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Letter from the Director

The *Solar Futures Study* is the result of extensive analysis and modeling conducted by the National Renewable Energy Laboratory to envision a decarbonized grid and solar's role in it. It's designed to guide and inspire the next decade of solar innovation by helping us answer questions like: How fast does solar need to increase capacity and to what level? How would such a large amount of solar energy impact the grid, the economy, and the solar industry? What technical advances are needed? How do we ensure access for all Americans?

Since the Department of Energy announced the SunShot Initiative in 2011, we've been working to answer these big, economy-wide questions through a series of vision studies—*SunShot Vision Study* (2012), *On the Path to SunShot* (2016), and now the *Solar Futures Study* (2021). Just as we found from the first study, technology development and cost declines continue to play a critical role in the future of solar. In fact, continued cost reductions in solar (as well as wind, batteries and other renewable technologies) are *essential* to making decarbonization affordable. In addition, we can no longer look at solar technologies in isolation—we must look at how they interact with the full energy system. For example, technologies like power electronics and storage have the potential to reshape how energy is produced and consumed, enabling renewable microgrids that can keep the lights on after a major storm or shift energy consumption to maximize cost savings.

As solar deployment grows, engagement with local communities becomes increasingly important. Solar deployment, especially on the distribution system, can bring jobs, savings on electricity bills and enhanced energy resilience. It is critical that these benefits are distributed equitably, and that communities have a voice in the where solar projects are located and how the benefits are allocated.

The past decade was transformative for solar, with rapid cost reductions and subsequent increases in deployment. It is now possible to envision—and chart a path toward—a future where solar provides 40% of the nation's electricity by 2035. This growth is necessary to limit the impacts of climate change, and our work to realize this vision could not be more urgent. There are many challenges to address, requiring diverse skill sets and approaches and extensive collaboration. If you are not already part of the solar community, we hope you will be inspired to join us in this work.

Thank you for taking the time to read our vision for solar's bright future!

Becca Jones-Albertus

Becca Jones-Albertus

Director, U.S. Department of Energy Solar Energy Technologies Office

List of Acronyms

5G	fifth-generation
AC	alternating current
AEO	Annual Energy Outlook
AI	artificial intelligence
ANM	active network management
ARPA-E	Advanced Research Projects Agency–Energy
ATB	Annual Technology Baseline
BA	balancing area
BIPV	building-integrated PV
BoM	bill of materials
BOS	balance of systems
CAISO	California Independent System Operator
CapEx	capital expenditures
CARE	California Alternate Rates for Energy
CC	combined cycle
CCS	carbon capture and sequestration
CCUS	carbon capture, utilization, and sequestration
CDR	carbon dioxide removal
CdTe	cadmium telluride
CE	circular economy
c-Si	crystalline silicon
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
Decarb	Decarbonization
Decarb+E	Decarbonization with Electrification
DER	distributed energy resource
DERMS	DER management systems
DfC	design for circularity
dGen	Distributed Generation (model)
DMS	distribution management systems
DOE	U.S. Department of Energy
DPV	distributed photovoltaics
DR	demand response
DSO	distribution system operator
DUPV	distributed utility-scale PV
EFS	*Electrification Futures Study*
EOL	end of life
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
EVA	ethylene-vinyl acetate
FCEV	fuel cell electric vehicle
FERC	Federal Energy Regulatory Commission
FFR	fast-frequency response
FPV	floating PV

FRCC	Florida Reliability Coordinating Council
GDP	gross domestic product
GFM	grid-forming inverter
GHG	greenhouse gas
GIS	geographic information systems
Gt	gigaton(s)
GW	gigawatt(s)
HDV	heavy-duty vehicle
HHV	higher heating value
HVAC	heating, ventilation, and air conditioning
IAS	integrated agricultural systems
IBC	interdigitated back contact
IBR	inverter-based resource
IEA	International Energy Agency
ILR	inverter-loading ratio
IRP	integrated resource planning
IT	information technology
ITRPV	International Technology Roadmap for Photovoltaics
LCA	life cycle analysis
LCOE	levelized cost of energy
LCOS	levelized cost of storage
LDV	light-duty vehicle
Li-ion	lithium-ion
LMI	low- and medium-income
MDV	medium-duty vehicle
MISO	Midcontinent Independent System Operator
ML	machine learning
MLPE	module-level power electronics
Mt	million metric ton(s)
NG	natural gas
NO$_x$	nitrogen oxides
NREL	National Renewable Energy Laboratory
NWS	non-wires solutions
NYISO	New York Independent System Operator
O&M	operations and maintenance
OT	operational technology
PERC	passivated emitter and rear cell
PFR	primary frequency response
PII	permitting, inspection, and interconnection
PM	particulate matter
POLO	polycrystalline silicon on oxide
PRAS	Probabilistic Resource Adequacy Suite
PSH	pumped-storage hydropower
PSS	product service system
PV	photovoltaic(s)
PV ICE	PV in Circular Economy tool

