power plants and CHP plants. Calculations include a carbon price of USD 30/tCO_2. This reflects the expected average social costs of emissions over the technology's lifetime. The actual emission price being charged to generators varies from country to country. This changes the private costs of investment experienced by investors.

For each power plant, the net capacity, overnight cost, refurbishment and decommissioning costs, and O&M costs are presented. Construction, refurbishment and decommissioning costs for all plants are dependent on the discount rate used, and so the costs presented are calculated at each discount rate. For solar PV, which efficiency is assumed to decrease by 0.5% each year, O&M costs vary depending on the discount rate. Also included are the fuel, waste and carbon costs, when relevant. For fossil fuel plants a column indicating the electrical conversion efficiency is included.

1. Alternate LCOEs assuming a 50% load factor are presented below.

Table 3.11a: Levelised cost of electricity for combined-cycle gas turbine (CCGT) at 85% capacity factor

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Australia	CCGT	506	48%	6.74	11.07	15.01
	CCGT (CCUS)	437	41%	19.95	32.78	44.43
Belgium	CCGT	500	60%	5.42	8.90	12.06
	CCGT	500	64%	7.12	11.71	15.86
	CCGT	500	58%	6.87	11.29	15.31
Canada	CCGT	471	57%	7.47	12.27	16.63
Italy	CCGT	790	60%	4.17	6.85	9.28
Japan	CCGT	1 372	56%	7.83	12.86	17.43
Korea	CCGT	491	56%	7.82	12.84	17.41
	CCGT	982	59%	5.92	9.72	13.18
Mexico	CCGT	503	51%	4.73	7.76	10.52
	CCGT	785	60%	4.71	7.74	10.49
	CCGT	835	58%	3.29	5.41	7.33
Romania	CCGT	750	58%	1.79	2.94	3.99
United States	CCGT	727	59%	6.72	11.04	14.96
	CCGT (CCUS)	646	48%	17.03	27.97	37.91
Non-OECD countries						
Brazil	CCGT	980	58%	6.76	11.11	15.06
China	CCGT	475	58%	3.95	6.49	8.80

Table 3.11b: Levelised cost of electricity for open-cycle gas turbine (OCGT) at 30% capacity factor

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Autralia	OCGT	537	31%	13.16	21.20	28.31
Belgium	OCGT	350	40%	10.47	16.86	22.51
	OCGT	500	41%	13.21	21.28	28.42
	OCGT	500	38%	11.63	18.73	25.01
Canada	OCGT	100	41%	22.48	36.20	48.34
	OCGT	243	40%	10.20	16.44	21.95
Italy	OCGT	130	37%	6.40	10.30	13.76
Non-OECD countries						
Brazil	OCGT	980	44%	14.56	23.45	31.32

Table 3.12: Levelised cost of electricity for coal plants at 85% capacity factor

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Australia	Supercritical pulverised	722	40%	14.79	27.21	38.78
	Supercritical pulverised (CCUS)	633	30%	27.28	50.20	71.54
	Supercritical pulverised (lignite)	709	32%	22.82	42.00	59.85
	Supercritical pulverised (lignite, CCUS)	570	21%	41.88	77.05	109.80
Japan	Ultra-supercritical	749	41%	14.70	27.05	38.54
Korea	Ultra-supercritical	954	43%	6.99	12.87	18.34
United States	Pulverised	138	36%	26.63	49.00	69.82
	Pulverised	140	36%	20.95	38.54	54.93
	Pulverised	650	40%	15.06	27.71	39.48
	Pulverised (CCUS)	650	31%	27.98	51.48	73.36
	Supercritical pulverised	650	42%	15.69	28.87	41.14
	Supercritical pulverised (CCUS)	650	33%	28.28	52.04	74.16
	Ultra-supercritical	641	43%	25.26	46.48	66.24
	Other coal (CCUS)	499	31%	36.41	66.99	95.46
Non-OECD countries						
Brazil	Other coal (lignite)	900	34%	13.31	24.48	34.89
China	Ultra-supercritical	347	45%	4.86	8.95	12.75
India	Ultra-supercritical	400	45%	6.97	12.83	18.29
	Ultra-supercritical	400	45%	6.75	12.42	17.71

Decommissioning (USD/MWh) 3%	7%	10%	Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh) 3%	7%	10%	Country
0.13	0.06	0.03	56.04	12.75	6.59	**82.24**	**86.51**	**90.42**	**Australia**
0.38	0.18	0.10	64.96	1.48	12.87	**99.64**	**112.27**	**123.84**	
0.10	0.05	0.03	45.88	10.18	6.00	**67.58**	**71.00**	**74.14**	**Belgium**
0.14	0.06	0.04	42.65	9.47	4.80	**64.18**	**68.69**	**72.82**	
0.13	0.06	0.03	47.06	10.45	6.67	**71.19**	**75.54**	**79.52**	
0.14	0.07	0.04	19.19	10.65	6.96	**44.41**	**49.13**	**53.46**	**Canada**
0.08	0.04	0.02	45.50	10.10	6.99	**66.83**	**69.47**	**71.88**	**Italy**
0.15	0.07	0.04	61.05	10.84	7.70	**87.56**	**92.52**	**97.06**	**Japan**
0.15	0.07	0.04	60.82	10.80	11.36	**90.95**	**95.89**	**100.43**	**Korea**
0.11	0.05	0.03	58.23	10.34	8.41	**83.01**	**86.76**	**90.19**	
0.09	0.04	0.02	21.62	12.00	5.28	**43.72**	**46.71**	**49.45**	**Mexico**
0.09	0.04	0.02	18.29	10.15	5.73	**38.97**	**41.95**	**44.68**	
0.06	0.03	0.02	18.89	10.48	5.51	**38.24**	**40.32**	**42.23**	
0.11	0.07	0.05	47.06	10.45	46.27	**105.68**	**106.79**	**107.82**	**Romania**
0.13	0.06	0.03	18.38	10.20	5.30	**40.73**	**44.98**	**48.88**	
0.33	0.16	0.09	22.91	5.09	14.22	**59.57**	**70.34**	**80.21**	**United States**
									Non-OECD countries
0.13	0.06	0.03	18.83	10.45	11.21	**47.37**	**51.65**	**55.57**	**Brazil**
0.06	0.03	0.01	53.54	10.45	13.49	**81.48**	**84.00**	**86.29**	**China**

Decommissioning (USD/MWh) 3%	7%	10%	Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh) 3%	7%	10%	Country
0.26	0.12	0.07	86.91	19.77	9.09	**129.19**	**137.09**	**144.15**	**Autralia**
0.20	0.10	0.05	68.24	15.15	7.50	**101.56**	**107.85**	**113.46**	**Belgium**
0.26	0.12	0.07	66.58	14.78	9.83	**104.66**	**112.59**	**119.67**	
0.23	0.11	0.06	71.83	15.94	7.99	**107.63**	**114.61**	**120.84**	
0.44	0.21	0.11	26.44	14.67	8.70	**72.72**	**86.22**	**98.27**	**Canada**
0.20	0.09	0.05	27.30	15.15	18.53	**71.37**	**77.50**	**82.97**	
0.12	0.06	0.03	73.98	16.42	11.11	**108.03**	**111.87**	**115.30**	**Italy**
									Non-OECD countries
0.28	0.13	0.07	24.82	13.77	16.71	**70.14**	**78.88**	**86.69**	**Brazil**

Decommissioning (USD/MWh) 3%	7%	10%	Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh) 3%	7%	10%	Country
0.21	0.07	0.03	29.65	25.47	8.69	**78.81**	**91.10**	**102.63**	**Australia**
0.38	0.14	0.06	39.58	3.40	19.34	**89.98**	**112.66**	**133.92**	
0.32	0.11	0.05	5.13	34.36	11.26	**73.90**	**92.86**	**110.65**	
0.59	0.21	0.09	7.89	5.28	25.56	**81.19**	**115.99**	**148.63**	
0.21	0.07	0.03	28.73	24.68	19.31	**87.62**	**99.84**	**111.29**	**Japan**
0.10	0.03	0.02	27.47	23.60	11.62	**69.78**	**75.59**	**81.04**	**Korea**
0.37	0.13	0.06	20.19	28.22	30.47	**105.89**	**128.01**	**148.76**	**United States**
0.29	0.10	0.05	20.36	28.46	22.25	**92.31**	**109.71**	**126.04**	
0.21	0.08	0.03	18.23	25.48	17.01	**75.98**	**88.50**	**100.23**	
0.39	0.14	0.06	23.50	13.14	30.45	**95.46**	**118.71**	**140.52**	
0.22	0.08	0.03	17.51	24.47	17.20	**75.09**	**88.13**	**100.35**	
0.40	0.14	0.06	22.38	12.51	30.15	**93.73**	**117.23**	**139.27**	
0.35	0.13	0.05	17.16	23.99	29.50	**96.27**	**117.27**	**136.95**	
0.51	0.18	0.08	23.32	13.04	42.96	**116.24**	**146.49**	**174.86**	
									Non-OECD countries
0.19	0.07	0.03	31.76	32.03	8.60	**85.88**	**96.94**	**107.31**	**Brazil**
0.06	0.02	0.01	28.02	22.70	14.97	**70.62**	**74.66**	**78.45**	**China**
0.08	0.03	0.01	26.43	22.70	8.53	**64.72**	**70.53**	**75.97**	**India**
0.07	0.03	0.01	26.43	22.70	38.65	**94.61**	**100.24**	**105.51**	

Table 3.13a: Levelised cost of electricity for nuclear plants at 85% capacity factor – New build

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
France	EPR	1 650	33%	21.32	47.46	73.29
Japan	ALWR	1 152	33%	21.05	46.87	72.37
Korea	ALWR	1 377	36%	11.46	25.51	39.39
Russia	VVER	1 122	38%	12.06	26.86	41.47
Slovak Republic	Other nuclear	1 004	32%	36.76	81.84	126.37
United States	LWR	1 100	33%	22.58	50.26	77.61
Non-OECD countries						
China	LWR	950	33%	13.28	29.57	45.65
India	LWR	950	33%	14.76	32.85	50.73

Table 3.13b1: Levelised cost of electricity for nuclear plants at 85% capacity factor – Long-Term Operation (LTO), 10 years

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Switzerland	LTO	1 000	33%	8.79	10.88	12.62
France	LTO	1 000	33%	10.05	12.45	14.44
Sweden	LTO	1 000	33%	7.10	8.79	10.19
United States	LTO	1 000	33%	6.25	7.74	8.97

Table 3.13b2: Levelised cost of electricity for nuclear plants at 85% capacity factor – Long-Term Operation (LTO), 20 years

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Switzerland	LTO	1 000	33%	5.04	7.22	9.11
France	LTO	1 000	33%	5.76	8.25	10.42
Sweden	LTO	1 000	33%	4.07	5.83	7.35
United States	LTO	1 000	33%	3.58	5.13	6.48

* Conservatively, decommissioning costs are calculated on the basis of 15% LTO overnight costs, assuming that decommissioning starts 5 years after shutdown and lasts for 10 years as for new build. However, depending on the individual project, some of the incremental decommissioning costs due to LTO have already been included in the LTO overnight costs or are very small. In these cases, incremental decommissioning costs due to LTO will be closer to zero. Provisions for final decommissioning costs have already been accounted for in the cost of electricity produced during the original design lifetime of the plant.

	Decommissioning (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
	3%	7%	10%			3%	7%	10%	
	0.36	0.05	0.01	9.33	14.26	**45.27**	**71.10**	**96.89**	**France**
	0.36	0.05	0.01	13.92	25.84	**61.16**	**86.67**	**112.13**	**Japan**
	0.20	0.03	0.01	9.33	18.44	**39.42**	**53.30**	**67.16**	**Korea**
	0.21	0.03	0.01	4.99	10.15	**27.41**	**42.02**	**56.61**	**Russia**
	1.80	0.96	0.64	9.33	9.72	**57.61**	**101.84**	**146.06**	**Slovak Republic**
	0.39	0.05	0.01	9.33	11.60	**43.90**	**71.25**	**98.56**	**United States**
									Non-OECD countries
	0.22	0.03	0.01	10.00	26.42	**49.92**	**66.01**	**82.08**	**China**
	0.25	0.03	0.01	9.33	23.84	**48.17**	**66.06**	**83.91**	**India**

	Decommissioning* (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
	3%	7%	10%			3%	7%	10%	
	0.71	0.40	0.27	9.33	12.92	**31.74**	**33.53**	**35.13**	**Switzerland**
	0.81	0.46	0.30	9.33	12.92	**33.11**	**35.15**	**36.98**	**France**
	0.57	0.32	0.21	9.33	12.92	**29.91**	**31.35**	**32.65**	**Sweden**
	0.51	0.28	0.19	9.33	18.69	**34.78**	**36.04**	**37.18**	**United States**

	Decommissioning* (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
	3%	7%	10%			3%	7%	10%	
	0.29	0.13	0.07	9.33	12.92	**27.57**	**29.59**	**31.43**	**Switzerland**
	0.34	0.15	0.08	9.33	12.92	**28.35**	**30.65**	**32.74**	**France**
	0.23	0.10	0.06	9.33	12.92	**26.54**	**28.17**	**29.66**	**Sweden**
	0.21	0.09	0.05	9.33	18.69	**31.81**	**33.24**	**34.55**	**United States**

Table 3.14: Levelised cost of electricity for solar generators

Country	Technology	Net capacity* (MWe)	Capacity factor (%)	Annual efficiency loss (%)	Investment (USD/MWh)		
					3%	7%	10%
Austria	Solar PV (residential)	0.02	11%	0.5%	43.54	64.47	82.28
Australia	Solar PV (utility scale)	100	28%	0.5%	21.75	32.20	41.10
	Solar thermal (CSP)	150	47%	0.0%	73.07	109.18	140.17
Belgium**	Solar PV (residential)	0.01	13%	0.5%	96.32	142.62	182.03
	Solar PV (residential)	0.01	12%	0.5%	75.17	111.30	142.06
	Solar PV (residential)	0.01	13%	0.5%	54.49	80.68	102.97
	Solar PV (utility scale)	1.00	13%	0.5%	51.87	76.79	98.02
Canada	Solar PV (utility scale)	20	25%	0.5%	37.41	55.39	70.69
	Solar PV (utility scale)	20	19%	0.5%	45.94	68.02	86.82
Denmark	Solar PV (residential)	0.01	12%	0.5%	67.13	99.39	126.86
	Solar PV (commercial)	0.10	13%	0.5%	44.65	66.11	84.37
	Solar PV (utility scale)	8	16%	0.5%	22.87	33.86	43.22
	Solar PV (utility scale)	8	18%	0.5%	24.02	35.57	45.40
France	Solar PV (residential)	0.01	18%	0.5%	66.53	98.51	125.73
	Solar PV (commercial)	0.50	18%	0.5%	33.27	49.26	62.87
	Solar PV (utility scale)	25	24%	0.5%	20.38	30.17	38.51
Hungary	Solar PV (residential)	0.004	15%	0.5%	87.49	129.55	165.35
	Solar PV (commercial)	0.05	14%	0.5%	66.32	98.20	125.34
	Solar PV (commercial)	0.50	14%	0.5%	54.97	81.39	103.88
	Solar PV (utility scale)	20	14%	0.5%	49.29	72.98	93.15
Italy**	Solar PV (residential)	0.004	20%	0.5%	65.14	96.45	123.10
	Solar PV (residential)	0.01	17%	0.5%	55.06	81.52	104.05
	Solar PV (commercial)	0.08	20%	0.5%	46.07	68.22	87.07
	Solar PV (commercial)	0.21	17%	0.5%	36.48	54.01	68.93
	Solar PV (commercial)	0.42	20%	0.5%	42.71	63.23	80.71
	Solar PV (utility scale)	0.83	20%	0.5%	29.11	43.10	55.02
	Solar PV (utility scale)	0.83	27%	0.5%	21.77	32.23	41.13
Japan	Solar PV (residential)	0.004	12%	0.5%	134.23	198.74	253.66
	Solar PV (utility scale)	2	14%	0.5%	98.94	146.50	186.98
Korea	Solar PV (commercial)	0.10	15%	0.5%	57.08	84.52	107.88
	Solar PV (utility scale)	2.97	15%	0.5%	56.43	83.55	106.63
Netherlands	Solar PV (floating)	8	14%	0.5%	42.05	62.25	79.46
	Solar PV (residential)	0.20	14%	0.5%	42.48	62.89	80.28
	Solar PV (utility scale)	8	14%	0.5%	39.47	58.44	74.59
Norway	Solar PV (commercial)	0.30	10%	0.5%	66.11	97.89	124.94
United States	Solar PV (residential)	0.01	14%	0.5%	96.37	142.69	182.12
	Solar PV (residential)	0.01	16%	0.5%	83.47	123.59	157.74
	Solar PV (residential)***	0.01	17%	0.5%	77.99	115.48	147.39
	Solar PV (residential)	0.01	19%	0.5%	94.38	139.74	178.36
	Solar PV (residential)	0.01	21%	0.5%	86.40	127.93	163.28
	Solar PV (commercial)	0.30	13%	0.5%	71.89	106.44	135.86
	Solar PV (commercial)	0.30	15%	0.5%	62.02	91.83	117.20
	Solar PV (commercial)***	0.30	16%	0.5%	58.14	86.09	109.88
	Solar PV (commercial)	0.30	19%	0.5%	49.76	73.67	94.03
	Solar PV (commercial)	0.30	20%	0.5%	45.97	68.07	86.88
	Solar PV (utility scale)	100	23%	0.5%	32.34	47.88	61.11
	Solar PV (utility scale)	100	26%	0.5%	28.06	41.55	53.03
	Solar PV (utility scale)***	100	28%	0.5%	26.03	38.55	49.20
	Solar PV (utility scale)	100	33%	0.5%	22.40	33.16	42.32
	Solar PV (utility scale)	100	36%	0.5%	20.35	30.13	38.46
	Solar thermal (CSP)	100	50%	0.0%	84.22	125.84	161.57
	Solar thermal (CSP)	100	61%	0.0%	69.36	103.64	133.05
	Solar thermal (CSP)***	100	64%	0.0%	66.53	99.41	127.63
Non-OECD countries							
Brazil	Solar PV (utility scale)	25	31%	0.5%	26.46	39.17	50.00
China	Solar PV (utility scale)	20	18%	0.5%	28.64	42.40	54.12
India	Solar PV (utility scale)	35	20%	0.5%	21.37	31.65	40.39

* All values represent AC capacity.
** A generic sizing factor of 1.2 was used to convert peak DC capacity into peak AC capacity.
*** Indicated as reference datasets by the providing country.

Decommissioning (USD/MWh)			O&M (USD/MWh)			LCOE (USD/MWh)			Country
10%	3%	7%	10%	3%	7%	10%	7%	10%	
0.99	0.54	0.33	43.57	43.18	42.92	**88.11**	**108.18**	**125.54**	**Austria**
0.50	0.27	0.16	4.63	4.59	4.56	**26.88**	**37.06**	**45.83**	**Australia**
1.67	0.91	0.56	19.46	19.46	19.46	**94.19**	**129.55**	**160.19**	
2.20	1.19	0.73	15.48	15.34	15.25	**114.00**	**159.15**	**198.01**	***Belgium**
1.72	0.93	0.57	13.78	13.65	13.57	**90.67**	**125.88**	**156.20**	
1.24	0.67	0.41	21.32	21.13	21.00	**77.05**	**102.48**	**124.39**	
1.18	0.64	0.39	12.90	12.78	12.71	**65.95**	**90.22**	**111.12**	
0.85	0.46	0.28	6.68	6.62	6.58	**44.94**	**62.47**	**77.56**	**Canada**
1.05	0.57	0.35	19.53	19.36	19.24	**66.52**	**87.94**	**106.41**	
1.53	0.83	0.51	14.23	14.10	14.01	**82.89**	**114.32**	**141.39**	**Denmark**
1.02	0.55	0.34	11.20	11.10	11.03	**56.87**	**77.75**	**95.75**	
0.52	0.28	0.17	7.04	6.97	6.93	**30.43**	**41.11**	**50.32**	
0.55	0.30	0.18	7.76	7.69	7.65	**32.34**	**43.56**	**53.23**	
1.52	0.82	0.50	24.54	24.31	24.17	**92.59**	**123.65**	**150.41**	**France**
0.76	0.41	0.25	24.54	24.31	24.17	**58.56**	**73.98**	**87.29**	
0.47	0.25	0.15	3.55	3.52	3.50	**24.39**	**33.94**	**42.16**	
10.35	8.61	7.38	3.56	3.53	3.51	**101.41**	**141.69**	**176.23**	**Hungary**
6.46	5.28	4.48	2.12	2.10	2.09	**74.91**	**105.58**	**131.91**	
3.33	2.55	2.08	20.53	20.34	20.22	**78.83**	**104.28**	**126.19**	
2.67	2.00	1.62	11.17	11.07	11.00	**63.13**	**86.05**	**105.77**	
10.26	13.30	16.01	166.34	164.82	163.86	**241.73**	**274.57**	**302.97**	***Italy**
1.26	0.68	0.42	58.06	57.53	57.19	**114.37**	**139.73**	**161.66**	
9.26	12.27	14.88	21.28	21.09	20.97	**76.62**	**101.58**	**122.91**	
0.83	0.45	0.28	16.67	16.52	16.43	**53.98**	**70.98**	**85.64**	
9.19	12.23	14.85	18.44	18.28	18.17	**70.34**	**93.74**	**113.73**	
0.67	0.36	0.22	14.76	14.62	14.54	**44.53**	**58.08**	**69.77**	
2.51	3.14	3.72	27.85	27.59	27.43	**52.12**	**62.95**	**72.29**	
3.07	1.66	1.02	23.12	22.91	22.77	**160.41**	**223.30**	**277.45**	**Japan**
2.26	1.22	0.75	24.56	24.34	24.19	**125.76**	**172.05**	**211.92**	
1.30	0.70	0.43	13.02	12.91	12.83	**71.41**	**98.13**	**121.14**	**Korea**
1.29	0.70	0.43	12.44	12.32	12.25	**70.15**	**96.56**	**119.31**	
1.94	1.40	1.11	22.92	22.73	22.61	**66.91**	**86.39**	**103.18**	**Netherlands**
1.98	1.43	1.13	25.38	25.17	25.03	**69.84**	**89.50**	**106.44**	
1.88	1.37	1.09	20.33	20.16	20.06	**61.68**	**79.97**	**95.73**	
1.51	0.82	0.50	42.13	41.75	41.50	**109.75**	**140.45**	**166.94**	**Norway**
1.06	0.57	0.35	12.59	12.47	12.40	**110.01**	**155.73**	**194.87**	**United States**
0.90	0.48	0.30	10.90	10.80	10.74	**95.26**	**134.87**	**168.77**	
0.82	0.44	0.27	10.19	10.09	10.03	**89.00**	**126.01**	**157.70**	
1.29	0.70	0.43	12.33	12.21	12.14	**108.00**	**152.65**	**190.93**	
1.17	0.63	0.39	11.28	11.18	11.12	**98.85**	**139.74**	**174.78**	
0.58	0.31	0.19	9.19	9.11	9.06	**81.66**	**115.87**	**145.11**	
0.48	0.26	0.16	7.93	7.86	7.81	**70.43**	**99.94**	**125.17**	
0.43	0.23	0.14	7.44	7.37	7.33	**66.01**	**93.69**	**117.35**	
0.35	0.19	0.12	6.36	6.31	6.27	**56.47**	**80.16**	**100.41**	
0.31	0.17	0.10	5.88	5.83	5.79	**52.16**	**74.06**	**92.77**	
0.20	0.11	0.07	6.74	6.68	6.64	**39.28**	**54.66**	**67.82**	
0.16	0.09	0.05	5.85	5.79	5.76	**34.07**	**47.43**	**58.85**	
0.14	0.08	0.05	5.42	5.38	5.34	**31.60**	**44.00**	**54.59**	
0.11	0.06	0.04	4.67	4.62	4.60	**27.17**	**37.84**	**46.96**	
0.09	0.05	0.03	4.24	4.20	4.18	**24.68**	**34.39**	**42.67**	
1.60	0.87	0.54	15.31	15.31	15.31	**101.14**	**142.03**	**177.42**	
1.32	0.72	0.44	12.61	12.61	12.61	**83.28**	**116.96**	**146.11**	
1.26	0.68	0.42	12.10	12.10	12.10	**79.89**	**112.20**	**140.15**	
									Non-OECD countries
0.60	0.33	0.20	6.58	6.52	6.48	**33.64**	**46.02**	**56.68**	**Brazil**
0.48	0.26	0.16	8.02	8.02	8.02	**37.13**	**50.68**	**62.30**	**China**
0.29	0.15	0.09	3.72	3.69	3.67	**25.38**	**35.49**	**44.15**	**India**

Table 3.15a: Levelised cost of electricity for wind generators – Onshore						
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)		
				3%	7%	10%
Austria	Onshore wind (>= 1 MW)	3.00	27%	35.01	52.31	67.15
Australia	Onshore wind (>= 1 MW)	100	42%	22.36	33.41	42.89
Belgium	Onshore wind (>= 1 MW)	5.00	30%	32.24	48.18	61.85
	Onshore wind (>= 1 MW)	30	28%	33.77	50.46	64.78
	Onshore wind (>= 1 MW)	4.50	25%	40.24	60.13	77.19
	Onshore wind (>= 1 MW)	30	28%	31.60	47.22	60.62
Canada	Onshore wind (>= 1 MW)	200	40%	22.31	33.34	42.80
Denmark	Onshore wind (>= 1 MW)	4.48	40%	15.18	22.69	29.13
Finland	Onshore wind (>= 1 MW)	30	40%	25.18	37.62	48.30
France	Onshore wind (>= 1 MW)	50	38%	25.45	38.04	48.83
Italy	Onshore wind (< 1 MW)	0.01	17%	201.93	301.74	387.39
	Onshore wind (< 1 MW)	0.19	18%	104.51	156.17	200.49
	Onshore wind (< 1 MW)	0.02	32%	112.98	168.82	216.74
	Onshore wind (< 1 MW)	0.06	20%	132.57	198.09	254.32
	Onshore wind (< 1 MW)	0.06	33%	90.52	135.26	173.66
	Onshore wind (< 1 MW)	0.10	31%	70.76	105.73	135.74
	Onshore wind (< 1 MW)	0.50	33%	52.14	77.90	100.02
	Onshore wind (< 1 MW)	0.80	32%	36.90	55.13	70.78
	Onshore wind (< 1 MW)	0.83	30%	50.36	75.24	96.60
	Onshore wind (< 1 MW)	0.90	48%	37.17	55.54	71.30
	Onshore wind (< 1 MW)	0.90	43%	42.08	62.88	80.72
	Onshore wind (>= 1 MW)	1.00	39%	51.02	76.24	97.88
	Onshore wind (>= 1 MW)	10	37%	25.19	37.65	48.33
	Onshore wind (>= 1 MW)	20	30%	32.91	49.17	63.13
Japan	Onshore wind (>= 1 MW)	20	20%	74.80	111.76	143.48
Korea	Onshore wind (>= 1 MW)	14.85	23%	56.48	84.40	108.36
Netherlands	Onshore wind (>= 1 MW)	50	48%	17.01	25.42	32.64
Norway	Onshore wind (>= 1 MW)	130	44%	13.89	20.75	26.64
Russia	Onshore wind (>= 1 MW)	60	27%	38.81	57.99	74.45
	Onshore wind (>= 1 MW)	280	27%	35.74	53.40	68.56
Sweden	Onshore wind (>= 1 MW)	5	42%	17.13	25.60	32.87
United States	Onshore wind (>= 1 MW)	100	53%	17.57	26.26	33.71
	Onshore wind (>= 1 MW)	100	49%	18.07	27.00	34.67
	Onshore wind (>= 1 MW)	100	47%	18.51	27.66	35.51
	Onshore wind (>= 1 MW)*	100	45%	19.09	28.52	36.62
	Onshore wind (>= 1 MW)	100	43%	20.23	30.23	38.81
	Onshore wind (>= 1 MW)	100	41%	24.40	36.46	46.81
	Onshore wind (>= 1 MW)	100	37%	28.52	42.62	54.72
	Onshore wind (>= 1 MW)	100	33%	39.25	58.66	75.31
	Onshore wind (>= 1 MW)	100	28%	50.70	75.76	97.26
	Onshore wind (>= 1 MW)	100	18%	85.66	127.99	164.32
Non-OECD countries						
Brazil	Onshore wind (>= 1 MW)	30	47%	18.32	27.38	35.15
China	Onshore wind (>= 1 MW)	50	26%	30.03	44.87	57.61
India	Onshore wind (>= 1 MW)	65	27%	21.36	31.92	40.98

* Indicated as reference datasets by the providing country.

Decommissioning (USD/MWh)			O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%		3%	7%	10%	
0.80	0.44	0.27	23.61	**59.41**	**76.35**	**91.03**	**Austria**
0.51	0.28	0.17	9.31	**32.18**	**43.00**	**52.37**	**Australia**
0.74	0.40	0.25	19.96	**52.94**	**68.54**	**82.06**	**Belgium**
0.77	0.42	0.26	13.23	**47.77**	**64.11**	**78.27**	
0.92	0.50	0.31	17.71	**58.86**	**78.33**	**95.21**	
0.72	0.39	0.24	10.29	**42.61**	**57.90**	**71.15**	
0.51	0.28	0.17	13.21	**36.04**	**46.83**	**56.19**	**Canada**
0.35	0.19	0.12	6.30	**21.84**	**29.18**	**35.55**	**Denmark**
0.58	0.31	0.19	6.94	**32.69**	**44.88**	**55.44**	**Finland**
0.58	0.32	0.20	17.73	**43.77**	**56.08**	**66.76**	**France**
4.61	2.51	1.55	591.75	**798.29**	**896.00**	**980.68**	**Italy**
2.39	1.30	0.80	27.55	**134.46**	**185.02**	**228.85**	
2.58	1.41	0.87	41.87	**157.43**	**212.10**	**259.48**	
3.03	1.65	1.02	41.46	**177.06**	**241.20**	**296.80**	
2.07	1.13	0.70	39.28	**131.87**	**175.67**	**213.63**	
1.62	0.88	0.54	29.29	**101.66**	**135.89**	**165.57**	
1.19	0.65	0.40	20.38	**73.71**	**98.93**	**120.80**	
0.84	0.46	0.28	19.69	**57.43**	**75.28**	**90.75**	
1.15	0.63	0.39	12.91	**64.42**	**88.78**	**109.90**	
0.85	0.46	0.29	15.37	**53.38**	**71.37**	**86.96**	
0.96	0.52	0.32	15.61	**58.65**	**79.01**	**96.65**	
1.17	0.63	0.39	14.56	**66.75**	**91.44**	**112.83**	
0.58	0.31	0.19	14.91	**40.68**	**52.87**	**63.43**	
0.75	0.41	0.25	9.94	**43.60**	**59.52**	**73.32**	
1.71	0.93	0.57	27.48	**103.98**	**140.17**	**171.54**	**Japan**
1.29	0.70	0.43	28.22	**86.00**	**113.33**	**137.02**	**Korea**
0.85	0.51	0.34	15.23	**33.10**	**41.17**	**48.21**	**Netherlands**
0.32	0.17	0.11	9.84	**24.04**	**30.76**	**36.58**	**Norway**
0.89	0.48	0.30	13.82	**53.52**	**72.29**	**88.57**	**Russia**
0.82	0.44	0.27	13.50	**50.06**	**67.35**	**82.34**	
0.39	0.21	0.13	27.15	**44.67**	**52.96**	**60.15**	**Sweden**
0.24	0.13	0.08	8.71	**26.53**	**35.10**	**42.51**	**United States**
0.23	0.12	0.08	9.57	**27.87**	**36.70**	**44.32**	
0.22	0.12	0.08	9.92	**28.66**	**37.71**	**45.51**	
0.22	0.12	0.08	10.26	**29.57**	**38.90**	**46.95**	
0.23	0.13	0.08	10.69	**31.16**	**41.05**	**49.58**	
0.31	0.17	0.10	11.36	**36.07**	**47.99**	**58.27**	
0.37	0.20	0.12	12.53	**41.42**	**55.35**	**67.37**	
0.57	0.31	0.19	14.15	**53.97**	**73.11**	**89.64**	
0.77	0.42	0.26	16.49	**67.96**	**92.66**	**114.01**	
1.32	0.72	0.44	26.07	**113.05**	**154.78**	**190.84**	
							Non-OECD countries
0.42	0.23	0.14	5.98	**24.73**	**33.59**	**41.28**	**Brazil**
0.59	0.32	0.20	13.18	**43.80**	**58.37**	**70.99**	**China**
0.34	0.19	0.12	3.72	**25.43**	**35.83**	**44.82**	**India**

Table 3.15b: Levelised cost of electricity for wind generators – Offshore

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)		
				3%	7%	10%
Australia	Offshore wind	100	51%	44.66	66.73	85.68
Belgium	Offshore wind	12	39%	39.68	59.30	76.13
	Offshore wind	50	39%	39.68	59.30	76.13
Denmark	Offshore wind	11.25	52%	25.46	38.04	48.84
	Offshore wind	11.5	52%	21.74	32.49	41.71
France	Offshore wind	500	45%	44.71	66.81	85.77
Japan	Offshore wind	100	30%	88.26	131.88	169.32
Korea	Offshore wind	99	30%	76.92	114.93	147.55
United States	Offshore wind	600	47%	27.15	40.57	52.09
	Offshore wind	600	46%	27.95	41.76	53.61
	Offshore wind*	600	46%	29.18	43.61	55.98
	Offshore wind	600	46%	30.61	45.74	58.72
	Offshore wind	600	45%	31.66	47.31	60.74
	Offshore wind	600	39%	37.22	55.62	71.40
	Offshore wind	600	30%	52.58	78.57	100.87
	Offshore wind	600	53%	30.04	44.89	57.63
	Offshore wind	600	51%	30.91	46.19	59.30
	Offshore wind	600	50%	32.33	48.31	62.03
	Offshore wind	600	50%	33.97	50.76	65.17
	Offshore wind	600	47%	36.44	54.46	69.91
	Offshore wind	600	37%	45.75	68.36	87.77
	Offshore wind	600	31%	61.15	91.37	117.30
Non-OECD countries						
China	Offshore wind	50	35%	41.93	62.66	80.44

* Indicated as reference datasets by the providing country.

Table 3.16a: Levelised cost of electricity for other renewable generation – Hydropower

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)		
				3%	7%	10%
Austria	Run of river (< 5 MW)	2.2	51%	18.43	42.40	64.05
Germany	Run of river (>= 5 MW)	24.5	65%	18.52	42.61	64.36
Italy	Run of river (< 5 MW)	0.02	55%	47.13	108.41	163.77
	Run of river (< 5 MW)	0.1	34%	35.36	81.33	122.86
	Run of river (< 5 MW)	0.2	55%	39.83	91.61	138.38
	Run of river (< 5 MW)	0.3	19%	32.82	75.49	114.03
	Run of river (< 5 MW)	0.25	15%	99.35	228.52	345.19
	Run of river (< 5 MW)	0.25	8%	155.72	358.18	541.06
	Run of river (< 5 MW)	0.5	20%	21.04	48.39	73.10
	Run of river (< 5 MW)	0.50	15%	100.17	230.40	348.04
	Run of river (< 5 MW)	0.50	22%	43.77	100.67	152.07
	Run of river (< 5 MW)	0.7	55%	31.92	73.43	110.92
	Run of river (< 5 MW)	1	15%	26.42	60.77	91.80
	Run of river (< 5 MW)	2.1	50%	25.63	58.94	89.04
	Run of river (>= 5 MW)	5	37%	33.16	76.28	115.22
	Reservoir (< 5 MW)	0.32	65%	24.32	55.93	84.49
	Reservoir (>= 5 MW)	15	38%	32.95	75.78	114.47
Japan	Reservoir (>= 5 MW)	12	45%	51.90	119.38	180.33
Norway	Reservoir (>= 5 MW)	30	52%	14.66	33.72	50.94
	Run of river (< 5 MW)	3.0	47%	16.77	38.58	58.28
United States	Run of river (< 5 MW)*	4.8	62%	41.51	95.47	144.21
	Run of river (>= 5 MW)*	82	64%	36.63	84.26	127.28
	Run of river (< 5 MW)*	4.2	60%	28.73	66.09	99.83
	Run of river (>= 5 MW)*,**	45	60%	27.06	62.24	94.02
	Run of river (< 5 MW)	3.7	66%	45.76	105.26	159.00
	Run of river (>= 5 MW)	44	66%	40.51	93.18	140.76
	Run of river (< 5 MW)	4.3	62%	42.13	96.89	146.37
	Run of river (>= 5 MW)**	94	66%	35.58	81.84	123.62
Non-OECD countries						
Brazil	Run of river (>= 5 MW)	247.5	50%	18.67	42.95	64.88
India	Reservoir (>= 5 MW)	175	60%	16.38	37.68	56.92

* These are projects for powering non-powered dams (NPD). They are thus brownfield projects, for which part of the investment costs have already been amortised.

** Indicated as reference datasets by the providing country.

Decommissioning (USD/MWh)			O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%		3%	7%	10%	
1.02	0.56	0.34	18.07	**63.75**	**85.36**	**104.09**	**Australia**
0.91	0.49	0.30	35.41	**76.00**	**95.20**	**111.84**	**Belgium**
0.91	0.49	0.30	27.64	**68.23**	**87.43**	**104.07**	
0.58	0.32	0.20	13.58	**39.62**	**51.94**	**62.61**	**Denmark**
0.50	0.27	0.17	12.33	**34.57**	**45.09**	**54.20**	
1.02	0.56	0.34	22.46	**68.19**	**89.82**	**108.57**	**France**
2.02	1.10	0.68	67.20	**157.48**	**200.18**	**237.19**	**Japan**
1.76	0.96	0.59	45.10	**123.77**	**160.98**	**193.24**	**Korea**
0.53	0.29	0.18	20.44	**48.12**	**61.30**	**72.70**	**United States**
0.53	0.29	0.18	21.43	**49.91**	**63.48**	**75.22**	
0.56	0.30	0.19	21.65	**51.39**	**65.56**	**77.82**	
0.58	0.32	0.20	21.95	**53.14**	**68.01**	**80.87**	
0.60	0.33	0.20	22.92	**55.18**	**70.56**	**83.86**	
0.70	0.38	0.23	26.32	**64.24**	**82.32**	**97.96**	
0.99	0.54	0.33	32.56	**86.13**	**111.67**	**133.76**	
0.56	0.31	0.19	14.11	**44.71**	**59.30**	**71.92**	
0.57	0.31	0.19	14.62	**46.10**	**61.12**	**74.11**	
0.60	0.32	0.20	15.49	**48.42**	**64.13**	**77.72**	
0.63	0.34	0.21	16.99	**51.59**	**68.10**	**82.38**	
0.67	0.36	0.22	19.18	**56.30**	**74.00**	**89.32**	
0.83	0.45	0.28	24.66	**71.24**	**93.47**	**112.70**	
1.12	0.61	0.38	27.08	**89.35**	**119.06**	**144.76**	
							Non-OECD countries
0.88	0.48	0.30	18.68	**61.49**	**81.82**	**99.42**	**China**

Decommissioning (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%			3%	7%	10%	
0.08	0.01	0.001	0	11.92	**30.43**	**54.32**	**75.97**	**Austria**
5.65	5.89	5.55	0	8.50	**32.67**	**57.00**	**78.41**	**Germany**
0.20	0.02	0.003	0	24.64	**71.97**	**133.07**	**188.41**	**Italy**
0.15	0.01	0.002	0	17.01	**52.52**	**98.36**	**139.87**	
0.17	0.02	0.002	0	21.47	**61.46**	**113.09**	**159.85**	
0.14	0.01	0.002	0	22.09	**55.04**	**97.59**	**136.12**	
0.42	0.04	0.006	0	29.18	**128.95**	**257.74**	**374.38**	
0.66	0.06	0.009	0	51.07	**207.45**	**409.31**	**592.14**	
0.09	0.01	0.001	0	13.01	**34.14**	**61.41**	**86.11**	
0.42	0.04	0.006	0	17.52	**118.12**	**247.97**	**365.57**	
0.19	0.02	0.003	0	12.07	**56.03**	**112.76**	**164.15**	
0.14	0.01	0.002	0	12.47	**44.53**	**85.91**	**123.39**	
0.11	0.01	0.002	0	8.71	**35.24**	**69.49**	**100.51**	
0.11	0.01	0.002	0	8.42	**34.16**	**67.38**	**97.46**	
0.14	0.01	0.002	0	27.53	**60.83**	**103.82**	**142.75**	
0.10	0.01	0.001	0	16.85	**41.27**	**72.79**	**101.34**	
0.14	0.01	0.002	0	18.37	**51.45**	**94.16**	**132.84**	
0.22	0.02	0.003	0	23.00	**75.12**	**142.40**	**203.34**	**Japan**
0.06	0.01	0.001	0	4.92	**19.64**	**38.65**	**55.86**	**Norway**
0.07	0.01	0.001	0	8.61	**25.45**	**47.19**	**66.89**	
0.14	0.01	0.002	0	22.24	**63.89**	**117.72**	**166.45**	**United States**
0.12	0.01	0.002	0	5.93	**42.69**	**90.21**	**133.22**	
0.09	0.01	0.001	0	24.42	**53.24**	**90.51**	**124.25**	
0.08	0.01	0.001	0	8.33	**35.47**	**70.58**	**102.35**	
0.16	0.02	0.002	0	23.40	**69.32**	**128.67**	**182.40**	
0.14	0.01	0.002	0	7.57	**48.22**	**100.76**	**148.33**	
0.14	0.01	0.002	0	23.17	**65.44**	**120.08**	**169.54**	
0.12	0.01	0.002	0	5.35	**41.05**	**87.20**	**128.97**	
								Non-OECD countries
0.08	0.01	0.001	0	3.16	**21.91**	**46.12**	**68.04**	**Brazil**
0.06	0.01	0.001	0	11.65	**28.09**	**49.33**	**68.57**	**India**

Table 3.16b: Levelised cost of electricity for other renewable generation – Biomass						
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)		
				3%	7%	10%
Italy	Biomass	0.45	89%	26.59	48.93	69.73
	Biomass	0.42	89%	38.16	70.22	100.07
Non-OECD countries						
Brazil*	Biomass	25.00	30%	18.85	34.68	49.42
India	Biomass	30.00	85%	5.06	9.32	13.28

* Fuel cost are zero, since the feedstock is bagasse, an agricultural residue from sugar cane processing.

Table 3.16c: Levelised cost of electricity for other renewable generation – Geothermal						
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)		
				3%	7%	10%
Italy	Geothermal	40	76%	26.65	50.04	72.42
	Geothermal	15	86%	43.69	82.06	118.76
	Geothermal	10	86%	60.03	112.74	163.17
	Geothermal	5	86%	67.14	126.09	182.48
United States	Geothermal	30	90%	24.00	45.08	65.25
	Geothermal	25	80%	36.30	68.17	98.67

Table 3.17: Levelised cost of electricity for combined heat and power (CHP) plants									
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)			Decommissioning (USD/MWh)		
				3%	7%	10%	3%	7%	10%
Denmark	Biomass	177	46%	45.40	83.54	119.04	0.64	0.23	0.10
	Biomass	261	46%	30.71	56.51	80.53	0.43	0.15	0.07
	Biomass	258	57%	26.71	49.14	70.02	0.37	0.13	0.06
	Biomass	358	57%	22.97	42.26	60.22	0.32	0.11	0.05
	Coal (Ultra-supercritical)	700	57%	20.27	37.31	53.16	0.28	0.10	0.04
	Gas (CCGT)	500	57%	10.77	17.69	23.97	0.21	0.10	0.05
	Gas (OCGT)	125	46%	8.86	14.26	19.05	0.17	0.08	0.05
Italy	Biomass	0.4	89%	38.16	70.22	100.07	0.54	0.19	0.08
Romania	Pulverised (Lignite)*	2 900	50%	10.48	19.29	27.49	2.18	2.34	2.33
	Gas (OCGT)*	195	90%	2.17	3.49	4.66	0.17	0.16	0.16
Slovak Republic	Gas (CCGT)*	6	70%	9.95	16.34	22.15	3.14	3.46	3.59
	Gas (OCGT)	36	98%	6.68	10.76	14.37	0.13	0.06	0.03

* The O&M costs for these plants include costs for refurbishment at regular intervals. Minor adjustments have been made to LCOE figures to compensate for the differentiated impact of these costs at 3% and 10% discount rates.

	Decommissioning (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
	3%	7%	10%			3%	7%	10%	
	0.37	0.13	0.06	0	26.89	**53.86**	**75.96**	**96.68**	**Italy**
	0.54	0.19	0.08	159.41	59.00	**257.12**	**288.83**	**318.57**	
									Non-OECD countries
	0.20	0.07	0.03	0	18.75	**37.79**	**53.50**	**68.20**	***Brazil**
	0.05	0.02	0.01	106	2.24	**113.59**	**117.82**	**121.77**	**India**

	Decommissioning (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
	3%	7%	10%			3%	7%	10%	
	0.37	0.13	0.06	0	17.96	**44.97**	**68.13**	**90.44**	**Italy**
	0.60	0.22	0.09	0	21.25	**65.55**	**103.52**	**140.10**	
	0.83	0.30	0.13	0	23.02	**83.88**	**136.06**	**186.32**	
	0.93	0.33	0.14	0	25.38	**93.45**	**151.80**	**208.01**	
	0.24	0.09	0.04	0	16.63	**40.87**	**61.80**	**81.91**	**United States**
	0.40	0.14	0.06	0	25.19	**61.88**	**93.50**	**123.91**	

	Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	Heat credit (USD/MWh)	LCOE (USD/MWh)			Country
					3%	7%	10%	
	111.18	0	33.29	-102.95	**87.55**	**125.28**	**160.65**	**Denmark**
	126.32	0	20.77	-72.67	**105.57**	**131.09**	**155.02**	
	76.87	0	19.36	-50.25	**73.05**	**95.25**	**116.06**	
	95.07	0	14.28	-39.01	**93.63**	**112.71**	**130.61**	
	21.28	20.22	10.73	-29.69	**43.10**	**59.95**	**75.74**	
	47.47	10.54	11.96	-14.82	**66.11**	**72.92**	**79.16**	
	67.65	15.02	10.77	-38.05	**64.41**	**69.73**	**74.48**	
	154.81	0	59.00	-114.62	**137.89**	**169.61**	**199.35**	**Italy**
	12.28	33.50	129.88	-1.63	**186.68**	**195.65**	**203.85**	**Romania**
	33.88	7.52	11.75	-4.34	**51.15**	**52.47**	**53.63**	
	84.46	18.75	7.74	-68.78	**55.25**	**61.97**	**67.90**	**Slovak Republic**
	57.46	12.75	6.10	-26.13	**57.00**	**61.01**	**64.59**	

Table 3.18: Levelised cost of electricity for storage technologies							
Country	Technology	Net capacity (MWe)	Storage capacity**** (h)	Capacity factor (%)	Investment (USD/MWh)		
					3%	7%	10%
Australia	Pumped storage	200	na	15%	22.59	47.98	68.27
Canada	ACAES***	250	4	15%	51.65	100.17	143.55
Denmark	Lithium-ion battery	19	0.33	15%	43.19	52.46	59.96
	Pumped storage	1 000	na	15%	111.54	236.86	337.03
Finland	Lithium-ion battery	1.14	5.26	15%	175.52	213.17	243.66
Italy	Lithium-ion battery	2	0.5	15%	40.34	48.99	56.00
Non-OECD countries							
India	Lithium-ion battery	1	na	15%	73.70	89.51	102.31
	Pumped storage	175	4	15%	14.18	30.12	42.86

* The required average operational profit (RAOP) is the required total operational profit (OP**) on a per unit of discharged energy basis.

** The total required operational profit (OP) is the total required revenue from discharging electricity minus the total cost from charging electricity.

*** Adiabatic Compressed Air Energy storage.

**** Without specific data available, the storage capacity was set at 4 hours by default.

Table 3.19: Levelised cost of electricity for fuel cells						
Country	Technology	Net capacity (MWe)	Capacity factor (%)	Investment (USD/MWh)		
				3%	7%	10%
France	Fuel cell	0.003	85%	58.60	82.30	102.41
	Fuel cell	0.2	85%	53.28	74.82	93.10
	Fuel cell	15	85%	21.31	29.93	37.24
Norway	Fuel cell	1	85%	31.86	44.74	55.67

3.4 Technology-by-technology LCOE data for flexible technologies at lower capacity factors

Tables 3.18 to 3.20 present again the calculated LCOEs for dispatchable power plants included in the EGC 2020 dataset, along with the relevant cost components, calculated at each of the three discount rates (3%, 7% and 10%). This time, however, the LCOEs for coal, nuclear and CCGT gas plants are all calculated at the same assumed lower capacity factor of 50%, while the LCOEs for OCGT gas plants are calculated at a capacity factor of 10%.

Actual capacity factors will depend on many country-specific factors, including relative fuel cost and the penetration of variable renewable power. Many baseload plants will in fact operate at lower capacity factors under actual operating conditions. The sensitivity of a given technology to capacity factor is determined by its ratio of capital to operating costs. Units with low variable costs are generally run at higher capacity factors, because there are many hours where their marginal costs are lower than other units. Conversely, units with high operating to capital costs are run at lower capacity factors, because there are relatively few hours where their marginal costs are lower than other units.

Decommissioning (USD/MWh)			Charging Costs (USD/MWh)	O&M (USD/MWh)	LCOS (RAOP*) (USD/MWh)			Country
3%	7%	10%			3%	7%	10%	
0.10	0.01	0.00	0	3.41	**26.11**	**51.40**	**71.68**	**Australia**
2.51	1.99	1.70	0	12.71	**66.88**	**114.87**	**157.96**	**Canada**
1.54	1.21	1.00	0	2.73	**47.46**	**56.39**	**63.70**	**Denmark**
0.50	0.05	0.01	0	8.08	**120.13**	**245.00**	**345.12**	
6.25	4.90	4.08	0	19.03	**200.79**	**237.09**	**266.76**	**Finland**
1.44	1.13	0.94	0	6.85	**48.62**	**56.97**	**63.79**	**Italy**
								Non-OECD countries
1.80	1.41	1.17	0	12.57	**88.07**	**103.49**	**116.06**	**India**
0.03	0.00	0.00	0	10.71	**24.93**	**40.83**	**53.57**	

Decommissioning (USD/MWh)			Charging Costs (USD/MWh)	O&M (USD/MWh)	LCOS (RAOP*) (USD/MWh)			Country
3%	7%	10%			3%	7%	10%	
1.55	0.96	0.66	111.11	42.66	**213.92**	**237.03**	**256.84**	**France**
1.41	0.87	0.60	111.11	22.59	**188.39**	**209.39**	**227.40**	
0.56	0.35	0.24	111.11	36.75	**169.74**	**178.14**	**185.35**	
0.84	0.52	0.36	111.11	1.69	**145.51**	**158.07**	**168.83**	**Norway**

It is important to bear in mind that the 50% capacity factor for coal, nuclear and CCGT gas plants and the 10% capacity factor for OCGT gas plants factor results do not represent the expected LCOEs for these technologies in 2025. Their function in the context of this publication is merely to show how sensitive these technologies are to changes in operating conditions. This topic is further explored in the sensitivity analysis presented in Chapter 5.

Table 3.20a: Levelised cost of electricity for combined-cycle gas turbine (CCGT) at 50% capacity factor

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Australia	CCGT	506	48%	11.46	18.83	25.52
	CCGT (CCUS)	437	41%	33.92	55.73	75.53
Belgium	CCGT	500	60%	9.21	15.13	20.50
	CCGT	500	64%	12.11	19.90	26.97
	CCGT	500	58%	11.69	19.20	26.02
Canada	CCGT	471	57%	12.70	20.86	28.27
Italy	CCGT	790	60%	7.08	11.64	15.77
Japan	CCGT	1 372	56%	13.31	21.86	29.63
Korea	CCGT	491	56%	13.29	21.83	29.59
	CCGT	982	59%	10.06	16.53	22.40
Mexico	CCGT	503	51%	8.03	13.20	17.89
	CCGT	785	60%	8.01	13.16	17.83
	CCGT	835	58%	5.60	9.19	12.46
Romania	CCGT	750	58%	3.04	5.00	6.78
United States	CCGT	727	59%	11.42	18.77	25.44
	CCGT (CCUS)	646	48%	28.95	47.56	64.45
Non-OECD countries						
Brazil	CCGT	980	58%	11.50	18.89	25.60
China	CCGT	475	58%	6.72	11.04	14.96

Table 3.20b: Levelised cost of electricity for open-cycle gas turbine (OCGT) at 10% capacity factor

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Autralia	OCGT	537	31%	39.49	63.60	84.93
Belgium	OCGT	350	40%	31.40	50.57	67.54
	OCGT	500	41%	39.63	63.84	85.25
	OCGT	500	38%	34.89	56.19	75.04
Canada	OCGT	100	41%	67.43	108.60	145.03
	OCGT	243	40%	30.61	49.31	65.84
Italy	OCGT	130	37%	19.19	30.91	41.27
Non-OECD countries						
Brazil	OCGT	980	44%	43.68	70.36	93.96

Table 3.21: Levelised cost of electricity for coal technologies at 50% capacity factor

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Australia	Supercritical pulverised	722	40%	25.14	46.26	65.92
	Supercritical pulverised (CCUS)	633	30%	46.38	85.34	121.62
	Supercritical pulverised (lignite)	709	32%	38.80	71.40	101.74
	Supercritical pulverised (lignite, CCUS)	570	21%	71.19	130.99	186.67
Japan	Ultra-supercritical	749	41%	24.99	45.98	65.52
Korea	Ultra-supercritical	954	43%	11.89	21.87	31.17
United States	Pulverised	138	36%	45.27	83.30	118.70
	Pulverised	140	36%	35.61	65.52	93.37
	Pulverised	650	40%	25.60	47.10	67.12
	Pulverised (CCUS)	650	31%	47.56	87.52	124.71
	Supercritical pulverised	650	42%	26.67	49.08	69.94
	Supercritical pulverised (CCUS)	650	33%	48.08	88.47	126.07
	Ultra-supercritical	641	43%	42.94	79.02	112.61
	Other coal (CCUS)	499	31%	61.89	113.88	162.29
Non-OECD countries						
Brazil	Other coal (lignite)	900	34%	22.62	41.62	59.31
China	Ultra-supercritical	347	45%	8.26	15.21	21.67
India	Ultra-supercritical	400	45%	11.86	21.82	31.09
	Ultra-supercritical	400	45%	11.48	21.12	30.10

Decommissioning (USD/MWh)			Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%				3%	7%	10%	
0.22	0.10	0.06	56.04	12.75	7.34	**87.81**	**95.06**	**101.70**	**Australia**
0.65	0.31	0.17	64.96	1.48	14.26	**115.27**	**136.74**	**156.40**	
0.18	0.08	0.05	45.88	10.18	7.55	**72.99**	**78.82**	**84.16**	**Belgium**
0.23	0.11	0.06	42.65	9.47	7.02	**71.48**	**79.15**	**86.17**	
0.22	0.11	0.06	47.06	10.45	8.89	**78.31**	**85.71**	**92.48**	
0.24	0.12	0.06	19.19	10.65	10.37	**53.14**	**61.18**	**68.54**	**Canada**
0.14	0.06	0.04	45.50	10.10	9.44	**72.25**	**76.73**	**80.84**	**Italy**
0.25	0.12	0.07	61.05	10.84	10.87	**96.32**	**104.74**	**112.46**	**Japan**
0.25	0.12	0.07	60.82	10.80	16.86	**102.02**	**110.44**	**118.14**	**Korea**
0.19	0.09	0.05	58.23	10.34	11.85	**90.67**	**97.04**	**102.87**	
0.15	0.07	0.04	21.62	12.00	8.82	**50.63**	**55.71**	**60.37**	**Mexico**
0.15	0.07	0.04	18.29	10.15	9.58	**46.18**	**51.25**	**55.89**	
0.11	0.05	0.03	18.89	10.48	9.20	**44.28**	**47.82**	**51.07**	
0.18	0.12	0.09	47.06	10.45	60.90	**121.64**	**123.53**	**125.28**	**Romania**
0.22	0.10	0.06	18.38	10.20	7.82	**48.04**	**55.27**	**61.89**	**United States**
0.55	0.26	0.15	22.91	5.09	20.23	**77.72**	**96.04**	**112.82**	
									Non-OECD countries
0.22	0.10	0.06	18.83	10.45	13.31	**54.30**	**61.57**	**68.24**	**Brazil**
0.10	0.05	0.03	53.54	10.45	15.94	**86.73**	**91.00**	**94.91**	**China**

Decommissioning (USD/MWh)			Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%				3%	7%	10%	
0.77	0.36	0.20	86.91	19.77	11.53	**158.46**	**182.18**	**203.34**	**Australia**
0.61	0.29	0.16	68.24	15.15	12.63	**128.03**	**146.89**	**163.72**	**Belgium**
0.77	0.37	0.20	66.58	14.78	26.90	**148.66**	**172.46**	**193.71**	
0.68	0.32	0.18	71.83	15.94	16.97	**140.32**	**161.27**	**179.97**	
1.31	0.62	0.34	26.44	14.67	24.56	**134.41**	**174.89**	**211.04**	**Canada**
0.59	0.28	0.16	27.30	15.15	48.48	**122.13**	**140.51**	**156.92**	
0.37	0.18	0.10	73.98	16.42	26.33	**136.29**	**147.81**	**158.10**	**Italy**
									Non-OECD countries
0.85	0.40	0.22	24.82	13.77	33.71	**116.83**	**143.06**	**166.48**	**Brazil**

Decommissioning (USD/MWh)			Fuel (USD/MWh)	Carbon (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%				3%	7%	10%	
0.35	0.13	0.05	29.65	25.47	12.57	**93.19**	**114.08**	**133.67**	**Australia**
0.65	0.23	0.10	39.58	3.40	25.75	**115.77**	**154.31**	**190.45**	
0.54	0.19	0.08	5.13	34.36	16.39	**95.22**	**127.47**	**157.70**	
1.00	0.36	0.15	7.89	5.28	34.95	**120.31**	**179.47**	**234.94**	
0.35	0.13	0.05	28.73	24.68	28.35	**107.10**	**127.87**	**147.34**	**Japan**
0.17	0.06	0.03	27.47	23.60	16.26	**79.38**	**89.26**	**98.52**	**Korea**
0.63	0.23	0.10	20.19	28.22	43.58	**137.90**	**175.52**	**210.79**	**United States**
0.50	0.18	0.08	20.36	28.46	31.84	**116.77**	**146.36**	**174.11**	
0.36	0.13	0.06	18.23	25.48	23.41	**93.07**	**114.35**	**134.29**	
0.67	0.24	0.10	23.50	13.14	41.64	**126.51**	**166.03**	**203.09**	
0.37	0.13	0.06	17.51	24.47	23.83	**92.86**	**115.03**	**135.81**	
0.67	0.24	0.10	22.38	12.51	41.45	**125.10**	**165.05**	**202.52**	
0.60	0.21	0.09	17.16	23.99	41.36	**126.06**	**161.75**	**195.22**	
0.87	0.31	0.13	23.32	13.04	59.83	**158.95**	**210.38**	**258.61**	
									Non-OECD countries
0.32	0.11	0.05	31.76	32.03	11.74	**98.47**	**117.27**	**134.89**	**Brazil**
0.10	0.04	0.02	28.02	22.70	18.45	**77.54**	**84.42**	**90.86**	**China**
0.13	0.05	0.02	26.43	22.70	11.01	**72.13**	**82.01**	**91.25**	**India**
0.12	0.04	0.02	26.43	22.70	41.13	**101.86**	**111.43**	**120.38**	

Table 3.22a: Levelised cost of electricity for nuclear technologies at 50% capacity factor – New Build

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
France	EPR	1 650	33%	36.24	80.69	124.6
Japan	ALWR	1 152	33%	35.79	79.67	123
Korea	ALWR	1 377	36%	19.48	43.37	66.97
Russia	VVER	1 122	38%	20.51	45.7	70.5
Slovak Republic	Other nuclear	1 004	32%	62.49	139.13	214.8
United States	LWR	1 100	33%	38.38	85.45	131.9
Non-OECD countries						
China	LWR	950	33%	22.58	50.26	77.6
India	LWR	950	33%	25.08	55.85	86

Table 3.22b1: Levelised cost of electricity for nuclear technologies at 50% capacity factor – Long-Term Operation (LTO), 10 years

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Switzerland	LTO	1 000	33%	14.94	18.50	21.5
France	LTO	1 000	33%	17.09	21.16	25
Sweden	LTO	1 000	33%	12.06	14.94	17.3
United States	LTO	1 000	33%	10.62	13.15	15

Table 3.22b2: Levelised cost of electricity for nuclear technologies at 50% capacity factor – Long-Term Operation (LTO), 20 years

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	Investment (USD/MWh)		
				3%	7%	10%
Switzerland	LTO	1 000	33%	8.57	12.27	15.5
France	LTO	1 000	33%	9.80	14.03	18
Sweden	LTO	1 000	33%	6.92	9.90	12.5
United States	LTO	1 000	33%	6.09	8.72	11

* Conservatively, decommissioning costs are calculated on the basis of 15% LTO overnight costs, assuming that decommissioning starts 5 years after shutdown and lasts for 10 years as for new build. However, depending on the individual project, some of the incremental decommissioning costs due to LTO have already been included in the LTO overnight costs or are very small. In these cases, incremental decommissioning costs due to LTO will be closer to zero. Provisions for final decommissioning costs have already been accounted for in the cost of electricity produced during the original design lifetime of the plant.

