Implications of variations in renewable cost projections for electric sector decarbonization in the United States

Highlights
We survey the U.S. wind/solar costs and model electric sector decarbonization impacts

Renewables are the largest generation resources in many decarbonization scenarios

Policy design and timing have larger effects on decisions than wind and solar costs

Low wind/solar costs have more limited impacts on carbon removal and firm capacity
Implications of variations in renewable cost projections for electric sector decarbonization in the United States

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SUMMARY

The costs of wind and solar technologies have dropped rapidly, but unknowns about technological change and emissions policies create uncertainty about future deployment. We compare projections of U.S. wind and solar costs across published studies and use an energy systems model to evaluate how these reductions could alter electric sector planning decisions and costs under deep decarbonization. Model results indicate that wind and solar are the largest generation resources for many scenarios and regions, but shares depend on assumptions about costs, policy targets, and policy timeframes (spanning 14% to 67% of national generation by 2035). Renewables cost reductions lower decarbonization costs and reduce projections for nuclear and carbon-captured-equipped generation, but policy decisions have a larger influence on future trajectories. Lower wind and solar costs have more limited impacts on deployment of carbon removal technologies and the capacity of clean firm technologies in reaching net-zero emissions in the electric sector.

INTRODUCTION

The costs of wind and solar power generation technologies have been dropping rapidly in recent years. Installed costs of utility-scale solar photovoltaic (PV) plants in the U.S. have decreased by 74% between 2010 and 2020, and levelized costs have fallen 85% to $34/MWh on average before accounting for tax incentives (Bolinger et al., 2021). Over the same period, installed costs of land-based wind power decreased by 42%, and the levelized costs fell by 65% to $20–30/MWh before subsidies (Wiser and Bolinger, 2021). The technological change and industry maturation underlying these trends have made solar and wind power among the lowest-cost options for generating electricity in many regions (Bistline et al., 2018; Lazard, 2020). However, unknowns about future technological change and emissions policies create questions about the pace and extent of renewables deployment moving forward.

Earlier studies have compared wind and solar cost projections across organizations, but these assessments are typically model assumptions and do not focus on the U.S. (Jaxa-Rozen and Trutnevyte, 2021; Krey et al., 2019; Victoria et al., 2021; Wiser et al., 2021a). These studies also generally do not examine how these differences may impact electric sector planning and decarbonization strategies, because cost assumptions alone do not uniquely determine deployment levels (Bistline, 2021a; Jaxa-Rozen and Trutnevyte, 2021). The extant literature using stylized cost trajectories for renewables indicates that investment decisions and policy costs are sensitive to technological cost assumptions, including those for variable renewables (Bistline and Young, 2019; Cole et al., 2021) but also that model structure plays an important role (Bistline, 2021b; Mai et al., 2018). Other studies (Grant et al., 2021; Luderer et al., 2021) look at the impact of lower wind and solar costs on electrification and economy-wide decarbonization using global integrated assessment models, whose lower temporal, spatial, and technological detail make them less appropriate for assessing power-sector-specific effects.

Our analysis extends the existing literature in several ways by:

- Comparing recent projections of solar and wind costs across published studies for the U.S., which provides a clearer sense of similarities and potential differences in cost assumptions than single studies alone;
Using a detailed energy systems model to evaluate how these assumptions about technological change for renewables and energy storage could translate into electric sector costs and planning decisions, not only for renewables but for a range of electric sector generation, storage, transmission, and carbon removal options;

Including a wide range of sensitivities, including being the first peer-reviewed article to assess impacts of accelerating zero-emissions goals to 2035, as per the updated U.S. nationally determined contribution (U.S. Government, 2021) and policy design for 100% electric sector decarbonization; and

Modeling electric sector investment and operational decisions with full hourly temporal resolution and a greater suite of technological options to better characterize the economic characteristics of variable renewables, energy storage, and dispatchable low-carbon technologies.

