System implications of continued cost declines for wind and solar on driving power sector decarbonization

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Global efforts on confronting climate change through reducing energy-related greenhouse gas (GHG) emissions have seen the most success in the electric power sector through the continued growth in variable renewable energy (VRE) generation, as well as fuel switching from coal to natural gas (NG) in some regions. For example, between 2009 and 2018, global capacity installations of wind and solar increased by a factor of ~3 and ~20 respectively, enabled by continued technology cost declines and policy support[1]. In some regions, like the U.S., this trend has been complemented by the displacement of generation from coal with gas, leading to U.S. power sector CO_2 emissions declining by 28% since 2005[2]. Despite these promising trends, deep decarbonization of the power sector remains a daunting challenge, as reflected by the fact that VRE sources accounted for only 9% of global electricity generation in 2018, while generation from coal, the most carbon-intensive fossil fuel, accounted for 38% of total generation and continues to grow in some regions (e.g., India)[3]. Several studies project that global electricity consumption could grow by as much as 45-50%[4] by 2050, driven by rapid growth of electricity use for services such as air-conditioning in currently under-served regions, electrification of other end uses like heat and transport, as well as increased digitization and associated proliferation of data centers to support cloud computing needs. This suggests that in order to ensure that power sector GHG emissions approach net-zero by mid-century, the rate of power sector decarbonization needs to be significantly accelerated. Given the long lifetimes of infrastructure investments in the power sector, the next 2-3 decades are likely to be pivotal in defining the longer-term GHG emission trends of the sector and the ability to achieve end-of-century climate stabilization goals.

The timely availability of low- or zero-carbon technologies that are also cost-competitive is a crucial lever for enabling the transition toward a more sustainable energy system. This document explores the potential for power sector decarbonization based on the cost-competitive addition of wind and solar technologies in the absence of any supporting policy, as per current technology cost and performance trends, as well as projected cost and performance in 2030. Additionally, the appendix provides an industry perspective[5] on the potential technology roadmap and opportunity for cost reductions achievable for VRE generation and energy storage technology by 2030. It should be

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[1] Renewable Capacity Statistics 2019, International Renewable Energy Agency
[2] Carbon dioxide emissions from the U.S. power sector have declined 28% since 2005, U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=37392, accessed May 15, 2019
[3] BP Statistical Review of World Energy June 2019, British Petroleum
[4] World Energy Outlook 2017, International Energy Agency
[5] Industry perspective provided by Iberdrola

noted that the findings in this document on system implications is an independent assessment of the potential outcomes that might result from declining wind and solar technology costs and does not in any way endorse the industry view on future technology costs described in the appendix.

Cost and performance outlook for wind, solar, and battery storage

Figure 1 summarizes 2018 capital costs of wind and solar photovoltaic (PV) technologies reported by various institutions, including the International Renewable Energy Agency (IRENA), National Renewable Energy Laboratory (NREL), the International Energy Agency (IEA), and Industry (Iberdrola). While costs of wind and solar have declined precipitously over the past decade, significant regional variations in costs remain, resulting from a variety of local factors. These may include renewable resource availability, the existence of a favorable economic regime, or the particular conditions of the project (e.g., synergies with adjacent projects for allowing economies of scale). Despite the different starting points, all projections for capital costs of wind and solar technologies agree that costs are expected to decline further, and in many cases, by similar percentages. For example, the 2018 edition of the annual technology baseline from NREL projects capital costs for solar declining by as much as 32% respectively by 2030 relative to 2019 costs, which is overlap with the estimates available from industry (see appendix). Table 1 summarizes 2030-2040 cost projections from the various institutions mentioned previously, which will be used to inform the system integration analysis in the next section.

Along with declining technology costs, the performance of wind and solar PV has also improved over time. For example, IRENA estimates that the capacity factor of solar PV projects has improved from 14% to 18% from 2010 and 2018[5]. For wind, the improvement in capacity factor have been more pronounced, due to a combination of increased hub heights, rotor diameter, and turbine size, resulting in the average project capacity factor increasing from 27% in 2010 to 34% in 2018[6]. Industry projections indicate that this trend is expected to continue with projected capacity factor improvements of 10% and 15% for solar and onshore wind, respectively (see appendix).

[6] IRENA, Renewable power generation costs in 2018, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/May/IRENA_Renewable-Power-Generations-Costs-in-2018.pdf

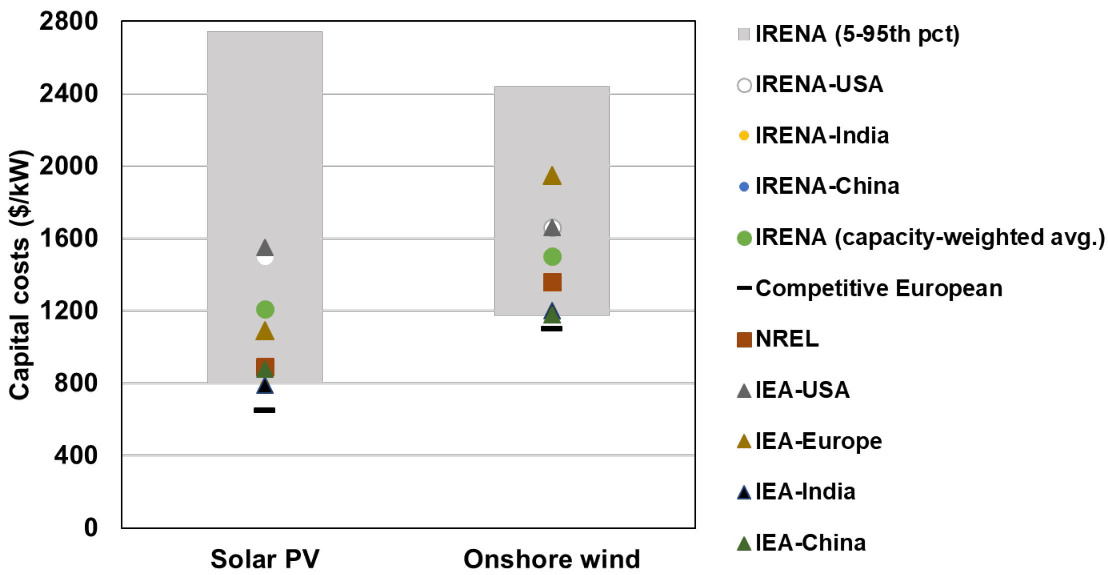

Figure 1. Summary of reported capital costs for solar PV and onshore wind in various regions in 2018-2019, as reported by various institutions. IRENA = International Renewable Energy Agency, IEA= International Energy Agency, NREL = National Renewable Energy Laboratory. The label "Competitive European" refers to cost of most cost-competitive projects in Europe, as provided by Iberdrola.

Compared to wind and solar, battery energy storage is a relatively nascent technology, with global deployments at 17 GWh energy capacity and 9 GW power capacity as of 2018[7]. Currently, lithium-ion batteries are the dominant storage technology being deployed with current capital costs for 4-hour energy storage systems approximately between 300-400 $/kWh[8]. Storage systems with smaller energy to power capacity ratios generally have higher capital costs on $/kWh basis, since the balance of system fixed costs (e.g., inverter, power electronics) are spread over a smaller energy capacity. In the U.S. to date, grid-scale battery storage installations have primarily aimed to provide frequency regulation services to the grid, but this trend may be shifting, as evident from recent announcements of storage projects in the 100's of MWs, both with and without co-located solar and wind capacity[9]. Future reductions in cost of battery packs and consequently grid-scale storage systems are anticipated by many projections, potentially enabling battery storage to play a greater role in wholesale electricity markets. As an example, Table 1 reports capital cost projections for battery storage systems in 2030-2040 with rated duration of four hours.

[7] Energy Storage Investments Boom as Battery Costs Halve in the Next Decade, https://about.bnef.com/blog/energy-storage-investments-boom-battery-costs-halve-next-decade/

[8] Fu et al., 2018 U.S. Utility-Scale Photovoltaics Plus-Energy Storage System Costs Benchmark, National Renewable Energy Laboratory, 2018, https://www.nrel.gov/docs/fy19osti/71714.pdf

[9] Greentech Media. PG&E's Record-Breaking Battery Proposal Wins Approval from Regulators 2018. https://www.greentechmedia.com/articles/read/pges-recording-breaking-battery-proposal-wins-loses#gs.5qatdt

Table 1. Summary of capital cost projections for wind, solar, and storage in 2030, as per various sources. Wherever ranges in costs are noted, they represent costs across regions or for different scenarios.

Source	Year of projected costs	Wind ($/kW AC)	Solar ($/kW DC)	Storage (4 hour) ($/kWh)
NREL ATB 2019[10]	2030	1125-1610[a]	565-1115[b]	125-300[11]
IEA WEO 2018[12]	2040	1160-1760[c]	430-810[c]	218
IRENA[13]	2025	1370	790	-
Industry[d]	2030	925	450	160

a. Cost range corresponds to different resource sites, b. Costs correspond to low-, medium-, and high-cost scenarios, c. Range spans costs in India, China, European Union, and U.S., d. Costs projections by Iberdrola – see appendix.

System outcomes for current and future renewables, storage costs

The projected cost and performance outlook for wind, solar, and energy storage technologies discussed in the previous section raises several questions about the potential penetration of these technologies in future electricity grids, as follows:

1) What is the cost-effective penetration of renewables given current technology cost and performance?
2) What are the system implications of the declining LCOEs of wind, solar, and energy storage technologies? (See appendix for LCOE projections as per industry view.)
3) What does the cost reductions in these technologies imply for the long-term role for thermal generation, storage, and power sector GHG emissions?