Decommissioning (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%			3%	7%	10%	
0.62	0.08	0.02	9.33	15.12	**61.31**	**105.22**	**149.06**	**France**
0.61	0.08	0.02	13.92	43.92	**94.24**	**137.6**	**180.9**	**Japan**
0.33	0.05	0.01	9.33	30.48	**59.63**	**83.23**	**106.8**	**Korea**
0.35	0.05	0.01	4.99	15.77	**41.61**	**66**	**91.3**	**Russia**
3.07	1.63	1.09	9.33	15.87	**90.76**	**166.0**	**241.1**	**Slovak Republic**
0.66	0.09	0.02	9.33	18.47	**66.83**	**113.33**	**159.76**	**United States**
								Non-OECD countries
0.38	0.05	0.01	10.00	34.41	**67.36**	**94.72**	**122.03**	**China**
0.42	0.06	0.01	9.33	31.83	**66.67**	**97.1**	**127.4**	**India**

Decommissioning* (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%			3%	7%	10%	
1.21	0.68	0.45	9.33	20.91	**46.39**	**49.42**	**52.15**	**Switzerland**
1.38	0.78	0.52	9.33	20.91	**48.71**	**52.18**	**55.29**	**France**
0.98	0.55	0.36	9.33	20.91	**43.27**	**45.73**	**47.92**	**Sweden**
0.86	0.49	0.32	9.33	30.72	**51.54**	**53.69**	**55.63**	**United States**

Decommissioning* (USD/MWh)			Fuel (USD/MWh)	O&M (USD/MWh)	LCOE (USD/MWh)			Country
3%	7%	10%			3%	7%	10%	
0.49	0.22	0.12	9.33	20.91	**39.29**	**42.72**	**45.84**	**Switzerland**
0.58	0.26	0.14	9.33	20.91	**40.62**	**44.53**	**48.09**	**France**
0.40	0.18	0.10	9.33	20.91	**37.55**	**40.32**	**42.84**	**Sweden**
0.35	0.16	0.09	9.33	30.72	**46.50**	**48.93**	**51.15**	**United States**

The value-adjusted levelised cost of electricity (VALCOE)

4.1 Motivations for looking beyond the LCOE

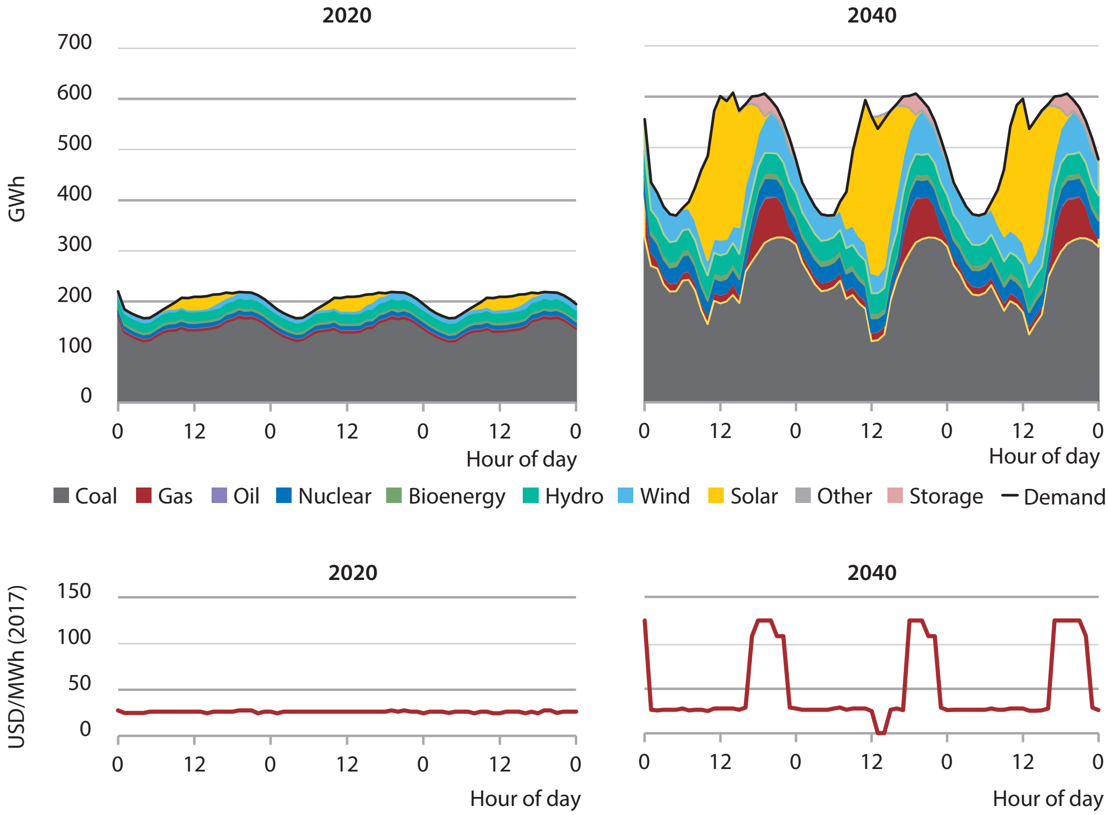
The levelised cost of electricity (LCOE) is the most commonly used metric to assess cost competitiveness of power generation technologies. The main strength of the LCOE is that it compresses all the direct technology costs into a single metric, including those related to construction, fuel, carbon prices, operations and maintenance, and can be applied equally well to technologies with a wide range of technical lifetimes.

However, the LCOE is not a complete metric of competitiveness, as it lacks representation of the value provided to the system. Power generation technologies primarily generate electricity (or energy) but also provide other services that are critical to the adequacy, reliability and quality of electricity supply. Among technologies that have similar operational characteristics and play similar roles in power systems – and therefore have similar value to the overall system – the LCOE can provide a robust metric of competitiveness. But not all power technologies contribute equally to these essential services.

A comparison of a utility-scale solar PV project with and without a battery storage system highlights the need to look beyond the LCOE alone. In terms of costs, adding a battery storage system to a solar PV project necessarily raises the total costs of the project and, when charged only by the solar PV array, reduces the total output due to the round-trip efficiency of storage. In this case, both factors indicate a higher LCOE for solar PV plus storage compared with solar PV alone. At the same time, the addition of a battery storage system would increase the value proposition of the project for the owner and system. Output could be aligned dynamically to system needs, providing energy when it is most valuable. The battery could provide ancillary services to the grid, including frequency control, and could displace the need for other types of dispatchable capacity. For a system planner or an investor considering both the costs and value aspects, solar PV plus storage could be the better choice despite having a higher LCOE.

The nature of electricity demand and supply is rapidly changing – demand patterns are shifting, the share of variable renewables is rising and the power system flexibility is increasing – underscoring the need to look beyond the LCOE. Electricity demand is set to reach higher peaks relative to the average in many regions and wind power and solar PV have become the most commonly built power technologies worldwide. Both trends are changing how power systems are being operated and providing a spotlight on the importance of system services. For example in India, solar PV is set to increase dramatically over the next two decades, changing the operations of the existing coal-fired power plant fleet and adding to the call for more flexibility from a wide variety of sources (see Figure 4.1). At the hourly level, the increased contribution of solar PV also shifts the highest-value hours to the evening as solar PV output ramps down. Considering the new operational realities and value propositions will be essential (and increasingly complex) for power system planners, developers and investors.

Figure 4.1: Hourly generation mix and wholesale market price of electricity in India in the WEO-2018 Stated Policies Scenario, 2020 and 2040



Demand almost triples, its profile becomes peakier, and variable renewables account for one-quarter of annual capacity, calling for more flexibility in the power system.

Source: IEA (2018).

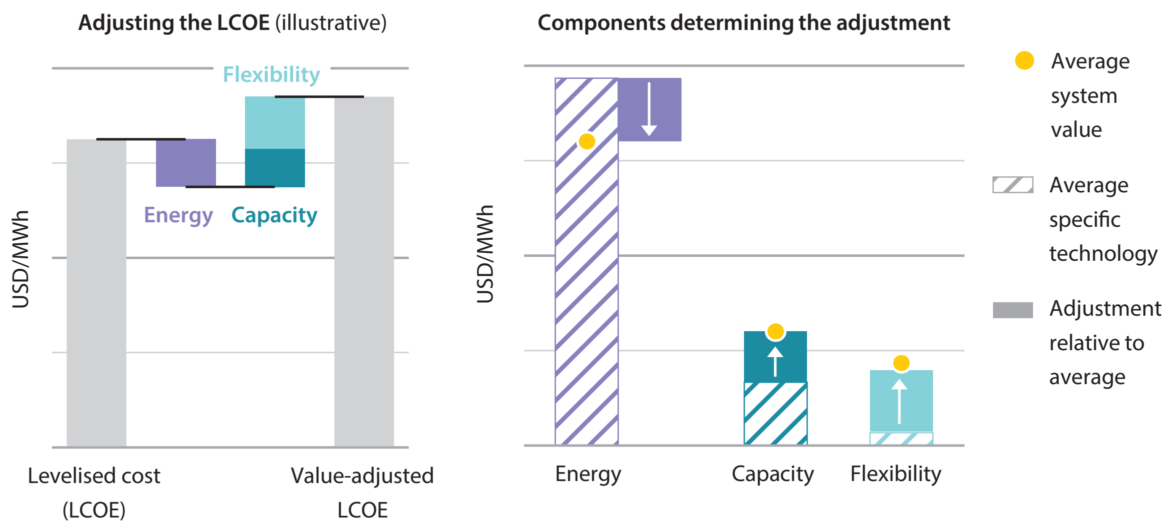
Recognising the importance of going beyond the LCOE and to enable more robust cross-technology comparisons in evolving power systems, a new metric for competitiveness was developed for the 2018 *World Energy Outlook* (WEO), called the value-adjusted LCOE (VALCOE). Developed with the analytical capabilities of the WEO hourly power supply model and real-world market structures and experience, the VALCOE underpins the capacity additions mechanism within the World Energy Model (WEM) (IEA, 2019a).

The VALCOE is part of a family of competitiveness metrics that go beyond the LCOE. The VALCOE is most closely related to the System LCOE (Ueckerdt et al., 2013), which provides a comprehensive theoretical framework for assessing system value beyond the LCOE. The VALCOE and System LCOE are similar in scope, and re-arranging terms can align significant portions of the computations. The VALCOE is also similar to the Levelised Avoided Cost of Electricity (LACE), a metric created for the *Annual Energy Outlook* published by the US Energy Information Administration (EIA, 2020). All of these metrics are related to standard profitability metrics, such as net present value and internal rates of return, that consider the costs and revenues associated with different power technologies. Analysis of total power system costs for various power generation mixes are also closely related, though they do not necessarily provide a direct indicator of competitiveness for individual technologies. There have been real-world applications of the concept, with a locational value-adjustments in clean energy auctions in Mexico in 2017 (Hochberg and Poudineh, 2018). As clean energy transitions progress around the world, experience with higher shares of wind and solar PV in large systems will increase and provide opportunities to refine the VALCOE and other metrics of competitiveness.

4.2 Key elements of VALCOE

For each technology, the VALCOE combines the LCOE for a given year with the value of the multiple system services it can provide in the context of the regional power mix at that time. More specifically, the VALCOE captures the value of three system services: energy value, flexibility value and capacity value by technology. The WEM hourly power supply model assesses these value streams for each technology and compares them against a region-specific system average (across all three-service categories). The sum of these differences – that is, the differences between these technology-specific value streams and the system average values - form the basis of the "value-adjustments" to move from the LCOE to the VALCOE (see Figure 4.2). The metric takes the perspective of system planners and is applicable in all regions, no matter the prevailing regulatory structure, as the same essential services are needed to support electricity reliability in all cases whether or not services are priced in a market. VALCOE aligns with an investor's perspective in fully developed and functioning markets, representing multiple value streams (or revenue stacking).

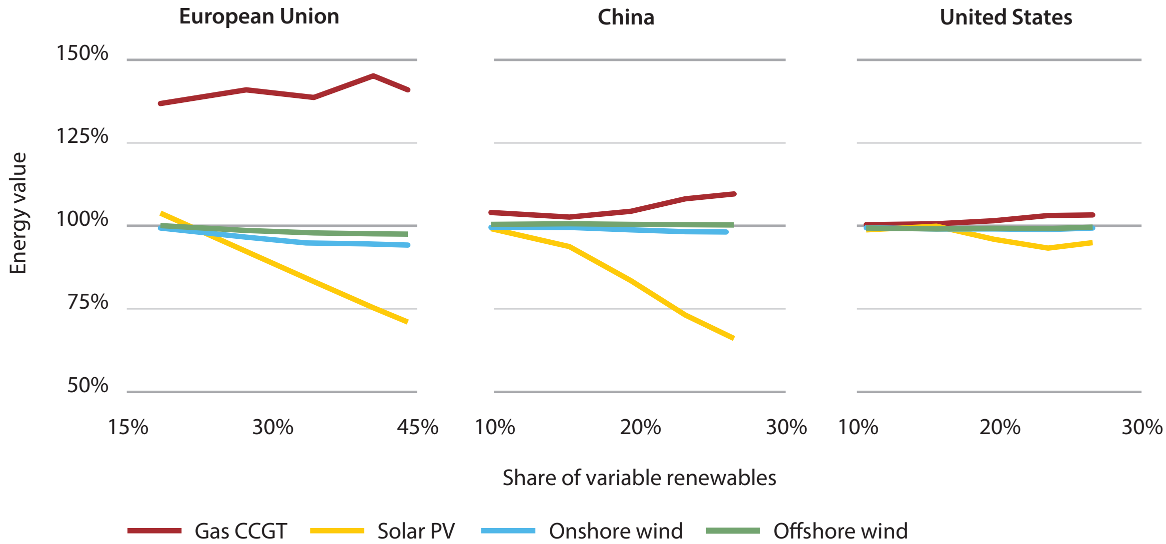
Figure 4.2: Illustrative example of adjusting the LCOE to incorporate value streams



Combining costs and value provides a more robust basis for evaluating competitiveness across technologies than costs alone.

Of the three value streams considered in the VALCOE, the energy value is generally the largest, varies significantly by technology and changes as the share of variable renewables increases. It is calculated as the average price received per unit of generation over the course of a year based on least-cost merit order dispatch and simulated wholesale electricity prices. Modelling electricity demand and supply on an hourly-basis in the WEM captures the effect of the changing power mix on energy values by technology. The energy value of a given technology also varies by region and penetration of variable renewables. It is sensitive to a variety of factors, including the profile of electricity demand, the installed power generation capacities, profile of wind and solar PV output, available energy storage capacity, prevailing fuel and carbon prices. The simulated energy values also capture the extent of cannibalisation effects as the share of variable renewables increase, whereby the expansion of variable renewables reduces their own market value. The simulations in the WEO show that the effect tends to be more significant for solar PV due to highly concentrated output during certain times of day compared with wind power (Figure 4.3), consistent with previous studies (Mills and Wiser, 2012; Hirth, 2013). Pairing solar PV with energy storage technologies can mitigate this effect.

Figure 4.3: Energy value by technology and region relative to average wholesale electricity price in the Stated Policies Scenario



As the share of variable renewables rises, wind power's energy value tends to be more stable relative to wholesale electricity prices compared with solar PV.

Note: Hourly simulations of electricity demand and supply are performed for each region as a whole (US, EU, China) without grid congestion to represent structural changes. In practice, each region is composed of several balancing areas and regularly experience grid congestion, both of which would have an effect on energy value depending on the location of the project.

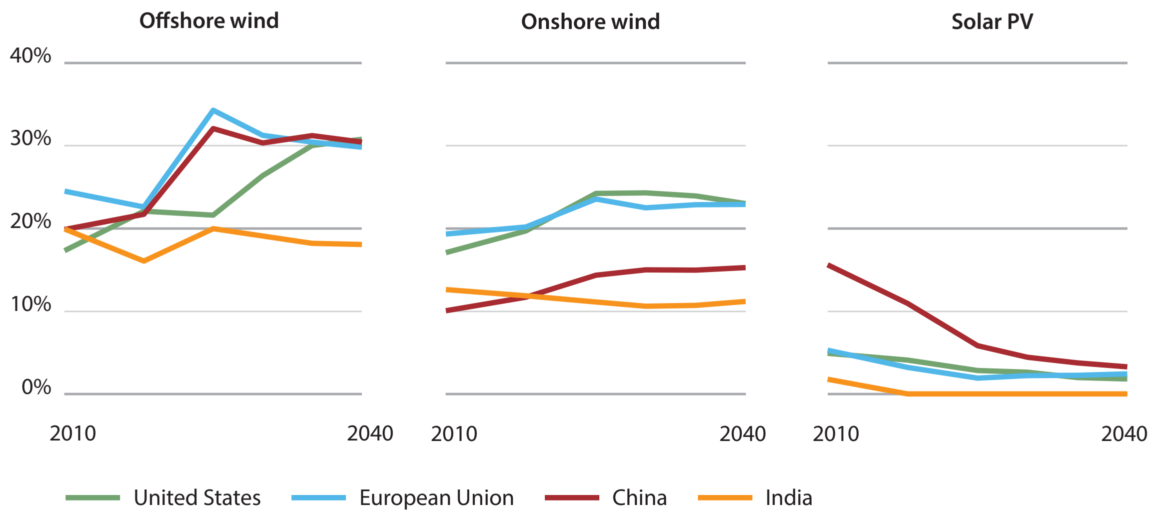
Source: IEA (2018).

Capacity value reflects the ability of a technology to reliably meet demand, contributing to the adequacy of the system. It is calculated as the capacity credit[1] of a technology multiplied by the estimated basis capacity value for the system in each region and year. The capacity credit indicates how much a technology is relied on to meet peak demand from a planning perspective. For dispatchable power plants, the capacity credit can be up to 95% of installed capacity, reflecting the plant's availability at times of peak demand after accounting for planned and unplanned outages. For renewables, capacity value is derived from technology-specific values with hourly modelling that vary by region and depend on the coincidence of system needs with simulated production profiles. Taking offshore wind as an example, rising performance levels (i.e. capacity factors reaching 60% for individual turbines and lower hourly variability compared to onshore wind), and alignment with system needs help to give offshore wind power a much higher capacity credit than solar PV in key markets (though still less than dispatchable power plants due its variability) (Figure 4.4). The basis capacity value in the World Energy Model represents the simulated market value for a unit of capacity credit and is related to the amount and type of existing power generation capacities by technology, their estimated availability, the level of peak electricity demand and the minimum required capacity margin. Representing system adequacy requirements to ensure electricity security, a minimum capacity margin is required above and beyond the peak level of demand in each region in any given year. The model simulates a market where power generation technologies compete to meet the required capacity margin at the minimum cost. Each technology effectively "bids" its available capacity credit at a price, which reflects their remaining revenue needs after accounting for energy and flexibility values (i.e. their LCOE minus the combined value of energy and flexibility services). The winning bid is that which secures a sufficient amount of capacity credit to meet the required

1. Capacity credit reflects the portion of installed capacity that can be reliably expected to be available during times of peak demand.

capacity margin at the lowest cost.[2] This approximates the approach in several real-world capacity markets, which are present in parts of the United States and Europe, and is an element of the electricity market reforms in Japan.

Figure 4.4: Average capacity credit by technology and region in the Stated Policies Scenario



Offshore wind makes a larger contribution to system adequacy in key markets than onshore wind and solar PV.

Source: IEA (2019b).

The last segment of system value is a technology's flexibility value, which is set to become more important as the share of variable renewables rises in regions around the world. Flexibility values encompass non-energy ancillary services required in power systems, such as primary and secondary reserves, frequency regulation and synchronous inertia. The ability to provide these services varies by technology, and so the amount of flexibility value they capture also varies significantly. In present-day power systems with relatively low shares of VRE, the flexibility value is a relatively small part of the value proposition for power plants that produce bulk energy, but can represent a much larger share for "peaking plants" – dispatchable power plants that focus on servicing peak electricity demand. For example, open-cycle gas turbines are able to respond to system needs more quickly than coal-fired power plants and so have been able to earn higher revenues per unit of electricity production in existing ancillary service markets. Battery storage also tends to have a high flexibility value because it has high availability and is able to respond extremely rapidly and accurately to system needs. In the WEM, the average value of flexibility increases in proportion to total generation and is related to the share of variable renewables, informed by market experience. Initial technology-specific values are based on market experience and rise in proportion to the average flexibility value. Where technologies' roles evolve, such as focusing on meeting system flexibility needs to a greater degree rather than providing bulk energy, so too will the value that they capture for each service (though the overall impact on system value is not obvious). Additional market experience in power systems with higher shares of variable renewables will provide opportunities to refine the assumed relationships and technology roles.

2. The maximum basis capacity value that can be set in any year is equal to the annualised capital repayment for the lowest cost peaking plant available, which are open-cycle gas turbines in many cases.

By capturing technology-specific costs and a wide set of value streams, the VALCOE provides a robust metric of competitiveness across technologies with different operational characteristics, including solar PV with and without storage, and more generally between variable renewables and dispatchable thermal technologies. However, the VALCOE does not attempt to be all-encompassing, as it does not account for network integration and other indirect costs, such as those related to pollution.

4.3 Sample results

The value adjustments by technology from the WEM hourly power supply model are based on electricity demand levels and patterns, the installed power capacity mix and fuel prices in 2025 in the WEO 2019 Stated Policies Scenario (STEPS). This scenario is based on the latest data for technologies and energy markets around the world, and explores the implications of existing policies and announced targets across all energy sectors. For this analysis, to be consistent with LCOE estimations, a carbon price of USD 30 per tonne of CO_2 emissions was applied to all power plants and included in the merit order dispatch. For each technology, value streams were compared against the system average to derive the value adjustments. Positive value adjustments indicate a technology is less competitive than the LCOE would suggest. After adjustments are applied to all technologies, the VALCOE then provides a basis for evaluating competitiveness.

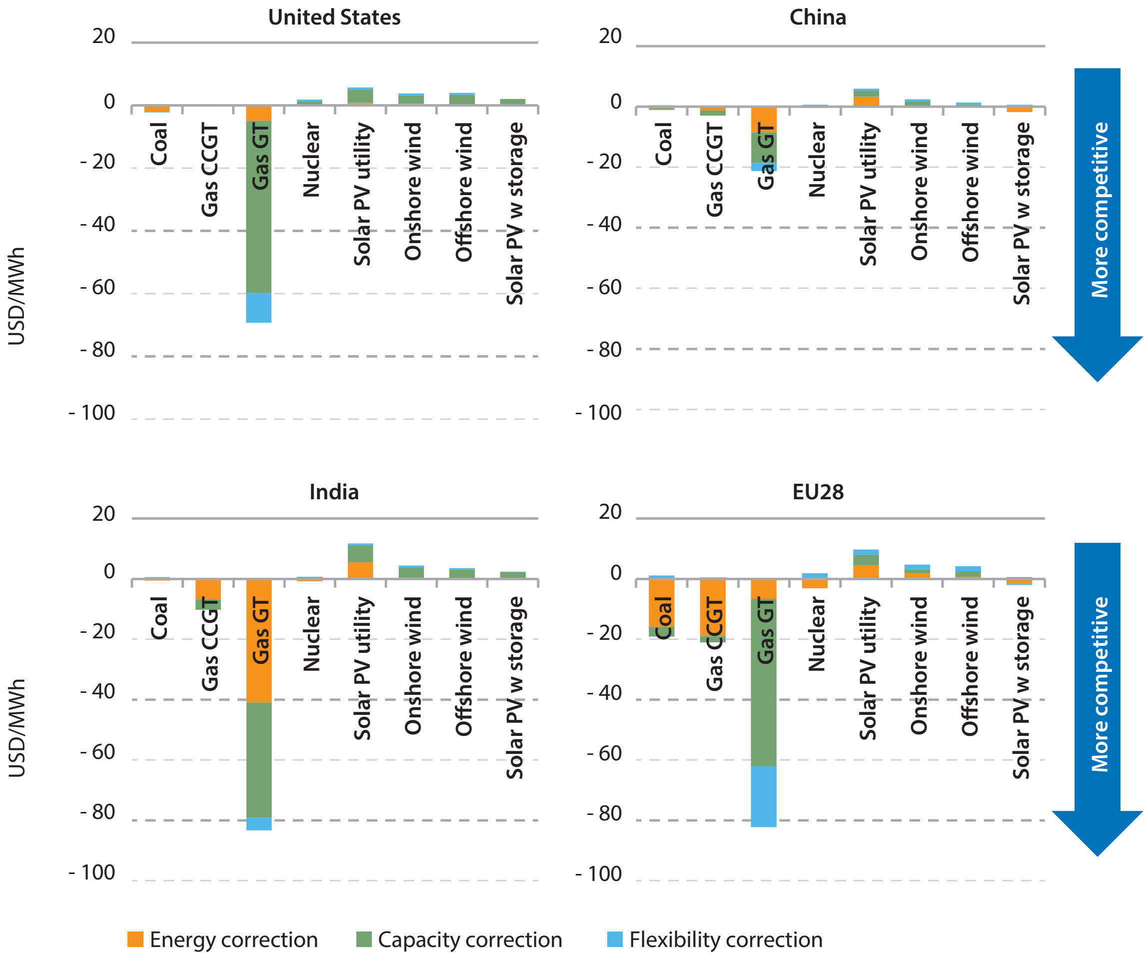
In most cases, the value adjustments in 2025 are modest, and reflect the fact that dispatchable thermal power plants provide the majority of electricity supply in most regions (see Figure 4.5). The results represent the average across the fleet of each technology and can be grouped into four categories, starting with the large value adjustment for open-cycle gas turbines (OCGTs). OCGTs are generally operated for a small proportion of the year and therefore can have relatively high LCOEs. However, the significant negative values indicate that OCGTs are far more competitive than their LCOEs alone suggest. This reflects that OCGTs provide electricity to the system when it is most valuable (and generally only a small proportion of the year), that these plants actively participate in ancillary service markets and contribute to the overall adequacy of power systems.

The second category of technologies generally has zero or minimal value adjustments in this analysis to 2025, tending to have values close to the system average. These include nuclear reactors in all four regions, coal-fired power in the United States, China and India, and combined-cycle gas turbines (CCGTs) in the United States and China. This point reflects the fact that these plants operate in the majority of hours in the year, contribute to system adequacy, and are capable of providing some flexibility to the system.

A third category includes technologies with small positive value adjustments, meaning that they are somewhat less competitive than LCOEs alone would suggest. Solar PV without storage has the largest effect, though still relatively modest, reflecting the concentration of all solar PV output in the same midday hours. The effect on wind power is less pronounced, as production profiles are more varied.

Combined-cycle gas turbines in the European Union and India are in a fourth category. In both cases, mid-merit operations in systems that highly value flexibility lead to significant value adjustments that mean CCGTs are more competitive than their LCOEs otherwise suggest.

Figure 4.5: Simulated value adjustments by technology and region based on WEO 2019 Stated Policies Scenario, 2025



By 2025, value adjustments are already important in evaluating the competitiveness of solar PV without storage, and remain important to peaking plants like open-cycle gas turbines.

As the generation mixes continue to evolve over the long term, particularly with rising shares of variable renewables in all of these regions, the importance and scale of the value adjustments will only increase. The competitiveness of power generation technologies will continue to be influenced by their operational attributes. For instance, cannibalisation effects could be more pronounced for solar PV without storage, possibly shifting the balance towards coupling battery storage systems more often. At the same time, the falling costs of solar PV could outweigh these effects. Flexibility will be the cornerstone of electricity security in future power systems and potentially more highly valued, which would boost the value proposition for dispatchable technologies. However, sector coupling could expand the pool of low-cost flexibility sources, including from the rapidly growing fleet of electric vehicles. In addition, higher shares of variable renewables will depress average wholesale electricity prices in general, which may raise value streams related to contributions to system adequacy. The net effect of these factors is not obvious for any technology, which highlights the need to carefully quantify the various effects. Further refinements of the VALCOE and other efforts to create a more complete metric of competitiveness for power generation technologies will be invaluable to policymakers, system planners, developers, investors and consumers around the world in support of the most cost-effective clean energy transitions.

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Sensitivity analysis

Simplifying assumptions have to be made when performing the cost analysis of generation units to enable comparability of results – for example by assuming a constant capacity factor or harmonised fuel price. In reality, the input parameters will vary across – or even within – countries. To better understand the sensitivity of the levelised cost of electricity (LCOE) with respect to the most important drivers, a sensitivity analysis is performed for a particular set of generation types and parameters, comparing the relative sensitivity of the individual technologies.

As technology costs are subject to region-specific influences and individual plant characteristics, a single LCOE value would oversimplify the results: in many cases, there is not the one single technology having lower costs than the rest. To account for this, the figures in this section show ranges of technology costs dependent on the variation of individual input parameters. As extreme values and outliers distort the illustration and aggravate the interpretation of the results, the figures are restricted to the median 50% of cases for flexible plants. As a very wide range of wind and solar PV technologies were received with similarly wide cost ranges, for these technologies the analysis focuses on the median 20% of costs. Furthermore, solid lines for each technology category indicate the median costs.

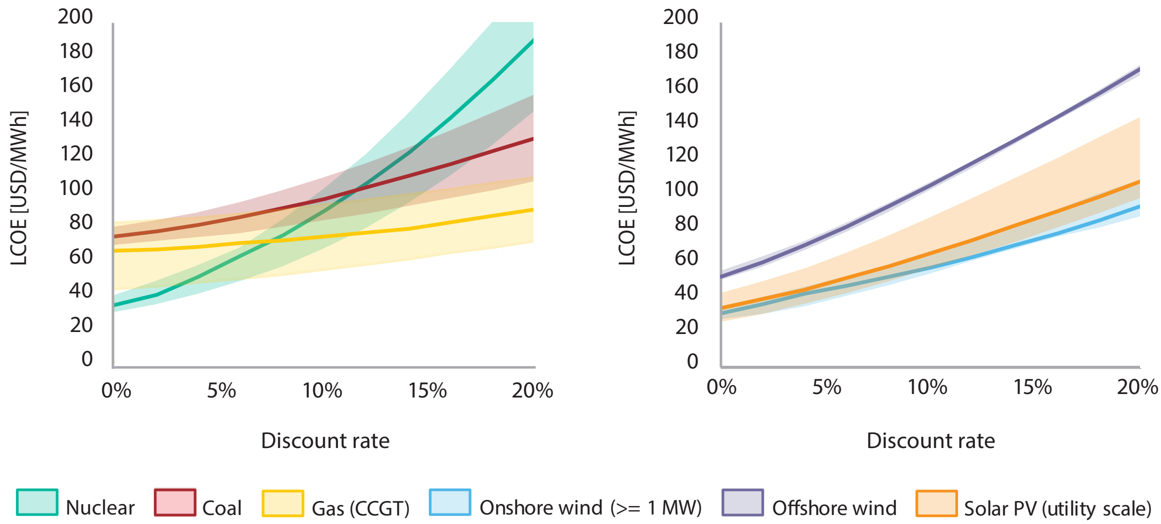
As the number of data points per country differ significantly for certain technologies, each country is represented only once, with their average cost technology, per figure and technology. If not stated otherwise, the sensitivities are performed with respect to the medium 7% discount rate case with 85% capacity factor for baseload plants (renewable load factors are country specific). The focus is on standard and most widespread technologies for gas- and coal-fired generation, i.e. excluding CCUS and CHP units.

5.1 Discount rate sensitivity

The discount rate affects several aspects of LCOE costs, such as construction, refurbishment and decommissioning expenses. In general, the more capital-intensive a technology is, the more sensitive it is to changes in the discount rate. The discount rate itself might also be influenced by how capital-intensive a technology is: a technology with relatively high upfront costs might be more exposed to market risks, which increases financing costs.

The impact of the discount rate is illustrated in Figure 5.1, with the discount rate being varied between 0% to 20%.

Figure 5.1: LCOE as a function of the discount rate
(left: non-renewables, right: renewables)



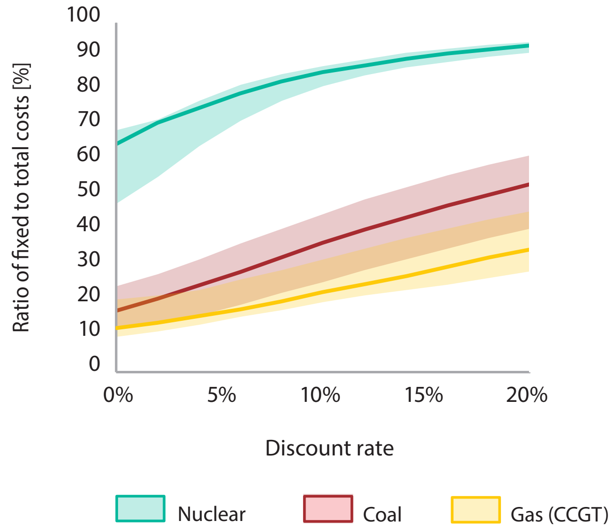
Note: Lines indicate median values, areas the 50% (20% for renewables) central region.

Within the group of flexible baseload plants, i.e. nuclear, coal and natural gas-fired CCGTs, the latter are the least susceptible to changes in the discount rate. The average costs of the median case are increasing by around 40% when comparing the 0% and 20% discount rate cases. Nuclear plants, due to their relatively high investment costs, are impacted the most: whereas they appear to have a cost advantage over coal- and gas-fired plants when assuming low (one digit) discount rates, they become relatively more costly when financing becomes more expensive (with median costs more than five times higher at 20% discount rate compared to the lower bound). Coal, typically ranging between nuclear and gas-fired plants in terms of the ratio between fix and variable costs, ranks between the two other technologies with respect to discount rate sensitivity. The fixed cost share is illustrated in Figure 5.2, showing how the share of fixed costs on total costs is increasing with the discount rate and illustrating the relative position of the individual technologies.

Another factor contributing to nuclear being more impacted by the discount rate is its relatively long technology lifetime: the higher the discount rate, the less beneficial are revenues at the end of the observation period.

The variable renewable energy technologies wind and solar exhibit relatively high upfront and low operating costs – as no fuel costs occur, the latter consists only of O&M and refurbishment costs. These properties make them especially susceptible to changes in the discount rate. Compared to likewise capital-intensive nuclear plants, they have a shorter deployment period, which counteracts its sensitivity. Nonetheless, the LCOE values increase similarly for all technology types by a factor of about three between the lowest and highest discount rate – positioning variable renewables below nuclear technologies, but above coal and natural gas CCGTs.

Figure 5.2: Ratio of fixed to total costs as a function of the discount rate



Note: Lines indicate median values, areas the 50% central region.

5.2 Load factor sensitivity

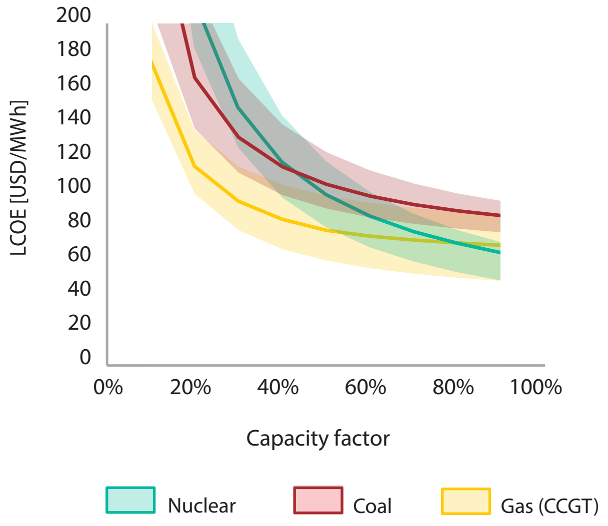
The levelised costs of generating electricity can the interpreted as the average market price a generation unit has to receive for its produced electricity over its lifetime to recover total costs. For baseload technologies, reflected in the assumption of a capacity factor of 85%, the LCOE reflects more or less average wholesale energy prices.

When deviating from the assumption of being operated in baseload, the timing and therefore the value of generation – reflected in the time-varying market prices – becomes more important: mid- and peak-load plants only operate when market prices are high and thus receive, on average, higher revenues per produced unit of electricity. At the same time, average costs increase as investment and fixed costs are distributed over less operating hours. The profitability thus depends on the power plants costs structure as well as the prevalent market price structure in individual markets.

Figure 5.3 illustrates the impact of varying the capacity factor on average production costs. Driven by its high share of fixed compared to variable costs, nuclear power plants are the most affected technology out of the three under consideration. Nuclear plants are, from an economical point of view, less suited to be operated at lower capacity factors. In an environment in which they can be operated at maximum capacity, they benefit however from their low variable costs.

Natural gas-fired CCGTs plants appear as the most versatile technology with respect to the economic impact of a varying number of operating hours: due to their relatively low investment costs and – depending on the region – low to moderate variable costs, they appear competitive in a wide range of use cases.

Figure 5.3: LCOE of coal, natural gas and nuclear as a function of the capacity factor



Note: Lines indicate median values, areas the 50% central region.

Coal-fired power plants appear to be in a challenging economic position given the underlying fuel and moderate CO_2-price assumptions (in this report uniformly USD 30/t CO_2) – they typically come along with higher investment costs than gas-fired plants but lose their competitive advantage of significantly lower variable costs due to low gas prices and more frequently occurring CO_2-reduction mechanisms. Nonetheless, in particular markets with access to low-cost coal (or expensive gas) or lower emission control costs, coal-fired plants can still be the most competitive option.

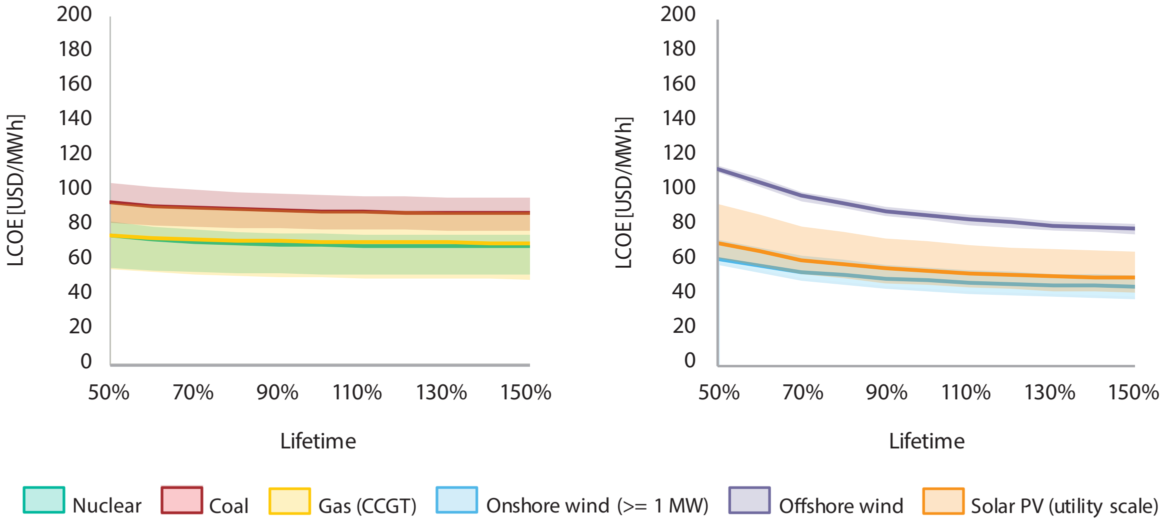
Also variable renewables such as wind and solar PV are subject to system conditions and might not be operated at their theoretical maximum. As their share in the generation mix increases, they might have to be curtailed to some extent.

5.3 Lifetime sensitivity

To assess the impact of the technical lifetime assumption on average generation costs, we vary this parameter in the range of 50% (i.e. cutting the lifetime in half) to 150% (i.e. increasing the lifetime by 50%) of the original values. A decrease in lifetime is equivalent to an early retirement, an increase is equivalent to a no-cost lifetime extension.

Each technology is assumed to have a different expected lifetime. The technologies under scrutiny in this section are expected to last from 60 years for nuclear plants to 40 and 30 years for coal and gas plants respectively. Wind and solar PV installations have been allocated an expected lifetime of 25 years.

Figure 5.4: LCOE as a function of lifetime



Note: Lines indicate median values, areas the 50% (20% for renewables) central region.

In general, decreasing the lifetime of an asset has a bigger impact on average costs than increasing it by the same amount. This is due to the discount rate, which renders costs and revenues in future periods less important – thus taking away years with profits is more relevant than adding the same number of years in the distant future.

For the same reason, changing the expected lifetime of an asset impacts those who have a shorter expected lifespan more: for a nuclear plant with assumed 60 years of operation, adding another year has virtually no effect. For a relatively short-living renewable technology, this could be different.

An additional driver is the ratio between investment and operating costs: if costs occur predominantly at the beginning, shortening the lifespan means having to recover high costs over fewer years. With relatively low investment costs, reallocating these costs is less severe.

For all flexible technologies, the impact of reducing or increasing the lifespan in the given range has little impact on average costs. For all three, the difference between the lower and upper value ranges between 7% and 12%, showing that at 7% discount rate and 30 or more years of expected lifetime – in combination with a lower ratio of fix to total costs for the shorter lived assets – changing the latter by a few years hardly plays a role for average costs.

For wind and solar units, which are more susceptible to lifetime changes due to their lower life expectancy and high share of investment costs, cutting the expected lifetime in half increases average costs between 27% and 31%. Extending it by 50% on the other hand reduces costs by around 8% to 9%.

5.4 Fuel cost sensitivity

When analysing the fuel cost sensitivity of the average generation costs, it is important to keep several aspects in mind.

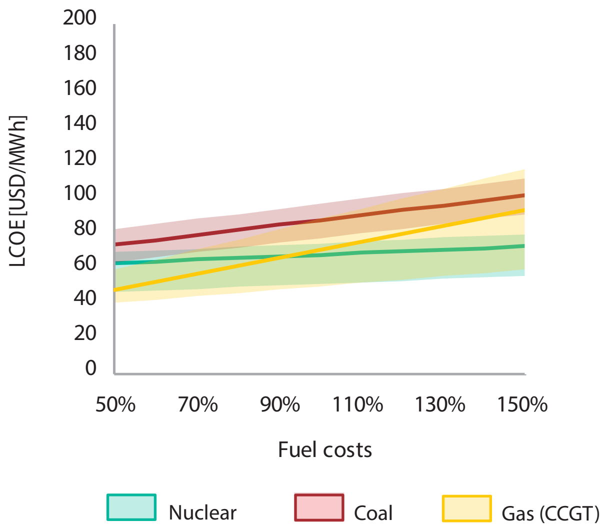
Fuel costs can vary significantly depending on the region. This is especially the case for the price of natural gas, the price assumption in this analysis being that in America only about one-third of the price paid in the rest of the world.

Fuel prices are in most cases not stable but being negotiated in international markets and varying depending on the global economy and short- and long-term outlook of supply and demand. Additionally, prices may be subject to long-term supply contracts as well as seasonal fluctuations. This is true to different extents for the different fuels: whereas coal and gas prices can vary significantly even within a year, nuclear fuel costs can be considered as being relatively stable.

The share of fuel expenditures on total costs varies largely between technologies: whereas nuclear plants are characterised by high investment but relatively low fuel costs, this ratio is typically reversed in the case of natural gas plants.

Important for the interpretation of the results is also to keep in mind that the technologies are to different extents exposed to competition (assuming the power plant dispatch is done according to least cost considerations). Whereas the variable costs of nuclear technologies are relatively low and even a significant increase would hardly affect its short-run competitive position, coal and natural gas plants – depending on the market – are frequently competing for market shares. Thus, an increasing or decreasing price for one of them can also affect their capacity factor, which additionally affects their average generation costs. For the sensitivity analysis, we assume a constant capacity factor of 85%.

Figure 5.5: LCOE as a function of fuel cost



Note: Lines indicate median values, areas the 50% central region.

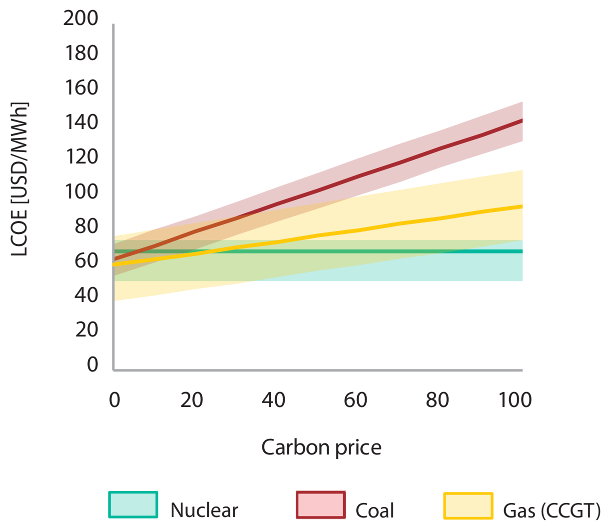
Figure 5.5 illustrates that nuclear plants are only slightly affected by increasing or decreasing fuel costs by 50% in either direction – due to total nuclear costs being dominated by fixed costs. Average median costs change by about 8% in either direction when reaching the end of the sensitivity range. Natural gas CCGT plants are the most susceptible among the analysed technologies with LCOEs changing by about 7% with every 10% change of the fuel price (4% for coal). Natural gas prices, in particular, also vary widely from region to region. In this report natural gas varies from an assumed USD 3.2 per MBtu in North America to USD 10 per MBtu in Japan. Figure 5.5 uses average LCOE values over all countries.

5.5 Carbon price sensitivity

A uniform emission price of USD 30 per tonne of CO_2 is assumed throughout this report. In 2020 only a fraction of all markets had implemented a CO_2 mechanism (World Bank, 2020). In the European Emission Trading System (ETS), emission allowances have occasionally already exceeded USD 30, and many countries implemented higher national prices. To analyse the impact of these different prices on the competitiveness of baseload technologies, we varied the emission costs in the range of USD 0-100 per tonne CO_2.

Figure 5.6 illustrates the effects of different emission prices. As nuclear plants do not emit CO_2, they are not affected (but included as a reference). Coal, which causes approximately twice the carbon output per generated unit of electricity than natural gas, is the most sensitive to varying carbon prices.

Figure 5.6: LCOE as a function of carbon price [in USD/tCO_2]



Note: Lines indicate median values, areas the 50% central region.

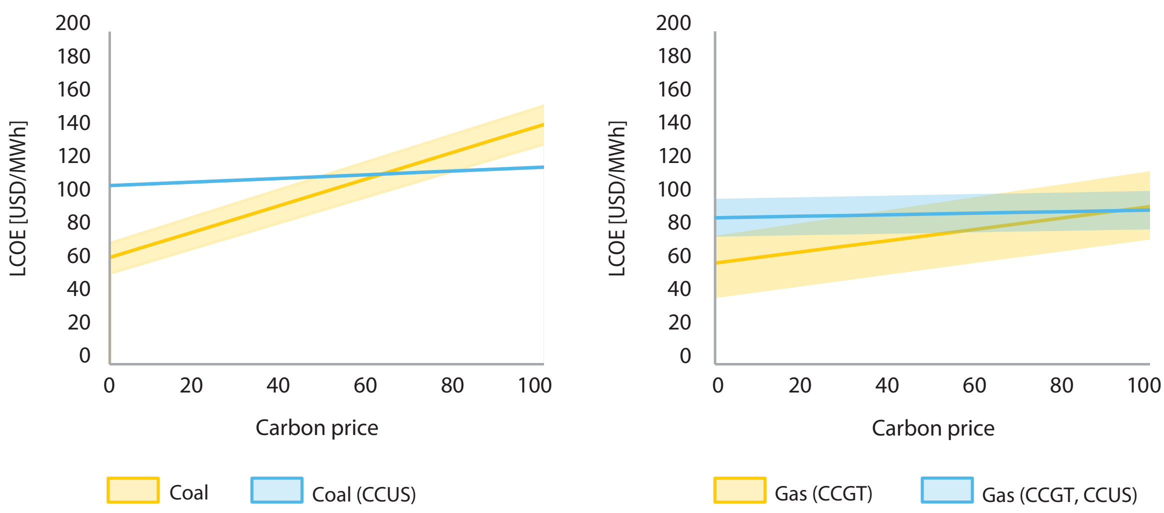
Increasing (decreasing) the carbon price by 10% changes the LCOE of the median coal technologies by around 8% – and thus almost twice as much as the median costs of a CCGT. Under the given fuel price assumptions, at emission costs of around USD 50/t CO_2, average ordinary coal technologies without carbon capture have a clear cost disadvantage towards gas-fired CCGTs.

In the default case with emission costs of USD 30/tCO_2, equipping coal and gas plants with a carbon capture and storage unit (CCUS) is, due to the higher investment costs of CCUS equipment and the reduced thermal efficiency, more expensive than unmitigated fossil fuel-based electricity.

With higher emission costs however, the picture could change. For coal power plants, due to the fuel's relatively high carbon content, CCUS units become competitive at around USD 50 to 60 per tCO_2. For gas-fired CCGTs, only carbon prices above USD 100/tCO_2 would make plants with CCUS competitive. At such high carbon prices renewables, hydroelectricity or nuclear are likely to constitute the least-cost options to ensure low-carbon electricity.

Although the necessary carbon price levels required for triggering a cost advantage of CCUS plants exceed the majority of today's prices, they are still relatively low compared to existing estimates of the social cost of carbon. Although the estimates carry great uncertainties, global social costs could exceed USD 100 per tCO_2 (Nordhaus, 2017). Thus, if flexible low-carbon generation is needed, competitive alternatives are lacking and affordable fossil resources are available. Depending on national circumstances, with sufficiently high carbon prices, CCUS could be a possible complement in certain low-carbon power mixes.

Figure 5.7: LCOE with and without CCUS for various carbon prices [in USD/t CO_2]



Note: Values at 7% discount rate. Lines indicate median values, areas the 50% central region.

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Part 2

Boundary chapters



The levelised cost of storage (LCOS)

6.1 Introduction

This boundary chapter on the levelised cost of storage (LCOS) aims at generalising the concept of levelised cost of electricity (which is commonly applied to electrical power generation technologies) for dedicated electrical-storage devices.[1,2] The objective of this chapter is to clarify and unify different approaches or interpretations of what is commonly referred to as LCOS. To this purpose, we introduce specific metrics, which each focus on particular aspects of the cost of storage, in order to compare and integrate them in a single coherent approach to LCOS.

The emphasis of this contribution is on inter-temporal energy arbitrage, i.e. buying electrical energy when it is cheap, storing it for a carefully determined time-period and selling it at a later moment at a higher price. The costs of doing so, composed of a fixed capital investment for the store, and the fuel costs, i.e. the cost of the electricity used for charging, can be interpreted in a manner analogous to classic cost accounting for electricity generation in terms of the levelised cost of generating electricity (LCOE). This is an area receiving increasing attention and a number of interesting attempts have been made to clarify the cost and value of electricity storage. In describing the different elements of value and cost of storage for arbitrage, we rely heavily on the work by Belberdos et al. (2017a, 2017b) and Belberdos (2019). Furthermore, some hints are offered on how to estimate the value of storage for applications and services other than arbitrage, thereby referring to recent published material by Schmidt et al. (2019). A list of references is provided at the end of the chapter and the reader is encouraged to consult the further literature referred to in the abovementioned publications.

6.2 A primer on electricity storage: Applications, available technologies, current and estimated future costs

Due to the (desired or imposed) growing annual share of electrical energy originating from renewable technologies subject to naturally-fluctuating power flows (like PV solar and wind), characterised by relatively low load factors, the combined installed capacities of those technologies in the future are expected to be much larger than typical/conventional electrical peak power demand.[3]

1. "Dedicated electricity storage" refers to storage technologies and applications for electricity in and electricity out.

2. In general, throughout this boundary chapter, the terms "storage device", "storage unit", "storage facility" and "store" are used as synonyms.

3. In this chapter, the terms "power" and "energy" are used in their proper physical sense: power is the time rate of change of energy; energy is the time-integral of power over a certain period. Power can also be interpreted as a flow or flux: amount of energy per second flowing from one point to another. "Installed power capacity" is the maximum power that a storage device can discharge (and charge), often simply abbreviated as "capacity". Note, however, that for storage devices also the installed energy capacity is important. The regrettable habit in some circles to blindly use the word "power" as a synonym of "electricity" must be avoided in the context of storage. "Power" is charged into or discharged from a storage device, but it is "energy" that is stored. For further clarification on the relationship of power and energy in a storage context, see Belderbos et al. (2017b).

The weather-related character of their electrical power production entails a mismatch between instantaneous electric power demand and supply; at some moments much more power will be produced than needed; at other times insufficient supply may result. Future electric power systems with high shares of naturally-fluctuating renewables (often referred to as VRE)[4] can only function properly if sufficient flexibility measures can be relied upon, such as flexible thermal generation, sufficient high-voltage transmission, active demand response/participation, sector coupling, spilling/curtailment of superfluous generation, and, of course, dedicated storage of electrical energy.[5] In ideal energy markets, all these flexibility options should be able to compete on cost and value in a level playing field and an optimal portfolio of flexibility options should emerge.[6] Clearly, the availability of significant amounts of cost-effective dedicated electrical storage would make a world of difference in markets with large fractions of naturally-fluctuating renewables. Evidently, cost-effectiveness is key here and it is therefore of utmost importance to clearly determine the value and the costs, and hence the competitiveness of different electrical storage technologies in a variety of applications and services.

Storage technologies can be used by different actors (e.g. generating companies of different sizes), large and small consumers, system operators) in a range of applications, related to provision of energy services, grid services and installed power capacity services, on the transmission network, distribution network or "behind-the-meter". There are several ways to categorise these applications and services (e.g. Belderbos, 2017b and 2019 and IRENA, 2020, among others) but it is advisable to utilise the classification by Schmidt et al. (2019), as it allows reference to their published results illustrating the value of using particular storage technologies for providing certain services. Schmidt et al. (2019) have indeed classified 25 unique-purpose applications into 12 so-called core applications. The result of the consolidation exercise leads to the core applications as shown in Table 6.1.

4. "Naturally-fluctuating renewable energy sources" are often referred to as VRE, for "variable renewable energy". When using that designation, however, it must be understood that the VRE are not only (deterministically) variable, but that they also have a stochastic character.

5. Ideally, curtailment should be limited to a minimum by relying on the other flexibility measures. However, system stability and cost/benefit analyses steering overall investment decisions will unavoidably lead to some curtailment. (As simple examples, the capacity of the invertor for rooftop PV installations is almost always sized lower than the installed peak power of the solar panels. Likewise, transmission lines will never be sized to the maximum peak that may occasionally occur.)

6. "Optimal" refers to short-term operational as well as long-term (planning) objectives, encompassing also reliability, availability, resilience, etc.