Our objective is to quantify the impacts of alternate projections for wind and solar costs on electric sector capacity planning decisions and costs and to evaluate how these impacts vary based on the timing and policy definitions for reaching deep decarbonization targets in the power sector. We find that wind and solar costs from different organizations span a wide range both for current estimates (driven by differences in technology, location, plant size, and financing) and for future projections (which vary in scenario assumptions and approach). Model results indicate that assumptions about policy targets, policy timeframes, and technological costs alter electric sector planning—including renewables deployment—and system costs. Wind and solar are the largest generation resources for many scenarios and regions, but shares largely depend on policy and technology assumptions (spanning 14% to 67% of national generation by 2035).

RESULTS

Wind and solar cost comparison

We look at single-axis tracking solar PV, onshore wind, and offshore wind capital cost projections developed by several organizations to understand how they vary and why they differ. Costs are adjusted to a 2020 base year and, in the case of solar PV, converted to $/kWAC to allow for a common baseline for comparison. We then develop cost curves for Low, Mid, and High scenarios for each technology to investigate how these varying cost projections impact results from the energy systems model.

Figure 1 shows, in gray, the individual cost projections from the studies evaluated. For all three technologies, there is a wide range of costs even for current costs in the 2020 base year. This variation can be attributed to differences in technology, location, and plant size, along with assumptions around financing, interest during construction, contingencies, and plant boundaries. For solar PV, the range reflects different PV module technologies and plant sizes. For onshore wind, the range reflects the impact of wind resource class on wind farm design and cost. For offshore wind, it also reflects a range of assumptions around fixed-bottom and floating foundation types, distance to shore, and water depth, all of which significantly influence capital cost.

The cost range widens when looking at projections to 2050. Several approaches exist for developing technology cost projections (Table S1), and the organizations use varying approaches to develop these projections, ranging from endogenous learning rates in a capacity expansion model without explicit assumptions about technology-specific improvements to very detailed assumptions about the different technology improvements assumed for each case. However, in general, the wide variation in projections is intentional, with individual organizations often looking at several scenarios to capture conservative, moderate, and advanced assumptions about future technology and cost improvements.

Although the ranges of capital cost projections are wide, they are also informative. By looking at the percentage change from a common base year and grouping the cost improvement projections into low, mid, and high projections, we develop improvement curves on a percentage basis for the three scenarios for each technology, which we then use to calculate capital cost projections using a common starting capital cost. These low, mid, and high sensitivities are shown in black in Figure 1 and used in the remainder of the analysis.

Although our analysis focuses on varying cost projections, there are additional factors that will impact renewables plant economics and potential improvements beyond a decrease in capital cost. One key consideration is capacity factor, which is expected to continue to improve for wind and solar technologies.
because of advancements in the technologies, including taller towers and larger rotor diameters for wind, and module changes and loss reductions for solar. There are also expected reductions in operation and maintenance (O&M) costs because of improved maintenance practices and technology maturity, and improvements in financing costs as the market matures and there is less risk associated with their development. Trends in capacity factor and O&M are captured in the modeling in subsequent sections, though alternate cases are not developed for each scenario as we do for capital costs.

Figure 1. Variable renewable cost projections over time across different scenarios and organizations
Light gray lines show individual projections, and black lines illustrate the Low (dashed), Mid (solid), and High (dotted) sensitivities used for the remainder of the analysis.
(A) Solar PV with single-axis tracking in $/kWAC terms.
(B) Onshore wind.
(C) Offshore wind. All values are expressed in 2020 U.S. dollars.
Modeling electric sector deep decarbonization

To evaluate how wind and solar cost reductions impact electric sector decarbonization strategies, we use an energy systems model, REGEN, that features detailed temporal, spatial, and technological resolutions (EPRI, 2020). These characteristics are especially important in the electric sector capacity planning and dispatch model owing to their influence in evaluating the economics of variable renewables, energy storage, and dispatchable technologies (Bistline, 2021b). This model is documented in detail in EPRI (2020). Summaries of key features are provided here and the STAR Methods section. The electric sector model simultaneously optimizes capacity investments and retirements, energy storage, hourly system dispatch, interregional transmission capacity, trade, CO₂ transport and storage, and carbon removal given assumptions about policies and technologies. Hydrogen production is endogenously optimized and can come from steam methane reforming with or without carbon capture (so-called “blue” and “gray” hydrogen, respectively) and electrolysis from zero-emitting electricity (“green” hydrogen), which can function as long-duration energy storage. The variant of REGEN used for this analysis includes hourly capacity investments and operations to represent the unique characteristics of variable renewables and energy storage, especially with deeper decarbonization.

