COMPETITIVENESS OF RENEWABLE-GENERATION RESOURCES

A Review of the Role of System Integration Costs, Regional Differences, and Externalities

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Preface and Acknowledgements

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COMPETITIVENESS OF U.S. GENERATION RESOURCES
A Review of the Role of System Integration Costs, Regional Differences, and Externalities

Introduction

The rapid expansion in recent years of renewable-power-generation capacity in the United States and elsewhere around the world suggests that wind and solar can be competitive with traditional power technologies. That is certainly the message from news headlines, often based on levelized cost of electricity (LCOE) calculations and long-term power purchase agreement (PPA) prices. However, generic LCOE estimates cannot be generalized across wider geographies. PPA prices could be misleading unless policy drivers of these prices are also discussed. "Grid-parity", primarily used for distributed energy resources (DER) such as rooftop solar, is another confusing term as it compares the cost of new DER to the retail cost of electricity delivered to customers (i.e., inclusive of costs for transmission and distribution, or T&D) rather than generation cost of a new investment.[1]

Costs Trends, Contract Prices, and Subsidies

The costs of renewables components have been coming down, especially for solar photovoltaic (PV) panels. Given the decline in manufacturing and installation cost of wind turbines and panels, large-scale wind and solar projects can be built and start generating cheaper electricity than thermal generation in some locations with highest wind speeds or best solar insolation and with existing grid access, especially if there is no natural gas delivery infrastructure to enable natural gas generation and/or the price of natural gas fuel for generation is "high." However, such cost competitiveness is not generalizable. Wind and solar facilities cannot be developed competitively in locations with poor wind speed or solar insolation, especially if there is access to "cheap" natural gas.[2]

Despite falling component costs, most projects would not have been developed without subsidies and mandates (e.g., renewable portfolio standards, or RPS, programs) by federal, state, and local governments.[3] Griffiths et al. (2017) compiled data on federal financial support mechanisms to electricity generation technologies in recent years, including production tax credits (PTCs) used primarily for wind and investment tax credits (ITCs) used primarily for solar,

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[1] There is an ongoing debate around net energy metering (NEM) policies that encourage the adoption of DER by allowing customers with DER to sell excess generation back to the grid at retail prices. Since retail rates are still regulated in most jurisdictions, these policies are challenged by local utilities because they undermine revenues, and shift fixed costs to customers without DER installed on their residences or businesses. The counterarguments highlight the value provided to the system by DER.

[2] "High" and "cheap" are intentionally vague because the competitiveness of new power plants will depend on other regional factors such as load profiles, generation portfolios, quality of wind and solar resources, and so on. However, regardless of these factors, natural gas prices above $5/MMBtu can be considered high and those less than $3/MMBtu can be considered cheap.

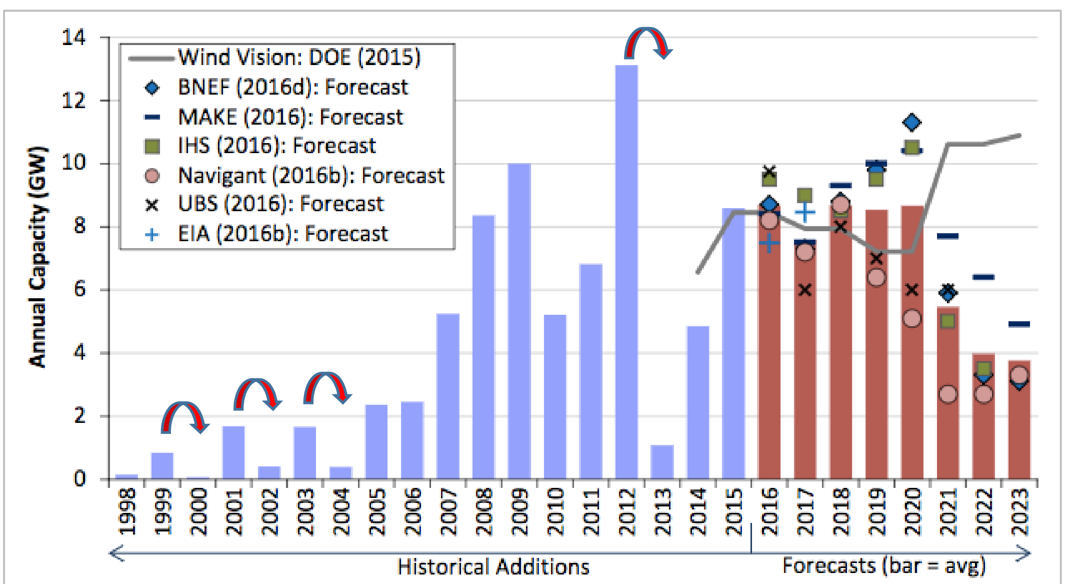
[3] Other studies reached similar conclusions (MIT, 2015; Platzer, 2015).

and concluded that solar benefited the most (declining from a peak of $321/megawatthour, or MWh, in 2013 due to one-time ARRA[4] funding to $43/MWh by 2019) and wind the second most (declining from peak ARRA level of $57/MWh to $15/MWh).

Although total support for fossil fuels is roughly equivalent to that for renewables, per-MWh support is in the range of $1–$2/MWh. The per-MWh cost is small because the support is not directly provided to the generation technology but rather the fuel extraction (e.g., natural gas drilling cost credits and depletion allowances), mitigation of negative externalities (e.g., federal funding for emissions from coal combustion), or insurance (e.g., the Price-Anderson Act limited liability pool for nuclear). Since only a third of marketed natural gas is used for power generation and gas-fired plants can operate at much higher capacity factors, per-MWh federal financial support is very low. A similar study of state-level financial support (Griffiths et al., in press) indicates that California supports solar at about $140/MWh and wind at about $45/MWh. The state support would be in addition to federal support in many cases. Other states and many municipalities provide financial support in myriad ways that cloud analysis of cost competitiveness of energy technologies and fuels.

As shown in **Figure 1**, every time the PTC program was allowed by Congress to expire at the end of the year and not renewed quickly, wind-capacity additions fell significantly (1999–2000, 2001–02, 2003–04, 2012–13). The most recent extension of federal tax credits in early 2016 encouraged a new wave of investments. The PTC gradually declines by 2020, after which most outlooks forecast a drop in wind installations.

Figure 1: Historical and Forecast U.S. Wind-capacity Additions



Source: AWEA (historical additions), individual forecasts, DOE 2015 (Wind Vision)

Source: Wiser and Bolinger (2016)

[4] American Recovery and Reinvestment Act of 2009.

State RPS mandates do not provide direct financial incentives but often call for trading of renewable energy credits (RECs). In some markets, **REC prices were as high as $50/MWh in 2016**. In other markets, REC prices fell to the $0–$2/MWh range once the RPS target was reached. But these targets can be reset. Some states have specific targets for the share of solar. Solar REC prices were above $600/MWh in 2010–11 in New Jersey in response to aggressive targets set by a state that also happens to have low solar insolation (i.e., with low capacity factors for solar) and also a high cost of solar panels at the time. Despite lower panel costs, solar RECs remain expensive in some regions*.* **In 2016, solar REC prices in Washington, D.C. and Massachusetts, two other low-insolation regions, were between $450 and $500/MWh.** In other northeastern states, solar REC prices continue to be higher than regular REC prices.

Crucially, the prices offered by wind and solar developers in power purchase agreements (PPAs) reflect the incorporation of federal, state and local support mechanisms into project economics and financing. **PPA prices do not reflect the naked cost of production from a new facility.** Still, they have been higher than average wholesale prices in some markets (e.g., the ERCOT market). Also, the persistent lack of profitability for many renewables developers suggest that PPA prices are too low.[5]

In fact, concerns about the lack of profitability are increasing within the renewables sector. Wind and solar have near-zero operating costs (the "fuel" is free). Often, they get dispatched at negative prices to take advantage of tax credits. Also, as the share of renewables capacity increases, wind and solar output have to be curtailed because of excess generation, causing them to lose more revenues. This suppression of wholesale prices will increase as the share of renewable generation increases (e.g., solar in California). Low prices undermine revenues to levels insufficient to recover capital costs. It is difficult to envision new generation capacity investment in such a low-price environment without continuation of tax credits or mandates, or a form of integrated resource planning approach where costs can be incorporated into regulated rate bases.

A vicious cycle seems to be triggered as some states started to offer subsidies or tweaked their market design to create additional revenue sources to thermal generators, most visibly some nuclear units. It is difficult to see how a competitive electricity market can be sustained when a large percentage of generation capacity receives "out-of-market" compensation of some sort.[6]

There is a vicious cycle in the international sphere as well. An anti-dumping trade petition was filed with the U.S. International Trade Commission in 2017 by two U.S. manufacturers against

[5] In a separate paper, we report financial results from the solar industry. In many cases, financially engineered business models (e.g., yieldcos) are constructed in which public support backs debt instruments for capacity investments. Yieldcos were modeled after the Master Limited Partnerships, MLPs, that benefited the oil and gas midstream industry for a long time Solar yieldco metrics tend to revolve around the number of installations (in the case of rooftop development) or growth in dispatched generation (in the case of grid-based projects). Financing schemes that chase capacity additions, subsidy-driven behavior and transmission-curtailed underutilization result in poor profitability of renewable generation.

[6] See Gülen et al. (2016) for a discussion of challenges facing competitive markets.

PV imports from China and elsewhere. The petitioners were asking for tariffs that would nearly double the cost of imported PV panels.[7] Manufacturing accounts for a very small portion of solar-related jobs in the United States. As a result, the wider U.S. solar industry opposed the petition. In early 2018, the U.S. announced a tariff of 30% that will decline 5% a year until it reaches 15%. According to an analysis by GTM Research, 47 gigawatts of direct current (GW_{DC}) of planned solar installations were considered at risk if the original tariff request were granted.[8] GTM's updated analysis in 2018 predicted a reduction in solar installations of only 7.6 GW_{DC} through 2022.[9]

System Integration

With increasing penetration of renewable energy in the power system, grid operators face new operational challenges associated with the intermittency and variability of renewable generation. Even subtle variations in wind and solar resources require voltage and frequency controls to protect energy systems and ensure reliability. Managing these resources requires a variety of tools such as balancing energy and backup capacity (typically from conventional generation sources) or, alternatively, some form of external energy storage (such as pumped hydro)[10] to ensure delivery of electric power and reliability of electric power systems. Some of these distortions are managed by system operators using new or modified ancillary services that are mostly priced in the market; but, others are managed via out-of-market compensation.[11]

Often, new transmission investment is necessary to accommodate wind and solar from the best locations that are located far away from major load centers. As the share of renewables increase, they risk getting curtailed especially when transmission capacity cannot be increased at the same pace. In many systems, the cost of new transmission capacity is uplifted (or, "socialized") across the entire market, which partially explains why retail costs per unit of

[7] In the early 2010s, other anti-dumping cases were fought by European and U.S. manufacturers versus Chinese manufacturers.

[8] http://www.utilitydive.com/news/gtm-proposed-solar-tariffs-could-put-47-gw-of-planned-installations-at-ris/445901/.