Table 6.1: Grouping of 12 core applications in which storage technologies can participate

Role	Application	Description
	1. Energy arbitrage	Purchase power in low-price and sell in high-price periods on wholesale or retail market
System Operation	2. Primary response	Correct continuous and sudden frequency and voltage changes across the network
	3. Secondary response	Correct anticipated and unexpected imbalances between load and generation
	4. Tertiary response	Replace primary and secondary response during prolonged system stress
	5. Peaker replacement	Ensure availability of sufficient generation capacity during peak demand periods
	6. Black start	Restore power plant operations after network outage without external power supply
	7. Seasonal storage	Compensate long-term supply disruption or seasonal variability in supply and demand
Network Operation	8. T&D investment deferral	Defer network infrastructure upgrades caused by peak power low exceeding existing capacity
	9. Congestion management	Avoid re-dispatch and local price differences due to risk of overloading existing infrastructure
Consumption	10. Bill management	Optimise power purchase, minimise demand charges and maximise PV self-consumption
	11. Power quality	Protect on-site load against short-duration power loss or variations in voltage or frequency
	12. Power reliability	Cover temporal lack of variable supply and provide power during blackouts

Source: Schmidt et al. (2019).

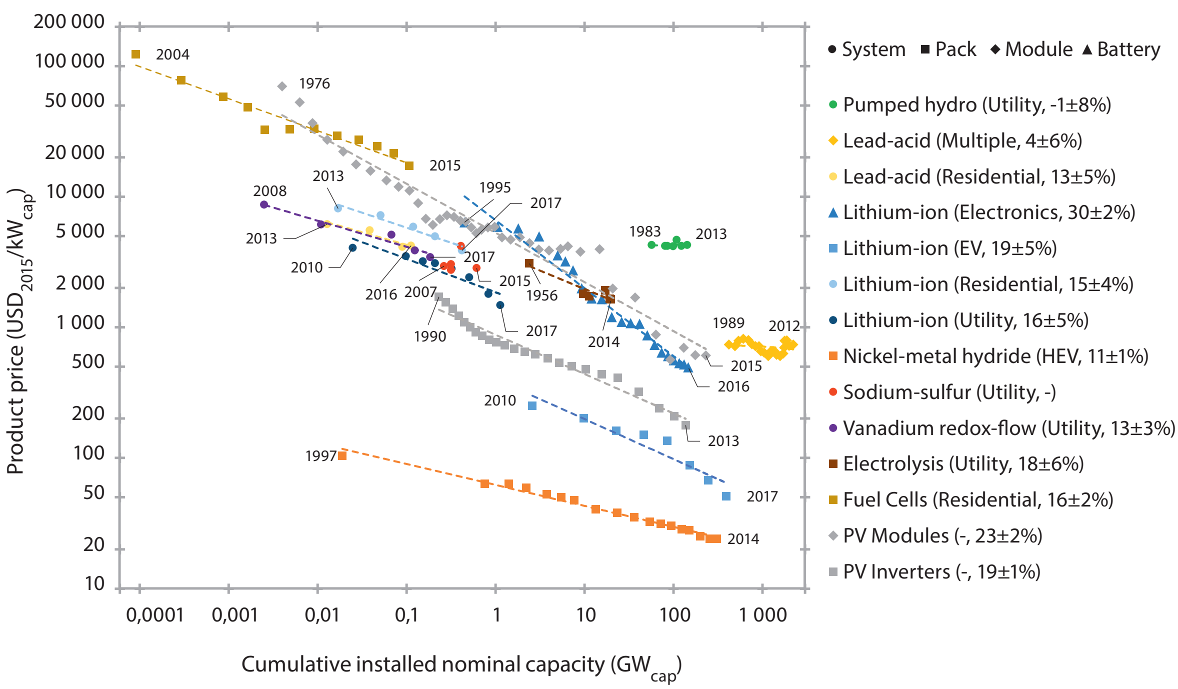
In contrast to the *applications* indicated above, there exists wide range of different storage *technologies*, which can conveniently be categorised in five groups:

1. mechanical storage,
   a. such as pumped hydro storage, compressed air storage, flywheels;
2. chemical storage,
   a. e.g. P-to-H_2-to-P with crucial technological components electrolysers and fuel cells,
   b. and/or more extended ‘P-to-fuels-to-P’, with *fuels* possibly also CH_4, NH_3, liquid fuels;
3. electro-chemical storage,
   a. such as batteries, redox flow batteries;
4. electric storage,
   a. e.g. supercapacitors;
5. thermal storage, e.g.
   a. (high-temperature) molten salt thermal storage,
   b. very-high-temperature firebricks.

Today, pumped hydro storage still by far dominates the global storage mix.[7] According to IRENA (2017), it accounts for 96% of the total installed electric storage power capacity worldwide, followed by thermal storage (almost 2%), electro-chemical storage (a bit more than 1%) and other mechanical storage (somewhat less than 1%). In the future, the share of electro-chemical storage is expected to grow due to efficiency improvements and decreasing costs.

In its supplementary information, Schmidt et al. (2019) provides characteristics of several storage technologies for the year 2015. Although many characteristics have their relevance, the most important characteristics are the installed (discharge) power capacity *P*, the installed energy capacity *E* (allowing thus the specification of the discharge duration *E*/*P* at nominal power per cycle), the typical number of cycles over the lifetime, the round-trip efficiency, the specific investment costs per unit energy stored (USD/kWh), the specific investment costs per unit discharge power (USD/kW) and the response time.[8] For the investment costs, the online repository mentioned in Schmidt et al. (2019) includes an updated version of the experience curves relating the overall cumulative installed discharge power capacity (GW_{cap}) to capital costs per kW installed, and the overall cumulative installed stored energy capacity (GWh_{cap}) to capital cost per kWh installed; both are reproduced below in Figures 6.1 and 6.2, respectively.

Figure 6.1: Experience curves for electrical energy storage (EES) technologies per nominal discharge power capacity, in different uses



Note: The percentage terms in brackets express the Experience Rate ER ± uncertainty.[9] Fuel cells and electrolysers must be considered together.

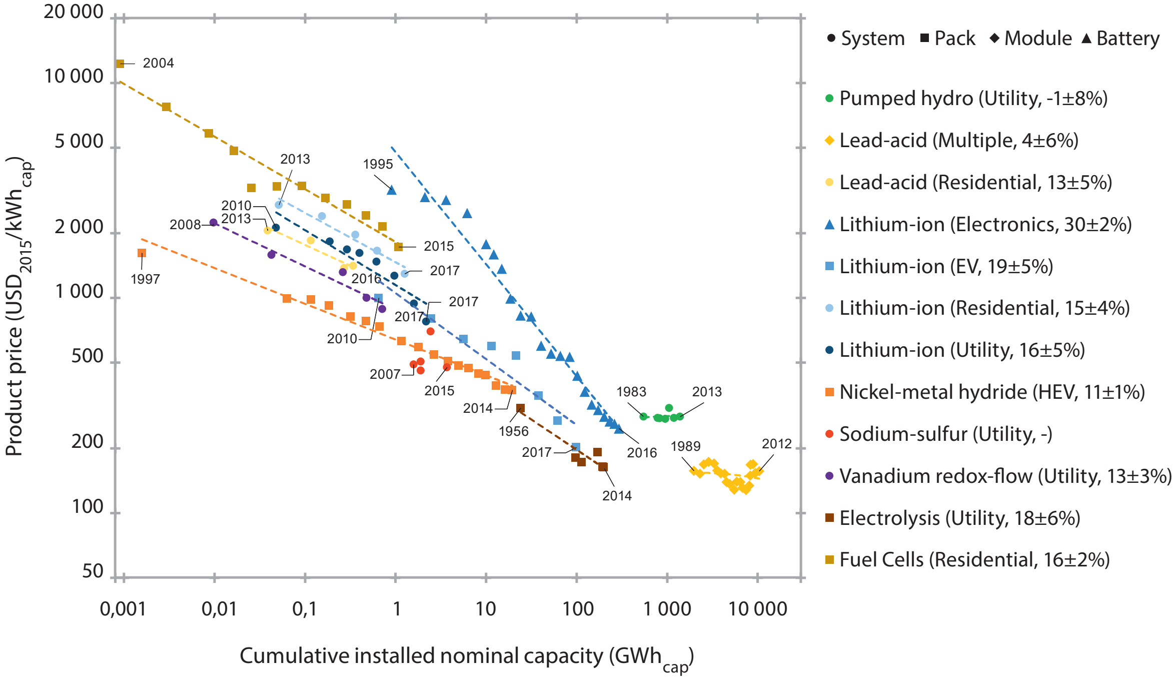
Source: Schmidt et al. (2018).

7. More precisely mid-2017.

8. Note that *E/P* represents the charging and discharging duration at nominal power in the absence of losses, i.e. for an efficiency of 100%.

9. For the exact definition of the uncertainty bracket, see Schmidt (2017 and 2019).

Figure 6.2: Experience curves of electrical energy storage (EES) technologies per nominal energy storage capacity, in different uses

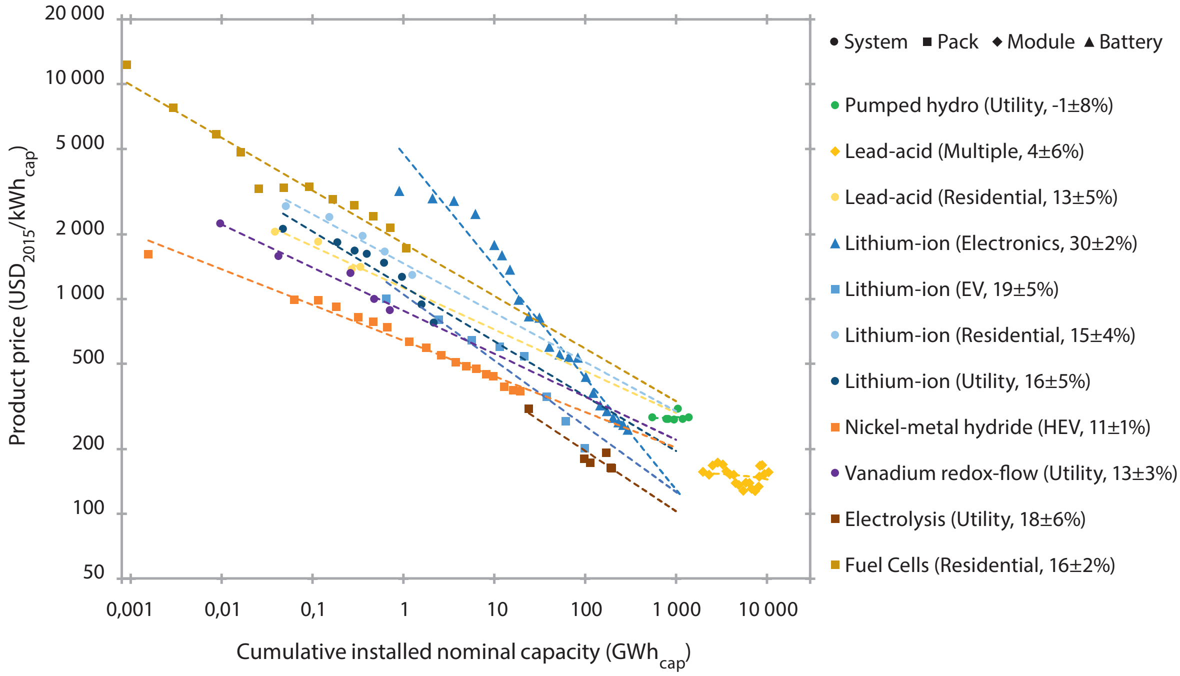


Note: The percentage terms in brackets express the Experience Rate ER ± uncertainty. Fuel cells and electrolysers must be considered together.

Source: Schmidt et al. (2018).

The analysis by Schmidt et al. (2019) also provides an extrapolation of *future cost estimates* based on the above experience curves. Furthermore, based on the market penetration model explained in Schmidt et al. (2017), their online repository also gives an update of the expected future costs as a function of time. Both updated figures are given in Figure 6.3 (extrapolation of Figure 6.2 up to 1 000 GWh installed stored energy capacity) and Figure 6.4.

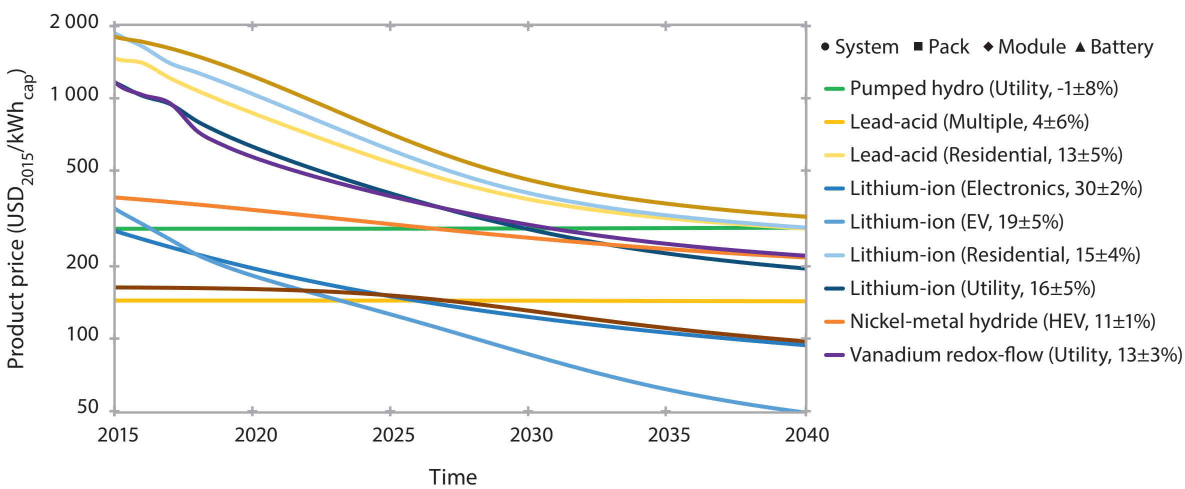
Figure 6.3: Expected future product price based on the experience curves (of Figure 6.2) for electrical energy storage (EES) technologies per nominal stored energy capacity, for their different uses



Note: The percentage given between brackets in the legend express the Experience Rate ER ± uncertainty. Fuel cells and electrolysers must be considered together.

Source: Schmidt et al. (2018).

Figure 6.4: Expected future product price as a function of time, based on Figure 6.3 and an S-type market penetration model



Note: The S-type market penetration model is explained in Schmidt et al. (2017). The percentage given in brackets in the legend express the Experience Rate ER ± uncertainty. Fuel cells and electrolysers must be considered together.

Source: Schmidt et al. (2018).

6.3 The levelised cost of storage (LCOS)

To develop the different metrics related to the levelised cost of storage (LCOS), it helps to recall the original meaning of the *LCOE*. The levelised cost of electricity for an electric power generating unit is properly defined as the average electricity price that is required to cover the full lifetime costs of the plant composed of operations (including fuel, carbon and O&M costs) and investment including the required rate of return on the capital invested. Thus, the LCOE is the fictitious stable (i.e. average) electricity price needed to make the present value of the sum of all costs and all revenues over the entire operational life of the unit equal to zero and is calculated by Equation 2 in Chapter 2 of this report.

To introduce a levelised cost of storage (LCOS), a 1-on-1 translation of the LCOE might be considered, thereby adapting its meaning in the sense that fuel cost becomes charging cost (i.e. the price at which input electrical power is bought by the storage facility) and "MWh generated" becomes the amount of MWh discharged and thus sold in the market. The meaning of LCOS would therefore read as: the average electricity price during discharging required to cover the full lifetime costs of the storage plant composed of operations (including charging cost, carbon and O&M costs) and investment including the required rate of return on the capital invested.[10]

Equivalent definitions of the levelised cost of storage (LCOS) are indeed used by Pawel (2013), Jülch (2016) and Schmidt et. al. (2019). Sometimes the expressions are formulated a bit differently, but they effectively all mean the same; as an example, Schmidt et al. (2019) also introduces an extra term to take into account an end-of-life value. Nevertheless, a drawback of the LCOS definition given above is that the cost of charging depends on the wholesale electricity price profile for which the cost metric is established. This makes it dependent on the surrounding electricity system and its temporal price profile. The World Energy Council (WEC, 2016) has therefore proposed a formulation for the LCOS where the cost for input energy, or the charging cost, is deliberately left out of the calculation to avoid obscuring the results with too many assumptions. In this way, indeed, a system-independent metric is obtained that is applicable to each technology regardless of the power system at hand, but with the caveat that it ignores the fact that the input electric power represents a manifest operational cost, whereby also the operational losses (reflected by the round-trip efficiency) are ignored.

A more complete metric does need to take into account the charging cost, which unpredictability and system dependence are indeed methodologically inconvenient. The system dependency of the actual time-dependent charging cost complicates the universal application of the LCOS metric for each technology and its value should always be considered in relation to the underlying electrical power system. Having said that, however, we will introduce a tailor-made metric in which the charging cost appears to be absent, but where it is implicitly taken into account: that metric will be named the required operational profit which suffices to repay the investment and fixed operational costs. This is an important step forward in operationalising the LCOS metric while remaining methodologically coherent.

This boundary chapter aims at giving a more comprehensive analysis of the levelised cost metric applied to storage technologies. In so doing, we introduce three so-called required cost metrics (further sometimes referred to as the R-metrics) closely related to the generic LCOS, but including charging costs to a varying degree. In a next stage they will need to be compared to the available revenue-based metrics (sometimes referred to as the A-metrics) that are based on the wholesale price profiles of the electricity market where the storage is to be installed. Furthermore, we reflect on the metrics' practical convenience in the context of energy arbitrage. In this regard, the perspective taken in this chapter is that of an actor who sees a varying electricity price profile on which he can act to arbitrage between moments with high prices and moments with low prices. For this first part (Sections 6.4 to 6.6), Belderbos (2017a) is the inspiration. In a smaller second part (Section 6.7), a brief introduction to the possible use of the LCOS concept for other applications such as system operations, network operations and end-use consumption – as delineated in Table 6.1 – will be given, as an introduction to the work by Schmidt et al. (2019).

10. For a power-to-gas-to-power storage facility using synthetic methane, a carbon cost (CO_2 price) remains relevant.

6.4 Arbitrage cost metrics for storage technologies: The normative approach

In contrast to the traditional terminology that stresses a cost viewpoint, the metrics in this chapter are derived from, and labeled according to, a logic that takes a price perspective, which allows drawing clearer distinctions between the different metrics. It is nevertheless important to emphasise that in the end, they will be expressed as cost metrics.

As a reminder, for typical generation units (both of the conventional and naturally-fluctuating renewable type), the LCOE can be interpreted as an average fictitious electricity price that allows break even considering all costs. In the following, three storage cost metrics, which differ with respect to charging costs, are considered:

- the required average discharge price (RADP);
- the required average price spread (RAPS);
- the required average operational profit (RAOP).

Each one of these metrics is based on the principle of strictly balancing revenues with costs. In a cost-benefit analysis (CBA), a storage project would thus have a zero net present value. All three are fully-fledged cost metrics.

6.4.1 Three metrics for LCOS and breaking even: RADP, RAPS and RAOP

RADP

The required average discharge price (RADP) is essentially a literal translation of the traditional LCOE concept applied to a storage device. For the sake of simplicity and transparency of the formulation, carbon costs and decommissioning costs or end-of-life value are omitted, as are any variable O&M.[11] The formulation for the required average discharge price is thus:

$$\text{RADP} = \frac{\sum_t (OCC_t + FOM_t + TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \quad (1)$$

where:

OCC_t = Overnight Construction Costs in year t

FOM_t = Fixed Operation and Maintenance costs in year t

TCC_t = Total cost of electricity used for charging in year t

MWh_t^d = The amount of electricity discharged in MWh in year t

$(1 + r)^{-t}$ = The discount factor for year t, with r being the discount rate

11. For full-cycle power-to-methane-to-power storage, CO_2 might be emitted by the electricity-producing unit and should thus be taken into account. However, for most storage facilities, there would be no (operational) CO_2 costs and thus that term can be omitted.

Similar to the LCOE, which reflects the required average electricity price that a generator sees during operation hours to break even all cost, the RADP reflects the required average electricity price a storage unit needs to see during discharge hours to break even considering fixed costs and charging costs. The charging cost is the sum of the actual electricity prices during charging periods multiplied by the charged volume, or said differently, the relevant ACC is the weighted average cost obtained by averaging only during the charging hours and accounting for the amount of charged energy. The average charging cost is thus by definition equal to:

$$ACC \triangleq \frac{\sum_t (TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^c (1+r)^{-t}} \tag{2}$$

The ACC is, however, conventionally expressed per unit of output, i.e. MWh_t^d. This relationship can be established by the fact that for any year t, MWh_t^d =RT MWh_t^c, with η_{RT} being the round-trip efficiency, ignoring self-discharging and exogenous charging (e.g. via rain or snow water in pumped hydro reservoir systems). It therefore holds that the ACC can be expressed as:

$$ACC = \frac{1}{\eta_{RT}} \frac{\sum_t (TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{3}$$

RAPS

The second cost metric is the required average price spread (RAPS) and is defined as the required average discharge price (RADP) minus the average charging cost (ACC). Taking into account that the total charged quantity is equal to the total discharged quantity (which appears in the denominator of the metrics) corrected for the round-trip efficiency η_{RT} as explained above, the required average price spread can be written as follows:

$$RAPS = \text{RADP} - \text{ACC} = \frac{\sum_t (OCC_t + FOM_t + (1-\eta_{RT}) \cdot TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{4}$$

Equation (4) shows that this price-based metric covers the investment costs, the fixed operation and maintenance costs as well as the costs of the efficiency losses during the round-trip charging and discharging processes. It does not however include the charging costs as such. RAPS is thus the difference, which is required to break even, between the average price obtained for discharged electricity and the average cost of electricity used for charging.

RAOP

Finally, we define the required average operational profit (RAOP) as the required total operational profit (OP) on a per unit of discharged energy basis. The total required operational profit is the total required revenue from discharging electricity minus the total cost from charging electricity:

$$\text{Required total OP} = \sum_t (OCC_t + FOM_t + TCC_t) \cdot (1+r)^{-t} - \sum_t (TCC_t) \cdot (1+r)^{-t} \tag{5}$$

Since the charging cost TCC_t cancels out, the "Required total OP" for breaking even must equal the total costs expended for capital investment and fixed operation and maintenance costs. Hence, the expression for the required average operational profit reduces to Equation (6).

$$\text{RAOP} = \frac{\sum_t (OCC_t + FOM_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{6}$$

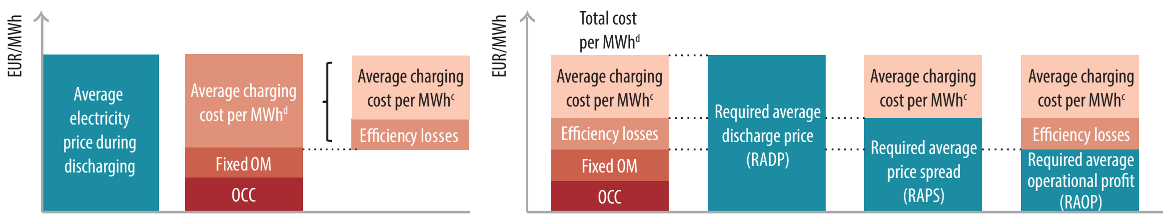
In other words, RAOP can be thought of as the average price that would be required for breaking even if charging costs were zero.

6.4.2 Comparison of the three required LCOS cost metrics for energy arbitrage

Although the required metrics (sometimes referred to as the R-metrics) have been derived from imposing cost/benefit break even by looking at the revenues from the electricity prices, it is important to observe that their expressions exhibit the costs per unit discharged electric energy. Figure 6.5 shows a summary of the cost components covered by the required average discharge price (RADP), the required average price spread (RAPS) and the required average operational profit (RAOP). As can be seen, the three metrics differ in the extent to which they account for charging costs:

- the RADP includes the total charging cost per unit of discharged energy which consists of the average charging cost and the cost associated with efficiency losses;
- the RAPS only accounts for the part of the charging cost associated with efficiency losses; and,
- the RAOP does not make explicit reference to any charging costs.

Figure 6.5: Summary of the different cost components covered by RADP, RAPS and RAOP



A small numerical example, taken from Belderbos (2019a) illustrates the three required cost metrics (i.e. the R-metrics). It consider only a single year of operation for simplicity; the capital costs and fixed operation and maintenance cost are therefore converted in an equivalent annual fixed cost (basically representing the annuity). Table 6.2 shows the assumed fixed cost on an annual basis, the round-trip efficiency, the total number of discharging hours and the average charging cost for a chosen reference case. The parameter values used are not based on a specific technology but are merely chosen for illustrative purposes. For all cases, the storage unit is assumed to charge and discharge at nominal power,[12] and assuming no binding restriction on the amount of energy (E) stored.

12. This is not necessarily the case in real situations but results can easily be generalised by expressing them in equivalent full load hours.

Table 6.2: Storage parameters used for the reference case	
Installed power capacity (P)	1 MW
Equivalent Annual Fixed cost (OCC + FOM)	EUR 30 000
Round-trip efficiency (η_{RT})	80%
Number of discharging hours (NDH)	1 000 h
Averaged charging cost (ACC)	EUR 20/MWh[c]

The RADP, RAPS and RAOP are calculated for the reference case of Table 6.2. For 1 000 h of discharging at nominal capacity of 1 MW (and thus discharging 1 000 MWh), a total amount of 1 250 MWh (= 1,000 h x 1 MW/) needs to be charged, costing EUR 25 000. Using Equations (1), (4) and (6), this leads to the results shown in Table 6.3.

Table 6.3: Different cost metrics for a storage with parameters as provided in Table 6.2	
RADP	EUR 55/MWh[d]
RAPS	EUR 35/MWh[d]
RAOP	EUR 30/MWh[d]

From this example, it should be clear that:

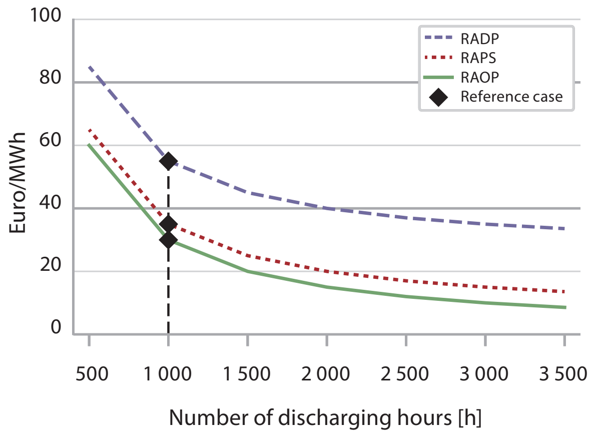
- The required average discharge price (RADP) covers all fixed and variable costs. The sum of all costs for the installed 1 MW unit in this example equals EUR 30 000 fixed cost and EUR 25 000 charging cost, resulting in a total cost of EUR 55 000. Divided by 1 000 MWh of discharged electricity results in a required discharge price of EUR 55/MWh[d].

- The required average price spread (RAPS) is equal to the required average discharge price, RADP = EUR 55 /MWh[d] , minus the average charging cost (ACC), EUR 20/MWh[c] , which is equal to EUR 35 /MWh[d]. Putting it in a different perspective, the RAPS is also equal to the fixed cost and cost due to efficiency losses. Indeed, applied to this example, the efficiency losses per MW capacity for a 1 000h discharge amount to (1 250 MWh[c] – 1 000 MWh[d]) x EUR 20/ MWh[c] = EUR 5 000. Added to the fixed cost and divided by all discharged electric energy leads to a required average price spread (RAPS) of EUR 35/MWh[d].

- The required average operational profit (RAOP) only needs to cover the fixed costs as shown and explained by Equation (6): dividing the capital cost of EUR 30 000 by all discharged electrical energy (being 1 000 MWh) leads to an RAOP of EUR 30/MWh[d]. Note that the RAOP does not explicitly account for any operational costs as this is implicitly captured in the definition of the required average operational profit (RAOP).

Clearly, all three metrics change with the numbers of full load discharge hours as fixed costs are spread over a greater output. The three required cost metrics of a storage unit with characteristics as given in Table 6.2 are shown in Figure 6.6 for different numbers of discharge hours. The reference case, with NDH= 1 000h, is indicated by the diamond symbol. Given their definitions, the R-metrics, RADP, RAPS and RAOP evolve together. RADP and RAPS stay vertically parallel, as their difference is the constant average charging cost (ACC). RAOP stays parallel as the difference to RAPS is the constant efficiency loss.

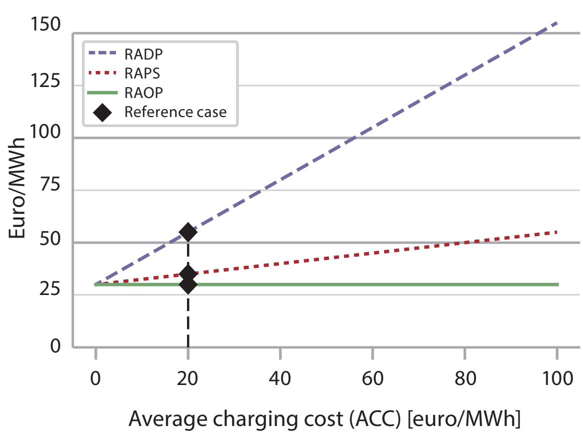
Figure 6.6: The R-metrics RADP, RAPS and RAOP as functions of the number of discharging hours assuming constant average charging cost and constant round-trip efficiency



Source: Belderbos et al. (2017a).

To further highlight the dependency of the R-metrics on the average charging cost ACC, it is instructive to show one more parameter variation based on the example of Table 6.2 and Table 6.3. Figure 6.7 displays this dependency, where again the reference value of Table 6.3 is indicated by the diamond.

Figure 6.7: Dependency of RADP, RAPS and RAOP as a function of the average charging cost (ACC) for a storage device with characteristics as given in Table 6.3, with constant round-trip efficiency and constant amount of discharged electricity



Source: Belderbos et al. (2017a).

The required average discharge price, RADP, fully depends on the average charging cost, ACC, whereas the required average price spread, RAPS, only has a weak dependency, because of the losses (round-trip efficiency less than 100%). This weak dependency on RAPS is by and large negligible for high-efficiency storage units such as Li-ion batteries with ~ 85% efficiency, but may be considerable for low-efficiency stores like P-to-methane-to-P with round-trip efficiencies of only ~ 30%. The required average operational profit RAOP is independent of the average charging cost ACC. All this is reflected by the slope of the three lines as given by Equations (7) and (9).

$$\frac{\partial \text{RADP}}{\partial \text{ACC}} = \frac{\sum(1+r)^{-t}}{\eta_{RT}} \tag{7}$$

$$\frac{\partial \text{RAPS}}{\partial \text{ACC}} = \frac{(1-\eta_{RT})\sum(1+r)^{-t}}{\eta_{RT}} \tag{8}$$

$$\frac{\partial \text{RAOP}}{\partial \text{ACC}} = 0 \tag{9}$$

More parameter variation, such as the dependency of the R-metrics on the round-trip efficiency, with accompanying graph, can be found in Belderbos et al. (2017) or Belderbos (2019).

Before leaving this example it is important to indicate two important observations for these R-metrics so far.[13] First, in the example of Table 6.2 and Table 6.3 and the parameter-variation of Figure 6.6, the charging cost was assumed to be constant for all charging activities. Second, these results were obtained without the need to explicitly specify the energy storage capacity E, nor the charging and discharge duration times-which in the loss-free case would be equal and simply be given by E/P, although it must be recognised, however, that it was assumed that E was sufficiently large. Also, there was no need to specify the time duration during which no charging or discharging takes place, although that limits the overall total amount of MWh that can be discharged (or the time during which electric power can be discharged).

6.5 Arbitrage price-based metrics for storage technologies: The empirical approach

The three different required average cost metrics express the conditions for the storage investor to break even on the full investment costs, including the required rate of return on investment as well as possible operational costs, depending on the metric, whereby revenues come from energy arbitrage. To assess whether storage investors would indeed break even, these required average cost metrics must be compared to available average prices, as faced by the storage unit. Such available average prices could be accessed by the storage unit if and when it would be physically available at that time. Note that available prices are not the same as simply market prices. The reason for the difference is that possibly occurring high prices may be unattainable (and hence not available) for a storage unit, as it may find itself in an empty, fully-discharged state. Similarly, low prices, which would, in principle be attractive for charging, will be irrelevant if it is already in a fully charged state.

Using the notion of available prices, the three following revenue-based A-metrics can be formulated:

- the available average discharge price (AADP);
- the available average price spread (AAPS);
- the available average operational profit (AAOP).

13. This limitation will be lifted later on in the discussion.

6.5.1 Three A-metrics in search of profitability: AADP, AAPS and AAOP

AADP

The AADP is equal to the average electricity price during actual discharge hours and is entirely defined by a given price profile and storage operation, as expressed in Equation (10),

$$\text{AADP} = \frac{\sum_t Discharge\ revenue_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{10}$$

where:

Discharge revenue	= Total revenue of discharged electricity in year t
MWh_t^d	= The amount of electricity discharged in MWh in year t
$(1 + r)^{-t}$	= The discount factor for year t

AAPS

Secondly, the AAPS is defined as the difference between the AADP and the ACC as expressed in Equation (11):

$$\begin{aligned} \text{AAPS} &= AADP - ACC \\ &= \frac{\sum_t Discharge\ revenue_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} - \frac{\sum_t (TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^c (1+r)^{-t}} \end{aligned} \tag{11}$$

AAOP

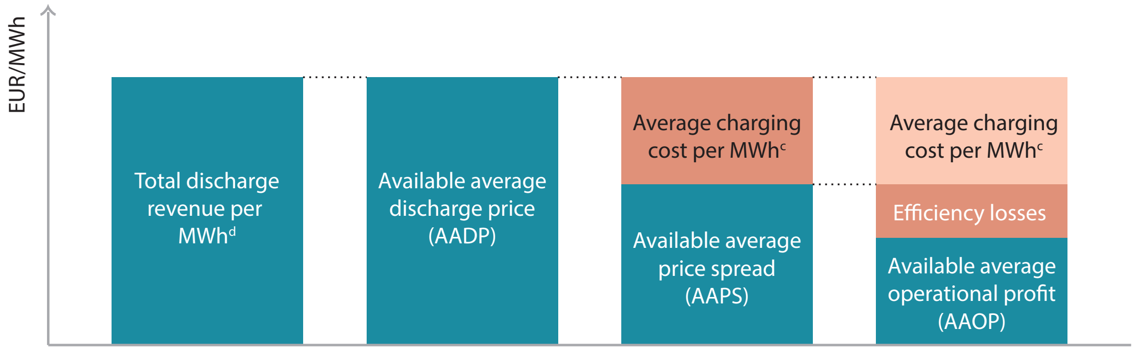
Finally, the AAOP is expressed in Equation (12). It is equal to the total revenue from discharged electricity minus the total cost of charged electricity, averaged over the total amount of discharged electricity:

$$\text{AAOP} = \frac{\sum_t (Discharge\ revenue_t - TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{12}$$

It must be pointed out that the A-metrics can only be computed exactly after the chronologic price profile is known. Hence the precise amount of maximum revenue and therefore the profitability can only be known "after the fact"; that is why this should be based on historical price profiles. How this can be dealt with in practice will be discussed in Section 6.6.

To summarise, Figure 6.8 shows the three available average revenue-based metrics and how they relate to the total discharge revenue per discharged MWh.

Figure 6.8: Summary of the difference between the A-metrics, AADP, AAPS and AAOP



Note: With a focus on the maximum obtainable (net) revenue stream.

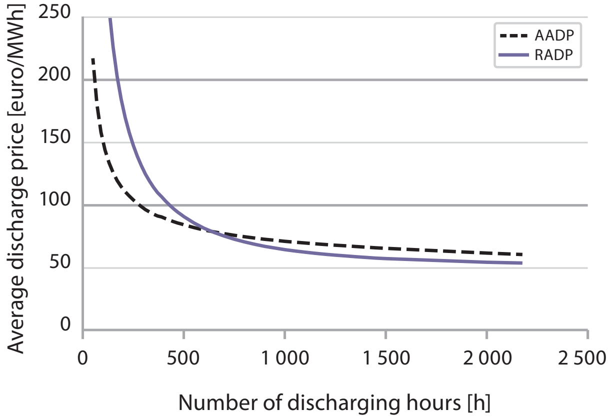
It should be observed from Equations (10), (11) and (12) that the A-metrics reflect the maximum obtainable revenues by a storage unit (for AAPS and AAOP corrected for charging costs and/or efficiency losses) derived from a particular price profile by charging and discharging power. At this stage, the A-metrics do not refer to any break even requirement with the costs. The break-even condition only comes up when the A-metrics are compared to the R-metrics. That aspect is the subject of the next section.

6.5.2 Similarities and differences between the required and the available metrics

The reader will undoubtedly have noticed the similarities between what we call the required metrics (the R-metrics) and the available metrics (the A-metrics). Nevertheless, there are fundamental differences between the two types of metrics. It is therefore instructive to highlight the similarities and differences in order to avoid confusion and to be armed with the right interpretation to follow the discussion below.

As an example, Figure 6.9 depicts a comparison between the required average discharge price, RADP, and the AADP as a function of the number of discharge hours (NDH).

Figure 6.9: Comparison between the required and available average discharge price metrics, RADP and AADP, as a function of the number of discharge hours



Note: For a storage unit with E/P= 10h and round-trip efficiency of 80%.

Source: Belderbos et al. (2017a).

The revenue-based A-metric has been calculated from historical price profiles. In this discussion and Figure 6.9, the Belgian day-ahead electricity prices in 2015 have been used (Belpex, 2016), but any other price profile would do. The A-metrics are computed by means of a short computer program which optimises the charging and discharging decisions of the storage operator, assuming perfect foresight of the prices and taking into account the installed storage capacity in terms of charging power, discharging power and energy storage. The optimisation result is a charging and discharging sequence for the entire year and allows calculating the total charging cost, total discharging revenue, an available average charging price and the three A-metrics. In the following examples, the A-metrics are calculated as a function of the number of discharging hours (NDH) which is prescribed in a range from 250h to 3 000h. For each point on the curve, the NDH is imposed on the storage operator as the maximum number of hours he is allowed to discharge in a year.

Figure 6.9 thus shows the AADP for different amounts of total discharged electrical energy – and thus for a different number of discharge hours (NDH) at nominal discharge power – for Belgian day-ahead electricity prices of 2015 (obtained via an optimisation programme). The AADP decreases for increasing NDH, which is reasonable since for any a-priory given value of NDH the storage operator is incentivised to discharge first during hours with very high electricity prices. When more discharging hours are allowed or possible, the storage operator will also discharge during hours with lower electricity price which thus decreases the average revenues that can be earned based on the available prices. It is stressed that the AADP curve reflects the maximum possible revenue obtained from the available price profile.

Besides the revenue based A-metric, Figure 6.9 also depicts the required cost metric for break even, RADP, computed from the expressions in Equations (1), (2) and (3) which contain the fixed cost terms with and , the denominator with the discharged electrical energy effectively reflecting the NDH, but also the ACC, which now should be compatible with the electricity price profile. Indeed, the RADP is now *not* calculated with a constant ACC, but with the prevailing average charging cost obtained from the optimised charging sequence which was used to calculate the AADP. The RADP in Figure 6.9 exhibits a decreasing trend for an increasing NDH, effectively similar to Figure 6.6 as discussed before, where a given constant charging price was applied. However, the downward trend in Figure 6.9 should not be generalised. Indeed, an increasing RADP with increasing NDH could occur because of an increasing average charging cost, ACC. As said, the average charging cost, ACC, used in the RADP calculation is thus now based on the ACC obtained from the AADP computation which increases for larger NDH. This increase in ACC counters to some extent the decrease in fixed costs per unit of discharged electricity. Depending on which of both effects is strongest, the RADP could show an increasing or decreasing trend for increasing NDH.

The intersection between the RADP and the AADP curves in Figure 6.9 indicates the exact amount of electricity that needs to be discharged, expressed as a number of discharging hours at full power capacity, for the storage owner to break even the full investment cost and the costs made for charging. Clearly, the same conclusion cannot be drawn if the RADP curve would have been calculated by using an a priori given, or actually estimated, ACC. In such case, the intersection point would only give an indication of the break-even point. Therefore, a more accurate estimation of the ACC, compatible with the optimisation procedure for charging and discharging, has to be made in order to compare the RADP to the AADP.

6.5.3 Impact of E/P-ratio on the available price-metrics for arbitrage

Figures 6.10, 6.11 and 6.12 show respectively the AADP, AAPS and the AAOP as a function of the number of discharging hours for different *E/P* ratios (and a constant round-trip efficiency of 80%). As can be seen, for any given *E/P* ratio (which effectively reflects the ideal charging and discharging durations), the available price metrics decrease for an increasing number of discharging hours (NDH). As said in the context of Figure 6.9, this is reasonable since a very limited number of discharging hours incentivises the storage operator to discharge only during hours with very high electricity prices. When more discharging hours are allowed or possible, the storage operator will also discharge during hours with lower electricity price which thus decreases the average revenues that can be earned based on the available prices. Note that the decrease of the AAOP is stronger than the decrease of the AAPS, which in turn is stronger than the decrease in the AADP. This is because both the AAPS and the AAOP depend on the average charging cost, which increases as a function of the number of discharging hours NDH.[14] As such, the AAPS and the AAOP decrease not only due to a decreasing average available discharge price, but also due to an increasing average charging cost.

Furthermore, the figures show that smaller *E/P* ratios shift the curves downward and that the number of hours for which arbitrage is profitable is reduced. Indeed, for small *E/P* ratios, a storage operator might be unable to discharge during a substantial period of consecutive hours with high prices as he can only store a limited amount of energy for such small *E/P* ratios. This can limit the profitable arbitrage hours for the storage operator and force the operator to discharge during hours with lower prices, resulting in a lower AADP, AAPD, AAOP.

Figure 6.10: The available average discharge price as a function of the number of discharge hours (NDH)

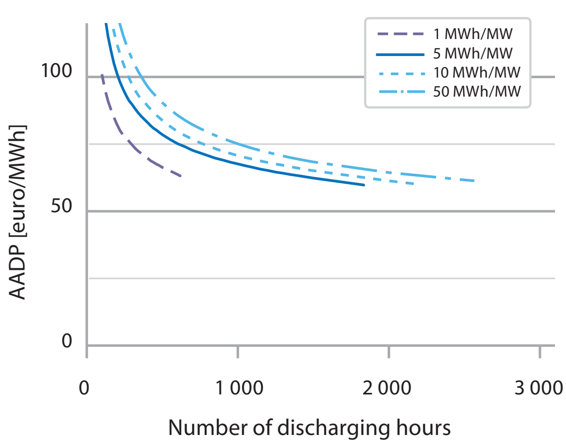
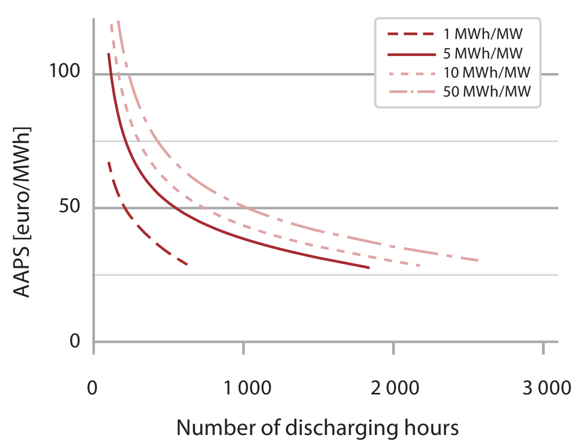


Figure 6.11: The available average price spread as a function of the number of discharge hours (NDH)

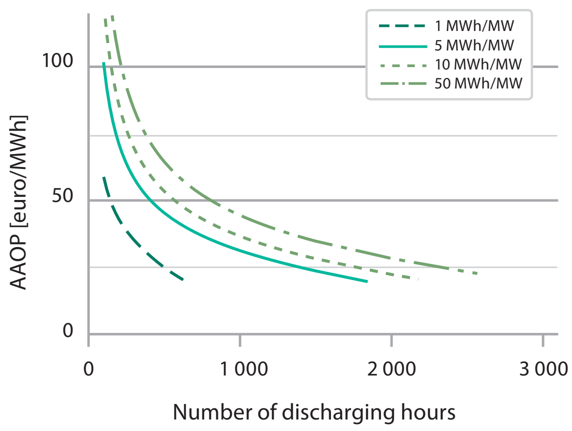


Note: The different curves are for different *E/P* values as indicated in the legend and η_{RT} = 80%.

Source: Belderbos et al. (2017a).

14. For completeness, the AADP does not directly depend on the value of the ACC, but its computation does take into account an optimal sequence of charging and discharging periods, with corresponding charging costs and discharging revenues.

Figure 6.12: The available average operational profit as a function of the number of discharge hours (NDH)



Note: The different curves are for different *E/P* values as indicated in the legend and η_{RT} = 80%.
Source: Belderbos et al. (2017a).

6.6 Combining all normative and empirical metrics: Storage costs and price arbitrage in practice

By comparing a required cost metric to the corresponding available revenue-based metric, an investor can assess the profitability of a certain storage unit. When the required cost metric is lower than the available revenue metric, it is profitable for the storage owner to invest in the storage unit. The amount of discharged electricity necessary to break even the investment, is provided by the intersection of the required and available metrics (see Figure 6.9).

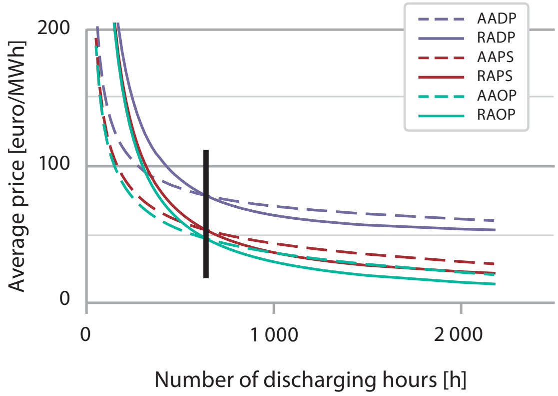
Figure 6.13 presents a comparison between the three required cost metrics and their corresponding available revenue-based metrics. The intersection between the required and available metrics indicates the exact amount of electricity that needs to be discharged, expressed as a number of discharging hours at full power capacity, for the storage owner to break even all costs considered in each of the three required metrics.

As can be seen, the break-even point is equal for all three pairs of metrics. This implies that the number of discharge hours at which it becomes profitable to invest in a particular storage unit does not depend on the chosen set of required/available price metrics.

However, recall that the required RADP and RAPS metrics both depend on the *average charging cost* associated with the storage unit. As was explained in the context of Figure 6.9, the RADP and RAPS values shown in Figure 6.13 have been calculated based on the actually available ACC, resulting from the optimisation exercise for the A-metrics. Only if the computation for these two R-metrics uses the actually available ACC will the three intersection points coincide. If a merely guessed ACC had been used then the RADP and RAPS curves would be different (and actually not quite consistent with their A-metric counterpart) resulting in different intersection points.

Furthermore, the attentive reader will have observed that the R-cost-metric describing the required operational profit, RAOP, of Equation (6), does not depend on the ACC. So, the intersection of the RAOP and the AAOP curves give the precise intersection point, and we have just explicitly proven that the RADP and RAPS intersections are only correct if the actual ACC, compatible with the optimised AADP and AAPS are used.

Figure 6.13: Comparison of the three available and the three required metrics



Note: For a storage unit with E/P = 10h and round-trip efficiency of 80%.

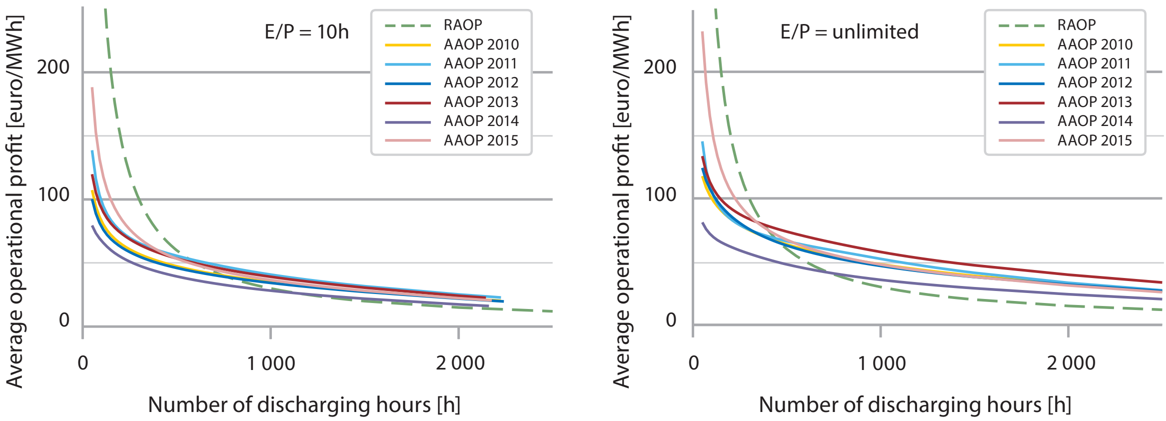
Source: Belderbos et al. (2017a).

Hence, it is not necessary to assume ex ante any particular charging cost before calculating the RAOP as a function of the expected number of discharging hours. Nevertheless, the profitability of a storage unit for the investor and the required number of discharge hours, can only be determined after the revenue-based A-metric has been determined (which does make use of the optimised/minimised charging cost). In summary, when using the RAOP, there is no concern about the charging cost for displaying the dependency of RAOP on the NDH. To find the required NDH for profitability for a particular price profile, this RAOP must be compared with the AAOP curve, which maximises the arbitrage revenues and obviously takes into account the charging costs.

There is, clearly, a caveat. Although the behaviour of the RAOP curve as a function of the NDH can be computed without the need for price profiles, we have of course based our profitability analysis on historical price profiles to compute the revenue-based A-metrics. In addition, for whatever possible guessed future given price profile, the optimisation programme uses perfect foresight. The perfect foresight aspect is difficult to deal with in a simple analysis. The historical aspect can be dealt with satisfactorily (at least assuming that the future will not behave dramatically differently from the past years) if one employs the historical profiles of several years and even perhaps applies some kind of random perturbation of those past years' price profiles.

Purely as an example, Figure 6.14 shows the results for the past years 2010-2015 (for the Belgian day ahead market prices) for the AAOP for a storage unit with an E/P of 10 hours (LHS panel) and one with unlimited E/P (RHS panel). The dotted line representing the RAOP is independent of the price profiles and independent of the E/P ratio; it is the same in both panels. It is therefore recommended to use the RAOP. Although all AAOP curves differ slightly, they are of the same order of magnitude, especially for a higher number of discharging hours. The difference between the left and right panel shows that the E/P ratio has a considerable impact on the AAOP and thus the profitability of a storage unit. The number of discharge hours required for profitability seems to be smaller for large energy capacities (more precisely for large E/P or thus discharge durations).

Figure 6.14: RAOP and AAOP in the Belgian day-ahead market (2010-2015) for two storage units of different size and cost



Note: Left, the *E/P* = 10 MWh/MW; right, *E/P* is unlimited; the remaining parameters of Table 6.1 apply.

Source: Belderbos et al. (2017a).

6.7 Beyond arbitrage storage services or applications

6.7.1 Transition of NDH to cycles and cycle duration

The analysis in the previous subsections concentrated entirely on energy arbitrage, and most of the analysis was performed based on the total number of discharge hours (NDH) per year. It is instructive to split the overall discharging per year into the discharge duration per cycle and the number of charging-discharging cycles per year. This leads to an alternative way for depicting the LCOS results, and it permits furthermore to expand the LCOS analysis towards applications other than energy arbitrage, as listed in Table 6.1. At the same time, this different viewpoint can serve as an introduction to recent work by Schmidt et al. (2019) in which a first attempt to evaluate the (far) future profitability of several storage technologies for a multitude of applications and services has been undertaken.

The number of full cycles is identical to the number of discharging cycles since every discharging cycle is always preceded by a charging cycle. The relationship of the time duration for charging and discharging – both at the nominal power capacity *P* – is as follows: $\tau^c = \tau^d/\eta_{RT}$. In the interest of transparency of these few introductory paragraphs of Section 7.1, we assume that the depth of discharge (*DoD*) is 100%.

It is appropriate to say a few words about the round-trip efficiency η_{RT}. Although it is not fundamentally necessary to exactly split up the round-trip efficiency between the charging and the discharging parts of the overall storage cycle, it is nevertheless convenient to split it up in equal parts.

If we define as the E/P ratio, being the charging or discharging durations in the absence of any losses, thus for η_{RT} one has[15]

$$\frac{E}{P} \triangleq \tau \quad (13) \qquad \tau^c = \tau / \sqrt{\eta_{RT}} \quad (14) \qquad \tau^d = \tau\sqrt{\eta_{RT}} \quad (15)$$

clearly indicating that, compared to the optimal duration E/P, charging at nominal power takes longer, whereas discharging goes faster, with the consequence that more energy must be pumped into the store than E, and that less energy can be withdrawn from it than the stored amount E. We can thus write

$$MWh^d = N_{cyc}\, E\sqrt{\eta_{RT}} \tag{16}$$

$$MWh^c = N_{cyc}\, E/\sqrt{\eta_{RT}} \tag{17}$$

where we have defined the number of cycles per year by and assuming that the discharge time duration is constant for each discharge, we can also write that[16]

$$NDH = N_{cyc}\,\tau^d = N_{cyc}\left(\frac{E}{P}\right)\sqrt{\eta_{RT}} = \tau\, N_{cyc}\sqrt{\eta_{RT}} \tag{18}$$

With all this information, one can also derive that

$$NDH_{max} \leq \frac{8760}{\left(1 + \frac{1}{\eta_{RT}}\right)}, \tag{19}$$

with the equality referring to the case with zero response time and no maintenance. Equation (19) serves as a warning that for technologies with very low round-trip efficiencies (such as P-to-methane-to-P with η_{RT} ~ 0.3)) the maximal number of discharging hours is limited to about 2 000h, independent of whatever price profile.

6.7.2 The LCOS or the RADP in terms of # cycles and discharge duration

The expression for the LCOS used by Schmidt et al. (2019) is effectively the same as the RADP used in this document, albeit with some extra add-ons relevant for practical implementation. Their expression includes an end-of-life cost (which de-facto could be considered as a negative decommission cost), an efficiency for self-discharge, corrections for cycle and time degradation, for replacement, etc. They consider for each technology the optimal depth of discharge (DoD), use a discount rate of 8%, postulate a fixed electricity price for charging (i.e. the ACC) equal to USD 50/MWh for most applications.[17] For the investment cost of the technologies the information pictures in the experience and time-evolution curves of Figures 6.1 to 6.4 are used.

15. This is more accurate than was written in Belderbos (2017a).

16. Instead of N_{cyc} Belderbos et al. (2017a) would use the symbol χ_a, whereas Schmidt et al. (2019) uses the symbol Cyc_{pa}.

17. Except for the "behind-the-meter" end-customer applications bill management, power reliability and power quality, for which USD 100/MWh is used.

It is useful to stress three particular points in this context, when interpreting the work by Schmidt et al. (2019):

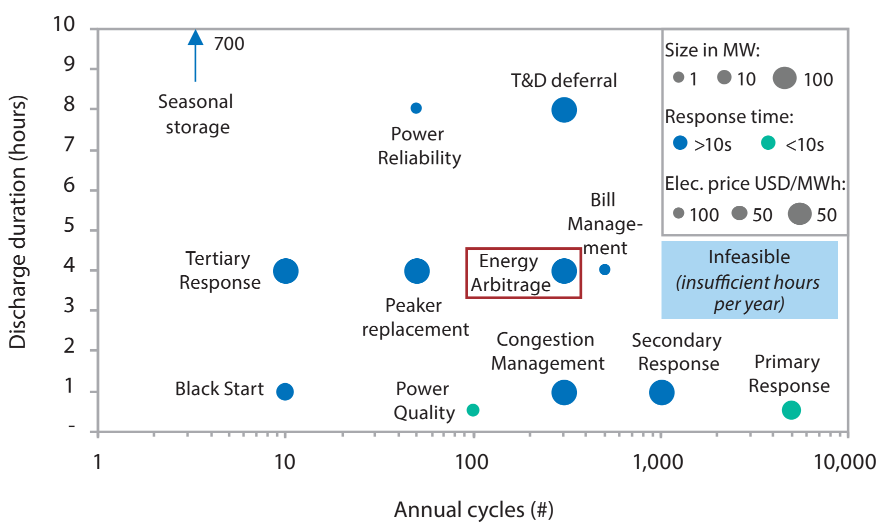
- First, from the expression of the discharged amount of electrical energy in Schmidt et al. (2019), it can be deduced that the round-trip efficiency is allocated entirely to the discharge side.

- Second, when referring to the postulated electricity price of $\wp$ = *USD 50/MWh*, which is appropriately adjusted to $\wp/\eta_{RT}$ to be used in the LCOS expression with units currency per unit discharged electrical energy, *USD/MWh*^{d}, it must be understood that this electricity price is assumed to exist only as input to the storage during charging, i.e. it is the *ACC* defined above.[18] The LCOS as computed is the actual earning per MWh that the storage must obtain per discharged MWh to break even. For energy arbitrage and seasonal storage the $LCOS_{Schmidt}$ is thus nothing else than the earlier defined RADP, which – when the storage discharges into the grid – would thus be the required electricity price for break even. For other applications where remuneration perhaps occurs via other revenue schemes such as ancillary service markets or auctions, the $LCOS_{Schmidt}$ expresses the earnings that the storage unit should get to deliver that particular ancillary service; in the light of broader applications, it is perhaps not unwise to generalise the earlier defined designation RADP into RADE where the *E* stands for Earnings.

Schmidt et al. (2019) effectively fixes all parameters (such as the efficiencies, the charging cost, etc.) for the nine storage technologies considered[19] in order to be able to compute a levelised storage cost for energy arbitrage and other applications[20] by assigning a priori (and thus actually to some extent arbitrarily and independent of the system considered) the number of annual cycles and the discharge duration for each application. The results of their LCOS are plotted in a 2-D diagram (N_{cyc}, τ^d).