Here, we use a state-of-the-art power systems planning model with high temporal and technological resolution to independently evaluate the system impacts of anticipated cost reductions and technology improvements for solar, wind, and storage technologies, as described earlier. The next section describes the salient details of the model relevant for this analysis as well as the setup of the case studies considered here. This is followed by a discussion of the key findings and brief discussion of the impact of the modeling assumptions on the key outcomes of this study.

Methodology

The power systems planning model used in this analysis, GenX[14], takes the view of a centralized system planner to determine the cost-optimal portfolio of investments in generation, transmission, and storage needed to meet electricity demand in a future year. It does this while adhering to various grid operating constraints as well as any policy directives, such as renewable energy mandates and/or CO_2 emissions caps. GenX incorporates several novel modeling features that are relevant for studying high VRE penetration scenarios. These include: 1) modeling annual power sector operations at an hourly resolution with unit commitment and economic dispatch and procurement of ancillary services (e.g.,

[10] NREL Annual Technology Baseline 2019: https://atb.nrel.gov/electricity/2019/data.html
[11] Cole and Frazier, Cost Projections for Utility-Scale Battery Storage, https://www.nrel.gov/docs/fy19osti/73222.pdf, National Renewable Energy Laboratory, 2019.
[12] World Energy Model Documentation: 2019 version, International Energy Agency.
[13] The Power to Change: solar and wind cost reduction potential to 2025, International Renewable Energy Agency
[14] Jenkins and Sepulveda, Enhanced Decision Support for a Changing Electricity Landscape: The GenX Configurable Electricity Resource Capacity Expansion Model, MIT Energy Initiative Working Paper, 2017

spinning and regulation reserves) that enables an improved characterization of grid dispatch and the cost/value of flexible resources under these scenarios; 2) modeling the available suite of demand and supply side resources as well as hybrid systems, such as integrated fossil-renewable power plants and solar plus storage facilities; and 3) the ability to explicitly consider the investment trade-offs between centralized and distribution generation and storage assets[15]. In this study, we will only utilize the first feature described above.

We study the system implications of the projected technology outlook in the context of two different grids, North and South, which are defined using load and VRE characteristics as per conditions prevalent in ISO New England and ERCOT regions, respectively. In the global context, the North system resembles VRE resource characteristics in regions like United Kingdom and Ireland while the South system is loosely representative of VRE resource patterns in Spain and other tropical regions (e.g., India). Each system is modeled as: 1) isolated grids with no power exports or imports, 2) a single load balancing area without transmission constraints, and 3) under greenfield conditions; i.e., without any existing generation capacity. Table 2 and Figure 2 summarize the key assumptions on system conditions and non-renewable technology capital costs, respectively. Even though offshore wind and pumped hydro technologies are promising with respect to achieving cost-effective decarbonization, these technologies were excluded in this analysis due to limited access to data to characterize their operations and costs for the studied regions. Moreover, these technologies may only be available to certain geographical regions.

Table 2. Key system parameter assumptions for the study

Parameter		Value
Load		Projected 2013 hourly load profile with annual growth of 1.4%
Gas price ($/MMBtu)		4
Cost of capital (%)		8
Technology lifetime (years)		Gas: 30; VRE: 25; Storage: 15; Coal: 40 Nuclear: 50
Non-served reserve cost ($/MW)		1000
Non-served energy cost ($/MWh)		9,000
Regulation reserve requirement (%)	Load	1
	VRE	0.32
Spinning reserve Requirement (%)	Load	3.3 (up & down)
	VRE	7.95, 2 (up/down)

The annual load profile in 2030 for the North and South system is estimated by scaling up the annual hourly load profile of 2013 from ISO New England and ERCOT using an annual growth rate of 1.4%. This

[15] Further details can be found at https://epscenter.mit.edu

growth is consistent with recent load growth trends in the ERCOT grid. To account for potential improvements in capacity factors for wind and solar generation in 2030, we scale up capacity factor profiles from 2013[16] as per the estimated technology improvement factors (see appendix for details)[17]. The North system load has higher peak to mean ratios, higher quality wind resource, and lower quality solar resource compared to the South system, as seen in Figure 3. To facilitate comparison of system outcomes and their sensitivity to load, as well as VRE resource characteristics, both systems are scaled to have the same peak load (85 GW) and similar annual electricity demand (400-420 TWh).

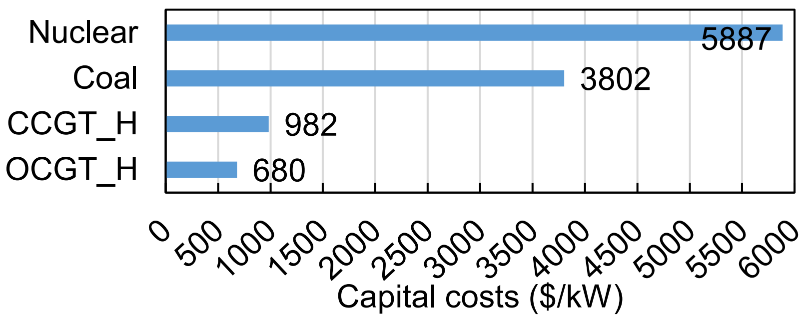

Figure 2. Capital cost assumptions for thermal technologies considered in the analysis. CCGT_H = Combined cycled gas turbines (H Class); OCGT_H = Open cycle gas turbines (H Class).

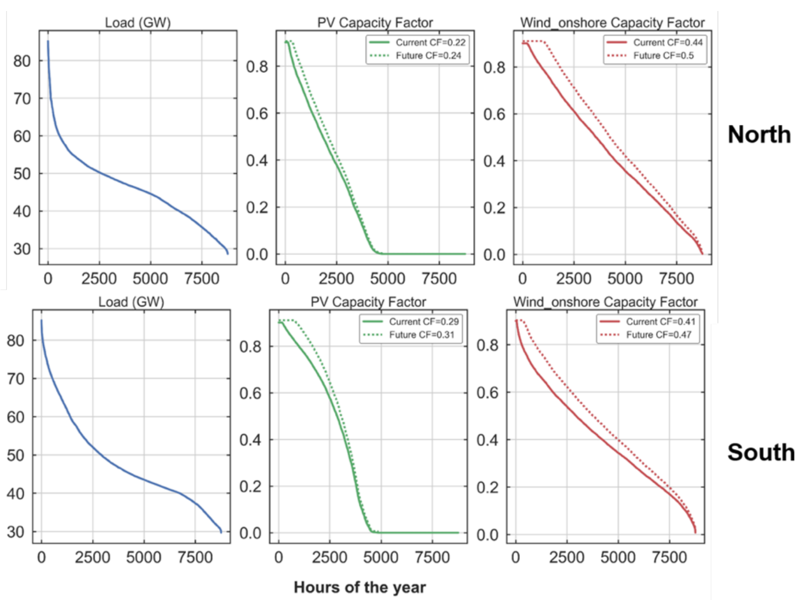

Figure 3. Modeled distribution of hourly load, wind and solar PV capacity factors for North and South systems for current and future capacity factor (CF) scenarios. CF = Annual Average Capacity Factor

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[16] These capacity factor profiles are derived from the resource availability (wind speed, solar irradiance) data available from the National Renewable Energy Laboratory's solar radiation database and Wind toolkit dataset.
[17] The hourly capacity factor for each technology is scaled up as per the technology improvement factor, while ensuring the following factors: 1) capacity factor in any given hour does not exceed 90%, and 2) the annual average capacity factor is scaled up by the same technology improvement factor.

Impact of wind, solar costs, and capacity factor improvements

System outcomes for current technology costs

Figure 4 shows the breakdown of capacity and generation for the range of present technology costs noted in Figure 1 for the North and South system. In the absence of any policy supporting low-carbon generation, the range of current estimates of capital costs for wind and solar result in VRE penetration (as a share of annual demand) up to 25% and 29% of annual demand across the North and South systems, respectively. The differences in VRE penetration between the North and South system stem from differences in underlying VRE resource availability and their correlation with load. Despite its lower annual average capacity factor, solar is deployed in three out of the four scenarios in the South system, while wind is only deployed in the industry cost scenario. The greater correlation of solar availability with load, as compared to wind, implies that solar generation tends to displace generation from the most expensive thermal generators in the system (i.e., OCGT, in this case). In contrast, in the North system, where solar resources are relatively poor, wind generation is the dominant VRE resource, but is less correlated with load as compared to solar resource availability. This results in increased peak net load requirements for the North system, which is met by gas generation in the scenarios evaluated in Figure 4. Consequently, wind-dominant systems like the North see greater roles for gas generation than systems with a more balanced VRE generation mix. It should be noted that the scenario outcomes shown in Figure 4 are not indicative of current deployments in any region but rather provide a benchmark of system outcomes under a greenfield scenario (i.e., no existing generation capacity) and in the absence of any VRE support policies (e.g., tax credits, penetration requirements).

Nearly all of the scenarios in Figure 1 see little storage deployment, indicating that the current capital costs for grid-scale battery storage remains uneconomical when competing against gas generation with $4/MMBtu gas prices. Since gas generation dominates total generation for the scenarios analyzed in Figure 3, the level of VRE penetration is quite sensitive to gas price assumptions with higher gas prices leading to increased VRE penetration and vice versa. The assumed gas price of $4/MMBtu is consistent with long-term trends anticipated in the U.S. context[18], but higher gas prices may be reasonable in regions with limited domestic gas resources (e.g., India, Europe). If gas prices are doubled to $8/MMBtu, VRE penetration in the South system more than doubles in the case of industry cost scenario, raising from 29% to over 70%, while the VRE penetration in the IRENA average cost scenario increases to 60%. The role of storage also increases in the $8/MMBtu gas price scenario for the South system, with the capacity of four-hour storage deployment equal to 7% and 1.5% of peak demand in the industry cost scenario and IRENA average cost scenario, respectively.