PWh	petawatt-hour
Quad	quadrillion Btus
R&D	research and development
RA	resource adequacy
RCRA	Resource Conservation and Recovery Act
RE	renewable energy
RE-CT	renewable energy combustion turbine
ReEDS	Regional Energy Deployment System
SCADA	supervisory control and data acquisition
SCC	social cost of carbon
sCO_2	supercritical carbon dioxide
SEIA	Solar Energy Industries Association
SETO	Solar Energy Technologies Office
SHJ	silicon heterojunction
SIPH	solar industrial process heat
SO_2	sulfur dioxide
SPP	Southwest Power Pool
SVTC	Silicon Valley Toxics Coalition
T&D	transmission and distribution
TCLP	toxicity characteristic leaching procedure
TES	thermal energy storage
TLS	transport layer security
TOPCon	tunnel oxide passivated contact
TRP	Technical Review Panel
TSO	transmission system operator
UPV	utility-scale photovoltaics
USMCA	United States–Mexico–Canada Agreement
VACAR	Virginia-Carolinas
VRE	variable renewable energy
W_{AC}	watts alternating current
W_{DC}	watts direct current
WH	water heating
WHEJAC	White House Environmental Justice Advisory Council
WRF	Weather Research and Forecasting

Executive Summary

Dramatic improvements to solar technologies and other clean energy technologies have enabled recent rapid growth in deployment and are providing cost-effective options for decarbonizing the U.S. electric grid. The *Solar Futures Study* explores the role of solar in decarbonizing the grid. Through state-of-the-art modeling, the study envisions deep grid decarbonization by 2035, as driven by a required emissions-reduction target. It also explores how electrification could enable a low-carbon grid to extend decarbonization to the broader energy system (the electric grid plus all direct fuel use in buildings, transportation, and industry) through 2050.

The *Solar Futures Study* uses a suite of detailed power-sector models to develop and evaluate three core scenarios. The "Reference" scenario outlines a business-as-usual future, which includes existing state and federal clean energy policies but lacks a comprehensive effort to decarbonize the grid. The "Decarbonization (Decarb)" scenario assumes policies drive a 95% reduction (from 2005 levels) in the grid's carbon dioxide emissions by 2035 and a 100% reduction by 2050. This scenario assumes more aggressive cost-reduction projections than the Reference scenario for solar as well as other renewable and energy storage technologies, but it uses standard future projections for electricity demand. The "Decarbonization with Electrification (Decarb+E)" scenario goes further by including large-scale electrification of end uses. The study also analyzes the potential for solar to contribute to a future with more complete decarbonization of the U.S. energy system by 2050, although this analysis is simplified in comparison to the grid-decarbonization analysis and thus entails greater uncertainty.

Even under the Reference scenario, installed solar capacity increases by nearly a factor of 7 by 2050, and grid emissions decline by 45% by 2035 and 61% by 2050, relative to 2005 levels. That is, even without a concerted policy effort, market forces and technology advances will drive significant deployment of solar and other clean energy technologies as well as substantial decarbonization. The target-driven deep decarbonization of the grid modeled in the Decarb and Decarb+E scenarios yields more extensive solar deployment, similarly extensive deployment of wind and energy storage, and significant expansions of the U.S. transmission system. In 2020, about 80 gigawatts (GW) of solar, on an alternating-current basis,[1] satisfied around 3% of U.S. electricity demand. By 2035, the decarbonization scenarios show cumulative solar deployment of 760–1,000 GW,[2] serving 37%–42% of electricity demand, with the remainder met largely by other zero-carbon resources, including wind (36%), nuclear (11%–13%), hydroelectric (5%–6%), and biopower/geothermal (1%). By 2050, the Decarb and Decarb+E scenarios envision cumulative solar deployment of 1,050–1,570 GW, serving 44%–45% of electricity demand, with the remainder met by wind (40%–44%), nuclear (4%–5%), hydropower (3%–5%), combustion turbines run on zero-carbon synthetic fuels such as hydrogen (2%–4%), and biopower/geothermal (1%) (Figure ES-1). Sensitivity analyses show that decarbonization can also be achieved via different technology mixes at similar costs.

