Technology improvement and emissions reductions as mutually reinforcing efforts

Observations from the global development of solar and wind energy

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Executive Summary

Mitigating climate change is unavoidably linked to developing affordable low-carbon energy technologies that can be adopted around the world. In this report, we describe the evolution of solar and wind energy in recent decades, and the potential for future expansion under nations' voluntary commitments in advance of the 2015 Paris climate negotiations. These two particular low-carbon energy sources—solar and wind—are the focus of our analysis because of their significant, and possibly exceptional, expansion potential.

Technology differs from the static picture we might implicitly assume. Deploying a technology coincides with and engages a variety of mechanisms, such as economies of scale, research and development (R&D), and firm learning, which can drive down costs. Lower costs in turn open up new deployment opportunities, creating a positive feedback, or 'multiplier' effect. Understanding this aspect of technology development may help support collective action on climate change, by lessening concerns about the costs of committing to reducing emissions. The deployment of low-carbon energy technologies that are necessary to accomplish greenhouse gas emissions cuts, helps bring about improvements and cost reduction that will make further cuts more feasible.

Among low-carbon electricity technologies, solar and wind energy are exemplary of this process. Solar and wind energy costs have dropped rapidly over the past few decades, as markets for these technologies have grown at rates far exceeding forecasts. In the case of solar energy, for example, the cost of reducing emissions by replacing coal-fired electricity with photovoltaics has fallen 85% since 2000.

Getting these technologies to their current state of development was a collective accomplishment across nations, despite minimal coordination. Public policies to stimulate research and market growth in more than nine countries in North America, Europe, and Asia—including the U.S., Japan, Germany, Denmark, and more recently, China—have driven these trends. Firms responded to these incentives by both competing with and learning from one another to bring these low-carbon technologies to a state where they can begin to compete with fossil fuel alternatives. Technology has improved as a result of both research and successful private-sector commercialization efforts.

Commitments made in international climate negotiations offer an opportunity to support the technological innovation needed to achieve a self-sustaining, virtuous cycle of emissions reductions and low-carbon technology development by 2030. As a way to achieve emissions reductions, solar and wind technologies are already in a cost competitive state in many regions and are rapidly improving.

We posit that the more that parties to climate negotiations are aware of the state of these technologies, and especially the degree to which technology feedback stands to bring about further improvements, the more opportunity there will be for collective action on climate change.

These are our summary findings. We make several specific observations about the development of solar and wind energy:

- Over the past four decades wind electricity costs have fallen by 5% per year and solar electricity costs have fallen by 10% per year, on average. Since 1976, photovoltaic (PV) module costs have dropped by 99%. For the same investment, 100 times more solar modules can be produced today than in 1976. Wind capacity costs fell by 75% over the past three decades.
- Solar is now nearly cost-competitive in several locations, and wind in most locations, without considering the added benefit of pollutant and greenhouse gas emissions reductions. When these external costs are considered, the cost competitiveness improves substantially.
- Over the last 15 years, the cost of abating carbon from coal-fired electricity with solar in the U.S. has dropped by a factor of seven. Over the last 40 years, the cost has fallen by at least a factor of 50 (given a flat average coal fleet conversion efficiency in the U.S. during this period).
- Wind and solar installed capacity has doubled roughly every three years on average over the past 30 years. These growth rates have exceeded expectations. For example, the International Energy Agency 2006 World Energy Outlook projection for cumulative PV and concentrated solar power (CSP) capacity in 2030 was surpassed in 2012. The Energy Information Agency 2013 International Energy Outlook projection for cumulative PV and CSP capacity in 2025 was surpassed in 2014.
- Countries have traded positions over time as leaders in solar and wind development. Japan, Germany, Spain, Italy, and most recently China have led the annual installed capacity of solar since 1992. Japan was the leader in cumulative capacity in the first decade and Germany led in the last decade. Since 1982, the U.S., Denmark, Germany, Spain and recently China have led annual wind installations. Over this period the U.S., Germany and China traded off as the countries with greatest cumulative installed wind capacity. In per capita terms Denmark has dominated wind installations. Sweden and Denmark have led in per capita cumulative wind R&D. Switzerland and the U.S. have invested the most per capita in solar R&D. The U.S. has invested more cumulatively than any other nation in both wind and solar R&D between 1974 and the present day.
- Current climate change mitigation commitments by nations in advance of the 2015 Paris climate negotiations could collectively result in significant further growth in wind and solar installations. If countries emphasize renewables expansion, solar and wind capacity could grow by factors of 4.9 and 2.7 respectively between the present day and 2030.
- Based on future technology development scenarios, past trends, and technology cost floors, we estimate these commitments for renewables expansion could achieve a cost reduction of up to 50% for solar (PV) and up to 25% for wind. For both technologies this implies a negative cost of carbon abatement relative to coal. Forecasts are inherently uncertain, but even under the more modest cost reduction scenarios, the costs of these technologies decrease over time.

From these observations and modeling estimates, we also draw several broad implications for climate change mitigation efforts:

- **Negotiations as opportunity-building rather than burden-sharing.** The potential for reducing emissions in the long-term can grow with global collective efforts to achieve near-term emissions cuts. Climate negotiations may provide an opportunity for nations to take advantage of this multiplier effect and drive down the cost of mitigating carbon emissions by 2030. The cost of mitigating carbon can fall faster if countries increase and sustain over time their commitments to deploying renewable and other clean energy technologies. As today's commitments are strengthened, the potential emissions reductions that can be made in the post-2030 period may also increase.

- **Importance of knowledge-sharing and global access to financing.** Two challenges should be addressed if renewables growth is to reach its full potential. The upfront costs of renewables can be significant, while the variable costs are low. Equitable financing for all nations will be critical for allowing the global growth of these technologies. Knowledge sharing to bring down the 'soft costs' of these technologies, which includes all investments required for onsite construction, will be equally important. Knowledge-sharing and public policy incentives to stimulate private sector development of exportable combined software and hardware systems to reduce construction costs around the world can help support the global growth of clean energy.

- **Growing need for technologies that address renewables intermittency.** As their generation share grows, intermittency will limit the attractiveness of wind and solar technologies, particularly beyond 2030. Further development of energy storage and other technologies, such as long-distance transmission and demand-side management will be needed to reliably match supply with demand. The current electricity share of solar and wind in most nations, and natural gas back-up generation, leaves time for these other technologies to develop. Lessons learned from developing solar and wind energy can be applied to the development of these other technologies, particularly energy storage.

- **Historical legacy.** Developing clean energy is a measurable historical legacy for the nations that take part, with the potential for immeasurable benefit to humankind. Parties to the United Nations Framework Convention on Climate Change represent an all-inclusive gathering of nations that has arguably already left its mark by encouraging commitments by a handful of them to drive down the cost of clean energy. Further progress is within reach.

1. Introduction

Expectations about the amount of emissions reduction achievable are influenced by views on how technology will or will not develop. Parties to climate talks make assumptions, often implicit, about how easily low-cost, scalable clean energy can be deployed. These assumptions can strongly impact negotiations, but despite their important role in the discussion, views about technology are often not directly discussed or tested. In the absence of readily available information to the contrary, mental models of technology costs may take a static view. At other times, technology dynamics are taken into account but in a limited way, with performance assumed to change linearly with time.

One major aim of this report is to bring to these discussions a dynamic, nonlinear viewpoint that is more consistent with how technologies really evolve. This more realistic behavior centrally affects the prospects for meeting global climate targets. We describe how technology dynamics impact renewables costs, and the possible implications for the costs of cutting emissions pre- and post-2030. The introductory section below reviews a few key topics that form a backdrop for our analysis.

Mechanisms for reducing greenhouse gas emissions and the role of technology

Emissions cuts can be implemented by a variety of mechanisms: (1) direct control in the form of a cap or tax, (2) indirect control through clean energy or technology performance standards, coupled by demand side management [1], and (3) enabling policies including renewable portfolio standards, technology subsidies, and research and development (R&D) funding. No single policy instrument is best in all situations [2]. Direct control may be most economically efficient in theory, allowing the market to determine how and when technologies are deployed to meet climate goals [3]. However, in practice other policies can address distributional impacts, promote and reward innovation in the presence of knowledge spillovers, enable coordination across actors, reduce administrative costs, and promote action where direct control is not politically feasible [4].

Regardless of the implementation strategy, low-carbon energy will necessarily play a major role in achieving the reductions in global greenhouse gas (GHG) emissions needed to reach the climate change mitigation goals set by most nations. Other mitigation options include reducing energy demand and mitigating GHGs from agriculture, waste and land-use change, but none will be sufficient alone to achieve the low levels of GHG emissions required to limit the increase in global mean temperature to 2°C. Even with extreme demand-side efficiency measures, very-low-carbon energy technologies would be required to meet a significant fraction of global demand by 2050—one study finds that 60-80%

low-carbon energy is required for the U.S. [1]. The cost of low-carbon energy will therefore greatly influence the cost of mitigating climate change.

Several low-carbon energy technologies available today could support long-term emissions reduction cuts while meeting demand, but none have yet displaced fossil fuels to capture a majority share. The two low-carbon options emphasized in this report are solar and wind energy, both intermittent renewable energy sources. These technologies do not have the largest market share of very-low-carbon technologies, and they have barely made a dent in global emissions thus far, but they have shown faster growth in recent years than other options. Market growth has been supported by and has contributed to falling costs, with particularly rapid cost declines observed for solar. High growth rates have likely been achieved because of several characteristics of wind and solar photovoltaics, including the flexible scale of installation, and a more even distribution of growth potential across nations than alternatives such as nuclear energy, hydroelectricity, bioenergy, and concentrated solar power. This growth potential is determined by energy resource availability and a variety of other factors, including the effect on local water resources, land-use impacts on local populations, workforce expertise required for expansion, and a variety of perceived risks [5].

For these and other reasons outlined in the report, we focus our investigations on wind and solar among the set of very-low-carbon technologies. A large further expansion potential in these technologies alone could have a significant impact on the prospects for emissions cuts. We emphasize, however, the importance of investing in a variety of low-carbon technologies, beyond solar and wind, given the inherent uncertainty about the future, and difficulty in predicting future technology winners. Relying at least in part on carbon-focused policy instruments will allow the market to select the most economically efficient option at any given time.

This report concentrates on very-low-carbon energy technologies for electricity but does not deal in depth with other end-use sectors. Recent research suggests that electricity may play an increasing role in transportation [6], and may offer near-term opportunities for the decarbonization of personal ground vehicle travel to meet intermediate emissions reduction targets (to 2030) [7, 8]. Further development of energy technologies and systems is likely to be required for longer-term emissions reductions in personal and commercial ground transport [9]. Air transport and shipping also require further advancement of low-carbon alternatives. Direct heating remains an important end-use sector that has traditionally received less attention. Home energy systems, combining solar energy, electric vehicles, and both passive and active heating and cooling may offer a growing set of solutions as interest in these systems increases over time, especially when combined with increased urbanization [10, 11].

Climate change negotiations and clean energy technology development

The climate is a shared global resource whose preservation requires collective action [12, 13]. The upcoming Paris climate negotiations present an opportunity to coordinate national and multinational efforts to mitigate climate change [14, 15]. As negotiations have progressed over the course of meetings on five continents spanning more than two decades, discussions have reflected a growing sophistication about options to enable emissions cuts [16]. However the impact of technology innovation on the cost of mitigating climate change, and the opportunity to use international climate change negotiations as a platform to collectively influence technology innovation, has not been fully exploited. While the ability to predict technology development over time is inherently limited, growing evidence of fast rates of technological improvement and explanations of the drivers of this improvement provide some insight. It is clear that the experience that has accumulated in the development of clean energy technologies, and expectations about future improvement potential should begin to more directly inform international climate negotiations.

Climate negotiations provide a unique opportunity to explore prospects for the collective development of clean energy technologies. The negotiations are impressively inclusive, with the United Nations Framework Convention on Climate Change (UNFCCC) having 196 parties [17]. Climate negotiations have arguably already played a role in supporting the development of clean energy technologies. While it is difficult to measure this effect, policies supporting clean energy in various regions and nations were likely spurred in part by the negotiations' contributions to growing international recognition of climate change. Even though a global deal has not yet been reached, these more limited successes in raising awareness of the problem have almost certainly supported the growth of clean energy markets and technology development.

We propose that a deeper understanding of energy technology innovation can also help the negotiations. Technologies have improved over time in their ability to transform raw materials into more valuable resources. This technology innovation has been a primary driver of economic growth and rising atmospheric concentrations of GHGs since the onset of industrialization. The central question in the context of climate change mitigation—and other sustainability challenges—is whether we can now harness technology innovation but adjust its course to do more with less environmental impact, all while supporting economic activity. Recent progress in renewable energy is now widely recognized, yet renewables still provide less than 4% of global electricity. Explicitly addressing questions around the growth potential of these and other low-carbon energy technologies can inform the international debate on climate change mitigation. The potential for global cooperation under the umbrella of climate negotiations may be enhanced by recognition of past observed and future potential technological improvement.

Toward this end, our report addresses the following questions:

- How have solar and wind energy technologies evolved in recent decades? (Chapter 2)
- What countries have contributed to the development of these technologies? (Chapter 2)
- How might solar and wind energy installations expand with nations' Intended Nationally Determined Contributions (INDCs)? (Chapter 3)
- Under projected future installation levels, how might the costs of these technologies change? (Chapter 4)
- In sum, what lessons about renewable energy technology evolution are most salient for climate change negotiations? (Chapter 5)

2. Historical trends in photovoltaics and wind energy conversion

2.1 Historical growth in installed capacity and research

The expansion of solar power, here confined to PV, and wind power has been a result of the efforts of many different nations, with different countries taking the lead in capacity additions and research and development (R&D) spending over time. Here we provide a brief overview of historical support for PV and wind from different countries, illustrating the shifting global dynamics that have driven these technologies forward.

Over the last two decades, global PV deployment has increased steadily in terms of both annual installations and cumulative capacity (Figure 2.1). Individual countries, in contrast, have seen much more dramatic year-to-year changes in annual installations, often due to policy intervention. Historically, a small group of countries has consistently led the world in annual PV capacity additions. From 1992–2003, Japan led the market with consistent growth in residential PV deployment. From 2004–2012, Germany was the primary driver for PV with its national Energiewende policy, which called for—and realized—a massive expansion in renewable energy generation (principally wind, biomass, and solar). Spain and Italy took the lead for one year each, peaking in 2008 and 2011, respectively, before dropping off. Inconsistent deployment in those countries is attributable to policy changes as well, with rapid growth spurred by premium feed-in tariff regimes followed by market contraction in response to a hasty policy retreat, tariff cuts, the introduction of capacity quotas, and the global financial crash. Since 2013, China has been the world leader in PV installations.

Although we highlight the leaders in annual installation, we note that many other countries have contributed significantly to PV capacity additions and hence to experience-related declines in PV module and system prices (see Appendix). Indeed, because the PV module market is global, all countries' contributions to stimulating markets are important. As an example, the U.S. has never led the world in annual PV installations or cumulative capacity, yet the U.S. PV market has grown consistently since 2000 and contributes meaningfully to the global market. Furthermore, this simplified leaderboard obscures important upstream contributions to global cost reductions, such as public support for R&D and commercialization. We examine R&D funding trends in more detail later in this report.

Observed PV installation trends are similar when normalized to each country's population (Figure 2.1, Appendix) or economic output (see Appendix). One exception is that Australia supplants Japan as the global leader in the early years in both cases, and Japan (not China) leads in annual installations in

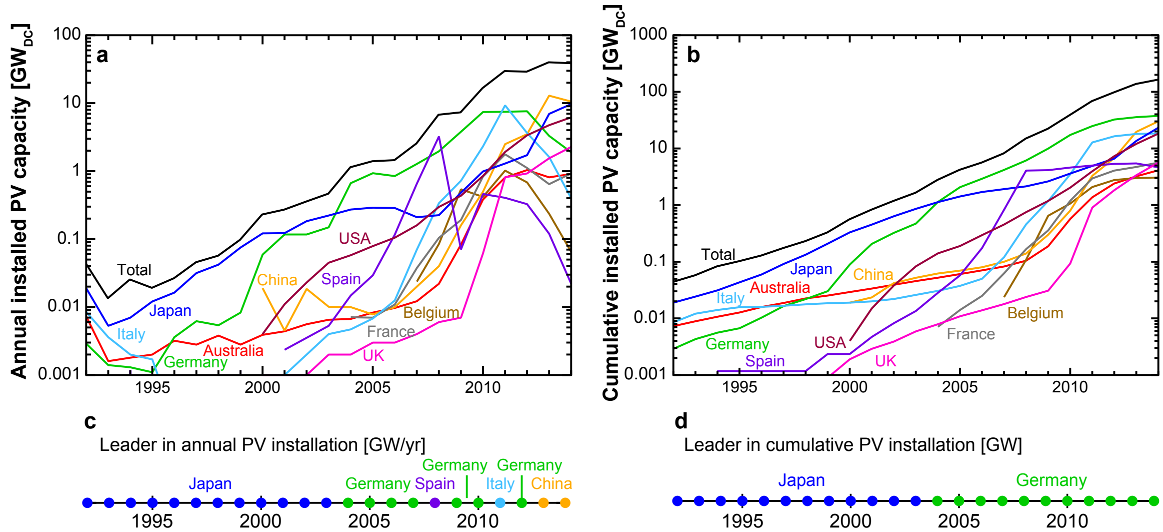

Figure 2.1: Installed capacity of photovoltaics (PV) in different countries over time. (a) Annual installed capacity of PV in GW_{DC} per year, differentiated by country, for the ten countries with the highest cumulative installed capacity in 2014 [18, 19, 20]. (b) Cumulative installed PV capacity in GW_{DC} for the same ten countries. Decommissioned projects are not subtracted from the total. (c), Annual leader in annual PV installation. (d), Annual leader in cumulative PV installation.

recent years.

Figure 2.2 shows the corresponding annual and cumulative installed capacity of wind power worldwide. The early market for wind power was driven by the U.S., which held the lead in cumulative capacity until it was overtaken by Germany in 1997. The rapid growth of wind power in China since 2009 has positioned it as the current worldwide leader in installed wind capacity. While the U.S., Germany, and China have been the largest drivers of total wind generation capacity, Denmark has dominated in wind deployment per capita and per GDP, and currently produces the equivalent of roughly 40% of its electricity demand in wind power.

R&D on wind and PV technologies has similarly been the result of efforts across many nations, and has been led on an absolute scale by many of the same countries that have been leaders in deployment. The appendix shows the annual and cumulative spending on publicly-funded PV and wind R&D across the ten IEA member countries with the highest current cumulative R&D spending on these technologies. The U.S. has been the global leader in cumulative R&D spending on each of these technologies throughout the entire observed period, carried by a significant surge of funding beginning during the 1973 oil crisis and reaching a peak during the 1979 oil crisis. The U.S. has been a frequent leader in annual R&D funding since then, with Germany and Japan often taking the lead for PV and Italy and the UK taking the lead for wind. R&D funding for PV and wind per capita and per GDP, shown in the Appendix, tell a somewhat different story. Wind per-capita and per-GDP R&D funding has been nearly entirely dominated by the Nordic countries, primarily Denmark and Sweden. Norway and the Netherlands (breaking the Nordic-only pattern) also led by these metrics for a few years. PV R&D funding per capita and per GDP has primarily been led by Switzerland, with the U.S., Germany, and other countries taking the lead at various times.

The global expansion in the deployment of wind power, and particularly in the deployment of solar power, has consistently outstripped projections. Figure 2.4 shows a series of ‘reference scenario’

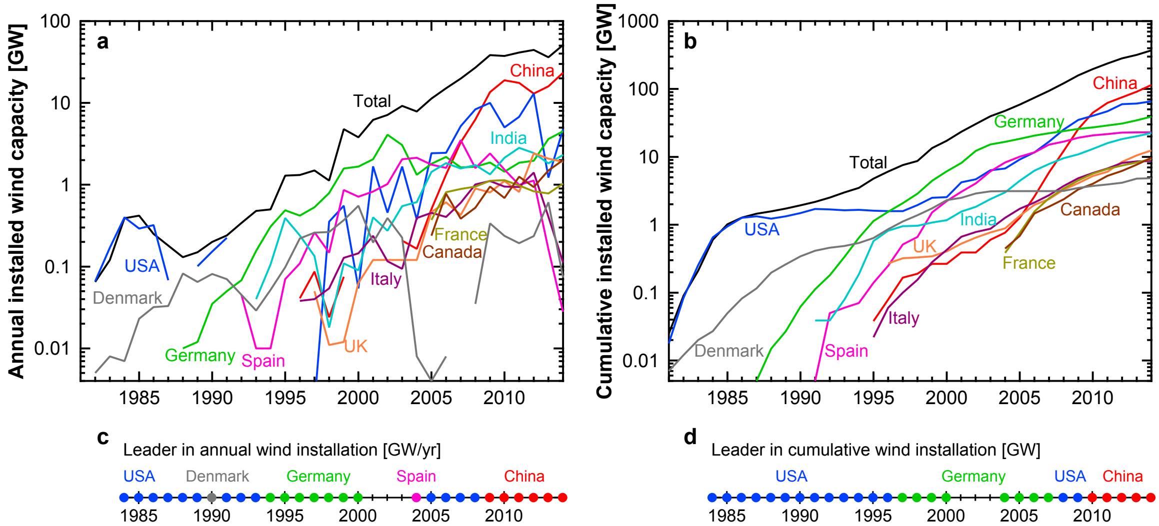

Figure 2.2: Installed capacity of wind power in different countries over time. (a) Annual installed wind capacity in GW per year, differentiated by country, for the ten countries with highest cumulative installed capacity in 2014 [21, 22]. (b) Cumulative installed wind capacity in GW for the same ten countries. Decommissioned projects are not subtracted from the total. (c) Annual leader in annual wind installation. (d) Annual leader in cumulative wind installation.

projections from the International Energy Agency's (IEA's) World Energy Outlook reports for the worldwide cumulative electric generation capacity of fossil, nuclear, wind, and solar power alongside actual historical capacity [24, 25, 26, 27, 28, 29, 30, 31]. While fossil generation capacity has largely followed projections, and nuclear generation capacity has significantly undershot projections, wind and solar capacity have consistently overshot projections. Indeed, IEA projections have been continuously revised upward to capture solar and wind growth: the WEO 2006 projection for wind capacity in 2015 was surpassed in 2010, and the projection for solar capacity in 2030 was surpassed in 2012. While the 'reference scenario' projections do not capture the effect of the significant deployment policies that have driven wind and solar adoption, even the IEA's 'New Policies' and '450 ppm' scenarios have had to be consistently revised upwards to account for the previously unexpected growth in deployment of these technologies. Projections from the U.S. Energy Information Administration (EIA) have been similarly low; the EIA's International Energy Outlook 2013 projection for cumulative solar capacity in 2025 was surpassed the year after the release of the report, in 2014 [32, 33, 34].