[18] EIA Annual Energy Outlook 2019 (with projections to 2050), https://www.eia.gov/outlooks/aeo/

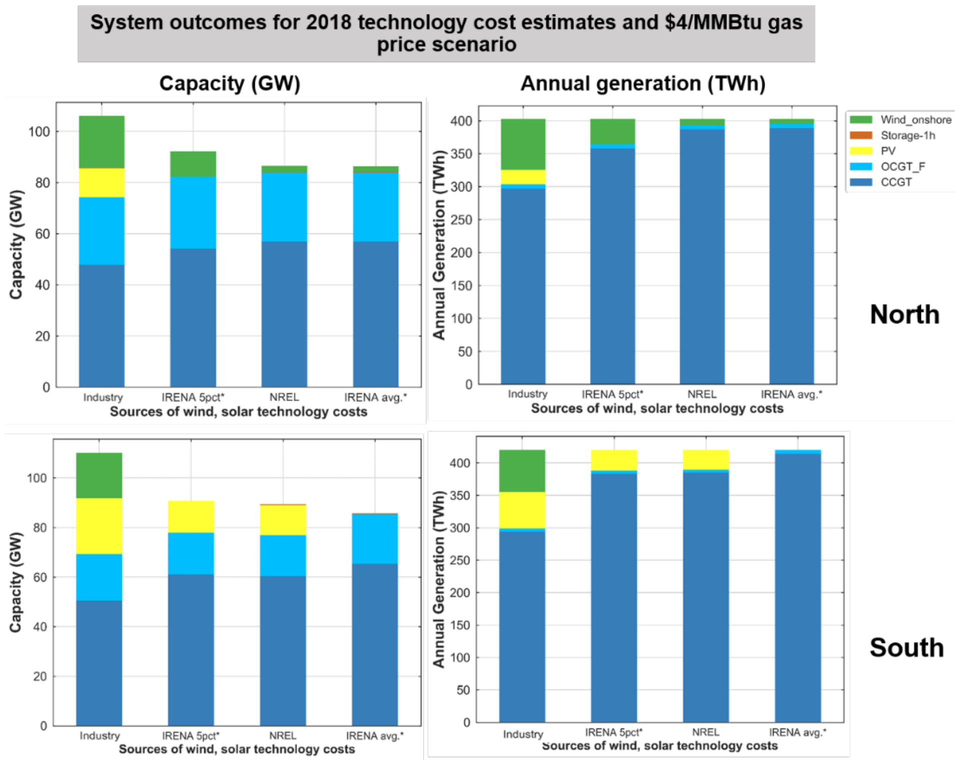


Figure 4. Capacity and generation breakdown under different estimates of wind and solar capital costs, estimated for 2018, across the North (top row) and South systems (bottom row). Current technology costs from various sources: Industry ("Competitive European" label in Figure 1, sourced from Iberdrola): 650 $/kW DC (PV), 1100 $/kW (Wind), IRENA 5pct : $800/kW DC (PV), $1500/kW (Wind), NREL: $893/kW DC (PV), $1360/kW (Wind), IRENA avg.: $1200 /kW DC (PV), $1500/kW (W). In all cases, we assume storage costs to be the same at $300/kWh and $700/kWh for four-hour and one-hour duration systems, respectively. OCGT_F = Open cycle gas turbine (Frame), CCGT = Combined Cycle Gas Turbines. PV inverter loading ratio (DC to AC ratio) fixed at 1.3 for all cost scenarios*

Results for future technology cost and performance scenarios

Figure 5 summarizes the achievable VRE penetration for the North and South systems under a range of possible future capital costs for wind and solar generation and a future cost projection for battery storage (and $4/MMBtu gas prices). Not surprisingly, with declining wind and solar costs, the level of VRE penetration increases, with a maximum penetration of ~60% of annual demand in the case of the South system, which corresponds to a system average GHG emissions intensity of 137 gCO_2/kWh[19]. In the case of the North system, the maximum VRE penetration is lower at 53%, owing to the lower value of solar and wind resources relative to the South system, as explained above. The CO_2 emissions intensity corresponding to the scenario with highest VRE penetration in the North system is 164 gCO_2/kWh. For both wind and solar, we find that the impact of subsequent cost reductions results in a smaller increase in VRE penetration. For example, for the South system and wind costs fixed at $1050/kW, reducing solar costs by $75/kW, from $1150/kW to $1075/kW, increases VRE penetration by

[19] As reference, the U.S. Energy Information Administration estimates that the average CO_2 emissions intensity of electricity generation sources in California, Texas, and the U.S. for 2017 was 215, 529, and 457 gCO_2/kWh, respectively.

5% (from 35% to 40%), while a similar magnitude of cost reductions going from $700/kW to $625/kW results in VRE penetration increasing by <1%. This reflects the competition between value and cost for VRE technologies, with the latter declining with increasing VRE penetration due to the non-dispatchable nature of VRE resources[20]. Nonetheless, Figure 5 suggests that achieving the lowest technology cost projections for wind, solar, and energy storage has the potential to transform the power system from being predominantly reliant on thermal generation to primarily reliant on VRE generation. Notably, declining technology costs for wind and solar makes it possible to partially decarbonize the power sector while also marginally reducing the system average cost of electricity, since the increased capital expenditures on VRE capacity are more than offset by the reduction in fuel costs associated with thermal generation (see cost trends in Figure 5[21]).

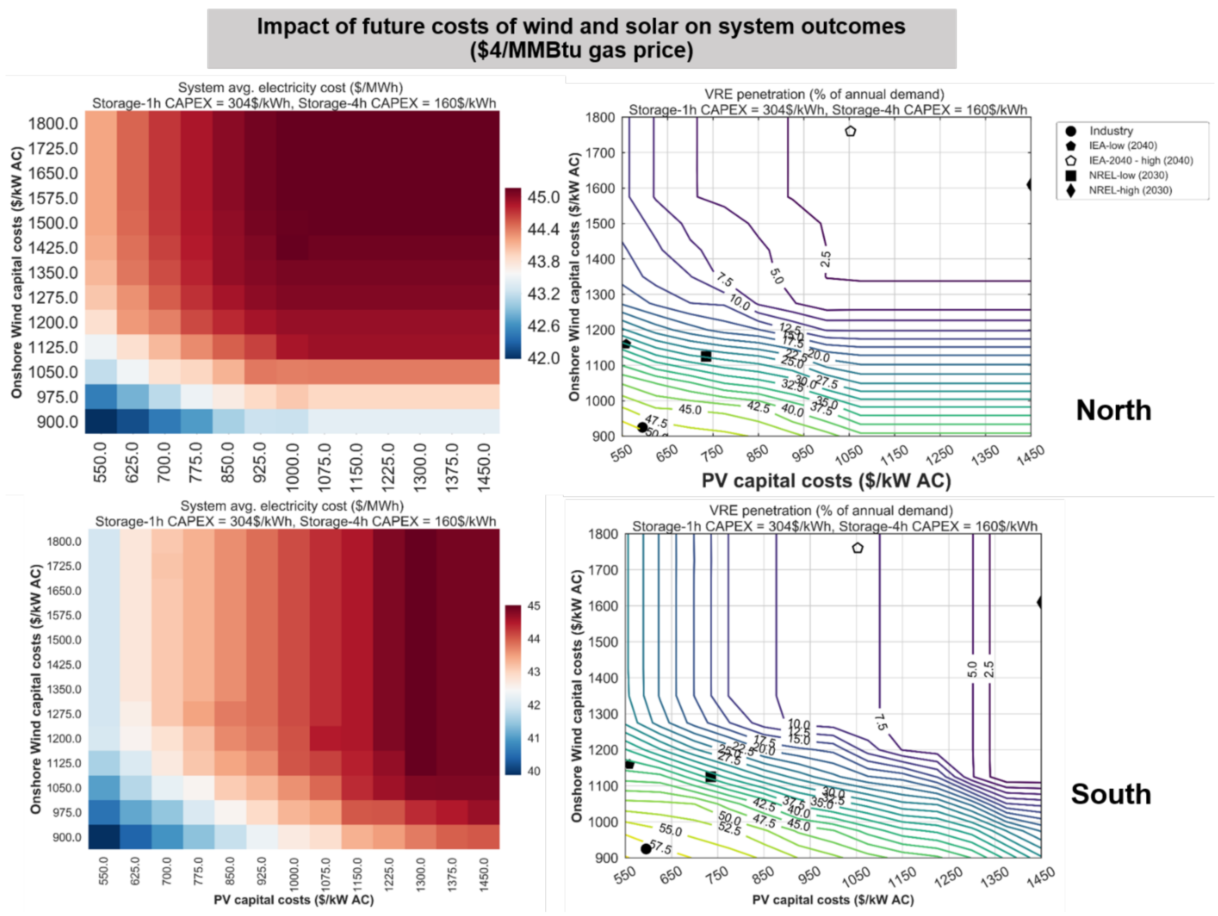


Figure 5. System average electricity cost (first column) and VRE generation (second column) as share of annual demand for a range of capital costs for wind and solar for the North (top row) and South system (bottom row). Note that the system average electricity cost metric does not include the operating cost of existing transmission or the capital and operating costs of new transmission investments that may be needed to accommodate the load growth. Results are based on current capacity factors for technologies.

[20] Sivaram V., Kann, S., Solar power needs a more ambitious cost target, Nature Energy, 1, 16036 (2016).
[21] System costs are ~$44/MWh for the scenarios in Figure 1 vs. $39/MWh for the highest VRE penetration scenario in Figure 5 for the South system.