The by Schmidt et al. (2019) assigned couples (N_{cyc}, τ^d) for the applications of Table 6.1 are shown in Figure 6.15. Energy arbitrage has been highlighted by a red box.

Figure 6.15: Assigned couples (cycles per annum, discharge duration) for concrete modeling for each listed application of Table 6.1



Note: The couple assigned to arbitrage is (N_{cyc} = 300 cpa, τ^d = 4 h).

Source: Schmidt et al. (2019).

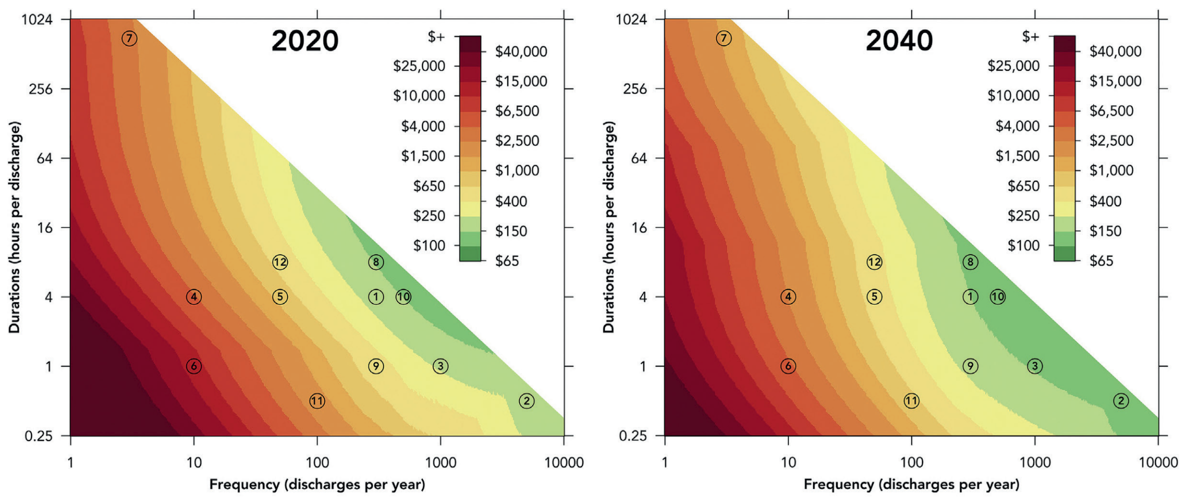
18. Schmidt (2019) uses the symbol *P* for electricity price, which we avoid since we prefer *P* for installed power capacity; hence our choice to use script $\wp$ to designate the electricity price.

19. The technologies considered in Schmidt (2019) are pumped hydro, compressed air, flywheel, four types of batteries (lead-acid, lithium-ion battery, sodium-sulphur, redox-flow), hydrogen and supercapacitor.

20. The applications considered are those listed in Table 6.1 above.

Figure 6.16 then shows the results obtained by Schmidt (2019) for the $LCOS_{Schmidt}$ or thus effectively the required average discharge earnings (RADE) in the 2-D diagram (N_{cyc}, τ^d) for the years 2020 and 2040.[21] However, at every point of the 2-D grid, the figure only depicts the result for the cheapest technology (simply chosen from the results for 9 storage technologies after having scanned the full 2-D domain).

Figure 6.16: Projected levelised cost of the cheapest technologies displayed in a 2-D plot (number of annual cycles N_{cyc}, discharge duration τ^d) for the years 2020 and 2040



Note: The circled numbers refer to the modeled values of (N_{cyc}, τ^d) for the 12 applications listed in Table 1. The colour legend refers to the optimal required values for the LCOS Schmidt or thus Required Average Discharge Earnings (RADE).

Source: Schmidt et al. (2019).

The circled numbers in the 2-D plot of Figure 6.16 refer to the assigned points (N_{cyc}, τ^d) modelled for the applications mentioned in Table 6.1. The circled point labeled by '1' refers to energy arbitrage. The colors refer to the optimal values for the $LCOS_{Schmidt}$ or thus the required average discharge earnings (RADE). One observes that the color variations are quite similar in both panels, but please be aware that this always refers to the most optima technology; hence for different technologies scattered over the panel.

To make the link with the earlier sections on the required average discharge price or required average discharge earnings (in more general terms), it should be clear that the $LCOS_{Schmidt}$ must be seen in line with Figure 6.6 shown before for $RADP = f(NDH)$, whereby the conversion of the number of cycles and the discharge duration to NDH follows from Equations (13), (15), and (18) above, but slightly adjusted for the depth of discharge (*DoD*) as follows[22]:

$$NDH = N_{cyc}\,\tau^d\,DoD = N_{cyc}\left(\frac{E}{P}\right)\sqrt{\eta_{RT}}\;DoD \tag{20}$$

For all technologies the typical *DoD* thus must be accounted for. As an example, the *DoD* = 100% for pumped hydro and hydrogen, whereas the *DoD* for Li-ion batteries is 92% when used for energy arbitrage and about 60% when used for secondary response (Schmidt et al., 2019).

21. Recall that the expected investment costs are based on the experience curves Figure 6.1-6.4 above.

22. Note that in the convention of Schmidt et al. (2019), the equation would read as follows: $NDH = N_{cyc}\,\tau^d\,DoD = N_{cyc}\left(\frac{E}{P}\right)\eta_{RT}\;DoD$, since the losses are fully allocated to the discharge side.

6.8 Concluding remarks

The transition towards high shares of naturally-fluctuating renewable energy sources (VRE) has increased the flexibility needs required for covering demand at all time and for a secure operation of electric power systems. Together with other flexibility options, certainly storage applications over different timeframes will play a key role in ensuring sustainable electricity supplies. To facilitate this transition in a cost-efficient manner, a correct assessment of all potential flexibility providers' costs and system value is indispensable. For comparing the generating costs of different electricity generation technologies, metrics like the LCOE have traditionally been used (see Chapter 3). In complement to LCOE and system costs analysis, this boundary chapter carefully investigates an analogous summary cost metric that specifically applies to storage technologies, the LCOS.

In practice, a great variety of storage options with very different technical and economic characteristics exist. This chapter has attempted to analyse them in a single unified conceptual framework. Within the context of energy arbitrage, three LCOS-metrics have been introduced that differ in the extent to which they account for the (system dependent) charging costs. The required average discharge price (RADP) can be thought of as a literal translation of the LCOE applied to storage technologies, which includes a charging cost instead of a fuel cost, and is expressed per unit of discharged energy. The other metrics, i.e. the required average price spread (RAPS) and the required average operational profit (RAOP) do not take into account the full charging costs. The RAPS only accounts for efficiency losses, whereas the RAOP does not entail any charging costs at all.

To determine whether an investment in a particular storage technology is worthwhile, these required cost metrics need to be compared to their available revenue-based counterparts, which represent a measure for the revenues that can be exploited by the storage technology in the specific power system. It was shown that the break-even point for all three pairs of required and available metrics occur at the same number of discharge hours (NDH). This property makes the RAOP particularly useful for determining this break-even point, as it does not require an estimation of the charging cost and as such, is a system independent metric.

Of course, storage technologies can have other applications than energy arbitrage. These applications range from the provision of ancillary services over peak-power plant replacement, to facilitating seasonal storage. Each of these applications has distinct operational characteristics that imply certain operational requirements if a storage technology were to be used for that specific application. The NDH can in this perspective be further decomposed as a function of the number of annual cycles and discharge duration. In the electricity markets of the future, there will be different storage technologies for different applications (e.g. seasonal storage, inter-temporal arbitrage in day-ahead and reserves markets or system control). They will also be remunerated differently-market, call for tender, vertical integration of TSO. The competitiveness of different storage, and in fact broader flexibility options, will depend on their costs and on the price dynamics, i.e. the market designs and load curves, for the different applications. While LCOS calculations need to be performed with the specific application in mind, this chapter nevertheless provides one unified conceptual framework that should facilitate the economic analysis of storage in tomorrow's electricity markets.

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Carbon pricing and zero emission credits

7.1 Carbon pricing as a means of rendering explicit the differences in the full cost of different generation technologies

Carbon pricing in the electricity sector drives a wedge between the costs of low-carbon and carbon-intensive power generation, considering the impacts the latter has on the climate and hence on human health, economic development and the environment. In the context of the *Projected Costs of Electricity: 2020 Edition*, carbon pricing can thus be interpreted as a manner of making visible the true costs of an electricity generation option including social costs that it generates. *Projected Costs 2020* includes a carbon price of USD 30 per tonne of CO_2 for power plants beginning operations in 2025. This is somewhat higher than the average price of USD 25 per tonne of CO_2 in 2019 in the EU Emission Trading System (EU ETS), yet lower than the price of a European emission allowance (EUA) in summer 2020. USD 30 per tonne of CO_2 are lower than what is usually considered the full social cost of carbon emissions (see, for instance, *The Full Costs of Electricity Provision*, NEA, 2018) or the level of the carbon taxes in certain OECD countries (in Sweden, for instance, the carbon tax currently stands at EUR 114 per tonne of CO_2). It nevertheless remains a level with the potential to have significant impacts on the relative competitiveness of different generation options. In many markets, a carbon price of USD 30 per tonne of CO_2 increases the variable costs of coal-fired power generation such that they are higher than those of gas-fired power generation. It thus enables fuel switching between the two technologies.

Other means of creating this wedge are possible. Instead of carbon pricing, policymakers can also remunerate low-carbon generation technologies for their contribution to reducing carbon emissions. While neither the distributional implications nor the impacts on electricity prices are the same as carbon pricing, they accomplish the same essential objective.

Carbon pricing internalises the negative externality of climate change inducing greenhouse gas emissions by making carbon-intensive generation less competitive. Minimising overall economic costs requires that carbon pricing, whether by making carbon-intensive generation more expensive or whether by making low-carbon generation less expensive, is applied in an equitable manner across all sectors and technologies.

In this chapter, we will focus on the main instruments used to price carbon or to promote low-carbon electricity generation such as Zero Emissions Credits (ZECs) in cases where direct carbon pricing is impossible or politically infeasible. Border taxation adjustments for carbon embedded in traded goods, which are currently much discussed in connection with the proposed European New Green Deal, are not part of this chapter. The latter are mainly an instrument of trade policy aiming at creating a level playing field between imports and local production.

In 2019, the World Bank counted 57 carbon pricing initiatives around the globe, at the regional, national, provincial and municipal level, up from 51 in 2018 (World Bank, 2019). They consist of 28 emission trading systems (ETSs) in regional, national and subnational jurisdictions and 29 carbon taxes regimes, primarily applied on a national level. In total, these carbon-pricing initiatives cover 11 gigatonnes of carbon dioxide equivalent (Gt CO_2e), or about 20% of global greenhouse gas (GHG) emissions.

Carbon pricing has many supporters among economists and international institutions that range from the United Nations to the Carbon Pricing Leadership Coalition. In addition, the OECD has consistently argued in favour of carbon pricing. Economists appreciate the fact that carbon pricing achieves the targeted emission reductions at the lowest cost and has the benefit of treating carbon-free firms neutrally (Baran and Fankhauser, 2020). Programmes like the PMR (Program for Market Readiness) and others assist countries in the design and implementation of carbon pricing regimes.

The commitments under the 2015 Paris Agreement are inducing a number of additional countries to introduce carbon pricing. In both North America and Latin America, more than 20 countries have considered the use of some type of carbon pricing in their NDC. The report of the high-level Commission on carbon prices (CPLC, 2017) for instance states:

> Countries may choose different instruments to implement their climate policies, depending on national and local circumstances and on the support they receive. Based on industry and policy experience, and the literature reviewed, duly considering the respective strengths and limitations of these information sources, this Commission concludes that the explicit carbon-price level consistent with achieving the Paris temperature target is at least USD 40–80/t CO_2 by 2020 and USD 50–100/t CO_2 by 2030, provided a supportive policy environment is in place.

7.2 Principal instruments for differentiating the costs of technologies according to their carbon emissions

Section 7.2 will introduce the main instruments for differentiating the costs of carbon-intensive and low-carbon generation options. This will include instruments that straightforwardly price carbon. It will also include instruments that remunerate the contribution of low-carbon emission options.

Each subsection of this section will begin with a conceptual introduction followed by recent relevant examples from OECD countries. Other instruments that can indirectly reduce carbon emissions are subsidies to low-carbon generation through feed-in tariffs, feed in premia, contracts-for-difference or green certificate schemes that lower the costs or increase the revenues of low-carbon power production and thus improve its competitiveness. Some of these instruments are discussed further below. Other instruments such as, for instance, priority access are not part of this section.

There are two main ways to establish a carbon price, the government can levy a carbon tax on fossil fuels thus encouraging a switch to less carbon-intensive production or consumption. The alternative is to introduce a cap-and-trade system.

Implementing a carbon tax does not take place in a vacuum but requires careful integration into the existing policy context. The World Bank and the OECD have developed the FASTER principles for Successful Carbon Pricing, a set of principles for the design of a carbon-pricing instrument (OECD, 2019; World Bank, 2019):

- **Fairness.** Effective initiatives embody the “polluter pays” principle and ensure that both costs and benefits are shared.
- **Alignment of policies and objectives.** Carbon pricing is not stand-alone mechanism. It is most effective when it meshes with and promotes broader policy goals, both climate and non-climate related.
- **Stability and predictability.** Effective initiatives exist within a stable policy framework and send a clear, consistent, and (over time) increasingly strong signal to investors.
- **Transparency.** Effective carbon pricing is designed and carried out transparently.
- **Efficiency and cost-effectiveness**. Effective carbon pricing lowers the cost and increases the economic efficiency of reducing emissions.
- **Reliability and environmental integrity.** Effective carbon pricing measurably reduces practices that harm the environment.

Carbon pricing has not only the direct effect of reducing GHG emissions but can also lead to co-benefits in terms of improvements in public health, energy efficiency and accelerated innovation. It remains so far unclear what is better for innovation, a carbon tax or an ETS type. Experience from the Swedish tradable green certificate scheme shows that even quota-based instruments can lead to rapid innovation in highly competitive sectors.

Taxes and emissions trading systems overlap frequently. However, taxing emissions that are subject to a trading system does not result in additional emission reductions if the cap is binding. The overlap then may compromise the cost-effectiveness of abatement as it undoes the uniformity of the price signals sent by a trading system. While this does not necessarily mean that taxes and trading systems should never be combined, the justification for levying taxes on ETS-covered emissions should be to address other market failures, or raise revenue (see *Effective Carbon Rates: Pricing CO_2 through Taxes and Emissions Trading Systems,* OECD, 2016).

There is an ongoing debate whether carbon taxes can work by themselves or should be part of broader policy packages. Acemoglu et al. (2012), for instance, argue that carbon pricing alone is not enough, but should be complemented with research support. OECD-IEA-ITF-NEA (2015) also supports the importance of policy packages over pure carbon pricing, a view supported by Greaker et al. (2018).

A final point of consideration is the time dimension of the effects of carbon pricing. In the short run carbon pricing leads to fuel switching (technologies fixed and at least one productive input fixed), in the medium run we see an adjustment of capital investment and energy demand and in the long run technologies change.

Carbon taxes

The government directly applies a tax on the carbon content of fossil fuels. Their most remarkable feature is that there is no cap on greenhouse gas emissions. While generally thought to be the economically most efficient instrument, the large distributional impacts to the detriment of carbon emitters and associated stakeholders can create political resistance.

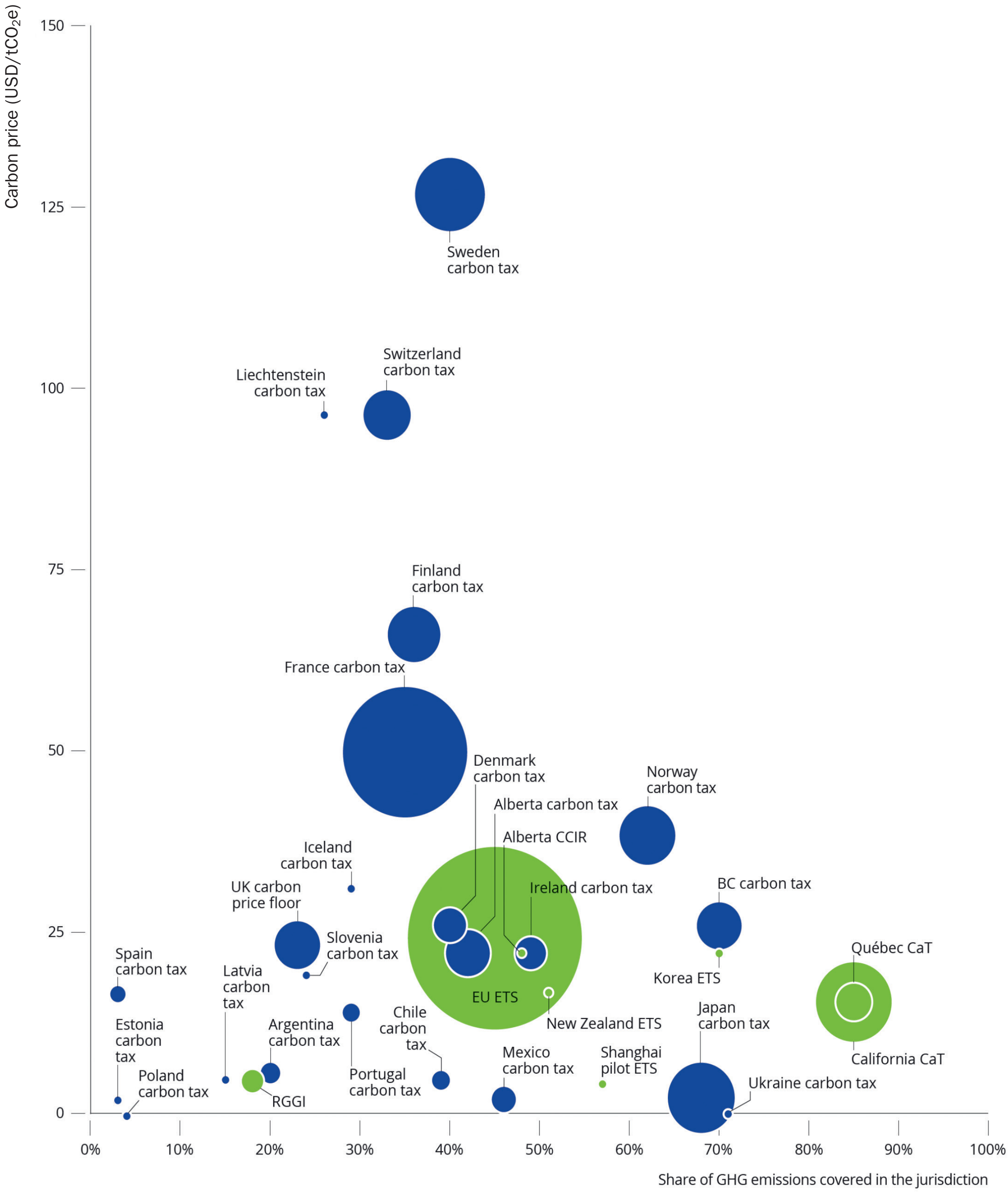
Taxing carbon relates to the idea of Pigou (1920) to tax an amenity by its marginal damage. For example, put a tax on an environmental bad or on a health hazard such as cigarettes, sugar, alcohol etc. The idea here is to reach an optimal consumption of the bad from a societal perspective, balancing cost and benefits to society.

OECD (2006) distinguishes two different kinds of environmental taxation – taxes imposed directly on pollution or emissions and taxes with indirect relationship between pollution and a subject of taxation. The difference between these kinds of environmental taxes lies in the subsequent reaction of a polluter; however, the distribution of tax revenues can be also different.

Usually, unless the tax is prohibitively high and a tax converts to a regulation prohibiting the use of an environmentally bad, Pigouvian taxation will not remove the bad entirely by reducing its use to zero from society but reduce its use through the pricing of a good causing an amenity. Since the main purpose of a carbon tax is to increase the price of an activity detrimental to society and does not have the main purpose to generate income to the treasury the income could be used for redistributive purpose compensating for the effects of the tax without distorting the incentives from the tax. In principle, the income could also be used to support research or the market introduction of technologies addressing the pollutant. This is frequently a politically expedient option. However, from an economic point of view, the revenue from carbon taxes is part of the government budget and its use is not necessarily connected to the residual damage.

Many countries around the globe have implemented carbon taxes, but as Figure 7.1 shows, the instrument choice, the apparent levels, and the shares differ quite heavily. The highest level of carbon taxes is found in Sweden, while the highest revenues from taxation is generated in France, even though both countries participate in the European Union Emission Trading System (EU ETS).

Figure 7.1: Carbon price, share of emissions covered and carbon pricing revenues of implemented

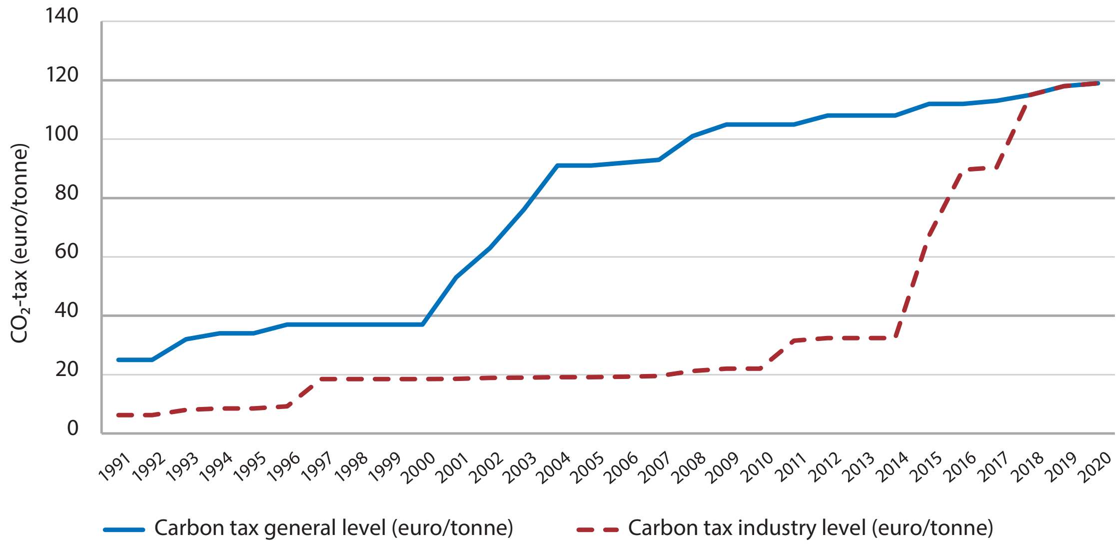


Source: World Bank (2019).

Sweden was among the very first countries to introduce a tax on carbon in 1991. The carbon tax was initially levied on all sectors with exemptions for the industry exposed to international competition. With the introduction of the EU ETS, industries within the ETS were exempted from carbon taxation except for district heating that was included in the EU ETS but continued to be subjected to the carbon tax.

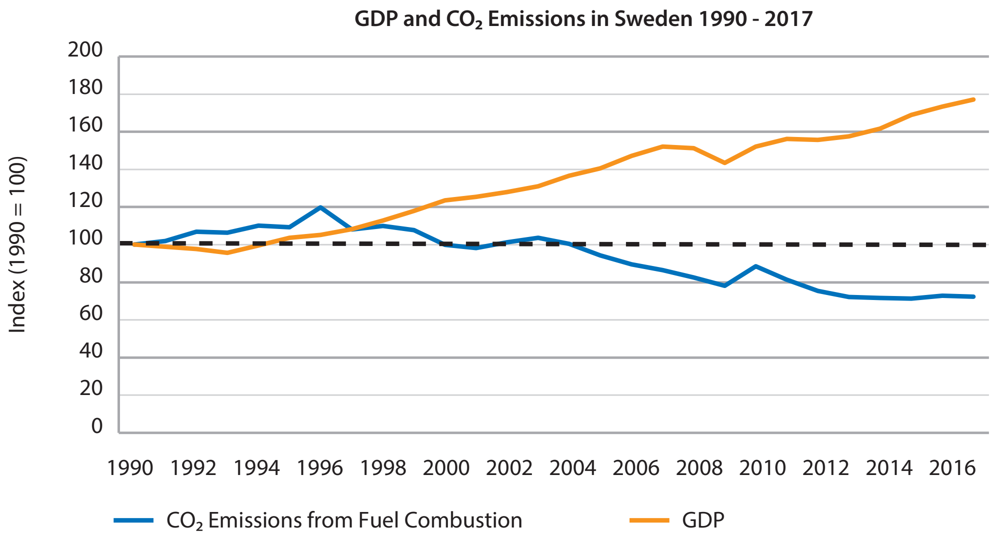
The carbon tax was introduced in 1991 at a rate corresponding to SEK 250 (EUR 23) per tonne of carbon dioxide (t CO_2)[1] emitted and has gradually been increased to SEK 1 190 (EUR 110) in 2020 (currency conversion based on an exchange rate of SEK 10.80 per EUR). The tax was part of a larger tax reform where the taxation of labour was reduced, and the reduction was compensated for by an increase in environmental taxation. Reductions for industries outside the EU ETS were abolished in 2018. Figure 7.2 shows the development of the Swedish carbon tax since its inception.

Figure 7.2: The Swedish CO_2 tax over time (USD/tonne)



Today the Swedish carbon tax contributes considerably to the Swedish state budget generating about SEK 23 billion (EUR 2.15 billion). Figure 7.3 shows that Sweden still experienced significant economic growth in the period after the introduction of the carbon tax. However, this could be related to the reduction of labour cost that was partly financed by the carbon tax. Other factors to be structural change in the economy, moving from industrial production to the service sector.

Figure 7.3: GHG-emissions and GDP development in Sweden since the introduction of the carbon tax



1. Actually, the carbon tax is levied on the average emission from the use of each type of fossil fuel using emission factors.

Beyond the internalisation of negative externalities, there is an ongoing discussion about the additional dynamic benefits of strict environmental regulation. Such a win-win relationship was first postulated by Michael Porter when he formulated in his "Porter hypothesis" that such regulation can improve both environmental quality and the competitiveness of enterprises (see, for instance, OECD, 2006).

Advantages

- In countries with a well-functioning tax system, a carbon tax is easy to implement above existing excise taxes. This type of tax is not suitable from a state budget perspective since its very purpose is to erode its tax base.
- Low economic cost, does not distort economic efficiency

Disadvantages

- Goal achievement not guaranteed.
- Tax base not stable.
- Not always based on true carbon content, requires correct emission factors.
- Risk of carbon leakage when the outside world does not tax carbon emissions.

Emission trading

Carbon-emitting industries receive tradable allowances under an overall constraint. This way the price of the carbon will be determined by the market. Different forms of quota allocation permit modulating distributional impacts. The largest and best-known emissions trading system for GHG emissions as of today is the EU ETS. According to ICAP (2020) there are 21 emissions trading systems covering 29 jurisdictions in place across the globe. Another nine jurisdictions are expected to put systems in place in the coming years, among them China and Columbia. A further 15 jurisdictions are considering an ETS as part of their policy-mix.

Emissions trading was first proposed by Dales (1968) and Weitzman's (1974) seminal paper on prices vs. quantities showing that a quota system and a tax/subsidy scheme are equivalent given certain assumptions. A quota system can be used for different purposes, e.g. to implement a market-based support scheme for renewable support, as a cap-and-trade system to limit emissions of a certain pollutant and so on. The earliest implementation of the idea stems from the 1990 US Clean Air Act Amendments and the market for SO_2-emissions under the Acid Rain Program (Benz and Truck, 2009) that initiated sulphur dioxide permit trading and largely eliminated the acid rain problem. A quota system usually limits the amount of emissions of a pollutant each year thus securing the previously set goal is achieved. If the goal is somewhere in the future the quota system can be combined with a trajectory with an annual reduction of the total emissions. Some quota systems such as the EU ETS allow for banking of emission rights thus allowing for inter-temporal optimisation. If an emitter does not use all emission rights the polluter owns, the surplus emission rights can be used at a later point of time.

Different allocation mechanisms have been or are in use as well as combinations of these.

- Free allocation through grandfathering usually combined with a new entry reserve and benchmarking (EU ETS 1 and 2).
- Auctioning of emission rights (e.g. EU ETS 3rd period).
- Combinations of both with a share of emission rights allocated through grandfathering and a share that is auctioned.

From an economic point of view, the allocation of emission rights should not make a difference, even with free allocation. The important point is that there is an opportunity cost for polluters. Opportunity costs mean in this case that even though the emitter receives the emission rights for free they have a market value. The emitter can now either use the emissions rights to cover emissions or reduce emissions and sell excess emissions rights to maximise profits. The emitter will use emission reducing technologies or reduce production to the point where the marginal cost of reducing emissions is equal to the price of the emission right on the market. Even though the method allocation does not matter for the outcome in terms of emissions, the distribution of income changes. With auctioning, the revenue from auctioning ends up in the state budget and can be used for whatever purpose or the revenue can be directly used for redistributive purposes. The larger the share of allowances auctioned in terms of the total number of allowances the closer to a carbon tax emission trading becomes.

The main difference between a carbon tax and emissions trading is the role of the price. In the case of a carbon tax, the government sets the price of carbon and the resulting carbon abatement is unknown. In the case of a quota system, the abatement is known but the price is a result of supply of and the demand for emission rights.

Other than the uncertain 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. Outcomes, just as for carbon taxes, will depend on continuing political adjustments and adaptations of the rules as much as on demand, or new technological developments.

Advantages of emissions trading

- Goal achievement almost guaranteed.
- Off the state budget.
- Can be linked to other compatible cap-and-trade systems such as the EU and Swiss ETS.
- Low transaction costs if implemented correctly (Jaraitê et al., 2010).
- Well-administered cap-and-trade schemes may exist at large scale without incurring significant losses in cost-effectiveness (Zaklan, 2020) and allocation can be used as a part of the policy bargaining process.

Disadvantages of emissions trading

- Costly monitoring, reporting and-verification (MRV) mechanism needed.
- Heavy administrative burden (Coria and Juraite, 2019).
- Allocation of emission rights leads to varying distributional effects, with occasionally politically unwanted results such as windfall profits to producers, high costs to consumers.
- Risk of carbon leakage when the outside world does not tax carbon emissions

Hybrid systems

Hybrid tax usually combines a carbon tax with emissions trading: in these systems, a carbon tax creates a level of certainty for investors by creating a price floor. Such a floor can either be stable or gradually increase through time. In addition, the quantitative constraint provides an opportunity for carbon trading. In principle, the tax it becomes the carbon price when the equilibrium price in the ETS is lower than this level.

Several countries have complemented carbon pricing with carbon price floors such as Canada, where the provinces are free to choose the carbon pricing instrument, however, the carbon price may not be below CAD 10 and is set to increase to CAD 50 by 2022 (Parry and Mylonas, 2018) . For those jurisdictions that do not meet the benchmark, a federal backstop system will be applied which has two components: a regulatory charge on fossil fuels and a regulatory trading system called the Output-Based Pricing System (OBPS) that applies to power generation and certain industrial facilities. In the provinces in which the backstop applies, the OBPS took effect on January 1, 2019, and the fuel charge took effect in April 2019.

The United Kingdom introduced a carbon floor in order to speed up the transition to low-carbon electricity generation in times of low EU ETS prices. The Carbon price floor (CPF) was introduced in 2013. The CPF was initially set at GBP 16 (EUR 18.05) per tCOe and was set to increase to GBP 30 (EUR 33.85) in 2030. In the United Kingdom the carbon floor (PF) was realised in the form of a tax on the use of fossil fuels in the power sector.

In Finland (IEA, 2018), there is also a hybrid system in place. A carbon tax thus applies to facilities under the EU ETS. Combined heat and power (CHP) is thus subject to both energy/ CO_2 and electricity taxation, which strongly increased since the 2011 tax reform. To avoid overlaps with the EU ETS and to promote energy-efficient CHP, the CO_2tax was halved for the latter. CHP and fuels used for electricity generation are also exempt from the electricity tax. This has not done away with all inconsistencies, the CHP tax reduction, for instance, is however more important for coal than for natural gas.

Support for low-carbon power generation

Policy motivations for such measures are a complex mix of (1) technology-specific support, (2) recognition of the disadvantages of low-carbon generators with high capital-intensity in competitive electricity markets in the absence of carbon pricing and (3) recognition of the contribution of such technologies to the reduction of carbon emissions and other public policy objectives.

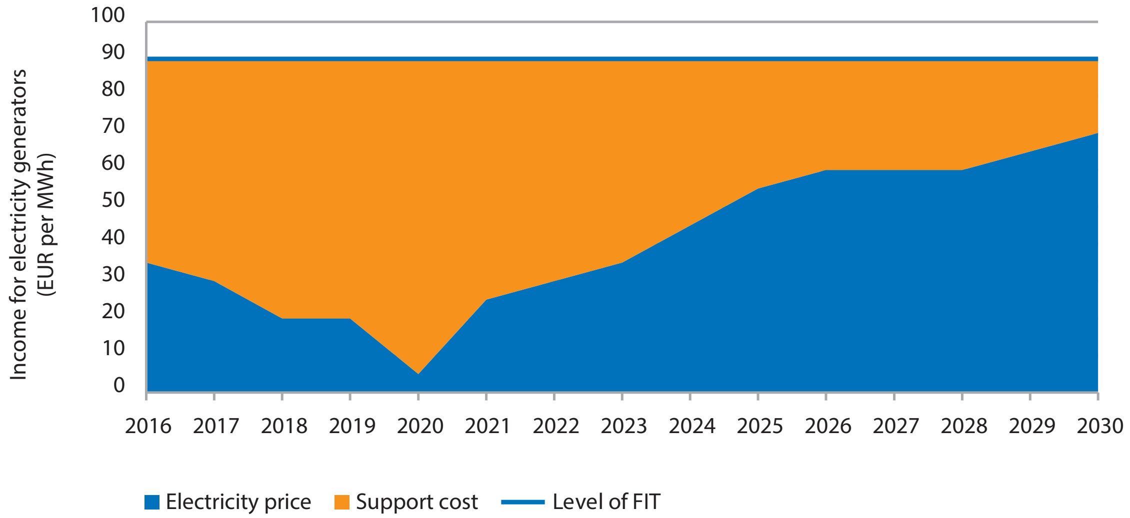
Feed-in-tariffs (FITs), feed-in-premia (FIPs), contracts for difference (CFDs) and production tax credits (PTC) are instruments that either isolate low-carbon generators from market prices by guaranteeing a fixed revenue per unit of output, reduce the exposure to market risk or provide a tax credit for every MWh produced. It has also resulted in variable renewables (VRE) with zero-marginal costs keeping producing even at negative prices (up to the level at which the per unit support is exhausted). It depends on the precise formulation of the measure to which extent it is a straightforward technology-specific subsidy, e.g. if support is provided without competitive tenders and only for certain technologies, or whether it can indeed be considered as part of the remuneration for the service to provide low-carbon electricity. A further question is whether electricity customers (FITs, FIPs and FDDs) or taxpayers (PTCs) bear the costs of such measures.

Support schemes for low-carbon electricity generation can be divided into two groups, price based, and volume-based schemes. The choice of support scheme is independent of the allocation mechanism, e.g. auctioning. Auctioning does not automatically imply the presence of a specific support scheme but usually auctioning is a measure to decide upon a needed support level. This section intends to give a short survey of the most common support schemes for renewable electricity production, but intends in no way to be comprehensive, especially when it comes to legal evaluation of certain support schemes in the light of e.g. European state aid rules. There also exists a plethora of support schemes not directly linked to production such as investment tax credits, property tax abatement, accelerated depreciation and others. None of them will be treated in this section either.

Feed-in tariffs

Feed-in-tariffs used to be a very common support scheme within in the European Union. A well-known example is the German feed-in tariff that in 2012 made Germany the country with the largest installed capacity of solar PV (EPIA, 2013). Today, Germany still is the country with the highest installed capacity per capita according to IEA-PVPS 2020. Power generators are usually awarded an in advance fixed support per MWh produced for a predetermined number of years. The investor is thus guaranteed a fixed remuneration, reducing the market risk to zero, which is usually seen as a great advantage by the industry. This support can be differentiated for different technologies as in the German support scheme. The support scheme can and should be combined with annual revisions of the support levels for new entries to account for technological progress. The support scheme can be run through the state budget and thus be allocated to the taxpayer or can be financed by a direct surcharge on the electricity price allocating the cost of support to the electricity consumers. The choice depends inter alia on the question whether the objective is to decarbonise the electricity sector or, through electrification, the wider energy sector. The administration of the support scheme is often left to the transmission system operator who pays out the support, takes over the produced electricity and sells it on the market and charges the customers either directly or through the DSOs. A feed-in tariff can be quite costly if the support level is set too high due to information asymmetry regarding the cost of production and the speed of technological progress between the power generators and the government but can be very effective at increasing the share of renewables quickly. The same information asymmetry can swing the outcome in the other direction, when the remuneration is too low, renewable electricity production will not happen. Figure 7.4 shows the remuneration to the power producer in the ideal case of known generation cost as well as the cost of the support scheme depending on the electricity price.

Figure 7.4: Feed-in tariff



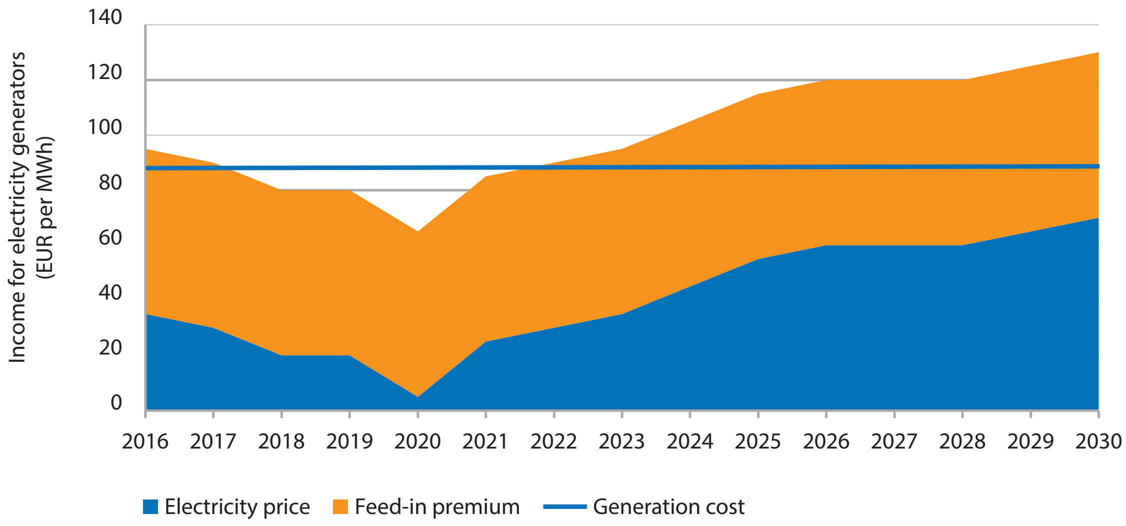
Source: Swedish Energy Agency (2015).

Feed-in-premium (FIP)

FIP is a support scheme that combines a market-based remuneration with a fixed premium that is independent of market price. The electricity generator receives two income streams, the revenue from the sale of electricity to the market and the premium. The thought behind this is to provide a certain form of stability but to continue to expose power generators to some market and price risk. The latter, in particular, provides incentives to choose and operate technologies in a manner such that their system contribution, i.e. the price they earn is relatively higher.

Either the State decides upon the support level in advance or the premium is determined through an auction. The balance of the revenues of power producers comes from selling electricity on the market, which provides incentives for reducing the cost of generation. The state support can be realised in different ways, a fixed payment or a fixed percentage of the electricity price. This risks however, that the support at times can be below the needed level and at other times be beyond the support level required. A feed-in premium has the advantage of reducing the exposure to market risk for the electricity producer but still leaving incentives to reduce cost and for technological progress increasing profitability for the producer. From a producer's point of view, since market risk is not completely removed, a fee-in tariff would still be preferable. Figure 7.5 provides an illustration how a FIP works in principle.

Figure 7.5: Feed-in premium

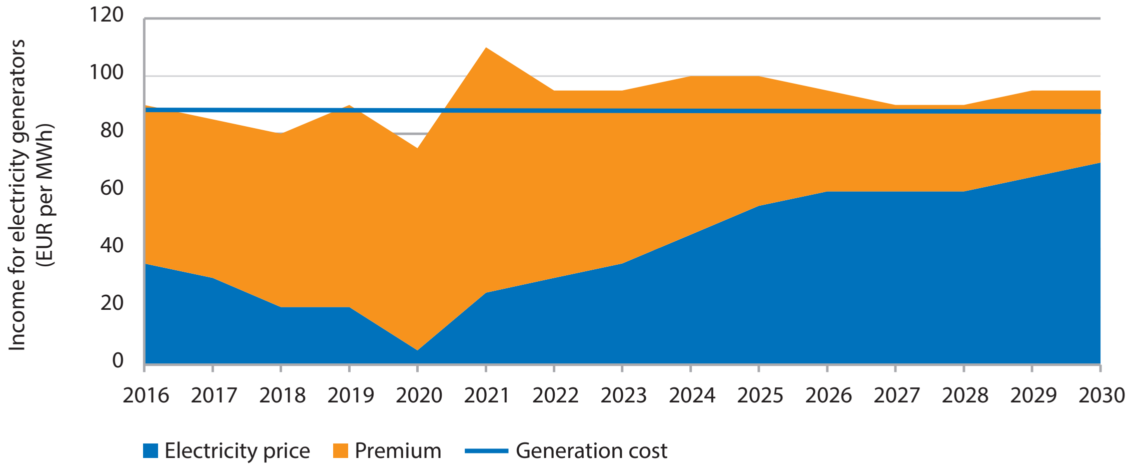


Source: Swedish Energy Agency (2015).

Sliding premia or contracts for difference

Sliding premia as illustrated in Figure 7.6 have the generation cost and the required support as their starting point. Power generators thus have two income streams, the actual electricity price and the premium. The reference electricity price is usually defined in function of the average cost of a plant in a given technology category over a given period. If averaging periods are very short (i.e. for instance one hour), a sliding FIP or CFD behaves almost like a FIT with regard to the risk profile faced by the producer. The market electricity price is almost certainly equal to the average price. If averaging periods are longer (i.e. one or several months), project operators face a higher exposure to market risks as the risk of deviations of the actual electricity market price from the reference price increases. A contract for difference (CFD), as for instance applied in the United Kingdom, is a special case of sliding FIP in which the winning price also constitutes a remuneration ceiling. Low-carbon installations are required to pay back to the regulator the income they received during times in which the reference electricity price is higher than their bid price.

Figure 7.6: Illustration of sliding premium/CFD



Source: Swedish Energy Agency (2015).

Tradable green certificates

TGC-systems were at times quite popular with some EU countries such as Denmark, the United Kingdom, Sweden, Belgium and Poland as well as the EU Commission. As of today, we find TGC-system at least in, Australia, Sweden, Belgium (Walloon Region) and Texas (Renewable energy credits, RECs). The Swedish system for example is supposed to operate until 2045 with a current goal of 18 TWh in new renewable electricity production in 2030 compared to 2020. Tradable green certificate is a volume-based support scheme.[2] Amundsen and Mortensen (2001) describe a green certificate as follows:

> In short, the Green Certificates market consists of sellers and buyers of certificates. The sellers are the producers of electricity using renewable sources. These producers are each allowed to sell an amount of certificates corresponding to the electricity that they feed into the electricity network. The buyers of certificates are distribution companies that are required by the government to hold a certain percentage of certificates corresponding to total end-use consumption of electricity. The Green Certificates are thus seen as permits for consuming electricity. The system implies that the producers using renewable energy sources receive both the wholesale price and a certificate price for each kWh fed into the electricity network.

Like in an ETS in a TGC-scheme a desired volume of renewable electricity production at a certain point of time can and usually is (but not necessarily has to) determined in advance. What is determined is the desired share of renewable electricity consumption of total consumption. Producers then receive one certificate per MWh for renewable electricity. Consumers, possibly through their suppliers, are obliged to buy such certificates as a part of a predetermined fraction of their electricity consumption. In Sweden, electricity wholesalers acquire green certificates for their customers and include the cost in the electricity bill. This creates a market for certificates. The quotas are determined in advance towards the long-term goal and reviewed regularly to control that the goal is achieved even if energy consumption changes. Green certificates provide technology-neutral support[3] to renewable electricity through the market. In a TGC-system, the producer of renewable electricity faces two risky income-streams, the income from selling electricity and the

2. In August 2020, the Swedish government put forward a proposition to end access for new production to the system by the end of 2021 and to terminate the system as a whole by the end of 2030.

3. Technology-neutral in this context means that each type of low-carbon generation, usually a renewable technology, receives the same number of certificates per MWh produced.

income from selling green certificates. The income streams are nowadays often secured through a Power Purchase Agreement (PPA) selling the production in advance at a fixed price to one buyer. However, this way of reducing risk is not specific to a green certificate scheme but to all systems where the producer is exposed to market risk. The price of the green certificates should, in theory, be equal to the long run marginal cost for the pivotal power producer. Setting a binding long-term target for green power production greatly helps in establishing stable equilibrium prices.

Production tax credits

The Production Tax Credit (PTC) is a state incentive that provides financial support for the development of renewable energy facilities. In the US companies that generate electricity from wind, geothermal, and "closed-loop" bioenergy (using dedicated energy crops) are eligible for a federal PTC, which provides a 2.3-cent per kilowatt-hour (kWh) incentive for the first ten years of a renewable investment. In the United States, also CCUS and nuclear energy can receive PTCs. In In principle, a PTC could be used to subsidy any kind of (carbon-free) electricity generation.

Zero emission credits (ZECs)

Currently, this instrument is primarily employed by US state regulators to provide capacity support to nuclear energy to value its contribution in terms of fuel diversity, security of supply, carbon emission reductions and reduced environmental impacts. Frequently, the aim of the measure is to counteract the fall in electricity prices induced by the advent of VRE receiving PTCs. Currently, ZECs still constitute technology-specific support rather than across-the-board remuneration for contributing to carbon emission reductions and improved air quality, even though the level of the ZEC is explicitly connected to the value of an avoided tonne of CO_2. Their costs are so far borne by electricity customers, which means the financing charge increases general electricity prices (see also box below "Pricing Emission Avoidance: The US Experience with Zero Emission Credits (ZECs)").

Pricing emission avoidance: The US Experience with zero emission credits (ZECs)*

Economists have traditionally focused on the pricing carbon emissions as the preferred policy to address climate change. This has regularly led to resistance by fossil-fuel based power producers concerned about higher costs and electricity consumers concerned about higher prices. However, the objective of reflecting the differential in social costs between low-carbon and fossil fuel-based electricity generation and furthering a structural shift towards low-carbon generation can also be achieved by the alternative means of supporting the latter. While the economic costs of taxing emissions and remunerating emission reductions are comparable, their distributional effects and hence their social acceptance might be very different.[4] For many years, renewable energy sources have benefited from support mechanisms, as those described in Section 7.2. However, nuclear electricity, which produces neither carbon nor other emissions, had so far not benefited from equivalent measures.

4. When taxing emissions, in the long run the economic costs of reductions are always borne by electricity customers. In the second case, it depends on the source of financing for the premia that remunerate emission reductions. If government budgets are the source, taxpayers will ultimately bear the cost and electricity prices will remain unchanged. If the source is a surcharge on electricity prices, again electricity customers will pay. However, even in the latter case, impacts will not be completely the same. In the tax case, carbon-intensive producers include their *marginal* costs of internalising emission into their price bid. In the support case, all producers or distributors will include the average costs of support into their prices. While prices for electricity producers will go up in both cases, ultimate effects will depend on the structure of the load curve, demand, relative costs and billing procedures.

In terms of political acceptability, short-run impacts can also be important. With a carbon tax, a coal plant taxed at its marginal cost might find itself excluded from the merit order for good and shut down immediately. With a subsidy for emission reductions, the same coal plant absorbing the average costs or emission reductions might continue in the market for some time with a reduced number of hours.

(continued Pricing emission avoidance)

In 2016, the US states of New York and Illinois introduced zero emission credits (ZECs) to reward also nuclear power for its contribution to reducing carbon emissions. From an economic point of view, it would be preferable if both sets of policy instruments (support for either renewables or nuclear) were provided in a manner that was *not* technology specific. In this case, any low-carbon technology could claim support for a tonne of CO_2 avoided. This is currently not yet the case, neither in the United States nor elsewhere. However, the ZEC programme could constitute a blueprint for remunerating emission avoidance rather than taxing emissions. In this perspective, it contains lessons that go beyond nuclear power.

The immediate trigger for the introduction of ZECs was that many nuclear plants have been facing the prospect of early closure, as low gas prices, an absence of carbon pricing and extensive support for renewable power have challenged their economic viability. Nuclear plants in New York, Illinois, Connecticut, New Jersey and Ohio were thus facing early closure. While there were variations in approaches, the predominant policy was for states to create a zero emission credit (ZEC) to ensure that the value of generation without air emissions would be factored into decisions about the future of the plant. Due to these policies, 14 nuclear units with almost 14 GW of low-carbon baseload power avoided closure.

What are zero emission credits?

Zero emission credits (ZECs) are payments that electricity generators receive to compensate them for the valuable attribute of not emitting greenhouse gases in the production of electricity. ZECs work similarly to renewable obligations that support renewable energy production in many states. Like renewable energy credits (RECs) that are generated by wind and solar generators and sold to utilities, ZECs are sold to utilities that are *required* to purchase a certain number of these credits from low-carbon generators. The utility then rolls the cost of the credits into electricity customers' bills. Just like in the case of a carbon tax or an emission trading system, electricity consumers will ultimately support the cost of switching towards a low-carbon system.

From the point of view of a nuclear plant owner, ZECs provide a source of revenue for the service of reducing climate change-inducing greenhouse gas emissions that had previously been provided free. Before these programmes were in place, the markets only paid nuclear plants for the electricity they produced.[5] State air regulators and public health advocates did recognise the clean-air benefits, but nobody paid for them directly. ZECs at least internalise the service of low-carbon power production.

Setting a ZEC Price

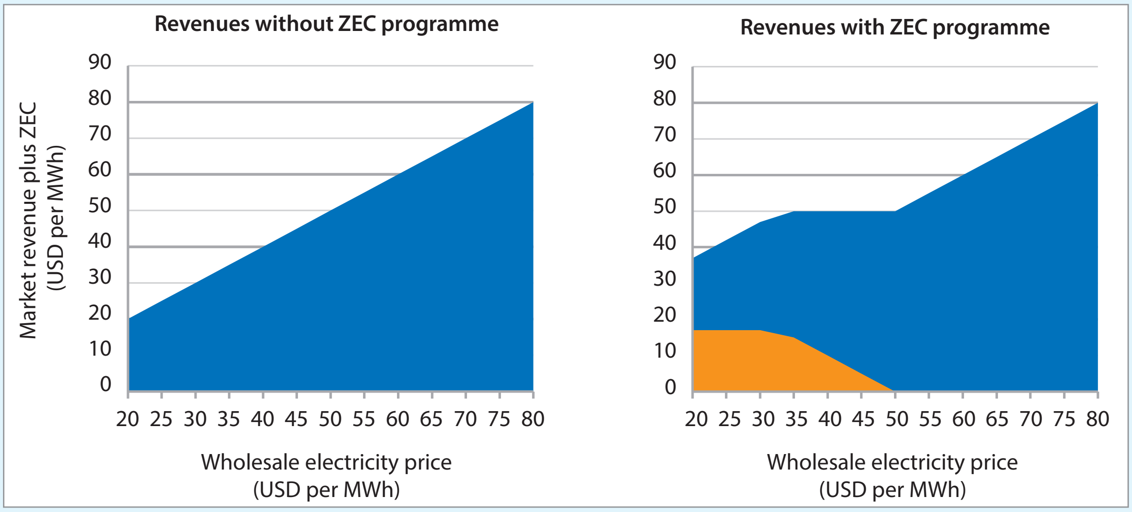
Since the idea of the ZEC is to provide an incentive to preserve non-emitting generation, the price of the ZEC should relate to the value of the avoided emissions. The initial ZEC programmes in New York and Illinois used the social cost of carbon (SCC) as the starting point for determining credit value. The SCC indicates the long-term economic impact of emissions. A central estimate of the SCC established is USD 42 per t CO_2.

5. Nuclear plants may also qualify for capacity payments in some markets. Capacity markets ensure that there will be sufficient generation at times when the electricity system is under stress. Since nuclear plants run over 90% of the time, the vast majority of the revenues for these plants are from wholesale electricity sales. When ZEC prices are calculated, capacity payments are included on a per-megawatt-hour basis.

(continued Pricing emission avoidance)

On this basis, regulators convert the SCC into a dollars-per-megawatt-hour value by multiplying the SCC by the average emissions generated by plants running on natural gas or coal. If the fuel is natural gas, the emissions rate will likely be somewhere around 0.5 t CO_2/MWh. It will be roughly double that number for coal plants. Multiplying the SCC by an emissions rate will yield a baseline ZEC measured in dollars per megawatt-hour. Current ZEC programmes also include a phase-out provision so that the value of a ZEC decreases if the market prices for electricity rise. This shows the extent to which current ZEC programmes are temporary expedients to compensate for low electricity prices. Changes in electricity prices, of course, do not imply changes in the SCC. An environmentally coherent policy framework would provide ZECs corresponding to the SCC independent of the level of electricity prices.

The figures below summarise the basic framework. The first figure shows the one-to-one relationship between the market price of electricity on the bottom axis and the final value received by the nuclear generator on the vertical axis, as would happen in standard electricity markets. The second figure shows the impact of a ZEC on revenues and how its decrease as market prices increase. Once the wholesale power price increases to a pre-set level (notionally depicted at USD 33/MWh in this simplified example), the ZEC, shown in red, is reduced dollar-for-dollar as market prices exceed this threshold. In other words, in current designs ZECs act as a price floor that is gradually removed market prices rise.



Challenges to ZEC Programmes

While ZECs are an innovative policy instrument to remunerate low-carbon producers for the service of emission avoidance they provide, they also impose an added cost on utilities, and to the extent that the latter can pass them on, to electricity consumers. ZEC programmes have thus been challenged in federal courts. Fossil fuel-based competitors also turned to federal energy regulators arguing that ZECs distorted wholesale markets. The legal challenges did not succeed; the regulatory challenge was more successful.

The challengers argued to FERC that they had made investments in fossil capacity in the expectation that nuclear plants, now receiving ZECs, would have been forced to close, which would then have resulted in higher market prices. FERC sided with the challengers. The Commission held that it was solely an economic regulator and therefore precluded from weighing the environmental benefits of such a policy. FERC held that if generators are receiving payments from state programmes then their bids to provide services in the market should be changed to reflect the value of these payments. Logically, this decision also affected the deployment of new wind and solar resources developed with the support of comparable state programmes.

(continued Pricing emission avoidance)

This decision has created tensions between state governments and regional wholesale markets. It is widely accepted that more widespread carbon pricing would be a more robust solution to these state-by-state solutions, but the prospects currently seem remote in a US context. State governments are now trying to decide how much they want to rely upon organised electricity markets to shape the power sector. This would be an understandable but unfortunate development. From an economic point of view, it would be preferable if the contribution to emission avoidance by nuclear power, renewables and hydro were correctly valued at the SCC in a comprehensive carbon management policy framework.

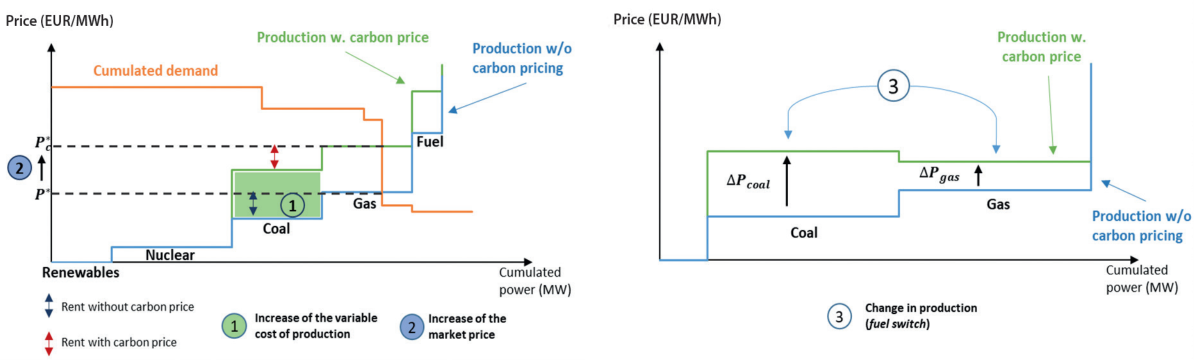
* This box is based on a personal contribution by Matthew P. Crozat, Senior Director, Business Policy, Nuclear Energy Institute, United States.

7.3 Impacts on electricity prices

Different instruments can have different impacts on both wholesale and retail electricity prices. If taxes and emission trading raise prices, support measures for low-carbon electricity generation tend to decrease electricity prices net of the cost for the support scheme in the long run. Carbon pricing schemes as opposed to low-carbon support schemes give incentives for fuel switching between different carbon-intensive generators such as coal and gas. Fuel switching, i.e. the differentiated impact on individual technologies, thus needs to be carefully accounted for in both cases.

According to economic theory an emission trading scheme for carbon leads to a rise in marginal costs equal to carbon opportunity cost regardless of whether allowances are allocated for free or not. In an electricity market with marginal cost pricing carbon pricing works through the merit-order effect. Carbon pricing affects/increases the marginal cost of fossil technologies such as coal and gas power and thus affects the relative price between carbon-free and fossil technologies and between different fossil technologies. If the price change is large enough the order between carbon-free and fossil production is changed in favour of carbon-free technologies. That means that the transmission into prices depends on whether fossil technologies are needed to satisfy demand or not (which technology is on the margin). Looking at a power system with both renewable and fossil power generation, if demand at a certain hour is satisfied by carbon-free technologies alone there will be no price effect at all. If demand cannot be satisfied by carbon-free production, the marginal cost including carbon pricing of the production technology that lies at the margin will determine the market price. Low-carbon producers will then be able to reap inframarginal rents as shown in Keppler and Cruciani (2010).