All scenarios are run under three sets of variable renewables (Figure 1) and energy storage (Figure S4) cost assumptions: low, mid, and high. Each scenario varies the costs of onshore wind, offshore wind, solar PV, and battery storage based on the trajectories developed in earlier section. Costs of all four technologies are varied simultaneously across the three main cases. Sensitivities are also run where technological costs are varied independently to examine cross-technology interactions and a broader range of outcomes. We examine the impacts of renewables and storage costs across the following dimensions in the analysis:

- CO₂ policy targets: A “Reference” scenario examines all on-the-books federal and state electric sector policies and incentives as of June 2021 as described in the STAR Methods section. A “Net-Zero” scenario implements a cap on national CO₂ emissions in the power sector on top of existing policies. This technology-neutral cap implies that any emissions produced from operations must be balanced by an equivalent amount of carbon removal from Bioenergy with Carbon Capture and Storage (BECCS) or Direct Air Capture (DAC). A “Carbon-Free” scenario implements a national zero-CO₂-emissions cap but excludes all CO₂-emitting technologies, which excludes fossil units with and without Carbon Capture and Storage (CCS).

These scenarios are summarized in Table 1.

Impacts of renewable and storage projections on electric sector decarbonization strategies

Figure 2 shows how assumptions about policy targets, policy timeframes, and technology costs alter electric sector planning, including renewables deployment. Under a net-zero emissions policy, carbon removal from BECCS enables natural gas to balance variability from wind and solar (37 GW of BECCS creates a negative flow of 250 Mt-CO₂ annually for the 2035 Mid case). BECCS is the primary carbon removal technology to meet net-zero targets due to its lower cost of net CO₂ removal and provision of firm negative-CO₂ electricity as a coproduct, but sensitivities in the supplemental information (Figure S15) illustrate how DAC deployment increases under alternate technological cost and availability assumptions. The carbon-free scenarios exhibit rapid builds of nuclear and energy storage (including both short-duration batteries and long-duration storage via electrolytic hydrogen) to balance larger solar and wind expansions. Common elements of decarbonization pathways include phasing out coal generation (Figure S11),
maintaining existing hydropower and nuclear, and much higher wind and solar deployment (Figure S15), which generally align with other studies in the literature (Bistline and Blanford, 2021; Bistline et al., 2018; Jenkins et al., 2018). Note that electrification in the zero-emissions scenarios increases load, but higher prices from more restrictive target definitions can offset this growth by discouraging electrification and increasing energy efficiency (see STAR Methods for a discussion of the end-use model structure and Figure S19 for results).

Renewables are the largest generation resource for many scenarios and regions, but shares depend on policy and technology assumptions. The extent of variable renewable deployment depends critically on policy design decisions (e.g., about which technologies are eligible): Wind and solar generation shares span 44–55% (52–65%) in the 2035 (2050) net-zero scenarios and 59–67% (67–70%) in the carbon-free scenarios. Value deflation means that least-cost pathways include emerging technologies such as advanced nuclear, hydrogen, and carbon-capture-equipped capacity.

Lower costs for wind, solar, and batteries displace the highest marginal cost generation, which depends on the region and scenario (Figure S9). Nationally, lower renewables costs reduce generation from gas (with and without carbon capture) and new nuclear in the Net-Zero and Carbon-Free scenarios, respectively (Figure 2). Solar and battery storage have the largest increases with lower costs and can displace wind generation in some instances. Impacts for lower and higher renewables costs are largely symmetric in the zero-carbon scenarios. Overall, policy stringency and design have larger impacts on the generation mix than do renewables costs.