Figure 6 shows the impacts of anticipated improvements in capacity factor of wind and solar plants on the overall system generation mix for three different future cost projections for the North and South systems. In general, for the same capital costs, capacity factor improvements lead to increasing VRE penetration. Across both systems, the largest impact of improving capacity factors is observed for the NREL-low 2030 cost scenario, which corresponds to the scenario with the highest PV capital costs and the second highest wind capital cost of the three scenarios. Much of the increase in VRE generation comes from additional wind generation, given the larger percentage improvements projected in wind vs. solar capacity factor (15% vs. 9%). In terms of system costs, the increased capacity utilization of VRE assets further raises their value to the power system and leads to a ~5% reduction in system average electricity costs compared to the scenario with current capacity factors for the cost scenarios shown in Figure 6.

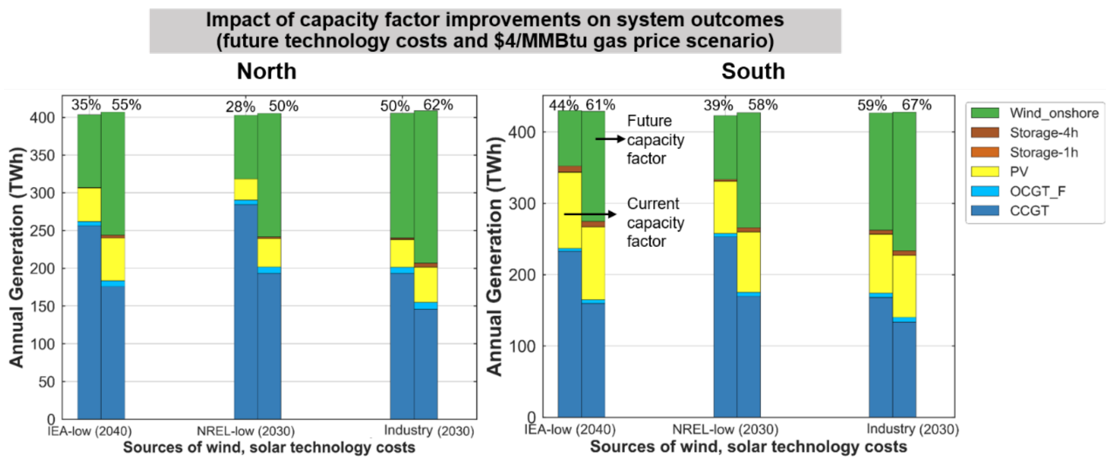


Figure 6. Impact of capacity factor improvements on generation mix under three future wind and solar capital cost scenarios for the North and South systems. Cost scenarios as defined in Table 1. In all cases, we assume storage costs to be the same at $160/kWh and $304/kWh for four-hour and one-hour duration systems, respectively. Percentage numbers noted above each bar correspond to share of annual demand met by wind and solar generation.

Impact of storage costs

The role of energy storage, while relatively small in terms of contribution to total electricity generation, is vital for cost-effectively integrating VRE resources by reducing their curtailment and managing their variability through discharging during times of low VRE generation. Figure 7 quantifies the importance of energy storage in VRE-dominant grids by comparing the system outcomes for the South system under different storage cost scenarios.

For current and future capacity factor trends, the system CO_2 emissions intensity in the low-cost storage scenario are ~ 16% and 18-19% lower than the corresponding values for the high cost scenario for the North and South systems, respectively. The increased emissions intensity is due to the increase reliance on gas generation to balance the variability of VRE generation under the high cost storage scenario. The impact of energy storage additions on system costs and emissions may be more pronounced under scenarios of higher gas prices (i.e., > $4/MMBtu), due to the greater cost of using gas generation to manage VRE variability. Finally, a related conclusion of this analysis is that regions with other flexible resources, like pumped hydro-based energy storage facilities, will likely see lower costs of integrating the same amount of VRE generation, all else remaining equal.

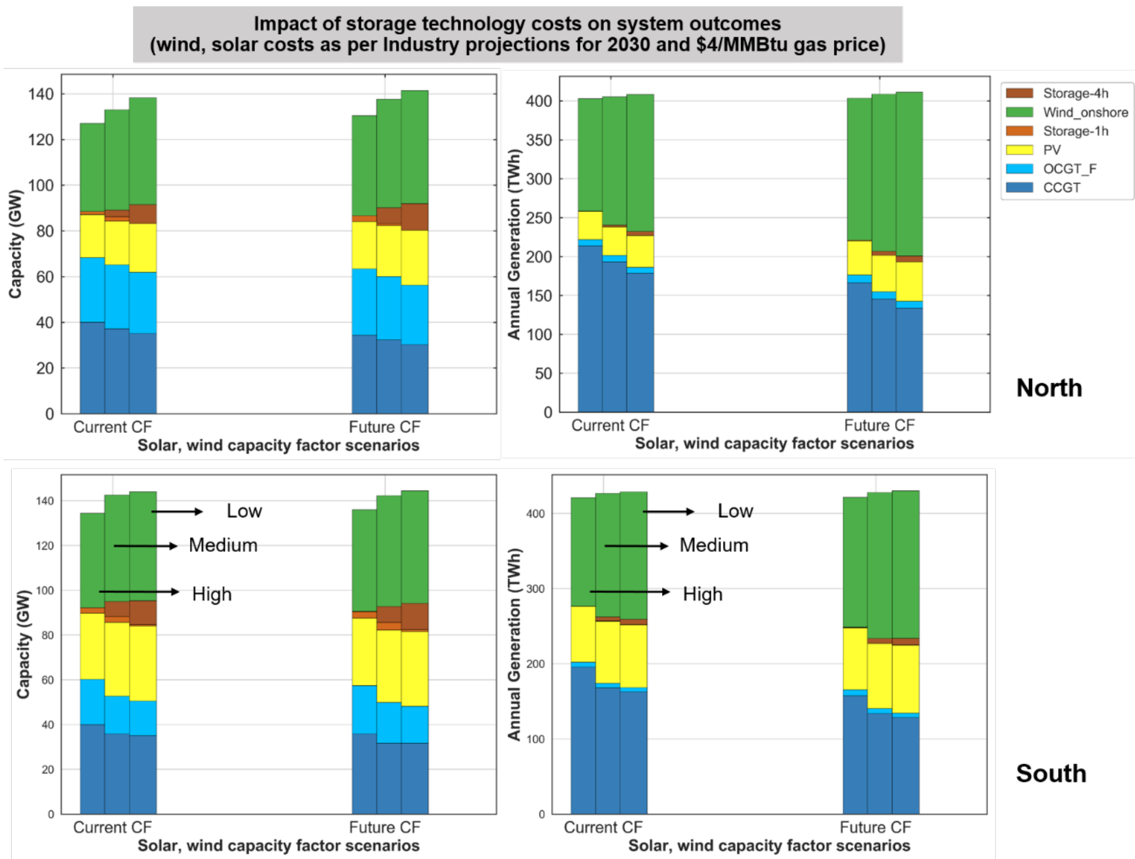


Figure 7. Impact of storage costs on capacity and generation trends for current and future capacity factor scenarios and future cost projections for the North (top row) and the South (bottom row) systems. Storage capital costs scenarios defined as per costs of four-hour duration storage systems: Low= $125/kWh, Medium = $160/kWh, and High = $300/kWh. Cost of storage with one-hour duration: Low =$295/kWh, $304/kWh, and $705/kWh. Across the scenarios shown, wind and solar capital costs are held constant as per the Industry cost projections for 2030 (noted in Table 1).

Model assumptions and implications

Similar to other modeling studies, this study is based on several modeling assumptions and the below discussion highlights the potential implications of the major assumptions. First, the analysis is based on a single-load balancing area in each region, which implicitly assumes that the system has sufficient transmission capacity between the various nodes in each region to accommodate intra-region power flows. Due to relatively low areal energy density of VRE resources, their large-scale deployment will likely occur away from major urban clusters, which makes transmission a key element for their integration. While it may be reasonable to overlook transmission constraints over a small geographic area where the spatial variability in VRE resource quality may be relatively small, when considering larger regions, transmission network expansion may be required to import power from nodes with the highest quality VRE resources to the major demand centers. The impact of transmission constraints (or costs of expansion) could likely reduce the VRE penetration below the levels estimated here.

Second, the analysis uses a single capacity factor profile to characterize the hourly availability of VRE resources in each system which represents an average capacity factor of the entire geographic region. This assumption implicitly leaves out the option of smoothing overall VRE generation in a region by deploying VRE capacity strategically at sites with different capacity factor profiles to minimize the overall flexibility requirements from other assets in the system, like storage and gas generation. Consequently, this assumption might over-estimate the flexibility needs of integrating VRE resources and limit the overall share of VRE generation.

Third, the model is initialized with no existing generation capacity to serve demand in 2030. In the U.S. context, recent trends in gas prices and declining VRE technology costs have seen several premature retirements of thermal generation assets, particularly for coal power plants, and more recently for gas generation[22]. While these trends make it reasonable to assume the coal fleet is retired, other thermal generation sources, like gas generation, nuclear, as well as hydropower, are likely to be available in this timeframe. In the absence of any policy supporting low-carbon generation, a greenfield system provides greater opportunity for VRE penetration than a system with existing generation capacity; i.e., brownfield. Modeling the system implications of cost reductions for wind, solar, and storage in a brownfield system might result in lower VRE penetration as there is limited incentive to prematurely retire existing generation capacity and replace it with VRE generation. The outcomes of the case study modeled here, with greenfield conditions and no explicit policy scenario, can be viewed to approximate the outcomes for a brownfield system which has an explicit policy emphasizing generation from VRE resources as compared to thermal generation. Alternatively, the analysis presented here can be viewed as a long-term view of the power system (2040 and beyond in the case of U.S. and Europe) when existing fossil-fuel capacity in some regions would be retired, either because of lifetime or uneconomic operation.