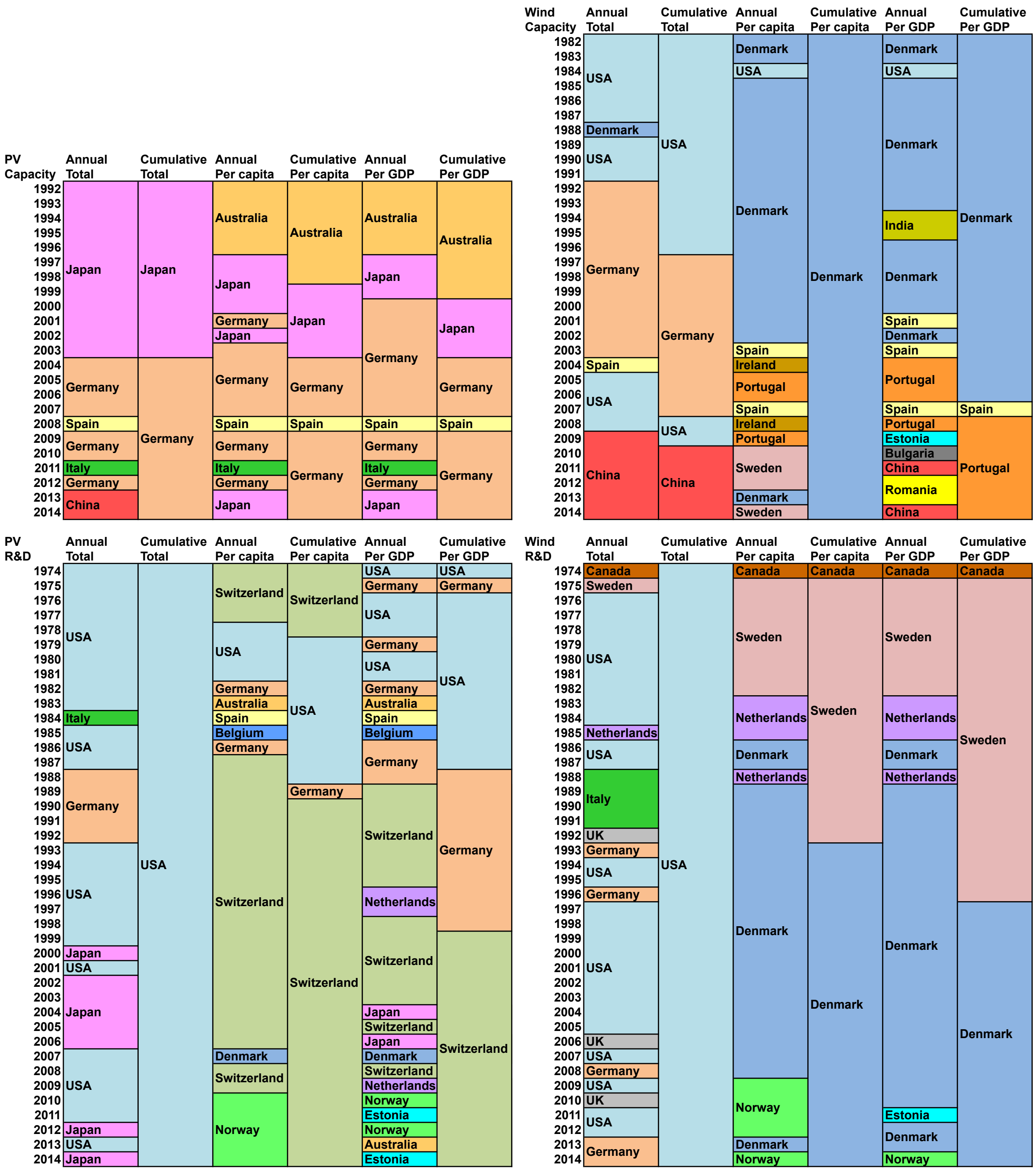

Figure 2.3: Annual leading countries in annual and cumulative capacity installations and R&D funding for photovoltaics and wind energy as a function of time[21, 22, 18, 19, 20, 23].

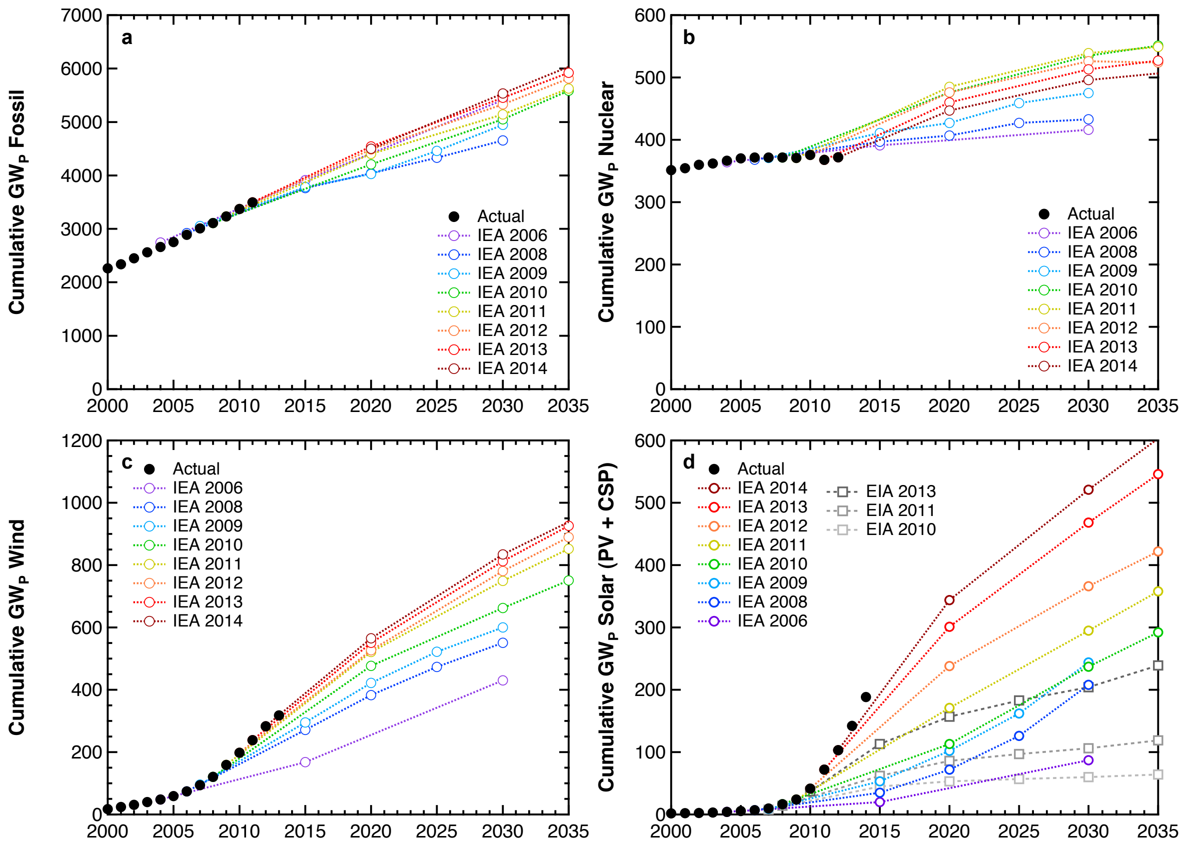

Figure 2.4: Literature projections for future capacity of different energy sources compared to actual capacity additions. Future projections for the cumulative capacity of fossil fuel (a), nuclear (b), wind (c), and photovoltaic (d) generation are denoted by empty circles for projections from the International Energy Agency (IEA) World Energy Outlook reports from 2006–2014,[24, 25, 26, 27, 28, 29, 30, 31] and by empty squares for projections from the U.S. Energy Information Administration (EIA) International Energy Outlook reports from 2010, 2011, and 2013.[32, 33, 34] Lines are given as guides to the eye. Actual cumulative capacity for each generation source is denoted by filled black circles and are taken from multiple references [18, 19, 20]. Panel d reproduced with permission from MIT.

2.2 Historical cost decline

The rapid global growth of wind and solar power has been driven by several reinforcing developments not fully accounted for in the IEA and EIA reference case scenarios. The observed growth has been driven by strong policy support for renewables adoption in the form of subsidies and renewable portfolio standards and by a rapid decline in the cost of these technologies (Figure 2.5). The real cost[1] of PV modules has fallen by roughly 99.4% over the past four decades, from $\sim$ 104 \$/W in 1976 to $\sim$ 0.67 \$/W in 2014. The cost of wind-generated electricity has fallen by roughly 74% over the past three decades, from $\sim$ 261 \$/MWh in 1984 to $\sim$ 67 \$/MWh in 2014.

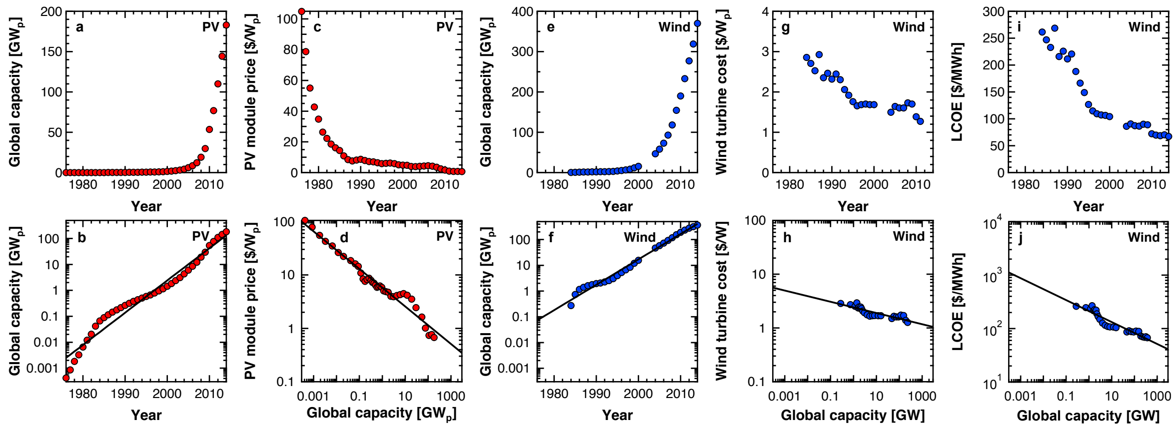

Figure 2.5: Global capacity and price history of photovoltaics and wind. a,b, Global installed capacity of PV in GW_{peak} over time [35]. c,d, Global average PV module price in $\$/W_{DC}$ plotted over time (c) and against cumulative installed PV capacity (d) [35]. e,f, Global installed capacity of wind in GW_{peak} over time [36, 37]. g,h Global average wind turbine price plotted over time (g) and against cumulative installed wind capacity (h) [38]. i,j, Global average levelized cost of energy (LCOE) from wind plotted over time (i) and against cumulative installed wind capacity (j) [36, 37, 39]. Trend lines in b and f are fit according to the equation $Capacity(t) = Capacity(t_0)e^{bt}$. Trend lines in d, h, and j are fit according to the equation $Price(t) = Price(t_0)Capacity^{-w}$.

The technological and cost dynamics of wind turbines are complex and warrant a detailed discussion. As shown in Figure capacity-cost-wright, the global average levelized cost of electricity (LCOE) from wind (measured in cost per watt-hour) has fallen more rapidly than the global average wind turbine cost (measured in cost per watt of capacity), which has oscillated around 1500 \$/kW since 1996—rising slightly in the late 2000s and falling after 2010. The rise in turbine prices in the late 2000s was due to a number of factors including rising materials, labor, and energy prices, increasing manufacturer profitability and demand growth, and variations in exchange rates and warranty provisions [40], but the general trend reflects changes in wind turbine properties designed to lower the cost of energy produced at the expense of higher (or at least constant) capacity cost.

Figure 2.6 illustrates some of the details behind these cost dynamics for turbines installed in the United States since 1998 [41, 42]. Average hub heights have increased from $\sim$ 60 m in 2000 to $\sim$ 80 m in 2014, enabling improved access to higher and more consistent wind speeds at higher altitudes. Average rotor diameter and turbine capacity have roughly doubled over the same time period; since the specific power (measured in watts of turbine capacity per square meter of swept rotor area) scales with the rotor diameter squared, average specific power has roughly halved. All else being equal, a decline

[1] All dollar values in this report are given in 2014 U.S. dollars unless stated otherwise.

in specific power leads to an increase in capacity factor, as the greater amount of power captured by the oversized rotor (particularly at low wind speeds) increases the fraction of time during which the comparatively smaller generator is operating at its rated capacity [43]. The increase in average capacity factor of wind projects installed in the United States has been counterbalanced since the mid-2000s by an increased build-out of lower-quality wind sites, resulting in a mostly flat average capacity factor among new projects installed since 2004 (although the capacity factors have still been increasing when differences in wind energy density at different project sites are corrected for [41].

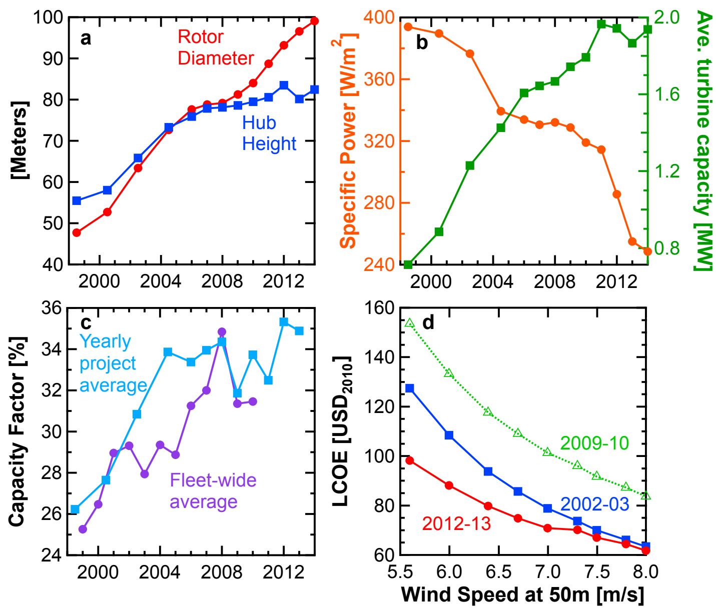

Figure 2.6: Trends in wind turbine parameters in the United States since 1998. a, Average hub height (blue circles) and rotor diameter (red squares) of wind turbines installed in the U.S. in a given year over time [41]. b, Average specific power (left axis, orange circles), measured in watts per square meter of swept rotor area, and average nameplate turbine capacity in MW (right axis, green squares) of wind turbines installed in the U.S. in a given year over time [41]. c, Average capacity factor of wind projects installed in a given year (blue squares)[41] and of the nationwide fleet of wind projects (purple circles)[42] in the U.S. over time. d, Averaged levelized cost of wind energy (LCOE) in the U.S. in USD2010/MWh as a function of wind speed for projects installed in 2002–2003 (blue squares), 2009–2010 (green triangles), and 2012–2013 (red circles) [42].

The most salient features resulting from these trends in turbine properties have been a marked decrease in the LCOE of wind power generated in low-resource sites (Figure 2.6 d), and a corresponding expansion of the geographic extent within which wind generators can be operated economically. In 2002–2003, wind energy produced in a class 2 wind resource area in the U.S. was roughly twice as expensive as wind energy produced in a class 6 resource area. By 2012–2013, that ratio had dropped to a factor of 1.6 [42]. Future increases in hub heights and decreases in specific power are expected to further level the playing field for wind generators in areas with different levels of wind resource, facilitating access to this resource across the nation and the globe [43].

Today, wind energy is cost-competitive, or nearly so, with natural gas- and coal-fired power plants in many regions when competitiveness is measured by the levelized cost of energy (LCOE) (Figure 2.7). Globally-averaged onshore wind electricity costs are estimated to be lower than central estimates for many other energy sources at the global level. Photovoltaics falls within the range of estimated costs for natural gas and coal electricity at the global level but still significantly above central estimates for the costs of these technologies. When a carbon tax of \$100/ton CO_2 (below the current imposed carbon tax in Sweden [44]) is applied, PV is competitive with natural gas or coal fired electricity at the global level. When external costs of air pollution are considered, the competitiveness of PV compared to natural gas or coal fired electricity increases significantly as well (see Section 4.2).

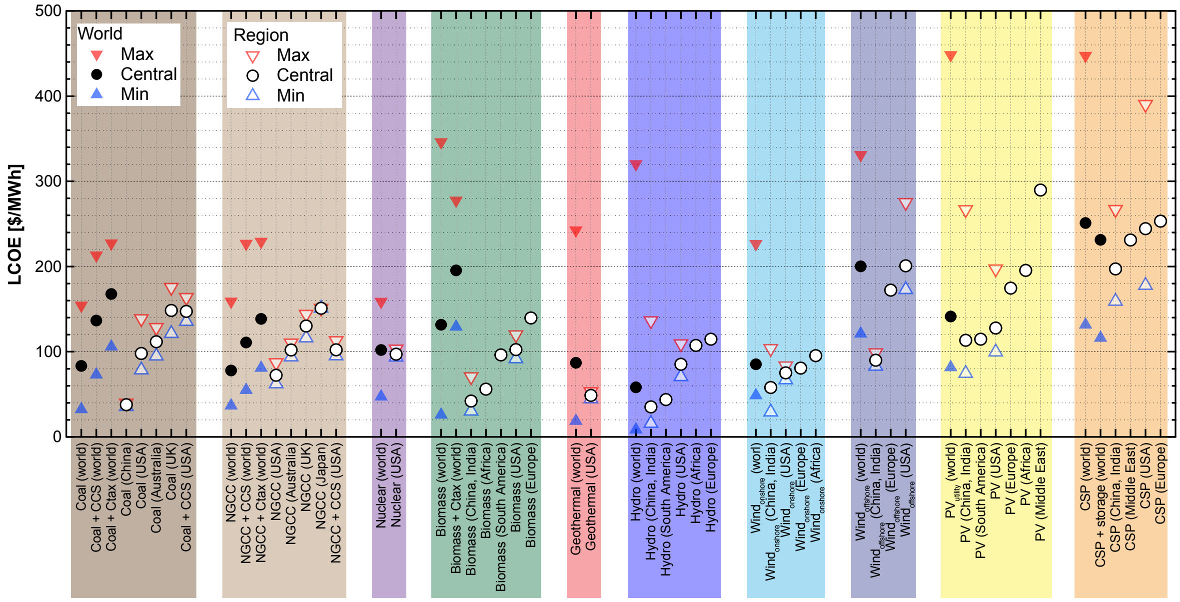

Figure 2.7: Global and regional average levelized cost of electricity (LCOE) in \$/MWh for different generation sources. Black and white symbols represent central values for 2012–2014, red triangles represent maxima, and blue triangles represent minima. Data are average values taken, where available, from IPCC AR5 WGIII, IRENA 2015, EIA 2015, and World Energy Council 2013 [45, 46, 47]. "Ctax" refers to a carbon price of \$100/ton CO_2, and is taken from IPCC AR5 WGIII [45].

2.3 Determinants of technology cost reduction and implications for emissions

It is evident that many technologies improve with time and experience. A striking fact about this improvement is that it is, to a significant extent, predictable. A long-recognized observation known as Wright's Law states that the cost of a technology will fall with its level of deployment according to a 'power-law' formula [48]. In intuitive terms, this observation implies that every 1% increase in the deployment of a technology is associated with a fixed percentage decrease in its cost. The percentage decrease is a number that varies between technologies, for example due to differences in technology design characteristics, and is usually measured from historical data. Technologies that are modular and small-scale are may improve more quickly, though a wide variety of other factors also affect the rate of cost decline [49, 48]. What is important is that the act of deploying the technology itself is what helps bring down costs.

The cost of a technology can decrease for many reasons. One important reason is that producers gain experience ('learning') as they produce the technology. This experience leads to improved designs and production methods that help lower costs. However, experience is not the only important mechanism; costs are clearly driven down for other reasons as well. Scale economies yield cost reductions from increasing the scale of manufacturing, and work independently of accumulated production experience.

Research and development also drive down costs independent of production experience. Technologies can also receive spillover benefits from production techniques first developed in other industries.

Separating the effect of these mechanisms is often very difficult. While the amount of cost reduction can show a remarkable degree of predictability, there are limits to this predictability [50]. In addition to having a strong systematic component to their evolution, technologies also display a significant amount of randomness. Cost reductions are also bounded by 'cost floors' that are determined by the costs of their raw materials inputs and other constraints (see Box 1). Nevertheless, technology evolution can be predicted well enough to forecast future technology costs [50]. In particular, using various formulas, one can forecast how much the cost of a technology will fall with a given level of deployment (see discussion in Section 4.1).

This aspect of technology evolution—systematic improvement with increased deployment—increases the importance of thinking strategically about what technologies to invest in. Investment in a technology is not like investment in a financial asset. While one hopes after investing in an asset that its value will increase, the act of investing itself will not change the value of the asset. In contrast, investing in technologies drives up deployment of the technology, which drives down costs and further increases the deployment potential of the technology. The result is a multiplier effect, where an initial level of deployment opens up new opportunities for deployment.

Another consequence of technology dynamics is that too much diversification across technologies can defray the benefits of the multiplier effect. In financial investing, there is a tradeoff between diversification and concentration. Concentration causes one to focus on assets with the highest expected returns, while diversification spreads out risk. In selecting a portfolio of technologies, the multiplier effect creates an additional force favoring concentration: The more heavily one invests in a technology, the greater the returns [48]. Nonetheless, uncertainties in forecasts still call for some diversification.

In this report we apply these insights from technology evolution research to solar and wind energy technologies. We also use models from this literature to project future technology costs (see Section 4.1).

In the case of low-carbon energy technologies, technology improvement can act as a multiplier of emissions reduction. The magnitude of this effect can be large. The reduction in the costs of photovoltaics between 2000 and 2014, for example, caused the cost of abating carbon through the use of this technology to fall by 85%. The abatement cost here is based on a comparison of coal electricity and photovoltaics installed in the U.S. Further details are given in Section 4.3.

Box 1: Why focus on solar and wind energy?

Solar and wind energy stand out as two of the most promising energy technologies for mitigating climate change, based on their low carbon intensity and cost improvement potential [51]. However, any technology entails social, economic, and environmental impacts [5] that may affect its suitability for large-scale deployment. In this box, we assess solar and wind in terms of their carbon intensity, past cost improvement, and growth and also their future scalability potential, including energy resource size and materials scalability.

Carbon intensity

Like other renewable energy technologies and nuclear electricity, PV and wind electricity have lower carbon intensity than fossil fuel-fired electricity. Fossil fuel-fired electricity is one to two orders of magnitude more carbon intensive than electricity from renewables and nuclear when life cycle emissions are taken into account. Direct emissions, which result from the combustion of fuels, comprise the majority of the life cycle emissions for fossil fuel-fired electricity. For renewable energy technologies, life cycle emissions are dominated by indirect sources. These are emissions that are released during operations upstream and downstream in the supply chain, such as manufacturing, transportation, construction, and decommissioning. As the carbon intensity of the electricity generation mix and transportation decreases, the indirect emissions of renewables have the potential to decrease even further.