[9] https://www.greentechmedia.com/articles/read/tariffs-to-curb-solar-installations-by-11-through-2022#gs.Bo8yTnQ.

[10] Although much discussed in the media, batteries do not play a significant role yet. Batteries are typically used for frequency control and other grid services but not for large-scale backup of intermittent resources. Less than one GW of battery storage are online as of the end of 2017 although a faster build-out is expected in near future as a result of declining costs and state mandates. Rapid build-out will enhance the impacts of battery demand from electric vehicles and have repercussions up the minerals supply chains. For example, lithium prices have tripled and prices of other minerals such as cobalt have also increased in 2017. These price signals will likely induce new investment in mining, processing, and transportation capacity. However, geopolitical and environmental impacts of these mining operations will also become more visible. CEE research highlights these uncertainties. Some call this the "new" resource curse (e.g., O'Sullivan et al., 2017).

[11] Increased cycling of dispatchable plants (typically, conventional thermal) to accommodate renewable generation reduces thermal-power-plant efficiency, resulting in higher fuel consumption and higher emissions per kilowatt hour (kWh) produced, and causes more wear on the equipment.

electricity have remained stable or even increased in some regions despite falling wholesale electricity prices.

More importantly, near-zero dispatch cost of renewables and frequent negative bidding lowers the average wholesale price and hurts the financial viability of existing conventional generators and, increasingly, renewables generators themselves. Negative bidding occurs because of transmission constraints and/or over-generation relative to demand at any point in time. Wind generators cannot collect their PTCs unless dispatched. As such, negative prices typically have a floor roughly equivalent to the PTC. Existing generators also lose revenue because they generate less to accommodate renewables.

Lost revenues by conventional generators that were built under the expectation of a competitive market are stranded costs as the rules of the games have been changed on these investors by government policy. This is akin to stranded cost recovery granted to regulated utilities when markets were restructured in the 1990s. Low natural gas prices, which reduce wholesale electricity prices, and new, or the threat of new, environmental regulations (such as Mercury and Air Toxics Standards, MATS, or the proposed Clean Power Plan, CPP, to reduce greenhouse gas or GHG emissions) have been the main drivers of more than 50 GW of thermal capacity retirements since the early 2010s. Policy-driven penetration of renewables triggered the early retirement decisions in many cases. In reaction, many state regulators, governments, and electric system operators have been developing policies or implementing market design changes to save some of the existing thermal plants.

Societal Benefits

On the other hand, renewables offer certain societal benefits. Multiple policy drivers create the growing appetite for renewables, including environmental concerns associated with conventional energy sources (air, water, land),[12] energy security, and the desire for developing local economies via domestic manufacturing. Increasingly, *decarbonization* has become a driver. Competitive electricity markets do not price externalities such as environmental impacts of fossil-fuel generation unless direct, including market-based, policy intervention is taken; nor do they inherently enhance energy security or fuel local economic growth although economic theory and empirical evidence suggest that competition and choice lead to efficiency and innovation. Many economists argue for taxing carbon so that electricity prices reflect the social cost of GHG emissions. Alternatively, a cap-and-trade market design can be used. This approach has been successfully used before in reducing sulfur dioxide or SO_2 emissions but cap-and-trade

[12] Renewables also have environmental impacts on land (e.g., utility-scale PV has a larger footprint per megawatt than do conventional energy technologies) and species (e.g., avian, desert, coastal or offshore ecology), as well as the environmental impacts associated with mining, processing, and transportation of minerals necessary for manufacturing renewable-technology equipment. Increasingly these latter impacts include batteries, that are seen as mitigating intermittency, and battery supply chains. These impacts grow along with the scale-up of installed renewables capacity. As such, in the future, the discussion around perceived environmental benefits of renewables technology and battery energy storage may shift.

experiments with carbon have mostly failed around the world for a variety of reasons including political oversupply of emissions permits.

In the absence of a carbon tax or market, states have been experimenting with alternative policies to reduce GHG emissions, including renewables mandates. Whether subsidized renewables is the least-cost option and best available alternative for internalizing externalities (e.g., reducing GHG emissions) or to achieve any of the other objectives is a question worth investigating but is beyond the scope of this review.[13] The bottom line is that any holistic comparison of costs needs to include costs of externalities and mitigation tradeoffs as well as system integration costs.

Focus of This Review

In this review, we investigate the competitiveness of renewable generation resources in a more holistic approach. To be comparable with mainstream discussions, we evaluated generation-technology costs using the LCOE approach. LCOE is a commonly used metric to compare the cost of various power-generation technologies but it is flawed as a policy tool. It only considers overnight capital, operating, and fuel costs, and basic operational characteristics of heat rate and capacity factor. A more complete estimate would include other costs, including regional variation of inputs, externalities, and system-integration costs. Rhodes et al. (2017) contributes significantly to the understanding of how regional variations and externalities could matter. Using estimates from existing literature, we present a new set of LCOE estimates, including system integration costs. We also offer an LCOE for existing facilities. In a world of stagnant or declining load, existing facilities are often the cheapest options to meet demand because their capital costs are mostly amortized.

Levelized Cost of Electricity (LCOE): Conventional Formula and Drawbacks

LCOE is the metric most commonly used to compare the economics of generation technologies for a new plant, typically on a per megawatt-hour (MWh) basis. Several publicly available sources for LCOE are given in **Table 1**. Differences in assumptions lead to different LCOE estimates across these sources.

It is important to note that LCOE is mainly used by the media and high-level policy discussions. Power plant developers do not use LCOE in their assessment of investment opportunities or in integrated resource planning (IRP), where existing resources are an integral part of the evaluation process. Nevertheless, LCOE-driven policies could impact their investment decisions. Investors consider many region-specific factors, including but not limited to subsidy policies at state or local levels, existing generation portfolios including expected retirements and other

[13] The National Research Council (2013) offers an interesting data point: "If the revenue lost as a result of the PTC/ITC is divided by the reduction in CO_2 emissions, just under $250 in revenues are lost per ton of CO_2 reduced. While this does not represent the social cost of reducing the ton of CO_2 emissions (because revenue losses are not a dead-weight loss, as explained in Chapter 2), the fiscal cost per ton of CO_2 reduced is high relative to other, more efficient approaches."

potential new builds, load growth potential, grid topography and access to grids, access to fuel infrastructure, ability to contract, and policies regarding environment, distributed generation, demand response and other elements of the power system.

Table 1: Sources of Commonly Referenced LCOE Estimates

Organization/Institution	Source
Lazard	Levelized Cost of Energy Analysis[14]
U.S. Energy Information Administration	Annual Energy Outlook[15]
U.S. National Renewable Energy Laboratory	Levelized Cost of Energy Calculator[16]
International Energy Agency	Projected Costs of Generating Electricity[17]
Energy Institute at UT-Austin	Full Cost of Electricity Calculators[18]

The conventional formula for LCOE captures overnight capital cost and its financing costs (capital recovery factor, CRF), operating and maintenance costs (fixed O&M, FOM, and variable O&M, VOM), fuel costs (the product of the fuel price and the plant heat rate, HR[19]), and annual expected generation (the product of 8760 hours in a year and capacity factor, CF, of a technology[20]).

$$LCOE = \frac{CRF \times capital + FOM}{8760 \times CF} + VOM + HR \times fuel\ price$$

This representation of LCOE is a misleading indicator of competitiveness and does not capture any of the social costs of different generation technologies because it ignores many factors, including the following:

- Regional differences of its components (capital costs, FOM, VOM, fuel price, HR and CF)
- Externalities (emissions, impacts on water and land, waste disposal)
- System-integration costs (balancing, grid costs, curtailment costs, stranded assets)

The subsequent sections discuss each item in greater detail.[21]

[14] See https://www.lazard.com/perspective/levelized-cost-of-energy-2017/.
[15] See https://www.eia.gov/outlooks/aeo/electricity_generation.cfm.
[16] See http://www.nrel.gov/analysis/tech_lcoe.html.
[17] See https://www.oecd-nea.org/ndd/pubs/2015/7057-proj-costs-electricity-2015.pdf.
[18] See http://calculators.energy.utexas.edu/.
[19] Heat rate is the efficiency of a plant in converting energy content of the fuel into electricity.
[20] Capacity factor is the ratio of the net electricity generated for the time period considered (typically a year) to the energy that could have been generated at continuous full-power operation during the same period. See https://www.nrc.gov/reading-rm/basic-ref/glossary/capacity-factor-net.html.
[21] One could add subsidies to the list as well. However, given the variety of subsidies at different government levels and disagreements regarding what constitutes a subsidy, we exclude them in this report. Griffiths et al. (2017) and Griffiths et al. (2018) provide some $/MWh estimates for federal and state subsidies, respectively, while highlighting the difficulties of dissecting subsidy debate and data. It is worth noting, however, that subsidies at different levels of government (federal, state, city) impact financing terms (i.e., CRF).

Regional Differences

Many components of LCOE—overnight capital expense, financing costs, operating costs, fuel prices, and capacity factor—vary across regions. Rhodes et al. (2017) use regional multipliers from EIA (2013) for capital and fixed operating costs, historical data from various sources on average annual generation, and natural-gas-hub prices to estimate LCOE for each technology across all counties in the United States.[22]

Widely Varying Annual Generation across Regions

Conventional LCOE often gives the impression that the same capacity factor applies across all geographies. **In fact, the capacity factor changes significantly for all technologies across geographies. The range is much wider for wind and solar because the quality of wind speed and solar insolation varies widely across different geographic areas** (see **Appendix 1** for resource maps of wind and solar PV in the United States). Lazard (2017) offers wind and solar LCOEs for five aggregate regions in the United States, which is not granular enough to capture the variability of the capacity factor. To a much lesser extent, heat rates for thermal plants also vary by region because of changes in ambient conditions (temperature, humidity).

Inconsistent Use of Historical versus Technical Capacity Factors

Thermal-generator-capacity factors used in LCOE calculations are typically based on historical utilization, which is a function of system characteristics such as electricity-demand (load) profiles, mix of generation assets, fuel prices, and transmission bottlenecks. As such, historical CFs do not reflect "technical" capability of those plants.

For example, in many regions, natural-gas combined-cycle (NGCC) plants were utilized at an average capacity factor of 50% or less because of overbuilding of generation capacity, lack of load growth, higher fuel prices at times, and the increased penetration of renewable resources. After the retirement of more than 50 gigawatts (GW) of coal-fired capacity between 2010 and 2017, the utilization of many gas plants in regions of heavy coal retirements started to increase. In short, **using a "historical" capacity-factor value in calculating LCOE of an NGCC leads to a higher LCOE than that warranted by the technical capability of an NGCC**. This is also true for all dispatchable resources (e.g., coal and, to a lesser extent, nuclear).

In contrast, a "technical" capacity factor is often used for wind and solar mainly because these variable resources get dispatched in full when they are available as long as there are no transmission constraints. Wind and solar technical capacity factors are often based on annual generation profiles developed by the National Renewable Energy Laboratory (NREL), or others via engineering analysis. Increasingly, historical data guide these estimates.