Figure 7.7: The merit order with and without carbon pricing



Source: Keppler and Paskoff (2020).

There are a couple of studies on the pass-through of cost increases on wholesale markets such as Nakamura (2008). With the start of the EU ETS, several studies starting with Sijm (2006), Honkatukia (2006) and Fell (2010) studied the pass through of emission cost to the electricity price. Carbon pass through, following Sijm et.al. (2006), is often defined as the ratio of the change in electricity price over the increase in cost for the generator:

$$R = \frac{\Delta\, p(electricity)}{\Delta\, cost\ (power\ generator)}$$

Correctly assessing pass-through rates requires an analysis hour by hour. Regarding the impact of carbon prices on power prices the literature is ambiguous. Some authors argue for a full (or almost) full pass through (Sijm et al., 2006; Honkatukia et al., 2006) while others only see a partial pass through or none at all to wholesale prices (Levy, 2005). Typical pass-through in the empirical literature range from 30% to 150%. Pass-through rates depend on the use of method, but also on relative variable costs, carbon content and market structure. Chernyavska and Gullì (2007) evaluate to what extent firms in imperfectly competitive markets will pass-through into electricity prices the increase in cost. They show that the pass-through rates/ increase in price can be higher or lower than the marginal CO_2 cost. The pass-through rate depends on several structural factors, the degree of market concentration, the available capacity, the power plant mix in the market and the power demand (peak vs. of-peak hours).

In conclusion pass through is usually around 100% but can be lower if (a) fuel switching occurs or (b) renewable production alone satisfies demand and no fossil-based power generation is used on the margin in addition the results also depend on the granularity of the analysis.[6]

Effect on the individual power producers

As is evident from the description above carbon pricing will increase the cost of electricity production from fossil fuels and higher carbon intensity plants will experience a larger cost effect than lower carbon intensity plants. Carbon pricing thus will have several effects on a power producer with a portfolio of plants, for one it will induce a shift from less efficient plants to more efficient plants and it will induce a change from coal to gas everything else unchanged. If the effect of carbon pricing on the merit order is large enough it will in addition shift production from fossil fuel-based generation technologies to renewable power generation technologies. In connection with this transition we see the appearance of what is commonly called “sunk cost”, that is fossil plants that have not reached the end of their technical lifetime and initially calculated economic lifetime before carbon pricing was introduced will be phased out in favour of new plants. The effect on the individual producer will depend on the extent to which the producer can shift the increased cost to the wholesale price.

Carbon pricing will also most likely speed up innovation both when it comes to fossil-based power plants as well as providing a push towards low-carbon technologies.

A real live example for the effectiveness of carbon pricing is the development of emissions within the EU ETS. In 2019, total CO_2 emissions from fossil fuel combustion declined by 4.3% in the European Union (not including the United Kingdom), mainly due to the substantial increase in the carbon price on the EU Emission Trading Scheme (EU ETS) in 2019 (over EUR 25/t CO_2), which incited power producers to use more gas and renewables. Emissions covered by the EU ETS declined even by 8.7% in 2019 and contracted by 15% in the EU power sector, as power producers substituted coal-fired power generation with renewable and gas-fired generation (Enerdata, 2020).

6. Two further theoretically interesting cases exist. First, market power would also reduce pass-through, as a monopolist would take into account the impact of higher prices on demand and revenue foregone. Second, with certain iso-elastic demand curves – unlikely in electricity markets – a pass-through higher than 100% would be the profit-maximising solution.

7.4 Distributional impacts

Other than the well-being of the general population due to reduced impacts from climate change, carbon pricing in whichever form influences the revenues of generators and the prices that they quote to their customers. In the electricity sector, carbon prices will drive a wedge between the costs and profits of low-carbon generators such as nuclear, hydro or renewables and those of fossil-fuel generators.

When considering these distributional impacts, it is important to distinguish between short run and long run impacts, in particular when considering the profits of operators. In pure theory, assuming competitive electricity markets with free entry and exit, profits are always zero in the long run. However, this is frequently not the most policy-relevant perspective. Barriers to entry and long investment cycles in the electricity industry ensure that electricity generators keenly observe the impact of carbon pricing on their profits.

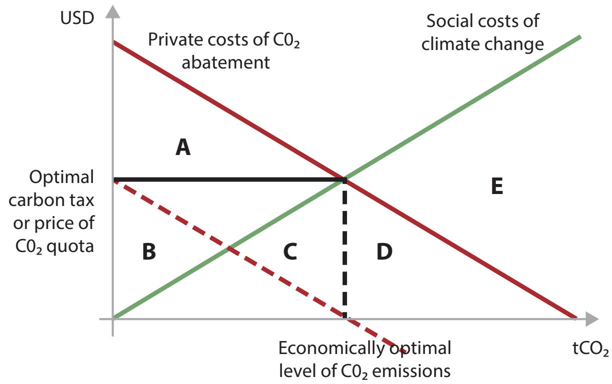
Looking at the distributional impacts of carbon pricing one must first consider the distribution of the costs of reducing emissions between carbon emitters such as fossil fuel-based electricity generators and their customers on the one hand and governments and taxpayers on the other. Second, one must consider its differentiated impacts on different generating technologies, especially in electricity markets. In both case, the distributional impacts will depend decisively on the instrument chosen. The distributional impacts of a carbon tax, a carbon trading system with free allocation, a technical standard or a per unit subsidy for emission reductions will not be the same.

Distribution between fossil- fuel-generators, government and the general population

The Pigouvian framework for internalising social costs such as climate change inducing carbon emissions in order to maximise economic welfare is a useful first step for discussing the distributional impacts of carbon pricing (see Pigou, 1920). Although it is limited to static optimisation and thus does not consider dynamic effects, it allows developing a good intuition for the distributional impacts between generators and their customers and the general population of different forms of carbon pricing. The magnitudes are considerable and amount to billions of USD (see below for the results of a case study of the French and German electricity sector). The benefits and costs of different stakeholders change dramatically in function of different forms of carbon pricing. This, for instance, explains the fierce resistance that carbon pricing frequently encounters as it heavily reduces the benefits of carbon emitters.

Figure 7.8 below provides a simple representation of the Pigouvian framework, whose main building blocks are the marginal social costs of carbon, i.e. the impacts of climate change, and the marginal private costs of reducing carbon emissions. Since a dollar saved is a dollar earned, the latter are also equivalent to the marginal private benefit of emitting carbon. The right to emit carbon at no cost is thus economically valuable. In technical terms, it constitutes what one refers to as an environmental rent. In the absence of carbon pricing, this rent arises in the form of higher consumer welfare due to cheaper goods and services. In Figure 7.8, this private welfare corresponds, in the absence of carbon pricing to the combined areas A, B, C and D. At the same time, of course, carbon emissions create the concomitant social cost of climate change, corresponding to the areas C, D and E. From the point of view of an economist such as Pigou, the welfare of consumers and the welfare of the general population suffering from climate change have equal standing. The optimal trade-off then intervenes logically at the intersection of the marginal private costs of abatement and the marginal social costs of climate change. At this point, the combined welfare of both parties will be maximised and the total carbon rent will be maximised. In order to reach the optimal point policymakers have essentially four instruments at their disposal. These are (1) setting a carbon price in the form of tax for every t CO_2 emitted, (2) setting a quantitative cap on total emissions (which puts an implicit price on carbon), (3) creating a market for emissions with quotas either allocated freely or through auctioning or (4) subsidising emitters for reducing their emissions.

Figure 7.8: The Pigouvian Framework of optimal static internalisation



Instruments in these four categories have vastly different distributional implications. For reasons of clarity, it is useful to abstract for the moment from dynamic effects and uncertainty. Both play a role in the concrete design and implementation of carbon pricing. However, the fundamental differences in distributional impacts between these four kinds of instruments are even more important and structure the global debate on carbon pricing in fundamental ways. Table 7.1 below summarises these distributional impacts. The first observation is, of course, that the status quo of no carbon pricing will have a considerably lower overall welfare than the four measures of internalisation. Among the latter, all will yield the same overall benefit.[7] From a general economic point of view, all four are thus equally legitimate.

Interestingly, from the viewpoint of the general population affected by climate change there is also no difference in the welfare impacts of the different measures. The general population will suffer residual damages C in each case, but will be relieved of the damages corresponding to areas D and E. This is the decisive benefit of all forms of carbon pricing. However, from the point of view of carbon emitters and the customers as well as governments and taxpayers, there are stark differences between different measures.

As already mentioned carbon emitters will in principle pass on their private benefits and cost savings to their consumers as competitive firms will compete on price. Even if market imperfections might leave part of the benefits to emitting firms and their shareholders, the rank ordering of the different measures is obvious. Emitters prefer a per-unit subsidy for reducing emissions (where B+C corresponds to the amount of the total subsidy) as the preferred instrument over doing nothing (no carbon pricing), a quantitative cap or permit trading with free allocation. A carbon tax or permit trading with auctioning follows last. This easily explains the resistance of carbon-emitting fossil fuel-based producers to any form of straightforward carbon pricing.

Table 7.1: The distributional impacts of different forms of carbon pricing

	No carbon pricing	Carbon tax	Quantitative cap	Carbon trading (free allocation)	Carbon trading (auctioning)	Subsidy
Population affected by climate change	-C-D-E	-C	-C	-C	-C	-C
Carbon emitters and their customers	A+B+C+D	A	A+B+C	A+B+C	A	A+B+C+B+C
Government and taxpayers	0	B+C	0	0	B+C	-B-C
Total carbon rent	**A+B-E**	**A+B**	**A+B**	**A+B**	**A+B**	**A+B**

7. The above statement is theoretically not quite correct. A pure quantitative cap putting only an implicit price on emitting carbon will have somewhat lower welfare benefits than measures with explicit carbon pricing, which reduce carbon emissions in the most efficient manner. However, the welfare losses are second-order, when compared with the overall welfare gains of carbon pricing.

The preferences of governments and taxpayers are, or rather should be, ranked precisely in the inverse order: carbon taxes or permit trading with auctioning should be preferred to a quantitative cap or permit trading with free allocation. Subsidies should be the least palatable choice. However, social choices are not always determined according to disinterested rationality. Historical precedent, transaction costs, deep-rooted perceptions and relative political power can arrive at or entrench choices very different from those suggested by economic theory. As well-established carbon emitters ponder substantial welfare losses due to carbon pricing, the benefits of carbon pricing to governments and taxpayers may well be larger but are spread over a greater number of people. The former thus have relatively greater incentives and lower transaction costs to build coalitions and engage in effective lobbying. Given that already the *status quo* is very profitable for carbon emitters, they can also limit themselves to impeding change rather than advancing any particular policy.

If historical precedent and considering transaction costs favour subsidies or the status quo, dynamic considerations favour carbon pricing whether by measure of a tax or a permit trading system. Why? Because only a price signal provides producers with an effective incentive over time to search for more efficient and less emitting technologies. This "induced technological change" is perhaps the most important long-term benefit of carbon pricing in the real world, as the cost of having to pay for each tonne of carbon emitted concentrates minds and focusses effort.[8] Considerations of uncertainty, i.e. the likelihood of missing either the optimal amount of emissions abatement or the optimal cost point, favour a straightforward carbon tax even over and above the argument of dynamic effects. This is because the most welfare-relevant uncertainties arise at the level of the economy. Providing economic actors with a stable long-term price signal reduces investor uncertainty, the cost of capital and, ultimately, the cost of abatement. However, as mentioned, these are second-order considerations. From an economic point of view, the only truly unacceptable option is the absence of any form of carbon pricing

Distribution between different power generation technologies[9]

In order to understand the distributional impacts of carbon pricing on electricity generators one must consider two issues: first, the interaction between carbon prices and electricity prices indicated in Section 7.3; second, the changes in "inframarginal rents" introduced by carbon pricing. Inframarginal rents are the principal form, in which the revenues and profits of operators in the electricity sector arise. Such rents arise because electricity is not storable. Otherwise, one would produce electricity with the technology that has the lowest average costs, stock it and use whenever needed. This however is not possible in the electricity sector where different technologies will supply the electricity supply that will meet demand second by second.

A generator earns inframarginal rent each time when his variable costs are lower than the market price. This temporary rent will go towards the financing of his fixed costs. The market price is set by the technology with the highest variable cost that is still called upon at a given moment. As explained in the previous section, the price itself as well as the difference between the variable costs of different inframarginal technologies and the price will change due to carbon pricing. Recent work by Keppler and Paskoff (2020) provides an overview of the distributional impacts of a carbon price of EUR 30/t CO_2 on the inframarginal rents of power producers in France and in Germany. Modelling the changes in prices and the merit order and assessing the resulting changes in hourly inframarginal rents, it finds that carbon pricing increases the overall inframarginal rent of power producers due to carbon trading in France and Germany by EUR 22.5 billion with free allocation and of EUR 17.1 billion with auctioning.

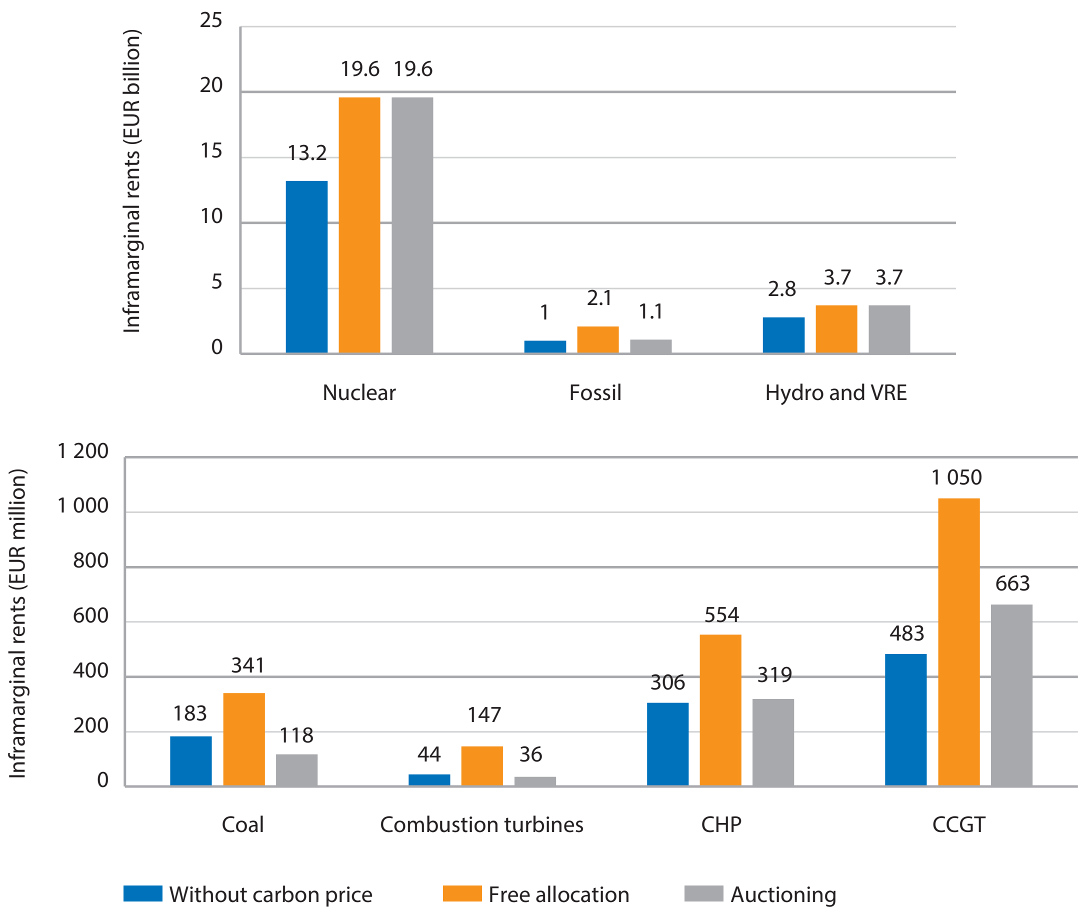
8. Subsidies do not perform well at all in a dynamic perspective. Here, a producer will receive a higher subsidy to the extent that his emissions are larger and his costs of abatement higher. In a static framework without uncertainty or asymmetries of information, this will not have an impact as both emissions and abatement costs are fixed. However, one can easily appreciate the incentives at play in a dynamic context, even where producers do not deliberately exploit any asymmetries of information.

9. This section borrows heavily from Keppler and Paskoff (2020).

The first observation is that carbon trading can be highly profitable for electricity producers even in the case of full auctioning. This differs from the conclusions of the preceding subsection, which presented the simple Pigouvian framework. This is because the simple Pigouvian framework does not distinguish between electricity producers and electricity consumers. As shown in Section 7.3 above, carbon pricing immediately feeds through into electricity prices. Electricity consumers thus pay for the increase in inframarginal rents. Long-term consumption will decline due to higher prices and reduce consumer surplus further.

The second, quite intuitive, observation is that the gains from carbon pricing vary strongly with the technology. Whether a utility employs low-carbon or fossil fuel-based technologies makes, in particular, a difference between the rents under auctioning or free allocation. Under free allocation, everybody gains, even coal- and gas-based producers, due to higher prices and constant costs. Under auctioning, in particular coal-based producers will lose, since they will have to buy their quotas, but are unable to pass on the cost increase to the extent that they are not price-setting marginal fuel.

Figures 7.9a and 7.9b: Inframarginal rents of electricity producers in France



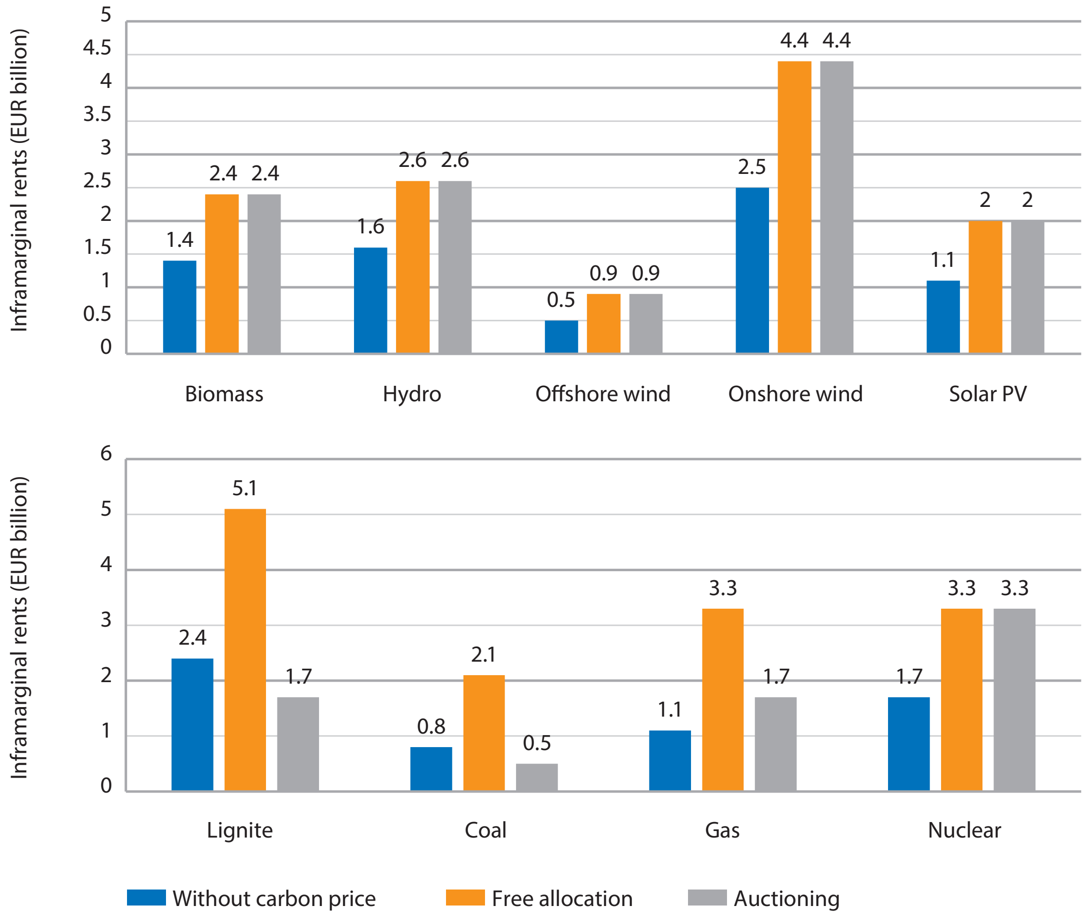
Source: Keppler and Paskoff (2020).

The third observation the authors make based on the results for France and Germany is that the structure of the overall electricity mix plays a large role. In France, where nuclear energy provides 75% of electricity and hydroelectricity and renewables another 15%, the benefits from carbon pricing are largely independent of whether quotas are auctioned or allocated at no cost. Only coal-based power producers would experience losses of roughly EUR 0.1 billion under auctioning. Overall, French electricity producers would gain an additional EUR 8.4 billion from carbon pricing under free allocation and EUR 7.4 billion under auctioning (see Figures 9a and 9b above). Of these, nuclear power plants would gain EUR 6.4 billion in both cases. Hydropower and variable renewables (VRE) such as wind and solar PV would gain an additional EUR 0.9 billion in both cases.

In Germany, the high share of fossil fuels in the electricity supply introduces a strong difference in inframarginal rents between free allocation and auctioning (see Figures 7.10a and 7.10b below). Under free allocation, the gains of German power producers from a carbon price of EUR 30/t CO_2 would thus amount to EUR 12.8 billion. Of these, EUR 2.7 billion would accrue to lignite, EUR 1.3 billion to coal, EUR 2.2 billion to gas, EUR 1.6 billion to nuclear and EUR 5.0 billion to renewable energies (biomass, hydro, onshore ad offshore wind and solar PV). Onshore wind alone would gain EUR 1.9 billion.

The story is very different under auctioning. While carbon-free technologies would experience an identical increase in inframarginal rents, this is obviously not the case for fossil-fuel based producers. Lignite-based producers would experience a loss of EUR 0.7 billion when switching from a system without carbon pricing to a system with auctioning, while coal would lose EUR 0.3 billion. Gas-fired power producers due to fuel switching would instead still gain EUR 0.6 billion. Total gains in inframarginal rents due to carbon pricing at EUR 30 per t CO_2 would thus amount in Germany to just EUR 9.5 billion. Producers based on lignite and coal would be absolutely worse off by EUR 1 billion with a EUR 30/t CO_2 price in a carbon trading system with auctioning.

Figures 7.10a and 7.10b: Inframarginal rents of electricity producers in Germany



Source: Keppler and Paskoff (2020).

Higher carbon prices would of course increase the inframarginal rents. Due to fuel switching, this increase would not take place in precisely a linear fashion, however the orders of magnitude of the relative increase would be comparable.

All increases in inframarginal rents ultimately result from higher electricity prices. In other words, consumer surplus will be transferred from electricity consumers to power producers in the form of higher inframarginal rents. The fact that electricity consumers lose consumer surplus due to carbon pricing is in political economy terms a strong reason to consider subsidy solutions, i.e. to reducing the costs of low-carbon producers. However, one needs to keep in mind that such solutions usually have a more limited impact on fuel switching in the short run and on changes in the generation mix in the long run. In addition, it weakens incentives to reduce electricity consumption and to invest in energy efficiency.[10] Finally, as mentioned, subsidies have unfavourable dynamic qualities and cause economic efficiency losses due to the need to finance them through increased taxes or charges.

If governments auction the quotas, they will earn the resulting revenues. In other words, under auctioning, electricity consumers wholly pay for the somewhat lower gains of producers. Under free allocation, consumers and governments share the costs of their somewhat higher gains. The allowances received at no cost will serve to enable fossil-fuel based electricity production and thus translate into overall higher inframarginal rents.

It is instructive to compare the relative share of the gains that depend on the mode of allocation or on the increase in electricity prices. As electricity production in France is largely decarbonised, only few quotas are actually issued. Giving them away free or auctioning them off does not make a big difference, so the price effect dominates. In Germany, where the power sector in 2017 emitted roughly seven times as much as in France, switching from auctioning to free allocation more than doubles the additional inframarginal rents of power. This share is paid for by government through revenues foregone. The price effect would contribute only half. In principle, the price effect is supported by consumers. This is true for wholesale markets. However, at the level of retail consumers, final tariffs for end users will result from a complex interplay of partly off-setting forces. For instance, higher wholesale prices will reduce the support payments for renewables.

The most important effect of carbon pricing is the reduction of carbon emissions and the incentive for further carbon-reducing technological progress. Beyond that, they differentiate with auctioning strongly between the profitability of low-carbon and fossil fuel producers. This will in the long run, i.e. allowing for exit and entry, further spur the transformation of the electricity sector towards low-carbon generation. All three effects together ensure that carbon pricing is a highly effective means of reducing emissions.

10. In a framework of static optimisation, one can however replicate the impacts of first-best carbon pricing by way of unit subsidies for each tonne of CO2 abated that is previously assessed against a firm baseline. In systems with few transaction costs, competitive suppliers will also pass on the remuneration for such emission reductions to consumers willing to reduce their consumption or to adopt energy efficiency measures, i.e. pay them for *negawatts* or rather *negatonnes* of CO_2.

7.5 Policy conclusions

In a context of overwhelming evidence of manmade climate change due to the emission of greenhouse gases, about 40% of which stem from electricity generation, pricing the carbon emissions of electricity generators or supporting their emission avoidance is unambiguously welfare improving. Carbon pricing, whether directly or indirectly, is the appropriate manner to integrate the objective of reducing greenhouse gas emissions into the incentives of private agents and the policy frameworks of governments. From an economic point of view, the most efficient instruments are those that internalise the social costs, i.e. climate change, directly by putting an appropriate price or surcharge on the vector that causes it, i.e. CO_2 emissions. Ideally, such a surcharge would target all carbon emitters in a uniform manner, independent of the industry or economic sector in which they operate. Integrating external effects in this manner would make carbon-intensive generation more expensive than low-carbon generation, lead to fuel switching and changes in the generation mix and, in addition, provide incentives for demand reduction and energy efficiency as well as for induced technological change.

However, carbon pricing also needs to account for the realities of everyday policy making. While experts recognise the theoretic superiority of carbon pricing since at least four decades, it has elicited fierce resistance by fossil fuel-producers, electricity consumers and their respective advocates. As shown, carbon pricing has sizeable distributional effects. Welfare transfers between different types of generators as well as between electricity consumers, generators and governments amount to billions of USD annually. Even environmentalists occasionally voice reservations about "pricing the environment". In such situations, where the first best solution is unattainable, it is important to realise that this does not mean that countries are condemned to the *status quo* of unabated carbon emissions with electricity sectors based primarily fossil fuels.

The preceding sections have presented the wide array of instruments that policymakers have at their disposal to create a wedge between the costs of fossil fuel-based electricity generation and low-carbon generation based on renewables or nuclear energy and thus reduce carbon emissions. These instruments go beyond the classic first-best instruments of carbon taxes or emission trading systems. Indeed, carbon pricing does not necessarily require taxing the emissions from fossil fuel-based electricity generation and making it more expensive. Remunerating low-carbon electricity generation such as nuclear energy, renewables and hydroelectricity in order to reduce carbon emission can achieve very similar objectives at comparable overall costs.

Of course, OECD governments have long practised such policies primarily by providing guaranteed returns to capital-intensive low-carbon producers in the form of feed-in tariffs (FITs), feed-in premia (FIPs), contracts for difference (CFDs) and, most recently, zero emission credits (ZECs) or by reducing their tax burdens through production tax credits (PTCs). Clearly, this does not make all forms of lowering the cost of low-carbon electricity production first best instruments. Current solutions too often still rely on governments picking winning technologies. In addition, as implemented currently, such solutions have limited impacts on fuel switching in the short run and can weaken incentives to reduce consumption and increase efficiency. However, such shortcomings are largely due to detailed design and implementation. At this point in the debate, it is appropriate to think about support for emission reduction in a more systematic and economically more coherent manner. Generalised per unit support for each tonne of carbon abated, assessed against a firm baseline, can indeed replicate most results of a straightforward carbon tax. Even where this is not possible, e.g. for a lack of an appropriate informational infrastructure regarding baselines, generalised support for low-carbon generators is a viable alternative. The fact that support for low-carbon generation does not differentiate between the emission performances of coal- and gas-based generation is secondary in the light of long-term carbon neutrality objectives. The key point for effective climate policy in the electricity sector remains creating a cost wedge between low-carbon and fossil fuel-based generators.

All forms of carbon pricing need to be mindful of distributional effects between generators, but also between consumers, generators and governments. Due to the economic importance of the electricity sector, carbon pricing heavily affects the welfare of different stakeholders. In particular, straightforward carbon taxes, despite all their real economic benefits, reduce the surplus of electricity customers. To the extent that the consumption of fossil fuel-based electricity is a key driver of climate change this is justifiable. However, in many countries electricity constitutes also a merit good with important positive externalities. While the implementation of effective policies to reduce carbon emission is no longer negotiable, these policies must remain socially acceptable.

An important option in this context consists in financing support for carbon emission avoidance through general government funds. In this manner, taxpayers rather than electricity consumers would carry the economic costs for ensuring the public good of climate change avoidance. While taxing carbon emissions remains a straightforward first-best solution, there are indications in that subsidising emission avoidance is in a number of OECD countries a politically more sustainable solution. The large economic recovery programmes following the economic crisis in 2020 in the wake of the COVID-19 pandemic could be the right moment to implement such policies at the appropriate scale.

Different countries, both inside and outside the OECD, will choose different policy packages and different distributional arrangements. However, after years of sterile stand-offs between supporters and detractors of carbon taxes, the discussion has advanced and there is now a more sophisticated understanding of the available options for carbon pricing and their impacts. For all country serious about their commitments under the Paris Agreement, there now exist appropriate options for reducing electricity sector emissions that allow striking a balance between economic efficiency, environmental integrity, social fairness and political sustainability.

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Perspectives on the costs of existing and new nuclear power plants

8.1 Status of nuclear development and role in future energy systems

If countries are to meet their objectives under the 2015 Paris Agreement to reduce their greenhouse gas emissions, a significant contribution of nuclear power is indispensable. According to the IEA Sustainable Development Scenario (SDS) new nuclear capacity and ambitious lifetime extension programmes for existing nuclear power plants are needed. This growing role for nuclear power to meet decarbonisation objectives is also confirmed by the Intergovernmental Panel on Climate Change (IPCC, 2018).

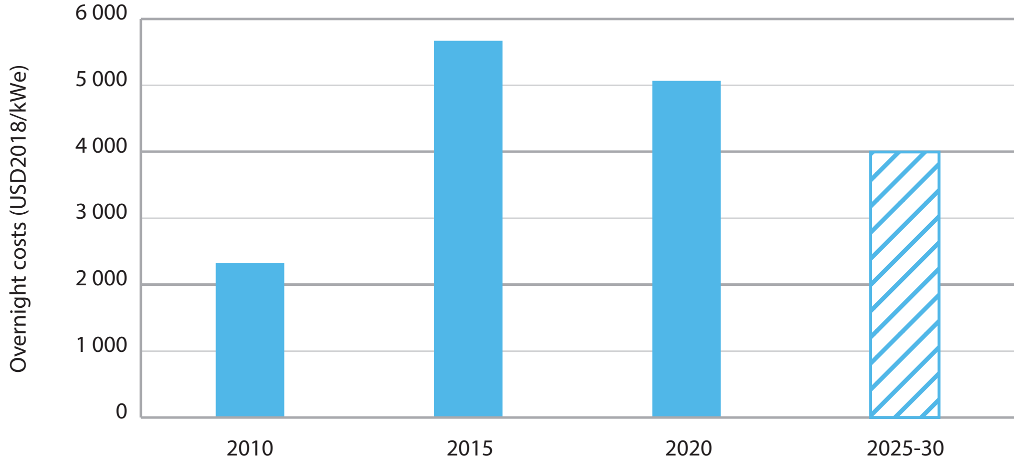
So far, however, nuclear power is not on track to reach its required share in global electricity generation. In fact, the rate of annual capacity additions of currently 5 GW would need to at least double between 2020 and 2040 to meet the SDS.

As outlined in the SDS scenario, without lifetime extensions beyond 40 years, the pressure on the nuclear supply chain will increased dramatically requiring capacity additions of up to 20 GW starting from 2021 (IEA, 2020). In addition, decarbonisation efforts will become more challenging and more expensive at both the level of the plant and the system with the premature closure of nuclear capacity (IEA, 2019). However, in several countries the existing nuclear fleet is impacted by current electricity market designs that that do not appropriately value the attributes of capital-intensive low-carbon technologies dispatchable such as nuclear and hydro power plants. Policy decisions are also leading to early closures. Otherwise, long-term operation (LTO) of existing nuclear power plants (NPP) remains a highly competitive low-carbon investment in the electricity supply.

For nuclear new build, there are many reasons for the short fall of capacity additions compared to the SDS scenario. The most impactful factors are related to the high cost of new nuclear projects, particularly in countries that have not built nuclear plants in recent decades. For those countries that have launched new projects, the experience has been difficult. These first-of-a-kind (FOAK) Generation III projects, particularly in most OECD countries, have been affected by construction delays and cost escalations (see Figure 8.1). Consequently, stakeholder and public confidence in the ability of the nuclear industry to build new projects has been eroded. Additionally, the perception that new nuclear plants carry high project risk dissuades investors and has further reduced the ability of countries to attract financing for future projects.

These issues are not present in those countries that have been building plants continuously. In those countries, with experienced project organisations and well-established supply chains, a number of nuclear projects are delivered in a more predictable manner achieving significant cost reductions. The results of the 2020 edition of *Projected Costs of Generating Electricity* suggest that nuclear power in OECD countries could join this trend and enter in a phase of rapid learning over the next decade (see Figure 8.1). With several projects near completion that have served to establish industrial capabilities, future projects could take advantage of the experience gained and be more competitive.

Figure 8.1: Trend in the projected cost of new nuclear in OECD countries



Source: IEA/NEA (2005, 2010, 2015, 2020).

Lastly, the development of new nuclear technologies is gaining pace. Small modular reactors (SMRs) have been capturing the attention of policymakers as technology options to address part of the challenges observed in recent nuclear projects. With higher share of factory fabrication their delivery model could yield higher predictability and productivity rates. SMRs also offer opportunities to expand the role of nuclear energy for the decarbonisation of the energy mix. This is especially the case in non-electrical applications of hard-to-abate sectors where low-carbon technology options are more limited. However, while significant progress has been made in the validation of the first designs, many challenges remain. The completion of first prototypes during the 2020s will therefore be essential in the demonstration of the expected benefits of SMRs.

Overall, countries willing to pursue the nuclear option have at their disposal three main technology solutions to reduce cost at the system and plant level with nuclear power:

1. *LTO of existing nuclear assets*. Most cost-effective solution but representing a limited pool of projects according to the findings of the NEA Expert Group on Maintaining Low-Carbon Generation Capacity through LTO of Nuclear Power Plants: Economic, Technical and Policy Aspects (EGLTO).

2. *Cost reductions in large Generation III reactors*. These types of projects are moving from FOAK conditions and could leverage a series of incremental strategies to improve their economic performance as documented in the NEA study *Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders* (NEA, 2020).

3. *Technology innovation through SMRs*. Thanks to their technical features, these reactor concepts may provide further cost reduction and extend the value proposition of nuclear power. However, several challenges need to be overcome in order to reach commercial viability.

8.2 Long-term operation (LTO) of existing nuclear assets: The most cost-effective low-carbon solution

8.2.1 Definition and technical considerations

The long-term operation (LTO) of NPPs can be defined as "operation beyond an established time frame which has been justified by a comprehensive safety assessment" (IAEA, 2008). The period usually considered is the so-called design lifetime in which the facility (or a component) is expected to perform according to their technical specification. For light water reactors (LWRs), the dominant technology around the world, the design life typically considered is 40 years.

This value is based on initial design assumptions related to the lifetime of some key components that cannot be replaced such as the reactor pressure vessel. This, however, should not be confounded with the remaining useful life of a component during which it is expected to safely provided its intended function[1] and that is, in most cases, greater than 40 years.

Trends in the United States, where 90% of fleet has been granted lifetime extensions from 40 to 60 years, and an increasing number of units are envisaging 80 years of operation, confirm the absence of any major technical barriers to LTO.

8.2.2 Economic considerations and evaluation of LTO costs

In 2018, the NEA Ad hoc Expert Group on Maintaining Low-Carbon Generation Capacity through LTO of Nuclear Power Plants: Economic, Technical and Policy Aspects (EGLTO) was established, among other reasons, with the purpose to provide updated cost figures of extended operation of the existing fleet. The present analysis builds on the preliminary findings and results of the EGLTO's final report (NEA, forthcoming a).

In line with the object of this report, the present economic analysis of LTO is focused on the evaluation of LTO investment and the LCOE metric. Nevertheless, it is important to highlight that a more comprehensive analysis of the economics of LTO should take into account other economic criteria such as market conditions, the impact of LTO refurbishments on the availability of the plants and a detailed risk assessment (NEA, 2012).

Once a nuclear power plant has been built, costs are low and stable. However, as the end of the design lifetime approaches, investment costs suddenly increase as operators perform major refurbishments to safely extend the lifetime of the plant.[2] These expenses correspond to the LTO investment costs. In general, their evaluation is not a simple task. The first challenge is to isolate the envelope of the LTO investments. By definition, LTO investments are those that contribute to the extension of the lifetime of a plant beyond 40 years. They are usually different from replacements carried out as part of regular maintenance procedures (see Figure 8.2) as they involve heavier components and more extended outages. Typical SSCs replaced during LTO refurbishments include:

- Mechanical equipment: upper vessel heads, steam generators, turbines, pumps, motors, large diameter piping, etc.
- Electrical equipment: Alternators, transformers, high voltage posts, electrical boards, etc.

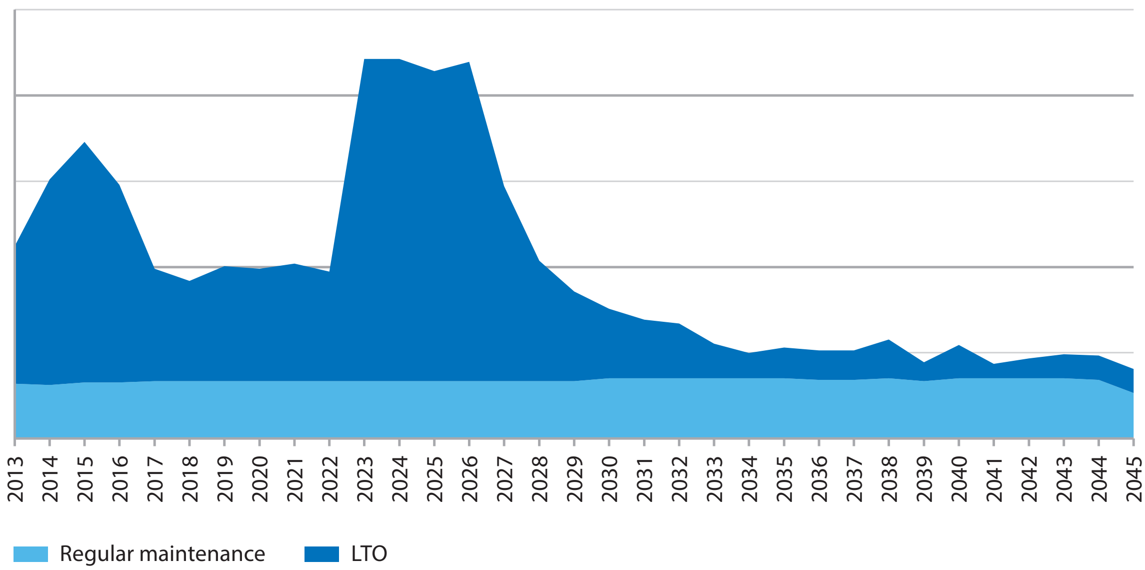
1. The Western European Nuclear Regulators' Association underlines that there may be no real cliff edge effect due to ageing when a nuclear power plant is being operated longer than the initial design lifetime of some of its components. It also suggests that the initial design lifetime of the reactor vessel may no longer be relevant as being periodically re-evaluated considering actual plant operation and condition as well as current knowledge about ageing phenomena (WENRA, 2011).

2. These cost trends are quite specific to nuclear technology as they also aligned with regulatory decisions. For other technologies, for instance, LTO expenses are simply part of their fixed operation and maintenance costs.

- Instrumentation and control: control room, cables, sensors, etc.
- Civil works: including cooling towers
- Post Fukushima:[3] filter vents, diesel generators and other special protections

Labour and indirect cost are also part of the scope of the LTO investment and they can account for significant share. Main indirect cost items involve project management, regulatory and licensing interfaces and initial engineering efforts necessary to evaluate to extent of the LTO refurbishment.

Figure 8.2: Distribution of LTO investments



Source: NEA (Forthcoming, a)

While this categorisation is clear, its application may face some limitations in practice. It is important to underline that the scope of an LTO programme is not universal and varies from a project to another depending on the initial conditions of the plant and the regulatory framework. At the same time, LTO investments are usually performed alongside other plant enhancements (i.e. power uprates, flexible operations, etc.) and safety upgrades. The accounting conventions adopted by some utilities may not differentiate LTO expenses from the rest making these cost data difficult to retrieve.

Another issue lies in the time distribution of LTO investments. In fact, depending on the context and plant situation, the expenditure profile could be upfront at the end of the initial design lifetime, or spread over several years before the LTO decision (see Figure 8.2). As such, it is possible to identify some NPPs for which the actual LTO investments at the end of the design lifetime are very low as operators have been investing on a continuous basis in order to maximise the lifetime of the asset. In this case, the evaluation of the LTO costs will require the analysis of the investment patterns of the plant over time and the identification of those investments relevant to LTO for the application of the LCOE formula.

3. One could argue that post-Fukushima is not an LTO cost per se as is not related to ageing. In fact, most of these upgrades are not necessary to extend the life of the plant. However, under current regulatory framework, no lifetime extension would be granted without complying with post-Fukushima standards.

Evidence from the Loviisa project in Finland indicates that an increase of the operational lifetime of a NPP has no major impact on decommissioning costs (NEA, 2016). Costs associated with the dismantling and handling of contaminated components generated during the refurbishment process are generally directly included in LTO investments. As such, it can be considered that the initial decommissioning costs have been largely provisioned during the initial lifetime period, and that there are no additional costs during the LTO period. Furthermore, from a financial perspective, the lifetime extension period allows for a reduction of the provisions allocated to the decommissioning fund.[4]

Taking into account all these considerations and the evidence collected from several case studies, the EGLTO concluded that an average overnight LTO investment could range from USD 450 per kWe to USD 950 per kWe. This variability could be largely explained by the differences in the scope of LTO investments due to the reasons indicated previously. Moreover, these numbers have been estimated in a conservative way as they consider all plant enhancements as LTO expenses.[5] Table 8.1 shows the associated LTO LCOE for different real discount rates, capacity factors and lifetime extensions periods.[6] The assumptions are summarised at the bottom of the table. The case with a capacity factor of 75% is a sensitivity analysis that captures short-term economic outlook in some OECD countries.

Overall, these results confirm that LTO of NPPs remains one of the most competitive options of low-carbon electricity generation, in line with recent IEA findings (IEA, 2019).

Table 8.1: LTO LCOE values for LWRs as a function of the lifetime extension period, discount rate, overnight costs and capacity factor

Overnight LTO investment costs (USD/kWe)	LWR LTO LCOE (USD/MWh)					
	10 years			20 years		
	Discount rate			Discount rate		
	3%	7%	10%	3%	7%	10%
	Capacity factor = 85%					
450	29.4	31.2	32.6	26.4	28.6	29.7
700	33.4	36.1	38.3	28.7	31.4	33.8
950	37.4	41.1	44.1	31.0	34.7	38.0
	Capacity factor = 75%					
450	31.9	33.9	35.5	28.4	30.5	32.2
700	36.5	39.5	42.0	31.0	34.2	36.9
950	41.0	45.1	48.5	33.6	37.9	41.6
Min.	**29.4**			**26.4**		
Max.	**48.5**			**41.6**		

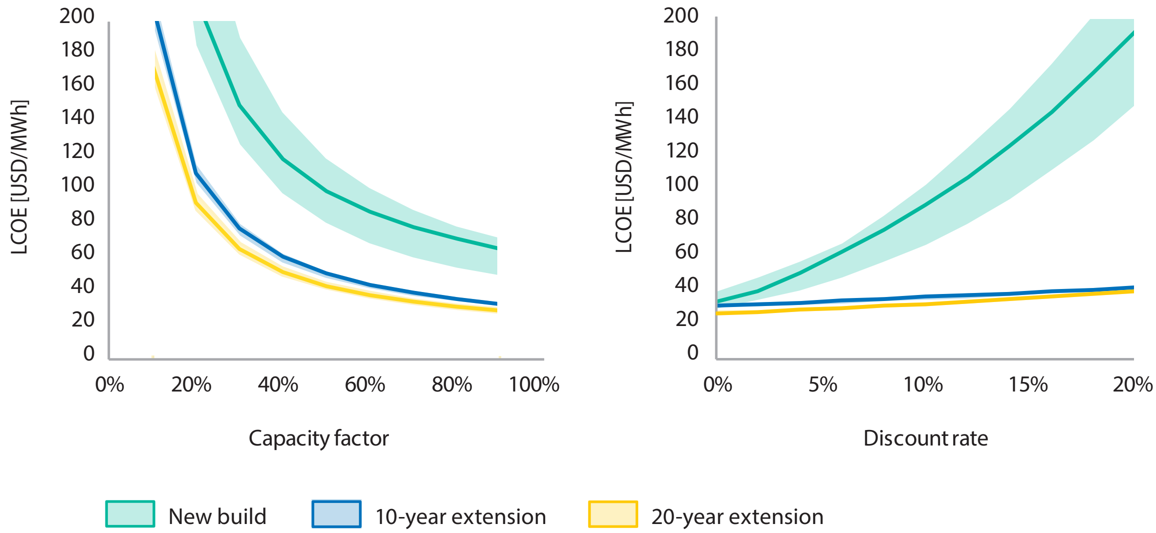
Note: These values have been computed assuming a refurbishment period of two years, fixed O&M costs of USD 85/kWe variable O&M of USD 1.5/kWh, front-end fuel costs of USD 7/kWh and back-end fuel cost of USD 2.33/kWh. The overnight LTO investment costs include other plant enhancements beyond LTO and 5% of contingencies. Decommissioning costs have been assumed as completely provisioned during the initial design lifetime. The financial benefits of postponing decommissioning expenses (e.g. returns of the funds assets) are not included in the LCOE calculations.

4. In an audit on the evaluation of the decommissioning costs in France, government experts estimated that a lifetime extension from 40 to 50 years could lead to a reduction of the required provisions for decommissioning of the existing fleet by EUR 3.2 billion (DGEC, 2015). From a LCOE perspective, this would translate into a negative cost for the decommissioning of nuclear plants that enter LTO.

5. This means that power uprates, safety upgrades and other type of plant enhancements not meant to extend the life of the plant are included in the overnight costs of LTO considered in the present study.

6. The lifetime extension period presented in Table 8.1 (i.e. 10 and 20 years) are the typical values considered for LWRs reactors in most countries. Other technologies such as PHWRs and VVERs take into account life extensions of 30 years.

Figure 8.3: Sensitivity of LCOE of new build and LTO of NPPs to capacity factor (left) **and discount rate** (right)



Note: The band width gives an idea of the variability of the data collected in the present study. The bold line corresponds to the median of all LCOE values.

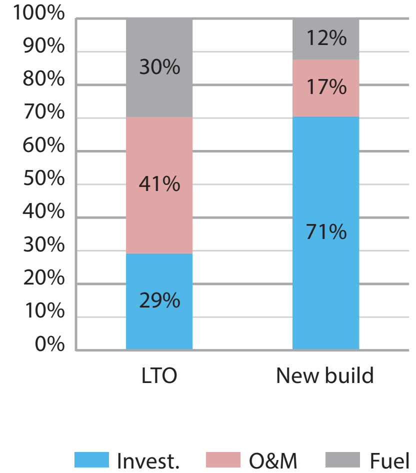
The sensitivity analysis included in Figure 8.3 gives an appreciation of the first-order impact of the capacity factor (or electricity price, looking at the value side) on the economic performance of LTO. This behaviour supports the early closures observed in the United States and in Sweden owing to degraded market conditions. The impact can be attenuated with longer lifetime extension periods. The dominance of parameters governing the revenue side over the costs also indicates that operators have an incentive to perform power uprates (or any other plant enhancement increasing the availability of the plant) during LTO projects as this will improve attractiveness of the business case (IAEA, 2018).

In contrast, LTO is slightly impacted by variations in the discount rate. This can be explained by the cost structure of the existing nuclear fleet. While capital costs dominate in the generation cost of new nuclear, operational expenditures represent 70% of the costs for the existing fleet (see Figure 8.4, right). Also, this cost structure is somehow similar to the one of fossil fuel plants which confers an economic advantage allowing to better withstand market shifts and improving the economic rationale of flexible operations which, overall, increases the value option of extending the life of the existing fleet.

Finally, with LTO bands being considerably thinner than for new nuclear, it is possible to conclude that LTO refurbishments are more predictable and face lower project risks. With around 100 reactors older than 40 years, the industry has benefited from a volume of projects sufficiently large to ensure learning effects and sustain supply chain capabilities over time. A comparison with NEA (2012) values confirms these trends showing that LTO costs are lower and far better contained today (see Figure 8.4, left).

Figure 8.4: Evolution of LTO LCOE for different lifetime extension periods (left) **and cost profile of lifetime extensions versus new nuclear** (right)

Note: LTO 2012 values from NEA (2012) have been computed for overnight costs ranging from USD_{2010}500 to USD_{2010}1 090 per kWe, discount rates of 3% and 8% and a capacity factor of 85%. LTO 2020 values cover the results presented in Table 8.1.



Note: Overnight costs of USD 700 and USD 4 500 per kWe for LTO and new build, respectively. Real discount rate of 7% at a capacity factor of 85%. The operational expenditures assumptions are detailed in Table 8.1.

8.3 Cost reductions in large Generation III reactors: Significant cost reduction opportunities in the short and long terms

Nuclear new build in OECD countries is at a critical juncture with the completion of several FOAK projects. These projects were initiated after a long hiatus for nuclear construction that significantly eroded the nuclear supply chain and the industry's capabilities. This is reinforced by a de-industrialisation trend in some OECD countries. In addition, initial budget estimates were heavily influenced by the lack of design maturity and execution planning at the time of the construction start, as well as the increasingly uncertain political context. The sums invested in these FOAK projects have served to finance not only the construction of the reactors themselves, but also to rebuild these capabilities. Understanding the prospects and drivers of nuclear construction costs reduction is therefore key to addressing the risk perception of near-term nuclear new build projects.

8.3.1 Recent trends in nuclear new build

The trend in projected overnight construction costs is presented in Figure 8.1 above for OECD countries and shows a significant increase in costs between 2010 and 2015. The same applies to the construction delays. The announced schedules for these projects were typically of 5-6 years. Those already in operation were built in around 10 years. Some of them are still under development and could be tentatively delivered more than 15 years after their construction start.

Some of these recent projects are presented in Table 8.2, illustrating a similar trend in projected overnight construction costs for OECD countries. Differences between initial announced budgets and ex-post construction costs reflect the cost escalations that have affected these projects, but the gap should be analysed cautiously as the initial announced budgets are the result of very specific conditions.

Table 8.2: Construction costs of recent FOAK Generation III/III+ projects

Type	Country	Unit	Construction start	Initial announced construction time	Ex-post construction time	Power (MWe)	Initial announced budget (USD/kWe)	Actual construction cost (USD/kWe)
AP 1000	China	Sanmen 1, 2	2009	5	9	2 x 1 000	2 044	3 154
	United States	Vogtle 3, 4	2013	4	8/9*	2 x 1 117	4 300	8 600
APR 1400	Korea	Shin Kori 3, 4	2008	5	8/10	2 x 1 340	1 828	2 410
EPR	Finland	Olkiluoto 3	2005	5	16*	1 x 1 630	2 020	>5 723
	France	Flamanville 3	2007	5	15*	1 x 1 600	1 886	8 620
	China	Taishan 1, 2	2009	4.5	9	2 x 1 660	1 960	3 222
VVER 1200	Russia	Novovoro-nezh II-1 & 2	2008	4	8/10	2 x 1 114	2 244	**

* Estimate. ** No data available.

Notes: MWe = megawatt electrical capacity. kWe = kilowatt electrical capacity.

Source: NEA (2020).

As a result, stakeholder and public confidence in the capability of the nuclear industry to deliver new build projects has been eroded. This situation has also raised the level of perceived investment risk, intimidating investors and further reducing the chances of attracting financing for future projects.

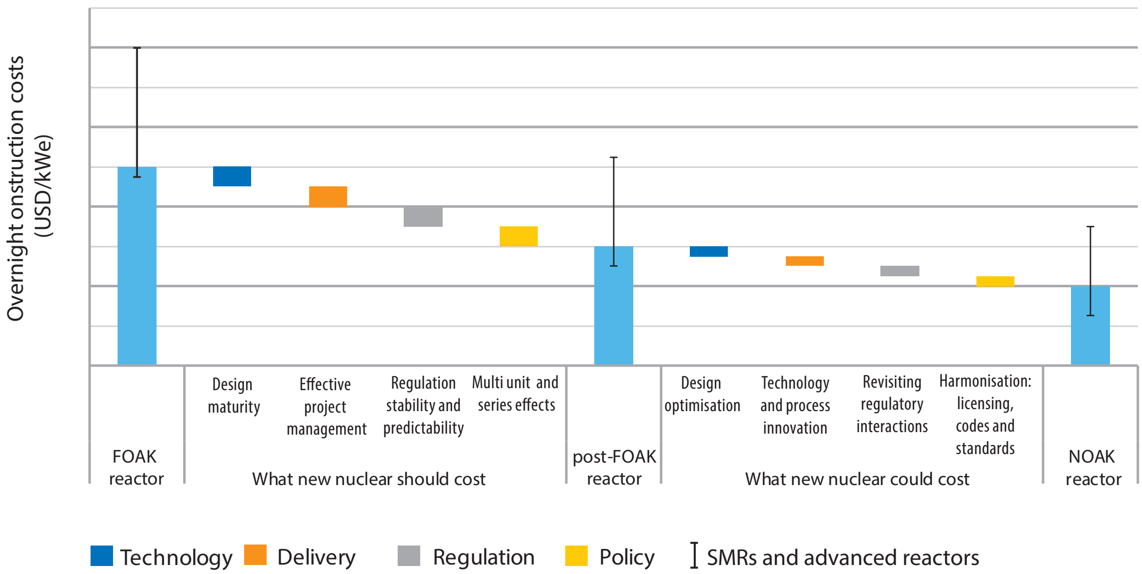
However, if the nuclear industry in western OECD countries takes advantage of the accumulated experience and the lessons learnt from recent projects, nuclear plant construction can enter in a more rapid learning phase allowing it to deliver the next projects at lower cost and with significantly less uncertainties.

In several countries, nuclear power is delivered today essentially on time and on budget. In China and Korea, a significant number of projects have been executed in less than six years over the last decade. These differences could be explained by alternative design features (in terms of constructability, for example). However, even for a same design, there are notable differences depending on the country in which the reactor is being built. This gap cannot be explained solely by site-specific conditions inducing slight design modifications. Thus, the challenges experienced in western OECD countries in delivering new nuclear are not inherent to the technology itself but rather depend on the conditions in which these projects are developed and executed, and on the interactions between the different stakeholders.

8.3.2 Key drivers for reducing the construction costs of nuclear new build

The NEA study *Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders* (NEA, 2020) identifies eight drivers to unlock positive learning as well as continuous improvement on large Generation III reactor projects. These drivers are summarised in Figure 8.5.

Figure 8.5: Nuclear cost and risk reduction drivers



Note: kWe = kilowatt electrical capacity.

Source: NEA (2020).

Lessons learnt from historical and recent nuclear new build projects

Historical and recent evidence suggest that the lessons learnt are well understood and can be easily implemented in future projects. Several non-OECD countries delivering competitive nuclear projects today, are already taking advantage of them. As a result, the next nuclear project should be delivered at lower costs after entering in a phase of more rapid learning. Key lessons learnt include:

- Design maturity: The detailed design has to be completed and ready for construction. This implies early involvement with the supply chain during the design process in order to integrate the necessary requirements to improve constructability.
- Project management: The design also requires a robust implementation strategy with a clear definition of responsibilities and identification of competences at all levels and stages of the project. A strong and experienced project management team is essential to ensure its proper execution and to deal effectively with all interfaces and unexpected risks.
- Regulation: Predictability and stability of the regulatory regime is a precondition for the implementation of these measures.
- Multi-unit and series effect: Once sufficient level of design maturity has been achieved, there is a strong opportunity in freezing the design configuration and systematically replicate it as many times as possible building up supply chain capabilities.

In the near term (early 2020s), considering these lessons learnt, the most effective way to achieve construction costs reduction is to develop a nuclear programme that takes advantage of serial construction with multi-unit projects on the same site, and/or construction of the same reactor design on several sites.

Cost reduction opportunities in the short term (up to 2030)

In the short term (up to 2030), with the previous drivers and conditions already in place, the cost of nuclear projects could be further reduced.

In technology and process innovation, a range of cost reduction opportunities could be exploited through the interplay between the reactor design and the associated delivery processes. These drivers are not necessarily sequential and can be mobilised even during early planning stages in order to accelerate learning.

There is evidence that countries in more advanced stages of learning are already benefiting from these opportunities and working on a continuous improvement basis similar to other industries. In addition, in order to maximise the potential of cost reduction, the right balance between improvement and replication needs to be found in order not to alter the positive learning dynamics. Timely decision making has also to be acknowledged with the objective to ensure the right pace of new construction and diminish the risk of over engineering.