Carbon capture and storage (CCS) has often been cited as an attractive technology that can help defer climate change by reducing the carbon intensity of fossil fuels and buy time to develop other options [52, 53, 54]. CCS has the potential to reduce the life cycle greenhouse gas emissions of fossil fuel-fired electricity by 75% on average [55, 56]. However CCS does not bring the carbon intensity of coal- or natural gas-fired electricity down to a level that is comparable to PV, wind or other renewables [56]. There is also uncertainty around issues such as the time that the captured CO_2 would remain trapped in reservoirs [52] and the capacity of the reservoirs [57]. There are also open questions about the feasibility of building and operating CCS at large scales globally since applications have been at demonstration stage [54]. Considering its high carbon intensity as well as the technical and economic uncertainties, we do not focus on CCS in this analysis.

Past cost improvement and growth

PV and wind have experienced sizable growth and cost decline in recent years. Figure 2.5 shows the global cumulative deployment and cost of PV modules and wind electricity. PV module cost has fallen 10% per year over the past 40 years and the cost of wind electricity has decreased by about 5% per year over the past 30 years. The deployment levels for PV and wind have increased by about 29% and 22% per year on average, respectively. These dramatic improvements have been possible due to public policies incentivizing the growth of markets and industry efforts in response to these incentives to improve these technologies and reduce their manufacturing costs. Publicly funded research has also supported the early-stage development of these technologies.

Although other low-carbon energy technologies have also experienced improvements, their costs have not improved as rapidly as those of PV and wind or their capacity growth rates have not been as high. Nuclear and hydroelectricity, for example, have experienced lower rates of cost decline than PV or wind. Hydroelectricity is a mature technology; its cost has decreased only 1-3% with every doubling of cumulative capacity since the 1970s [58]. It already has a significant share ($\sim$ 15%) in the global electricity generation mix; however, environmental and social concerns may constrain its future deployment [59]. Nuclear electricity is the second largest low-carbon energy technology in the global electricity generation mix after hydro ($\sim$ 11%); however, its capital costs have been following an increasing trend [60, 61] and safety risks are causing countries to revise their future plans especially after the Fukushima accident [61].

Geothermal and biomass electricity have not grown as rapidly as PV or wind. Global installations have grown only by 10% per year on average since the 1970s (as opposed to 20-30% per year for wind and PV) [60, 59], although geothermal electricity cost has decreased significantly (5% per year in 1980-2005 [60]). Overall global geothermal electricity capacity is still at a relatively small scale (10 GW as of 2010) and not evenly distributed geographically due to local geothermal resource conditions as well as other technical and economic factors such as availability of water, financing, and infrastructure [59]. The current scale of electricity generation from biomass is larger than geothermal; as it provides about 1% of the world's electricity [59]. However, electricity generation biomass and renewable waste grew much slower than PV and wind, only by 4% per year on average since 1990.

Future cost improvement potential

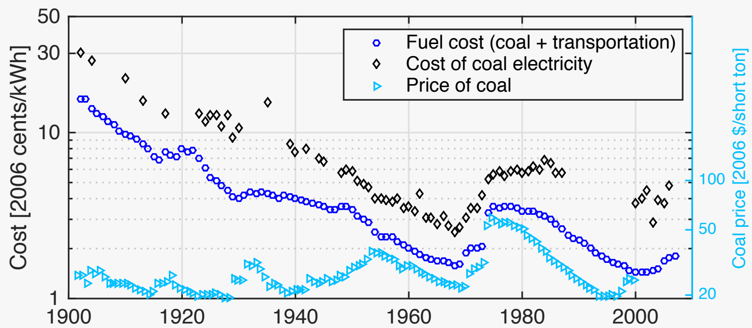

Figure A: Cost of coal electricity, fuel cost component, and price of coal. The total cost of coal fired electricity (black diamonds, with y-axis on the left), the fuel cost = price of coal + price of transporting it to the plant per kWh generated (dark blue dots, with y-axis on the left), and the price of coal at the mine (light blue triangles, with the y-axis on the right). The cost of coal electricity has fluctuated over the past four decades without a clear trend up or down. (Reproduced from McNerney et al. 2011 [62]).

Over time, technologies can hit cost floors that are determined by the costs of input commodities and other limits to cost improvement. In the case of coal-fired electricity in the U.S., for example, ever since improvements to the fleet average thermal efficiency stopped around 1960, the fuel cost component of coal electricity has fluctuated around a constant value, without a clear upward or downward trend (Figure A). The fuel cost in this case would impose a cost floor on future cost decreases of coal-fired electricity, even if the improvement in thermal efficiency were to reach 100%. Because of the large contribution of commodity costs to the total cost of coal- and natural gas- fired electricity, these can be considered commodity-like technologies [62]. This behavior is similar to the behavior of long-term prices of other commodities including agricultural products and raw materials such as metals (Figure B-panel a).

All technologies will eventually be bounded by the costs of input commodities, and will eventually enter a commodity-like regime. However, before reaching this point, technology costs have been shown to evolve following a trend in time or with accumulated experience [50]. Figure B-panel b shows that not only energy technologies but also many other technologies follow regular trends as opposed to the commodities. In addition to their exceptional record of past cost improvements, PV and wind have the potential for further improvements since they are not yet close to their cost floors, unlike coal and natural gas electricity.

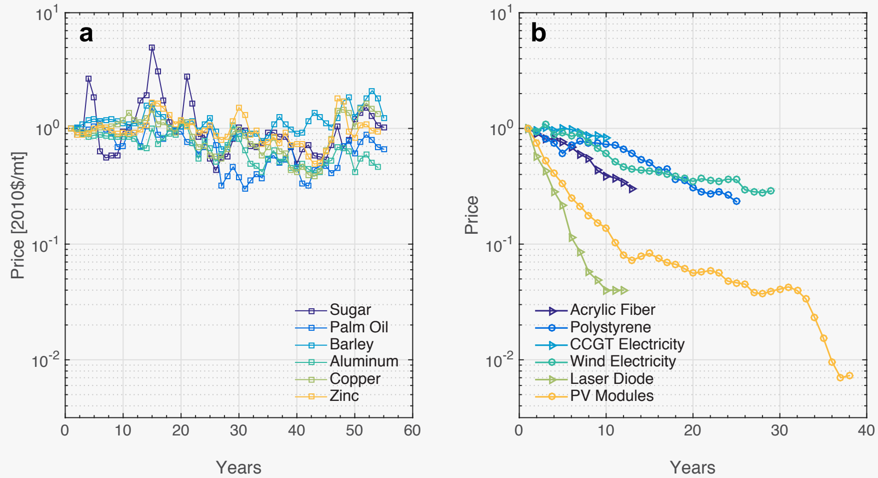

Figure B: a, Normalized price of selected commodities between 1960 and 2014. Commodity prices fluctuate around a more or less stable mean value over time. Metal price data has been obtained from U.S. Geological Survey Historical Data [63]. Other commodity prices have been obtained from World Bank [64]. b, Normalized price of selected technologies over time. All data have been obtained from the PCDB database [60]. (Prices have been normalized, where the first year's price is equal to 1. Years on the x-axis show $t - t_0$,where t is the actual year (e.g. 2007) corresponding to each price data point, and t_0 is the starting year of the price data.)

Future scalability potential

The scalability of a technology can be defined as its ability to grow in size without exceeding certain thresholds. In the case of energy technologies, the size of the energy resource and materials availability are important determinants of whether an energy technology can be scaled up to provide a significant share of global electricity generation.

a. **Energy resource size**

Resource availability is expected to support further expansion of solar and wind energy. Solar has by far the largest resource size among renewable energy sources. The estimated size of the solar energy resource ranges between 1,000 and 100,000 EJ/year[a] [56], sufficient to satisfy all of the global electricity need (approximately 90 EJ/yr today [65] and 100 EJ/yr in 2030 [66]). Wind and other renewable sources could also supply a significant portion if not all of global electricity demand individually, based on a range of resource size estimates. The estimated sizes of each of geothermal, wind, hydro, ocean, and biomass energy range between 10 and 1,000 EJ/year [56]. As technology advances, the technical potential of renewable energy sources is expected to increase even more. Another important factor to consider is the geographical distribution of energy resources, since the distribution will determine where each technology has a higher deployment potential. Solar and wind energy resources vary across the world (see the Appendix for resource maps), but all countries have significant expansion potential for solar and wind energy conversion relative to current levels of deployment, even those that are more limited in their solar and wind resource [56]. The projections of possible renewables growth under INDC commitments (Section 3) fall well within assessments of solar and wind resource availability in these locations [67, 68]. If considering other renewable resources, the expansion potential is even greater. In fact, in all regions of the world, the combined size of renewable energy sources has been estimated to be sufficient to supply the yearly electricity demand [56]. Managing the integration of intermittent renewables at large scale can pose several challenges that are discussed further in Section 4.3 and Box 2.

b. **Materials scalability**

Materials availability is an important determinant of scalability. Low-carbon energy technologies will need to meet their materials requirements in order to contribute a larger share of global electricity and achieve significant emissions reductions. Several studies have shown that PV, wind and other sources of low-carbon electricity generation can be more materials-intensive than fossil fuel-fired electricity [69, 70]. However material requirements do not pose a scalability constraint on large-scale deployment for most of the PV and wind technologies.

Wind turbines are constructed from various metals and other material commodities such as fiberglass. Figure C-panel a compares the current global annual production of the wind turbine materials to the quantity of materials that would be required between now and 2030 to deploy enough wind capacity to supply 5%, 8.9%, 50% and 100% of global electricity generation in 2030, where 8.9% is the fraction of electricity generated by wind in 2030 based on INDCs (Section 3). Figure C-panel a shows that the material requirements exceed current annual production only for fiberglass. For other materials, the current annual production could support the projected wind deployment levels based on INDCs (8.9% of the electricity in 2030) or even higher deployment. Currently wind turbines represent a small portion of the total demand for each commodity. As the wind turbine industry demands more of these materials, the suppliers are likely to respond and increase availability because these materials are abundant and produced as primary products, and have established supply chains serving a variety of end-uses [70, 68]. In addition, rare earth materials availability does not appear to be a limitation to the growth of wind energy because of a sufficient supply of these materials and the fact that only a small fraction of wind turbines utilizes them [71, 72].

Like wind turbines, PV systems depend on materials for energy conversion as well as for other functions. Figure C-panel b and Figure C-panel c compare the current global annual production of the PV materials to the quantity of materials that would be required between now and 2030 to deploy enough PV capacity to supply 1%, 3.8%, 50% and 100% of global electricity generation in 2030, where 3.8% is the fraction of electricity generated by PV in 2030 based on INDCs (Section 3). PV technologies require commodity materials for functions such as encapsulation, environmental protection and support, including base metals such as aluminum and copper and other commodities such as flat glass, plastic, concrete, and steel. Figure C-panel b indicates that there is not a materials constraint for PV from the BOS materials perspective, except for flat glass for high levels of PV adoption. Overall, the projected PV deployment levels based on INDCs (3.8% of global electricity generation in 2030) and even higher deployment can be supported by the current annual production levels. As in the case of wind, these materials are abundant and can likely respond to rising demand.

For some PV technologies, however, active cell materials might encounter availability constraints (Figure C-panel c) [73, 74, 75]. The current commercial thin-film PV technologies (CdTe and CIGS) require rare materials such as tellurium and indium. Unlike commodities, these materials are produced in small quantities (on the order of hundred metric tons a year) as byproducts of more abundant materials. To support higher levels of thin-film PV deployment, the production of these rare materials would require growth rates that have not been observed in the history of any metal [75] and it is not clear whether the supply of byproducts can respond easily to increases in demand. On the other hand, crystalline silicon (c-Si) PV, which has about 90% market share globally, is unlikely to run into materials constraints since silicon is abundant. Substituting a more abundant material for the silver electrodes will be important for c-Si PV to reach its full growth potential [75].

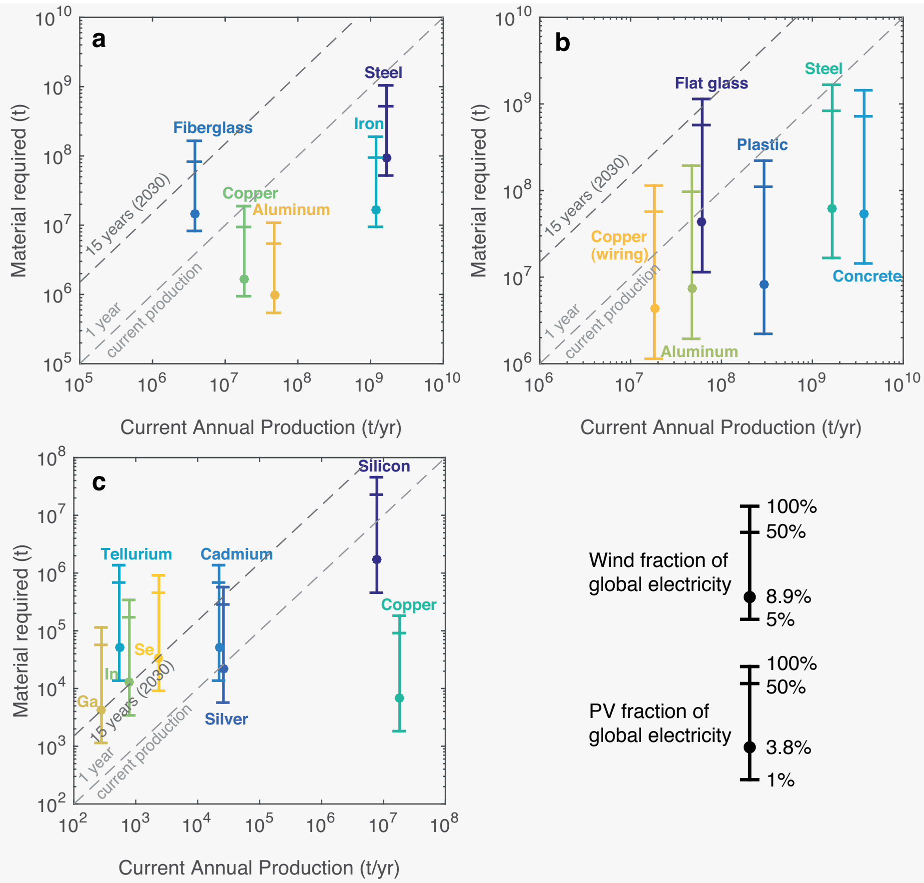

Figure C: Wind (a) and PV BOS (b) and PV cell (c) material requirements versus current global annual production of each material. Material requirements are the quantities that would be required between now and 2030 to deploy enough capacity to supply 5% {1%}, 8.9% {3.8%}, 50% and 100% of global electricity by wind {PV}. The 8.9% and 3.8% cases are the values we estimate for 2030 based on INDCs (Section 3). The wind and PV capacities in 2030 are estimated by assuming 5% {1%}, 8.9% {3.8%}, 50% and 100% of the 30,000 TWh global electricity generation [66] is provided with 30% {15%} capacity factor for wind {PV}. For panel a, material intensities are average values for current turbines: 90 t/MW for steel, 14 t/MW for fiberglass, 17 t/MW for iron, 1.7 t/MW for copper and 1 t/MW for aluminum [40]. For panel b, material intensities for PV BOS are current average values: 50 t/MW for flat glass, 9.7 t/MW for plastic, 63 t/MW for concrete, 73 t/MW for steel, 8.5 t/MW for aluminum, and 5 t/MW for copper [68]. For panel c, material intensities are current average values without taking material losses into account: 2000 t/GW for silicon and 25 t/GW for silver [68], 60 t/GW for cadmium, 60 t/GW for tellurium, 8 t/GW copper, 15 t/GW indium, 5 t/GW gallium, and 40 t/GW for selenium [75].

[a] The range in the estimates is due to various assumptions about land availability, economic constraints, and technical constraints such as capacity factors and energy conversion efficiencies across different studies.

3. Commitments under countries' climate pledges (INDCs)

Countries' GHG emissions reductions pledges in advance of COP21 have been assessed largely in the context of limiting the global mean surface temperature increase [76]. Also important are their potential implications for expanding low-carbon energy, considering that technology innovation resulting from expanding clean energy markets can reduce the costs of cutting emissions. Here we focus on the possible growth in solar (PV) and wind installations under countries' voluntary pledges.

Collectively, current GHG emissions reduction pledges offer an opportunity for substantial clean energy expansion. If the top emitters (China, U.S., EU-28, India, Japan) achieve significant shares of proposed emissions cuts by decarbonizing their electricity sectors, with sizable contributions from the expansion of solar (PV) and wind capacities, global cumulative 2030 solar (PV) capacity could reach 4.9 times current capacity, and wind capacity could reach 2.7 times current capacity. Projections are inherently uncertain, particularly for developing countries where reliable data sources are more scarce. However, estimates of future market sizes can serve as benchmarks for the order of magnitude of wind and PV market growth under current GHG mitigation targets, and the resulting implications for the potential cost competitiveness of these electricity sources.

3.1 Emissions reduction targets: Theory and practice of INDCs

The core idea behind the Lima Call for Climate Action in 2014 was to expand the scope of global climate governance, as well as to increase its transparency. To achieve this, the Lima call invited countries to submit written statements of intended climate policies for the post-Kyoto period (their INDCs) by March 2015 [77]. The goal was to collect information on intended but not binding emissions reduction goals to allow quantitative assessments of expected GHG emissions cuts over time.

To date 131 of 193 UN member countries have submitted their pledges to the United Nations Framework for Climate Change, covering roughly 90% of global GHG emissions in 2010 [78]. Among them are the biggest current emitters: China, the U.S., the European Union, India, Russia, Japan, and Korea. However, several developing countries and Gulf states have not put forward any pledges, including Iran, Pakistan, Yemen, Malaysia and Venezuela (see Figure 3.1), while others have presented their targets as contingent on international financing support.

INDC pledges show considerable structural variability. Countries have formulated INDCs as percentage reduction targets relative to historical emissions levels or future business-as-usual levels

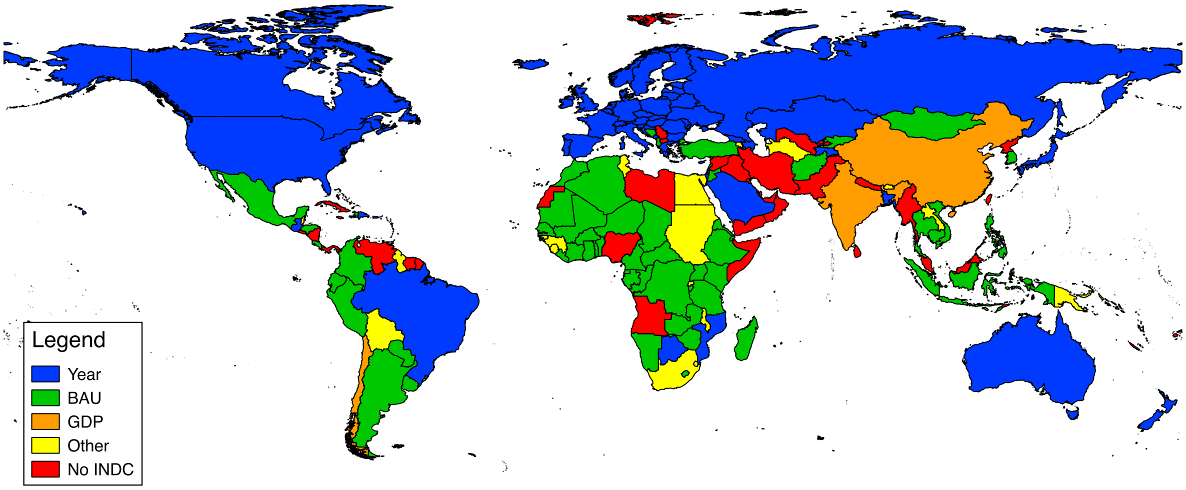

Figure 3.1: Countries that submitted INDCs prior to November 10, 2015, color-coded by structure of their INDC. The majority of countries has defined GHG mitigation targets relative to future BAU emissions levels (green, BAU). The second largest group of countries has set targets relative to historical emissions levels (blue, Year) and relative to historical carbon intensities of economic activity (orange, GDP).

and as targets to reduce the carbon intensity of economic activity. These approaches have different implications for the range of possible 2030 emissions levels, making comparisons of intended efforts more complex. Both China and India, currently the largest and fourth largest GHG emitter, respectively, target reductions of the CO_2 and GHG intensity of their GDPs relative to that of 2005. Depending on realized economic growth trajectories, actual 2030 economy-wide GHG emissions vary by as much as 2,400 Mt CO_2-equivalents (in the case of India), which is on the order of the county's entire GHG emissions in 2010. Similar conclusions hold for countries that announced GHG mitigation targets as percentage cuts relative to BAU emissions in 2030 (see Figure 3.1)—with intended BAU levels largely unspecified, GHG emissions pathways are uncertain. Pledges may be based on national energy policy frameworks with more specific language on sectoral GHG mitigation targets and their timelines, but are often not stated explicitly in INDCs.

Despite the uncertainties in future GHG emissions pathways, however, even moderate emissions reductions pledges provide opportunities for substantial expansions of low-carbon electricity generating capacity. To assess current pledges through the lens of low-carbon energy development opportunities in the post-Paris period, we analyze expected changes in the electricity generation capacities of major economies under their submitted INDCs through the year 2030. The analysis is based on the assumption that mitigation strategies are applied to all economic sectors to achieve economy-wide GHG mitigation targets, even if INDCs specify no concrete targets for the electricity sector.

3.2 INDC-based capacity expansions: Model

Estimates for clean energy expansions under different INDCs are based on a combination of electricity and energy technology demand forecasts (see Figure 3.2 below). The relationship between electricity demand growth and economic growth is assumed to vary over time, reflecting different country-specific stages of economic development and electricity intensity thereof.

For the 'no-policy' case, GHG emissions are estimated based on a forecast of generation shares in

2030, assuming no policy in support of renewable energy sources is in place, and that present market shares equal future market shares. The target GHG budget is derived from economy-wide 'allowed' CO_2 or GHG emissions estimated based on the INDC (where central estimates are based on mid-range percentage reductions), using an estimated 2030 share of electricity emissions in total emissions. This share is based on reported present-day shares and expected decarbonization rates of different economic sectors over time [19]. The difference between expected and intended power sector emissions in 2030 defines the emissions to be reduced through increased generation from non-fossil power sources. The high- to low-carbon shift is then attributed to different generator types based on the median of a range of 2030 scenarios, including data from IEA, BNEF and EIA, and taking into account existing national policy targets for the expansion of individual sources.

As indicated in the country-specific assessments below, results are sensitive to assumptions about electricity and economic growth, changes in capacity factors of different generators over time, decarbonization rates of different economic sectors, as well as emissions factors of different electricity sources. The impact of changing input parameters on results is demonstrated in more detail in the Appendix.