However, **the use of a technical capacity factor is inconsistent with the use of an historical capacity factor for dispatchable plants and may be artificially reducing the LCOE of wind and**

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[22] Since any of these assumptions can change over time and some interested parties may have more accurate data on their region, two online calculators are provided: http://calculators.energy.utexas.edu/.

solar. As shares of wind and solar increase, they are curtailed more regularly, because of either transmission congestion or generation in excess of demand. More historical data are becoming available and are being used to develop more-accurate annual hourly generation profiles and average capacity factors.

To be consistent, LCOE calculations for all technologies should use technical capacity factors determined by engineering design. In locations with transmission constraints, an adjusted LCOE (with a lower CF) would be more accurate. Or, alternatively, LCOE with technical CF can be increased by the cost of transmission expansion that is necessary to connect the new resource.[23] The use of historical CFs is not recommended as these change as conditions change per earlier discussion.

No Capture of System Dynamics

Although using technical capacity factors would improve the interpretation of LCOE across geographies, doing so still falls short of capturing the dynamic nature of electricity systems. For example, increasing penetration of intermittent and variable resources can reduce the capacity factor for thermal resources, because they are forced to cycle more often to accommodate variable resources. However, **some thermal resources will still be needed to balance variable and intermittent generation, so having a higher LCOE does not mean much**. Helm (2017) recommends an equivalent firm power (EFP) contract for capacity, which would require intermittent resources to contract directly with backup generation capacity. These contract costs would increase the LCOE of intermittent resources and render them more comparable to dispatchable resources.

In different regions, different dispatchable resources can provide the balancing and backup services. For the foreseeable future, these will likely be simple-cycle thermal units but even the combined-cycle gas turbines and coal plants have been used for these purposes.

Wide Range of LCOE Estimates

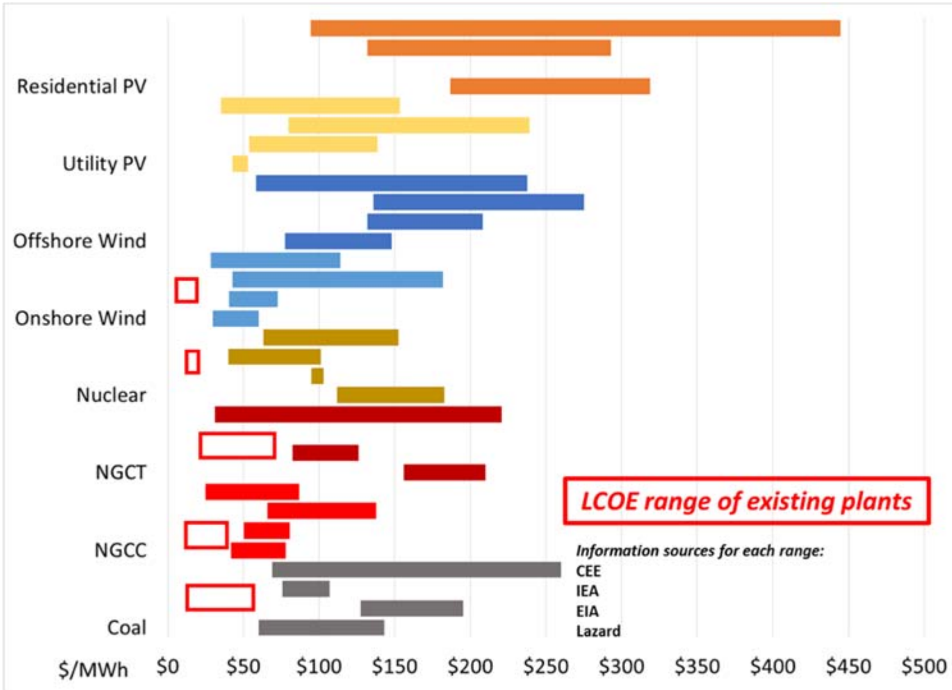
In **Figure 2**, we summarize the minimum and maximum LCOE estimates from various sources. The wide range is a reflection of regional differences (capital costs, FOM, VOM, fuel price, HR and CF). Different assumptions regarding technology (e.g., thin-film versus crystalline PV) can influence CF values. Financing costs can also differ across sources. Empty red boxes reflect our attempt at offering a sense of how much it costs to produce from existing power plants.

Our (CEE) ranges are typically larger than the others because we use the most extreme U.S. values for each component of the LCOE formula from multiple sources. For many components, the extreme values are either from Rhodes et al. (2017) or Lazard (2017). Lazard (2017) offers the lowest LCOE estimates for utility-scale solar PV and wind plants with narrowest ranges. Lazard (2017) estimates for gas and nuclear plants tend to be higher, at least at the higher end of the ranges mainly due to natural gas price and CF assumptions.

[23] The FCe calculator allows for the user to add transmission costs.

Figure 2: Range of Conventional LCOE Estimates Due to Regional Differences

*Excluding externalities, system-integration costs, and subsidies ($/MWh)**



*For each technology, sources are (from top to bottom) UT-Austin Bureau of Economic Geology's Center for Energy Economics (**CEE**), **IEA** (2015), **EIA** (2017), and **Lazard** (2017). See References for details.

The International Energy Agency (IEA) estimates are based on data from 181 actual plants in 22 countries, including the United States prior to 2014. On average, IEA (2015) estimates tend to be lower for coal and nuclear, because many countries building these facilities do not experience the same cost structures of U.S. projects (higher costs for labor, material, compliance with environmental and safety regulations). In contrast, the IEA's NGCC costs are much higher, because of the higher cost of natural gas, which is often linked to the oil price in most of the countries (except for the United States) in the IEA sample. IEA costs for wind and solar reach higher levels than those of most U.S. estimates, which may be explained by the older data (costs have come down since 2014) and the higher cost of projects in Japan.

The following is a summary of key differences in input assumptions among the sources.

- Natural-gas price assumptions cover a wide range. Lazard (2017) assumes $3.45/MMBtu, while CEE utilizes $2.33/MMBtu for the minimum estimate and $5.00/MMBtu for the maximum estimate. Nationwide, the price of natural gas delivered to electric power plants averaged $3.3/MMBtu between 2015 and 2017. In certain regions such as near the Marcellus shale play, natural gas prices have been lower.[24] International projects captured

[24] As a result of cheap natural gas and coal retirements, gas-fired capacity has been expanding significantly in the Marcellus region.

in IEA (2015) typically have higher natural-gas prices because these are tied to the price of oil in many countries and reflect 2014 or earlier projects (i.e., before the oil price decline in late 2014).

- Lazard (2017) maximum-capacity factor for onshore wind (55%) and utility-scale PV (32%) are the highest CFs reported in the literature and are probably limited to best resource locations without transmission congestion or over-generation challenges. Maximums from Rhodes et al. (2017) are 51% and 26% for onshore wind and utility-scale PV, respectively. These differences lead to a more-than-$2 increase in minimum LCOE for onshore wind and an $8 increase in minimum LCOE for utility-scale PV.
- Capacity factors for NGCC cover a wide range. Lazard (2017) range is from 40% to 80%. Technical CF for NGCC can be 80% or higher in a system where gas plants form the baseload and are not forced to cycle. EIA (2017) has as high as 87%.
- Weighted average cost of capital (WACC) assumptions vary significantly. Lazard (2017) uses 9.6% for all plants; IEA (2015) uses 7%; EIA (2017) uses 5.5%; and CEE uses 5.5% to 9.6%, depending on plant type and minimum vs. maximum estimates.
    - The higher the WACC, the greater the LCOE increase for higher capital-cost technologies. For example, if we increase the WACC from 6.4% to 9.6%, keeping all else the same, the LCOE for NGCC will increase by 11%, while the LCOE for onshore wind increases by 21% and the LCOE for utility PV increases by 24% given their higher capital intensity. This comparison highlights the importance of tax credits and other subsidies provided to wind and solar as they allow for more attractive financing terms.
- Lazard (2017) assumes conventional coal without carbon capture and sequestration (CCS) in their minimum estimate, while imposing 90% CCS in the maximum estimate. In contrast, the IEA base estimate for coal LCOE does not include CCS; but IEA (2015) estimates that CCS would add 30% to 70% to the coal-plant costs depending on the capture percentage and location.

NGCC often has the lowest LCOE in the United States as long as there is access to natural gas infrastructure and the price of natural gas remains below $3.50/MMBtu. But, **the simple comparison of generic LCOE calculations can be misleading as they ignore variation of inputs due to regional considerations.**

Much Lower LCOE of Existing Plants

LCOE is calculated for new facilities. Adding subsidized resources have an impact on existing resources, which offer value to the grid. They should be considered as part of the overall resource needs of an electric power system, as is done routinely by grid operators and utilities that conduct integrated resource planning.[25] Thus, **Figure 2** above offers LCOE estimates for

[25] As discussed earlier, there are many market design changes around the country, including FERC resilience and price formation dockets, system operators' changes to capacity markets and nodal price calculations. They often seek to improve compensation of existing facilities for the services they provide (e.g., fast-start capabilities). Also,

fully-amortized generation assets (red rectangles), assuming that capital costs are fully depreciated.[26]

Existing onshore wind has the lowest LCOE range given the lack of fuel costs and low FOM and VOM. However, industry reporting suggests that most 20-year-old wind farms will require retrofitting to replace aging parts and/or to increase their capacity factors. These new capital upgrades would increase LCOE for the existing wind farms, but we do not have reliable data on these capital costs. In some cases, old wind farms can be fully replaced by new facilities at the same site. Existing nuclear units also have very low LCOE, but operating costs have increased for many existing plants, according to reports from the Nuclear Energy Institute (2016). Many nuclear plants are retired or saved by state subsidies, which also suggest that their costs probably are not as low as the LCOE suggests. Finally, existing NGCC units have low LCOE depending on the price of natural gas.

Even existing NGCTs typically have a higher LCOE than that of onshore wind and utility-scale PV. But NGCTs, or similar fast-start resources, are needed to balance the system against intermittent and variable wind and solar generation. As the penetration of wind and solar increase, so will the need for NGCTs (or, the need for an alternative solution with attendant cost considerations). More NGCTs may be needed in a system with growing renewables, regardless of the high LCOE of NGCTs. However, increasingly, these assertions are being challenged. Some expect that the expansion of battery storage, especially when combined with solar systems, and dispersed wind and solar generation interconnected with a large transmission network will eliminate the need for new NGCTs as early as mid-2020s, at least in some regions.[27]

Representative LCOE

The LCOE ranges in **Figure 2** are difficult to carry forward for the rest of our analysis. Hence, we developed a CEE "representative LCOE." **Table 2** provides the key assumptions. The only assumption we make is the natural gas price.[28] All other assumptions are based on multiple sources, including those used in **Figure 2**. For each technology, a mix of sources is typically used based on our cross-referencing and judgment.

The representative LCOE is our attempt to reflect the average cost of building a new power plant, starting construction in 2017, of a given technology at locations in the United States

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more holistic resource assessments evaluate T&D options in addition to generation to meet system needs reliably and cost effectively. All of these changes appear to get the electric power industry closer to an IRP approach.

[26] We ignore solar and offshore wind because not many large-scale facilities are older than 20 years.

[27] For example, see https://www.greentechmedia.com/articles/read/battery-storage-is-threatening-natural-gas-peaker-plants?