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[1] Unless otherwise noted, capacity numbers in this report are reported in alternating-current terms. We assume an inverter loading ratio (ILR) of 1.3 for utility-scale photovoltaics (PV). ILRs for distributed PV vary but are usually lower.

[2] In the core Solar Futures scenarios, PV constitutes the vast majority of solar capacity deployed. Less concentrating solar power (CSP) capacity is installed, although CSP plays a significant role in the Decarb scenario by 2050.

Although the *Solar Futures Study* emphasizes decarbonizing the grid, the Decarb+E scenario envisions decarbonization of the broader U.S. energy system through large-scale electrification of buildings, transportation, and industry. In this scenario, electricity demand grows by about 30% from 2020 to 2035, owing to electrification of fuel-based building demands (e.g., heating), vehicles, and industrial processes. Electricity demand increases by an additional 34% from 2035 to 2050. By 2050, all these electrified sectors are powered by zero-carbon electricity. In this scenario, the combination of grid decarbonization and electrification abates more than 100% of grid CO_2 emissions relative to 2005 levels (Figure ES-2).
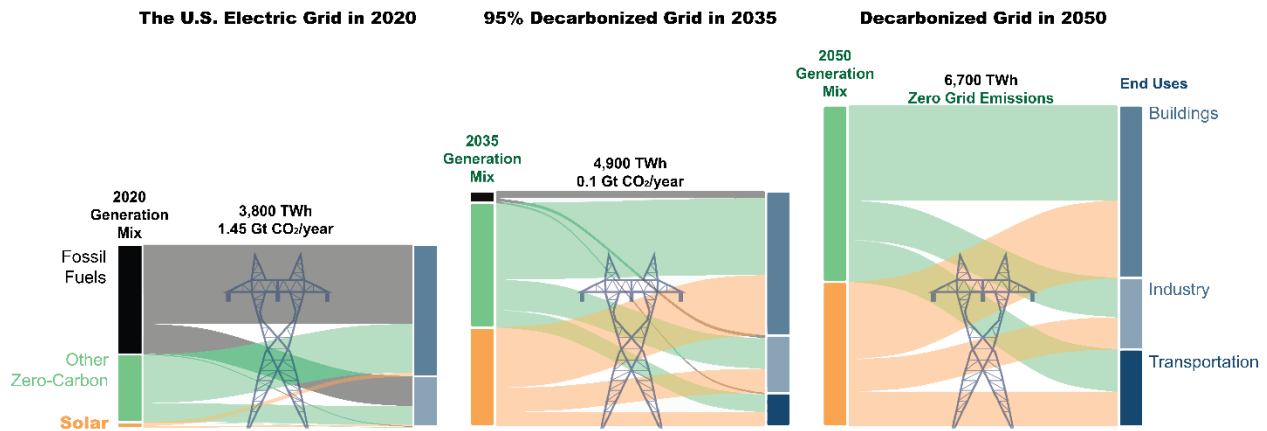
Figure ES-1. Grid mixes and energy flows in 2020, 2035, and 2050 under the Decarb+E scenario
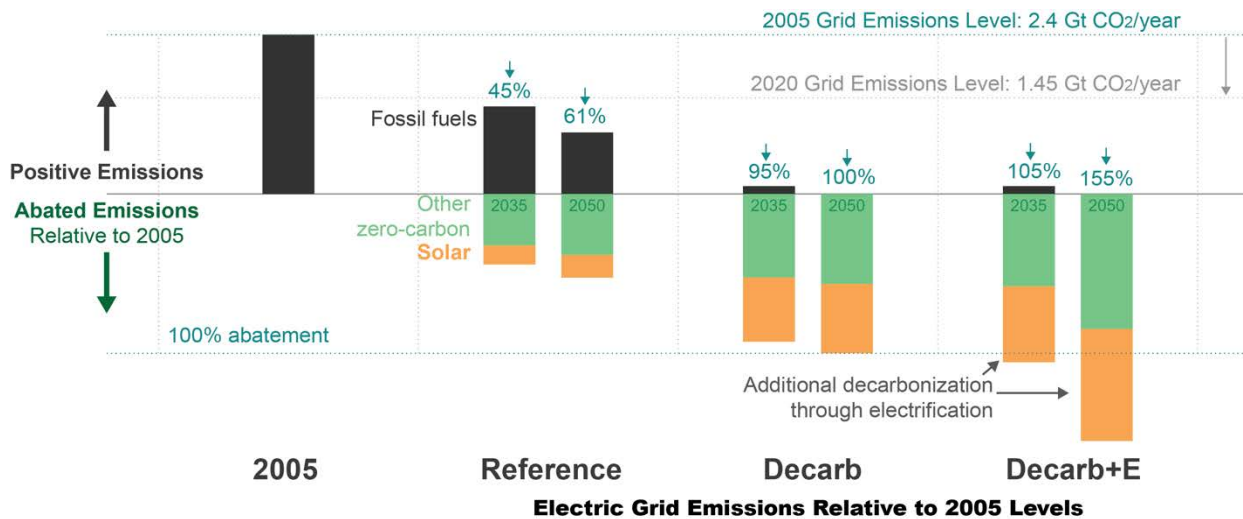
Figure ES-2. Grid emissions and abated grid emissions by scenario in 2035 and 2050, relative to 2005 grid emissions