Conclusions and future work

The precipitous decline in costs of wind and solar generation observed over the past decade has made renewables adoption cost-competitive in several regions around the world, even in the absence of supportive policies. Here, we investigated the prospects for renewables deployment in future grids for a range of 2030 cost projections and find that there is a possibility for VRE generation to become the dominant share of electricity supply over the next decade, if historical cost reduction trends persist. This study also echoes assessments from other studies that highlight the importance of continued advancement in wind and solar technologies to enable cost-effective decarbonization of the power sector[20]. Besides wind and solar capital costs, the study also quantifies how other system and technology descriptors impact the level of renewables penetration in future grids. For instance, for the same set of cost assumptions, systems primarily reliant on wind (e.g., North) are estimated to achieve lesser VRE penetration than systems with equally good wind and solar resources (e.g., South). Higher natural gas prices will also favor increasing VRE penetration and so will declining capital cost of battery

[22] IEEFA, New Risk Factors Emerge as GE Shutters California Power Plant— 20 Years Early, Institute for Energy Economics and Financial Analysis (IEEFA) whitepaper, July 2019, https://ieefa.org/wp-content/uploads/2019/07/New-Risk-Factors-Emerge-as-GE-Shutters-California-Power-Plant_July-2019.pdf

energy storage. Future work will quantify the impact of relaxing the major assumptions made in this study on system outcomes. In particular, it would be important to quantify how sensitive renewables penetration is to modeling of intra-regional transmission constraints and existing generation assets and their potential economic or lifetime-based retirement.

Appendix: Industry view on cost, performance evolution to 2030 of the key energy technologies[23]

Methodology

A detailed assessment of potential cost reductions of key technologies is essential for evaluating potential decarbonization of the future electricity mix. Most technology cost forecasts for renewables are based on a learning-curve analysis, which considers the technology cost reduction potential with increasing scale of adoption. Historically, however, the cost reductions realized for renewables have beaten the most aggresive forecasts, suggesting a need to consider a bottom-up assessment that is based on anticipated cost and performance improvements of key components. Here, we rely on a bottom-up approach that reviews the impact of detailed innovations for each technology for estimating technology costs in 2030, thus preventing the results from being biased based on uncertain market or volume forecasts. The current analysis is based on the experience of Iberdrola, which has more than 30 GW of installed renewable capacity globally, as well as in third party publications, discussions with key suppliers and original equipment manufacturers (OEMs), and universities and research centers (Figure 1).

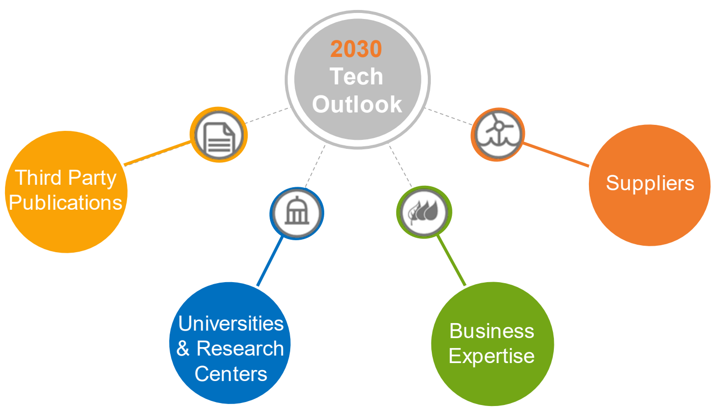


Figure 1. Sources of input informing Iberdrola 2030 cost outlook

The analysis developed in this document focuses on the mechanisms for technology cost reductions based on the innovations that industry is already working on today. These advances are therefore not only feasible, but also probable.

Onshore Wind

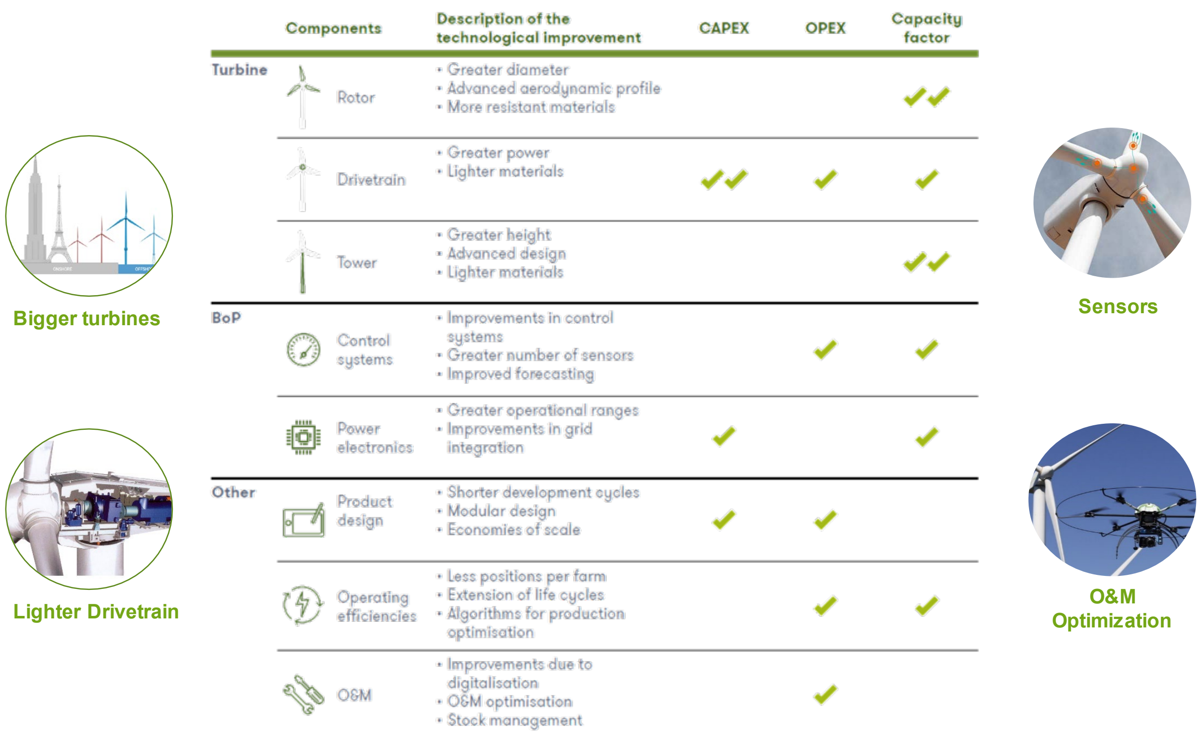
Today, onshore wind energy is the renewable technology with the highest installed capacity in the world, after hydropower. Since the year 2000, wind energy has gone from being practically non-existent to having almost 600 GW installed by the end of 2018, which represents an average annual growth of

[23] The material presented in this section was developed by Iberdrola authors using an internally-developed methodology.

more than 20% over this period. This upward trend is expected to continue, reaching up to ~1,500 GW by 2030.

Current cost and bottom-up analysis

In order to analyze the investment cost, we will use a 100 MW project in Europe as a base case. The capital expenditure (CAPEX) of an onshore wind farm currently stands at about $1,100/kW, a large share of which being the cost of the turbine (~70%). In the coming years, reductions in capex are expected, although the main technological improvements are aimed at increasing the annual energy production. The downward trend in costs and the increase in production hours are due to the emergence of various technological innovations, summarized in the table below.



	Components	Description of the technological improvement	CAPEX	OPEX	Capacity factor
Turbine	Rotor	• Greater diameter • Advanced aerodynamic profile • More resistant materials			✓✓
	Drivetrain	• Greater power • Lighter materials	✓✓	✓	✓
	Tower	• Greater height • Advanced design • Lighter materials			✓✓
BoP	Control systems	• Improvements in control systems • Greater number of sensors • Improved forecasting		✓	✓
	Power electronics	• Greater operational ranges • Improvements in grid integration	✓		✓
Other	Product design	• Shorter development cycles • Modular design • Economies of scale	✓	✓	
	Operating efficiencies	• Less positions per farm • Extension of life cycles • Algorithms for production optimisation		✓	✓
	O&M	• Improvements due to digitalisation • O&M optimisation • Stock management		✓	

Figure 2. Summary of anticipated technological improvement for various components of onshore wind.

In particular:

Larger rotors and increased unit power: The introduction of larger rotors (~30% large diameter), allows for increasing load factors (or capacity factors); this is achieved by more advanced aerodynamic profiles and more resilient and lighter materials. The increase in turbine power (up to 6 MW by 2030) will reduce number of turbines for a given wind farm power capacity, allowing for lower unit costs and operating costs (OPEX).

Higher towers: Increasing the height of the towers will increase the load factor. Improved design and use of lighter materials will enable access to more constant and faster winds.

Standardization and digitization: The standardization of auxiliary equipment and components will drive the generation of greater economies of scale. Growing digitization and deployment of sensors with all equipment will allow for capture and processing of a greater volume of technical and operating data. Applying advanced data analysis will improve weather forecasting processes, control systems, plant availability, and production levels, reducing operating costs.

Based on the impact of these innovations, the forecasted evolution of CAPEX, OPEX, capacity factor and levelized cost of electricity (LCOE) is shown in Figure 3. Our analysis suggests that the aforementioned technological improvements will lead to a reduction in the LCOE by 2030 of approximately 30%.