[28] The price of natural gas at $3.0/MMBtu is lower than most other studies. However, given the projections of continued production of natural gas from unconventional fields both as dry and associated gas, the lower price can be defended. The average price of natural gas delivered to power plants between 2015 and 2017 was $3.3/MMBtu; but, in locations where most new builds are likely to happen such as the Marcellus region, power plants had access to much cheaper natural gas.

where it is most likely to be built (e.g., given state mandates, historical capacity expansion and high utilization, access to cheap natural gas from shale gas fields such as the Marcellus). As "best" locations are depleted, one would expect the investment to shift to the next tier of locations (e.g., with lower CF, higher cost natural gas). Admittedly, this approach is subjective but yields estimates that are comparable to other LCOE estimates.

Table 2: Key Assumptions for CEE Representative LCOE

Unadjusted for air emissions, system integration costs or subsidies

	Coal CCS 30%*	NGCC	NGCT	Nuclear	Onshore Wind	Offshore Wind	Utility PV	Res. PV
CAPEX (000$/MW)	$5,880	$1,000	$832	$7,091.5	$1,715	$4,205	$1,400	$2,000
Fixed O&M (000$/MW)	$58.8	$6	$10	$116.5	$43	$93	$16	$20
Variable O&M ($/MWh)	$5.00	$2.00	$6.95	$1.38	--	--	--	--
Capacity Factor (%)	84%	70%	20%	90%	43%	48%	26%	21%
Fuel Price $/MMBtu)	$1.08	$3.00	$3.00	$0.70	--	--	--	--
Heat Rate (MMBtu/MWh)	10.40	6.5	9	10.45	--	--	--	--
Interest Rate (%)	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	5.8%
Economic life (Years)	40	20	20	40	20	20	20	25
Representative LCOE	$80.1	$37.2	$82.4	$86.4	$53.1	$112.2	$62.4	$94.3

* Coal-fired generation with CCS assuming 30% capture based on EIA (2017) and Rhodes et al. (2017).

Although we would expect the value of inputs to be roughly the same for the next few years, significant changes to some inputs cannot be ruled out. For example, some expect CAPEX of utility-scale solar PV projects to decline further towards $1,000,000/MW.[29] The CAPEX of offshore wind may be higher than the value we assumed once the large-scale projects start construction as there is not much experience with offshore wind in the U.S. The price of natural gas may be higher or lower than the $3/MMBtu assumed in this analysis. Capacity factors can fluctuate over the years for many reasons including technological improvements and changes in generation portfolios and/or load profiles.

Overall, the representative LCOE is lower than the simple average of ranges shown in **Figure 2**, but higher than the minimum of those ranges since we find many of the assumptions that yielded minimum estimates to be either specific to a few locations or aspirational (e.g., dependent on technology or cost improvement that are yet to be proven or difficult to accept given past performance). For residential PV, we used the minimum assumptions for rooftop solar (assumed for C&I customers by Lazard, 2017) to demonstrate that, even with the lowest estimate, rooftop solar is more expensive than other technologies.

[29] However, the import tariffs imposed on solar panels in early 2018 will counteract this expectation.

Externalities

Given that one of the main reasons for supporting renewable generation has been the reduction of potential environmental damage associated with conventional electric power generation, it is important to consider externalities as a missing component of LCOE. Integration costs of and subsidies provided for renewable resources are often contrasted to the environmental costs of conventional thermal technologies that depend on fossil fuels. An LCOE that is enhanced to capture externalities would provide for a more-complete comparison to an LCOE that also includes system integration costs of variable generation resources—a comparison that we will make later in this report.

From a full-cycle perspective, activities related to energy consumption—from fuel and mineral extraction, processing, and transportation; to electricity production, distribution, and use; to disposal of waste products—can create effects on human health and the environment. As noted above, the cost of those effects may not be fully captured in market prices. As such, the uncaptured costs are "external" to the market price. Importantly, external effects can be both positive and negative. Examples of positive externalities are public health improvements associated with the use of cleaner fuels for generation, and economic benefits of cheaper energy supplied by domestic resources or technology. Examples of negative externalities are air emissions from combustion of fossil fuels that may impact public health, and ecological impacts of all technologies given their physical footprint on land and water resources. Over the years, cap-and-trade and/or penalties yielded significant reductions in many emissions (e.g., those of sulfur dioxide or SO_2).

Externalities also are associated with mandating and subsidizing renewable power in the form of reducing non-renewable power plant utilization, reducing power prices and, therefore, the profitability of non-renewable power plants. As mentioned earlier, this creates stranded costs if non-renewable generation that otherwise could be dispatched is withdrawn from the market to accommodate intermittent resources. Furthermore, spinning reserves, i.e., thermal generation available to ramp up when renewable energy is not available, have emissions consequences as they emit more when they ramp up and down faster, larger MWs, and more frequently.

Cost of Emissions

The cost of emissions can be calculated on a per-MWh basis and added to conventional LCOE. Rhodes et al. (2017) capture the externalities associated with air emissions (SO_2, NO_X, $PM_{2.5}$, PM_{10}, greenhouse gas emissions [GHG] of CO_2 and CH_4) on a regional basis (e.g., the severity of local emissions is not the same in urban versus rural areas, or in industrialized versus less-industrialized regions).

$$LCOE = \frac{CRF \times capital + FOM}{8760 \times CF} + VOM + HR \times fuel\ price$$

$$+ \sum_{j \in \theta} E_j \times SCE_j + E_{GHG,one-time} \times SCE_{GHG,one-time} + E_{GHG,NC,ongoing} \times SCE_{j,CO_2}$$

Where *E* is the per-MWh emission rate and *SCE* is the social cost of emissions per unit of emission. There are two categories of GHG emissions: those associated with ongoing generation; and one-time costs associated with the fuel/mineral supply chain, manufacturing and transportation of equipment, construction, and decommissioning. Within the electricity sector, generation of electricity accounts for the majority of external effects. Other activities in the electricity cycle are less significant once distributed across a lifetime of generation.

The literature widely discusses potential economic damages of non-GHG emissions to human health and the environment. Literature estimates were used to legislate the Clean Air Act and its amendments, and to develop associated regulatory or market structures since the 1970s. Although these estimates on damages of air emissions are peer-tested, it is important to note the following caveats. First, no consensus on some of the assumptions used in calculating externality costs (e.g., value of human life at different ages or locations, discount rates) exists. Second, the cost of externalities associated with water use or pollution, land use or pollution, bird kills, and others are not included, as these estimates are still evolving.

The literature on the social cost of carbon calculations is more recent. The Climate Leadership Council, a new international policy institute,[30] suggests starting with a carbon tax of $40 per metric tonne (t). IMF (2016), a report issued after the 21st Conference of the Parties in Paris (COP 21, December 2015), indicates that a 2010 EIA modeling estimate of cost to achieve a 10% reduction in emissions is $30/t[31] but that $50/t may be required for countries to reach Paris targets of roughly 56 gigatonnes by 2030 (UN, 2015, p. 9). IMF (2016) further notes that $60/t could be a more effective price for emissions reductions to meet 2030 targets based on current modeling (see p. 19). In short, there is no consensus on the right carbon price to achieve COP21 goals.

By comparison, carbon prices in existing cap-and-trade systems have been lower than any of these estimates in recent times (e.g., $6–$7 in Europe, largely blamed on willingness to allow utilities to issue large numbers of permits; but also $4–$8 with the Regional Greenhouse Gas Initiative in the U.S. Northeast, and $12–$13 in California).

We apply cost estimates to representative LCOE (**Figure 3**). The U.S. Environmental Protection Agency modeled different social cost of carbon estimates in its assessment of the Clean Power Plan for different years. These costs reflect 5%, 3%, and 2.5% discounting of damages in future years for a plant life of 35 years. Out of that range, we use $20/t, $62/t, and $88/t to cover a reasonable range.[32]

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[30] https://www.clcouncil.org/.

[31] IMF (2016) also mentions that $30/t is the carbon tax price used on all fossil fuels in British Columbia, which has no reliance on coal and that $30/t could be a reasonable target for revenue to finance climate mitigation.

[32] However, the National Academies of Sciences, Engineering, and Medicine (2017) makes recommendations on updating the social cost of carbon calculations, pointing to some of the shortcomings of current methodologies such as the characterization of uncertainty, transparency and consistency of modeling assumptions, and the relationship between discounting and economic values.

Figure 3: Representative U.S. LCOE Including Air Emissions

Cost of air emissions excluding externalities associated with water, land, ecological impacts, system-integration costs, and subsidies ($/MWh).

With representative LCOE, NGCC would remain the cheapest technology for a new power plant at a $20/t carbon price. Higher carbon taxes would allow onshore wind to become more competitive, on average. At more than about $45/t, utility-scale solar PV can be cheaper than NGCC.[33]

System-Integration Costs

Wind and solar generation impose costs to electricity grids, which are paid by electricity customers, taxpayers and/or shareholders of mostly competing assets but also of renewables companies. In this section, we briefly describe causes of these system-integration costs, define their manifestations, and provide estimates for them from a wide literature search.

Causes of Renewables System-Integration Costs

Drivers of system-integration costs are grouped into three main categories:

1. Intermittency and variability of renewables generation;
2. Remoteness of best resources from load centers; and
3. Low operating cost and subsidies.

Intermittency and Variability of Renewables

Renewable resources (primarily, wind and solar) are different from conventional thermal facilities. **They are not dispatchable on the command of a grid operator.** This intermittency problem can be managed with dispatchable resources in the system for balancing and backup, which require compensation of generation units that provide these services. Typically and

[33] As with any LCOE comparison, locational considerations can create exceptions to this overall conclusion.

historically, conventional thermal generation resources such as combustion turbines are kept in reserve and used when needed. They are compensated via ancillary services markets (e.g., spinning or non-spinning reserves).

Alternatively, some form of external energy storage such as pumped hydro can be used. Increasingly, batteries are discussed for providing this balancing service; but, at the time of writing, there is a relatively small amount of battery capacity providing balancing service.[34]

With more historical data, intermittency patterns are better forecast but the need for backup is not eliminated. Geographic diversity of wind and solar can help reduce system-wide intermittency, but requires additional investment in long-distance transmission lines to connect remote wind or solar farms with sufficiently different availability throughout the day.

Wind and solar are also variable. Variability can be predictable in terms of cycles throughout a day and across seasons, but meteorological conditions (e.g., clouds, storms) as well as technical difficulties (e.g., equipment malfunction) can also cause unpredictable variability in very short time frames. This uncertainty can be more challenging and costly to accommodate in the grid than intermittency.

Reliability is the most important responsibility of a grid, or system, operator. Reliability must be provided at least cost (i.e., economic dispatch), especially in competitive wholesale electricity markets. **To achieve the twin goals of reliability and cost minimization**, system operators dispatch electricity from the least expensive to most expensive of a fleet of generation units across the high-voltage transmission network—subject to congestion on this network, and operational characteristics and location of each generation unit—to maintain demand–supply balance instantaneously at all times.