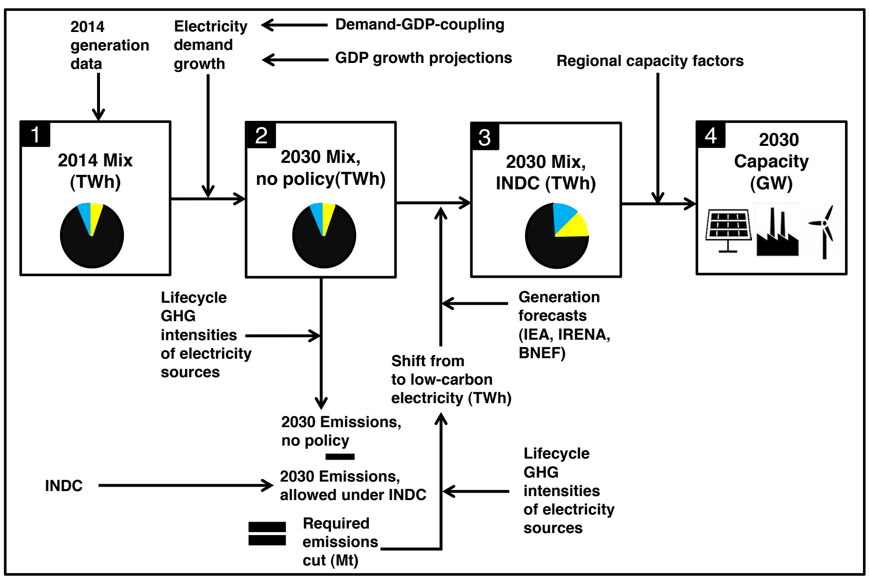

Figure 3.2: Modeling expected installed solar PV and wind generation capacity for different components of a country's Intended Nationally Determined Contribution.

3.3 INDC commitments: Challenges and opportunities in major world economies

Overall, INDC-based clean energy capacity expansions could increase the share of solar PV and wind in the capacity mix of current top GHG-emitting economies from 13% today to an estimated 33% in 2030 (including China, U.S., EU, India and Japan), corresponding to a 17% energy share of wind and solar PV generation cumulatively in 2030. Globally, we estimate that solar PV could contribute 3.8% of the global electricity mix in 2030, and wind power could provide 8.9%, based on IEA's estimated electricity demand in 2030 [66], if a 4.9 and 2.7-fold expansion of solar PV and wind capacity is realized by 2030 (see Figure 3.3). While achieving these shares requires aggressive expansion of clean energy, particularly in developing nations, the scale of INDC-based projections is similar to other scenarios reflecting renewable energy targets in response to ambitious climate policies. The International Energy Agency for instance projects a 29% share of wind and solar PV capacity in total capacity for the same group of top emitters, based on a scenario with accelerated climate ambition and renewables deployment [19].

Among the largest economies analyzed in this report, China plays a key role in both global clean energy expansion and in global emissions growth. As shown in the top left panel of Figure 3.4, China alone could contribute 32% of expected cumulative solar and wind power capacity additions between 2014 and 2030. This could happen if, for example, China were to achieve a 60–65% reduction in CO_2 intensity of its GDP by through aggressive solar PV and wind capacity expansion—roughly quadrupling the cumulative wind and solar PV capacity between 2014 and 2030—in addition to moderate nuclear and hydro capacity expansions, corresponding to a factor 1.5 increase of nuclear and hydro capacity cumulatively between 2014 and 2030. At the same time, China emitted roughly one third of global GHG emissions in 2013, and is expected to increase its GHG emissions by roughly one third by 2030 under its INDC.

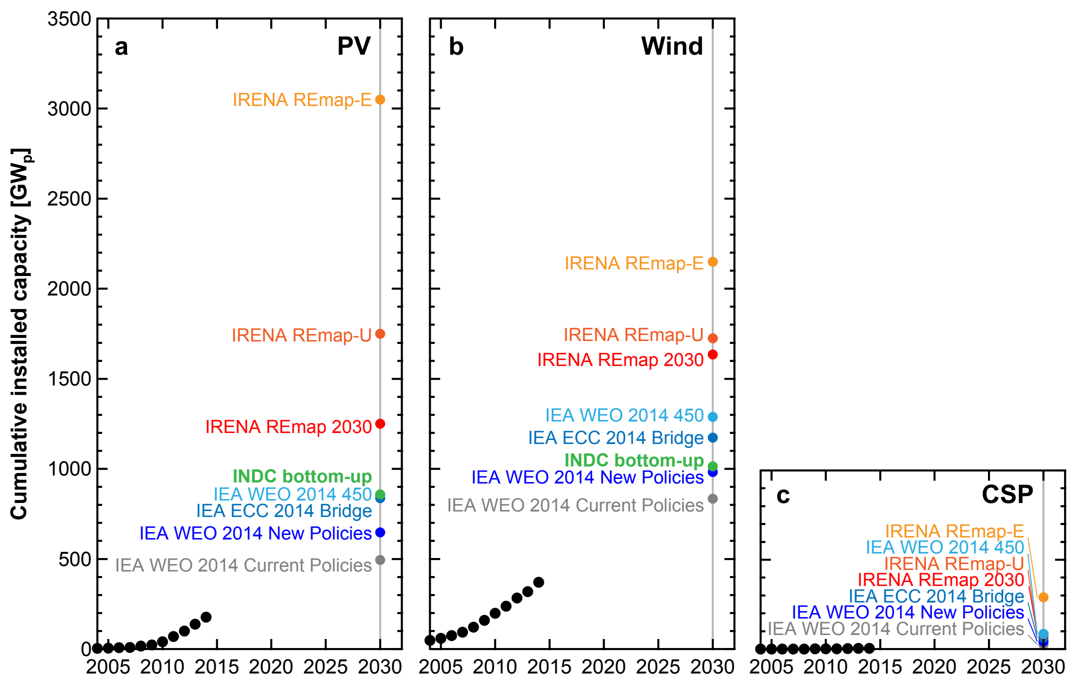

Figure 3.3: Scenarios for solar and wind capacity expansion. Black circles represent actual cumulative installed capacity of PV (a), wind (b), and concentrated solar thermal power (CSP) (c). Colored circles represent installed capacity in 2030 according to different projections and scenarios from IEA, IRENA, and this work.

The European Union put forth the most ambitious emissions mitigation target when compared against a 1990 baseline. The corresponding 11% share of global wind and solar PV capacity additions between 2014 and 2030 is comparatively smaller, however. Apart from largely flat expected electricity demand in the 2014–2030 period, this also reflects individual EU countries' early investments in solar PV, wind and hydropower, resulting in a larger share of non-fossil sources in present-day cumulative generation capacity (more than half of 2014's capacity, compared to slightly over one third in the U.S.

for instance) and corresponding to smaller energy infrastructure transformations required to achieve power sector GHG mitigation targets.

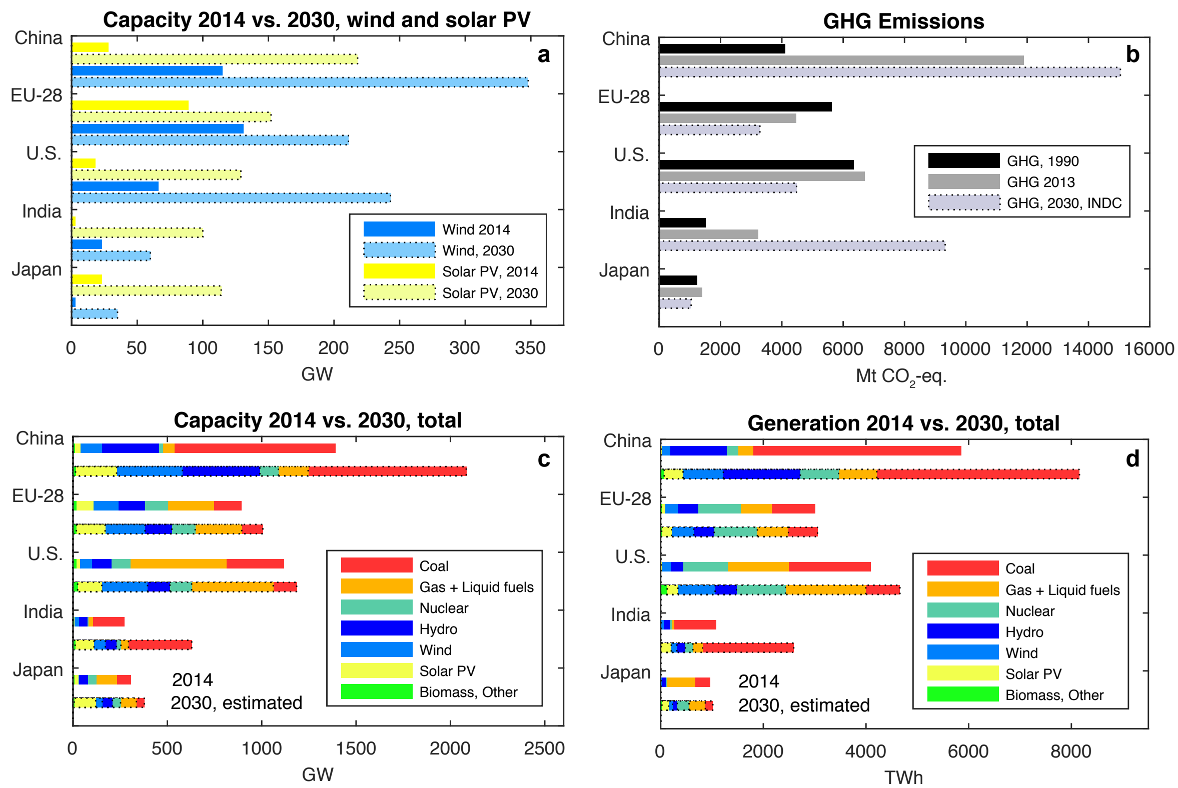

Figure 3.4: Solar PV and wind generation capacity for INDC-based high renewables scenario (a); emissions reduction pledges and expected economy-wide emissions levels if INDCs are realized (b) (India's emissions could be 10-35% lower if its low-carbon power capacity target shown in (a) is reached); Shares of different electricity sources in terms of installed power capacity in 2014 and 2030 (c); Contributions of different generation types to cumulative electricity generation in 2014 and 2030 (d).

China, on the other, hand is projected to lead in terms of cumulative power generation from renewable energy sources. In 2030, if the renewables expansion scenario studied here is realized, China would supply roughly one third of its electricity demand from renewable sources (14% from wind and solar PV), only slightly below the EU's estimated 35% renewables share in 2030 (20% from solar PV and wind generation).

3.4 INDC commitments: Country-by-country assessment

China

China's ongoing transition from a manufacturing-oriented to a more diversified, service-oriented economy introduces uncertainties to projections of economic growth and electricity demand in the near and long term. Current estimates for GDP growth in the 2020 to 2030 period range between 3 and 5% per year [79, 80], and the impact of these projections on future emissions pathways is reinforced by China's choice of setting an intensity target for CO_2 emissions mitigation: a 60–65% reduction of GDP CO_2 intensity from 2005 levels by 2030 [81].

While different economic growth trajectories have strong implications for the upper and lower bound of China's estimated CO_2 emissions in 2030, expected low-carbon generation capacity additions are relatively constrained to a 200–235 GW range for solar PV capacity by 2030 and to a 325–370 GW range for wind by the year 2030 (assuming a mid-range reduction of carbon intensity, i.e. 62.5% from 2005 levels). This is because a CO_2-intensity target leads to a power sector emissions budget that scales with GDP, allowing more CO_2 emissions for higher growth rates.

Achieving the estimated capacities by 2030 will require ambitious wind and solar PV deployment, but in the context of China's national energy policy it should be noted that implied growth rates (CAGR) between 2014 and 2030 are below those corresponding to the country's short-term wind and solar PV deployment targets. Meeting the stated goals of 200 GW wind capacity and 100 GW solar PV capacity by 2020 would correspond to annual capacity growth rates of roughly 10 and 24% for wind and solar PV over the next 5 years, as compared to a roughly 7 and 14% growth until 2030 to reach INDC-based wind and solar PV capacities by 2030.

Overall, however, estimated capacity additions are highly sensitive to assumptions about the shares of different economic sectors in cumulative CO_2 emissions in 2030. Estimated 2030 solar PV and wind capacities vary as much as 30% from the central estimate for a 5% change of the electricity's percentage contribution to overall GHG emissions. Similarly important is the emissions factor of coal-fired power plants in 2030, where a 10% increase or decrease of per-kWh emissions leads to a roughly 20% deviation of cumulative estimated solar PV and wind capacity expansions from the central estimate presented in Figure 3.4. These results highlight the importance of improving data availability on emissions factors and sectoral energy use to inform the debate on detailed plans for climate policy implementation. This is especially important in light of recent, albeit preliminary, reports on possible underreporting of China's coal consumption in the past [82] as well as overestimations of emissions from coal use in the 2000–2012 period [83].

India

India targets a 33–35% reduction of the GHG intensity of its GDP from 2005 levels by the year 2030 [84]. The country's INDC also defines a goal for the power sector, which is to increase the share of installed non-fossil capacity to 40% by 2030 from currently 30%. In addition to this fractional target, India aims to install 100 GW of solar PV and 60 GW of wind capacity by 2022. These power sector-specific targets and the economy-wide target do not reflect the same pace of GHG emissions mitigation. A 34% GHG intensity reduction by 2030 would not, for a range of assumptions on the share of power sector emissions of total emissions, require substantial shifts from fossil to non-fossil electricity generation. This is because the power sector GHG target would be roughly 5–40% larger than the GHG emissions associated with India's 2030 Business as Usual power generation mix in 2030. In this scenario, the share of different generation sources in cumulative generation is held constant between 2014 and 2030, corresponding to a 'no policy', coal-heavy development of India's power sector.

Meeting the 40% low-carbon generation capacity target, however, would substantially alter India's electricity infrastructure. For a range of assumptions regarding the share of 2030 power sector GHG emissions in economy-wide emissions, a 40% non-fossil capacity target would correspond to a 40–60% reduction of GDP intensity between 2005 and 2030, as opposed to the INDC-based target of a 33–35% GHG-intensity cut.

In a scenario where India's solar (PV) and wind installation targets are realized, reaching the targeted 40% capacity share by 2030, India would expand renewables generation capacity by a factor 3 between 2014 and 2030. The central estimates of 100 GW solar PV capacity and 60 GW wind capacity by 2030 are roughly 30 times and 3 times India's current solar and wind installed capacity, respectively. Both capacity targets, but particularly the solar PV target, have been critically discussed in the context of potential financing barriers to large scale deployment [85], in addition to grid integration challenges [86]. Thus, central capacity and generation estimates for India in 2030 are based on achieved but delayed expansions of solar PV and wind to target levels, reaching 100 GW of solar PV and 60 GW of wind by 2030 instead of 2022.

Potential financing barriers, as well as the implications of sectoral and economy-wide targets mentioned earlier, are important to consider in the context of COP21 negotiations: India has presented the 40% non-fossil capacity target as contingent upon international financial support. Thus, an ambitious, financially cooperative Paris agreement may yield substantial build-outs by 2030, while the (non-conditional) GHG intensity target leads to capacities equivalent to a no-policy, coal-heavy scenario.

U.S.

In March 2015, the U.S. was among the earliest parties to submit an INDC, targeting an economy-wide GHG reduction of 26–28% below 2005 levels by the year 2025 [87]. This target is less ambitious than the U.S. short-term target outlined prior to the United Nations Climate Change Conference in Copenhagen in 2009 (a 30% cut from 2005 levels by 2025), but essentially reinforces intended long-term GHG emissions pathways: The intended 14–17% reduction below 1990 GHG emissions corresponds to a linear interpolation between the U.S. Copenhagen pledge for 2020 (17% GHG cut below 2005 levels by 2020) and the country's long-term national goal, targeting an 83% cut below 2005 levels by 2050.

Importantly, however, two targets relevant to clean energy expansion prospects were not announced until after the INDC submission. This includes the Environmental Protection Agency's final Clean Power Plan rule, as well as the U.S.-Brazil joint statement on climate change, which targets a 20% share of electricity generation from non-hydro renewables in both countries by the year 2030. There are important differences between these targets: A 20% share is almost twice as much as projected in both EPA's main Clean Power Plan scenarios, assuming rate-based or mass-based compliance [88]. Thus, prospects for wind and solar PV capacity expansions depend on how—and given remaining legal challenges, if—the Clean Power Plan (CPP) is implemented by individual states.

In its final version, the CPP targets a 32% reduction of power sector CO_2 emissions from 2005 levels by 2030. While the plan specifies state-specific CO_2 emissions rates (in lbs CO_2/kWh) to be achieved across regional power plant fleets by 2030, states can choose individual combinations of various decarbonization strategies, including coal-to-gas switching, supply- and demand-side energy efficiency and increased substitution of renewables and nuclear for CO_2-intensive electricity sources. Realizations of the same CO_2 mitigation target by 2030 can, depending on assumed electricity demand growth, have different implications for wind and solar PV capacity expansions by 2030: The EPA's main compliance scenario assumes supply and demand-side energy efficiency improvements, leading to flat electricity demand between 2014 and 2030 and a projected non-hydro renewables capacity of 171-174 GW cumulatively in 2030 (roughly 32 GW of PV and 117 GW of wind capacity, in a scenario where present shares of non-hydro sources are kept constant) [88]. In a scenario with slightly elevated electricity demand growth through 2030, in line with IEA's estimates for 2030 U.S. electricity demand, we estimate that meeting a 20% share of non-hydro renewables with PV and wind exclusively would lead to installed solar PV and wind capacities by 2030 in the range of 95 to 160 GW (129 GW central estimates) and 210 to 270 GW (242 GW central estimate), respectively, for a range of electricity demand levels in 2030. These numbers are based on extrapolating the economy-wide target for 2025 to the year 2030, resulting in a 39% economy-wide GHG reduction goal. Results are therefore sensitive to assumptions regarding the contributions of different sectors to achieving the economy-wide GHG mitigation target, as well as to emissions factors of coal-fired power generation electricity sources; however, estimated solar PV and wind capacities are on the order of 110 GW for solar PV and 230 GW for wind in 2030 for lower bound coal emissions factors under the INDC-based economy-wide GHG target. [1]

EU-28

Among the top ten emitters globally, the European Union has put forward the most aggressive GHG mitigation target with respect to 1990 emissions—a 40% reduction by the year 2030 is more than twice as high a percentage compared to the intended U.S. reduction from 1990 GHG emissions [93]. It should be noted however that EU-28 GHG emissions have already been exhibiting a downwards trend since 2004 [94]. The additional, INDC-specific effort can be quantified as increasing the rate of GHG mitigation from 1.7% per year in the 2004-2012 period to 1.8% per year in the 2012-2030 period.

The E.U.'s INDC specifies no specific targets for sectoral GHG mitigation or renewables capacity. It is expected however that domestic climate and energy policy will be guided by the 2030 framework for climate and energy that, in addition to the 40% GHG mitigation target, aims at a 27% share of renewable energy consumption and at least 27% energy savings compared with the business-as-usual scenario.

We estimate that applying the economy-wide GHG mitigation target for 2030 to the electricity sector may involve higher generation shares of renewable energy than targeted in the 2030 framework, depending on assumptions regarding electricity demand and energy efficiency improvements. Depending on the realized economic growth trajectory, installed solar PV and wind capacities may reach 130–170 GW and 180–230 GW under the INDC, corresponding to a 33–37% share of total capacity, and a 19–22% share of wind and solar PV generation in total electricity generation in 2030. Renewables (including wind, solar PV, biomass and geothermal energy) in this scenario would cumulatively provide a 32 to 35% share of total electricity generation. Results are similarly sensitive to coal emissions factors, where estimated capacity expansions vary by roughly 10% for a 10% variation of emissions factors.

Japan

While a leading nation in solar PV development in the 1990s and 2000s, Japan's GHG mitigation policies are expected to face new challenges following the 2011 Fukushima nuclear disaster [95, 96]. Instead of a 25% cut below 1990 GHG emissions by 2025 originally targeted in Japan's Copenhagen pledge, the country's submitted INDC aims at a 26% GHG reduction from 2013 levels (which corresponds to an 18% reduction below 1990 GHG emissions), largely due to a downwards revision in intended nuclear generation by 2030.

And while even the revised target has the potential to support substantial clean energy expansion, solar PV and wind capacity additions will depend on the role of nuclear power and natural gas-fired generation in Japan's electricity mix. If the government's plan to increase the share of nuclear generation

[1] Overall, the Clean Power Plan represents a critical building block of the overall U.S. strategy to meet the INDC-based GHG mitigation target. However, additional mitigation efforts may be required to align sectoral CO_2 and economy-wide GHG mitigation pathways, depending on realized decarbonization rates in different economic sectors, as well as on emissions pathways of other GHGs apart from CO_2. Methane emissions along the natural gas supply chain [89], for instance, introduce uncertainties as to whether the electricity sector's contribution to economy-wide GHG mitigation can be reliably achieved on the basis of current methane mitigation policies [90]. More ambitious mitigation efforts may be required given that substantial power sector natural gas consumption is projected by EPA for the 2015–2030 period [88], and building on recent findings that measurement-based emissions estimates tend to exceed emissions factors assumed in current emissions inventories [91, 92].

to 22% by 2030 is realized (as stated in the INDC and consistent with the country's Basic Energy Plan), Japan's solar PV and wind capacity in 2030 in a high-renewables scenario is estimated to increase to 65–120 GW and 28–45 GW (114 and 35 GW central estimates) in order to meet the economy-wide GHG mitigation target, for a range of possible electricity demand levels, emissions factors and power sector decarbonization rates. In contrast to the government's INDC scenario, this is assuming a significant shift away from coal and natural gas, doubling the share of wind and solar PV generation as compared to the government scenario. Meeting only half of the government's nuclear generation target on the other hand would require substantial expansions of natural gas fired generation capacity—as most large-scale hydropower sites have been developed [97]—or large-scale energy storage investments to manage wind and solar PV penetration levels beyond 30–40% of installed capacity.

Other countries

Among the largest developing economies, the countries with no or relatively low expected INDC-based wind/solar PV growth include Russia, Indonesia and Mexico. For Russia, the majority of the intended GHG cut (25–30% below 1990 levels by 2030) is expected to be covered by land use changes and forestry. Even if the 25–30% cut were to be achieved without accounting for forestry GHG emissions sinks, projected power sector GHG emissions in 2030 would be below the GHG cap and thus would not require notable shifts to low carbon generation.

In the case of Brazil, prospects for solar (PV) and wind power expansion hinge on the realization of its target to reach a 23% share of non-hydro renewables in the electricity mix by 2030. Given the already low GHG emissions intensity of power supply (due to a 75% share of renewables in generation today), the BAU electricity mix projection corresponds to masses of estimated 2030 power sector GHG emissions below the power sector GHG emissions budget derived from the economy-wide GHG target.