At the reactor design level, the experience gathered in the first constructions can be used to reach higher levels of simplification, standardisation and modularisation as well as to integrate the latest technical advances. Organisational efficiencies can also be unlocked through a new set of innovative processes.

Additional opportunities in the longer run (beyond 2030)

Longer-term (beyond 2030) cost reductions are also possible. There are indications that countries in more advanced learning stages are moving in this direction.

Further cost reductions can be achieved by means of higher levels of harmonisation in codes and standards, and licensing regimes. Other highly regulated activities such as the aviation sector have already undertaken significant efforts in this field with positive results. Without neglecting the strong political dimension and the need to protect the sovereignty of national regulators, international collaboration for regulatory harmonisation has demonstrated that it is possible to reach common positions in some areas.[7]

8.4 Economic perspectives on small modular reactors (SMRs)

Small Modular Reactors (SMRs) are defined as nuclear reactors with a power output between 10 MWe and 300 MWe. Designs with power outputs smaller than 10 MWe, often designed for semi-autonomous operation, have been referred to as Micro Modular Reactors (MMRs).

SMRs are often designed for factory fabrication, taking advantage of the benefits of economies of series, to be transported and assembled on site, resulting in shorter construction times. This is one of the key elements that might prove to make SMRs cost competitive with other energy options.

7. See Multinational Design Evaluation Programme, www.oecd-nea.org/mdep/common-positions/PUBLIC%20USE%20DCP-EPR-01-%20EPR%20Instrumentation%20and%20Controls%20Design.pdf.

The most mature SMR concepts are based on LWR technology. Other concepts are Generation IV reactors that incorporate alternative coolants (i.e. liquid metal, gas or molten salts) and advanced fuels. SMR deployment configuration can vary between single-unit installations, multi-module plants, or mobile power sets such as floating (i.e. barge-mounted) units. In 2018, the International Atomic Energy Agency (IAEA) identified more than 50 concepts under development with different technology and licensing readiness levels, including four concepts that were under construction at the time.

Due to smaller reactor cores, very large water inventories and lower power densities, LWR SMRs may benefit from reduced shielding requirements and reduced or eliminated offsite Emergency Planning Zones (EPZ) which, in turn, will result in added flexibility for the siting of these reactors. SMR designs often include an integral nuclear steam supply system and take advantage of overall system simplification. Inherent passive safety systems provide SMRs with greater and, in some cases indefinite, coping times in case of a loss of offsite power. Many SMRs are designed to be installed below-grade resulting in higher physical protection and protection from external hazards.

8.4.1 Key economics drivers of SMRs

While smaller cores bring the benefits described above, they also have a negative effect on the economic competitiveness of the unit. Reactor designers have traditionally scaled reactors up to larger sizes to take advantage of the economies of scale. In other words, because the fixed costs associated with a nuclear reactor grow very slowly as the size of the reactor increases, it makes sense to increase the output of the reactor to reduce as much as possible the cost per unit of electricity produced. To counterbalance the impact of diseconomies of scale, the business case of SMRs is supported by economies of series production, which in turn relies on design simplification, standardisation and modularisation.

The benefits of serial construction have been well documented in other industries, such as the shipbuilding and aircraft industries, in which serial manufacturing have resulted in learning rates between 10 and 20% (NNL, 2014). For the first SMR units, serial production may also allow to amortise non-recurrent costs, such as research, development and design certification costs.

To support serial construction and achieve learning rates of the same order of magnitude as these other industries, several specific drivers have been identified as summarised in Figure 8.5 below:

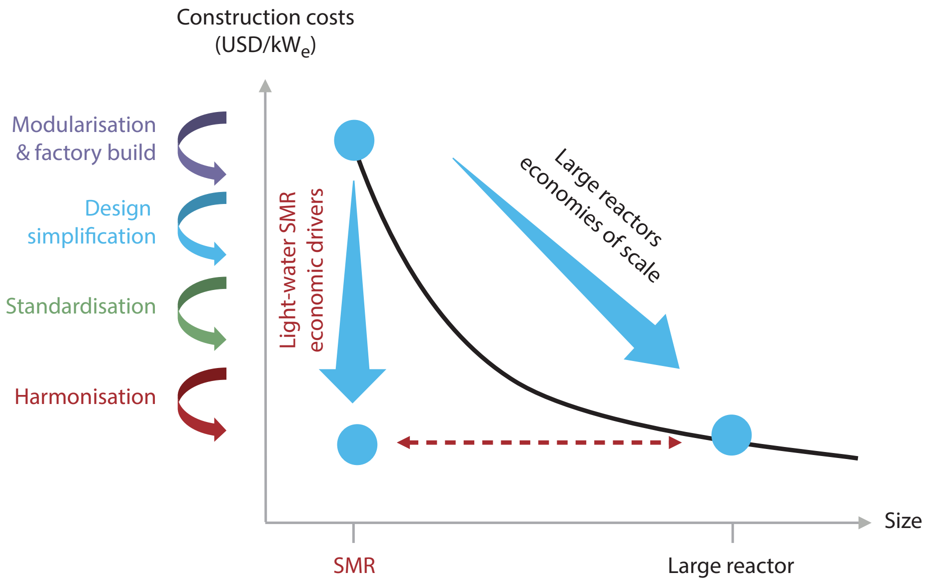
- Simplification: Passive mechanism improvements and greater design integration would reduce the number of components and result in containment building savings.
- Standardisation: The lower power output of SMRs reduces the need to adapt to local site conditions, raising the level of design standardisation compared with large reactors.
- Modularisation: Smaller SMR size means that transporting their modules would be easier than for large reactors. In fact, the degree of modularisation increases considerably for power outputs of less than 500 megawatts of electrical capacity (MWe). This trend could be improved with more aggressive modularisation techniques tailored to the logistical constrains and transport standards of each country. It is estimated that 60-80% factory fabrication levels are possible for SMRs (with power outputs below 300 MWe) (Lloyd, 2019). This would also facilitate the implementation of advanced manufacturing techniques such as electron beam welding and diode laser cladding by 2025 (EY, 2016). Others, such as powder-metallurgy hot isostatic pressing and additive manufacturing, are at lower technology readiness levels but significant progress is being made (EPRI, 2018).
- Harmonisation: Having access to a global market is necessary to foster series-production economies, but this is possible only with regulatory and industrial harmonisation.

In that respect, as highlighted in Figure 8.4, it is important to stress that SMR construction costs will be impacted by the key cost drivers identified for large Generation III nuclear reactors. However, some specific drivers will carry more weight. This is especially the case of the series effect, as well as simplification, standardisation, modularisation and harmonisation.

Attaining these economic benefits will require a co-ordinated effort between the different stakeholders, as well as a dedicated policy and regulatory framework. It is also imperative to appropriately estimate the size of the global market required to establish a robust supply chain and sustainable construction know-how that result in cost-competitive capital costs.

If SMRs can be serially manufactured in a manner similar to commercial aircraft, the economic benefits are significant. This requires, however, the market for a single design to be relatively large, which denotes the need for a global market. For this to be realised, regulators will need to consider how they might co-operate to enable a true global market for nuclear technologies.

Figure 8.6: SMR economic drivers that help compensate diseconomies of scale



Source: NEA (2020).

8.4.2 Market potential for SMRs: Broadening the value proposition of nuclear power

The smaller size and the shorter delivery times predicted make the upfront investments needed for SMRs smaller. As a result, customers and investors may face lower financial risk, which could make SMRs a more affordable and attractive option. Given their smaller size, SMRs also offer more flexibility to meet demand growth in smaller increments, which would also improve their overall business case.

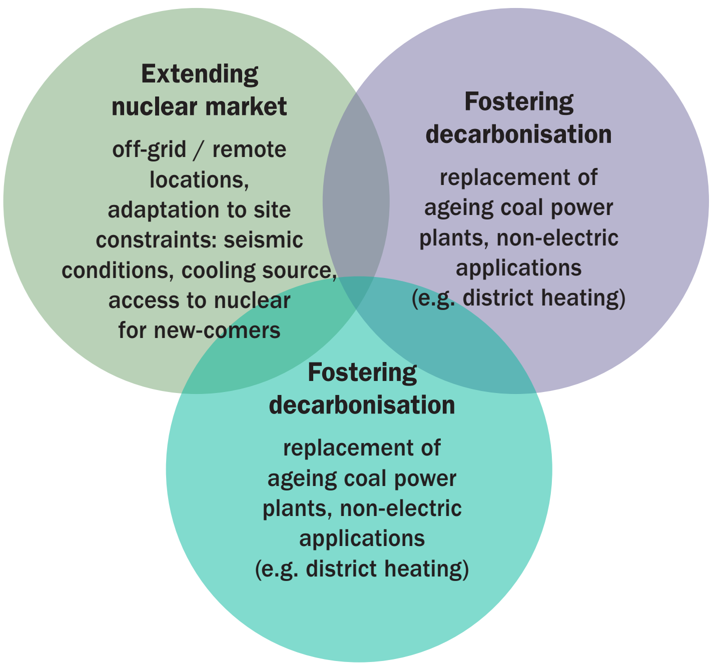
However, the anticipated advantages of series deployment will only be realised if SMRs can take advantage of a global supply chain and a global customer basis, which require a streamlined multinational licensing framework and co-ordinated international codes and standards for the manufacture of systems and components.

Although most SMR technologies are in the relatively early stages of development and significant uncertainties remain for their market outlook, at least three potential applications have been identified for SMRs, in addition to the traditional role of providing baseload electricity:

- Decarbonising energy systems by replacing coal plants and providing power for district heating and desalination applications. Most advanced designs such as non-LWR SMRs, that are designed to have higher operational temperatures, could supply process heat for industrial sectors where substituting carbon-intensive sources of energy would otherwise not be possible.
- Complementing the penetration of variable renewable energy (VRE) by providing system benefits based on the flexible operation of SMRs and the possibility to be part of an integrated portfolio of solutions in "hybrid" energy systems.
- Facilitating the expansion of the nuclear sector in regions where economic, geographical and/or grid-related constraints do not allow the use of large nuclear power plants. For such markets, SMRs may already be a cost-competitive way to replace diesel generators to produce electricity, heat and fresh water.

These different market drivers are therefore expected to broaden the value proposition of nuclear power as part of future integrated energy systems, supporting in particular the decarbonisation of hard-to-abate sectors. SMRs should therefore be seen as complementary to large Generation III nuclear power plants as they will address different market needs.

Figure 8.7: The market opportunities for SMRs



Source: NEA (Forthcoming, b).

8.5 Conclusions

The general cost projections and specific cost drivers identified in this chapter suggest that nuclear power support cost-effective decarbonisation in several complementary ways.

First, LTO remains one of the most cost-competitive options to generate low-carbon dispatchable electricity in many regions with a LCOE ranging USD 30-50/MWh. Thanks to lower CAPEX needs and back up by a solid industrial infrastructure, LTO faces limited project risks and represents a significant pool of “shovel-ready” projects to maintain SDS emissions targets within reach.

Second, thanks to the experience gained with recent FOAK projects, new nuclear can enter in a phase of rapid learning in western OECD countries with near-term overnight costs reductions of 20% to 30% compared to today’s levels. Moreover, leveraging several factors that arise at the technical, organisation and regulatory level could unlock additional cost reductions in new projects alongside with higher predictability in their delivery. More active government intervention in risk allocation and mitigation strategies for new projects will also have significant impact on financing. As result, financing costs, which can represent 80% of the total investment costs, could notably fall further improving the economic performance of nuclear.

Third, SMRs propose cost and risk reductions with factory built construction and higher affordability of the projects. Nevertheless, while some of these benefits have been documented in other industries, they still need to be proven in the nuclear sector. The construction of first prototypes may materialise some of the announce benefits of SMRs and thus accelerate their commercial viability. Government support is also essential on this front.

Countries envisaging to pursue the nuclear option will benefit from the mobilisation of these three complementary solutions. In these countries, while LTO may be more economically attractive, new nuclear projects are required to prepare the renewal of the fleets and ensure that nuclear power is on track to meet its long term contribution to decarbonisation. Progress made with the development of large Generation III reactors will also support the development of SMRs as most of the cost reductions drivers are not technology-specific. Finally, SMRs have specific value propositions and target specific markets and applications that could accelerate the decarbonisation of hard-to-abate sectors.

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Sector coupling and electrification: Understanding how the electricity sector can drive the decarbonisation of the overall economy

Sector coupling, the use of electricity in sectors such as transport, residential heating and the use of hydrogen, is integrating the electricity sector in new ways into the wider economy.

This specific form of technological progress promises significant benefits in terms of economic efficiency and reduction of greenhouse gas emissions. However, it also poses a considerable challenge in analysing the new economic constellations in a manner that informs social preference formation and political decision making in a pertinent manner. Those new constellations are no longer amenable to conventional approaches of analysis based on the modelling of individual sectors according to well-established methodologies such as sector-specific optimisation models. Recently, however, a systematic effort to come to terms at the conceptual level with these new developments and to prepare them for societal decision making has been undertaken by various organisations, and is yielding relevant new results (OECD, 2012 and 2019). It resulted in the new scenarios being published recently at national and European level, with more attention to economic analysis.

In France, this effort has been lead in particular by the Réseau de Transport d'Electricité (RTE), the transmission system operator for electricity, which has invested heavily over the last decade in new capabilities for modelling and policy analysis around the generation, transmission and consumption of electricity. The following chapter provides an overview of recent advances in analysing and understanding the impacts, benefits and constraints of sector coupling with a focus on the areas of transport, residential heating as well as the production, storage and use of hydrogen.

This chapter also examines how those analyses led to complex questions regarding the best way to "allocate" the low-carbon electricity generated in a given European member state, while taking into account the fact that the power system is more and more interconnected at European level and where emissions are partly governed by a joint mechanism (the EU ETS) and partly by national schemes.

9.1 The context in France: From a debate about the electricity sector to a coherent policy to decarbonise the overall economy

Context in France

Important steps have been made recently in France regarding scenario modelling, cost-assessment and economic-based policy making in the field of energy transition.

Part of this work has been made through successive reports published by RTE, acting on behalf of a broad mandate provided for by law.

It initially responded to a precise need: (i) articulating public objectives for the evolution of the electricity generation mix, regarding both the development of new renewables (wind, solar PV) and the reduction of the share of nuclear power; and (ii) integrating those prospects in a coherent picture that would include significant reductions in CO_2 emissions at country level to meet the goals of the 2015 Paris Agreement.

When this work was initiated in 2017, there was no reference scenario for the electricity sector fit for a broad public discussion. On the one hand, the long-term scenarios previously elaborated by RTE in 2014 were essentially adequacy studies and were not designed for forming the basis of a public debate. On the other hand, other scenarios used in the debate often lacked precise modelling of the power sector, failed to take into account the results of existing adequacy studies, or did not integrate correctly the European scale of power system operation. This is to say that the balance between nuclear and renewables was essentially addressed under a political framework.

Secondly, studies including a detailed economic analysis were rare and no cost-assessment methodology had been explicitly agreed upon among stakeholders. In the economic field, the pros and cons of the different options for decarbonising energy were thus largely undocumented.

Lastly, the discussion mainly concentrated on electricity in an isolated manner – which is not surprising given the political nature of the debate on nuclear and renewables – but failed to address key challenges for decarbonising the overall economy, and consequently did not address properly sectoral integration.

Building new scenarios for the electricity sector

It is in this context that RTE initiated a large work of scenario building for the electricity sector in 2017, in consultation with stakeholders. Before moving towards the analysis of sector coupling as such it was deemed essential to reconstruct a solid basis in traditional electricity sector analysis.

This resulted in November 2017 in the publication of five scenarios for the power sector on the 2020-2035 period (RTE, 2017). The scenarios varied according to when the power mix would be "rebalanced", that is to say when it would reach the politically defined objectives of 50% for the share of nuclear power in the overall electricity generation, and 40% for the share of renewables. This allowed very different policy options to be addressed, from a strategy based to a large extent on continuing with the existing nuclear reactors fleet – complemented with the progressive addition of renewables (*Volt* scenario) - to a complete nuclear phase-out over the next 20 years (*Watt* scenario), Each scenario was analysed on three dimensions: technical feasibility and performances regarding security of supply, CO_2 emissions for the power sector, and costs for the society.

This work formed the basis of the elaboration of the new multiannual energy plan (PPE) by the French government. In November 2017, the government announced that the 50% target would be postponed beyond 2025, as it would otherwise lead to maintaining coal-fired generation plants and building new gas turbines; the reverse to a coherent policy to reduce CO_2 emissions. In early 2018, it selected two out of the five scenarios (named *Ampère* and *Volt*) for public debate. In mid-2018, the draft provisions for the PPE were published, the final scenario for electricity being a combination between *Volt* and *Ampère*. In April 2020, the PPE was published and came into force.

This new set of scenarios helped taking important decisions on electricity in a given framework, the debate on the share of nuclear power versus renewables in electricity generation, which is very specific to France. Yet in the meantime, the policy discussion had partly shifted towards carbon neutrality, with many European countries (including France) committing themselves to achieve net-zero emissions by 2050 and the European Union proposing a large policy change through the European Green Deal project.

From sector-specific objectives to the broader goal of carbon neutrality

Considering the broader perspective of achieving net zero emissions by 2050, the scenarios established in 2017 presented obvious limitations.

First, they focus on the 2020-2035 timeframe. This is a key period for obtaining significant results on CO_2 emissions, but it obviously needs to be complemented, for example to integrate structural transformations on sector coupling that could materialise in the 2030s – but more probably in the 2040s.

Second and more importantly, they do not differentiate well on the metric of CO_2 emissions for the electricity sector at national level. The reason is specific to France and the "initial" state of decarbonisation in electricity generation, which was already 93% carbon-free. Rebalancing the electricity mix (higher share of renewables, reduction of the share of nuclear power) does not provide *per se* gains on CO_2 emissions: only the decommissioning of the last coal-fired generation units (scheduled for 2022), and, to a lesser degree, the anticipated reduction in the use of gas-powered CCGTs, will have a marked effect on CO_2 emissions for electricity generation, bringing them from around 25 Mt CO_2/y in the period 2010-2020 to around 10-15 Mt CO_2 by around 2025-2030. Therefore, contrary to other countries such as Germany, Italy, Spain, or the United Kingdom where developing renewables in the power mix directly leads to reduced CO_2 emissions, there is no substantial gain on CO_2 emission to come from electricity generation.

Focusing on GHG emissions for electricity generation in France only may thus provide a bias in the evaluation, by failing to take into accounts two important results:

1. Changes in the electricity mix in France may have a limited effect on GHG emissions at national level, but this is no longer the case at European level. Developing wind and solar PV, if it is not compensated by equivalent decommissioning of nuclear units, brings electricity exports up and mainly helps reducing load factors for gas- and coal-fired generation units at EU level. Accordingly, in some of the scenarios studied by RTE, a massive increase in electricity exports from France to other countries would occur from 2025 onwards and could culminate to levels well beyond 100 TWh/yr in 2035 (compared to around 60 TWh/yr presently).
2. The different policy options on electricity generation have impact on the ability to decarbonise the wider economy, by allowing more transfers towards electricity as a final energy (in transportation or buildings), a more ambitious sector coupling in the form of power-to-X (for example with low-carbon hydrogen).

The different scenarios established in 2017 have thus different potentials and interests with regard to their contribution to reducing GHG emissions at the level of the overall European economy. Taking into account this broader perspective is even more important now that the electricity sector forms the basis of nearly all scenarios of carbon neutrality by 2050, with a development of direct electrification and power-to-X to a large extent (EC, 2018; IEA, 2019a; ENTSO-E & ENTSO-G, 2020).

In order to address this new nature of the debate and complement the work on scenario-building presented in 2017, RTE has since launched three dedicated studies on new uses for electricity, including power-to-hydrogen: the first on electric vehicles (EVs), the second on low-carbon hydrogen, and the third on buildings and heating. Those three studies have the objective of providing an in-depth study of the technical, economic and environmental consequences of those transfers of use. They require (1) a methodology to provide a thorough assessment of CO_2 emissions reduction beyond the power sector (including life-cycles assessment) and (2) a methodology to identify the associated costs for the power sector and beyond.

This work is a first step before an unprecedented (and ongoing) study of new scenarios for 2050, with and without new nuclear units, to reach carbon neutrality.

9.2 Benchmarking scenarios: The need for a method to analyse impacts at the system level

In France, electricity is currently largely decarbonised. Renewables (wind and PV) and nuclear energy are the two options considered for this performance to remain on the long run. Key policy elements at stake are different depending on the period considered:

- In the short to medium term (2020-2035), the public debate on the electricity mix is mostly about new renewables and *existing* nuclear assets and the best way to diversify electricity generation, which is based at 70% from nuclear power;
- At longer horizons (2040, 2050, 2060), the debate focuses on the (possible) competition between renewables and *new* nuclear units to achieve net zero, considering that most of the existing nuclear reactors will be decommissioned in any case at those horizons. Many position papers and stakeholders' expression aim to weight on this debate.

Two opposing approaches… which do not provide relevant results

The simplest approach – still widely used in the public debate and often advocated by supporters of renewables – consists in comparing the generation cost of 1 kWh of nuclear and 1 kWh of wind or solar energy and is often referred to as the levelised cost of energy (LCOE).

At first sight, this indicator is interesting: it takes into account all costs (investments and capital, operation and maintenance, fixed costs and variable/fuel costs) over the lifetime of assets. However, the LCOE approach to compare technologies suffers from major limitations as it does not take into account the cost of integration in the power system (see also the analysis in Chapters 2 and 4 of this report for more details).

Accordingly, simulations conducted for the Bilan prévisionnel have shown that, past a certain level, the massive development of renewables created a "cannibalisation effect", meaning that the continuous increase in zero-marginal cost units of a given types undermines their own value (the continuous development of some units undermine their own value though a collapse in energy prices). This effect has been identified in particular for solar PV during the summer though the calculation of average hourly revenues of PV panels under a large variety of situations. Similarly, other studies[1] have concluded that non-dispatchable units lead to an increasing need for flexibilities or grid reinforcement that come with a cost. As a result, it is widely admitted that even if the LCOE of renewables is below that of new nuclear generator, this brings no indication on the best solution on the economic point of view.

On the other hand and regardless of the academic state of the art, the public debate on energy matters in France has seen some critics of renewables promote an alternative narrative, based on the idea that a system based on renewables would need to be supported by back-up units that would make it strictly equivalent to a 100% dispatchable generation mix. In this approach, each megawatt of variable renewable added has to be complemented by one megawatt of storage, generation or demand response capacity, regardless of the initial situation of the power system and of existing flexibilities. The idea that a gas plant is "behind" every new wind farm is, for example, very often expressed in local public debates in France by opponents to wind energy. This approach has important limitations as it does not quantify precisely the need for capacities and does not consider the existing flexibilities (e.g. hydro reservoirs, interconnectors making it possible to benefit from larger scale optimisation of the power system).

The limitations of the LCOE approach has led economists to think about going beyond the LCOE indicator and develop new methodologies to analyse the costs of the power system. In particular, this is the idea of the method developed by the NEA and by the IEA with the VALCOE (Value-

1. For studies related to France, see, ADEME (2018) and Villavicencio (2017).

Adjusted LCOE) approach which is presented in Chapter 4. This type of approach takes into account the differences in terms of services for the power system by including an estimation of additional costs for capacity, flexibility or even grid and balancing costs.

The VALCOE approach clearly provides a much relevant understanding of the economics of power system and an easy way to compare the average costs of different technologies, including system costs. It helps to identify the cheapest technologies to develop in a marginal approach from the current system.

However, long-term planning of the electricity mix, with the integration of major changes on generation and consumption of energy, still requires additional economic evaluation tools. Using an indicator "by technology" has indeed intrinsic limitations as it actually depends on some sort of allocation of the overall system costs between technologies, raising methodological difficulties. Moreover, both LCOE and VALCOE approaches are not suitable for evaluating the overall economic issues of sector coupling and electrification which are increasingly important for the decarbonisation of the economy. For those reasons, RTE has chosen to use a different method to evaluate the costs and benefits of different transformations of the power system.

9.3 Evaluating the costs at system level: An appropriate approach to compare the true economic costs of different policy options

In order to guide public decision making about planning of the energy mix, RTE has developed, from 2017 onwards, a comprehensive socio-economic approach in its different studies on the evolution of the power system in France. This methodology has been described in documents and discussed with stakeholders. It consists in assessing the overall cost of each scenario, that is to say of each policy option, with a multiplicity of sensibility checks to account for the large uncertainty over some of the key parameters (especially at a distant horizon like 2050). This work allows a comparison of a large set of scenarios, based on homogenous and fully transparent methodology and metrics.

The comparison between the costs of different power generation mix is relevant only if the boundary conditions are identical. This means in particular that the macroscopic conditions (GDP growth, demography, degree of electrification, and prospects on energy efficiency) must be common to all scenarios – which is often not the case in the public debate. It is thus necessary to go through another step of scenario harmonisation and to develop a unique testing ground with homogeneous hypotheses. Therefore, in order to ensure consistency of results, the comparison of costs provided for in *Bilan prévisionnel* 2017 was applied to standardised hypotheses (on GDP, demographics, public policies in other European countries, and electricity consumption).

The analysis performed under this framework provided important results:

- Maintaining a significant part of the existing nuclear capacity until 2035 appears to be a non-regret option from an economic point of view and CO_2 point of view (regardless of key hypotheses on technology costs for renewables and nuclear, the scenarios with the larger part of existing nuclear units were the most affordable ones for the society). It is interesting to note that this conclusion is robust to a change in the expected cost of expanding the lifetime of existing reactors.
- There is a strong rationale for developing renewables such as onshore wind in the coming years, in addition to the current low-carbon generation fleet, in the prospect of decarbonising electricity generation at European level and other sector at national level. Most of the cost of renewables corresponds to the initial take-off of the technology, for example for solar PV or offshore wind. It is important to note that this does not mean that renewables can develop without support schemes in the general case – on the contrary, computation of hourly revenues for low-carbon technologies show that public support remains necessary in many situations as long as carbon does not reach a price on the EU ETS corresponding to its society value.

- The policy option of forbidding the building of any new power plant using fossil fuels has also been found to be economically sound (it does not increase costs from the society perspective).

Comparing scenarios under a uniform testing ground with standardised hypotheses can also pose difficulties, as the interest of developing scenarios is especially to build coherent perspectives and storylines (one scenario may be fit for a given context, but clearly not for another one). For example, RTE tested one scenario of nuclear phasing-out (*Watt*) in which all nuclear units would be decommissioned when attaining 40 years of operation. Even with an ambitious policy to develop renewable energy sources at a much faster rate than today, such a scenario brings the need for building new gas-fired units and leads to increasing CO_2 emissions in electricity generation. Yet this need for new fossil fuels generation units may be mitigated (but not cancelled) in case an intensive energy efficiency programmes is implemented and together with a broad public engagement in energy sufficiency. Of course, when analysed on a uniform testing ground with standard hypotheses on individual behaviours, energy efficiency and electrification rates, this scenario performs poorly on the cost and CO_2 metrics, but this does not tell all the story about it. This actually shows that for a phasing-out of nuclear to be implemented and still allow a decrease in CO_2 emissions at national level in France (albeit less important than in other scenarios) very strict boundary conditions need to be met, with strong societal choices including a very fast expansion of renewables and a significant commitment to energy sufficiency with sharp reduction of energy use.

The comparison of policy scenarios in France regarding their cost, security of supply and CO_2 emissions also depends on the policy of neighbouring countries regarding their energy mix: sensibility checks on the energy mix in the neighbouring countries are therefore an important part of the analysis and required to ensure the robustness of conclusions.

The same will apply to the degree of electrification. All energy scenarios for 2050 (ENTSO-E and G, European Commission, Eurelectric, NGOs) rely on a strong development of electricity use in transportation, buildings and the industry. This needs to be taken into account when comparing scenarios for the power sector. Some scenarios could, for example, lead to maintaining a small amount of CO_2 emissions in electricity generation if it makes it easier to expand to a vast degree renewables to cope with new uses for electricity. This means that the scope of GHG accounting and of the economic analysis must be expanded beyond the power sector itself, and integrates the various form of sector coupling and of direct development of electricity uses.

The approach used here for cost estimation takes into account all costs on the energy system, including the costs of appliances (e.g. electric vehicles, electrolysers and hydrogen storage facilities, heating systems). It can provide CO_2 abatement costs at the societal welfare perimeter, to be used for public decision making. They are not comparable to CO_2 abatement costs at the individual level, presented, for example, by the IEA in its recent publication *Sustainable Recovery* (IEA, 2020).

CO_2 emissions assessments do not integrate the possible compensation effects on other sectors through the functioning of the EU ETS market, which can be discussed. The alternative approach would consist in assuming that each tonne of CO_2 emission avoided would lead to an emission in another sector as the EU-ETS is a cap-and-trade mechanism. Such a reasoning means that the only policy to reduce GHG emissions in sectors covered by EU ETS would be to adapt the cap of the mechanism, and that sector-specific policies do not have any effect on global GHG. Yet the level of the cap is in fact, subject to political discussions, and adapted to the real level of emission and the price level (e.g. stability reserve). Moreover, many CO_2 emissions are not considered in the EU ETS (such as emissions from cars, buses and trucks, of battery manufacturing outside Europe, of gas or domestic fuel heating systems): the loopback effect of CO_2 reduction on EU ETS price and GHG emissions of other sector may therefore heavily depend on the sector and on fiscal provisions specific to each country.

Box 9.1: Specifics of the cost-assessment methodology developed by RTE

This approach relies on the following points

Costs taken into account

The costs are considered from the society perspective (societal welfare), or alternatively from consumers only.

Societal welfare assessment does not include economic transfers between the energy sector and the rest of the economy. In particular, taxes on certain activities (e.g. power generation) are not factored in the calculation.

All costs of the energy system, differing from one scenario to another, have to be taken into account: generation costs, networks costs for transmission and distribution (including interconnectors), demand-side management systems costs or willingness-to-accept, etc. It is possible to limit the assessment only to the power system, under the condition that all scenarios have the same interactions with the other part of the energy system (same level of electricity in the end-use), but it is often not the case: this means that it is necessary to embark in the assessment all the consequences on other sectors.

For a given country, the value of the electricity balance with neighbouring countries has also to be taken into account (for example in France, it can yield differences of several billions of euros between scenarios).

Externalities

Energy generation and consumption have many externalities. The perimeter of externalities is wide and most of the externalities do not have a consensual value to consider. CO_2 emissions could be valued at the carbon market price (if the analyses is restricted to the perimeter of the power system participant) or the public value for the climate / shadow price of carbon (which is public in several European member states, but has not been settled at European level).

Taking into account the time horizon

The comparison of different energy systems leads to different repartition of costs over time and different systems at the end of the period considered. A precise method would consist in a simulation over a very long period of time, in order to limit the distortion effect of comparing different scenarios having different system at the end of the period.

A simple way to limit this effect (and in particular the effect of investment costs made at the end of the period) is to reason on annual costs.

Necessity of multi-scenario analyses and sensibility checks

Costs of technologies are subject to many uncertainties: technical progress, economies of scale in large-scale developments, regulatory evolution and their impact on costs, etc. A robust economic assessment requires to consider different scenarios on all the key parameters.

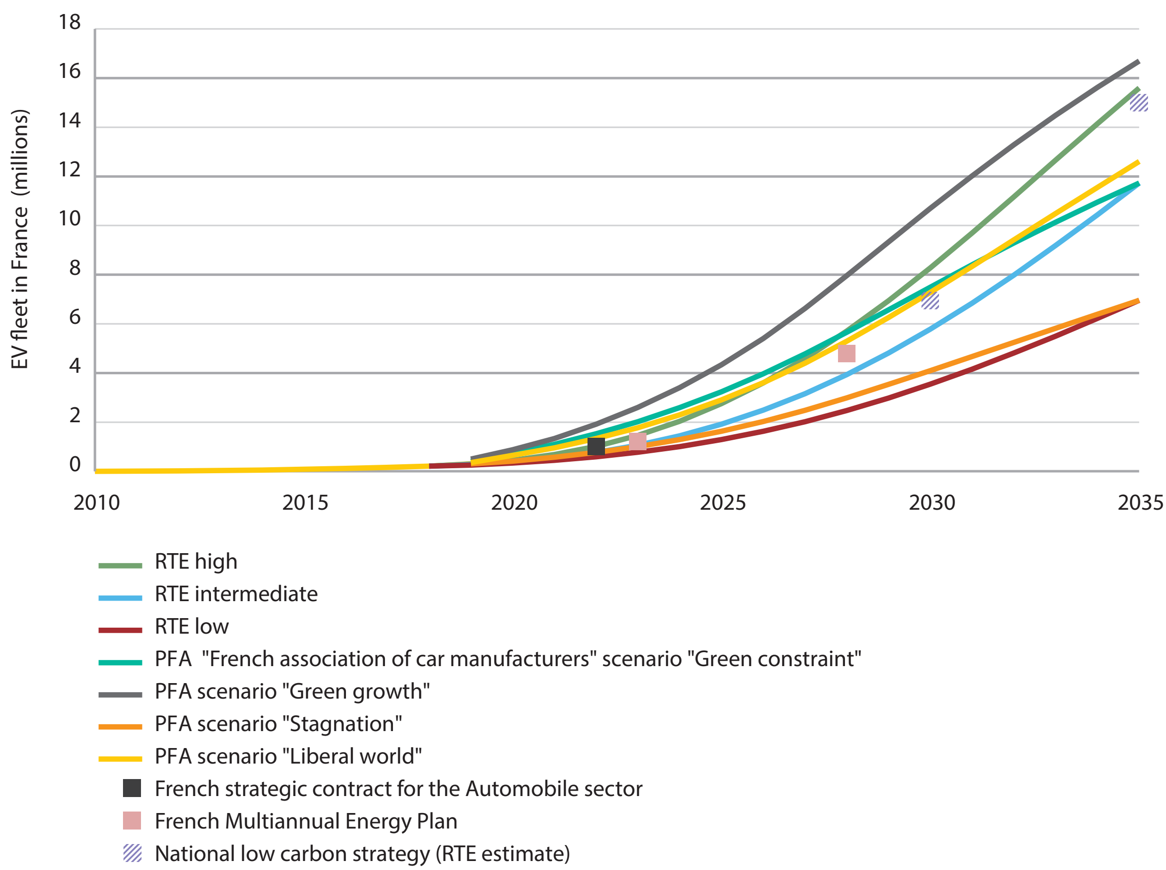
The following sections are devoted to the results and what we learnt from the three specific analyses performed by RTE on the options for developing electricity instead of fossil fuels: transportation, heating in buildings and hydrogen.

9.4 Sector 1: Electric mobility – A no regret option for decarbonisation at reasonable cost

Context and rationale for public action

In France, the energy consumption of the transport sector accounts for almost 30% of the final energy consumption and around 30% of GHG emissions, 95% of which is emitted by road transport. Achieving net zero by 2050 require a major reduction in the emissions in this sector.

Figure 9.1: Projected changes in the numbers of light-duty electric vehicles in France, including all technologies: 100% electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV)



Source : RTE (2019).

While electric vehicles are not the only solution for decarbonising the transport sector, their development is significantly more advanced than the alternative low-carbon technologies. Due to their energy efficiency and the fast reduction in batteries manufacturing costs, EV and PHEV are currently considered as the main solutions for reducing the GHG emissions of road transport, using low-carbon electricity.

The various projections of manufacturers and authorities are based on developing one million electric vehicles in France by 2022-2023, slightly less than 5 million by 2028, and possibly between 7 to 16 million by 2035 (private vehicles and light duty commercial vehicles included). EVs and PHEVs would then amount to between 20% to over 40% of the total number of vehicles. The development would initially concern mainly private vehicles and light-duty commercial vehicles, but would ultimately include HGVs (electric buses and trucks).

The massive development of electric vehicles is a challenge and a pivotal change for the energy and transport sectors. Several conditions must be met for this development to be successful: accessibility of charging points, industrial change in the automotive sector, security of the electricity supply, and managing the environmental impacts and costs for both the community and the user are key factors to facilitate the development and integration of e-mobility. All those factors were weighted in and assessed, using both an electricity dispatch model and a mobility model based on available data on people's transportation habits. The main results have been published recently (RTE, 2019) in order to identify the key drivers for a successful transition to electric vehicles.

Technical results

According to different scenarios tested (between 11.7 and 15.6 million EVs on the road in 2035 in France), electric consumption for the transport sector (including rail transport) is expected to reach between 40 and 65 TWh/yr. This represents less than 15% of the total electricity consumption in France by 2035, and is also less than the rise in electricity consumption in France between 2000 and 2010.

Importantly, even with the scheduled decommissioning of some existing nuclear reactors, the recent energy strategy adopted by French authorities provides for a significant increase in low-carbon electricity generation (nuclear and renewables), which is expected to progress from less than 500 TWh today to more than 600 TWh in 2035). Current forecasts see electricity consumption to be broadly stable on the coming years, with the possibility to a slight increase as from 2030). In any case, assuming energy efficiency continues to develop in electricity uses (digital equipment, cooling and heating, household appliances, lighting), total consumption could be in the region of 500 TWh/yr even with an ambitious development of e-mobility and other new electricity uses. This is far enough to allow for an electrification of mobility. The key issue concerns the impact on the consumption peaks and the security of supply of the power system.

Detailed analysis shows that the power system is able to "absorb" the heavy holiday traffic periods of July and August in France, or the long public holiday weekends: this alone is not significant to cause concerns for security of supply. In fact, long-distance journeys account for a small proportion of the total distances travelled each year, and – based on detailed modelling of mobility habits – they tend to concentrate at times when the power system has important margins in terms of supply: summer, weekends, public holidays, etc.

It is actually the daily mobility patterns which represent the main challenge for the electricity system. In the absence of any incentive for consumers to engage into some form of smart charging, even if not sophisticated (through simple time-of-use tariffs such as peak-off peak), power demand would be partially concentrated between 7 and 9 pm on week days.

Nevertheless, an important development of smart charging is not a prerequisite for e-mobility integration into the power system.

Even in the most stressful scenario (big cars with large batteries aiming at increasing cars' autonomy, little access to charging at work and a low development of smart charging), system adequacy can be ensured with only a limited development of smart charging:

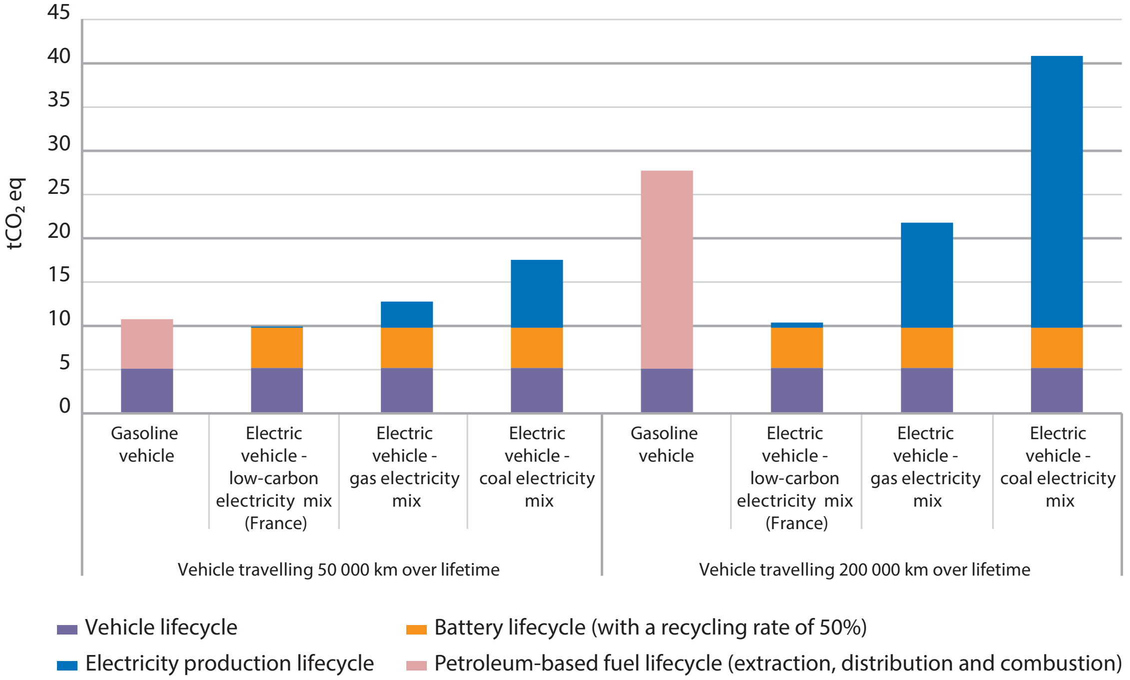
- The diversity of vehicle use profiles (workers who may or may not return home at lunch time, non-workers, etc.) would lead to inherently varied charging patterns, which helps limiting consumption peaks associated with EV charging: in much the same way as people today do not all turn their ovens or electric hobs on at the same time, even if no specific incentive is put on EV charging, there would still be a natural spread of charging over time.
- The projected electricity generation mix in the long-term energy plan offers comfortable capacity margins by 2035 (nuclear power would still provide 50% of the overall electricity generation, renewables would have been largely developed, and cross-border interconnection capacity would have been developed by a factor of 2).

Results for CO_2 emissions

The different studies (FNH, 2018; Agora Verkehrswende, 2018; ECF, 2019) comparing the life cycles of internal combustion engine (ICE) vehicles and electric vehicles generally agree on the environmental analysis of e-mobility in terms of GHG emissions. The 2019 study confirms these results, taking due consideration of all sources of emissions (in the power sector, during the manufacturing phase of batteries, under a large variety of scenarios, etc.). In a country like France, with an electricity system already nearly fully decarbonised, EVs or PHEVs with smaller batteries are the best solution in terms of carbon footprint (including life cycle analysis) as soon as the vehicle travels more than 30 000 to 50 000 kilometres over its lifetime (which is almost always the case as the average for a vehicle in France is 200 000 km).

This is to say that, in standard conditions, carbon emissions reductions at national level are not offset by additional emissions in other countries due to the production of battery, even when the latter are manufactured in countries where coal remains the dominant fuel for electricity generation (China, Poland,[2] etc.). Depending on the size, production sites, recycling rate and the timescale considered, electric vehicles have a carbon footprint two to four times lower than ICE vehicles.

Figure 9.2: Carbon footprint of a vehicle over its entire life cycle depending on the type of engine, the electricity production mix and the distance travelled (reference year 2035)



Source : RTE (2019).

This study also shows that additional benefits could derive from relocating battery production in countries where the generation mix is nearly decarbonised, like France, concentrating on smaller cars with lower battery storage capacity and higher recycling rates, and developing smart charging.

2. As Poland is part of the EU-ETS mechanism, impact on CO2 emissions of Poland could have a loopback effect through the cap on EU-ETS. See Section 9.3 for a further discussion of the EU ETS.

With 15.6 million EVs,[3] the reduction in the carbon footprint of the transportation sector can be expanded from circa 25 Mt CO_2/yr to 40 Mt CO_2/yr.

Cost assessment

The comparison between electric and ICE vehicles is a recurring debate. Whereas this is often seen from the consumer side (through the TCO, total cost of ownership), the methodology detailed in Section 9.3 of this chapter leads to consider complete system costs for the two kinds of mobility.

For electric as well as ICE vehicles, the main cost components are the manufacturing phase itself (including batteries for EVs), followed by maintenance and insurance over the lifetime. For ICE vehicles, fuels (oil imports, refining and distribution) represent an important component, whereas the charging infrastructure (that is yet to roll out in our countries, for private as well as for public actors) is the key parameter for EVs (the cost of electricity generating the electricity used in cars is in itself not significant).

Based on this analysis and when excluding externalities, the overall economic cost of electric vehicles appears clearly greater than that of ICE vehicles – due to the cost of the batteries and of charging infrastructures. The better engine efficiency of the electric motor is not enough to balance these costs, meaning that the additional cost represents around EUR 10 000 per vehicle over its lifetime. It is therefore through subsidies (including taxes on fuel) and stricter regulations that make EVs attractive enough for consumers and for them to enjoy a relative expansion in use.

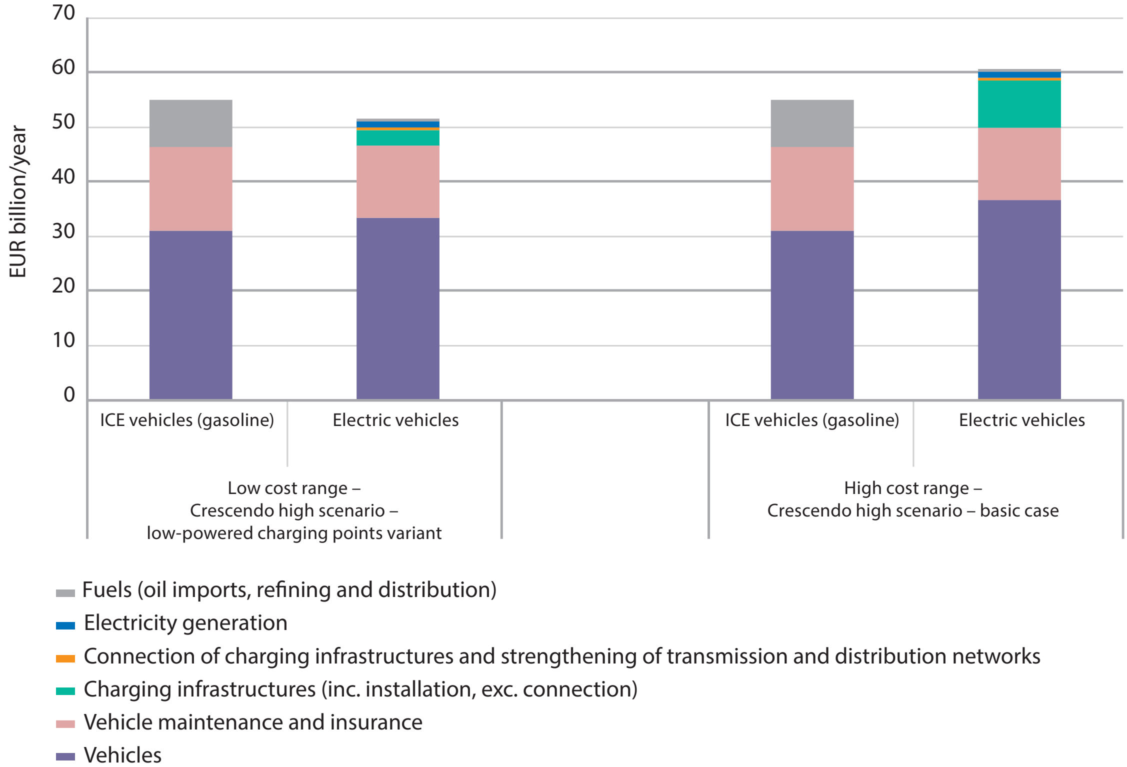
A full socio-economic assessment requires to value externalities in addition to material costs. The first step is to integrate the costs of CO_2 emissions: there exists an abundant literature on the collective cost of GHG emissions (and a market price through the EU ETS). Going further requires to integrate other externalities, such as noise, local pollution, resource depletion, etc., for which there are no clear consensus references.

All things considered, the complete system cost of ICE is still lower than that of EVs for the time being: valuing CO_2 to a very high price and other externalities would be necessary to inverse the balance. The turning point seems to occur around 2025. When integrating the long lead times of such policies and the fact that the new vehicles sold today will still be on the roads in 10 years from now, incentivising consumers to switch to EVs immediately makes sense.

By 2030-2035,the conclusion is that – in line with other studies (Bloomberg, 2020; ECF, 2019; OPESCT, 2019) – that the overall cost of electric mobility should be equivalent to the cost of traditional cars using oil (in a range of 10% lower and 10% higher) even without integrating externalities. The driving force behind this profound change is the expected drop in the cost of batteries.

3. It also includes ~150,000 electric trucks and buses.

Figure 9.3: Total annualised costs for 15.6 million vehicles by 2035 by engine type



Source : RTE (2019).

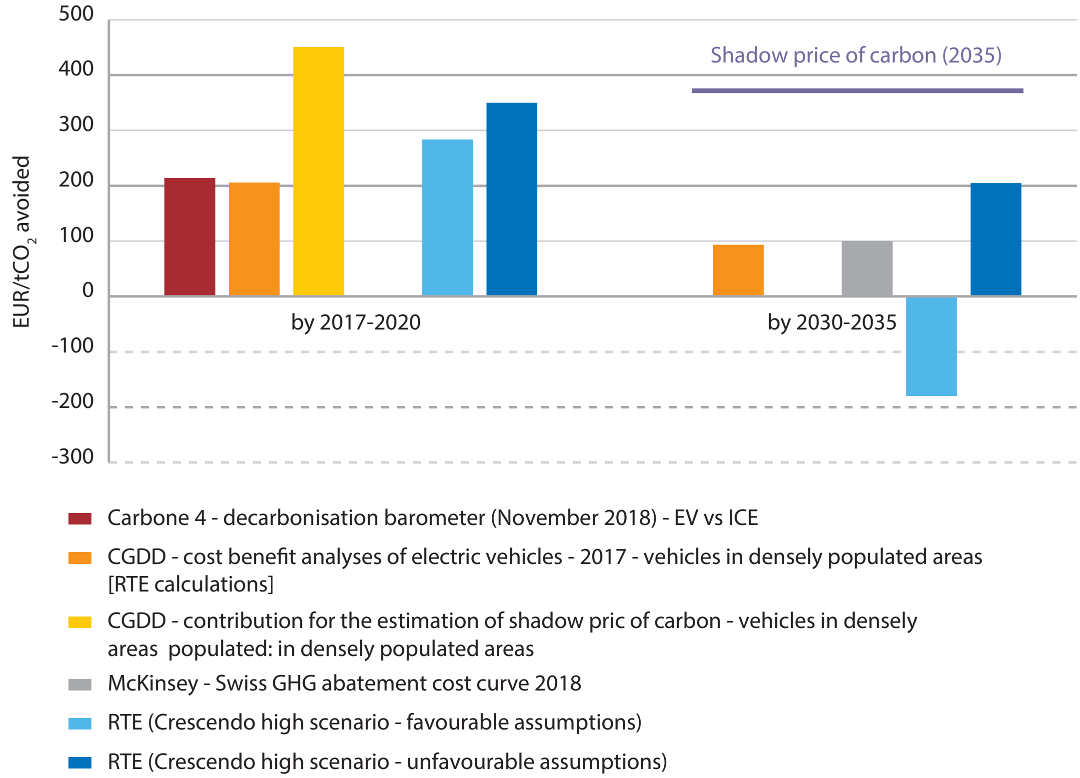
This allows a determination of the CO_2 abatement cost for this policy, at around EUR 250 to 350/t CO_2 avoided over the whole lifetime of the vehicle – a level which must be compared with the shadow price of CO_2 and of other external effects (electric vehicles emit fewer fine particles than ICE vehicles and therefore reduce the associated public health problems), and also compared to alternative ways of reducing emissions.

This result falls in line with results from previous studies. With the expected reduction in the cost of batteries, the additional cost of e-mobility will fall, to an extent which is subject to considerable uncertainty (dependence on assumptions on changing costs, battery capacity, the price of oil, etc.).

When integrating the level of uncertainty over EVs costs, the policy of developing electric vehicles seems very favourable: from no additional costs – and even a reduction in costs without taking into account CO_2 – to an abatement costs of EUR 200/t CO_2 maximum by 2035 when taking unfavourable assumptions. This last value might seem high compared to the current value of CO_2 allowances on markets but it is actually well below the shadow price of carbon which has been estimated in France at EUR 375/t CO_2 in 2035 (Centre d'analyse stratégique, 2019).

Indeed, reducing GHG emissions appears more costly in the future as the easiest and cheapest actions should have already been implemented.

Figure 9.4: Estimated costs of reducing greenhouse gas emissions by the electrification of transport



Source : RTE (2019).

Beyond this inversion in the costs assessment, several conclusions can be derived from this analysis. First, it appears that the specific cost item associated with electricity generation represents a small part of the cost of electric mobility but also something limited compared to the total costs of adapting the electricity system, which is itself only a fraction of the overall cost of a mobility scenario. The annual electricity generation cost for electric mobility is estimated to be EUR 1 to 2 billion by 2035 for 15.6 million EV. And this cost of generating electricity for e-mobility can be largely optimised through smart charging. Even with simple smart charging devices (allowing to start the charge at home at a specific moment of the day) leads to significant savings for the electricity system, up to 1 billion euros. This can put some sense of perspective to headlines and declarations branding "electric mobility" as a revolution for the electricity system: it is surely a significant change, but it will take some time before transport represents a significant share of electric consumption.

Second, smart charging of electric vehicles – even through relatively unsophisticated forms of incentive like time-of-use tariffs – can play a role in reducing those costs. As long as EVs can be frequently connected to the system, optimising EVs charging on a weekly basis is technically feasible given the current capacity of batteries and the main uses of vehicles. If this theoretical analysis is confirmed by practical experience from users, EVs could prove a powerful tool for operating the power system (by allowing to cope with renewable energy sources' variability) as well as a means to reduce GHG emissions.

9.5 Sector 2: Power-to-hydrogen – Decarbonising industry and heavy transportation at more significant abatement costs

Context and rationale for public action

The development of synthetic gases, and in particular hydrogen, should play a significant role in sector coupling and in energy transition.

The European Union has recently announced that hydrogen would be a priority area of the European Green Deal and a key instrument for reaching net-zero greenhouse gas emissions by 2050. In Europe but also in China, Japan and the United States, governments are currently drawing up plans to foster the development of low-carbon hydrogen.

In its report, *The Future of Hydrogen,* published in 2019, the IEA states that "Hydrogen can help tackle various critical energy challenges" (IEA, 2019b). Hydrogen is indeed often presented as both a source of flexibility and a key factor in achieving GHG emission reductions. These different reasons, however, should be clearly distinguished in prospective analyses.

In France, a first government Hydrogen plan was launched in 2018. It required RTE to undertake a study of the issues for the French power system. This study was submitted to the minister of Energy and published in January 2020 (RTE, 2020a).

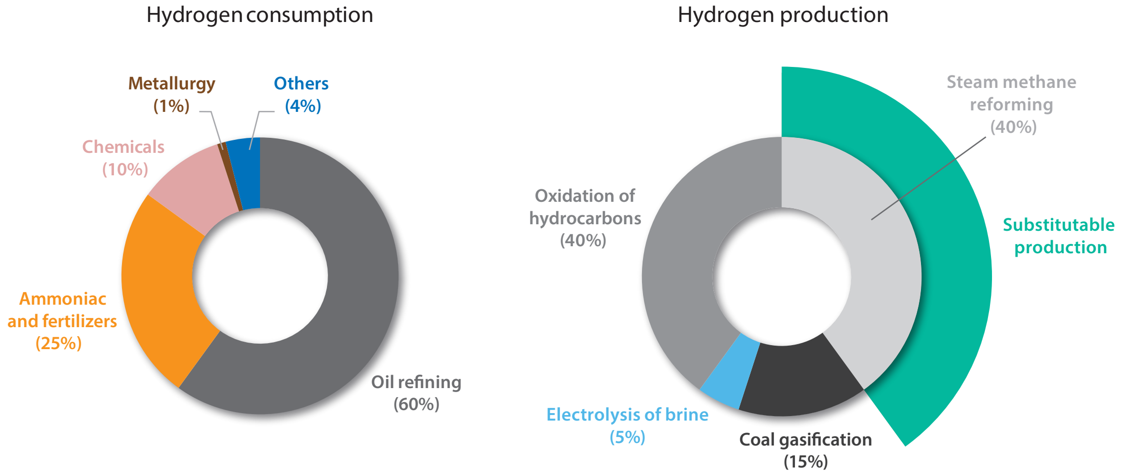
The study distinguished two key time horizons for hydrogen production.

In the medium term, hydrogen offers a solution for reducing emissions of the industrial sector by replacing the hydrogen today produced from fossil fuels and used in oil refineries, fertiliser plants or other industries (chemicals, aeronautics, etc.). It also creates opportunities to reduce emissions in the transport sector (for heavy transport and trains, as a replacement for oil) or gas networks.

In the long term, developing production and storage of low-carbon hydrogen can offer an additional system flexibility solution, particularly interesting in view of scenarios with a significant share of renewable energies in the power mix.

In France, as in other countries, the first step is therefore to develop in the coming years significant volumes of low-carbon hydrogen production, in order to help reduce the emissions of the industrial sector. Indeed, almost 1 million tonnes of hydrogen is used today in France (and around 70 million tonnes of pure hydrogen in the world) by industry, and its production, widely based on fossil fuels, accounts for significant quantities of GHG emissions: around 10 million tonnes of CO_2 in France, which represents 2% of national emissions.

Figure 9.5: Current consumption and production of hydrogen in France



Source : RTE (2019).

The law on energy and climate passed in 2019 and the multiannual energy plan published by the government in April 2020 outlines the objective to reach between 20 to 40% of low-carbon hydrogen by 2030.

As one the main options to produce low-carbon hydrogen today is based on the electrolysis process which uses electricity, the achievement of the French public objectives requires significant amounts of carbon-free electricity to support the development of this new process (up to 30 TWh in 15 years, which is almost 6% of contemporary total electricity demand in France).

Similar to the analysis on the development of EVs, this evolution does not raise any technical concerns with regard to system adequacy. Energy efficiency and expansion of renewables are expected to ensure sufficient carbon-free electricity generation to cover electricity supply needed for hydrogen production planned for 2030-2035. Furthermore, the flexibility of electrolysers give them the ability to stop during peak periods, thus avoiding creating any specific problem in terms of the security of supply.