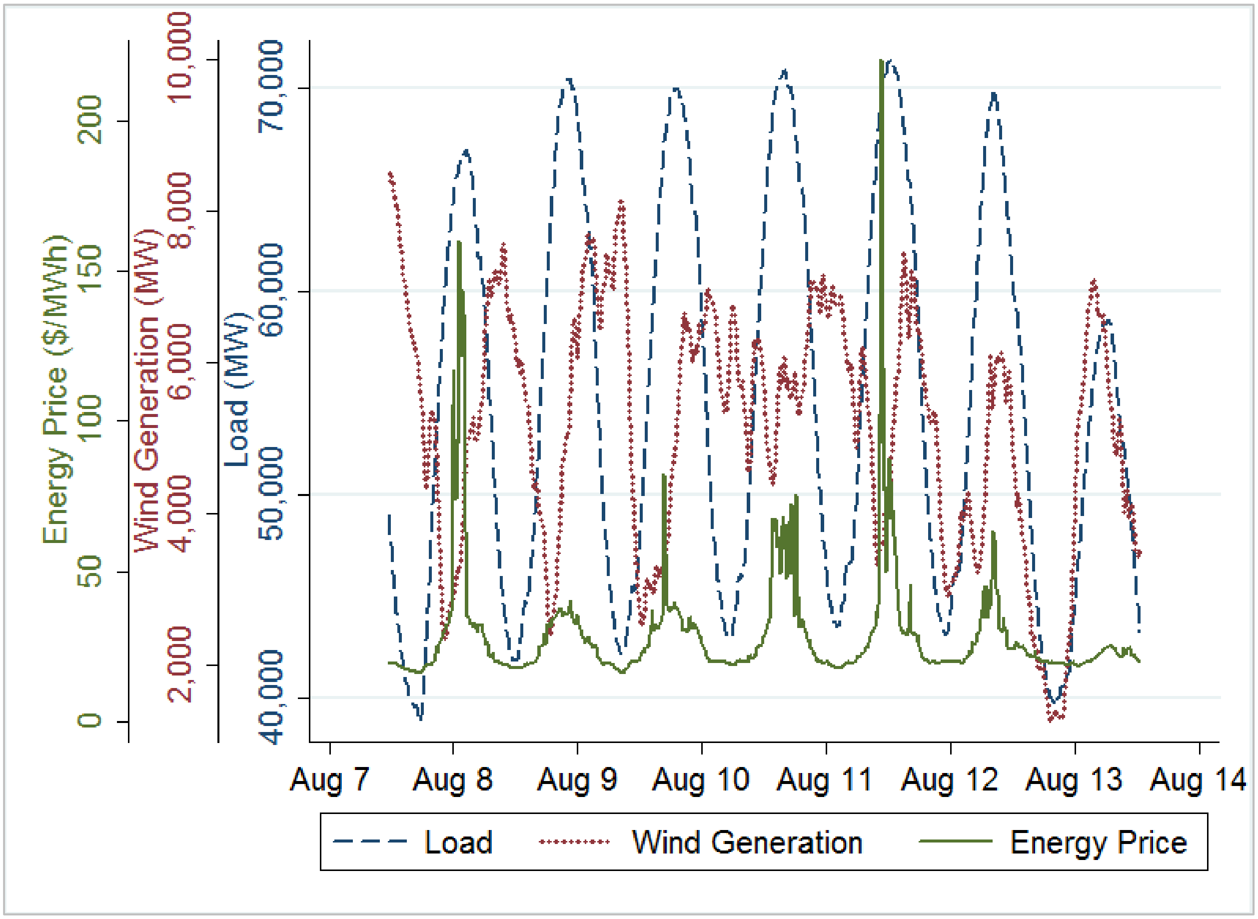
This optimization problem is challenging because electricity demand fluctuates across the hours, day, week, and seasons, sometimes unexpectedly as a result of extreme weather events. **Figure 4** summarizes the week of August 7–13, 2016, for Texas' ERCOT grid system. The total load varies during each day (up to a 30,000-MW swing within one day) and across the whole week (more than 11,000-MW difference between the peak load on August 11, which was also the annual peak in 2016, and peak load on August 13, which was a Saturday).

A typical week in winter or shoulder months (e.g., March, April, October, November) would have a similar pattern but at much lower load levels. In recent years, the winter peak load has been less than 40,000 MW (about the minimum daily load experienced in the week of August 7–13) as compared to 70,000 MW in **Figure 4**. The minimum load in winter or shoulder months has been as low as 30,000 MW in 2016. Note that the difference between daily peak and trough

[34] Less than one GW of battery storage are online as of the end of 2017 as compared to roughly 87 GW of wind and 27 GW of solar (40 GW including estimated rooftop capacity). Importantly, most of the existing battery storage is used grid services and not designed for renewable backup.

is smaller in winter and shoulder months than the daily peak–trough difference in summer months.

Figure 4: 15-min Real-time Load, Wind Generation, and Energy Prices in ERCOT.



The balancing of demand and supply across various time periods throughout the year necessitates a mix of generation assets with different operational characteristics. Typically, nuclear, coal, and/or combined-cycle gas plants, known as *baseload plants*, are used at high capacity factors to cover the minimum load at all times. However, some of these plants will not run 24 x 7 during winter or shoulder months since baseload during these months is much lower than baseload in summer months.

Plants that are capable of following load (i.e., capable of ramping up and down in minutes to seconds) run fewer hours in a year and have low-capacity factors. These power plants have simple designs such as combustion or steam turbines and are known as *peakers*. Some plants are super-peakers that run only a few hours a year during the highest-demand periods (e.g., the daily peaks in **Figure 4**). Peakers and super-peakers, though cheaper to build than most other plants, need to generate enough revenues from those few hours of generation in a year to cover their costs. Thus, their operators bid high enough prices for these few hours (e.g., the price spikes in **Figure 4**) to make these plants economic.

Price spikes can also occur, albeit less frequently, at lower-demand hours if there are unplanned outages of generation or transmission facilities. Overall, these market prices are signals to market participants to evaluate new investments or retirements.[35] Increasingly, these prices can also induce demand-side response in terms of energy efficiency and conservation, managing the load throughout the day, or investing in distributed generation and/or storage assets. This description, however, applies to the energy-only markets such as the one in ERCOT. Many competitive systems also have capacity markets that provide additional price signals for new investment in generation capacity. Hence, the energy prices do not have to reach as high levels as they do in energy-only markets although they are still important.[36] In regulated systems, the IRP approach provides the necessary revenues to utilities to build infrastructure, including different types of generation facilities and T&D, to meet reliability goals.

Among others, Joskow (2011) declared LCOE flawed because of the mismatch between generation from non-dispatchable resources (i.e., wind and solar) and demand/load. Prices are often the highest during peak load periods. Using the ERCOT market as an example, the value of wind generation is lessened because it is negatively correlated with wholesale energy prices. **Figure 4** represents one week in summer, but the same pattern manifests itself in varying degrees throughout the year. On an annual basis, the correlation between load and price is 0.47 (based on daily average) or 0.21 (based on 15-min intervals). In contrast, the correlation between wind generation and price is -0.25 (daily) or -0.11 (15-min intervals).[37] Thus, a cash-flow analysis that calculates revenues based on hourly (or 15-min) prices used for financial settlement could indicate that a wind generator's annual revenues are lower than its LCOE because wind blows mostly during off-peak hours when prices are lower. In fact, prices are often negative because wind generators need to get dispatched when available to collect on their production tax credits. Similarly, CAISO (California) experiences negative prices at increasing frequency but they occur during mid-day when solar generation is highest.

Remoteness of Best Resources from Load Centers

The best renewable energy resources are, to a large extent, not located within or proximal to major load centers. Investment in high voltage transmission lines to connect these projects are often necessary. Per-unit transmission cost will be lowest if capacity utilization across hours can

[35] It must be noted that ERCOT used to have price caps as low as $1,000/MWh. After a year of close calls (2011), the price cap is now $9,000/MWh. Still, another price reform, known as operating reserve demand curve (ORDC) was also implemented to enhance the price signals, especially for peakers. These reforms are partially necessitated by the increasing penetration of wind and solar.

[36] Price formation reform efforts, mentioned earlier, is a good example of how even the competitive systems with capacity markets need to ensure that real-time prices (energy and ancillary services) provide accurate price signals to fill the gap left from capacity markets.

[37] Note that these correlations are based on ERCOT-wide averages. In fact, prices are determined every 15 minutes in several thousand locations across the ERCOT market. The correlation between wind generation and prices at some locations where wind is prevalent is more negative. In other regions, wind does not have much impact.

be maximized, which is not possible with intermittent renewables as facilities near a transmission connection have nearly identical hourly generation profiles.

Once built, transmission is used by all generators, which complicates the task of discerning costs and pricing for transmission capacity that is mainly attributed to renewable energy generation but there are some clear cases such as the Competitive Renewable Energy Zone or CREZ lines in Texas or three major north-to-south lines under consideration in Germany. It is possible to envision that the EFP contract proposed by Helm (2017) can be extended to include cost of transmission investment beyond average system expansion that is clearly targeted for a specific resource.

In many cases, government subsidies and mandates induced development of too much renewable generation capacity too quickly, i.e., before sufficient transmission capacity could be developed and/or system load grew to a level to absorb them. Increasingly, wind or solar can generate more than demand at any point in time. System operators in California, Texas, and Germany, among other geographies have been curtailing renewable generation. Transmission constraints worsen the problem. Slow load growth in some regions, sometimes exacerbated by expansion of DER such as rooftop solar, worsens the mismatch. A related, complicating factor is that DER expansion is "invisible" to system operators as these facilities are at customer site (known as "behind-the-meter") and do not need to follow grid procedures such as interconnection assessment.

Low Operating Cost and Subsidies

When available, renewables get dispatched before other resources both by regulatory mandate and because their operating costs are very low and without any fuel costs. However, wind generators often bid negative prices in order to collect on federal PTC. Solar resources are developed primarily with the help of ITC and lack the same incentive to bid negative as wind farms. But, since they are available closer to or on peak hours in many systems, they lower prices during these periods when, as discussed above, energy prices have been the highest historically. Finally, wind and solar displace existing generation. Although this would be perfectly acceptable in a competitive market, renewables are not built based on competitive market price signals. They are built thanks to federal tax credits, state mandates, and some local incentives. In short, existing generators lose revenues because of both lost market share and reduced prices.

This negative externality on existing generators is conceptually the same as stranded cost recovery that was granted to regulated utilities when their markets were opened to competition. Regulated utilities argued that they made investments under the regulatory compact. Opening electric power markets to competition posed a threat to their cost recovery at allowed returns. Similarly, merchant generators made investments under the competitive-market construct, but renewables are imposed on competitive markets by government policies.

In 2016, New York and Illinois created subsidies in the form of zero emission credits (ZECs) for some of the nuclear plants in these states. The subsidies range from $10 to $17/MWh, depending on the assumptions. These states felt it necessary to offer the subsidies to prevent the premature retirement of nuclear plants that could not compete in an environment of low electricity prices and subsidized renewable-capacity additions. Other states are considering similar subsidies to nuclear plants. For several years, system operators and the Federal Energy Regulatory Commission (FERC) have been working on "price formation" dockets to address gaps in market price signals, partially caused by penetration of renewables. The U.S. Department of Energy (DOE) asked FERC to devise a mechanism to value "resiliency" of baseload plants such as coal-fired units that could store fuel on site. Although FERC rejected the DOE proposal, there is now a docket on resiliency. System operators are developing proposals. FERC recently approved ISONE's (the independent system operator for New England) proposal to separate its capacity market into two segments, one for subsidized resources, and another for everything else.[38] This review is not the venue for a detailed discussion of these solutions but they exemplify the wide range of market distortions, at least partially caused by penetration of low-dispatch cost, subsidized renewables.