Indonesia's target to reduce GHG emissions 29% below BAU GHG emissions in 2030 leads to a similar result. The INDC-based power sector budget exceeds estimates of 2030 power sector GHG emissions in a no-policy scenario (where the carbon intensity of the generation mix is held constant). This means that no additional shifts from high- to low-carbon generation would be necessary, while allowing large scale expansions of coal generation capacity under Indonesia's pledge. However, the country targets a 23% share of renewable energy in total energy consumption by 2025 [98], which is positioned in the INDC as a key component of Indonesia's decarbonization efforts. And while a 23% target has been termed overambitious in a 10-year time frame [98], given the country's nascent solar (PV) and wind market scale of 15 MW and 1 MW, respectively, any progress made can be a building block for more substantial expansions in the post-2020 and -2030 period. By that time, countries with large expected future energy demand growth like Indonesia may benefit from further cost reductions due to solar (PV) and wind market expansions globally.

4. Projected cost reduction under INDCs

Our primary tool for projecting the future cost dynamics of photovoltaics and wind power is Wright's Law. We first describe the fundamentals of Wright's Law, including its range of applicability and limitations. We then apply this analysis to the capacity cost of PV modules and inverters and to the wind levelized cost of energy (LCOE). For PV balance of system (BOS) costs, where location-specific factors make a global analysis inappropriate, we describe different scenarios for future cost evolution based on expert projections from the literature [99]. We then convert PV system prices to LCOE, discuss the sensitivity of our results to various assumptions, and compare our LCOE projections for PV and wind to the current LCOE of fossil generation sources.

4.1 Forecasting technological progress

Equations, Theory, and History

Performance curves are empirical relationships between a technology's performance and prevalence [49, 50]. The most well-known example of a performance curve is the experience curve, which relates the cost of a technology (a measure of performance) to its cumulative production (a measure of prevalence). This relationship is the basis for the most widely used approach to forecasting technology costs, and the approach with the best empirical support [50].

The experience curves of many, though by no means all, technologies have been observed to approximately follow a power-law functional form [100, 101, 102]. When they do, they are said to obey Wright's Law [48, 103]. According to Wright's Law, costs (c) decrease according to the cumulative production of the technology (y) raised to a power (b):

$$c(y) \sim y^{-b}.$$

Various theories have been proposed for Wright's Law. The apparent connection between cost and cumulative production has led to the following interpretation: Cumulative production serves as a proxy for the amount of experience (hence the name) that a firm or industry has gained with producing the technology. As experience is acquired, changes are made to the design of the technology or to its production process, resulting in cost reductions. As we discuss further below, it is not necessary to adopt this interpretation to make use of the Wright's Law model. One can use this model as a forecasting tool, without assuming that experience or learning is the driving force behind observed cost reductions.

Wright's Law is not the only model for technology cost evolution. Another example is a generalized version of Moore's Law [104] applied to the costs of technologies. Moore's Law is distinguished from Wright's in that it uses time as the predictive factor. In this model, the cost of a technology (c) decreases exponentially over time (t) at some rate (a):

$$c(t) \sim e^{-at}.$$

Technologies can at times appear to follow more than one of these models simultaneously. For example, a technology can appear to obey both Wright's Law and the generalized Moore's Law when the technology's production rate is growing exponentially. Although the predictive performance of both models can be similar, they are not exactly the same. Models show measurable differences in how well they predict the future costs of technologies, as has been shown through hindcasting on historical technology cost data [50]. Generally speaking, the most accurate model is also the one that is the most widely used: Wright's Law. For this reason we base our forecasts of solar and wind energy technologies on this model.

Even though a technology's cost may trend in a way that follows Wright's Law, there is still a significant degree of randomness in the evolution of technology costs. To capture this, we augment the basic Wright's Law model above with statistical noise, e_t:

$$c(y_t) \sim y_t^{-b} + e_t,$$

By incorporating uncertainty, this augmented model allows us to construct error envelopes around our forecasts.

The apparent relationship between cost and cumulative production in experience curves has led many to view observed cost reductions as deriving mainly from gains in experience. This in turn has led other researchers to question the hypothesis that experience, however interpreted, is the real cause of observed cost reductions [105, 106, 107]. Our view is in line with this critique. Many mechanisms contribute to reducing the cost of a technology besides experience and learning, including economies of scale, research and development, and technology spillover [108, 105, 109, 110, 111, 112, 107]. For our purpose here, we take an agnostic view toward what the actual drivers of cost reduction in solar and wind energy technologies are. We treat the Wright's Law model, in the augmented statistical form above, as a forecasting tool. We think of cumulative production as correlating well with a variety of processes that conspire to drive costs down.

To apply this model, we have to decide how to measure the cumulative production of energy technologies. Different countries have produced different amounts of these technologies, leading to different totals of cumulative production when measured by country. For PV modules and wind turbines, we argue that the best measure of cumulative production is not country-specific, but global. PV modules and wind turbines are products with global markets, and historically there are many instances of firms in one country building off of technological development in other countries [113, 114]. This suggests that the processes driving cost reduction—whether experience, scale economies, R&D, spillover, or anything else—correlate best with the combined cumulative production of all countries.

The Wright's Law forecasting model can be applied to the cost of PV modules because of the characteristics of this technology. As a manufactured good, module design improvements or production process improvements can spread from one firm to another, or from one country to another. The processes that lead to cost reduction accumulate globally. In contrast, PV BOS costs do not share these characteristics. BOS costs are dominated by the costs of on-site construction and financing, including labor, permitting fees, site inspection and preparation, and other administrative fees. BOS costs also depend on local taxes. These costs are highly location-dependent, and the processes which lead to reductions in these costs are hard to transfer between countries. Because of this, it would be inappropriate to use Wright's Law to model BOS costs. Instead we use expert elicitation, drawing from expert projections from [99].

Forecasting technological progress using Wright's Law

In this work we use Wright's Law to model the historical costs and forecast future costs of PV and wind technologies. We make several data and modeling decisions in order to achieve a robust analysis. The choice of appropriate axes—that is, the variables used to represent 'performance' on the y-axis and 'experience' on the x-axis—is an important feature of Wright's Law. Detailed discussions can be found in the literature on the proper application of Wright's Law to energy technologies and other technologies; here, we seek only to describe the features relevant to our global analysis of PV and wind energy.

There are four natural choices for the y-axis, or 'performance' variable: the cost or price of generating capacity (in $/W), or the cost or price of electricity (in $/MWh) amortized over the lifetime of the generation project. Cost, where available, is generally preferred over price as the y-axis variable, as unit cost is less sensitive to exogenous market dynamics and variations in supply and demand than unit price. However, a manufacturer's direct costs are often not publicly available, and one player's price (here, the manufacturer) is simply another player's cost (here, the installer or electricity customer). Price is therefore often used, both because it acts as a proxy for cost and because it is more directly related to the costs to the consumer. From a climate policy perspective, the most appropriate metric for comparison is the cost of electricity, or LCOE, as the difference in cost between a unit of electricity generated from a desirable source with low carbon emissions (such as wind or PV) and a unit of electricity generated from an undesirable source with high carbon emissions (such as coal without CCS) represents the fee or subsidy required to make the desired source economically competitive (see Box 2).

In the case of PV, the full system cost incorporates BOS components that vary widely by location and that would not be expected to evolve at the same learning rate as the PV module and inverter. Since the LCOE cannot be directly differentiated into costs resulting from each component, and since PV LCOE is highly dependent on insolation levels (which are unaffected by learning), we use the market price of PV modules and inverters in $/W as the y-axis 'performance' variable for these two components. For modules and inverters, the capacity cost in $/W directly captures cost reductions resulting from learning, such as improvements in efficiency, reductions in manufacturing costs per unit, and reductions in materials intensity. For BOS, we take BOS prices in $/W reported in the literature for different regions and apply different assumptions, described in detail below, about how these prices will evolve. We then combine the module, inverter, and BOS prices into an overall system price, which we convert to LCOE (for a given level of insolation) to enable comparison to the cost of electricity from other energy sources.

In the case of wind power, the system price in $/W does not capture the full effects of learning, as developments in wind turbine properties have led to decreased energy cost ($/Wh) for a given wind resource density through improvements in capacity factor, at the expense of higher system prices ($/W). The LCOE for wind is also somewhat less closely tied to resource density than the LCOE for PV, given the development of turbines with high hub heights and low specific power that enhance energy capture and push down energy cost in low-wind areas. We therefore use LCOE ($/Wh) directly as the y-axis 'performance' variable for wind.

There are three natural choices for the x-axis, or 'experience' variable: cumulative generation capacity in watts, cumulative energy generation in watt-hours, or the number of generation units (PV modules or wind turbines) installed. The x-axis variable should quantify the form of experience that could plausibly lead to improvements in performance (i.e., to reductions in cost per unit produced). For PV and wind, the large majority of the lifetime cost of a project results from the initial capital expenditure associated with the installation of the project; there is no recurring fuel cost, and operations and maintenance expenses are much smaller than for other energy generation technologies. In this case generation capacity, or the number of generation units, are better proxies for 'experience' than cumulative energy generation, since they correlate more directly with experience in installation, the largest contributor to project costs. Cumulative generation capacity is generally preferable to the number of generating units, since the capacity of generation units has increased over time and since data on generation capacity are more readily available. Here, we use global cumulative capacity in watts as the x-axis 'experience' variable for both PV and wind.

Although the data requirements of the model we use are simple, care must be given to analyzing the data. For each technology, we test the robustness of the learning rate by changing the length of the dataset. In this way, we examine how well Wright's Law will perform when making projections into the future. We use time-series data that are as long and up-to-date as possible, in order to obtain learning rates that most fully represent the technological progress in PV and wind.

We also calculate an error envelope around the projected cost that is generated by Wright's Law. The error envelope is calculated based on a model by Nagy et al. [50] that measures how well Wright's Law and other performance curves predict the future costs of technologies. The parameters of the error model are estimated by using hindcasting on a large dataset of the historical cost and production of many different technologies including wind and PV.

It is also important to consider thresholds such as commodity cost floors that could limit technological progress. (See Section 4.2 and 4.3 for more detail on cost floors.) We also explore other functional forms involving separating commodity costs. We conclude that the use of a single-factor model (Wright's Law), whose formulation is shown in the equations above, is a suitable method for predicting future costs. See the Appendix for details on the modeling decisions.

4.2 Photovoltaics projected costs

We differentiate the system price of PV into three main components: the PV module, the inverter, and BOS. We make the simplifying assumption that PV deployment directed toward meeting INDC targets will be dominated by ground-mounted utility-scale PV systems, which are more economical and demonstrate less variability in costs across different nations than residential and commercial systems.

PV module

Figure 4.1 displays the relationship between price and installed capacity for PV modules [35]. Fitting Wright's Law over the entire range of the available data, from 1976 to 2014, a learning rate of 21.6% is observed. To make a projection for the future cost of PV modules, we assume that global average module costs will continue to evolve in a manner such that this learning rate stays constant through the

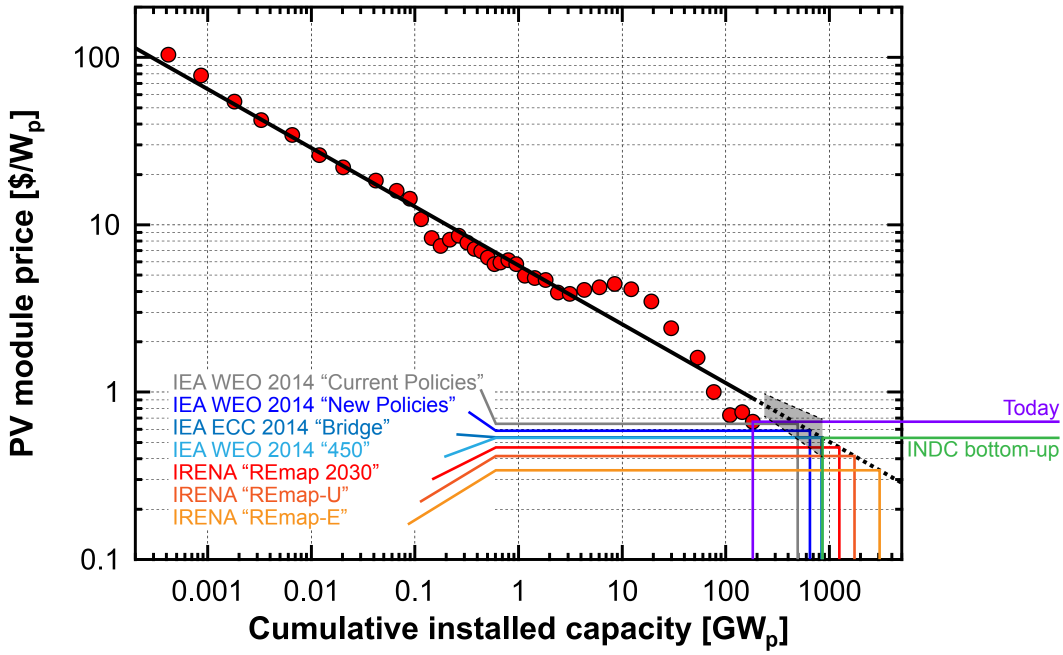

Figure 4.1: PV module price versus installed capacity. PV module prices in $/W$_{peak}$ and cumulative capacity in GW$_{peak}$ are from ITRPV 2015 [35]. The best-fit line represents a learning rate of 21.6%. Capacity values for 2030 according to different projections and scenarios are shown on the x-axis and translate into expected module costs in 2030 on the y-axis. The projected PV module costs are obtained by the Wright's Law model (black dotted line) and the error envelope (gray shaded area) is obtained by the error model by Nagy et al. [50]. The cost in 2030 is expected to deviate from the forecast by approximately ±25%. The error model is explained in more detail in the Appendix. (Reproduced with permission).

year 2030.[1]

Given this relationship between module price and cumulative PV capacity, a projection for module price in 2030 may be generated from a projection for cumulative 2030 PV capacity. A range of different projections for 2030 PV capacity are plotted along the x-axis of Figure 4.1, with their associated projected module costs on the y-axis. For the central 'INDC bottom-up' scenario considered in this study, with 858 GW of PV installed in 2030, we obtain a module cost of $0.53/W—roughly 20% lower than the 2014 average module cost of $0.67/W. According to our error model, the estimated PV module cost in 2030 is expected to vary from our forecasted value by ± 25%. This is the 'expected error,' not the maximum possible error. The details of the model and how we define the expected error can be found in the Appendix.

As discussed in Box 1, the cost of any technology is ultimately constrained by the cost of irreplaceable commodity inputs. For the crystalline silicon PV modules that currently account for more than 90% of the PV market, the primary irreplaceable commodity input is the silicon within the solar cell

[1] There are many alternative assumptions that could influence the choice of fitting range or the mechanics of the fit. If experience is assumed to depreciate over time, we might choose to exclude data from the very early years of module production from the fitting range; or if we had performed this analysis ten years ago, the last ten years' data would be excluded. Sub-components of the module price, such as the price of silicon, could also be independently modeled. To minimize the number of fitting parameters and avoid subjective assumptions, we use a one-factor model over the entire range of available data. We discuss the impact of alternative approaches in the sensitivity analysis later in this section and in the Appendix.

itself. The cost of silicon multiplied by the material intensity of silicon in a PV module (measured in grams per watt) therefore represents a floor for the PV module cost. Apart from a large price spike in the mid-2000s, both the price of silicon and the silicon intensity in PV modules have been steadily decreasing, and the total cost of the silicon in a PV module stands between $0.10-$0.15/W. This cost floor is sufficiently low compared to the projected 2030 module price of $0.46/W that it does not represent a constraint in our analysis.

Inverter

We analyze the cost dynamics of PV inverters using the same experience method as for the PV module. Figure 4.2 displays the cost of residential-scale (<20 kW) inverters from SMA, as reported by Fraunhofer 2015 [99], plotted against the cumulative global installed capacity of PV. Industry-wide data on inverter prices is more sparse than data on module prices, but in a competitive market the cost trend for other suppliers should be similar. A learning rate of 18.9% is observed over the 23 years of available data from 1990-2013. For the central 'INDC bottom-up' scenario discussed above, we obtain a 2030 price of $0.12/W. As in Fraunhofer 2015, we apply a scaling factor of -25% to the reported inverter price to account for the economies of scale realized for the larger inverters used in utility-scale projects, resulting in a final price of $0.09/W. As for PV module costs, we calculate an error envelope around the projected inverter cost generated by Wright's Law. The error envelope shows that the inverter cost in 2030 is expected to deviate from the realized cost by approximately $\pm 40\%$. (The details of the error model [50] can be found in the Appendix.)

BOS for Utility-Scale PV

PV BOS costs have become increasingly important with the rapid decline in module prices, and they now constitute well over half of utility-scale PV system costs in most countries. Utility-scale BOS typically includes hardware (e.g., inverters, trackers, racking, and wiring), engineering, procurement, and construction (EPC; e.g., labor, permitting, inspection, and interconnection (PII)), and other costs (e.g., financing, developer profit margin, and G&A). As described before, we consider inverter price evolution separately, even though inverters are typically considered as a component of BOS.

As shown in Figure 4.3, current reported utility-scale BOS costs vary widely between countries, and in some cases, between different data sources. Indeed, it has been observed for U.S. utility-scale plants that empirical top-down price estimates and modeled bottom-up prices can differ significantly [115]. We observe that the large developing markets of India and China achieve substantially lower BOS costs than many developed markets, including the U.S., Japan, and Australia, potentially due to lower labor costs and less stringent regulatory requirements.

The future evolution of utility-scale BOS costs is critical for the cost-competitiveness of solar PV worldwide, yet remains highly uncertain. Figure 4.3 compares several potential 2030 endpoints for BOS evolution. In particular, we consider the following bounding scenarios: (1) No progress: The world-average BOS remains constant at current levels. (2) Best-in-class: Some or all countries approach the current lowest BOS value of $0.61/W (India), perhaps through intentional sharing of policy and deployment best practices between nations. (3) Expert projection: Individual BOS cost components decrease according to expert projections from Fraunhofer 2015 [99]. It is difficult to assess the relative likelihood of each cost evolution scenario; therefore, we consider all of them in our analysis of total system price and levelized generation costs below.

PV System Cost Forecasts

The total cost of a PV system is the sum of the module, inverter, and BOS costs. In nearly all countries today, BOS dominates the total system cost (Figure 4.4); as a result, the assumption made for BOS

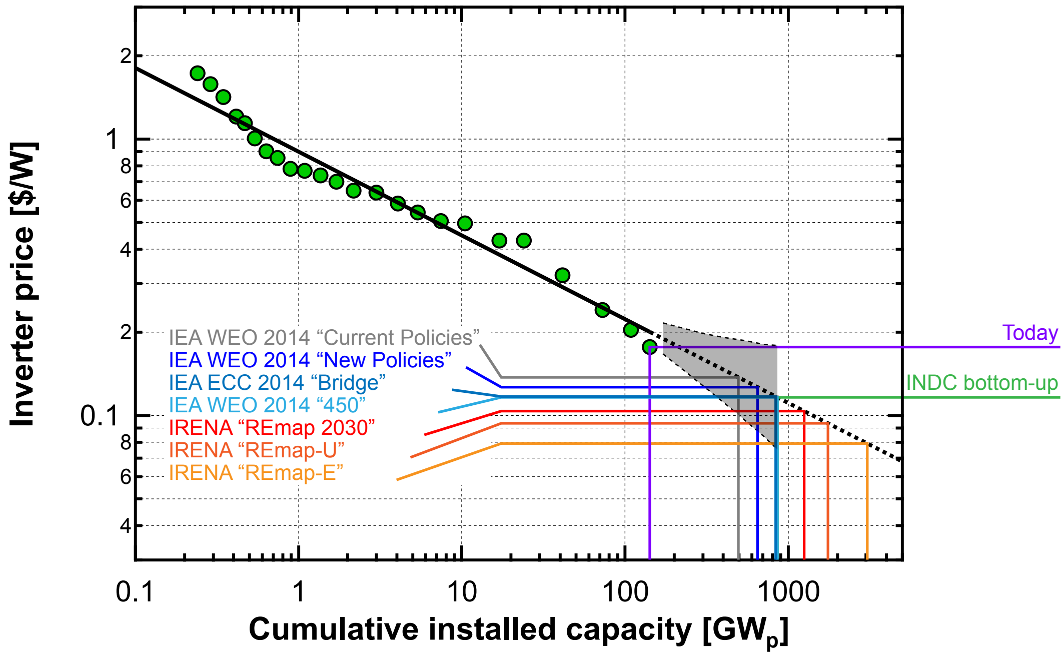

Figure 4.2: PV inverter price versus installed capacity. Inverter prices in $/*W* and cumulative PV capacity in GW_{peak} are from Fraunhofer 2015 [99]. The best-fit line represents a learning rate of 18.9%. Capacity values for 2030 according to different projections and scenarios are shown on the x-axis and translate into expected inverter costs in 2030 on the y-axis. Note that inverter costs displayed here are for a <20 kW inverter; in the system prices to follow, the inverter price is scaled down by 25%, as in Fraunhofer 2015, to account for the economies of scale realized in the larger (>500 kW) inverters used in utility-scale projects. The projected inverter costs obtained by the Wright's Law model (black dotted line) and the error envelope (gray shaded area) are obtained by the error model by Nagy et al. [50]. The cost in 2030 is expected to deviate from the forecast within approximately ±40%. The error model is explained in more detail in the Appendix.

cost evolution has the largest impact on the future system price. However, we note that the importance of PV module technology improvements for further cost reductions should not be overlooked: Since some BOS cost components vary with module area, improvements in module efficiency can have a significant impact on system costs.