Figure 3 shows installed capacities of generation technologies, energy storage, and carbon dioxide removal (CDR) as solar and wind costs are varied individually, which illustrates cross-technology interactions. Cross elasticities of demand between wind and solar are relatively limited, as solar costs have the largest impact on solar deployment and wind costs on wind deployment. Clean firm resources—such as nuclear, carbon-capture-equipped capacity, biomass, geothermal, hydropower, and zero-carbon gas-fueled plants (e.g., hydrogen)—are “technologies that can be counted on to meet demand when needed in all seasons and over long durations” (Sepulveda et al., 2018). Lower renewable costs reduce the reliance on clean firm technologies for generation but do not obviate their need, especially for providing dispatchable capacity during high residual load periods. Wind and solar can be partially substitutable for clean firm generation (Figure 2) but less so for capacity (Figure 3, fourth row).

Lower wind, solar, and battery costs have limited impacts on the value of carbon removal in reaching net-zero emissions (Figure 3, bottom row). Without negative emissions, challenges increase in terms of the scale of capital investment (Figure 4), extent of nascent technologies such as advanced nuclear and long-duration storage, and system operations with higher variable renewable shares (Figure S14).
from mid-cost for wind and solar to low-cost only decreases carbon removal via BECCS and DAC by 8% (from 287 to 265 Mt-CO$_2$/yr). The third row of Figure 3 also suggests that lower renewable costs and higher deployment do not necessarily guarantee large markets for energy storage. Conversely, high penetrations of renewables are possible even where energy storage is limited. Gas capacity can be useful for firm balancing of variable renewables, even with lower utilization as decarbonization deepens. Long-duration energy storage is a costly substitute, especially relative to low capacity factor gas with carbon removal to offset residual emissions. Energy storage deployment is highest with low solar costs and restrictions on gas as a balancing resource (i.e., under a carbon-free policy).

Figure S15 shows how the generation mix shifts under alternate technological assumptions. Renewables and carbon removal are key elements of least-cost decarbonization portfolios, though the deployment of different negative emissions technologies can change as can the mix of clean firm options, including larger roles for DAC, hydrogen, and CCS-equipped gas.

Figure S19 varies levels of end-use electrification and shows that insights about cross elasticities of demand for generation technologies are robust to these assumptions.
Timing of decarbonization and investments

Targeting a net-zero or carbon-free electric sector by 2050 instead of 2035 entails higher deployment of solar and battery storage, which are amplified with lower renewables and storage costs (comparing the top and bottom panels in Figure 2). Higher deployment of solar and batteries for a 2050 net-zero target and lower wind, nuclear, and gas with CCS are because of larger relative cost declines for solar PV and batteries over this longer horizon (Figures S4 and S5). 2050 decarbonization leads to lower CCS-equipped gas, wind, and new nuclear generation depending on the policy design.

Across all renewable cost assumptions, there is a significant acceleration of investments in the zero emissions scenarios relative to historical and reference levels (Figure 4). Capacity investments and changes from lower-cost renewables are highest with more restrictive policy design. For all zero- emissions scenarios, total wind and solar additions are at least 500 GW regardless of renewable cost assumptions. Capacity installations beyond these levels are scenario-dependent, and deployment of CCS-equipped capacity, hydrogen, and new nuclear all vary across policy and

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**Figure 3.** Installed capacities of generation, energy storage, and carbon removal technologies across policy scenarios (columns) and wind/solar cost scenarios (panels)

“Clean Firm” includes nuclear, hydro, geothermal, hydrogen, and CCS-equipped capacity. “CDR” includes carbon dioxide removal from BECCS and DAC.
cost scenarios (including many states-of-the-world where capacity additions of individual technologies are zero).

Retirements are less sensitive to renewable cost assumptions as policy design is a larger driver of coal and gas retirements. Regardless of renewable costs, CO₂ policies accelerate coal retirement trends with nearly no coal generation beginning in 2035 even when 2050 zero emissions are targeted (Figure S11). Gaseous fuels have slower rates of decline owing to their lower emissions intensities and potential competitiveness of gas with CCS and hydrogen in net-zero and carbon-free systems.