Defining System-Integration Costs

There is no consensus on a formal definition of system-integration costs. Some studies (e.g., NREL, 2011) have used a version of the following working definition: **Integration costs include those incremental costs incurred in the operational time frames that can be attributed to the variability and uncertainty introduced by generation**.[39] Based on a literature survey, we decided to focus on five main categories of integration costs.[40]

- **Balancing costs** are associated with additional reserve capacity with the faster ramping capability that the system operator needs for real-time balancing to accommodate variability of wind and solar.
- **Grid costs** represent new transmission lines or other grid upgrades to accommodate remote renewable resources or DER, and the cost of increased congestion caused by the addition of renewables.
- **Adequacy, or back-up, costs** are the costs of peaking or super-peaking plants that have to be available to compensate for the intermittency of wind and solar.
- **"Full-load hour reduction" costs** capture the stranded costs incurred by existing generators per earlier discussion.

[38] https://www.utilitydive.com/news/split-ferc-approves-iso-ne-2-part-capacity-market-plan/518904/

[39] Calculating integration costs using this working definition typically involves running chronological production simulations for an extended period of time, typically for one to multiple years.

[40] Other costs may be included, but detailed cost estimates are lacking. For instance, increasing cycling by thermal units would reduce overall efficiency and increase emissions. There are also concerns about the inability of wind to provide system inertia. Neither cost appears to be significant, according to UKERC (2017).

- **"Overproduction" costs** refer to curtailed wind and solar because of overbuilding and/or transmission constraints.

While the first three cost categories have received the most attention in the industry and the academic literature, the last two are becoming more significant as the share of renewables increases.[41] The first three categories also have been addressed in varying degrees by system operators and/or regulators who developed new procedures or regulatory mandates, developed new ancillary services,[42] or otherwise compensated and reflected in customer bills (e.g., socialized cost of transmission upgrades in some systems). In contrast, "full-load hour reduction" and "overproduction" are negative externalities that are incurred by some market participants and/or society in general but that have not been internalized in system operations.

Ueckerdt et al. (2013) capture the evolution of research on system-integration costs and offer a conceptual representation of the five integration cost categories as well as estimates for European electric power systems. They offer a "system LCOE" that captures these system-integration costs, discussed in detail below.

Balancing Costs

Balancing costs occur because of variability of wind/solar generation and associated forecasting errors. They differ across time scales, as variability of renewable energy production and errors in forecasting of wind/solar generation change by the day, hour, or minute. A rising share of renewables increases the need for balancing resources that are dispatchable and capable of responding in shorter time frames (e.g., spinning reserves). These types of ancillary services, typically not expensive, are needed even without renewables; the addition of renewables leads to an increased need for additional ancillary services.

There have been significant improvements in day-ahead or hours-ahead forecasts because of the increasing amount of historical data and enhancements in forecasting techniques. However, noticeable errors still exist. For instance, in ERCOT between 2012 and 2015, average day-ahead wind-forecast errors improved from 8.8% to 6.8% for the off-peak season (October to May) and from 8% to 5% for the peak season (June to September). Hourly-forecast errors, which were lower historically, improved from 6.1% to 4.3% for the off-peak season and from 5.2% to 3.4% for the peak season. These forecast errors could translate into several hundreds to thousands of MWs that need to be balanced in real time. Also, they often need faster-ramping resources as the loss of generation is practically instantaneous.

Early literature on system-integration costs focused on balancing costs, making it probably the most extensively studied among all costs of system integration. Overall, balancing costs are

[41] The names of the last two categories are from Ueckerdt et al. (2013).

[42] Ancillary services are those services deemed necessary by the system operator to balance demand and supply at all times by allowing the stable flow of electricity across the transmission grid. They are traded in their own markets and provide additional revenues to those facilities providing ancillary services. Among others, they include frequency control, reactive power, spinning reserves, and non-spinning reserves.

found to be relatively small when the renewables penetration level is low (e.g., less than 5% of total annual generation). Costs can become more significant at higher penetration levels but are still less than $5/MWh in most regions (**Table 3**). These differences often reflect the existing generation mix and load profile of the region analyzed, but methodologies used to estimate these costs can also be a factor.

Table 3: Sample Studies on Balancing Costs

Reference	Method	Technology	Penetration Level*	$/MWh
Wu et al., 2015	Production cost and dispatch simulation	Utility PV	17%	$1.0 to $4.4
Baker et al., 2013	Review of studies	Utility PV	10% 20%	$5 $20
Mills et al., 2013	Production cost and dispatch simulation	Utility PV	18% of peak load 32.5% of peak load	$1.88 $3.77
Nieuwenhout and Brand, 2011	APX–ENDEX market data	Wind	4%	$0.66
NREL, 2011	Production-simulation model	Wind, onshore	20%	$5.13
		Wind, offshore	20%	$3.10
		Wind, on- and offshore	30%	$4.54
Meibom et al., 2009	WILMAR	Wind	20%	$3.0 Germany $2.2 Denmark

* As share of total annual generation unless otherwise noted.

Grid Costs

Grid costs are incurred primarily if new transmission investment is necessary to connect renewable resources that are far away from load (e.g., the CREZ lines in Texas) and if the addition of renewables raises congestion-management costs. Note that the latter can result from the addition of conventional plants, as well. Residential PV does not require a new long-distance transmission line and is not likely to cause congestion, but it can necessitate upgrades in distribution grids and cause reallocation of costs across distribution customers. Grid costs are highly region-specific. The literature reviewed for this report often does not distinguish between wind and solar PV or between utility-scale and residential PV, and yields a wide range of cost estimates (**Table 4**).

Below 10% share of annual generation, grid costs appear minimal. Above 10%, grid costs are estimated to be as low as $2/MWh or as high as $8/MWh, depending on the region. At higher penetration levels, grid costs are estimated at $22/MWh for 30% penetration, depending on the region and the mix of wind and solar.

Several jurisdictions in the U.S. are planning significant capital investments in their transmission and distribution networks to accommodate more renewable resources as well as to replace aging infrastructure with new facilities that are more capable of absorbing changing generation portfolios. For instance, Hawaii is planning to spend $8 billion to upgrade its electricity grid to achieve the state's 100% renewable goal. Southern California Edison plans to spend $2.1 billion for grid modernization. Other jurisdictions have similar plans.

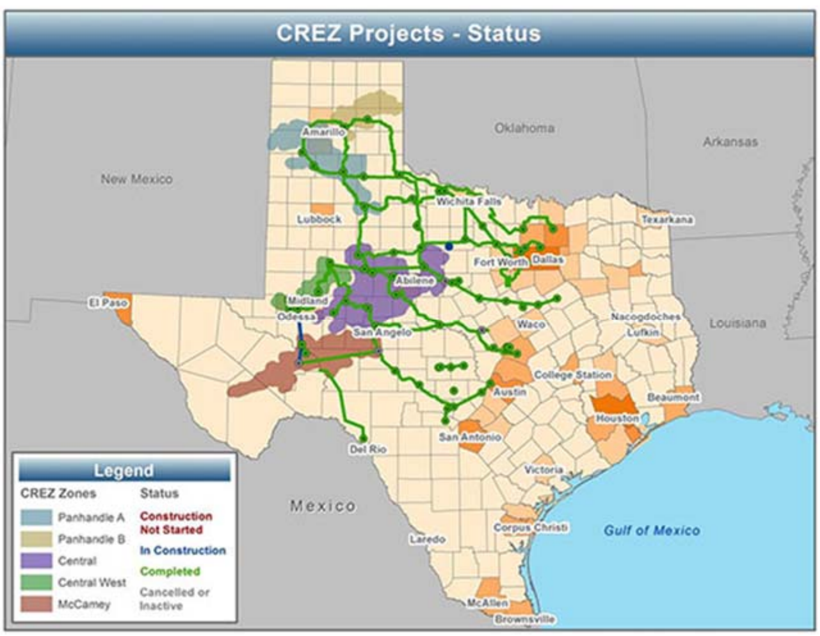
Table 4: Sample Studies on Grid Costs

Reference	Method	Technology	Penetration Level*	$/MWh
CEE	Grid capital cost allocation in ERCOT	Wind	10%	$7.25
Griffiths et al., 2018	Grid capital cost allocation in ERCOT	Wind	10%	$4.3
UKERC, 2017	Literature survey	Wind and solar PV	10% 30%	$6.5 $22
DENA, 2010	$1.1 billion annual in Germany	Wind and solar PV	39%	$11
NREL, 2012	Modeling of grid costs in U.S.	All renewables with 50% from wind and solar PV	80%	$6
Holttinen et al., 2011	Grid capital cost allocation	Wind	10% 40%	$2.2 $7.7

* As share of total annual generation unless otherwise noted.

The construction of CREZ long-distance transmission lines in Texas provides a good example of policy-driven transmission development for wind.[43] CREZ lines (**Figure 5**) cost $6.8 billion from 2009 to 2014 to integrate 18-GW of abundant wind resources in North and West Texas. However, per the open-access rules of the ERCOT grid, any generation can access these lines, although to date they have been used mostly by wind generators.

Figure 5: CREZ Long-distance Transmission Lines in ERCOT



Source: Today in Energy, EIA (https://www.eia.gov/todayinenergy/detail.php?id=16831). All CREZ projects on this map were completed by end of 2014. Orange counties have high electricity demand.

Assuming that CREZ transmission capacity is used exclusively by wind, the total cost, including financing, would be roughly $8 billion; with a capacity factor of 35% for wind generators, we

[43] See discussion of the history of CREZ policy development in Griffiths et al. (2018).

calculate the cost of CREZ per MWh of wind generation over 20 years as $7.25.[44] Griffiths et al. (2018) adopt a similar calculation but distribute the capital cost over a longer time period. Hence, they estimate only $4.3/MWh. This example highlights the importance of assumptions and methodologies in calculating grid costs.

Adequacy Costs

Adequacy, or backup, costs refer to the costs of compensating conventional capacity that cannot be retired because wind and/or solar have low capacity factors and often their peak generation do not coincide with peak demand.[45] Capacity credit is "a measure of how much conventional plant can be replaced by variable renewable generation whilst maintaining overall reliability at peak demand" (UKERC, 2017). This concept is the same as the "peak average capacity contribution" factor used by ERCOT when forecasting reserve margin.[46] ERCOT assigns 14% to West Texas wind, 58% to coastal wind, and 77% to solar. That is, only 14, 58, and 77 MW of every 100 installed MW of wind in West Texas, coastal wind, and solar, respectively, is counted on as available during peak load hours.[47] Following the UKERC (2017) definition, only 14 MW of conventional plants can be replaced by 100 MW of West Texas wind.