Here we consider five scenarios for utility-scale PV system cost in 2030:

1. **2014/2014 world average:** No change in module, inverter, or BOS price (assumes current world-average BOS) ('constant module,' 'constant inverter,' and 'constant BOS') - $2.10/W

2. **2014/2014 best-in-class:** Constant module and inverter; convergence to the lowest observed BOS price in 2014 ('best-in-class BOS') - $1.42/W

3. **2030/2014 best-in-class:** Decrease in module and inverter prices to prices predicted by experience-curve analysis ('module experience' and 'inverter experience'); best-in-class BOS - $1.23/W

4. **2014/2030:** No change in module price; inverter experience; decrease in BOS price according to expert projection [99] - $1.08/W

5. **2030/2030:** Module and inverter experience; expert BOS - $0.94/W

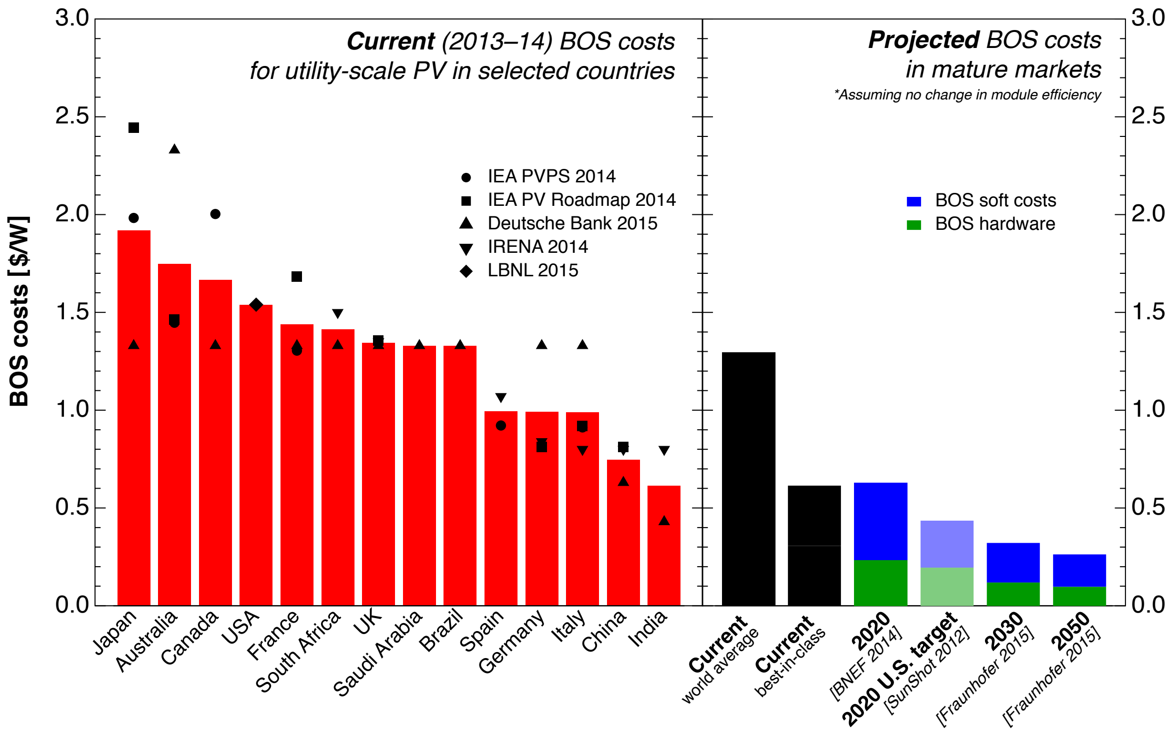

Figure 4.3: Current and projected future BOS costs for solar PV. Left: Typical reported BOS costs ($/W$_{DC}$) in 2013 and 2014 are shown for utility-scale solar PV systems in different countries. Significant variation exists both between countries and between data sources. BOS costs in the lowest-cost countries (China, India, and Italy) are only one-third to one-half the costs in the highest-cost countries (U.S., Japan, Australia). Furthermore, values reported by several international sources vary by up to a factor of 2. Where the total system price was reported, BOS costs were calculated by subtracting the 2014 year-end module price from the system price. Right: BOS cost projections—divided between hardware costs and soft costs—are shown for 2020, 2030, and 2050. The 2030 value was estimated from the Fraunhofer 2050 projection by assuming a constant annual percentage decline between 2015 and 2050. The current world weighted-average BOS value uses 2014 capacity additions as weights.

Sensitivity analysis – PV system price

Figure 4.5 shows the sensitivity of our central projections for the price of PV system components in 2030 to various assumptions, where the total PV system price is equal to the sum of the module, inverter and BOS, all measured in terms of $/W$_{DC}$. We briefly describe the details of the sensitivity to different assumptions here; a more detailed discussion can be found in the Appendix.

- **Module/Inverter – Stochastic Wright:** The Wright's Law model provides a central estimate for the cost for a given cumulative production level. To obtain error envelopes around the cost projections, we use a statistical model developed by Nagy et al. [50]. This model estimates the errors around the central projection based on both (a) how well Wright's Law can predict the costs of many different technologies including PV and inverters, and (b) fluctuations specific to the historical cost and production data for PV and inverters. The error envelopes are shown along with the central estimates in Figure 4.1. The Appendix provides more detail on the error model.
- **Module/Inverter – Stochastic Moore:** Although we use Wright's Law to make projections in this analysis, we also explored an alternative model, Moore's Law. Moore's Law posits that the cost

of a technology decreases exponentially over time. We use Moore's Law to make projections and also provide error envelopes using the error model explained above that accounts for both (a) how well Moore's Law can predict the costs of many different technologies including PV and inverters and (b) fluctuations specific to the historical cost and production data for PV and inverters. The Appendix provides more detail on the error model and shows plots with central cost estimates made by using Moore's Law and the error envelopes.

- **Module – Materials:** While our central projections are based on a single-factor learning model where experience (represented by cumulative global installation of PV systems) is the only determining variable for unit cost, the price of commodity material inputs is exogenous to the learning system and could act as an omitted variable, with an effect on module cost that is not captured by the single-factor learning model. The price of polycrystalline silicon has varied widely over the past four decades, dropping by nearly a factor of 10 from 1976 to 1998 before undergoing a large price spike in the late 2000s due primarily to a supply shortfall. Here we performed a regression analysis to disentangle the experience-induced module price decline from variations in the price of polysilicon. Projecting the future module price then requires an assumption for the future evolution of the price of polysilicon. Projections for the future cost of commodity materials are inherently uncertain, so Figure 4.5 displays a range of values across different assumptions for future polysilicon price dynamics. The lower value gives the projected module price assuming that the median year-on-year price change of polysilicon from 2014 to 2030 is the same as the median year-on-year price change between 1976 and 2014. The upper value gives the projected module price assuming that the polysilicon price in 2030 is equal to the average polysilicon price between 1976 and 2014.

- **Module/Inverter – Fitting Range:** Stochasticity and the influence of omitted variables can lead to variations in the observed learning rate over different data ranges. If experience is assumed to depreciate over time, one may utilize only a more recent subset of historical data to project future trends. The robustness of an analysis may also be tested by examining the projections that would have been made had the analysis been performed at some past date, using only the data available up to that date. Here, the lower value for 'Module – fitting range' utilizes data from the most recent 15-year window, from 2000-2014 (as might be done if experience is assumed to depreciate over time), and the upper value utilizes data from 1976-2009 (as might have been done if this same analysis had been performed five years ago in 2010). The upper and lower values are reversed for 'Inverter – fitting range:' The lower value utilizes data from 1990-2004 (as might have been done if this same analysis had been performed ten years ago in 2005), and the upper value utilizes data from the most recent 15-year window, from 1999-2013.

- **Module/Inverter – 2030 Capacity:** The use of Wright's Law to project future prices for PV modules implies that the projected price in 2030 depends on the projected PV capacity in 2030. A higher projected capacity would lead to a lower projected price and vice versa. The range displayed here shows the range of prices that would arise from the different projections shown in Figure 3.3. The upper value corresponds to the 'IEA WEO 2014 Current Policies' projection, and the lower value corresponds to the 'IRENA Remap-E' projection.

- **Inverter – 25%:** We use the same data and methods as described in Fraunhofer 2015 to make projections for future inverter prices. The historical inverter price data in Fraunhofer 2015 is for <20 kW inverters; utility-scale inverters at >500 kW capacity are assumed to be 25% cheaper due to economies of scale. We use the -25% scaling factor in our central projection; the upper value shown here corresponds to the projected inverter price in 2030 without applying the -25% scaling factor.

- **BOS:** Our BOS projections are described in more detail in Figure 4.3, but are reproduced here for comparison.

It is clear from Figure 4.5 that assumptions regarding the BOS price have the largest effect on total system price, followed by assumptions regarding the PV module. Assumptions regarding the inverter have the smallest effect on system price.

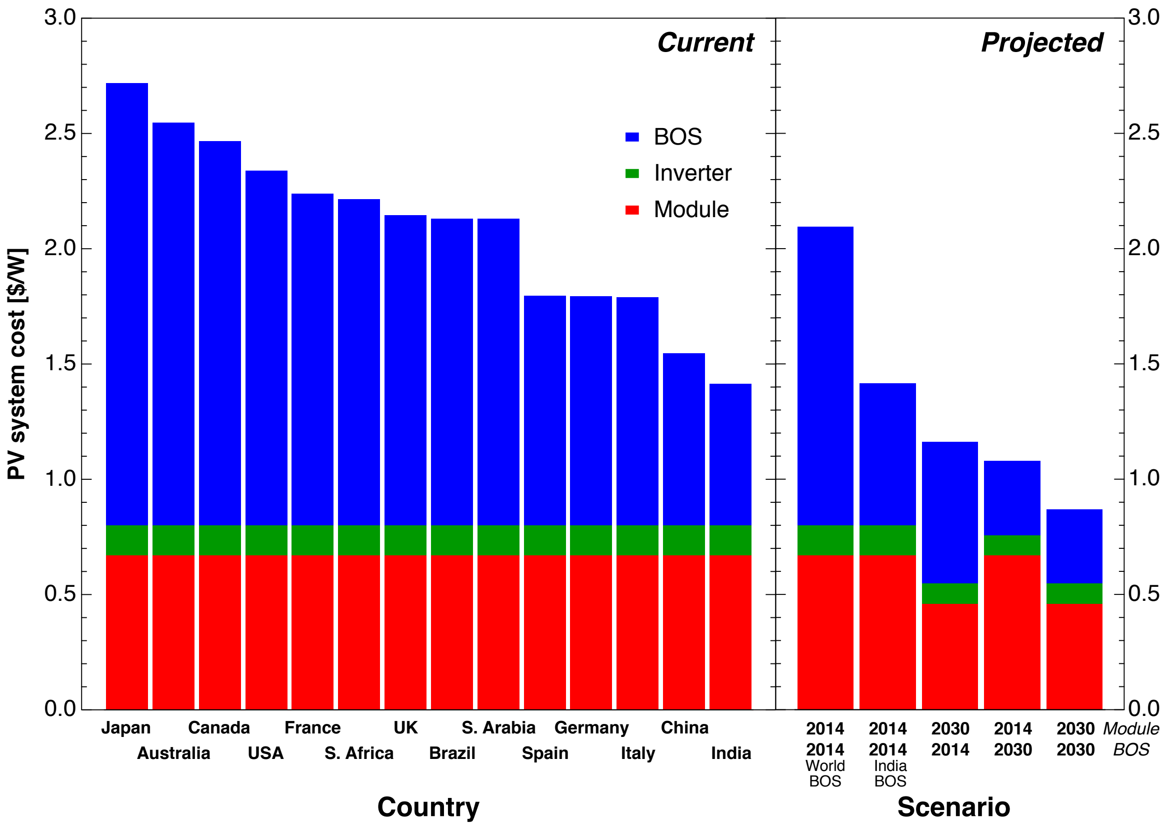

Figure 4.4: Current and projected price breakdown for utility-scale PV systems in different countries and under different cost reduction scenarios. Left: Current system price by country, assuming module and inverter prices are the same between countries. Right: 2030 PV system price in 5 scenarios: (1) No change in module, inverter, or BOS price (assumes current weighted-average world BOS, with 2014 annual installations by country as weights) ('constant module,' 'constant inverter,' and 'constant BOS') (2) Constant module and inverter; convergence of all countries to the lowest reported BOS prices in 2014 ('best-in-class BOS') (3) Decrease in module and inverter prices to prices predicted by experience-curve analysis ('module experience' and 'inverter experience'); best-in-class BOS (4) No change in module price; inverter experience; decrease in BOS price according to expert projection ('expert BOS') (5) Module and inverter experience; expert BOS.

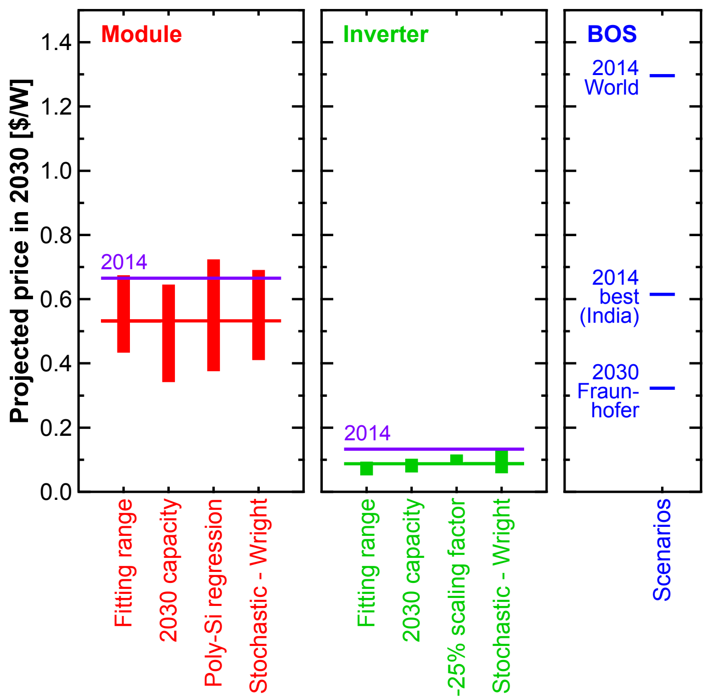

Figure 4.5: Sensitivity of projections of PV system price components to assumptions. Purple lines indicate 2014 prices for PV modules and inverters. Red and green horizontal lines indicate central estimates for module and inverter price in 2030 based on Wright's Law. Module price ranges are denoted by red bars; inverter price ranges are denoted by green bars; discrete BOS price estimates are denoted by blue lines. The assumptions leading to the upper and lower values for the module and inverter bars are described in the text.

Box 2: LCOE and Cost Competitiveness

The levelized cost of electricity (LCOE) is a commonly used metric for gauging the cost-competitiveness of renewable and conventional generation technologies [116]. The LCOE is the real cost per unit energy delivered of building and operating a generation facility over its useful life, including upfront capital costs, operating expenses, and financing costs. Costs can also be classified as upfront investment (typically proportional to capacity), fixed operations and maintenance (O&M; proportional to capacity), or variable O&M (proportional to the amount of electricity generated). Generation technologies differ in how their costs are distributed among these categories. For example, the cost of coal generation is divided roughly evenly between upfront capital and variable O&M costs [62]. In contrast, the cost of solar, wind, and other renewable technologies is dominated by upfront capital costs, with very low fixed and variable O&M.

While it is a simple way to compare the cost of electricity from different sources, LCOE is an imperfect metric. The economic viability of a new generating facility depends on a number of elements not captured in its LCOE, including existing transmission and distribution grid infrastructure, market prices, availability of financing, and numerous policy factors. We do not attempt to address the plethora of issues governing investment decisions. Instead, we focus on the LCOE of representative solar PV and wind projects and assess their cost-competitiveness with thermal generators in individual countries and globally. However, in this box we discuss limitations of LCOE when evaluating intermittent generation technologies (e.g., solar and wind) against conventional dispatchable technologies (e.g., coal and natural gas).

Electricity demand, wholesale market prices, and the output of solar and wind generators all vary with time. In the absence of energy storage, the value of solar electricity depends on the extent to which solar generation is correlated on average with the market price of electricity (Figure A). A positive correlation means that solar generation is more valuable than constant baseload generation, while a negative correlation means that solar is less valuable than baseload. Figure A shows the variability in both resource availability and wholesale electricity prices over 16 days at three different locations in the U.S., highlighting the typical positive correlation of solar generation and negative correlation of wind generation with electricity price [117, 118, 119, 120]. Indeed, at low solar penetration, solar tends to be positively correlated with market prices, and hence is more valuable than the LCOE alone would suggest (by a so-called value factor of around 1.1). At higher penetrations, solar generators systematically reduce market prices during daytime hours, reducing their own market value and making solar less competitive than the LCOE would suggest. For wind, typical value factors are below 1 even at low penetrations and decline further with increasing penetration.

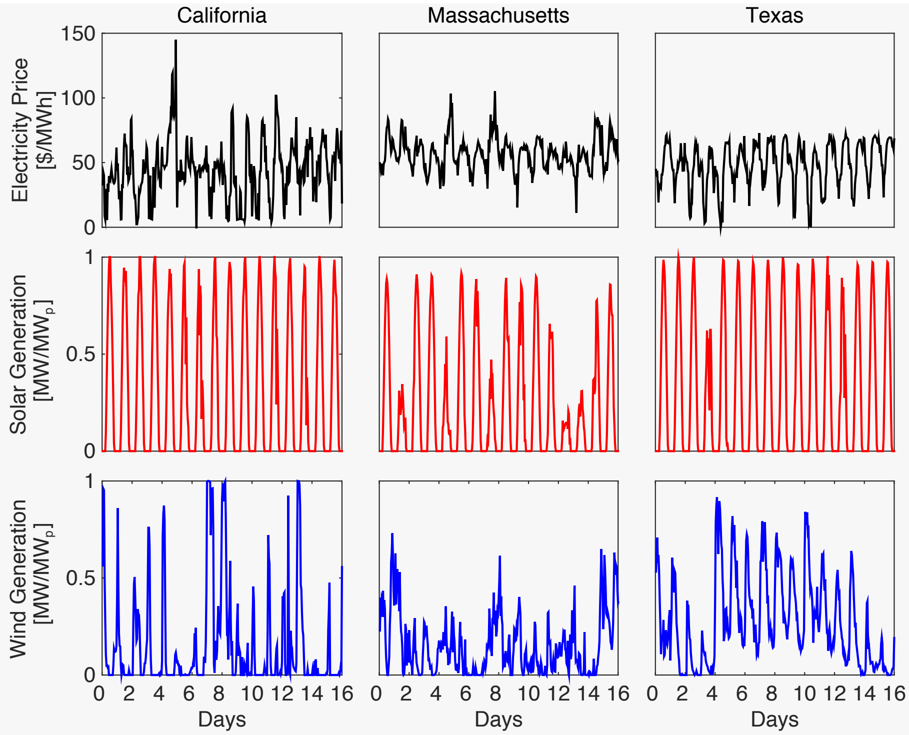

Figure A: Hourly time series data for real-time locational marginal electricity price and capacity-normalized solar PV and wind power output for Palm Springs, CA, Plymouth, MA, and McCamey, TX, for July 1, 2004 through July 16, 2004. To develop breakeven thresholds for renewable technologies, a full year's worth of historical real-time prices and resource availability are used to calculate the overnight capital cost ($/W) of PV or wind, using a capital recovery factor based on 5% interest over 20 years, which equals the revenue in a representative year [121]. Solar generation was calculated assuming a fixed-tilt PV system. Wind generation was calculated based on published performance data for a Vestas V90-3MW turbine [122].

The location-dependent value of renewables due to time-varying generation is shown in the following two figures, which compare different methods of calculating the value of renewables in five locations. In Figure B, the upfront capital cost at which solar or wind breaks even (i.e., the net present value of a solar or wind project exceeds 0) is calculated based on two different generation profiles: (1) the time-varying local hourly renewable generation profile (blue) and (2) a constant average annual generation (i.e., using the annual capacity factor and average electricity price) (red) for each location. Figure C shows the weighted annual-average electricity price received by solar or wind generators due to their time-varying production, alongside the unweighted annual-average electricity price.

For solar power, the resource is generally available when prices are higher than average, as shown by the higher blue bars in Figure C. At low penetration, smaller solar cost reductions are thus required to break even than would be expected for a baseload generator, as observed in Figure B. The converse is generally true for wind, where the average wind electricity price is lower than the annual-average electricity price, seen in the higher red bars in Figures B and C. Figures B and C were generated using hourly time series data for the wind and solar resource and for the real-time locational marginal electricity price.

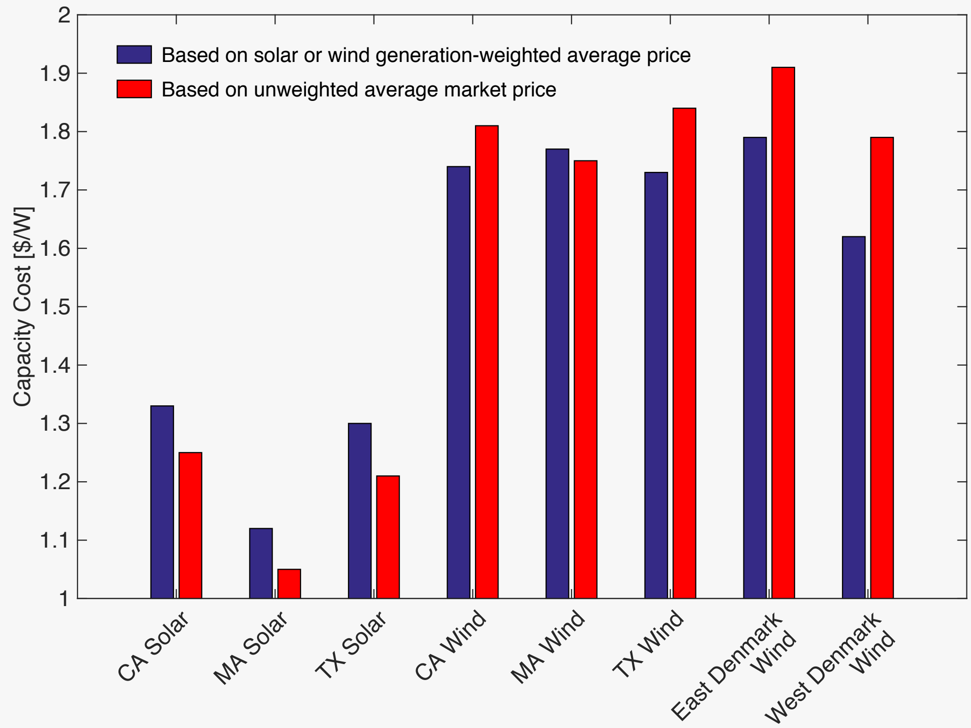

Figure B: Breakeven thresholds for solar panel and wind turbine power capacity costs installed in California, Massachusetts, Texas, and Denmark. To be profitable, the capacity costs of these technologies need to fall below the values based on the solar and wind electricity price (blue bars). The comparison demonstrates that assessing these technologies against the average electricity price leads to error—typically underestimation in the case of solar, and overestimation in the case of wind. The results shown are based on 2004 hourly resource availability and electricity prices in California, Massachusetts, and Texas; and 2008 data on wind generation and electricity prices in East and West Denmark. Denmark produced the equivalent of 19% of its electricity demand through wind energy in 2008 with approximately 2400 MW installed capacity in the West and 760 MW installed in the East. In 2004, wind contributed less than 5% of electricity production in Texas (but surpassed 10% in 2014 [116]) and less than 3% in California. Wind in Massachusetts and solar in Massachusetts, Texas, and California were all negligible in 2004, accounting for far less than 1% of total electricity production.