Implications of renewable assumptions on electric sector costs

CO₂ targets, timetables, and technological assumptions jointly impact electricity prices and policy costs (Figure 5). Electricity prices reflect changes in generation and new bulk transmission costs across scenarios averaged annually across the U.S. (noting the strong intra-annual and regional variability of prices). Policy design has the largest effect on costs across these scenarios, though renewable and storage costs have larger impacts in the Carbon-Free scenario. The lower sensitivity of costs to renewable assumptions in the Net-Zero scenario reflects the flatter optimum (Neumann and Brown, 2021) with policy flexibility and to the lower share of total system costs represented by wind and solar capital costs under the Net-Zero scenario, which also includes significant fuel costs relative to the Carbon-Free scenario (which is dominated by capital costs). Broader technological portfolios (i.e., moving from the Carbon-Free to Net-Zero policy) and advanced technologies (i.e., lower renewables costs) lower the costs of electric sector decarbonization. Accelerating the zero-emissions target brings higher near-term investment needs (Figure 4) and higher costs (Figure S8) before accounting for emissions reductions benefits (Shindell et al., 2021).

As shown in Figure 5 (bottom panel), Low (High) renewables and storage costs increase total electric sector costs by 43% (44%) in the Net-Zero by 2035 scenario and by 66% (90%) in the Carbon-Free scenario. Policy design (i.e., eligible technologies) has the largest effect for these scenarios.

Another method of assessing policy stringency and costs across scenarios is to compare the shadow prices on the CO₂ emissions cap constraint. Marginal abatement costs increase sharply as zero emissions are approached without carbon removal ($17,700/t-CO₂ to $29,100/t-CO₂ in 2050 across renewable cost scenarios). Costs in the Net-Zero case decrease to a range of $92/t-CO₂ to $99/t-CO₂ by 2050, which is the marginal cost of capture from BECCS. These marginal abatement costs indicate how renewable cost assumptions matter more for Carbon-Free policy conditions than Net-Zero ones and also how carbon removal can help to manage policy costs.

We also consider scenarios using renewable cost assumptions from 2015, specifically the National Renewable Energy Laboratory’s Annual Technology Baseline 2015. These comparisons illustrate how...
Cost reductions in recent years alter investments and the costs of electric sector decarbonization. As shown in Figure S16, expectations for wind and solar cost declines since 2015 have lowered the anticipated roles for CCS-equipped generation and new nuclear, which decline by 73% and 57%, respectively, in 2035 for the Net-Zero and Carbon-Free scenarios. This comparison also indicates that cost reductions in recent years have lowered costs of electric sector decarbonization, especially for 2035 targets without carbon removal (Figure S17), which lower policy costs by 29 percentage points and electricity prices by 15%.

Regional differences
There are considerable regional differences in renewable resource potential and generation mixes across scenarios. The East and South are most impacted by policy target definitions, but technology eligibility affects the generation mix and trade for all regions (Figure S12). Variable renewable deployment is concentrated in high-quality-resource regions (27–59% of generation in the West by 2035 and 18–87% in the Midwest). The East and South have lower quality wind and solar resources, which lead to lower deployment with reference renewable costs (5–36% of generation in the South by 2035 and 16–67% in the East). However, growth in renewables with lower costs is highest for these regions, which displaces gas-fired generation and carbon removal (Figure S13). Regional results indicate that resource-poor regions dominate capacity mix changes across renewable cost assumptions, because renewables deployment is high in areas with better wind and solar resources across all deep decarbonization scenarios regardless of the cost assumptions.
Coal generation declines rapidly across all regions in emissions-constrained scenarios (Figure S11), whereas the rate of gaseous fuel decline exhibits regional variation because of differences in renewable resource quality, fuel prices, existing capacity mixes, and state-level policies.

### DISCUSSION

Electric companies are determining their technology strategies and making planning and resource procurement decisions, and this research provides insights into these decisions and how such choices can vary based on assumptions about evolving policies and technologies. The analysis underscores several important considerations for understanding how cost reductions for renewables and energy storage could translate into electric sector planning, especially under deep decarbonization. First, wind and solar costs from different organizations span a wide range both for current estimates and future projections. Poor historical track records of cost projections, specifically underestimating wind and solar cost improvements (Creutzig et al., 2017; Wiser et al., 2021b; Xiao et al., 2021), likely mean that the modeling community should be circumspect about the confidence it attaches to future projections and should conduct sensitivities with a range of values to understand how insights may change. The results here suggest that current estimates may overestimate policy costs and clean firm generation shares if future renewables costs are lower than expected, but that these effects are smaller than those related to policy design questions.