The UKERC (2017) survey concludes that, at 25% to 30% renewables penetration, backup costs range between $5.2 and $9.1/MWh, with a maximum of $19.5/MWh at 50% penetration. These estimates are based primarily on wind-integration studies. Ueckerdt et al. (2013) estimate backup costs in Germany in the range of $8–$9/MWh for wind and $6–$7/MWh for solar. These estimates remain stable at penetration levels higher than 2%–3%.

Factors that impact these estimates include diurnal and seasonal profiles of generation, geographic distribution of wind and solar farms, peak demand periods, and the cost of building a new generation asset to balance the system. Note that studies considered new plant additions for penetration levels above 20%–30%. In most systems, existing thermal plants (e.g., peakers) have been sufficient to provide the backup service, keeping backup costs low. If a new plant is needed, the plant type chosen for the analysis matters. The cost of new entry in the United States is often calculated on the basis of an NGCT, because it is the cheapest plant to build and can ramp up fast. But some studies assumed more-expensive NGCCs built as backup.

"Full-Load Hour Reduction" Costs

"Full-load hour reduction" costs refer to stranded costs associated with reduced utilization of dispatchable thermal units, often including baseload plants, that are cycled down to accommodate variable renewable generation. These displacements increase as more

[44] $\frac{\$8\ billion}{Wind\ generation\ over\ 20\ years\ at\ 35\%\ CF\text{: } 20*18{,}000*0.35*8760 =\ 1{,}103{,}760{,}000\ MWh} = \$7.25/MWh$

[45] Although solar in southwest U.S. and California is often peak-coincident, this is not the case in Germany when peak happens during evenings, especially in the winter.

[46] The reserve margin is the reserve generation capacity that is desired to be available in the system above forecasted peak demand.

[47] Note that there is no capacity credit for thermal plants because there is no technological reason for not counting on the available capacity of these plants during peak hours.

renewables are added. Variable renewables are dispatched first when available, subject to transmission constraints.[48] However, the amount of wind and solar would not have been this high without government support and mandates, and market participants would not have experienced as many negative prices in the absence of federal production tax credits. Wind generators often bid negative prices (i.e., they will pay the grid to take their generation) to ensure dispatch in order to collect the PTC. They can bid roughly as low as the value of PTC. These negative prices, more frequent during periods of transmission congestion and/or low demand (see the next section on overproduction), further reduce revenues of existing non-renewable units.

In the case of ERCOT, 5,000 to 6,000 MW swings in wind generation occur within a day (**Figure 4**). **Note that wind generation peaks when demand is lowest or declining, which are also the time periods with lowest prices**. Tsai and Gülen (2017) estimate the loss of revenues in ERCOT at various levels of wind penetration: for every 5% increase in wind generation, gas plants in ERCOT lose $40 to $50 million a year in revenues.

"Overproduction" Costs

According to Ueckerdt et al. (2013), **overproduction costs** occur when wind or solar generate more than demand, and they have to be curtailed. Increasing penetration of wind/solar has already caused this phenomenon in California, Texas, and Germany, among other geographies. This curtailment would reduce the effective capacity factor of wind/solar. If used in LCOE calculation, this lower CF would increase the LCOE estimates for wind/solar. Overproduction cost is distinct from backup generation. It occurs at higher levels of penetration when similar generation profiles of renewables projects lead to overproduction at the same hour of the day; but this excess supply cannot be used to meet demand at other hours unlike dispatchable generation. Hence new investment would be required.

"System LCOE"

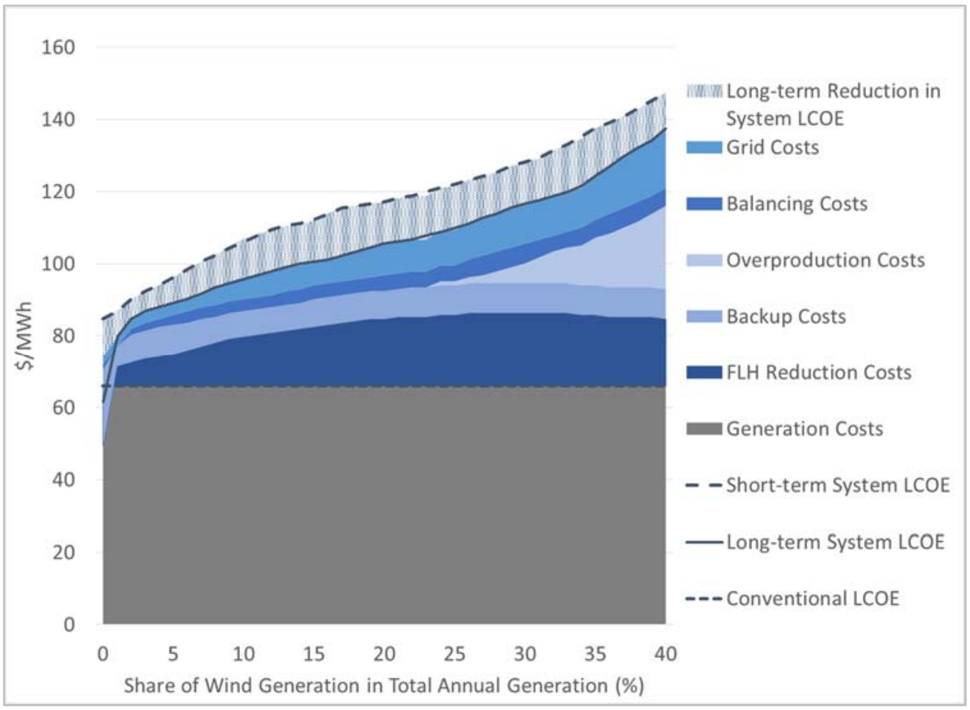
Ueckerdt et al. (2013) added system-integration costs to conventional LCOE, defining the final product as *System LCOE*. Ueckerdt et al. (2013) demonstrated that, in the short-term, the total system LCOE increases as penetration level of renewables gets higher. That is, if too much wind and solar capacity are added too quickly, costs will be higher. The system-integration costs will persist but decline over time as systems adapt.

In **Figure 6**, wind integration costs (blue-shaded categories) are depicted for a system in Europe that is dominated by thermal generators (gas, coal, and/or nuclear). Different systems will experience these costs at different levels depending on their generation mix, load profiles, grid connectivity, and the pace of renewable capacity additions among possible other factors.

[48] Dispatch priority is often mandated in state renewable programs, but note that wind and solar have low operating costs and that they would be dispatched first, even as part of economic dispatch.

Note that system-integration costs (blue shaded categories) can be as high as conventional LCOE (grey generation costs at the bottom) at 30% penetration, after which overproduction costs increase much faster while other system integration costs stabilize or start to decline. In the long-term, system LCOE is expected to be lower as system operators adapt to managing variable resources and as their variability is naturally balanced via geographic distribution and enhanced transmission grid. Also, stranded costs of existing generators (reduced revenues) decline with time. This reduction from short-term system LCOE to long-term system LCOE is marked by the shaded area on top in **Figure 6**.

Figure 6: Wind-integration Costs in a Typical Thermal System in Europe
At Various Penetration Levels



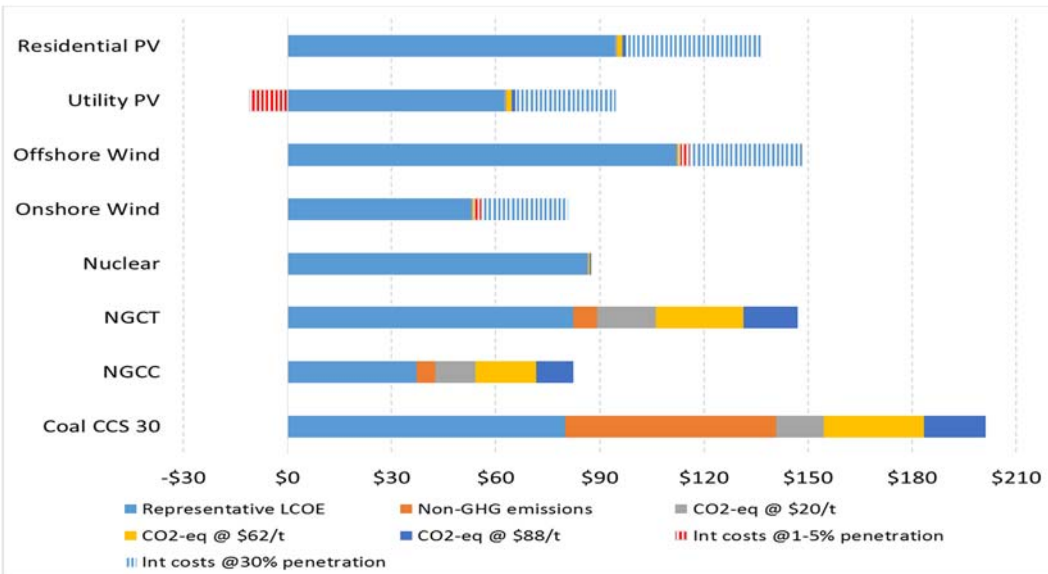
Source: Adapted from Ueckerdt et al. (2013).
Blue shaded series represent various categories of system integration costs.

"Full-load hour reduction" costs appear before "overproduction" costs (because renewables start displacing existing generators at low levels of penetration), then gradually increase and stabilize once the penetration level reaches about 20% for wind (15% for solar—not shown in **Figure 6**). Under high penetration levels (25% for wind, 15% for solar), overproduction costs begin to show up and keep increasing, rendering an overall upward trend of system-integration costs. These estimates are from Ueckerdt et al. (2013) and apply to Germany; but in similar systems (in terms of mix of generation, grid topography, and load profile), there is no reason to expect a different outcome.

We added integration costs to our representative LCOE estimates from **Table 2** and air emissions costs from **Figure 3** in order to discuss comparative impacts of externalities and integration costs on LCOE (**Figure 7**). In order to be as consistent as possible with the criteria for calculating representative LCOE estimates, we attempted to select reasonable system integration cost estimates for the U.S. systems that either have already added significant renewable capacity or are most likely to add more wind and solar (e.g., those with high renewable targets capacity). At low penetration levels (1-5%), utility-scale PV can reduce system costs because solar generation is mostly coincident with peak load periods. Shaving peaks lowers the system price. However, as the share of utility-scale PV generation increases (up to 30% in **Figure 7**), overproduction and "full-load hour reduction" costs surpass the savings associated with lower prices.

Figure 7: Representative U.S. LCOE with External Costs

Air Emissions and System Integration ($/MWh)



The literature on system-integration costs is diverse in terms of regional coverage, costs considered, penetration levels, and methodologies used. There is significant regional variability, even for the same penetration levels. Existing generation portfolios and load profiles impact estimates. Because of very limited analysis of residential PV, integration costs in **Figure 7** should be considered as possible ranges. With these caveats in mind, we can offer some observations:

- Ignoring externalities and system-integration costs, at $3/MMBtu natural gas, NGCC is the cheapest option on the basis of representative LCOE, followed by onshore wind and utility-scale PV (first solid blue bars in **Figure 7**).
- Not shown in **Figure 7**, onshore wind and utility-scale PV can be cheaper than NGCC for, among others, the following reasons:
    - in areas where wind quality and solar insolation is the highest (highest-capacity factors); or
    - if the natural-gas price is higher than $5/MMBtu; or
    - if NGCC utilization is curtailed; or
    - a combination of the above factors.