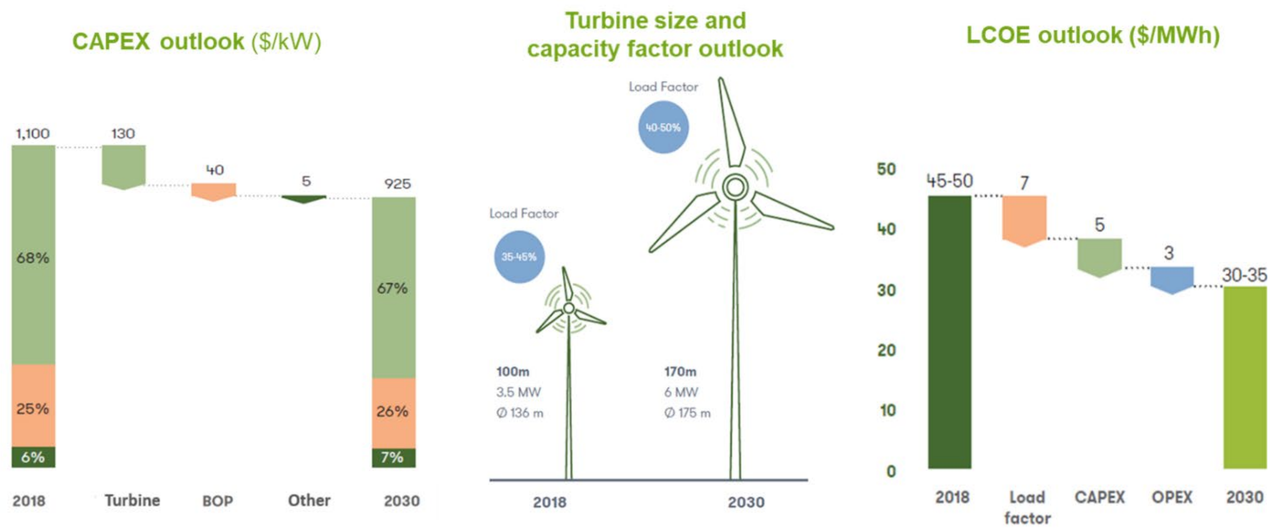


Figure 3. Summary of cost and performance outlook for onshore wind in 2030. LCOE = Levelized Cost of Electricity. BOP = Balance of Plant.

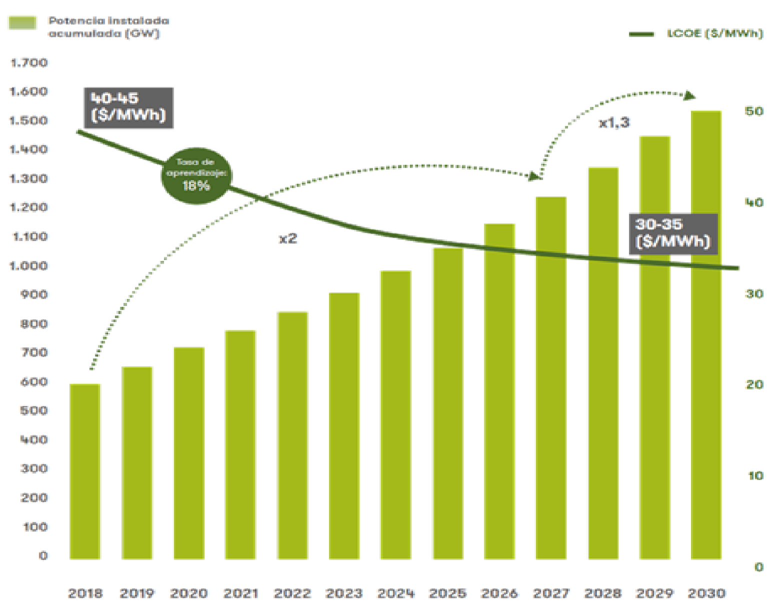


Figure 4. Top-down estimate of levelized cost of electricity (LCOE) trends for onshore wind.

Top down: Learning curve analysis

The learning curve analysis is consistent with the bottom-up analysis above showing a ~30% LCOE reduction to 2030 when using a 18% learning rate assuming a cumulative installed capacity by then of ~1,500 GW.

Offshore Wind

The progress of offshore wind technology made it possible to reach 23 GW of installed capacity in 2018 thanks to the impetus of countries such as the United Kingdom and Germany. It is anticipated that nearly 180 GW will be reached by 2030, which is six times the current installed capacity.

Current cost and bottom-up analysis

For analyzing investment cost, we have chosen the reference project to be a 500 MW wind farm in Europe. Currently, the investment cost of an offshore wind farm stands at $3,200/kW. Unlike onshore wind power, most of the investment costs relate to the cost of installation itself (~50%). By 2030, a strong average reduction of capex ($/kW) of up to 40% is anticipated, but the innovations will also increase production and reduce OPEX.

The downward trend in costs and the increase in production hours are due to the emergence of various technological innovations, summarized in the table below.

	Components	Description of the technological improvement	CAPEX	OPEX	Capacity factor	Financing costs
Equipment	Turbine	• Greater power • Greater rotor diameter • More resistant materials	✔✔	✔✔	✔	
	Foundations	• Design improvements	✔	✔		
Other Activities	Market maturity	• Economies of scale • Reduced risk	✔	✔		✔✔
	Operating efficiencies	• Optimised installation process • Improvements in transport equipment	✔✔			
	O&M	• O&M optimisation • Hub effect		✔✔		

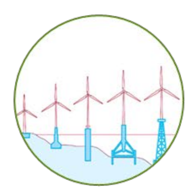


Figure 5. Summary of anticipated technological improvement for various components of offshore wind.

In particular:

Turbines of greater power: The increase in turbine power to 15 MW by 2030 will lead to a reduction in the number of positions, resulting in lower unitary capex ($/kW) and operating costs.

Larger rotors: In line with the turbines' greater power, the rotors will reach 220 meters in diameter. This 70% increase in size will be achieved by using more resilient materials and improving aerodynamics. These rotors will significantly increase the turbine load factor.

Economies of scale: The increase in installed capacity and the development of hubs will lead to economies of scale throughout the supply chain by optimizing the costs of installing and operating farms.

Based on the impact of these innovations, the forecasted evolution of CAPEX, OPEX, load factors, and LCOE is included in Figure 6. These technological improvements will lead to a reduction in the LCOE by 2030 of approximately 40%.

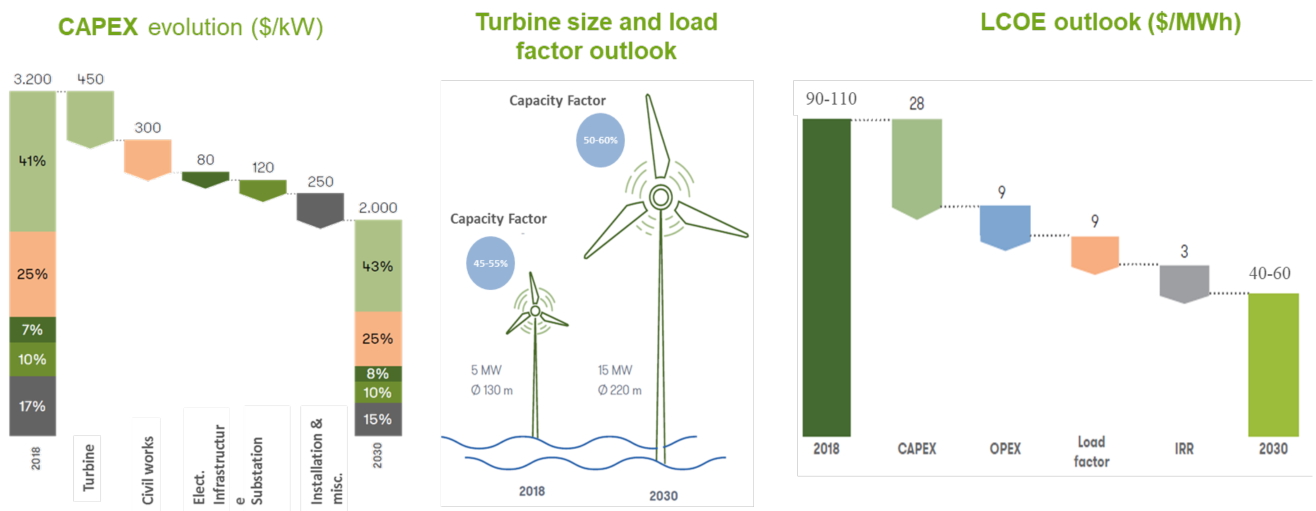


Figure 6. Summary of cost and performance outlook for offshore wind in 2030. LCOE = Levelized Cost of Electricity. BOP = Balance of Plant.

Top down: Learning curve analysis

The learning curve analysis is consistent with the bottom-up analysis above showing a ~40% LCOE reduction by 2030 when using a 18% learning rate, assuming a cumulative installed capacity by then of ~180 GW.