Second, despite variations in future wind and solar cost projections, the results here point to robust investments in variable renewables given particular policy designs. Renewables are the largest generation resource for many scenarios and regions, but shares depend on policy and technology assumptions and vary by region. Regions with lower quality wind and solar resources (e.g., the East and South) are more sensitive to renewable cost assumptions than resource-rich areas (e.g., the West and Midwest), where renewable deployment is high across all decarbonization scenarios.

Third, lower wind and solar costs allow these resources to be partially substitutable for generation from so-called “clean firm” generation options, such as nuclear and CCS-equipped gas, but not necessarily their capacities. This finding implies that planners should consider portfolios beyond merely solar, wind, and batteries and that near-term research and development should be extended to these emerging technologies so that they can deploy when they are needed. Lower renewables costs also have more limited impacts on the value of carbon removal in reaching net-zero emissions in the electric sector. However, when negative emissions are restricted by policy design, energy storage and clean firm capacity increase across all combinations of wind and solar costs. Pursuing electric sector zero-emissions targets without fossil fuels raises decarbonization costs, even with low wind and solar costs.

These scenarios illustrate the complex substitutability and cross elasticities across power sector resources, especially under deep decarbonization scenarios. Although the high-level takeaway that lower renewables costs reduce the value of CCS and decarbonization costs aligns with other recent studies (Grant et al., 2021; Luderer et al., 2021), we find more nuanced interactive effects across decarbonization portfolios and greater capacity of clean firm resources, energy storage, and carbon removal. The additional temporal, spatial, and technological detail in our modeling helps to better characterize the economics of these resources and facilitates these insights in areas that are omitted or greatly simplified in global integrated assessment models relative to the linked energy systems and capacity expansion model used here (Bistline, 2021b).

Finally, these results point to CO₂ policy design as having large influences on the timing of investments, generation mix, decarbonization costs, and retirements of existing capacity—often having a larger impact than renewable costs on many power sector outcomes of interest. The definition of zero emissions, specifically whether carbon removal can be used, is a key decision point for planners and policy-makers. Uncertainties about policy timing, stringency, and scope suggest that analysis should conduct a range of sensitivities to stress test findings and understand potential responses. In addition, our sensitivities on the timing of decarbonization indicate that accelerating decarbonization markedly influences the pace of investments, generation shares, and decarbonization costs.

### Limitations of the study

This work surveys the literature to determine ranges of cost projections for solar energy, onshore wind, and offshore wind in the U.S. and then uses these ranges in an energy model to assess potential deployment trajectories. This research points to several areas for future work.
First, although this analysis provides comparisons of wind and solar capital cost projections across organizations, it would be useful to compare other cost and performance parameters for wind, solar, and other technologies and to understand why these values differ. Although a detailed analysis of the drivers behind interorganizational and intraorganizational variation is beyond this paper’s scope, recent work (Jaxa-Rozen and Trutnevyte, 2021) using statistical learning to link global scenario characteristics to solar PV deployment offers potential explanations. That analysis indicates that the institutional background of scenarios, model properties, and climate policy account for a large fraction of variation in deployment, including higher variance across university studies (relative to corporate and government scenarios) and higher mean growth for non-peer-reviewed reports, while costs have a secondary contribution.

Second, the analysis does not explicitly model operational constraints (e.g., inertia) or detailed ancillary services markets. In addition, modeling of investments and operations is conducted at an hourly level, and there is no subhourly or sub-state detail (e.g., transmission and distribution constraints), though intraregional transmission and distribution costs are included. It is unclear how adding these features would impact investments in renewables and other technologies, but such considerations become more important as shares of inverter-based resources grow and existing capacity retires. Third, these scenarios focus on zero emissions in the electric sector; future work should examine how economy-wide net-zero emissions could impact renewables deployment. Finally, uncertainty is addressed in this work through scenario and sensitivity analysis, but future work to explicitly evaluate hedging strategies and robust decisions under uncertainty would be valuable.

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Detailed methods are provided in the online version of this paper and include the following:

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SUPPLEMENTAL INFORMATION
Supplemental information can be found online at https://doi.org/10.1016/j.isci.2022.104392.