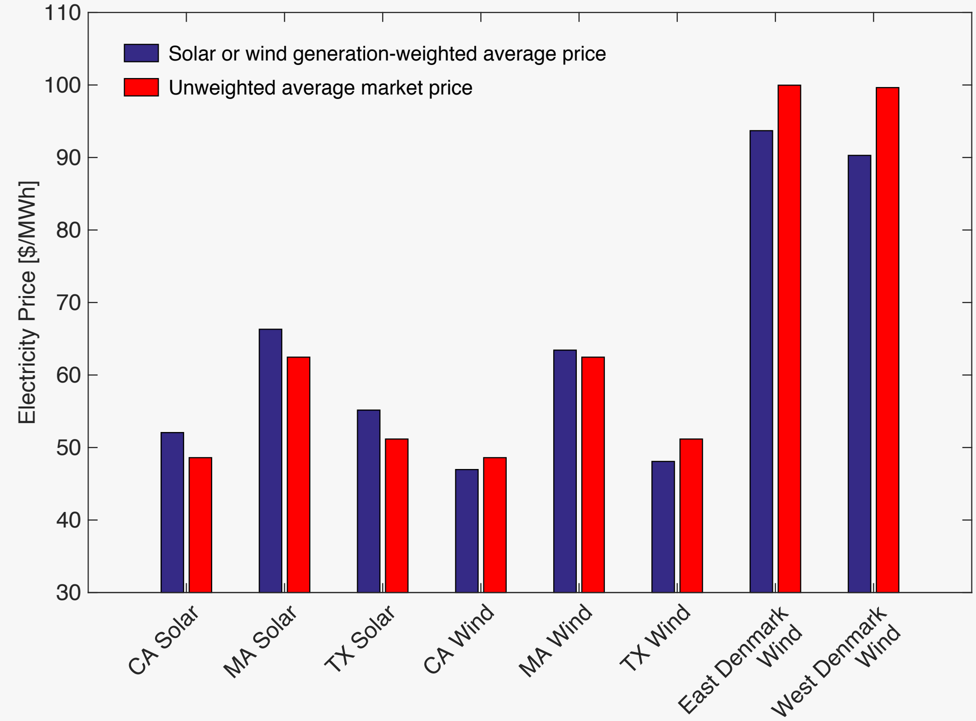

Figure C: Solar and wind average selling price vs. average price for all generators. The annual-average selling price of solar or wind (i.e., weighted by hourly generation) is shown in blue; the unweighted annual-average electricity price is shown in red. For Texas, Massachusetts, and California, resource and electricity price data are from 2004; for East and West Denmark, data are from 2008. In general, at low penetration levels, solar generators receive annual-average prices above the unweighted average market price—leading to higher breakeven capacity costs—while wind generators receive annual-average prices below the unweighted average market price—leading to lower breakeven capacity costs.

PV LCOE

We calculate the LCOE of utility-scale solar PV following the method of Reichelstein and Yorston [123], adjusting for country-specific system prices and average capacity factors. We assume a system life of 25 years, annual degradation of 0.5%, fixed O&M cost of 15 $/kW_{DC}$/yr, a weighted-average cost of capital (WACC) of 7.5%[2], an effective tax rate of 40%, and an accelerated depreciation schedule of 20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76% in years 1–6, respectively.

In Figure 4.6, we show the calculated LCOE today for selected countries with widely varying solar resource availability. The abundant resource availability in some countries (e.g., South Africa and Saudi Arabia) compensates for their relatively high system prices, yielding low LCOEs. The two countries with the lowest system prices—India and China—also have the lowest LCOEs, thanks to the relatively high resource in both countries (see Appendix).

The five system price decline scenarios outlined above translate to the LCOE curves shown in Figure 4.7. At the global-average capacity factor of 17.1%, the corresponding average LCOE values are 157 $/MWh (Scenario 1: 2014/2014 world), 110 $/MWh (Scenario 2: 2014/2014 best-in-class), 97 $/MWh (Scenario 3: 2030/2014 best-in-class), 86 $/MWh (Scenario 4: 2014/2030), and 76 $/MWh

[2]This is the WACC assumed for OECD countries and China by IRENA in [39]

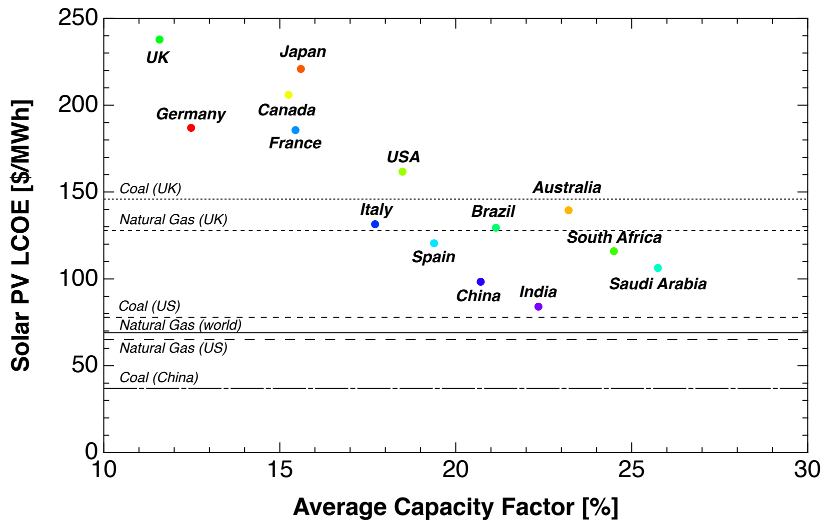

Figure 4.6: Current average LCOE of utility-scale PV systems in selected countries. The average capacity factor for each country was calculated by multiplying each country's average global horizontal irradiance (GHI) [124] by the calculated average ratio of capacity factor to GHI (3.9 ± 0.3 %/(kWh/m^2/day)) for fixed-tilt PV systems simulated at 1563 sites in the northern hemisphere using NREL's System Advisor Model. This scaling factor corrects for the effects of temperature and other weather-related effects on system performance.

(Scenario 5: 2030/2030). The actual LCOE may vary widely depending on the country- and location-specific insolation. Indeed, in some high-insolation regions, solar PV may be cost-competitive with conventional fossil generation even at current system costs.

Figure 4.9 shows the sensitivity of our central projections for PV LCOE in 2030 to various assumptions. All of the cases shown here assume that module cost and inverter cost decline following Wright's Law. The horizontal lines represent different BOS assumptions using the world-average capacity factor (17.1%); vertical lines of the same color use the same BOS assumptions. The parameters for the 'Module fitting,' 'Module materials,' 'Inverter fitting,' 'Stochastic Moore,' and 'Stochastic Wright' cases are the same as those described in Figure 4.5. The lower value for 'capacity factor' corresponds to the LCOE in a location with a capacity factor of 35%, equal to the maximum of the range reported in IRENA 2015 (IRENA 2015 Figure 2.5); the upper value for 'capacity factor' corresponds to the LCOE in a location with a capacity factor of 10%, equal to the minimum of the range reported in IRENA 2015 [39].

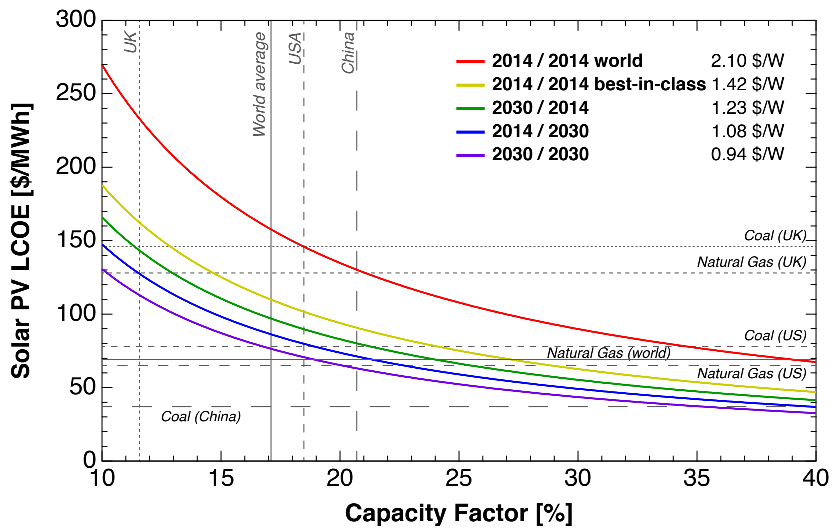

Figure 4.7: Levelized cost of electricity (LCOE) of utility-scale solar PV in 2030 for varying capacity factors under 5 system price reduction scenarios. Vertical lines denote the average PV capacity factors (based on average irradiance) for the world, UK, USA, and China: 17.1%, 11.6%, 18.5%, and 20.7%, respectively. The LCOE of new coal and natural gas combined-cycle generation in the same countries is shown for comparison. We note that the current world-average LCOE (2014/2014 world scenario) shown here is calculated from the system cost as described above, and as a result does not match exactly the value shown in Figure 2.7.

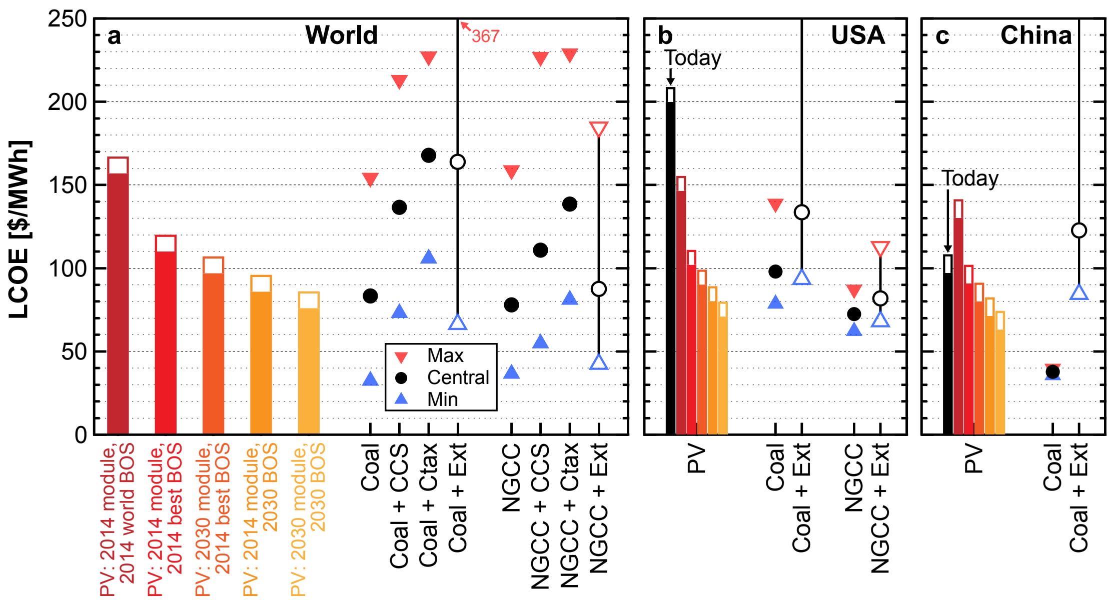

Figure 4.8: Comparison between PV LCOE projections and LCOE of fossil-fuel-fired generation. a, Projections for global average LCOE of PV compared to current estimates of the LCOE of coal and natural gas combined cycle (NGCC), coal and NGCC with carbon capture and sequestration (CCS), and coal and NGCC with a \$100/t CO_2 carbon tax. Red triangles represent maxima; black circles represent central estimates; blue triangles represent minima. A range of estimates of the external costs of air pollution for these different electricity sources, added to their LCOE, are shown as empty boxes for PV and empty symbols for coal and NGCC. b, Projections for the LCOE of PV in the United States compared to current estimates of the LCOE of coal and NGCC in the United States. c, Projections for the LCOE of PV in China compared to current estimates of the LCOE of coal in China. External costs from air pollution are estimated by combining emission factors from ecoinvent [125] with cost factors from [126]. External costs from causes other than air pollution are not considered in these estimates. More details on external cost calculations are provided in the Appendix.

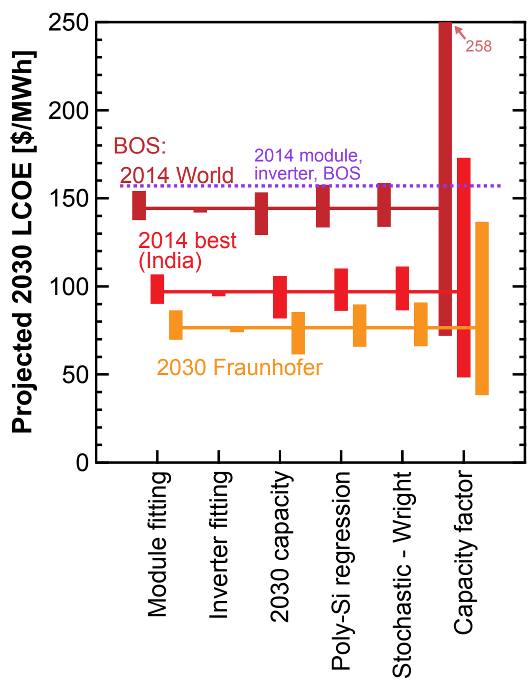

Figure 4.9: Sensitivity of PV LCOE projections to assumptions. All scenarios depicted here assume module and inverter prices decline according to Wright's Law, except for the purple dotted line, which indicates the 2014 world-average PV LCOE from Figure 4.7. Horizontal lines represent central estimates for three different BOS scenarios: constant 2014 BOS (dark red), decline to 2014 best-in-class (India) (red), and decline to the 2030 projection from Fraunhofer 2015 (orange). Vertical bars of the same color indicate the range of LCOE values arising from different assumptions regarding module and inverter cost evolution and capacity factor, making use of the same three BOS assumptions. The assumptions leading to the upper and lower values for the different bars are described in the text.

4.3 Wind projected costs

As discussed in the previous section, because the system price does not capture the full extent of learning for wind power, we apply Wright's Law to the levelized cost of electricity for wind power. Figure 4.10 displays the global average LCOE for wind against the cumulative global installed capacity of wind generation [36, 39]. A learning rate of 13.3% is observed over the available range of data from 1984-2014. For the 'INDC bottom-up' scenario described above, with 1014 GW of wind capacity installed in 2030, we obtain a 2030 LCOE of 51 \$/MWh, roughly 24% lower than the 2014 global average LCOE for wind of 67 \$/MWh.

We also show the error envelope around the projected LCOE that is generated by Wright's Law (Figure 4.10.) The error envelope is obtained by using a statistical model developed by Nagy et al. [50] that measures how well models like Wright's Law can predict the future costs of technologies. (For details on the error model, please refer to the Appendix.) According to this model, the wind LCOE in 2030 is expected to vary by approximately ±20% from the forecasted value.

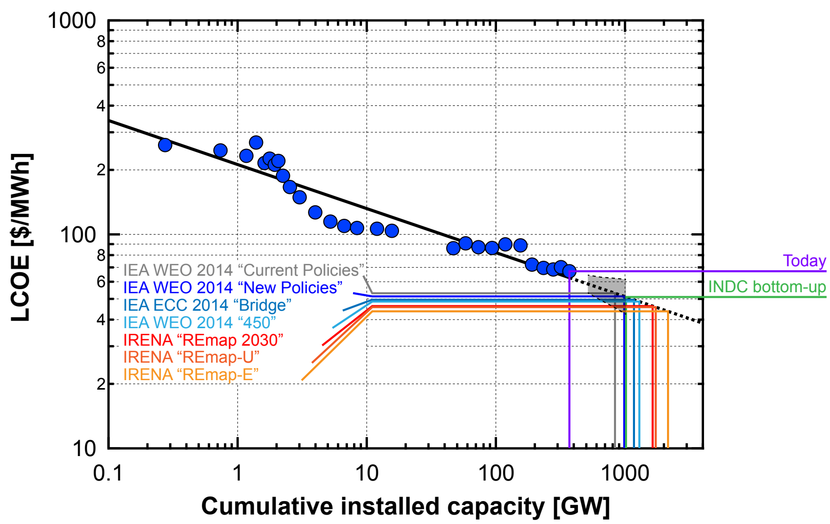

Figure 4.10: Wind LCOE versus installed capacity. World average wind LCOE in \$/MWh and cumulative capacity in GW_{peak} are from BNEF 2013 and IRENA 2015 [36, 39]. The best-fit line represents a learning rate of 13.3%. Capacity values for 2030 according to different projections and scenarios are shown on the x-axis and translate into expected electricity costs in 2030 on the y-axis. The projected wind LCOE is obtained by the Wright's Law model (black dotted line) and the error envelope (gray shaded area) is obtained by the error model by Nagy et al. [50]. The cost in 2030 is expected to deviate from the forecast within approximately ±20%. The error model is explained in more detail in the Appendix.

As for the case of PV, it is important to verify whether our cost projections would be within the range of the expected commodity-constrained cost floor for wind. As described in more detail in the Appendix, we estimate the contribution to the total turbine cost of the three main wind turbine commodity inputs—steel, fiberglass/resin, and copper—to be \$0.06, \$0.05, and \$0.01/W, respectively, for a commodity cost floor of roughly \$0.11/W. While it is not possible to link this cost floor directly with the projected LCOE, it is roughly 90% lower than the current world average turbine cost of around \$1.20-1.40/W, and safely below the range of our projections.

Figure 4.12 shows the sensitivity of our central projections for wind LCOE in 2030 to various assumptions. We briefly describe the details of the sensitivity to different assumptions here; a more detailed discussion can be found in the Appendix and in the discussion of Figure 4.5 above.

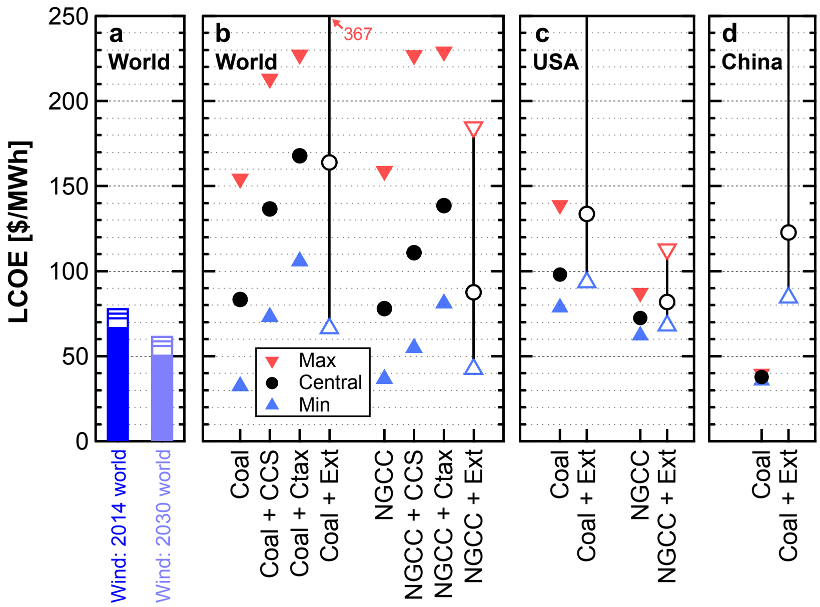

Figure 4.11: Comparison between wind LCOE projections and LCOE of fossil-fuel-fired generation. a, Projections for global average LCOE of wind compared to current estimates of the LCOE of coal and natural gas combined cycle (NGCC), coal and NGCC with carbon capture and sequestration (CCS), and coal and NGCC with a \$100/t CO_2 carbon tax. Red triangles represent maxima; black circles represent central estimates; blue triangles represent minima. A range of estimates of the external costs of air pollution for these different electricity sources, added to their LCOE, are shown as empty boxes for wind and empty symbols for coal and NGCC. b, Current estimates of the LCOE of coal and NGCC in the United States. c, Current estimates of the LCOE of coal in China. External costs from air pollution are estimated by combining emission factors from ecoinvent [125] with cost factors from [126]. External costs from causes other than air pollution are not considered in these estimates. More details on external cost calculations are provided in the Appendix.

- **Fitting Range:** The lower value utilizes data from 1984-2004 (as might have been done if this same analysis had been performed ten years ago in 2005), and the upper value utilizes data from the most recent 15-year window, from 2000-2014.

- **Capacity Factor:** The range shown here represents the range of capacity factors reported in IRENA 2015 (IRENA 2015 Figure 2.5), centered around IRENA's world weighted-average onshore wind capacity factor of 28%. The lower value corresponds to a capacity factor of 53%, and the upper value corresponds to a capacity factor of 13%.

- **LCOE Range:** The range shown here represents the range of LCOE values reported in IRENA 2015 (IRENA 2015 Figure 2.5 [39]), scaled down by the cost reduction factor in our central Wright's Law based projection (-24%, from 67 \$/MWh in 2014 to 51 \$/MWh in 2030). The LCOE here includes the contribution from a number of factors, including capacity factor, cost of capital, project and labor costs, etc.

- **2030 Capacity:** The range displayed here shows the range of LCOE values that would arise from the different capacity projections shown in Figure 3.3. The upper value corresponds to the 'IEA WEO 2014 Current Policies' projection, and the lower value corresponds to the 'IRENA Remap-E' projection.

- **Module/Inverter – Stochastic Wright:** We use a statistical model developed by Nagy et al. [50] to obtain error envelopes around the central cost projections made by using Wright's Law. The errors are calculated based on both (a) how well Wright's Law can predict the costs of many different technologies including wind and (b) fluctuations specific to the historical cost and production data for wind. The error envelopes are shown along with the central estimates in Figure 4.10. The Appendix provides more detail on the error model.

- **Module/Inverter – Stochastic Moore:** We also explored an alternative model, Moore's Law, to make projections. Moore's Law posits that the cost of a technology decreases exponentially over time. We use Moore's Law to make projections and also provide error envelopes using the error model explained above that accounts for both (a) how well Moore's Law can predict the costs of many different technologies including wind and (b) fluctuations specific to the historical cost and production data for wind. The Appendix provides more detail on the error model and shows plots with central cost estimates made by using Moore's Law and the error envelopes.

- **Steel Regression:** Here we perform a regression analysis to determine the contribution of the historical price of steel (the most significant commodity input, by weight, for wind turbine manufacture) to the historical decline of wind LCOE, in the same manner as described above for polysilicon in PV. Once again, assumptions regarding the future price dynamics of steel give rise to a range of estimates for LCOE in 2030. The lower value gives the projected LCOE assuming that the steel price in 2030 is equal to the world average cold rolled steel price between 1984 and 2011. The upper value gives the projected LCOE assuming that the average year-on-year price change of steel from 2014 to 2030 is the same as the average year-on-year price change between 1984 and 2011.

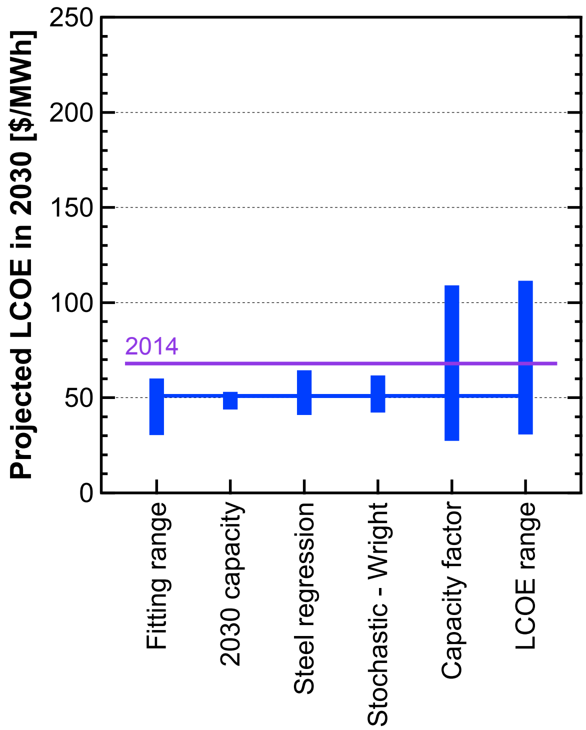

Figure 4.12: Sensitivity of wind LCOE projections to assumptions. The purple line denotes the 2014 global average wind LCOE, and the blue line denotes the projected 2030 global average wind LCOE according to the central-case Wright's Law analysis described in the text. Blue vertical bars take the 2030 Wright's Law projection as the central estimate. The assumptions leading to the upper and lower values for the different bars are described in the text.