Results for CO_2 emissions

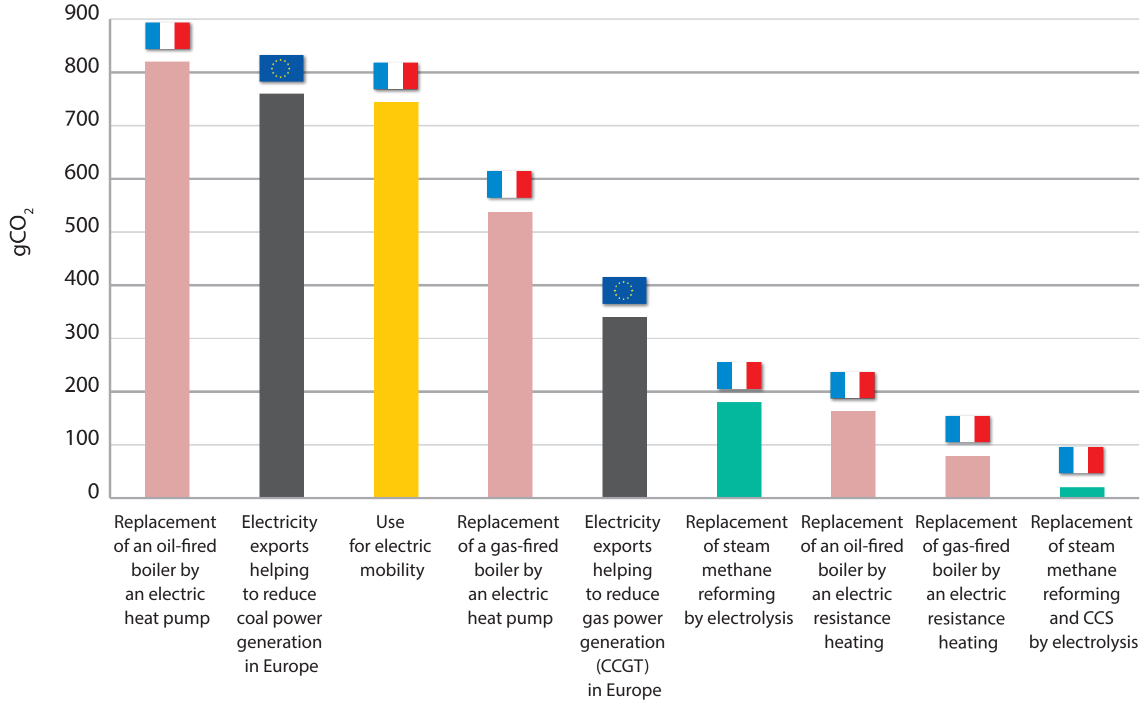
Hydrogen is often presented as a no-regret option in terms of decarbonisation. Yet, contrary to the transition towards electric mobility, simulations tell a more nuanced story – at least in the medium term and when considered in a European perspective.

At first sight, the question of hydrogen production seems simple, and does not prompt debates like those around the carbon footprint of electric vehicles given the initial process of manufacturing batteries. The following analysis therefore focuses on the carbon emissions associated with the process of producing hydrogen.

On the perimeter of France, the carbon balance of a transition towards hydrogen production by electrolysis is broadly positive, as fossil-produced hydrogen would be replaced by hydrogen produced with low-carbon electricity.

But the complete analysis should also take into account the impacts on electricity exchanges with other European countries.[4] The balance at European level then appears less clear. Indeed, the use of low-carbon electricity in France for hydrogen production is in competition with exporting electricity and avoiding fossil fuel electricity generation (in gas or even coal plants) by neighbouring countries, which have a more important impact on GHG emissions than the current use of natural gas to produce hydrogen in France.

Figure 9.6: GHG emissions avoided (and their location) by the generation of 1 kWh of carbon-free electricity in France depending on its use



Source : adapted from RTE (2019).

As a consequence, to ensure a positive carbon balance at European level, the development of hydrogen production should be complemented with the development of a corresponding volume of carbon-free electricity generation.

Adding all these effects, the development of low-carbon hydrogen, as planned by the French government, would reduce GHG emissions by at least 5 million tonnes per year in 2035, due to the replacement of steam methane reforming. This number could be increased when considering the possibility to use hydrogen for heavy transport or directly in the existing gas grid as a substitute for the fossil fuel natural gas.

4. See Section 9.3 where the way the ETS mechanism affects global emissions is discussed. The ETS mechanism indeed ensures a global level of emissions and with an unchanged cap a reduction in one sector will be offset by emissions in another sector.

Cost assessment

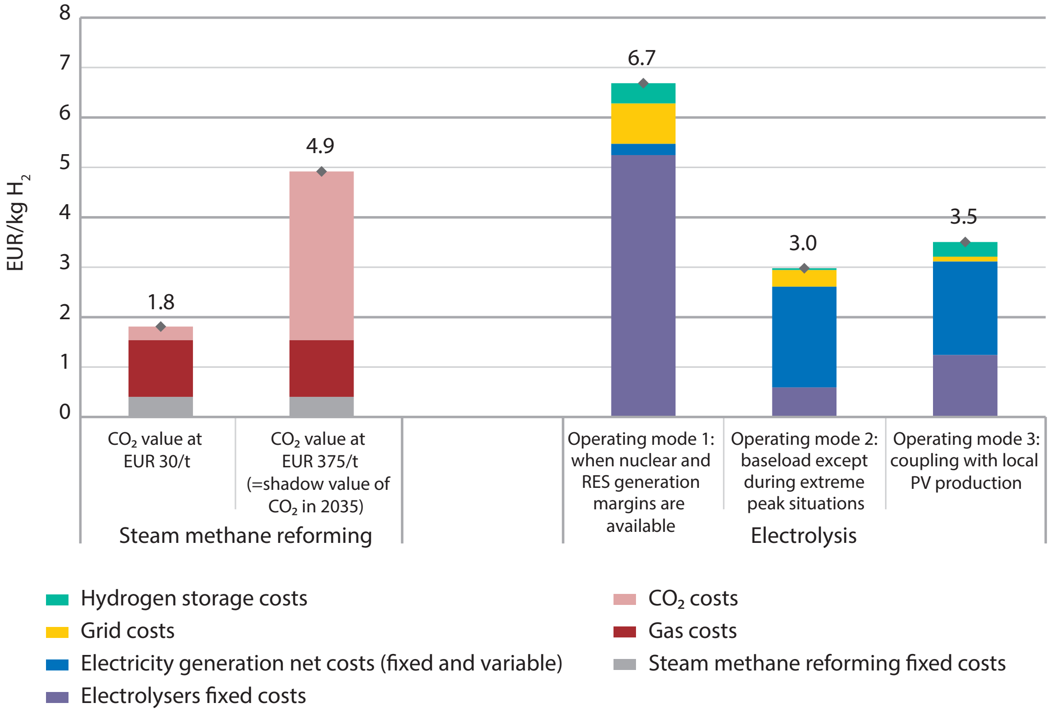
The economic analysis of the transition towards low-carbon hydrogen also needs to take into account all cost components. The main components are the costs of production equipment (electrolysers) but also the costs of electricity generation needed which could represent up to 60% of total costs of producing low-carbon hydrogen.

More precisely, the distribution of costs largely depends on the operating mode of electrolysers. If they are used only when electricity is totally carbon free and prices are low i.e. when margins on nuclear and renewable generation are available (operating mode 1 in Figure 9.7 below), their run time would be limited even in 2035 with almost 50% renewable energy sources in France, and the main driver of hydrogen production costs corresponds to the fixed costs of electrolysers (amortisation of CAPEX + OPEX). In such cases, costs related to electricity generation are not significant as the flexibility of electrolysers contribute to the economic optimisation of the power dispatch. On the opposite, if electrolysers are running in baseload mode (operating mode 2 in Figure 9.7 below), then the amortisation of investment costs of electrolysers is not really significant in the economic assessment and the major part of the costs corresponds to electricity generation (fixed and variable).

From a social welfare perspective, the comparison of production costs between electrolysis and steam reforming appears very dependent on the value of GHG emissions, but also on the operating mode of electrolysers. For a hypothesis of low CO_2 valuation (EUR 30/t, close to the current price on the ETS market), the full cost of electrolysis appears far above that of steam reforming. This explains why the hydrogen used today is still of fossil origin. On the other hand, when retaining a high value for environmental externality electrolysis generally appears cheaper. For example, by considering the shadow value of CO_2 which is considered to reflect the long term cost of CO_2 emissions is estimated at around EUR 375 /t in 2035 in France (Centre d'analyse stratégique, 2019).

This shows that it is relevant, from a socio-economic point of view, to substitute electrolysis for steam reforming in France in the next 15 years.

Figure 9.7: Comparison of costs of producing hydrogen between different production modes



Source : RTE (2020a).

It should be noted however that these figures refer to production costs of hydrogen in terms of societal welfare (i.e. net costs for all stakeholders involved, including socio-environmental externalities, as presented in Box 9.1) and not to the market price of producing hydrogen. Indeed, the cost from the point of view of a hydrogen producer could differ from societal welfare due to the effect of specific market arrangements, taxes or subsidies. In particular, the analysis shows that paradoxically, the increase of the CO_2 price on the ETS market would not necessarily encourage the development of low-carbon hydrogen in France as it would result in an increase of power prices and therefore an increase of electrolysis costs, which may be higher than the increase of costs for steam methane reforming. This effect comes from the fact that power prices are fixed mainly at European level with the operation of the interconnected power system, and still largely depend on fossil fuel and CO_2 prices, even if the French power mix is almost totally low-carbon.

In the broader public debate, this result can lead to two opposing interpretations. On one hand, some would support that it reflects a well-functioning market which allows an economic optimisation and a co-ordinated effort to reduce emissions at the European level. In this respect, it would be understandable that carbon-free electricity from nuclear and renewables in France is exported and used to reduce fossil-fuel power generation in neighbouring countries as a priority, before developing low-carbon hydrogen in France. On the other hand, the distributional effects appear to some as are too important not to be taken into account, and it is politically problematic to consider that the well-functioning carbon markets will make it unprofitable to develop new uses for low-carbon electricity in a country that has plenty of it. Accordingly, it is difficult to believe that European member states would agree to develop low-carbon generation in their country just to reduce emissions from the power sector in other member states. The economic assessment should therefore include an analysis on redistributive effects, in particular between different member states. For instance, member states that bear the financial support and environmental impacts of developing renewable generation would expect that it is useful for their energy mix, or at least that redistributive mechanisms would ensure a fair sharing of costs (which is not consistently the case with the European energy market). It is interesting to note that such an issue did not occur for electric vehicle: the efficiency of the electric vehicle makes it more efficient to use low-carbon electricity to decarbonise transportation at national level rather than power generation in neighbouring countries.

Furthermore, the figures presented above relate solely to the hydrogen production costs and do not include the costs associated with the conversion of energy uses to hydrogen. In fact, the economic assessment differs whether considering existing uses of hydrogen (in refineries or fertiliser plants for instance) and new uses of hydrogen (for instance in heavy transport). For the existing uses of hydrogen, there should be no additional costs of conversion to low-carbon hydrogen as the equipment used today is already designed to use hydrogen. This might also be true, to a certain extent, for the use of hydrogen in the gas grid: the existing gas grid can integrate small quantities of hydrogen but higher volumes would induce investments for the adaptation of the grid. In contrast, for new uses such as the conversion of trucks, trains or industry processes to hydrogen, additional equipment costs should be included in the economic analysis (in particular, the extra cost of a hydrogen vehicle compared to a conventional vehicle). Current studies conducted by RTE on long term scenarios will provide economic assessment on the development of these new uses for hydrogen.

9.6 Sector 3: Heating in buildings – The need to co-ordinate policies to advance buildings renovation and decarbonisation

Reducing the carbon footprint of buildings is a cornerstone of any policy aiming at achieving carbon neutrality. In Europe, in general, heating relies mainly on fossil fuels (coal, fuel, and natural gas through direct use or district heating networks), and is responsible for a large part of carbon emissions.

In France, buildings are responsible for 43% of total energy needs, and heating only amounts to 25% of energy needs. Buildings are responsible for around 80 MtCo2eq per year (including circa 65 Mt CO_2eq per year for heating), that is to say 15% of GHG emissions at national level.

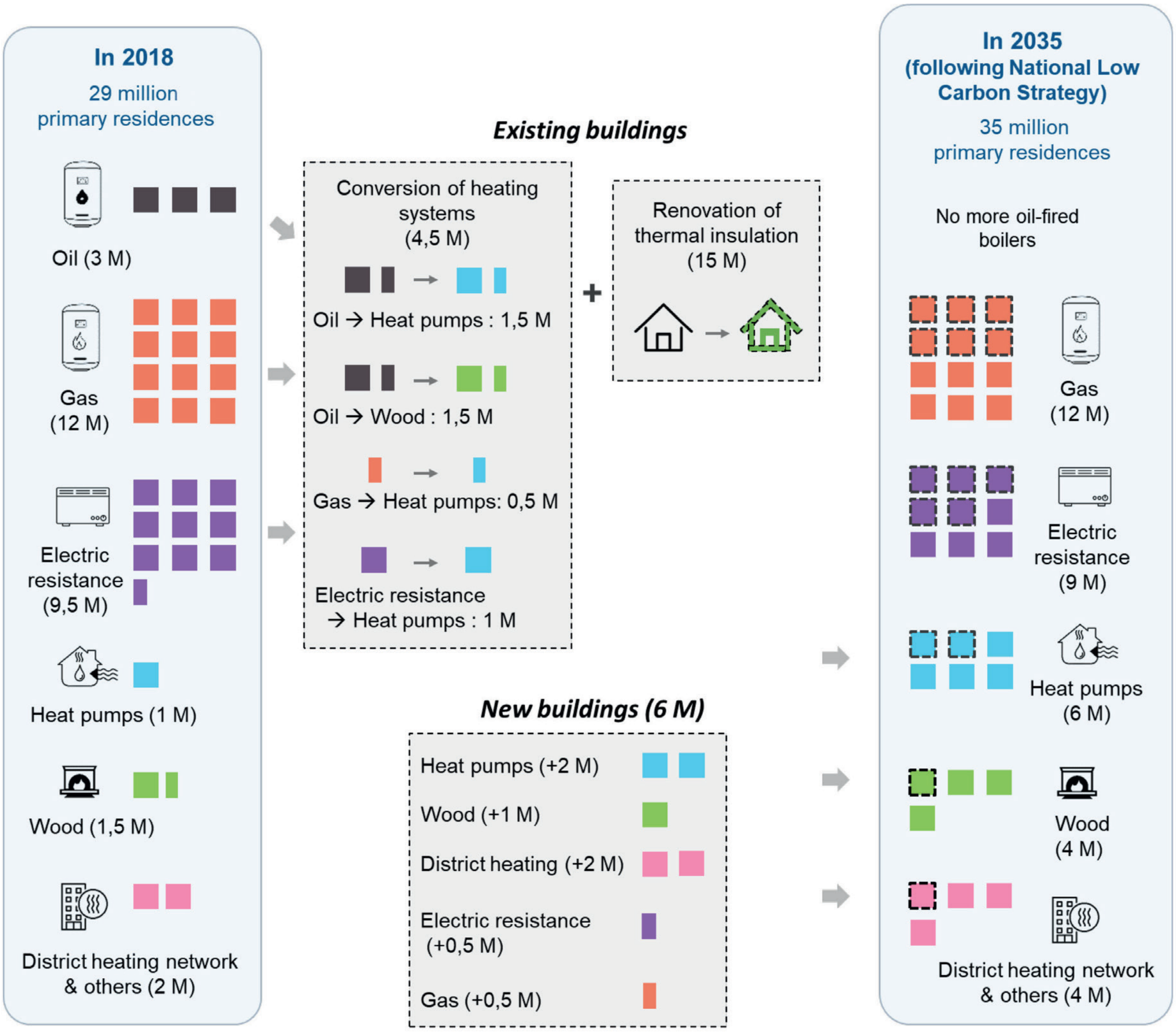
Contrary to several European countries, electric heating has been developed in France, mainly as from the 1980s. Yet natural gas remains the dominant fuel (it amounts to 40% of final energy consumption in heating in the residential sector), above domestic wood (27%), electricity (15%) and fuel oil (12%). Nowadays, electric heating tends to be more widely used in smaller apartments and houses.

Basically, the question of buildings has been addressed though two different frameworks.

The first idea is to largely reduce energy needs. This led to very strict regulations for new buildings in terms of primary energy consumption, and ambitious plans to renovate and insulate existing buildings. Given that this sector is characterised by a strong inertia (most of the buildings of 2050 already exist), it is for existing buildings that the ambition is the most challenging. The law of 2015 provides for a very ambitious objective that all buildings would be equivalent on average, by 2050, to new ones (low-energy buildings).

The second idea is to decarbonise heating fuel. This requires a switch to low-carbon solutions, as heat pumps, domestic wood, biogas or district heating and cooling networks using renewables or waste. In any case, this means more direct uses of electricity in buildings, or the development of power-to-heat solutions. In France, the National Low Carbon Strategy plans to develop massively the use of electrical heat pumps for building heating. Following this strategy, the share of electricity in the final energy consumption for heating would increase sharply from 15% today to around 30% in 2050 (the rest being heat from the environment, solid biomass fuels, biogas and district heating fueled with renewables or waste).

Figure 9.8: Projections on the evolution of heating systems in residential buildings in France between 2018 and 2035, according to the directions of the National Low Carbon Strategy



Source : RTE, based on data from DGEC, National Low-Carbon Strategy, 2020.

This prospect of further electrification has prompted a policy debate, which is not concluded. In the recent past, the development of electricity in buildings through electric heaters (convectors) has prompted an increase in peak load and sensitivity to temperature (2 300 MW/°C in winter). This led to complex and somewhat conflicting views about the ability of the power sector to integrate more electric heating and about the true balance of electrification in terms of its carbon footprint.

In this context, RTE is currently carrying out a study with the French Agence de la Transition écologique (ADEME) on the impacts of the different measures aimed at reducing GHG emissions of buildings. Similarly to the other studies mentioned in this chapter, this work is based on precise simulations performed by RTE, taking into account the whole European power system and modelling the supply-demand balance with an hourly resolution for many meteorological scenarios. This methodology is necessary to assess actual and potential impacts of the development of electric heating on the GHG emissions of the power sector and on peak load.

The provisional results show that electrification and an ambitious renovation programmes are both necessary to reduce emissions by 50% by 2030, and by nearly 100% by 2050. They also show that despite the development of electricity-based solutions for heating, peak load would be broadly stable France in the next 15 years, with a small increase or a small decrease depending on various parameters (flexibility on EV charging, the pace of development of energy efficiency measures, etc.). This result is explained by the fact that the impacts of new uses of electricity would be offset by energy efficiency gains, not only in heating but also in other existing uses (household appliances, lighting, etc.).

Regarding CO_2 emissions, electrification of heating, per se, is a no regret option for reducing emissions in France and in line with the current trajectory proposed in the National Low Carbon Strategy. At national level, there is no situation in which developing electric heating would lead to increase CO_2 emissions, through for example a higher use of gas-fired generation units. The sharp increase in renewable electricity generation makes it possible to accommodate most of the additional heating consumption with low-carbon production. In particular, ending the use of fuel oil in the residential sector (around 20 Mt CO_2/yr) provides benefits that largely outweigh an eventual small increase in fossil fuels use for electricity generation.

When considered at the European level, as it was the case for power-to-hydrogen, there is an inherent conflict between decarbonising electricity generation through French exports, and decarbonising heating in France. If carbon-free electricity generated in France is used to replace oil-fired boilers, the environmental benefits appears clearly greater than if this power is exported in neighbouring countries to reduce electricity generated from gas (same result as for the transition towards electric mobility). But if it is used to replace gas boilers, the result at the European level appears less clear and would depend on the energy efficiency of the buildings and the heating systems considered. Development of carbon-free electricity in France, in support of the development of electricity-based heating, would however ensure a positive carbon balance at the European level in all cases.

As for the economic assessment, provisional results of the forthcoming RTE-ADEME study show that the reduction of CO_2 emissions in the buildings sector will require massive investments for the renovation of buildings and the conversion of heating systems, around EUR 500 billion over the next 15 years (taking into account public and private investments). However, when annualising the benefits over the entire life cycle and comparing to the costs of a business-as-usual scenario, these investments appear economically relevant to reduce greenhouse gas emissions (CO_2 abatement costs are still to be estimated but provisional results reveal a value lower than the shadow price of carbon for 2035 in France).

In comparison with the previous studies on electric mobility and hydrogen, the economic assessment is however complicated by various factors, which makes it difficult to calculate a precise value for CO_2 abatement costs.

First is the fact that consumers are likely to seek an improvement of their comfort after a renovation of their houses, for example by increasing their heating temperature (as the energy necessary to obtain this temperature has been reduced with the renovation). This phenomenon, also referred as the "rebound effect", has been widely documented in recent years but its magnitude still remains uncertain. When taking it into account, the emission reductions might appear lower than expected, which results in an increased abatement costs.

Secondly and related to this effect, is the integration of the different externalities that are provided by building renovation. For instance, a better building insulation or a more efficient heating system can bring a better comfort for occupants and even prevent some health problems, which is valuable for society as a whole.

Another example is the difficulty to estimate the costs of renovation as it refers to a large variety of operations (window replacement, insulation of walls or roof, replacement or conversion of the heating system, etc.) and as costs are often not proportional to the number of operations completed (it may be more profitable to go for a "deep renovation" with many operations combined but it also requires a more important initial investment).

Eventually, a comprehensive analysis of the costs of benefits of transformations of the buildings sector, taking into account all the implications mentioned and including numerous sensitivity analyses, is therefore needed. This is the object of the forthcoming RTE study about heating in buildings.

9.7 Comparative analysis on the decarbonisation costs in the different sectors

The three dedicated studies on new uses for electricity eventually provide a detailed overview on the benefits of e-mobility, power-to-hydrogen and renovation of buildings/electric heating in terms of CO_2 emissions reduction, their impacts on the power system and the costs associated with these conversions for the next 15 years.

A preliminary comparative analysis is displayed in Table 9.1.

It shows that one of the most efficient ways to cut down emissions is to replace internal combustion vehicles with electric ones. It leads to an amount of avoided emissions (at least -25 Mt CO_2/yr) two to five times superior than the evolution of hydrogen and electric heating.

This result reflects the fact that the transport sector is today the main sector emitting GHG in France and that there is an important potential to reduce emissions. The building sector is also one of the main emitting sectors but it is characterised by slow changes (the renewal rate of buildings is around 1%/year compared to around 6%/year for the light vehicle fleet).

As for the economic results, the analysis shows that the overall costs of transition differ greatly between the three sectors. In the automotive sector, the conversion to e-mobility involves not only the adaptation of the power sector but also the conversion of thermal cars to electric ones, the construction of charging infrastructures and their connection to the grid. This leads to total annualised costs of several tens of billion euros per year, with costs of the power sector representing only a small fraction of these total costs. In the same vein, decarbonisation of the building sector involves the evolution of heating systems and the insulation of walls, roofs and windows. On the other hand, conversion to low-carbon hydrogen for existing uses in the industry "only" requires the replacement of steam methane reformers by electrolysers, thus leading to lower overall costs and to a higher share of costs of the power sector.

However, high overall costs do not necessarily keep electrification of these sectors from being considered. These overall costs should indeed be compared to the ones that would have occurred in a business-as-usual scenario. Hence, the costs of electric mobility (including the costs of electric vehicles) should be analysed against the costs of internal combustion vehicles and associated fuels. Likewise, the costs of electric heat pumps in the buildings sector should be compared to the costs of conventional fossil-fueled boilers.

This is the difference of these two values, which can be referred to as "net costs", put in relation to the impact on GHG emissions (in tonnes of CO_2 equivalent), that constitutes the "abatement costs" and helps identifying the priority actions in the fight against climate change.

For the transport and hydrogen sectors, studies show that abatement costs, while being largely dependent on the evolution of costs of the different technologies (for instance evolution of costs of electric vehicles or electrolysers), will certainly be lower than the shadow price of carbon recommended in France (EUR 375/t in 2035).

Table 9.1: Summary of technical, economic and environmental impacts of developing new uses of electricity

	E-mobility	Low-carbon hydrogen	Buildings/heating
Contemporary GHG emissions in France	~125 Mt CO_2eq/yr (road transport)	~10 Mt CO_2eq/yr (hydrogen in industry)	~65 Mt CO_2eq/yr (heating in buildings, exclusive of electricity)
Public objectives	1 million EVs by 2022 ~15 million by 2035 i.e. ~40% of light vehicles	20 to 40% of low-carbon hydrogen in 2030, corresponding to around 200 to 400 kilotonnes per year	Ending the use of oil-fired boilers by 2028 Reducing the emissions of buildings by 50% by 2030
Additional electricity consumption	↑~40 TWh in 2035 (+/- 10 TWh) (~0 → ~40 TWh)	↑~30 TWh in 2035 (+/- 15 TWh) (~0 → ~30 TWh)	↑~6 TWh in 2035 (effect of electrification of new and existing building only, without effect of thermal insulation) (51 TWh[5] → 57 TWh)
Additional peak-load	↑~4 GW in the high scenario for 2035 Between ↓5GW (contribution to capacity needs via V2G) and ↑8 GW depending on the flexibility of EV charging	↑~ 0 GW (as electrolysers are flexible)	↑~4 GW in 2035
GHG effect of electrification	Between -25 Mt CO_2/yr and -40Mt CO_2/yr, depending on batteries manufacturing, size, recycling, etc.	- 5 Mt CO_2/yr	Around -7 Mt CO_2/yr
CO_2 abatement costs	Between EUR -200/t CO_2 and EUR 200/t CO_2 in 2035 depending on the evolution of costs of EVs	Between EUR 144/t CO_2 and EUR 230/t CO_2	To be developed in next report

9.8 Energy system integration analysis and public policy making for decarbonisation: Next steps

This work should now be extended to a longer term perspective, to set the path to carbon neutrality. As members of the European Union are now committed to reaching net-zero emissions by 2050 with the European Green Deal, energy system integration and sector coupling will be further developed and accelerated.

5. Situation in 2035 considering the effort in thermal insulation defined in the Low-Carbon National Strategy but considering no new house using electricity for heating

In France, the National Low Carbon Strategy (SNBC) provides guidance to reach the objective of carbon neutrality. It specifies an emissions trajectory for the different sectors. One of the main outcomes is that new electricity uses are to be developed further in the period 2030-2050, especially in the industry, transport and buildings, along with much energy efficiency. Biogas and biofuels are also to be developed but their capacities are limited by the potential of national sustainable biomass. As a consequence, even though some current uses of electricity will be reduced thanks to energy efficiency, the development of new uses of electricity and sector coupling will drive electricity consumption up in the long term, to an extent which will be determined by the success or the failure of energy efficiency actions and by consumers' response to prices, regulations and social trends.

While the National Low Carbon Strategy provides detailed trajectories for the evolution of gas, hydrogen or power demand, it does not specify the power mix that should be implemented to cover electricity needs. Yet, the power system should evolve not only for the development of new electricity uses but also for the replacement of current nuclear reactors. Most of these nuclear power plants, which produce today around 70% of power in France, are supposed to be decommissioned between 2030 and 2050.

Two main options are considered – replacing part of the current nuclear fleet by new nuclear reactors in addition to renewables, or only developing renewable energies. Those two options still need to be assessed in detail (in terms of costs, technical and environmental aspects, etc.). This is being addressed in an extensive study on 2050 scenarios, steered by the RTE and carried out in consultation with all stakeholders (RTE, 2020b).

9.9 Conclusion

Planning an effective decarbonisation requires to go from sector-specific to an economy-wide assessment of GHG emissions and costs. This means taking into account first the implication of each policy options regarding electricity generation (hence the need to adopt robust assessment methods, such as going from LCOE to VALCOE, and from VALCOE to complete system cost comparison), and then the dynamic change it can drive for other sectors. The studies led by RTE help to clarify the issues and to assess the economic and environmental costs and benefits of evolutions in different sectors: electric mobility, hydrogen (in the industry), heating for the building sector, and pave the way for full evaluation of policy choices to attain net zero carbon emissions by 2050.

Evaluating the cost efficiency of different energy policies raise some methodological difficulties but a broad-based effort from energy economists in France, Europe and the rest of the world through the IEA and NEA, brings a common framework to compare the socio-environmental value of climate actions.

As many countries are now targeting net zero emissions for the second half of the century as required by the Paris Agreement, this work should be pursued to determine priority actions to address climate change in the most efficient and rapid way.

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Hydrogen: An opportunity for the power sector

10.1 The unprecedented momentum of hydrogen

The global energy sector is facing an unprecedented transformation in the pursuit of sustainability. This brings considerable challenges, such as the integration of high shares of variable renewable electricity generation or the decarbonisation of the industrial sector with limited technological alternatives to fossil fuels. Tackling these challenges will require the contribution from an ample suite of solutions, among which is hydrogen. Hydrogen is a very versatile fuel that can play a significant role in many sectors across the energy system, which is why it has attracted strong interest from a diverse range of stakeholders. National and local governments, electricity suppliers, manufacturing industries, oil and gas companies, electricity and gas utilities or automakers are just some examples of the stakeholders that have expressed interest in implementing different hydrogen technologies to contribute to their decarbonisation targets. The reasons for this interest can be found in the potential that hydrogen presents to help overcoming several of the challenges that the energy system is facing:

- Hydrogen can help integrating greater amounts of variable renewable energy, whose availability is not always well matched with demand. The generation of hydrogen through electrolysis powered by renewable energy is a promising alternative for storing electricity over long periods (days, weeks or even months). Hydrogen can be used for generating back-up power in periods of high demand and low renewable generation.

- Hydrogen offers ways to deliver emissions reductions in sectors that are proving difficult to decarbonise, such as long-haul transport or industry. The utilisation of low-carbon hydrogen can reduce the carbon footprint of these sectors. Moreover, the use of hydrogen produced by electrolysis can contribute to the development of a more integrated energy system.

- Hydrogen can also help improving air quality since its combustion does not emit certain air pollutants (such as particulate matter or sulphur dioxide) and its utilisation in fuel cells avoids the generation of any air pollutants, including nitrogen oxides. This is particularly important in urban environments, where air quality has become an important concern for public health.

- Hydrogen can help improving energy security due to the variety of sources that can be used for its production and its flexibility of use. Hydrogen can be produced from all fuels: natural gas, coal, oil, renewables, or nuclear. In addition, it can be directly used or converted into other products with different potential applications such as ammonia, synthetic methane and synthetic liquid fuels.

However, this is not the first time that hydrogen has generated high expectations. Hydrogen was in the spotlight in the 1970s due to the oil price shocks, and in the 1990s and early 2000s when concerns about climate change took centre stage. Hydrogen did not manage to fulfil the expectations created on these occasions due to the recovery of low oil prices and the lack of strong climate drivers. However, in the current scenario, with more developed hydrogen technologies and a greater attention to deliver deep emission reductions, the outcome could be different. For this possibility to be realised, hydrogen has several key challenges to overcome:

- Almost all current hydrogen supplies come from natural gas and coal, with considerable associated carbon dioxide (CO_2) emissions. The production of hydrogen emits more than 800 million tonnes of CO_2 per year (Mt CO_2/y) – equivalent to the CO_2 emissions of Indonesia and the United Kingdom combined. Hydrogen can become a strong decarbonisation actor only if its production is based on low-carbon routes, such as fossil fuels coupled with carbon capture and use/storage (CCUS) or using low-carbon electricity.

- Producing low-carbon hydrogen is still costly. The technologies for low-carbon production cannot compete with conventional hydrogen production technologies yet. However, the prospects look promising thanks to lessons learnt from the development of other low-carbon technologies such as solar panels, wind turbines or electric vehicles.

- The development of hydrogen infrastructure is slow and is holding back widespread adoption. The final hydrogen price for consumers strongly depends on the costs of the delivery of hydrogen which itself depends on the infrastructure available and its optimum utilisation. The deployment of robust infrastructures to minimise these costs requires planning and co-ordination among governments at different levels (national and local), industry and investors.

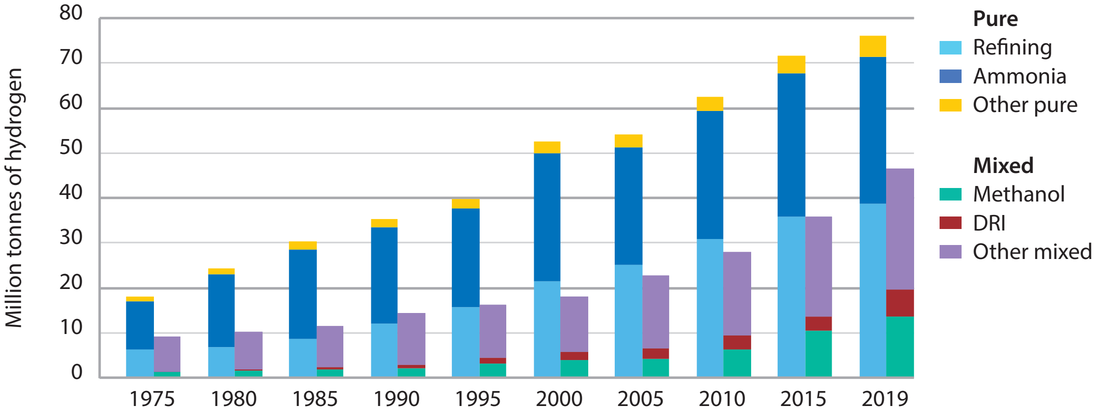
- Current regulations are limiting the development of a clean hydrogen industry. For example, certain regulations on hydrogen limits in the natural gas grids are a barrier for scaling up demand of low-carbon hydrogen. The adoption of international standards can help harmonising regulation and facilitate trade.

In this chapter, we provide an overview of the current situation of the hydrogen sector and the opportunities that are arising in the short/medium term, and could potentially arise in the long term, for the power sector to benefit from the big momentum that hydrogen is showing.

10.2 Hydrogen demand and potential for the future

Hydrogen has received the nickname of the "fuel of the future" but it has a long history as part of the energy system and it is already a big industry. The demand for pure hydrogen has increased more than threefold since the 1970s to reach around 75 million tonnes of hydrogen per year today (IEA, 2020). Demand comes mainly from oil refining and ammonia production (accounting for around 95% of the demand almost in equal shares) and other applications that require hydrogen in processes with very low tolerance to contaminants. In addition, certain industries also use hydrogen as a part of a mixture of gases typically called synthesis gas (syngas, composed by hydrogen, carbon monoxide, carbon dioxide and other light hydrocarbons). The demand of hydrogen in these processes has also increased significantly since 1975, currently accounting for around 45 Mt H_2/y, mainly from chemical production and the iron and steel sector ( ).

Figure 10.1: Evolution of global annual demand of hydrogen (pure and mixed) since 1975



Source: IEA (2020).

Hydrogen uses today

Oil refining is currently the main source of hydrogen demand (39 MtH_2/yr). Hydrogen is used in hydrotreatment and hydrocracking to remove impurities (especially sulphur) and upgrade heavy fractions into final products. The demand for hydrogen for refining purposes has grown substantially over time due to a larger demand for oil-derived products and also due to stricter fuel specifications, which led to lower acceptable levels of sulphur content. This growing trend is expected to continue in the future since oil-derived products demand is growing and the International Maritime Organisation has introduced fuel regulations limiting sulphur content to 0.5% from 2020. Beyond 2030, the pace of hydrogen demand growth is expected to slow down as oil demand is impacted by a combination of efficiency improvements and electrification (IEA, 2019). However, these trends for hydrogen demand in oil refining are quite uncertain due to the high impact of the COVID-19 crisis and how quickly and strongly the sector will recover from the economic downturn. Recent IEA forecasts suggest declines for gasoline (9%), diesel (6%) and jet fuel (37%) consumption in 2020 (IEA, 2020a; IEA, 2020b) which would lead to a drop in H_2 demand for oil refining to 36 Mt H_2 in 2020 (close to 7%). Most of the hydrogen consumed in oil refining is mainly produced on-site, as a by-product of catalytic naphtha reforming or by dedicated generation through steam methane reforming, with some contribution from coal gasification in areas with access to low-cost coal (like China). The remainder, which accounts for around a quarter of the demand, is procured from merchant suppliers, and it is often produced via steam methane reforming as well.

The chemical sector is another large consumer of hydrogen, with ammonia and methanol production being the second and third largest sources of hydrogen demand (33 Mt H_2/yr and 14 Mt H_2/yr respectively). The synthesis of these chemicals requires large quantities of hydrogen since it is part of their molecular structure. Most of the ammonia currently produced (80% of global production) is used to manufacture fertilisers, with the remainder used in other manufacturing industrial applications like explosives or specialty materials. Around two-thirds of methanol production is used in different chemical synthesis processes including formaldehyde, methyl methacrylate, solvents and larger organic chemicals with the reminder used as a fuel, blended in pure form or used for conversion into gasoline. Ammonia and methanol demands for these applications are also expected to grow in the future. Projected demands reach 38 Mt H_2/yr for ammonia 19 Mt H_2/yr for methanol by 2030. However, the COVID-19 crisis has also affected the chemical sector, generating uncertainty over short-term prospects of future demands. Methanol and ammonia producers estimated a decrease in demand of 7% and 5% respectively in 2020 compared to 2019. Similarly to the case of oil refining, the chemical industry relies on on-site natural gas reforming to meet its hydrogen demand due to its higher efficiency compared with coal gasification. Coal gasification is practically limited to China due to the lower cost of coal compared with natural gas. Hydrogen is also generated as a by-product in chlor-alkali processes and in the production of some high-value chemicals.

In steel manufacturing, the direct reduced iron steel production (DRI) is another large source of hydrogen demand, currently accounting for 6 Mt H_2/yr. DRI uses hydrogen mixed with other gases (like carbon monoxide), although some pilot projects are studying the feasibility of using pure hydrogen (HYBRIT, 2020). Roughly three-quarters of the hydrogen demand for DRI is supplied using natural gas reforming while the remainder is produced through coal gasification technologies. Steel demand is expected to grow globally (around 6% by 2030) as a consequence of the increase in infrastructure needs due to the growth in population in developing regions. This will certainly affect the demand of hydrogen, although it is difficult to determine the extent of this impact due to the influence of factors like the share of the different steel manufacturing technologies and the extent to which pure hydrogen can be used in DRI. Again, the COVID-19 crisis has a strong impact in the steel sector. The World Steel Association forecasts that steel demand will decrease by 6.4% in 2020 with an expected partial recovery in 2021 (WSA, 2020). In India, the largest DRI producing country, the decrease will be particularly sharp, with an expected 18% drop in 2020.

The evolution of the COVID-19 crisis in coming months will shape the trends of hydrogen demand in the near future in traditional hydrogen consuming sectors. Factors such as social distancing or a potential second wave of the pandemic with further lockdowns will determine how quickly these sectors can recover to pre-crisis levels of activity and hydrogen demand can resume its previous trends.

Emerging and new uses of hydrogen

In addition to the traditional demand sectors, hydrogen has been identified as a clean fuel with the potential to deliver greenhouse gas (GHG) emissions savings in several sectors. Some of these sectors are already increasingly demanding hydrogen and can become considerable sources of hydrogen demand in the near future. The new hydrogen applications with higher potential to become sources of large hydrogen demand are:

1. *Road transport*. Hydrogen has long being heralded as a potential clean transport fuel, although the current uptake of fuel cell electric vehicles (FCEVs) is very low. There has been a significant acceleration in the uptake of hydrogen in road transport since 2017 and new opportunities are appearing in other sectors that are particularly difficult to decarbonise, such as shipping and aviation. The use of both hydrogen itself (long-haul transport, maritime) and hydrogen-derived fuels (ammonia in shipping and synthetic hydrocarbons in aviation) are promising alternatives to fossil fuels.

2. *Power generation*. Hydrogen plays a negligible role in the power sector today, accounting for less than 0.2% of electricity generation. However, the use of hydrogen for flexible power generation and long-term energy storage or the co-firing ammonia in coal-fired power plants to reduce their CO_2 intensity appear as promising opportunities for hydrogen in the future.

3. *Domestic heat*. Buildings accounts directly and indirectly for 30% of the world final energy consumed. Direct emissions from fossil fuel combustion for space conditioning, water heating, cooking and other service applications account for about 3 Gt CO_2. Decarbonising the energy demand in buildings is a very complex task and it is very likely that it will require the future coexistence of a variety of energy sources and technologies, among which hydrogen is included.

4. *Industrial high-temperature heat*. The majority of the energy demand for high-temperature heating in the industrial sector comes from steel and chemical industries. However, there is still a large demand in other industries, such as cement. Direct electrification is extensively used in many high-heating applications, but some large-scale processes (like cement kilns) are particularly difficult to electrify and CCUS and hydrogen seem to be the only technological alternatives to enable decarbonisation.

These sectors have not avoided the impact from COVID-19 crisis. FCEV sales dropped in the first four months of 2020, compared with the same period in 2019, by 7%, 12% and 65% in China, Japan and the United States, respectively. In addition, tapping into the maximum potential of hydrogen as a clean energy solution in some applications, such as industrial high-temperature heat or power generation, relies on the progress of many demonstration projects currently under development. These could be delayed or even cancelled because of the economic downturn caused by the crisis. However, only minor delays due to slower activity caused by lockdowns have been announced and even some technology suppliers have announced plans to accelerate the development of hydrogen technologies. This is the case for Volvo and Daimler, which announced in April a joint venture to work on hydrogen fuel cell for trucks, or Bosch, which included the manufacture of fuel cells in their plans to response to COVID-19 crisis (Bosch, 2020; Daimler, 2020). In addition, several governments (such as Germany and the European Commission) have adopted in the last few months ambition national hydrogen strategies and included hydrogen technologies within the COVID-19 recovery packages.

The need for decarbonising traditional hydrogen consuming sectors, the increase in hydrogen demand of these sectors and the emerging demand from new sectors, offer a significant opportunity for the adoption of low-carbon hydrogen technologies. Fossil fuel technologies coupled with CCUS have a head start over electrolysis to deliver low-carbon hydrogen at scale. However, their deployment will depend on the availability of suitable geological CO_2 storage and the competitiveness and demand of CCU technologies. This opens the scope for scaling up hydrogen production via electrolysis.

10.3 Hydrogen production technologies

Hydrogen is a very versatile fuel that can be produced through many different technological routes and from many different energy sources, including fossil fuels, biomass and electricity (Figure 10.2). However, the economics of each technology have defined the current mix of technological options for hydrogen production:

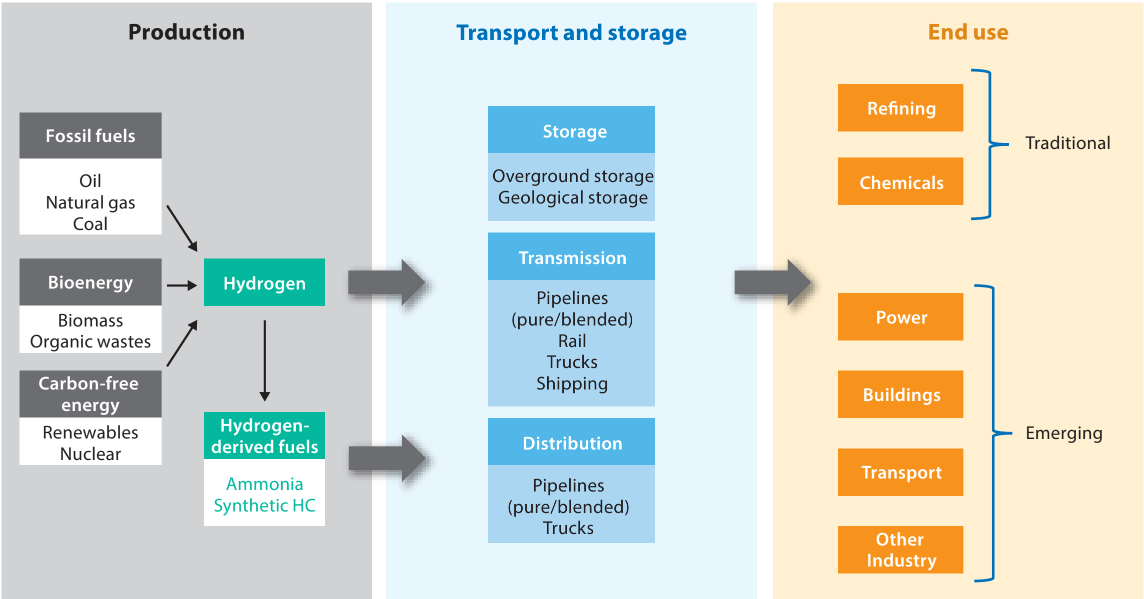
- Around three-quarters of the current hydrogen dedicated production uses natural gas reforming. The vast majority of this production is unabated with a very limited adoption of CCS.

- Coal gasification is the other major route of production, accounting for around 23% of global dedicated hydrogen production due to the extensive utilisation of this route in China. Similarly to natural gas reforming, most of the production of hydrogen from coal is unabated, with an anecdotic share of the supply incorporating CCS technologies.

- Partial oxidation of oil and electrolysis account for the remainder of the dedicated production.

Biomass gasification has long been suggested as a potential route for the future production of low-carbon hydrogen (or negative-carbon if the process is coupled with CCUS). However, technological barriers and feedstock limitations have so far prevented this technology from reaching commercialisation.

Figure 10.2: Hydrogen supply chain



Note: Synthetic HC = synthetic hydrocarbons.

Natural gas methane reforming

Steam methane reforming is the most widespread technology for hydrogen production. The natural gas reacts with steam at high temperature in the presence of a catalyst to produce syngas. Afterwards, a water gas shift process transforms the carbon monoxide in the syngas into carbon dioxide and hydrogen. The hydrogen is separated from the carbon dioxide and purified.

The production of hydrogen from steam methane reforming (SMR) generates, depending on the conversion efficiency, around 9 $kgCO_2$ per kgH_2. Therefore, the hydrogen produced by conventional SMR is far from being low-carbon. CCUS technologies can be used to minimise the carbon footprint of SMR, especially by retrofitting current production plants, although this brings about important implementation challenges. In traditional SMR designs, capture rates exceeding 90% can be achieved but this increases significantly the production costs. Alternative technologies, like autothermal reforming and gas heated reformers, have been developed with the objective of increasing the efficiency of the reforming process and facilitating the capture process. These advanced designs can deliver carbon reductions over 97% (Progressive Energy, 2020).

Coal gasification

Coal gasification is a mature technology for the production of hydrogen. It has been used for many decades, especially for the production of ammonia in chemical and fertiliser industries. Currently, the majority of the global production of hydrogen from coal gasification is based in China. In coal gasification, coal reacts at high temperatures in the presence of an oxidising agent (air, steam, carbon dioxide or a combination of them) in stoichiometric deficit to produce syngas.

This syngas undergoes the same sequence of processes as in the case of SMR. CO_2 emissions of hydrogen production from coal gasification are considerably larger than in SMR, over 20 $kgCO_2/kgH_2$. Therefore, coal gasification has to incorporate CCUS in order to produce low-carbon hydrogen. However, the use of CCUS technologies in coal gasification is particularly challenging. Coal contains more impurities than natural gas when it is processed and it requires considerably larger capture capacities, thus increasing the cost and the energy penalty of the capture process.

Water electrolysis

Water electrolysis is an electro-chemical process that uses electricity to split water into hydrogen and oxygen. Nowadays, water electrolysis accounts for less than 0.1% of the global hydrogen production, limited to sectors requiring relatively pure (therefore, high cost) hydrogen. Additionally, electrolytic hydrogen is also currently produced through chlor-alkali electrolysis in the production of chlorine and caustic soda. This route accounts for around 2% of total global hydrogen production.

There has been an acceleration in the deployment of electrolysis technologies, both in the number of projects and their size. The average unit size of the electrolysers installed in the early 2000s was around 0.1 MWe (megawatts electrical) and has increased up to an average of 1.0 MWe today. Numerous projects in the range of 1-6 MWe have been deployed since 2013 and a 10 MWe Power-to-Hydrogen project started operation in Japan in April 2020 (Asahi Kasei Corporation, 2020). Several projects for electrolysis plants of up to 20 MWe are under construction and projects with installed capacities in the hundreds of MWe have been announced for the early 2020s. Up to 2.8 GW in large-scale projects have been announced to be deployed just in the next three years, what could bring the installed capacity to 3 GW by 2023.

This could start creating economies of scale that will help to drive down capital costs and to scale up the supply chain of the electrolyser industry. Currently, there are three main types of electrolysers:

- *Alkaline electrolysers*. This is the most mature technology and has been in use since the 1920s. It is widely used in fertiliser and chlorine industries. Actually, alkaline electrolysers with capacities up to 165 MWe operated in the 20th century, but most of them were decommissioned as steam methane reforming became the most widespread technology for hydrogen generation. Besides maturity, it offers low capital costs due to the avoidance of precious materials. On the negative sides, alkaline electrolysers use a solution of potassium hydroxide as electrolyte that has to be recovered and recycled and are less flexible than other designs. With a minimum load of 10% to full design capacity, their ability to adapt to variable electricity inputs is limited.

- *Proton exchange membrane (PEM) electrolysers*. Although PEM were introduced in the 1960s by General Electric, they are a less mature technology. PEM electrolysers use pure water as an electrolyte solution and are relatively small, compared with alkaline, making them more attractive in dense urban areas and for mobile or remote applications. They are particularly well suited for decentralised production and storage at refuelling stations since they can generate hydrogen at high pressure (30-60 bar, compared to 1-30 bar for alkaline). In addition, PEM can operate more flexibly, with operation potentially ranging from zero up to 160% of design capacity, being possible to overload the electrolyser for some time. This makes PEM very attractive for providing grid services and to operate with the variable electric inputs. However, they use expensive electrode catalysts (platinum, iridium) and membrane materials, and their lifetime is currently shorter than that of alkaline electrolysers, resulting in a lower deployment. Significant R&D efforts are being made to find alternative materials and to improve operative lifetime.

- *Solid oxide electrolysis cells (SOEC).* SOEC are the least developed electrolysis technology. Some companies are aiming to bring them to market and there have been some announcements of projects using SOEC electrolysis to produced synthetic hydrocarbons at relatively large scale. The electrode and electrolyte in SOEC are made of ceramic materials with relatively low costs. They operate at high temperatures and can reach significantly higher efficiencies than alkaline and PEM. SOEC need a source of heat since they use steam in the electrolysis process. This brings about challenges to ensure low-carbon production of hydrogen since the origin of the heat source can also be a source of CO_2 emissions. However, it also offers interesting opportunities for process system integration. In the production of synthetic hydrocarbons, the synthesis processes, like Fischer-Tropsch synthesis and methanation, release excess heat that can be utilised in the production of the steam needed for the operation of the SOEC electrolyser.

Table 10.1: Techno-economic characteristics of different electrolyser technologies

	Alkaline		PEM		SOEC	
	Today	Long term	Today	Long term	Today	Long term
Electrical efficiency (LHV, %)	63-70	70-80	56-60	67-74	74-81	77-90
Stack lifetime (1 000s operating h)	60-90	100-150	30-90	100-150	10-30	75-100
Load range (% nominal load)	10-110		0-160		20-100	
CAPEX (USD/kWe)	500-1 400	200-700	1 100-1 800	200-900	2 800-5 600	500-1 000

Notes: LHV = lower heating value. No projections made for load range. For SOEC, electrical efficiency does not include the energy for steam generation. CAPEX represents system costs, including power electronics, gas conditioning and balance of plant; CAPEX ranges reflect different system sizes and uncertainties in future estimates.

Source: Agora (2018); Butler (2018); Element Energy (2018); FCHJU (2014); NOW (2018); Schmidt (2017); and IEA analysis.

Box 10.1: Nuclear power and hydrogen production

Nuclear power was considered an alternative for low-carbon hydrogen production since the earliest waves of interest in hydrogen in the 1970s, but this was never realised due to ups and downs in the nuclear industry, the higher hydrogen production costs compared with natural gas and the fact that hydrogen did not fulfil the expectations of expanding to new applications. Today, the progress achieved in electrolysis and the development of new emerging routes for hydrogen production from nuclear energy are creating new hopes in this sector:

- The electricity from nuclear power plants can be directly used by fuel electrolysers, providing flexibility to the nuclear plant while generating low-carbon hydrogen. In addition, the oxygen generated in the electrolysers can also be used in the nuclear reactors instead of just being vented. Some demonstration projects have already been announced in the United Kingdom and the United States to assess the incorporation of electrolysers into existing nuclear power stations (EDF Energy, 2020; Patel, 2019). .

- Steam from nuclear light water reactors can be used in steam methane reforming, reducing the natural gas use for heat generation and the carbon intensity of the hydrogen produced. Depending on local conditions, nuclear steam could be cheaper than steam generated from natural gas, providing an additional revenue for nuclear power plants.

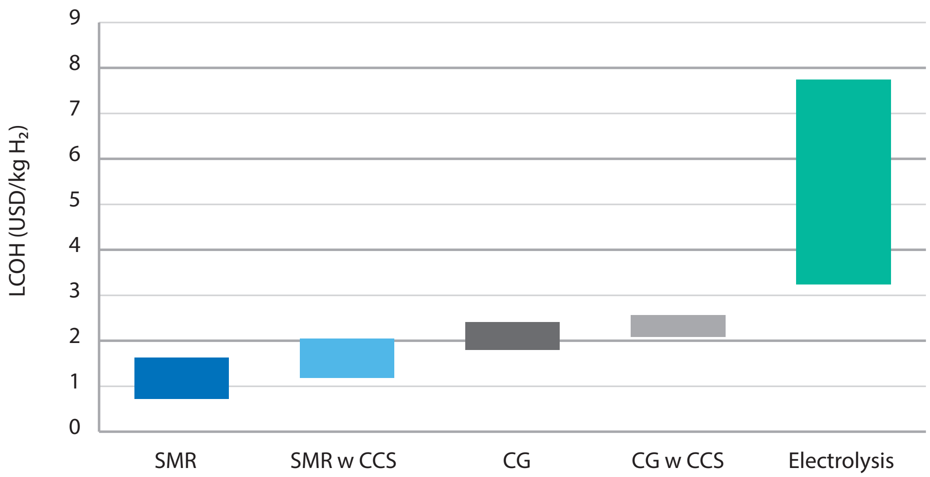
(continued Box 10.1)

- Small modular reactors could also play a role in SOEC electrolysis in the future. Exploring non-electric applications for small modular reactors, such as hydrogen, is part of the Joint Use Modular Plant (JUMP) research programme in the United States.
- Nuclear power plants simultaneously generate electricity and heat (temperatures of 300°C in commercial reactors). For this reason, nuclear plants can provide the heat needed for SOEC electrolysis. Research is underway to develop materials for these types of electrolysis cells that could be well suited to the temperature at which nuclear heat can be obtained.
- Nuclear power plants simultaneously generate electricity and heat (temperatures of 300°C in commercial reactors). For this reason, nuclear plants can provide the heat needed for SOEC electrolysis. Research is underway to develop materials for these types of electrolysis cells that could be well suited to the temperature at which nuclear heat can be obtained.

Costs of hydrogen production

The production cost of hydrogen is influenced by several factors with different weight in the final cost depending on the fuel used (natural gas, coal or electricity) and the technology (SMR with and without CCUS, coal gasification with and without CCUS or the different types of water electrolysis). The cost of hydrogen produced from natural gas varies in the range of USD 0.7-1.6/kg H_2 for unabated production (Figure 10.3). In the case of natural gas reforming with CCUS, the cost rises up to USD 1.2-2.0/kg H_2, although this price gap could be influenced in the future by the evolution of CCUS technologies and climate policies like carbon pricing or clean fuel standards.

Figure 10.3: Current levelised cost of hydrogen productions for different technologies



Notes:
– LCOH, levelised cost of hydrogen; SMR, steam methane reforming; CG, coal gasification, CCS, carbon capture and storage. Assumptions: 8% discount rate, 25 years system lifetime, natural gas price USD 1.6-6.7/MBTU, coal price USD 67-159/toe, electricity price USD 36-116/MWh.
– SMR CAPEX USD 910/kW H_2, OPEX 4.7% of CAPEX, 76% efficiency, 95% load factor.
– SMR w CCS CAPEX USD 1583/kW H_2, OPEX 3% of CAPEX, 69% efficiency, 95% load factor, 95% capture rate.
– CG CAPEX USD 2672/kW H_2, OPEX 5.0% of CAPEX, 60% efficiency, 95% load factor.
– CG w CCS: CAPEX USD 2783/kW H_2, OPEX 5.0% of CAPEX, 58% efficiency, 95% load factor, 90% capture rate.
– Electrolysis CAPEX USD 872/kWe, OPEX 2.2% of CAPEX, efficiency 64%, 3000-4000 full load hours. Electrolysis CAPEX calculated as the average of global alkaline and PEM CAPEX.

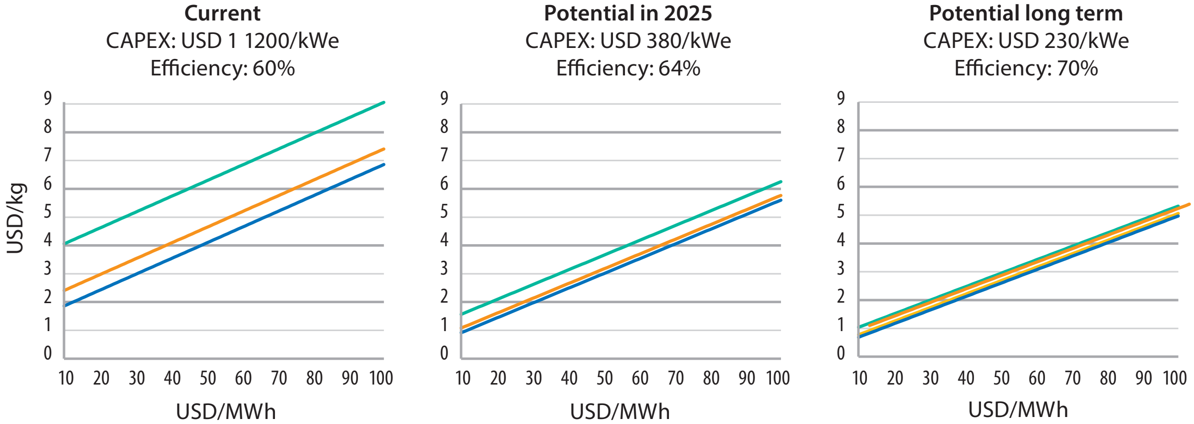
Source: IEA (2020).