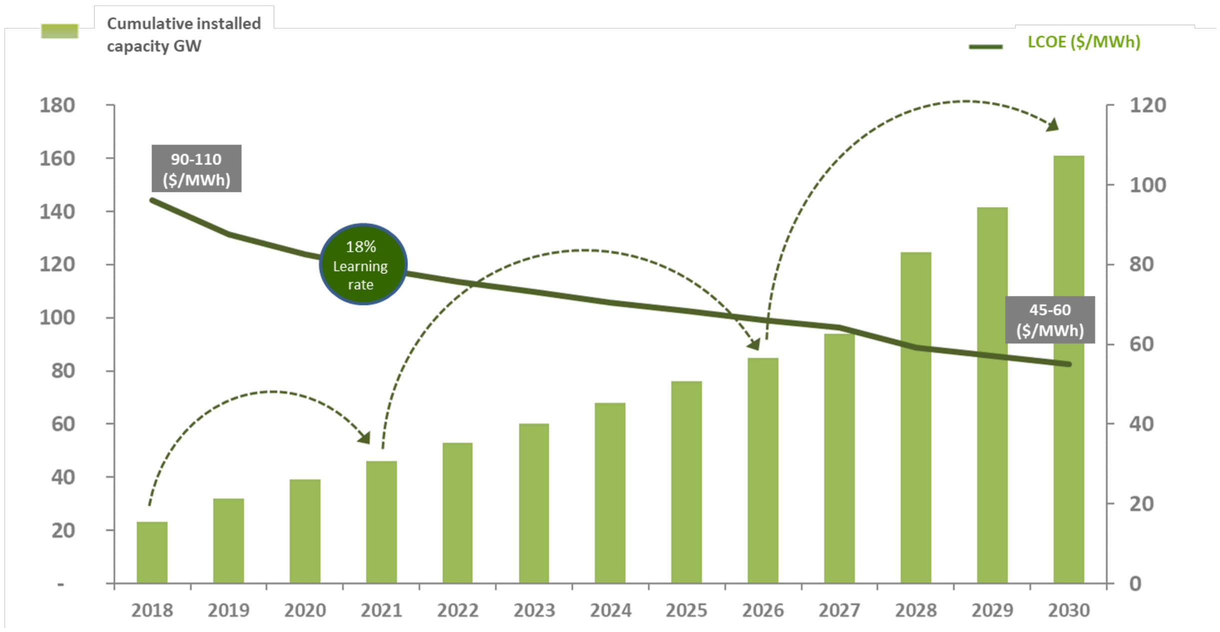


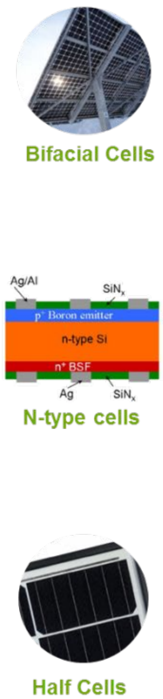
Figure 7. Top-down estimate of levelized cost of electricity (LCOE) trends for offshore wind.

Solar PV

Owing to the sharp drop in the prices of solar panels based on crystalline silicon, solar photovoltaics (PV) is one of the fastest-growing renewable generation technologies in recent years. Since 2005, global installed capacity has grown at an average annual rate of 45% to ~510 GW_{DC} by 2018. In the future, this upward trend is expected to continue until it reaches ~2,100 GW_{DC} in 2030, multiplying the current capacity by four.

Current cost and bottom-up analysis

To analyze the investment cost, a solar project with a capex of around $650/kW is used as a base case. The share of the cost of the panels is key in this cost as it is the component with the greatest potential for reduction. In the medium term, an average reduction of 30% of capex ($/kW) and 20% of the OPEX ($/kW/year) is estimated, as well as an increase of 10% of the capacity factor. The downward trend in costs and the increase in production hours are due to the emergence of various technological innovations, summarized in the table below.



	Members	Description of the technological improvement	CAPEX	OPEX	Efficiency
Module	Wafer	• More efficient use of silicon • Delocalisation of manufacture • Use of energy-efficient furnaces • Improvements in surface quality	✓		✓
	Cell	• PERC, treatment of the rear side to increase the life of free electrons • Bifacial cells • Half-Cell and Multi-Bars • N-Type			✓✓
	Module	• Dual glass			✓
Inverter	Power electronics	• String inverters • Improved power density • Increased voltage	✓	✓	✓
	Digitisation	• Big Data • Artificial Intelligence		✓	
BoS	BoS	• Cost of materials • Economies of scale • Standardisation and modularisation • Reduction of wiring by self-powering	✓✓		
Other	O&M	• Use of drones for predictive maintenance • Cleaning of panels using robots		✓	

Figure 8. Summary of anticipated technological improvement for various components of solar photovoltaics (PV).

In particular:

Improved manufacturing processes: Competition between suppliers has long been an incentive to reduce the cost of manufacturing solar panels from silicon ore. Innovation has enabled more efficient use of raw materials and the electricity consumption necessary to obtain crystalline silicon.

Increased efficiency of the panels: The most commonly used panels in PV plants are polycrystalline, with an energy efficiency of 17-18%. Many manufacturers have incorporated more sophisticated methods to obtain monocrystalline silicon, which, unlike polycrystalline silicon, has a uniform structure. It is estimated that in the medium term, there will be a wider adoption of monocrystalline panels due to their lower cost and better efficiency (around 20%).

The growing investment in R&D is driving the creation of technologies to make better use of the solar resource (bifacial cells), reduce degradation over time (N-Type, Double Glass), reduce resistance to the passage of electric current (multi-Busbars, Split Cells) and, in general, increase electricity output from the same solar spectrum (PERC, Passivated Emitter Rear Cell). A growing adoption of bifacial and high efficiency panels is expected by 2030, with efficiencies close to 25%.

These developments will have a dual effect: 1) greater use of the solar resource will result in a greater capacity factor and; in addition, 2) the increasing efficiency means that, over time, plants with greater capacity will occupy the same surface area, which will lower the unitary investment costs of the Balance of System (BoS).

Better inverters: Changing the design of the plants to integrate string-inverters instead of a central inverter will increase the availability of the plants by reducing the shadowing effect (i.e., the lack of solar exposure in one line limiting the generation of the plant as a whole). In addition, this design reduces the corrective maintenance costs associated with this equipment.

Based on the impact of these innovations, the forecasted evolution of CAPEX, OPEX, load factors, and LCOE is shown in Figure 9.

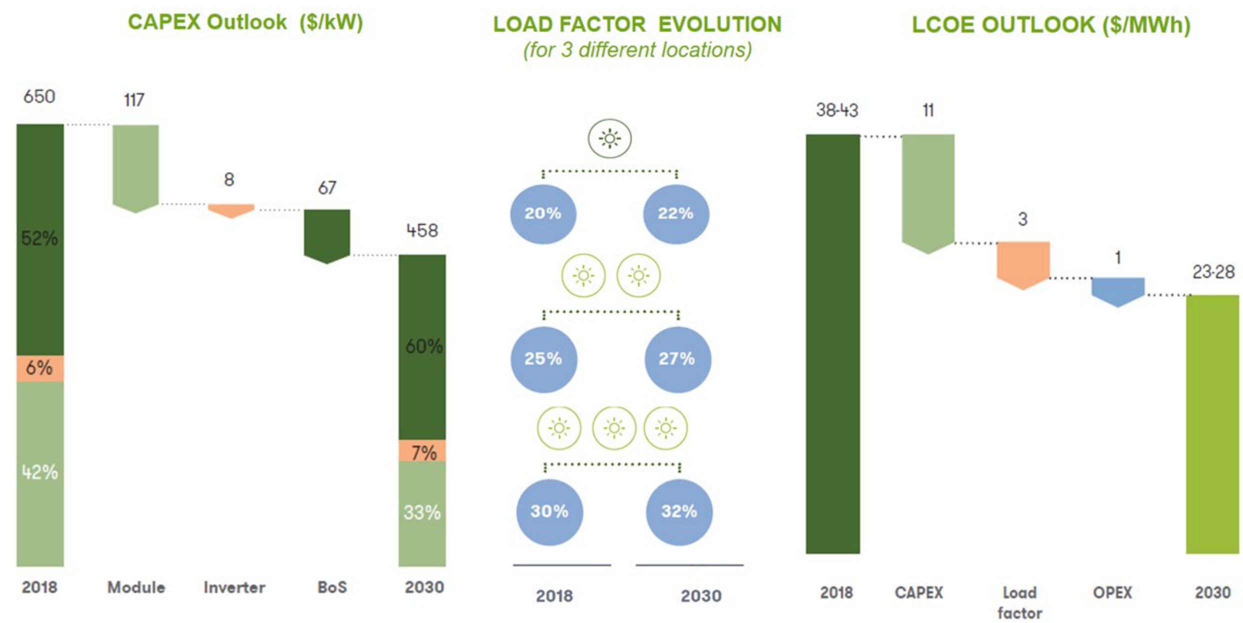


Figure 9. Summary of cost and performance outlook for solar PV in 2030. LCOE = Levelized Cost of Electricity. BoS = Balance of System.

Top down: Learning curve analysis

The learning curve analysis is consistent with the bottom-up analysis above, showing a ~30% LCOE reduction by 2030 when using a 24% learning rate for the solar panels and a 10% learning rate for the rest of the equipment costs, assuming a cumulative installed capacity of ~2,100 GW.

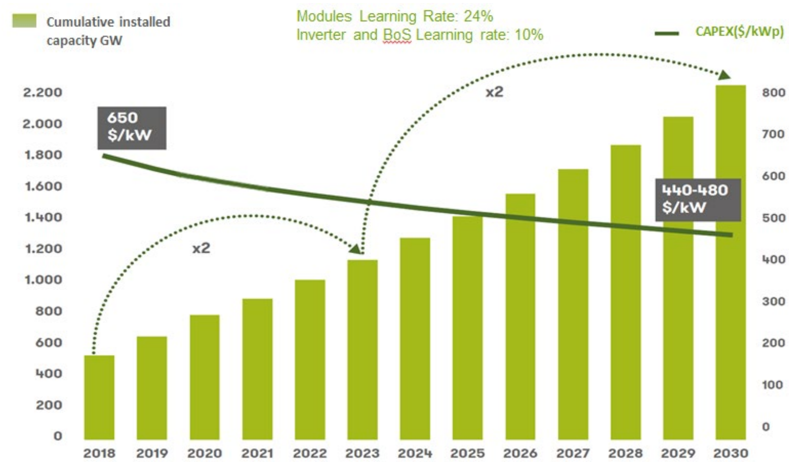


Figure 10. Top-down estimate of levelized cost of electricity (LCOE) trends for solar PV.

Energy Storage

In a system with high VRE penetration, short-, medium-, and long-term energy storage will be necessary. There are multiple storage technologies that differ in terms of power, storage capacity (duration), efficiency, density, etc. The selection of each technology is determined by its technical capacity to deliver a particular application, as well as its cost.