4.4 Implications of technology cost evolution scenarios for emissions abatement

Cost-competitiveness of wind and PV

The 2030 LCOE estimates shown above provide a basis for assessing the cost-competitiveness of solar PV and wind electricity with conventional thermal generation. Figure 4.8 shows that new solar PV generation at the world-average system cost and capacity factor is not economically competitive with average new-build coal and natural gas combined cycle (NGCC) generation today.[3] In most of our 2030 cost reduction scenarios, however, solar reaches costs comparable to coal and NGCC. World-average costs for wind electricity are already competitive with fossil generation today. Further cost declines toward our 2030 projections would make wind power the lowest-cost electricity source in many parts of the world.

The findings above hold for global averages, but not necessarily for individual countries or locations: For example, a country with abundant sunlight may have a much lower LCOE for solar PV than the world average; similarly, a country without substantial domestic natural gas reserves may have a significantly higher LCOE for NGCC than the world average. Thus solar may already be cost-competitive with thermal generation in some locations. We emphasize that these conclusions apply to busbar costs only, as our analysis focuses on utility-scale plants. In locations where policy allows distributed generation to be compensated at retail electricity rates, many solar PV and wind generators

[3] Legacy (fully amortized) plants can achieve much lower levelized operating costs than new generators.

are already at retail grid parity today.

There are several major sources of uncertainty inherent in any comparison of electric generation costs. For each parameter described below, variability tends to arise both from differences between countries and from intrinsic uncertainty in parameter values, which may appear as discrepancies in estimates from different sources.

Key sources of uncertainty for solar and wind cost estimates include the country-specific upfront BOS and system costs for solar, the available energy resource and system placement (resource availability varies widely even within individual countries), the cost of capital, and subsidy support. Each of these parameters can have dramatic effects on the cost-competitiveness of solar and wind. Furthermore, we emphasize that at high penetration levels, the market value of intermittent generation without storage will decrease, perhaps significantly (see Box 2).

Key sources of uncertainty for thermal generation cost estimates include fuel prices (particularly for natural gas) and environmental regulation. The cost estimates for coal and natural gas apply to the current regulatory regime; more stringent environmental regulations (e.g., particulate and CO_2 emissions limits, or a price on carbon) would increase the cost of coal and gas generation by forcing plants to install additional emissions controls and possibly implement carbon capture and storage (CCS) systems. Uncertainty in the future cost and performance of CCS technologies further adds to uncertainty in the future cost of thermal generation.

Technology improvement as a multiplier of emissions reductions

The projected decline in the LCOE of PV and wind has important implications for climate change mitigation efforts. Compared to a case in which future cost declines are not taken into account, this decline enables more ambitious renewable energy deployment commitments to be made for the same level of investment. Figure 4.13 illustrates this effect for PV and wind, with several key assumptions: We assume constant global capacity factors from 2015 to 2030 (17.1% for PV and 35% for wind) and that the levelized cost of electricity for a given project (based on our central cost projections described above) is applicable for the full project lifetime. We neglect the effect of project retirements, as typical project lifetimes are longer than the 15-year horizon considered here. We assume that annual deployment (GW/year) evolves with a constant annual percentage change to reach the cumulative target in 2030. While these assumptions simplify the true picture, in which capacity factors and LCOE values vary widely across the globe, this central case reveals general trends that would also apply in a more detailed analysis.

Reaching 858 GW of PV and 1014 GW of wind in 2030 under these conditions would result in the cumulative generation of an additional 8378 TWh of energy from PV and 18,003 TWh from wind over the period from 2015 to 2030, on top of the energy produced by the existing generation fleet in 2014. At today's average costs (157 $/MWh for PV and 67 $/MWh for wind), with no reductions in LCOE, this energy would carry a gross cost (not subtracting the cost of displaced electricity that would otherwise have been generated from other sources) of $1.32 trillion for PV and $1.21 trillion for wind (symbolized by the red boxes in Figure 4.13). If projected cost declines are taken into account, however, cumulative deployment levels of 1210 GW PV and 1207 GW wind could be reached by 2030 with the same total capital outlay (symbolized by the blue shapes in Figure 4.13).

A similar effect can be observed when considering the cost of abating CO_2 emissions through the replacement of coal-fired electricity with electricity from PV or wind. Figure 4.14a shows the amount of CO_2 abated per dollar spent when a unit of energy from PV (red) or wind (blue) is used to replace a unit of energy generated from the 2010 world average electricity mix (empty bar) or from coal (filled bar) as a function of time. Emission intensities for electricity from PV (46 g CO_2/kWh), wind (12 g

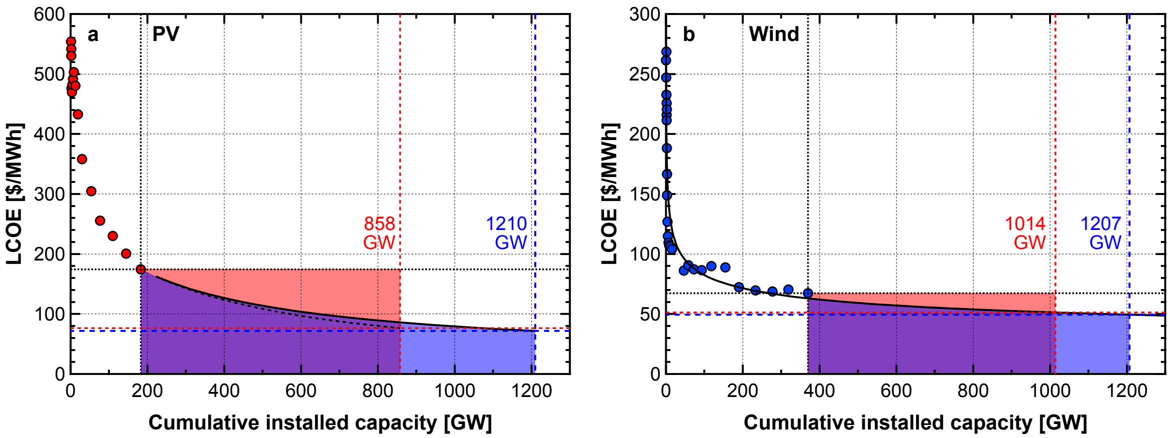

Figure 4.13: PV (a) and wind (b) deployment for a fixed investment under constant cost (red) and experience-based cost reduction (blue) scenarios. Red circles represent historical LCOE values for PV; blue circles represent historical LCOE values for wind. These results suggest that greater deployment can be achieved if realistic cost declines are taken into account.

CO_2/kWh), coal (932 g CO_2/kWh), and the 2010 world average electricity mix (528 g CO_2/kWh) are taken from IPCC AR5 WGIII and NREL 2013 [45, 127].[4] The drop in LCOE of PV and wind has led to a corresponding rise in carbon abatement per dollar from 2000 to 2014, and the experience-induced cost declines projected in 2030 would increase carbon abatement still further.

The same effect can also be described in terms of the net cost of abating CO_2 emissions by replacing a unit of electricity generated from a coal-fired power plant with a unit of electricity generated from PV or wind, as in Figure 4.14b. Here we have subtracted the world-average LCOE of PV and wind in each year from the current world-average LCOE of coal (83 $/MWh, from IPCC AR5 WGIII [45] and WEC 2013 [47]), implying a negative abatement cost for wind in 2014 and 2030 and for PV in 2030 in the '2030 module / 2030 Fraunhofer BOS' scenario. It is important to note that at high penetrations of wind and PV, the amount of electricity that could realistically be generated by wind or PV instead of by coal during hours of high wind or PV generation could be limited by economic constraints, and that the value of wind or PV generation during such hours would drop. Put another way, the associated integration costs that would be required in order for each MWh of energy generated by wind or PV to be fully utilized—whether through energy storage, long-range transmission, or demand response—could increase the associated CO_2 abatement cost. It is beyond the scope of this analysis to say whether the value decline of PV and wind at high penetrations would outrun the projected cost decline at increasing deployment levels. Yet the general trend—that a dollar invested in carbon abatement through the replacement of coal-fired electricity with electricity from PV or wind would, through experience-related cost declines, result in an increase in the carbon abatement associated with

[4] World-average wind LCOE values are from BNEF 2013 [36] for the year 2000; from IRENA 2015 [39] for the year 2014; and from our central projection, described above, for the year 2030. The world-average PV LCOE values for 2014 and 2030 are from are '2014 / 2014 world' and '2030 / 2030' scenarios, respectively, described above and shown in Figure 4.7. The LCOE of utility-scale PV in 2000 is unavailable, since 'utility-scale' PV has only been observed since the mid-2000s, so our value is generated using the 2000 module price of $4.82/W (from ITRPV 2015 [35]), a 2000 inverter price of $0.55/W (from Fraunhofer 2015 [99]), and a BOS price of $2.25/W, at a world-average capacity factor of 17.1% and using other assumptions noted above for the conversion of system price to LCOE. Values given here do not factor in the avoided cost of electricity from coal or the world average generation mix (i.e., the LCOE of coal or average grid electricity is not subtracted from the LCOE of PV and wind); actual CO_2 abatement per dollar would thus be higher if these avoided costs were factored in.

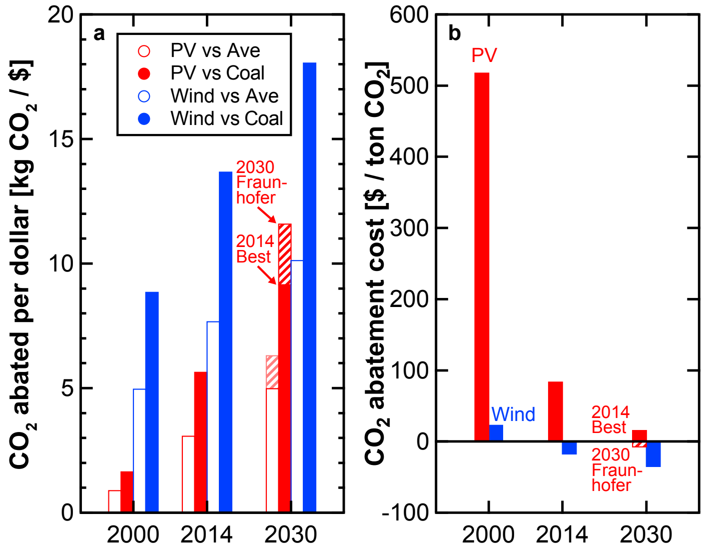

Figure 4.14: Evolution in CO_2 abatement cost for wind and PV over time. a, CO_2 abated per dollar invested in energy from PV (red) and wind (blue) when these sources are used to replace energy from the 2010 world average electricity mix (empty bars) and from coal (filled bars). Data sources are noted in the text. '2030 Fraunhofer' and '2014 best' represent the choice of 2030 BOS assumption for PV; all other 2030 assumptions (wind LCOE, PV module, PV inverter) use the Wright's Law projections described in the text. The cost of energy from coal or the average electricity mix is not subtracted from the LCOE of PV and wind. b, Marginal cost of CO_2 abatement by replacing electricity from coal with electricity from PV (red) or wind (blue). Here the current world average LCOE of coal (83 \$/MWh, from WEC 2013 [47]) is subtracted from the LCOE of PV and wind to provide the net cost of abatement. Considerations regarding integration costs and the value decline of PV and wind at high penetration are described in the text.

a subsequent dollar of investment—should hold until the point when the commodity cost floor of wind and PV is reached (a point well beyond the timespan considered in this study, as noted before).

Costs of renewables integration

Due to the sometimes unpredictable and uncontrollable nature of renewable electricity generation, large-scale renewable integration has additional costs not typically associated with traditional electricity generation. These costs arise when there is a temporal or spatial mismatch between electricity generation and electricity demand. Forecast errors can lead to differences between available power and commitments in the day-ahead market. Uneven resource availability can require costly transmission grid upgrades. And anti-correlation between demand and renewable generation can lead to renewable electricity being sold to the grid at times of lower-than-average prices. These factors can all lead to declines in the value of renewables as their level of market penetration increases [128, 129]. Renewable electricity, with its short-term variability, can also incur additional costs associated with ancillary services that adjust for short-duration differences between supply and demand [130].

A range of technological and infrastructure solutions have been proposed to mitigate these integration costs of renewable energy. These solutions tend to focus on energy storage, improved transmission, and demand management [131]. Bulk energy storage enables the temporal shifting of electricity availability, allowing renewable generators to sell electricity at times of higher prices, thus raising the marginal value of increased renewables capacity. Bulk energy storage does come with direct costs of its own, in terms of the new storage infrastructure and possibly additional transmission requirements. A diverse set of storage technologies in various stages of development are expected to lower the cost of electricity storage significantly. Many of the lowest cost technologies for bulk storage available today, such as pumped hydro storage and compressed air energy storage, tend to be location-constrained. Other storage technologies such as batteries do not have geographic constraints and have shown consistent cost reductions over time [132].

To mitigate costs due to spatial mismatch, increased investment in transmission infrastructure will allow for improved plant siting—i.e., locating renewables where resource availability is greatest, regardless of the distance from load centers. Additional transmission infrastructure will also provide natural smoothing of the short-term output of renewables [133]. Long-distance transmission can help reduce power fluctuations in wind and solar output as more geographically distant sites will have lower correlations in resource availability [134]. The adoption of storage or demand management techniques is expected to require further transmission improvements as well [135].

Finally, demand management technologies and policies work to more closely match electricity demand with electricity generation by incentivizing reductions in demand at times of lower resource availability [136]. Matching demand and generation on both short and long time scales mitigates both the loss in marginal value experienced by renewables at higher penetrations and the grid stability concerns associated with variable generation. Some proposed demand management schemes aggregate household or commercial loads and sell demand reductions to utilities [137].

Even with investments in bulk energy storage, additional transmission infrastructure, and demand management, lower-carbon, combustion-based technologies such as combined cycle gas turbines (CCGTs) can provide an important bridge toward widespread solar and wind integration. In the event of longer-than-expected disruptions in renewable production or dramatic spikes in demand, CCGTs can quickly spin up to meet demand, a capability that can obviate the need for investment in storage or transmission infrastructure to cover these rare events [138, 139]. Targeted investment in natural gas generation capacity will allow for faster widespread deployment of renewable technologies at lower cost and with less risk of supply disruption.

5. Conclusions and Discussion

Our results demonstrate that stimulating technology innovation through climate policy can amplify emissions reductions beyond the immediate gains that come from deploying a low-carbon technology. As the past data on solar and wind energy demonstrate, this amplification effect can result in a significantly decreasing cost of abating carbon as abatement efforts grow. Looking forward in time, under voluntary mitigation plans submitted by nations in advance of the COP21 meeting (INDCs), the growth in solar and wind energy could be significant, reaching a 3- to 4-fold increase in installed capacity. While solar and wind energy technologies stand to continue to decline in cost over this period, integration challenges will likely grow. We present a summary of our results here, and posit that climate negotiations offer a unique opportunity to support the development of low-carbon energy technologies. Furthermore, recognizing rates of technology development over time may help nations agree on a plan to collectively reduce greenhouse gas emissions.

Recent technology development strengthens emissions reduction potential

The data demonstrate a significant decline in solar and wind energy costs that was driven by the efforts of a few nations to support market growth and research in these technologies. Despite changing policies over time in these nations, taken together as a group they supported incentives that industries responded to, resulting in a steady growth in the markets of these technologies. Their effort was not coordinated but its pattern resembles a relay race, with countries trading off the leader's baton as efforts from individual nations rose and fell. The cumulative result has been a decline in the cost of photovoltaics unprecedented among energy technologies, and a substantial fall in wind electricity costs.

From 1976 to 2014, real costs of PV modules declined from $\sim$104 \$/W to $\sim$0.67 \$/W, a 99.4% decrease. Wind electricity costs fell from $\sim$261 \$/MWh in 1984 to $\sim$68 \$/MWh in 2014, a 74% decrease. On a globally averaged basis wind is now estimated to be competitive with fossil electricity. In some regions such as China, coal- and natural gas-fired electricity remain less costly than wind. Solar is competitive in some regions, though the global average photovoltaics cost of electricity is still twice that of the central estimate for coal and natural gas electricity. However, when the estimated external costs of air pollution are accounted for, both wind and solar energy costs are comparable to coal.

Past trends illustrate the reinforcing effect that technology development can have on reducing greenhouse gas emissions. For the same inflation-adjusted investment, 100 times more PV modules can be produced than 40 years ago. Accounting for full installation costs (including balance-of-system components and inverter), roughly three times more low-carbon solar can be deployed than just 10 years ago. As nations have committed to growing markets for these technologies, the cost per unit carbon avoided with solar and wind has dropped dramatically. While a causal relationship is difficult to pin down, a variety of research suggests that this cost decline has been supported by design innovations, scale economies in manufacturing and installation size, and improvements to production efficiency [105, 140, 141, 48, 49, 107]. These firms have capitalized on growing knowledge over time from a combination of public and private research.

Potential for sizable renewables expansion and further cost decline under INDCs

Under voluntary commitments submitted by nations in advance of the COP21 meeting, the global installed capacity of wind and solar could grow significantly. In a renewables-focused scenario, global installed capacity of solar would grow by a factor of 4.9, and wind by a factor of 2.7. Much of this growth could happen in China, the U.S., India, and the EU. China's wind and photovoltaics capacity could grow by factors of 8 and 3, adding roughly one third of cumulative wind and photovoltaics capacity additions between 2014 and 2030. At a global scale, it is estimated that wind and solar would provide 8.9% and 3.8% of electricity under these scenarios.

We investigate various scenarios for future cost reductions under these projected expansions. These scenarios are conditioned on past technology development trends and potential cost floors. Generation costs vary significantly by location, but under a variety of scenarios the global average PV cost is expected to reach within about 25% above to 6% below the average cost of natural gas- and coal-based generation by 2030. These comparisons assume unimproving costs of NGCC and coal, as has been observed in recent decades. In the fastest growth scenario that we studied, PV modules follow Wright's Law, and PV BOS costs reach projected declines due to improvements such as increasing module efficiency and system size. In more modest cost decline scenarios, BOS costs fall but module costs remain the same. Wind energy, if it sustains historical rates, stands to drop 24% in cost, and would cost significantly less than other sources by 2030.

Projections into the future are inherently uncertain, but conclusions can be drawn that are robust to these uncertainties. Under a wide range of cost evolution scenarios, wind and solar energy are widely cost competitive with other sources by 2030. Even if wind costs remained constant this technology is already widely competitive. China is an exception: Due to lower coal-fired energy costs in China, solar and wind are both expected to have higher energy costs, even in 2030. However, when health impacts of coal and natural gas are monetized and included in electricity cost estimates, solar and wind energy in China are both expected to fall within the cost-competitive range.

The potential for technology development to amplify emissions reductions is evident in these projections. The more that countries and firms commit to developing renewables, the faster the cost of doing so is expected to fall. This translates to a decrease in the cost of reducing emissions with these technologies over time. At today's cost, reaching a global commitment of installing 1014 GW of wind in 2030 would cost \$1.32 trillion. If projected cost declines are taken into account, we estimate the same investment would actually purchase 1207 GW—a 20% increase. Thus projected cost declines would permit a 20% increase to emissions reductions commitments without changing total cost of deployment. Taking into account cost declines for solar, a global commitment of 858 GW could be increased to 1210 GW, yielding a 40% increase to commitments without changing cost of deployment. Our projected cost of abating CO_2 emissions from a coal-fired power plant with wind is actually negative: -35 \$/ton CO_2. For solar, the projected abatement cost varies from +15 \$/ton CO_2 to -8 \$/ton CO_2.

Growth to these levels will require addressing the intermittency of solar and wind as the market share of these technologies grows. Intermittency compromises the ability of energy supply to meet demand, and can reduce the revenue of power plants. Storage technologies, long-distance transmission, and demand response can all play a role in addressing these issues, but further development is required. In the case of storage and long-distance transmission a key challenge is to reduce costs, while demand side management will require innovation in information systems and incentive structures to encourage participation.

Technology as pathway to consensus, negotiations as opportunity for technology development

Our results suggest that an awareness of technology development over time could change the way in which the prospects for emissions cuts are viewed. As more effort is invested, technologies tend to improve. This observation has significant implications for reaching consensus across nations at different stages of economic development, which is one of the most difficult hurdles faced in the negotiations.

Falling low-carbon energy costs over time should enable a smooth transition to decarbonization by nations at different levels of development. By the time the least developed nations are required to cut emissions, technology development through a global collective effort should make doing so a benefit rather than a burden. Early cooperation now to ease a future transition can be enabled by international efforts to achieve equitable financing and knowledge sharing. In some cases, as evidenced by INDC commitments in China, India, Costa Rica and Peru, nations with economies that are still growing rapidly, perceive opportunity in transitioning to a low-carbon energy mix sooner rather than later.

While technology development may help build consensus, the platform of the COP meetings can help support low-carbon technology development at a global level. This uniquely inclusive gathering of nations, and the recent prioritization of climate change mitigation among many heads of state [142, 143, 144, 145, 146], opens up powerful opportunities to address several technology development challenges. These include reducing hardware costs [147, 148], supporting access to favorable financing across nations [149], and sharing knowledge on the 'soft costs' of installation and permitting [147, 150, 148] and successful ways to grow renewables industries. As seen in the historical data we present, improvements to modular hardware—which can be manufactured in one location and installed in another—are globally accessible. The case of PV illustrates this point. PV modules and inverters have fallen in cost over the years, and these cost improvements have been accessible to all through the global marketplace for PV modules. However the soft costs of installation, including labor, permitting and on-site construction costs, still vary significantly across the globe [150].

Knowledge sharing and compiling best practices can help bring costs in different locations in sync (though some variability may remain across nations). Knowledge sharing will itself require innovation. In the public sector, this could come through the creation of incentives, for example. In the private sector, it could come through information technology development. Other examples of technological opportunities include storage hardware and home energy systems to achieve demand side management. Both could play a significant role in supporting renewables integration. The platform of international climate negotiations provides a unique opportunity to pursue these objectives given its inclusiveness and high-level support.

We highlight the opportunity that climate negotiations offer for technology development, and the role that technology can play in reaching consensus. Several recommendations emerge from our work:

- Nations should recognize the opportunity that these negotiations bring. Recent technology improvement arguably shifts the development of energy technology to mitigate emissions from burden to opportunity for governments and firms. Technology development can be seen as a return to cutting emissions. Recognizing the size of these returns should help nations reach consensus.

- Market growth should be further stimulated by public policy. Knowledge sharing on policies and the soft costs of technologies, including labor, permitting and installation, will be important. Efforts to offer equitable financing will also be critical.

- Drawing lessons from policies that successfully grew PV and wind markets, technologies that can support renewables integration should be incentivized. These include energy storage, long-distance transmission, and demand side management.

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