- Adding the cost of air emissions but still excluding system integration costs,
    - at about $20/t of carbon cost, NGCC and onshore wind cost the same; and
    - at about $40/t of carbon cost, NGCC and utility-scale PV cost the same.
- Adding system-integration costs, the LCOE-parity
    - between NGCC and *onshore wind* would require a carbon cost of about $25–$75/t depending on wind-penetration level (5% to 30%); and
    - between NGCC and *utility-scale PV* would require a carbon cost of about $20–$100/t depending on utility-scale PV penetration level (5% to 30%).
- Even with integration costs, onshore wind and utility-scale PV have lower LCOEs than nuclear and coal plants except for the case with high penetration of solar.
- NGCT is more expensive than onshore wind (even with maximum wind-integration costs) and utility-scale PV (even with maximum solar-integration costs but at a carbon price of about $20/t). But, as discussed before, NGCTs will likely be needed to balance the system with more wind and solar unless battery storage expands at grand scale.

Conclusions

In this review, we tried to provide a more complete picture of social costs of different generation technologies by pulling together data from the literature on regional differences, environmental costs, and system integration costs. We used LCOE to be comparable to existing estimates. Although these enhanced LCOE estimates offer a more holistic metric for comparing different generation resources, they still fall short in some respects. For example, due to lack of data or consensus on cost estimates, we could not consider externalities other than those associated with air emissions. Also, system integration costs cover a wide range as a result of different methodologies and assumptions, and, perhaps most importantly, different characteristics of individual system studied (e.g., generation mix, grid configuration, load profiles and growth patterns). With these caveats, we offer a summary of our LCOE estimates discussed in previous sections (**Table 5**).

Table 5: Representative LCOE* Estimates for a New Plant Excluding Subsidies

US dollars per megawatt-hour, or $/MWh

	Conventional LCOE	Including Air Emissions @ $20/t CO_2-eq	Including System Integration Costs (5% to 30% Penetration)	CEE Estimated Carbon Price** that Equates Final LCOE of Wind and PV to NGCC
Residential PV	$94.3	$95.0	$95.0-$134.0	$118-$211/t CO_2-eq
Utility-scale PV	$62.4	$63.1	$52.1–$92.1	$15–$111/t CO_2-eq
Offshore wind	$112.2	$112.4	$115.4-$144.9	$166–$238/t CO_2-eq
Onshore wind	$53.1	$53.3	$55.3–$78.3	$23–$78/t CO_2-eq
Nuclear	$86.4	$86.6	$86.6	--
NGCT	$82.4	$106.1	$106.1	--
NGCC	$37.2	$54.1	$54.1	--
Coal CCS 30%	$80.1	$154.6	$154.6	--

** Representative LCOE developed using the assumptions in Table 3.*

*** CEE calculations comparing the NGCC LCOE including only non-GHG emissions costs to wind and PV costs including system integration costs.*

Starting with the conventional formula (i.e., excluding externalities and system integration costs) for a representative facility of a given technology (see **Table 2** and associated discussion), we can see that a combined cycle plant that burns natural gas at $3/MMBtu (close to average expected price in the United States in the near future and more expensive than the price of natural gas delivered to power plants in some regions) is by far the cheapest option with an LCOE of $37.2/MWh followed by onshore wind at $53.1/MWh. But, it must be noted that there are locations in the United States that a wind or solar farm can generate cheaper electricity than natural gas given favorable wind speeds/insolation, and/or higher cost of natural gas delivered to the power plant.

Adding air emissions costs (non-GHG emissions, and one-time and continuous GHG emissions priced at $20/t CO_2-eq), NGCC remains the lowest cost option but now its LCOE is equivalent to that of an onshore wind farm ($54.1/MWh versus $53.3/MWh).

The incorporation and interpretation of system-integration costs requires care. The 5% level is meant to capture any level of penetration from 1-5%. The literature on system integration costs suggests that, in some systems, renewables, especially solar PV, can lower system costs in these ranges. Accordingly, in **Table 5**, we only show this negative cost impact for utility-scale PV. We then provide higher level penetration estimates, using 30% as the cap. There are very few large, closed systems with renewable penetration of larger than 30%, especially for an individual technology.[49] It is important to note again that not all systems will experience the same system-integration costs at the same penetration levels. For example, some may experience the 30% level we use at lower penetration levels and others may experience it at higher penetration levels.

Almost none of the system-integration costs are assigned to renewables projects. Instead they are socialized. So, this analysis is done from the perspective of social costs. Hence, it is appropriate to also look at the carbon and other emissions costs, the mitigation of which is often the justification for supporting renewables. Residential PV and offshore wind would need a carbon price of more than $100 per metric tonne even at low penetration levels to be competitive with NGCC. These implied carbon prices are much higher than carbon market prices in the United States or Europe and also higher than most social cost of carbon estimates. Only the implied carbon prices for utility-scale PV and onshore wind at low penetration levels are within the range of carbon market prices seen in the past. As their penetration increases, however, they would require higher carbon prices for social cost accounting to balance.

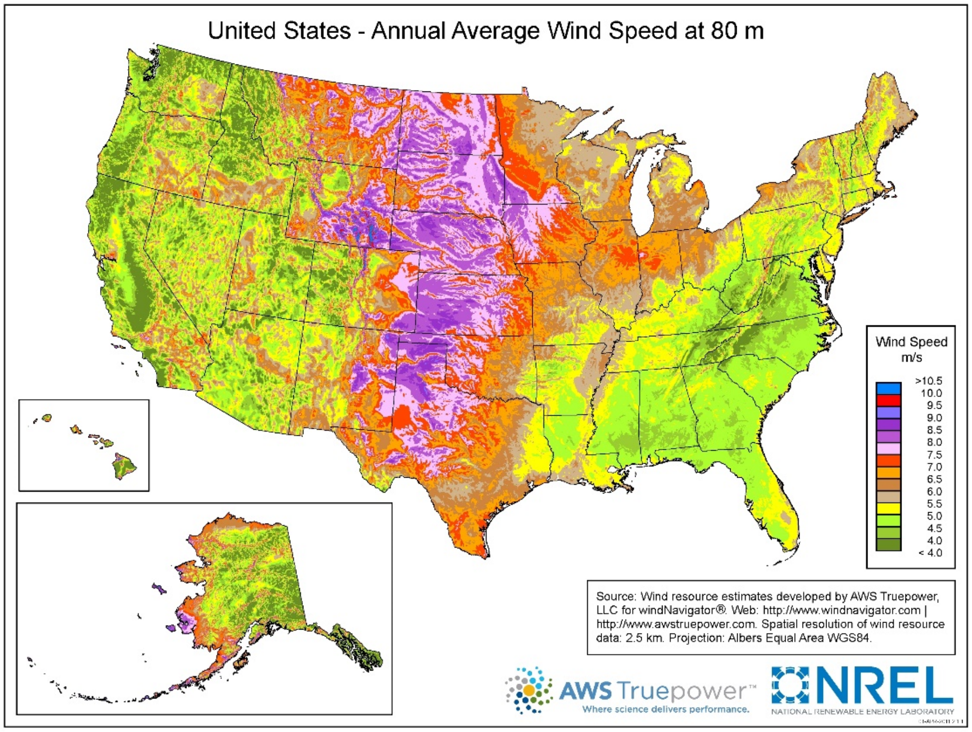
In summary, social cost accounting of generation technologies needs to improve by including a more complete spectrum of externalities, costs of which are borne by the society as citizens,

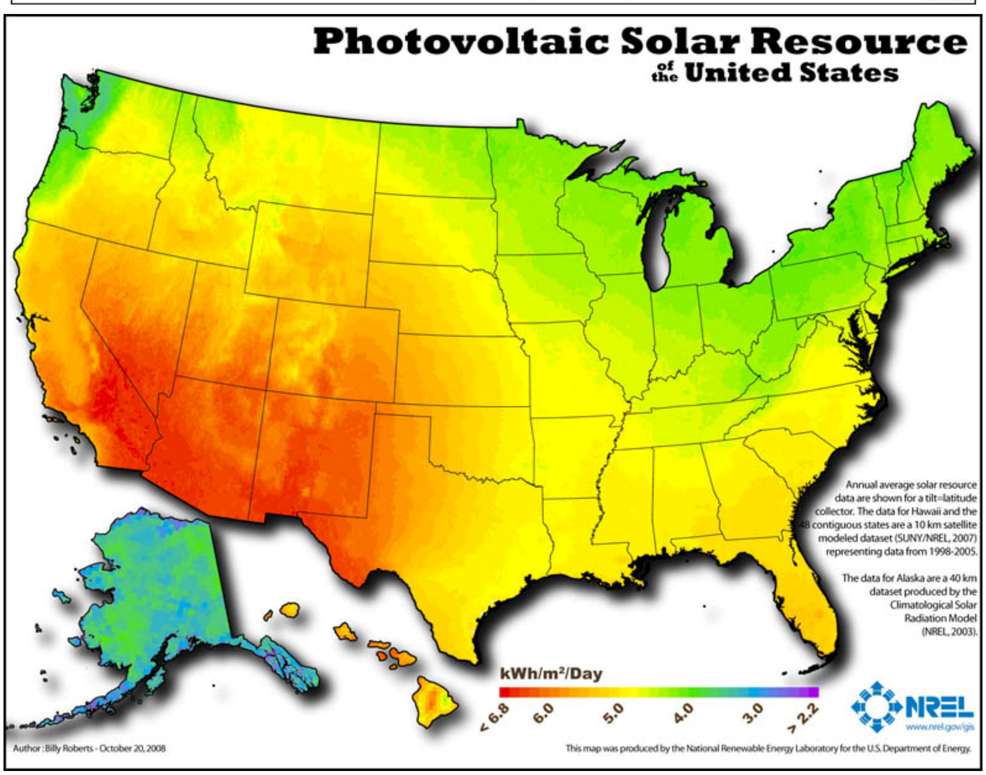
[49] Denmark reports a higher percentage of wind penetration but the country exports a lot of its wind generation (i.e., it is not a closed system). A larger more integrated grid will certainly facilitate higher renewable penetration. But, this is exactly the grid costs issue.

ratepayers, taxpayers and/or shareholders. Detailed dispatch modeling can help with system integration costs.

Finally, we should note that generous assumptions regarding social acceptance of infrastructure underpin future scenarios and outlooks that incorporate robust growth of renewable energy sources. These assumptions include continued cost improvements and/or ability of systems to adjust along with declining costs of adjustment like those portrayed in **Figure 6**. Organized public opposition to natural gas pipelines is fierce, regardless of whether pipeline capacity is needed to supply critical fuel for natural gas generation as a standalone baseload electric power source or to balance renewable generation sources. For that matter, public opposition to electric power transmission, and even to local distribution, is equally fierce. This is the case regardless of whether the improvements are needed to unlock renewable energy sources and ensure more optimal capacity factors and performance.

Appendix 1: Annual Average Quality of Wind and Solar PV Resource across U.S. and PV Technologies and Materials Complexity





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