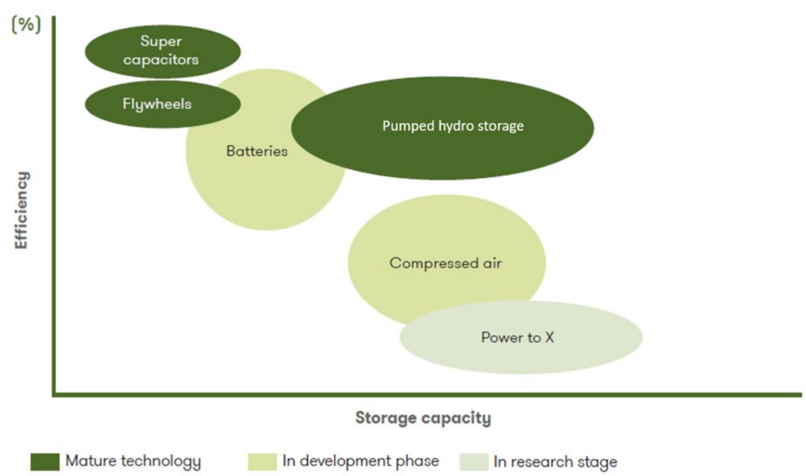


Figure 11. Classification of types of energy storage technologies based on efficiency and storage capacity.

Long-duration storage of large volumes of energy (>20 hours)

Until now, only one electricity storage technology, pumped-hydro, has proved technically and economically feasible for widespread use in the electricity sector. Its main competitive advantages are its moderate investment cost (600-1200 $/kW), a useful life of more than 100 years, unlimited discharge cycles, and a high number of storage hours (~20 hours, in some cases, over 200 hours). In spite of being a mature technology, new technological advances continue to take place that further strengthen pumped hydro's competitiveness and flexibility, and allow for opening up new paths of development.

These developments include variable speed turbines, which optimize machine performance at any point of operation, in either turbine or pumping mode, and enable a greater flexibility of operation as they allow regulating the load in pump mode. In addition, the use of variable speed technology opens up the possibility of adapting a larger number of existing hydropower plants for use as reversible power plants. In cases where no additional civil works are required, the investment cost of the retrofit could be as low as 100-250 $/kW. Pumped-hydro is and will be the most economical solution to the growing need to store large volumes of energy.

Medium volume and short duration storage (<4 hours)

Lithium-ion batteries are capable of storing medium volumes of energy for a duration of no more than 4-6 hours, providing backup capacity in periods of peak demand, regulating the frequency of the grid in milliseconds or optimizing the integration of VRE sources in the system.

The high demand of batteries that will come for electric vehicles explains the significant economies of scale and investments being made in the future development of this technology, which will undoubtedly see the most growth in its use by 2030. The cells that make up the battery modules of an electric vehicle and those of a stationary storage system are essentially the same.

Lithium-ion batteries are a large family of different chemistries, generally composed of a lithium metal oxide at the cathode and a graphite anode, both immersed in a lithium salt electrolyte. Depending on the specific chemistry, different performances are achieved in terms of energy density, life cycles, safety and cost, with NMC (Nickel-Manganese-Cobalt cathode) batteries currently showing the best balance between these four factors.

Current cost and bottom-up analysis

The cost of an NMC 111 battery pack (the same proportion of the three metals) for energy applications (four hours) is now around 200 $/kWh, and more than half of this is due to the cost of materials. By 2030, a 60-65% reduction in the cost of the battery pack is expected, down to 70-80 $/kWh, which will be achieved through a set of improvements, summarized in Figure 12.

	Components	Description of technological improvement	Cost	Energy density	Useful life
Manufacture	Manufacture	• Economies of scale • Automation • Redesign of manufacturing processes	✓		
Improved energy density	Cathode	• Greater thickness • Cheaper materials • Higher voltage and capacity • Increased cycle life	✓✓	✓	✓
	Anode	• Greater thickness • Use of silicon • Improved safety • Increased capacity	✓✓	✓	✓
	Other components	• Heat resistance • Less thickness • Lighter and cheaper materials	✓	✓	✓
Others	Disruptive technologies	• Solid state • Lithium sulphide (Li-S) batteries	✓		

Figure 12. Summary of anticipated technological improvement for various components of battery energy storage technologies.

In particular:

Automating and optimizing the manufacturing process: The growth of electric vehicles will further drive the automation of cell manufacturing and process improvement. Using water as a solvent or reducing the need for dry-rooms will lower the production cost.

Improving energy density: The active material in a cell will be increased (amount of chemical compound in the cathode and anode) and the non-active material will be reduced (separator, current collector, plastics, connectors, etc.) with work focusing on different areas of the cell.

Cathode. Innovations are geared toward the use of cheaper chemistries, reducing the amount of more expensive materials, such as cobalt, while increasing density (e.g., by increasing the proportion of nickel). This will mean evolving from the current chemicals NMC 111 to NMC 622 or NMC 811 (with a higher proportion of nickel than the other metals).

Anode. Future developments focus on the introduction of silicon instead of the current graphite, which will reduce its size and therefore its cost.

Other improvements: Advances are also anticipated in the use of electrolytes that withstand higher voltages or materials for the higher thermal resistance separator that will increase operating cycles and battery life. In addition, the development of solid-state electrolytes will allow for eliminating the separator and provide greater safety.

Top down: Learning curve analysis

Applying a learning rate of 16% to the projected cumulative battery production in 2030 of 7,500 GWh (equivalent to approximately 125 million electric vehicles) yields a cost of 70-75 $/kWh for a battery pack, representing a 60-65% decrease from the current level (Figure 13). The similarity between the two estimates allows us to assume realistic scenarios in which batteries will cost about 75 $/kWh in 2030.

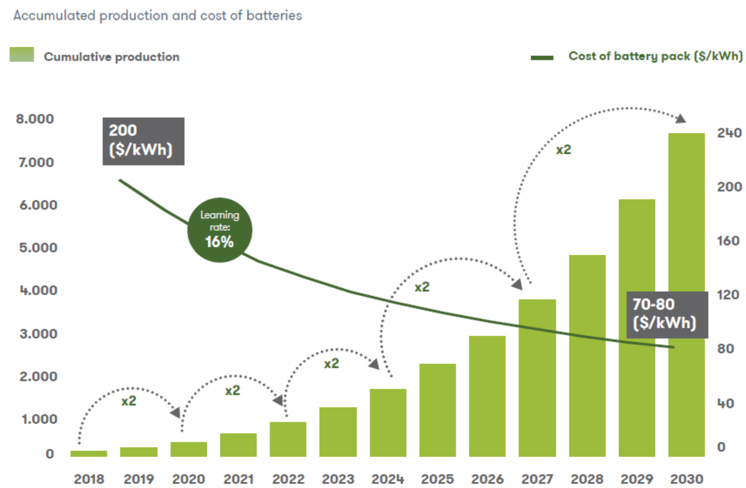


Figure 13. Top-down estimates for the cost of battery packs with increasing scale.

Storage systems in the electricity sector

A stationary large-scale lithium battery system consists mainly of batteries, a bidirectional inverter, protections, an air conditioning system, fire-suppression system, and management software.

A 10 MW/40MWh battery project in Europe with a current capex of around 350 $/kWh has been used as a base case, with the cost of battery pack contributing ~60% of system costs. In the medium term, a CAPEX reduction of 50-60% is expected, so that values around 150-160 $/kWh would be reached by 2030 (Figure 14).

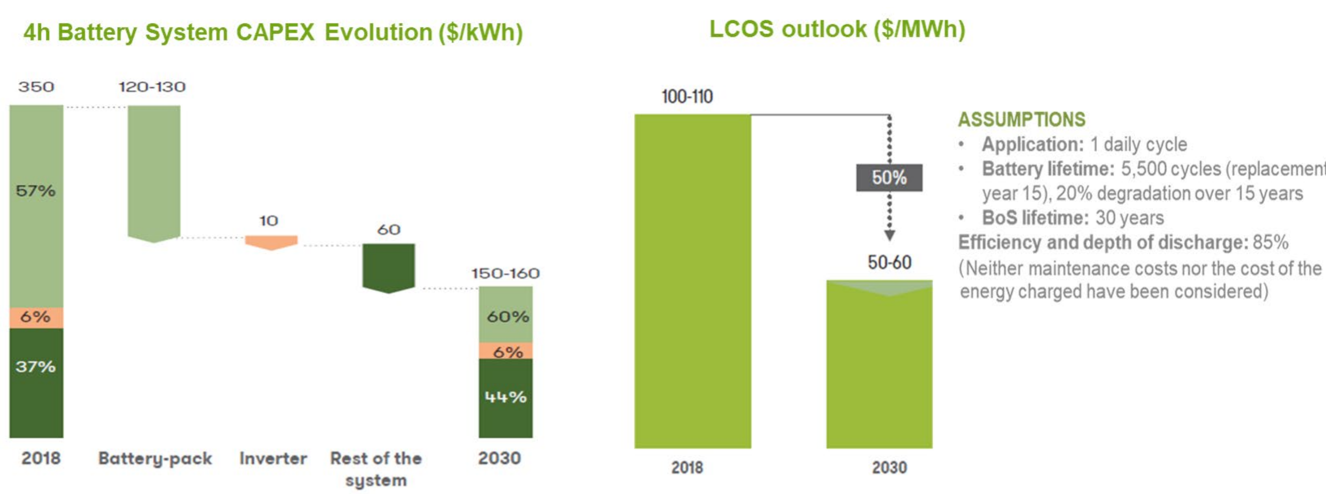


Figure 14. Summary of cost and performance outlook for grid-scale battery energy storage systems in 2030. LCOS = Levelized Cost of Storage.