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DECLARATION OF INTERESTS
The authors declare no competing interests.
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STAR METHODS

KEY RESOURCES TABLE

| REAGENT or RESOURCE | SOURCE | IDENTIFIER |
|---------------------|--------|------------|
| Deposited data      |        |            |
| Cost projections for wind and solar generation technologies | This paper (supplemental information) |
| Data generated for this paper | This paper (supplemental information) |
| Software and algorithms |        |            |
| General Algebraic Modeling System (GAMS) 32.2.0 | GAMS Development Corp. | https://www.gams.com/ |
| U.S. Economy, Greenhouse Gas, and Energy (REGEN) | EPRI | https://us-regen-docs.epri.com/ |

RESOURCE AVAILABILITY

Lead contact
Further information and requests should be directed to the lead author, John Bistline (bistline@epri.com).

Material availability
Not applicable.

Data and code availability
- Nonproprietary data that support the analysis within this paper is available from the lead contact upon reasonable request.
- This paper does not report original code.
- Any additional information is available from the lead contact upon reasonable request.

METHOD DETAILS

Cost comparison methodology
Cost projections are compiled from several recent studies published in 2020 and 2021:

- Energy Information Administration: Annual Energy Outlook 2021 (February 2021)
- National Renewable Energy Laboratory: Annual Technology Baseline (ATB) 2020 (July 2020)
- BloombergNEF: 2H 2020 LCOE Data Viewer (January 2021)
- Wood Mackenzie: H2 2020 U.S. Solar PV System Pricing (December 2020)
- Lawrence Berkeley National Laboratory: Expert Predictions about the Future of Onshore and Offshore Wind Energy (April 2021)

Most of these studies include several cost curves per technology, representing Low, Mid, and High cases that differ based on assumptions about technology improvements, learning rates, and other cost reduction considerations. To allow for comparison across studies, a common baseline is developed, with all cost data adjusted to constant 2020 dollars using Bureau of Labor Statistics (BLS) Consumer Price Index data and, for solar PV, cases with units of $/kW_{DC}$ or $/W_{DC}$ are adjusted to $/kW_{AC}$. These adjusted costs are shown in the gray lines in Figure 1.

Given the wide range of capital costs across the studies for the 2020 base year, we normalize the cost curves to look at the percentage change through 2050 using each cost curve’s 2020 cost as the baseline, represented by the gray lines in Figure S2. To develop the Low, Mid, and High scenario assumptions for use in this study, we look at the associated curves for each technology and develop an improvement curve that correlates with those cases. For example, to develop a Mid case scenario for solar PV, we look at the “Mid” cases (“Reference”, “Moderate”, or “Mid”, depending on the organization) across the studies.
and calculate the average percentage change across those cases. For the High case scenario development, studies that assume a default of no technology improvement or cost declines over time are excluded from the calculation to better represent a scenario that considers conservative improvement over time. In cases where the source study includes only a single cost projection, the cost curve is grouped with the set of cases that most closely align with that projection: If the single cost projection falls within the range of other “Mid” cases, it is also considered a “Mid” case; if the projected cost decline is greater than all “Mid” cases, the improvement curve is assigned to the “Low” group; if the projected cost decline is conservative and less than all “Mid” cases the improvement curve is assigned to the “High” group.

The resulting Low, Mid, and High scenario assumptions are represented by the black lines in Figure S2. These percentage change curves are then applied to a common starting capital cost for each technology to develop the capital cost projection curves shown in black in Figure 1 and used in the remainder of the analysis. These scenarios are not intended to bookend the full range of cost curves seen in the literature, but to provide a reasonable set of cost scenarios that fall within the range—both on a percentage improvement basis and overall capital cost basis—for use in the modeling analysis.

Energy systems modeling
To examine how renewables cost reductions could translate into electric sector planning decisions, this analysis uses EPRI’s U.S. Economy, Greenhouse Gas, and Energy (REGEN) model. REGEN is an integrated energy end-use and electric sector model with hourly resolution for investments and operations (EPRI, 2020). The electric sector model makes simultaneous decisions about generation investment, transmission expansion, energy storage and carbon removal capacity, and dispatch. REGEN was built to capture the unique economic and operational characteristics of renewables as well as the policies that support them (Blanford et al., 2018). The variant of REGEN used for this analysis includes full 8,760 hourly capacity investments and operations to represent the unique characteristics of variable renewables and energy storage, especially with deeper decarbonization. Investment and retirement decisions are made in five-year time-steps through 2050, but the focus here is on 2035 and 2050 generation and capacity mixes. Regional aggregation and reporting regions for this analysis are shown in Figure S1.