The capital expenditure (CAPEX) and, especially, the fuel prices are the most influential factors for the cost of hydrogen production from natural gas. Natural gas accounts for 60-80% of the production costs, depending on the availability and price of natural gas. Low production costs can be realised in regions such as the Middle East, Russia and the United States, while in countries relying on natural gas imports, such as China, Japan or Korea, hydrogen production costs using natural gas are higher

Low-cost coal resources in China create an ideal situation for coal gasification instead of natural gas reforming. Coal gasification presents lower efficiency and higher CAPEX requirements than SMR, but this is compensated by the low coal prices. However, the high carbon intensity of this process requires CCUS technologies for low-carbon hydrogen production, increasing the production costs by 5-15%.

The production cost of hydrogen from water electrolysis is influenced by several factors, including fuel costs, CAPEX requirements, conversion efficiency and annual operating hours. Figure 10.4 shows the levelised cost of hydrogen (LCOH) production today, and the potential costs in the near term and in the long term for PEM electrolysers. Similarly to SMR, fuel costs (electricity) are the main factor determining the cost of hydrogen production. At high electricity costs, the effect of other factors is diluted, whereas at low electricity costs, their impact increases. CAPEX requirements present a considerable margin for improvement, thus offering an opportunity for cost reductions in the long term.

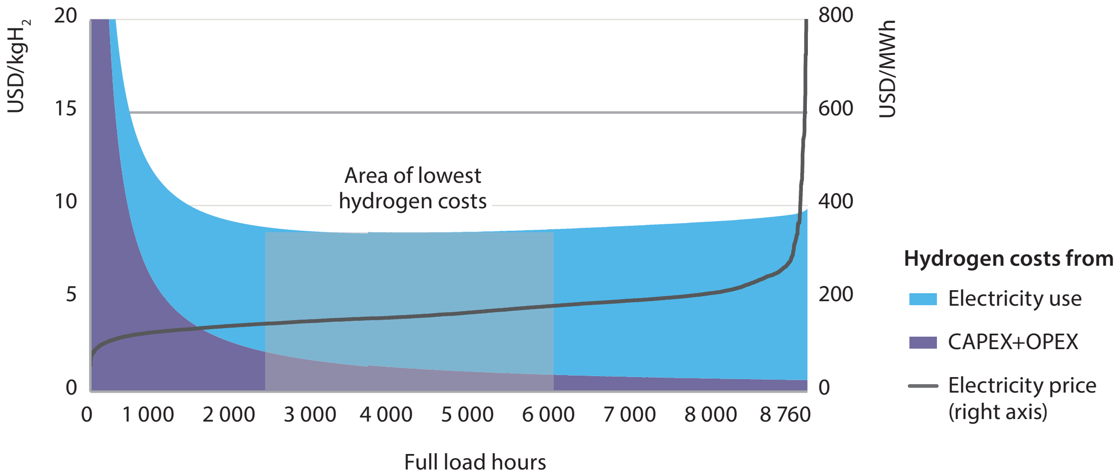
Figure 10.4: Current and projected levelised cost of hydrogen (USD/kg H2) production from water PEM electrolysis



Note: FLH, full load hours. Discount rate: 8%. OPEX (% of CAPEX): current 2%, potential in 2025 1.6%, potential long term 1.5%. Stack lifetime (hours): current and potential in 2025 95 000, potential long term 100 000. System lifetime (years): current 28, potential in 2025 and long term 30.

The operating hours also have an important impact on the final cost of hydrogen production. As the operating hours increase, the impact of CAPEX costs on the LCOH declines and the impact of electricity costs rises (Figure 10.5). This is particularly relevant in electrolysers that operate with grid electricity in systems with increasing shares of variable renewables, where surplus electricity may be available at low costs, but potentially only available for a very few hours within a year. Utilising only low-cost electricity implies a low utilisation of the electrolyser and high hydrogen costs due to the impact of CAPEX costs. With increasing utilisation hours, grid electricity costs increase, but the higher utilisation of the electrolyser leads to a decline in the cost of producing a unit of hydrogen. These opposite trends regarding the impact of CAPEX and electricity costs generate an optimum level of operating hours that lies at around 3 000-6 000 equivalent full load hours.

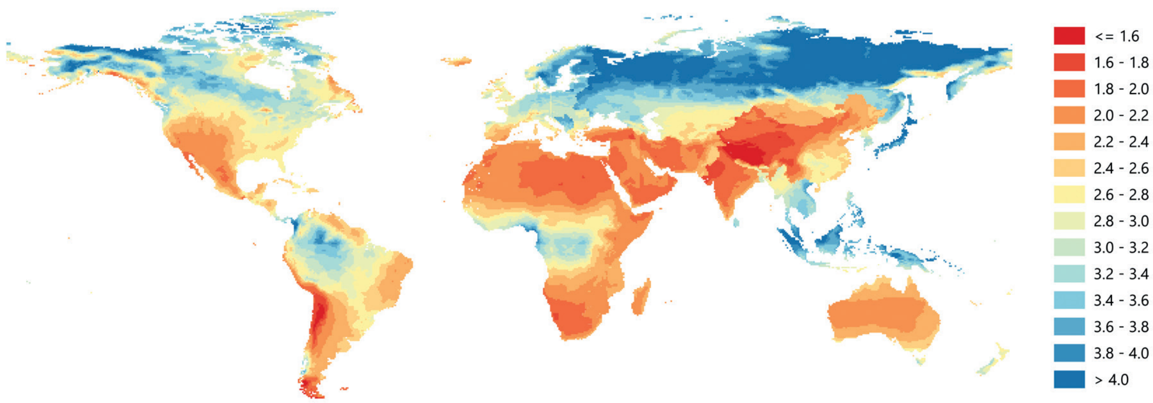
Figure 10.5: Hydrogen costs from electrolysis using grid electricity



Source: IEA (2019a).

The use of grid electricity does not guarantee the production of low-carbon hydrogen since, depending on the grid carbon intensity, the hydrogen produced can have a higher carbon footprint than fossil fuel-based hydrogen. The use of dedicated electricity generation from renewables or nuclear power offers a low-carbon alternative to grid electricity. The costs of solar PV and wind generation have shown a sharp decline in recent years and it is expected that these costs will decrease even further in the near future. For this reason, building electrolysers at locations with excellent renewable resources could become an attractive supply option for low-carbon hydrogen, even after taking into account the costs of transporting hydrogen from these locations to the end users.

Figure 10.6: Hydrogen costs from hybrid solar PV-onshore wind systems in the long term



Source: IEA (2019a).

Geospatial analysis considering the long-term potential for technology improvements and cost reductions in renewable electricity generation reveals that electrolytic hydrogen could become competitive against traditional fossil hydrogen production in certain regions (Figure 10.6). Some locations could produce electrolytic hydrogen at costs under USD 2/kg H_2. The high disparity on costs across different regions offers an opportunity for international trade of hydrogen, which is a backbone of a secure energy system. Regions with abundant solar and wind resources, such as Australia or Northern Africa, could export renewable energy in the form of hydrogen to regions with high energy demands and more limited or less attractive renewable resources, such as Japan or parts of Europe.

Hydrogen-derived fuels

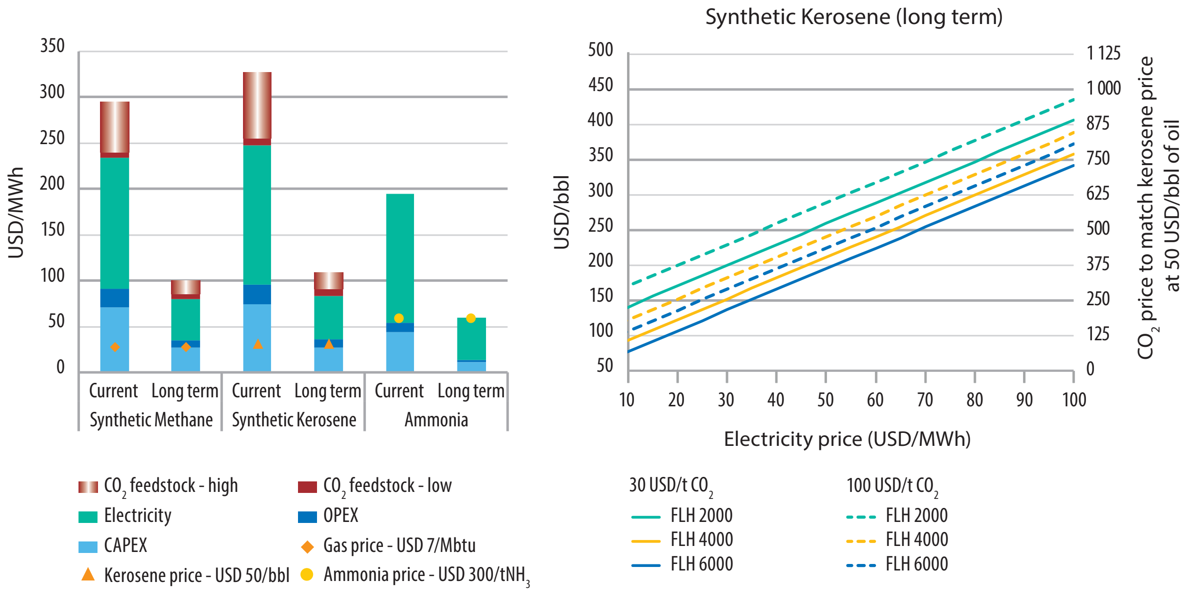
Products like methanol, methane, liquid hydrocarbons or ammonia can be synthesised from hydrogen. Some of these fuels can act as drop in substitutes of some fossil fuels and can be decarbonisation options for the so-called hard-to-abate sectors, where other decarbonisation alternative, such as direct electrification, are more difficult and costly. While the low energy density of hydrogen is a challenge for its transport, storage and utilisation in certain sectors (like shipping transport and aviation), hydrogen-derived fuels present higher energy density, facilitating transport and storage, and some of them can more easily make use of existing infrastructure for storage and transport.

The transformation of hydrogen into these derivatives involves, however, additional processing steps, leading to energy losses and increasing costs. Typically, 45-60% of the electricity used for the production of hydrogen-derived-fuels is lost across the value chain. In addition, many of the production routes of these fuels are at early development stages and require additional inputs (nitrogen for the production of ammonia and carbon for synthetic hydrocarbons), resulting in higher production costs than conventional production routes. For synthetic hydrocarbons, the origin of the carbon also affects the carbon footprint of the synthetic hydrocarbon. Only in the case of biogenic CO_2 (captured from at a bioenergy conversion plants, such as a biomass power plants) or CO_2 from direct air capture (DAC; CO_2 extracted from the atmosphere), the final fuel can be considered carbon-neutral:

- Synthetic methane is produced by converting hydrogen and carbon dioxide through a process called methanation. The majority of the projects so far for hydrogen-based fuels and feedstock have been aimed at producing synthetic methane, most of them located in Germany and other European countries.
- Synthetic liquid hydrocarbons (such as diesel and kerosene) are produced by converting hydrogen and carbon monoxide into long chain hydrocarbons using the Fischer-Tropsch synthesis process, followed by an upgrading process to produce usable liquid fuels.
- Ammonia is produced using the well-established Haber-Bosch process from clean hydrogen and nitrogen. SMR and coal gasification are the main routes for producing the hydrogen used in the synthesis of ammonia today, though some small-scale demonstration projects based on electrolytic hydrogen have been in operation for several years.

The economics of producing hydrogen-derived fuels using electrolysis depend on various factors, in particular the cost of electricity and, in the case of synthetic hydrocarbons, the availability and cost of the carbon source (Figure 10.7). The overall energy efficiency of the supply chain has a very high impact in the final cost of these fuels. Improving the efficiencies of the conversion processes, in particular of the electrolysis stage, can help to reduce the production costs for these fuels. CO_2 costs currently range from USD 30/tonne from bioethanol plants to USD 135-340/tonne from DAC. The competitiveness of these hydrogen-based fuels will also depend on the implementation of carbon prices (or alternative policy instruments) that could close the price gap with incumbent fossil fuels.

Figure 10.7: Current and long-term projected levelised costs of production of hydrogen-derived fuels and influence of electricity price, full load hours and CO_2 feedstock costs on the projected levelised cost of synthetic kerosene



Notes:

Left graph:

– 3 500 h full load hours and a discount rate of 8%. Electricity price USD 70/MWh (current) and USD 25/MWh (long term). CO_2 feedstock costs lower range based on CO_2 from bioethanol production at USD 30/t CO_2 (near and long term); CO_2 feedstock costs upper range based on DAC at USD 300/t CO_2 (near term) and USD 100/t CO_2 (long term).

– Electrolysis: CAPEX (current, long term): 872, 270 USD/kWe; Annual OPEX (% of CAPEX): current 2% and long term 1.5%; Stack lifetime: current 95 000 h and long term 100 000 h; System lifetime: current 28 and long term 30 years.

– Ammonia synthesis: CAPEX 108 USD/t NH_3; Annual OPEX 1.5%; Electricity consumption 4 GJ/t NH_3; Hydrogen consumption 0.0056 t NH_3/kg H_2;

– Methanation: CAPEX (current, long term) 845, 565 USD/kWh fuel; Annual OPEX 4%; Electricity consumption 0.013 $GJ/GJ_{product}$; Efficiency (% LHV): 77%,

– Fischer-Tropsch: CAPEX (current, long term) 890, 565 USD/kWh fuel; Annual OPEX 4%; Electricity consumption0.018 $GJ/GJ_{product}$; Efficiency (% LHV): 73%.

Right graph: FLH = full load hours.

Source: IEA (2020).

10.4 Opportunities for hydrogen and linkages to the electricity system

Low-carbon hydrogen possess a strong potential for contributing to GHG emission reductions in a wide range of sectors. Several opportunities can be materialised in the short term. The replacement of hydrogen from unabated fossil fuels by low-carbon hydrogen in existing industrial uses, the use of hydrogen in road transport or the injection of hydrogen in the gas grid are some of these short-term opportunities. These are technology-ready alternatives that will require relatively low investment compared with other low-carbon alternatives (when these are available) and that are already occurring at small scale. Scaling them up can deliver significant cost reductions that will improve their competitiveness and can help enabling other long-term opportunities for hydrogen. The use of hydrogen in the power sector to facilitate the integration of variable renewables (VRE), for example in flexible generation from hydrogen-fired gas turbines or the provision of large-scale and long-term storage, is among these long-term opportunities. Hydrogen and hydrogen-derived fuels can be options to decarbonise transport modes, such as shipping or aviation, where electrification is more difficult.

Alongside other low-carbon options for producing hydrogen, notably fossil fuels with CCUS, hydrogen from clean electricity can contribute to the decarbonisation of other parts of the energy system, in particular in areas, where direct electrification is difficult. This section provides an overview of the most appealing opportunities available in the short- and long-term for low-carbon hydrogen with a special focus on the role of and linkages with the electricity system.

Industrial sector and oil refining

The largest potential for low-carbon hydrogen resides in current uses in the industrial sector and oil refining. These applications represent an easy and immediate penetration route that will require no modification in the operation of these processes. This is reflected in the increase of projects focused on the use of low-carbon hydrogen in these sectors observed in recent years, along with the increasing number of announced projects to be deployed in early 2020s, with the vast majority of projects focusing on oil refining, the chemical sector and steel production (IEA, 2020c).

Current status and future opportunities

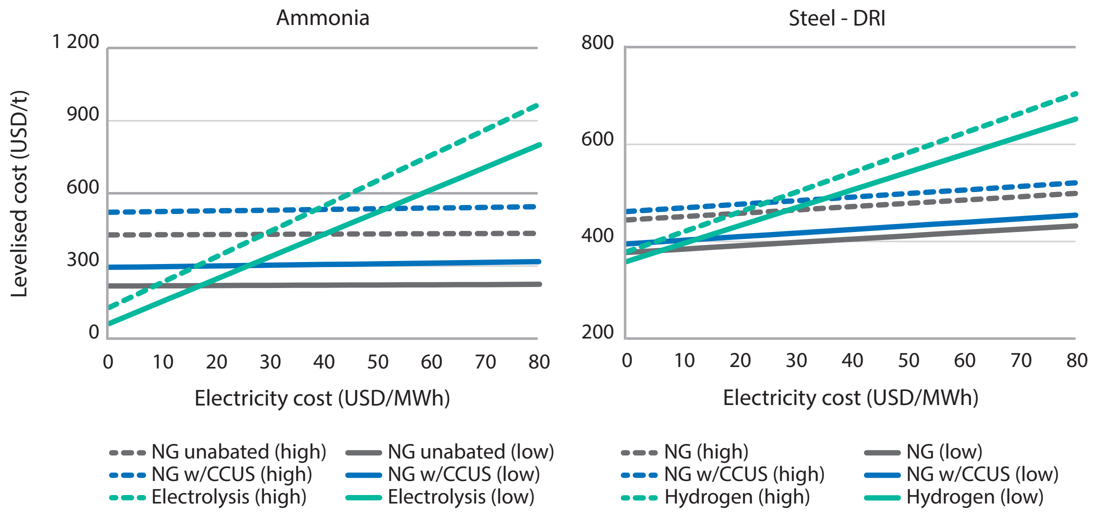
Depending on the application, different low-carbon hydrogen technologies may be better suited. For this reason, the opportunity and potential for the power sector and electrolytic hydrogen will differ depending on the industrial process:

- **Oil refining:** This sector presents a large on-site generation from natural gas, coal and naphtha, which is highly integrated within refining operations. Retrofitting these processes with CCUS seems to be the best alternative in the short term, as long as geological storage and/or markets for CO_2-derived products are available. An increase in demand for oil refining products will likely occur in the near future, although there is enough refining capacity available to meet this growth, limiting the need for new hydrogen capacity. However, the power sector could have an opportunity in replacing merchant hydrogen purchases with electrolytic hydrogen.
- **Chemical industry:** Similarly to oil refining, the majority of hydrogen demand in chemical manufacturing is produced on-site and CCUS technologies look like a promising alternative to minimise its carbon footprint. However, a strong increase in the demand for products like ammonia and methanol is expected due to economic and population growth. More production capacity will be needed, thus generating an opportunity for electrolytic hydrogen. In the case of carbon-containing products like methanol, the need for a source of carbon may pose additional barriers, but ammonia production is well suited to implement electrolytic hydrogen in new plants.
- **Iron and steel:** It is quite unclear whether CCUS or electrolytic hydrogen would be a better option to substitute fossil-derived hydrogen in this sector. It is possible to retrofit DRI facilities with CCUS, although around 30% of natural gas can be replaced with electrolytic hydrogen in the current DRI route. The complete conversion of DRI route to hydrogen is still under demonstration.
- **High temperature industrial heat** could be another source of hydrogen demand growth in the future where direct electrification faces implementation challenges (such as steam crackers or cement kilns). However, the different burning characteristics of hydrogen compared with incumbent fuels will require process and equipment modifications or adaptation.

Economics

The biggest barrier that low-carbon hydrogen faces to replace current fossil-based hydrogen in oil refining and the chemical sector is the cost penalty. Figure 10.8 presents a cost comparison for ammonia production and steel production through DRI. Electrolytic hydrogen requires low electricity prices in both cases to become competitive with fossil-based hydrogen or other low-carbon technologies (CCUS). Ammonia presents better prospects for electrolytic hydrogen since it can compete with production based on SMR with CCUS at electricity prices under USD 50/MWh, depending on natural gas prices. Moreover, with electricity prices below USD 20/MWh, it can become competitive against conventional technologies. Prices in the USD 20-50/MWh range are already observed for renewable generation, showing the good opportunity for electrolytic hydrogen in ammonia production in the short term. Electrolytic hydrogen would find more difficulties to be competitive in the DRI route for steel production. Only at very low electricity prices (below USD 10/MWh) it could compete with conventional DRI or DRI incorporating CCUS at low natural gas prices, whereas electricity prices under USD 40/MWh would be required to reach competitiveness at high natural prices.

Figure 10.8: Cost comparison of low-carbon hydrogen and conventional routes for ammonia and steel in the long term



Note: The levelised cost includes the cost of CAPEX on core process equipment, fixed OPEX, fuel and feedstock costs, and the cost of capturing, transporting and storing CO_2. Best practice energy performance is assumed for natural gas-based routes. Electrolyser CAPEX range = USD 455–894/kWe. Electrolyser efficiency range = 64–74% on an LHV basis. 95% DRI charge to the EAF is assumed in all cases.

Source: IEA (2019a).

Transport

Hydrogen has generated high expectations as a potential alternative to conventional transportation fossil fuels. However, the high cost of hydrogen and the slow progress in the development of fuel cells have prevented hydrogen to meet these prospects and the current use of hydrogen in transport is very low. This situation is starting to change since there has been a notable acceleration in the last couple of years thanks to the ambitious plans being developed by California, China, Korea and Japan. Energy demands in road transport are expected to grow strongly in the next decade, driven by demand for trucks and rising car ownership in emerging economies. Given that any road transport mode can be powered using hydrogen, the potential for hydrogen is very large. However, direct electrification also presents very strong prospects and has a considerable head start in certain road transport modes, such as passenger cars (IEA, 2019b). This suggest that hydrogen could have a bigger role in areas like long-distance transport, trucks or bus fleets, which operate with high power demands and long usage cycles, where electric vehicles run into limitations in terms of range and refuelling times.

Current status and future opportunities

In general, hydrogen and hydrogen-derived fuels appear as the only clean alternative for the transport energy demand that could not be electrified or met by biofuels. Table 10.2 summarises the current situation and the potential that hydrogen and hydrogen-derived fuels present in different transport modes. Hydrogen can complement direct electrification in road transport and rail and has a significant potential for being an alternative to conventional fuels in shipping. On the side of hydrogen-based fuels, ammonia offers particular advantages for shipping whereas synthetic jet fuel can play a substantial role in aviation. Due to the nature of these transport modes, they have a very limited pool of technological alternatives to current fossil fuels. The role of direct electrification is very limited given practical difficulties that come with the energy and power density requirements and drop-in fuels look like the most promising alternative. Biofuels are the furthest developed drop-in fuels, but their sustainable production presents serious challenges that limit their availability and they will not be able to completely replace conventional maritime and aviation fossil fuels. In addition, both ammonia and synthetic could take advantage of existing infrastructure with limited modification although their productions suffers, from these fuels look more like a long-term alternative.

Table 10.2: Potential uses of hydrogen and hydrogen-derived fuel in transport applications

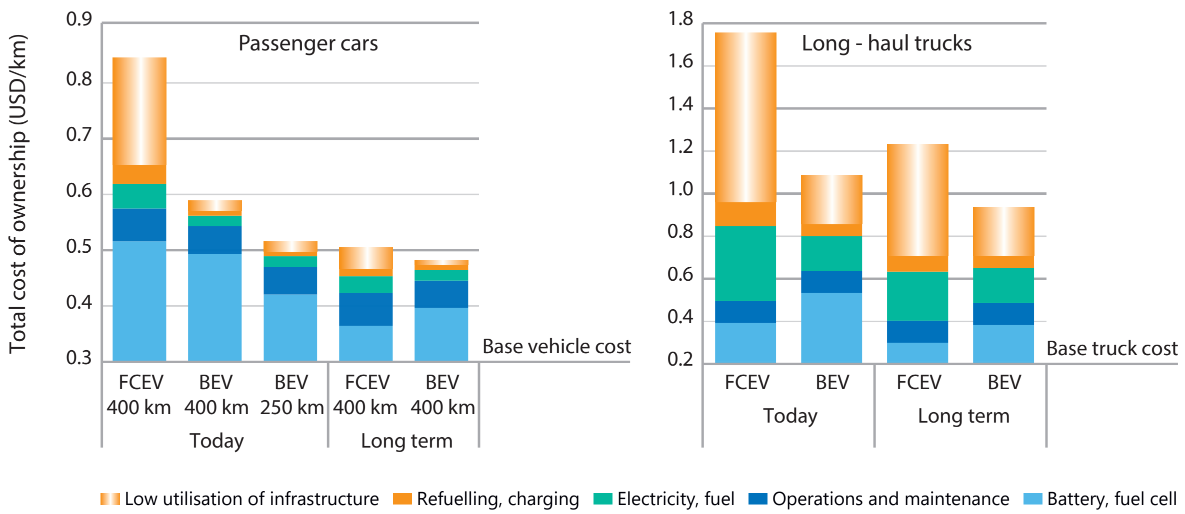
<table>
<tr><th rowspan="2">Transport mode</th><th rowspan="2">Current deployment</th><th colspan="2">Future deployment</th></tr>
<tr><th>Opportunities</th><th>Challenges</th></tr>
<tr><td>Cars and vans</td><td>Close to 19 000 vehicles in operation at the end of 2019, mainly in California, Japan and Korea.</td><td rowspan="2">Hydrogen: Short refuelling time; less weight added for energy stored; zero tail-pipe emissions; lower material footprint of fuel cells than lithium batteries.
Captive vehicle fleets can improve utilisation of refuelling stations; long-distance and heavy duty attractive option.</td><td rowspan="2">Hydrogen: Initial low utilisation of refuelling stations raises fuel cost; reductions in fuel cell and storage costs needed; efficiency losses on a well-to-wheels basis.
Synthetic fuels: Relatively high costs.</td></tr>
<tr><td>Heavy duty vehicles</td><td>More than 4 400 buses and 1 800 trucks in operation at the end of 2019, mostly in China. Several thousand to be deployed in early 2020s in Europe.</td></tr>
<tr><td>Maritime</td><td>Limited to demonstration projects for small ships and on-board power supply in larger vessels.</td><td>Hydrogen and ammonia are candidates for domestic shipping and the IMO Greenhouse Gas Reduction Strategy.</td><td>Hydrogen: Storage cost higher than other fuels.
Hydrogen/ammonia: cargo volume lost due to storage (lower density than current liquid fuels).</td></tr>
<tr><td>Rail</td><td>Two hydrogen trains operating in Germany in 2019. Expected to expand to 41 by 2023. Trials in China, Japan, Korea, the Netherlands, Italy and the UK.</td><td>Hydrogen trains can be most competitive in rail freight (regional lines with low network utilisation, and cross-border freight) and remote regions presenting challenges to electrify.</td><td>Rail is the most electrified transport mode; hydrogen and battery electric trains with partial line electrification are options to replace non-electrified operations, which are substantial in many regions.</td></tr>
<tr><td>Aviation</td><td>Limited to small demonstration projects and feasibility studies. Larger demonstration projects under development.</td><td>Synthetic fuels: Limited changes needed to current infrastructure.
Hydrogen: Together with batteries, can supply on-board energy supply at ports and during taxiing.</td><td>Synthetic fuels: Currently 4-6 times more expensive than kerosene, with potential to decrease to 1.5-2 times in the long-term.</td></tr>
</table>

Notes: adapted and updated from IEA (2019a).

Economics

As an example, the use of hydrogen in road transport is considered here. The competitiveness of FCEVs depends mainly on the fuel cell costs and the fuel delivery price, which in turn is affected by the production costs and the building and utilisation of refuelling stations (Figure 10.9). For passenger cars, the cost of fuel cells and on-board hydrogen storage have to decrease to make them competitive with battery electric vehicles at long driving ranges (400–500 km). This could attract consumers that prioritise range. Regarding refuelling stations, currently the utilisation ratio tends to be quite low due to the limited uptake of FCEVs. A potential opportunity at early deployment stages is to build hydrogen stations that serve captive fleets of buses and trucks, securing high refuelling station utilisation.

Figure 10.9: Total cost of ownership for passenger cars and long-haul trucks by powertrain, range and fuel



Notes: ICE = internal combustion engine. The y-axis intercept of the figure corresponds to base vehicle "glider" plus minor component costs, which are mostly invariant across powertrains.

Source: IEA (2019a).

Although the fuel cell and the utilisation of refuelling infrastructure are the main cost drivers, both long range and large vehicles present a high energy consumption per kilometre. This means that fuel costs make up a greater share of the total cost of ownership for this type of vehicles. Scaling up the production of electrolytic hydrogen will drive down the production cost and, therefore, the total cost of ownership of the vehicle. Recently, several projects for dedicated generation combining refuelling stations and gas grid injection to optimise operation have been developed.

Buildings

Decarbonising heat in buildings is very challenging since decision making involves many factors like building type, geographical location, equipment running and purchasing costs, energy prices or consumer acceptance. Many different technological options will be required for adapting to the needs of all types of building, infrastructures and users. Hydrogen can contribute to decarbonising heat provision in the building sector, depending on local conditions, such as building types and existing infrastructure. There are two options for utilising hydrogen in domestic heating: blending hydrogen in the existing natural gas networks or direct use of pure hydrogen.

Hydrogen blending into natural gas distribution grids

This option is particularly interesting in regions relying on natural gas for heating. Hydrogen blends up to 20% on a volumetric basis can make use of an important fraction of the existing natural gas distribution infrastructure and would require minimal infrastructure and end-use equipment adaptation. The use of 20% blending shares (on a volumetric basis) has already been demonstrated, although it represents only around 7% on an energy basis and, therefore, less than 7% decrease in GHG emissions depending on the carbon footprint of the hydrogen blended. Still, blending small fractions of hydrogen into the gas grid could represent a significant increase in hydrogen demand in the short term, thus contributing to the scale up and cost reduction of hydrogen generation technologies. However, it could also add a significant cost to the end user. Blending just 3% by volume into all natural gas use around the world would boost clean hydrogen demand by close to 12 Mt H_2/yr but would add around 3–15% to natural gas supply costs. Meeting this demand with electrolytic hydrogen would represent around 70 GW of electrolysis capacity.

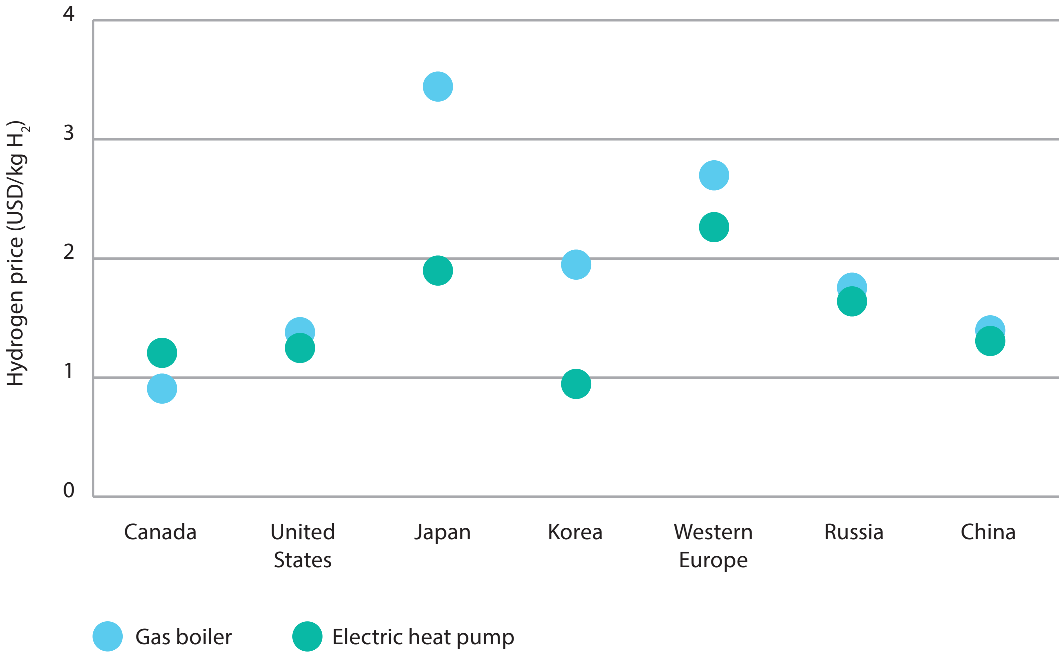
Higher blending shares or pure hydrogen use

There are already some networks operating with pure hydrogen in industrial hubs, but reaching hydrogen blending shares larger than 20% will require major modifications in infrastructure and end-use equipment. However, higher shares of hydrogen can be enabled by using synthetic methane, which is practically the same as natural gas since methane is the main component of natural gas (reaching more than 95% of its composition), and its injection in the gas grid can avoid the replacement of existing equipment. This is an option that has attracted a lot of interest in Europe, where several projects for the demonstration of power-to-methane for grid injection have been developed in the last decade. Yet, synthetic methane presents some challenges related to its carbon footprint, which requires a non-fossil CO_2 feedstock to be considered a low-carbon fuel. At the same time, the feedstock costs and the synthesis process and related conversion losses increase the costs of synthetic methane compared to hydrogen, thus leading to higher final consumer costs.

The case for 100% hydrogen presents the same challenges in terms of infrastructure and end-use appliances as the case of blending shares larger than 20%. The prospects for 100% hydrogen in the long term will strongly depend on the costs of the equipment and the hydrogen price. Consumers often prioritise upfront purchase prices over overall lifetime costs, taking into consideration other aspects such as safety, ease of installation or space requirements. Regarding the price of hydrogen delivered to consumers, it would likely need to be in the range of USD 1.5–3.0/kg H_2 to compete with natural gas boilers and electric heat pumps (Figure 10.10). In countries like Canada, with particularly low gas prices, the price of hydrogen would need to be below USD 1/kg H_2 to become competitive, whereas in other countries like Japan higher hydrogen prices (USD 3–4/kg H_2) might still be competitive.

Due to this complex interaction between hydrogen costs and consumer preferences, some types of building will be better suited to the use of hydrogen than others. The most cost-effective solution will depend on the type of building and geographical context. Hydrogen can have an opportunity to complement the electrification of heat in those situations when the benefits of adopting hydrogen can outweigh its lower efficiency. Low performing buildings with difficulties for heat pump installations and existing gas infrastructure are an attractive opportunity for the adoption of hydrogen use in buildings.

Figure 10.10: Hydrogen prices needed to become competitive against natural gas boilers and electric heat pumps in selected markets by 2030



Notes: Prices are average retail prices, including taxes, in USD 2017. Competitiveness of electric heat pumps assumes a typical seasonal efficiency of the heat pump in those countries. Price competitiveness does not include capital costs of the equipment.

Source: IEA (2019a).

System considerations

The use of blended or pure hydrogen in buildings presents synergies with the wider energy system, resulting in lower overall system costs than other alternatives like biomethane or full electrification of heat. Even in the most optimistic conditions (use of high-efficiency heat pumps and major building energy efficiency improvements), the full electrification of heat would require large-scale peak capacity or energy storage capacity. Biomethane depends on local availability of suitable biomass feedstock (e.g. animal manure). Global biomethane production would need to increase 20-fold to meet current heat demand, thus limiting the use of sustainable biomass resources for other applications. Therefore, hydrogen help reducing the stress on electricity systems and bioenergy resources.

Power sector

The transition towards electricity systems with high shares of variable renewable electricity will require a more flexible system and hydrogen in providing this flexibility to the electric grids, thus facilitating the integration of renewable electricity generation. Electrolyser can absorb high generation of renewables at times of low demand and support baseload technologies to avoid ramping. Electrolysers could increase system stability and reduce costs by flattening residual load (thanks to less ramping and avoiding start-ups and shut-downs), providing balancing power and it might even be used to release grid constraints, for example in the case of renewable electricity generation hubs with insufficient demand. The hydrogen generated under these conditions can be used for flexible generation at times of high demand and for long-term storage to provide electricity during long periods with very little wind or sunshine. Moreover, in regions with marked seasonal patterns of renewable supply or electricity demand, interseasonal storage may be required, and hydrogen looks as the most cost effective option. However, these opportunities will only be realised if the resulting full load hours when surplus electricity is available are high enough to justify the investment of the electrolyser (see Figure 10.5).

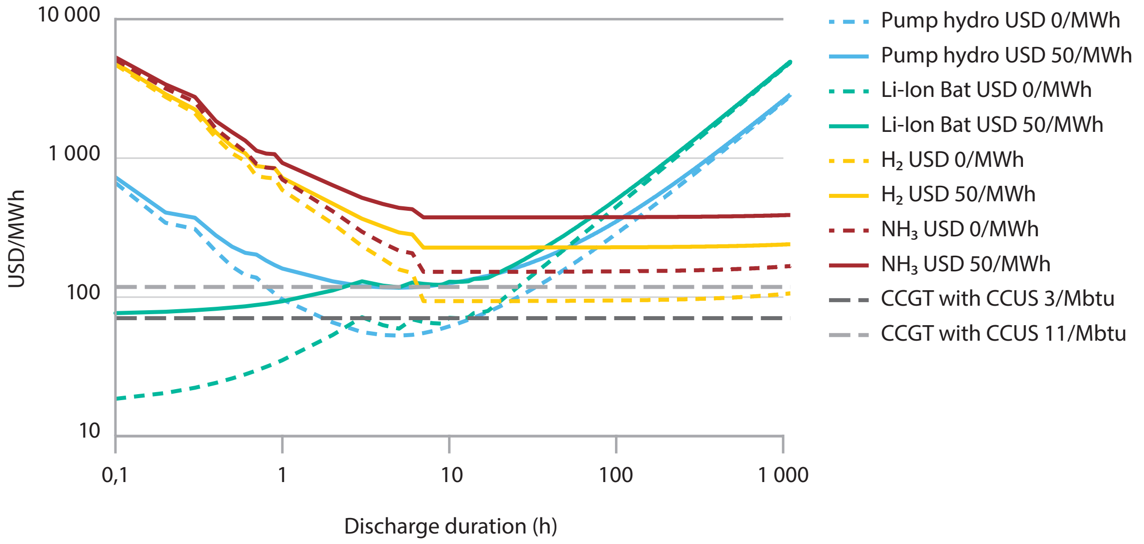
Large-scale and long-term energy storage

Hydrogen can be stored over ground, compressed or liquefied in tanks. However, underground storage in salt caverns, depleted natural gas or oil reservoirs and aquifers offers better prospects for long-term and large-scale storage. Salt caverns, which have been in operation for many years in the United States and the United Kingdom seem to be the best choice for underground storage. They are tight, thus presenting low risk of contamination, and operate at high pressures, which enable high discharge rates. Salt rock formations, however, exist not everywhere. Depleted gas fields or pore storage are more common, but experience with hydrogen is limited and investigated in research projects, like the H2STORE project (Energie Speicher, 2017). Hydrogen-derived fuels like synthetic methane or ammonia can also be interesting option. Methane, as mentioned before, could take advantage of the existing transport and storage infrastructure for natural gas, whereas ammonia can be stored in large steel tanks, which is already a common practice in the fertiliser industry.

The cost competitiveness of hydrogen and ammonia against other storage technologies is shown in Figure 10.11. Batteries are currently on the spotlight as the leading technology for electricity storage. They have achieved substantial cost reductions in recent years and this trend is expected to continue in years to come. Batteries are characterised by high storage cycle efficiency, therefore being well-suited for short-term storage and many storage cycles. However, they are less well suited for long-term and large-scale storage, as they suffer from self-discharge and because their low energy density an immense number of batteries would be needed for large-scale storage.

Pumped hydroelectric storage looks like a better alternative for electricity storage over longer periods. It has been used for many decades, reaching a global capacity of 156 GW in 2019. However, with very long-storage periods and low-number of cycles within a year, the CAPEX costs for the storage volume start to dominate the overall levelised storage costs.

Figure 10.11: Levelised costs of storage as a function of discharge duration and the electricity price



Note: Notes: Li-Ion = lithium-ion battery. Compressed hydrogen storage refers to compressed gaseous storage in salt caverns, ammonia storage to storage in tanks. For this analysis, the number of storage cycles within a year has been determined by dividing 8760 hours of a year by the charge and discharge duration, with charge and discharge durations assumed to be the same. Other operating regimes are possible, i.e. lower number of storage cycles for a given discharge duration. The underlying storage volume is assumed to correspond to the power output capacity times discharge duration.

Source: IEA (2019a).

Hydrogen and ammonia have relative low cycle efficiencies (around 40%), resulting in very high costs for short-term storage. However, the costs for the storage volume are very low, so that the costs when moving to longer storage periods and lower cycles increase only slightly. As a consequence of this, hydrogen and ammonia result in the lowest cost of storage when discharge duration reaches 20-80 hours or more, depending on the price of electricity. Moreover, it can become competitive against flexible power generation from natural gas with CCUS under certain natural gas prices.

Hydrogen as fuel for electricity generation

Hydrogen can be used in gas turbines, combined cycle gas turbines and fuel cells for generating power. The current share of hydrogen in power generation is negligible, accounting for less than 0.2% of electricity generation. Today, pure hydrogen is not used for power generation, with some small-scale exceptions, whereas the use of hydrogen-rich gases from industrial processes is more common.

Gas turbines: The existing gas turbines can handle hydrogen shares of 3-5%, with some of them reaching 30% or higher. Turbine manufacturers have developed small-scale turbines able to operate with pure hydrogen and expect to provide large-scale turbines able to run on pure hydrogen by 2030.

Fuel cells represent another opportunity for power generation with more immediate deployment for certain applications. There are currently four types of commercial fuel cell technologies:

- Polymer electrolyte membrane fuel cells (PEMFCs) operate at temperatures below 100°C and have a quick start-up time, but they require pure hydrogen or an external reformer to operate. They are used as micro co-generation units, operating with natural gas or LPG in buildings.
- Phosphoric acid fuel cells (PAFCs) operate today as stationary power generators with outputs in the 100-400 kW range. In addition to electricity, they produce heat at around 180°C that can be used for space and water heating.
- Molten carbonate fuel cells (MCFCs) operate at 600°C, thus being able to run on different hydrocarbon fuels without the need for an external reformer. MCFCs are used in the MW scale for power generation, while the produced heat can be used for heating or cooling purposes in buildings and industrial applications.
- Solid oxide fuel cells (SOFCs) can also run on different hydrocarbons without a previous reforming step since they operate at 800-1 000°C. SOFCs have similar application areas to MCFCs, but generally at kW scale (such as micro co-generation units or off-grid power supply).

The growing interest on stationary fuel cell is reflected on the rapid expansion of global installed capacity over the last decade. In 2018 almost 1.6 GW of capacity had been installed, though mainly running on natural gas and only around 70 MW with hydrogen as fuel. The global deployment of fuel cells reached 363 000 units and is largely dominated by a few countries, namely Germany, Japan, Korea and the United States. Japan accounts for the majority of the units, mostly micro co-generation systems for residential use and representing around 12% of the global capacity. The residential fuel cell market is also growing in Germany. Larger fuel cell systems have been deployed in the United States and South Korea to provide back-up power or produce heat and electricity for industrial processes or distributed systems.

Stationary fuel cells are highly efficient in converting hydrogen into electricity and heat (electric efficiency over 60%). Fuel cells are particularly attractive for flexible operation since they are able to achieve higher efficiency in part load than full load. However, they still have short technical lifetime when compared with gas turbines and typically have small power outputs (the largest fuel cell plants reach up to 50 MW compared with up to 600 MW for gas turbines). These factors make them more suitable for distributed generation, the provision of back-up power and off-grid electricity generation.

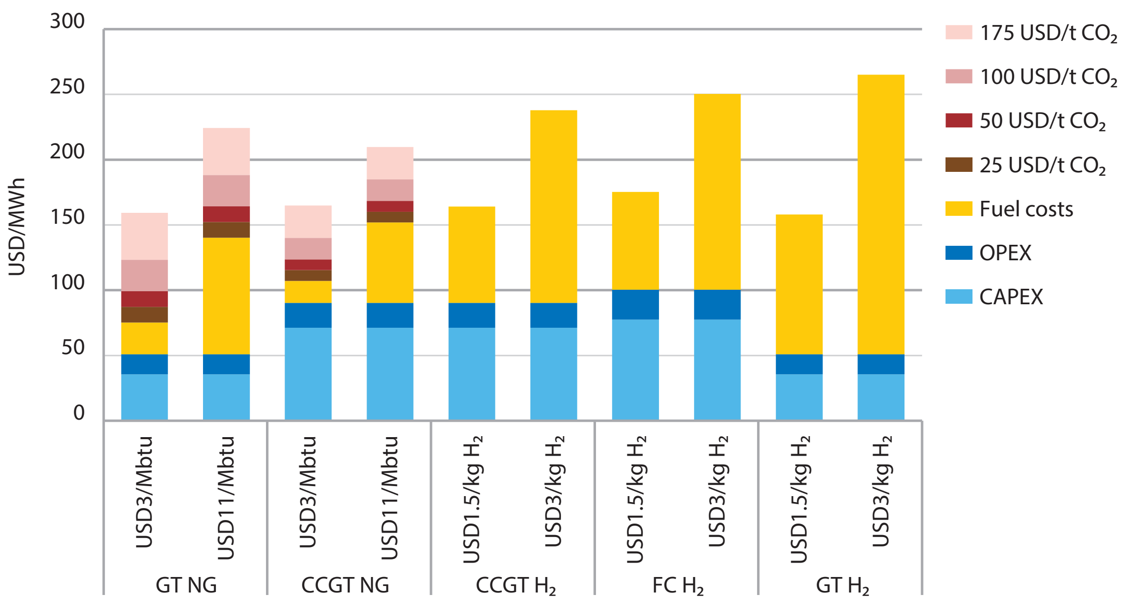
Co-firing of ammonia in coal power plants: Another opportunity for hydrogen to contribute in the decarbonisation of the power sector would be co-firing ammonia and coal. This has been successfully demonstrated in Japan with a share of 1% of ammonia in a medium size power plant (120 MW). The trials also demonstrated that NO_x emissions can be kept within usual limits and ammonia slip into exhaust gas can be avoided. Blending shares up to 20% might be feasible with minor adjustments to coal power plants and have already been demonstrated in smaller furnaces (10 MW thermal).

There is an important number of coal power plants worldwide in operation or under construction which will still be in operation for several years. It is projected that by 2030 around 1 750 GW of coal generation will be in operation and will still have a remaining lifetime of at least 20 years. Co-firing a 20% share of ammonia could avoid around 1.4 Gt CO_2 from the annual emissions generated by these coal plants. This would result in a demand of 860 Mt of ammonia and, therefore, 155 Mt H_2. However, the economics of this technological application for ammonia will strongly depend on the availability of low-cost low-carbon hydrogen.

Economics

The competitiveness of hydrogen technologies against natural gas for flexible power generation (load balancing and peak load generation) depends on the hydrogen and gas prices and the potential application of carbon prices (or comparable policy measures penalising CO_2 emissions). Figure 10.12 shows an example assuming a load factor of 15%. At low hydrogen price (USD 1.5/kg H_2) and high natural price (USD 11/MBtu), hydrogen technologies would require CO_2 penalties in the range of USD 25-50/t CO_2. However, in a scenario with low natural gas prices (USD 3/MBtu) these penalties will need to reach USD 175/t CO_2 for hydrogen technologies to become competitive against natural gas. At higher hydrogen prices, it will be very difficult for hydrogen to compete with natural gas.

Figure 10.12: Levelised cost of electricity generation from natural gas and hydrogen



Note: GT = gas turbine; CCGT = combined-cycle gas turbine; FC = fuel cell; NG = natural gas. CAPEX = USD 500/kW GT, USD 1 000/kW CCGT without CCS and hydrogen-fired CCGT, USD 1 000/kW FC. Gross efficiencies (LHV) = 42% GT, 61% CCGT without CCS and hydrogen-fired CCGT, 55% FC. Economic lifetime = 25 years for GT and CCGT, 20 years for FC. Capacity factor = 15%.

Source: IEA (2019a).

10.5 Conclusions and recommendations

Hydrogen is emerging again as a key player in the transition towards a clean, secure and affordable future energy system. It is leaving an unprecedented momentum reflected in the rapid expansion in the number of policies and projects around the world. Hydrogen had other previous false starts but the progress in the development of hydrogen technologies, the lessons learnt from the success in other clean energy technologies and the stronger societal commitment to deliver deep emissions reductions have created an unparalleled environment for the deployment of hydrogen technologies.

The power sector can play a critical role in the realisation of this new emerging opportunity. Nowadays, electrolytic hydrogen represents a small fraction of global hydrogen production. However, the production of hydrogen from low-carbon electricity has a strong potential to deliver carbon savings in otherwise hard-to-decarbonise sectors, such the industry and transport sectors. A substantial expansion in low-carbon electricity generation will be required – in addition to the growing electricity demands directly used in buildings, industry and transport – to provide the amounts of hydrogen needed in the hard-to-carbonate sectors. For example, if all aviation fuel demand in 2019 had been covered by synthetic kerosene from electrolytic hydrogen, this would have resulted in an electricity demand of 11 000 TWh, more than 40% of global electricity generation today. However, hydrogen can also support the decarbonisation of the electricity system and the integration of VRE by being one of the few technology options for long-term and large-scale electricity storage. This will contribute to the creation of a more integrated and flexible energy system.

Clean hydrogen has to overcome several barriers to enable this contribution to a clean energy transition. The most significant barrier is the price gap with conventional high-carbon hydrogen production technologies. Fortunately, clean hydrogen technologies have achieved a development stage in which they are ready to scale up and bring down costs. As a result, hydrogen could become more widely used. Near-term opportunities, like the deployment of clean hydrogen production and use in industrial ports and hubs supporting transport fleets and corridors to make fuel cell vehicles more competitive or the use of existing gas infrastructure, can facilitate the scaling up of these technologies. This can support the adoption of clean hydrogen in conventional hydrogen uses today and, especially in new applications that can significantly stimulate clean hydrogen demand.

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Annexes

A1: Learning rates for adjusting data for commissioning year 2025				
Country	**Technology**	**Original commissioning year**	**Factor to transform costs to 2025**	**Cost reduction until 2025 (%)**
Australia	Pumped storage	2022	1.00	0
	Onshore wind	2020	0.95	5
	Offshore wind	2020	0.96	4
	Solar PV (utility scale)	2019	0.75	25
	Solar thermal (CSP)	2020	1.00	0
Austria	Run of river	2020	1.00	0
	Solar PV (residential)	2020	0.87	13
	Onshore wind	2020	0.95	5
Canada	Solar PV (utility scale)	2021	0.90	10
	Onshore wind	2022	0.98	2
Italy	Biomass	2018	1.00	0
	Biomass (CHP)	2018	1.00	0
	Geothermal	2023	1.00	0
Korea	Solar PV (commercial)	2018	0.68	32
	Solar PV (utility scale)	2018	0.70	30
	Onshore wind	2018	0.88	12
	Offshore wind	2018	0.75	25
Netherlands	Solar PV (commercial)	2022	0.91	9
	Solar PV (utility scale)	2024	0.96	4
	Solar PV (floating)	2024	0.89	11
	Onshore wind	2023	0.95	5
Russia	Offshore wind	2022	0.95	5
	Offshore wind	2021	0.93	7

* Cost reductions based on IEA estimations in co-ordination with the respective countries.

List of abbreviations and acronyms

AC	alternative current
ACAES	adiabatic compressed air storage
ALWR	Advanced Light Water Reactor
A-USC	advanced ultra-supercritical
BICGT	biomass internal combustion gas turbine
BIGCC	biomass internal gasification combined cycle
BOS	balance of system
BWR	boiling water reactor
CAES	compressed air energy storage
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CCUS	carbon capture and storage (or sequestration)
CFDs	contracts for differences
CHP	combined heat and power
CPV	concentrating photovoltaic
c-Si	crystalline silicon
CSP	concentrating solar power
DC	direct current
D&D	decommissioning and dismantlement
DNI	direct normal irradiance
EGC	electricity generating costs
EGS	enhanced geothermal systems
EOR	enhanced oil recovery
ETP	IEA Energy Technology Perspectives study
ETS	emissions trading scheme
FCs	fuel cells
FiTs	feed-in-tariffs
Gen IV	generation IV
GJ	gigajoules
HLW	high-level waste

HTR	high-temperature reactor
IDC	interest during construction
IGCC	integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kWe	kilowatt of electricity capacity
LCOE	levelised cost of electricity
LFR	lead-cooled fast reactor
LHV	lower heating value
LNG	liquefied natural gas
LWR	light water reactor
MMBtu	million British thermal units
MWh	megawatt-hour
NCU	national currency unit
NGCC	natural gas combined cycle
OCGT	open-cycle gas turbine
O&M	operation and maintenance
PV	photovoltaic
PWR	pressurised water reactor
RD&D	research, development and demonstration
SC	supercritical
SFR	sodium-cooled fast reactor
SMR	small modular reactor (Chapter 8)
SMR	steam methane reforming (Chapter 10)
SOFC	solid oxide fuel cell
USD	US dollars
VALCOE	value adjusted levelised cost of electricity
VRE	variable renewable energy
2DS	2 degree scenario
2DS hi-Ren	high-renewable variant

List of Members of the EGC Expert Group and Experts who contributed to the report with data or comment (by country)

Shamim Ahmad	Australia
Candice El Asmar	Australia
Nicole Thomas	Australia
Katharina Giesecke	Austria
Michael Sorger	Austria
Erik Delarue	Belgium
William D'haeseleer (Chair)	Belgium
Tim Mertens	Belgium
Mariana de Queiroz Andrade	Brazil
Ganesh Doluweera	Canada
Isabel Murray	Canada
Saba Zarghami	Canada
Jan Krkoška	Czech Republic
Lubor Žežula	Czech Republic
Filip Gamborg	Denmark
Thøger Kiørboe	Denmark
Mikkel Sørensen	Denmark
Christoph Wolter	Denmark
Jacob Hjerrild Zeuthen	Denmark
Marie-Ursula Vaks	Estonia
Timo Ritonummi	Finland
Jean-Jacques Coursol	France
Gilles Mathonniere	France
Endre Börcsök	Hungary
Veronika Oláhné Groma	Hungary
Attila Hugyecz	Hungary
Péter Jelen	Hungary
Luigi Mazzocchi	Italy

Carmen Valli	Italy
Hiroyuki Ishida	Japan
Kenta Kitamura	Japan
Yuhji Matsuo (Co-Chair)	Japan
Manabu Nabeshima	Japan
Seunghee Hong	Korea
Ahreum Kim	Korea
JoonHan Kim	Korea
Kwon Kim	Korea
SeungSu Kim	Korea
Myungduck Park	Korea
Ana Souza	Mexico
Luuk Beurskens	Netherlands
Sebastiaan Hers	Netherlands
Smekens Koen	Netherlands
Binod Koirala	Netherlands
Jørgen Bækken	Norway
Jarand Hole	Norway
Janusz Malesa	Poland
Manuela Fonseca	Portugal
Eugen Banches	Romania
Marius Danila	Romania
Cosmin Ghita	Romania
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Tatiana Medyakova	Russia
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Sergey Scheglov	Russia
Nikita Vasiliev	Russia
Jan Petrovič	Slovak Republic
Martin Vanek	Slovak Republic
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Klaus Hammes	Sweden
Warren Schenler	Switzerland
Ismail Aydil	Turkey
Michael Apicelli	United States
Russell Conklin	United States
Francesco Ganda	United States

Seungwook Ma	United States
Brian Shelbourn	United States
Thomas J. Tarka (Co-Chair)	United States

Expert representatives in a personal capacity

Marko Aunedi	Imperial College London
John Bistline	Electric Power Research Institute (EPRI)
Alain Burtin	EDF R&D
Matthew P. Crozat	Nuclear Energy Institute (NEI)
Brent Dixon	Idaho National Laboratory (INL)
John Paffenbarger	Exelon Corporation
John Parsons	Massachusetts Institute of Technology (MIT)
Dany Pudjianto	Imperial College London
Ulrik Stridbæk	Orsted
Christian Stolzenberger	VGB PowerTech e.V.
Falko Ueckerdt	Potsdam Institute for Climate Impact Research (PIK)

Representatives of International Organisations

Marco Cometto	International Atomic Energy Agency (IAEA)
Fernando De Sisternes	World Bank
Michael Taylor	International Renewable Energy Agency (IRENA)

OECD PUBLISHING, 2 rue André-Pascal, 75775 Paris Cedex 16, France.

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Projected Costs of Generating Electricity

This joint report by the International Energy Agency and the OECD Nuclear Energy Agency is the ninth in a series of studies on electricity generating costs. As countries work towards ensuring an electricity supply that is reliable, affordable and increasingly low carbon, it is crucial that policymakers, modellers and experts have at their disposal reliable information on the cost of generation. This report includes cost data on power generation from natural gas, coal, nuclear, and a broad range of renewable technologies. For the first time, information on the costs of storage technologies, the long-term operation of nuclear power plants and fuel cells is also included. The detailed plant-level cost data for 243 power plants in 24 countries, both OECD and non-OECD, is based on the contributions of participating governments and has been treated according to a common methodology in order to provide transparent and comparable results.

Low-carbon electricity systems are characterised by increasingly complex interactions of different technologies with different functions in order to ensure reliable supply at all times. The 2020 edition of *Projected Costs of Generating Electricity* thus puts into context the plain metric for plant-level cost, the levelised cost of electricity (LCOE). System effects and system costs are identified with the help of the broader value-adjusted LCOE, or VALCOE metric. Extensive sensitivity analyses and five essays treating broader issues that are crucial in electricity markets round out the complementary information required to make informed decisions. A key insight is the importance of the role the electricity sector plays in decarbonising the wider energy sector through electrification and sector coupling.

The key insight of the 2020 edition of *Projected Costs of Generating Electricity* is that the levelised costs of electricity generation of low-carbon generation technologies are falling and are increasingly below the costs of conventional fossil fuel generation. Renewable energy costs have continued to decrease in recent years and their costs are now competitive, in LCOE terms, with dispatchable fossil fuel-based electricity generation in many countries. The cost of electricity from new nuclear power plants remains stable, yet electricity from the long-term operation of nuclear power plants constitutes the least cost option for low-carbon generation. At the assumed carbon price of USD 30 per tonne of CO_2 and pending a breakthrough in carbon capture and storage, coal-fired power generation is slipping out of the competitive range. The cost of gas-fired power generation has decreased due to lower gas prices and confirms the latter's role in the transition. Readers will find a wealth of details and analysis, supported by over 100 figures and tables, that establish the continuing value of the *Projected Costs of Generating Electricity* as an indispensable tool for decision-makers, researchers and experts interested in identifying and comparing the costs of different generating options in today's electricity sector.

Nuclear Energy Agency (NEA)
46, quai Alphonse Le Gallo
92100 Boulogne-Billancourt, France
Tel.: +33 (0)1 73 21 28 19
nea@oecd-nea.org www.oecd-nea.org

NEA No. 7531

International Energy Agency (IEA)
9, rue de la Fédération
75739 Paris Cedex 15, France
Tel.: +33 (0)1 40 57 65 00
info@iea.org www.iea.org