The scenarios in this analysis explore power sector decarbonization along several dimensions (Table 1). A Reference scenario captures on-the-books federal and state electric sector policies and incentives as of June 2021, including federal tax credits (including the production tax credit for wind, investment tax credit for solar, and 45Q for captured CO2), state-specific renewable portfolio and clean electricity standards, and state-specific CO2 policies (e.g., California’s economy-wide emissions targets, Regional Greenhouse Gas Initiative cap-and-trade). Two zero emissions scenarios examine alternate interpretations of electric sector targets: Net-Zero (where net CO2 emissions equal zero, and any emissions produced from operations are balanced by an equivalent amount of carbon removal) and Carbon-Free (where electricity generation either does not use fossil fuels or does not emit CO2). The target timing is also varied where these zero-emissions scenarios are reached in 2035 and 2050 (Figure S3). All policy scenarios are run with the alternate renewables and energy storage cost trajectories. Sensitivities are also run where solar and wind costs are varied independently to examine cross-technology interactions and a broader range of outcomes. Cost assumptions for all other technologies are held at their reference or Mid values. Other scenario assumptions (e.g., capital costs of other technologies, fuel prices) are discussed in the supplemental information (Note S2).

REGEN represents a range of energy storage technologies such as batteries, compressed air energy storage, existing pumped hydro, and hydrogen via electrolysis. For batteries, the model endogenously selects battery storage investment and system configurations (i.e., ratio of energy capacity to power capacity). The cost structure is specified in terms of the power rating/capacity costs ($/kW) and energy capacity costs ($/kWh) (Minear, 2020). Figure S5 illustrates cost reductions for four-hour lithium-ion systems over time for the Low, Mid, and High cost scenarios. REGEN independently optimizes the capacity of hydrogen production via electrolysis and generation from hydrogen turbines. Electrolysis capital costs are shown in Figure S6. The cost of electricity is endogenously determined from the grid mix in the model. These costs are not varied across the renewables and storage sensitivities.

Natural gas price assumptions come from the U.S. Energy Information Administration’s Annual Energy Outlook, specifically the 2020 reference case (Figure S7).
A metric used to compare electric sector costs across scenarios, regions, and time is average generation prices. These reported prices reflect generation and new bulk transmission costs and differ from marginal wholesale electricity prices, providing a more complete metric for assessing total resource costs (Bistline, 2021c). The analysis also compares incremental policy costs across scenarios, which are the difference between total electric sector expenditures in the scenario with CO₂ caps and a reference scenario without policy. Electric sector costs include investment, fuel, operations, and maintenance costs for generation, bulk transmission, energy storage, and carbon removal assets, but exclude intra-regional transmission and distribution costs.

Time-synchronized hourly load comes from the REGEN end-use model, which characterizes the economic and behavioral incentives for end-use technology adoption and captures heterogeneity across households, industries, and regions. The model endogenously determines energy demand by fuel across transport, buildings, and industrial sectors over time for each structural class and region (Bistline et al., 2021). Load management is incorporated through deferrable electric vehicle charging. To reflect the deep decarbonization context of the power sector sensitivities for the Net-Zero and Carbon-Free scenarios, the end-use model assumes federal CO₂ pricing of $50/t-CO₂ in all sectors and regions beginning in 2025, escalating at seven percent per year. This carbon price is a proxy for decarbonization incentives at the end-use level. These assumptions lead to significant electrification (Figure S18) and declines in economy-wide CO₂ emissions of roughly 70% below 2005 levels by 2050. Outputs of the end-use model include regional electricity demand and hourly load shapes for each model period.

Additional model details and input assumptions are provided in the full REGEN documentation (EPRI, 2020), supplemental information, and REGEN website: https://us-regen-docs.epri.com/