In terms of the broader U.S. energy system, the Decarb+E scenario reduces CO_2 emissions by 62% in 2050, compared with 24% in the Reference scenario and 40% in the Decarb scenario. The 38% residual in the Decarb+E scenario reflects emissions from direct carbon-emitting fossil fuel use, primarily for transportation and industry. We do not model elimination of these

remaining emissions in detail, but a simplified analysis of 100% decarbonization of the U.S. energy system by 2050 shows solar capacity doubling from the Decarb+E scenario—equating to about 3,200 GW of solar deployed by 2050—to produce electricity for even greater direct electrification and for production of clean fuels such as hydrogen produced via electrolysis.

The *Solar Futures Study* is the most comprehensive review to date of the potential role of solar in decarbonizing the U.S. electricity grid and broader energy system. The study was initiated by the U.S. Department of Energy's Solar Energy Technologies Office and led by the National Renewable Energy Laboratory.

Additional key findings of the study include the following:

- **Achieving the decarbonization scenarios requires significant acceleration of clean energy deployment.** Compared with the approximately 15 GW of solar capacity deployed in 2020, annual solar deployment doubles in the early 2020s and quadruples by the end of the decade in the Decarb+E scenario. Similarly substantial solar deployment rates continue in the 2030s and beyond. Deployment rates accelerate for wind and energy storage as well.

- **Continued technological progress in solar—as well as wind, energy storage, and other technologies—is critical to achieving cost-effective grid decarbonization and greater economy-wide decarbonization.** Research and development (R&D) can play an important role in keeping these technologies on current or accelerated cost-reduction trajectories. For example, a 60% reduction in PV energy costs by 2030 could be achieved via improvements in photovoltaic efficiency, lifetime energy yield, and cost. Higher-temperature, higher-efficiency concentrating solar power technologies also promise cost and performance improvements. Further advances are also needed in areas including energy storage, load flexibility, generation flexibility, and inverter-based resource capabilities for grid services. With the requisite improvements, solar technologies may proliferate in novel configurations associated with agriculture, waterbodies, buildings, and other parts of the built environment.

- **Solar can facilitate deep decarbonization of the U.S. electric grid by 2035 without increasing projected 2035 electricity prices if targeted technological advances are achieved.** In the Decarb and Decarb+E scenarios, 95% decarbonization is achieved in 2035 without increasing electricity prices (compared with Reference scenario marginal system costs of electricity), because decarbonization and electrification costs are fully offset by savings from technological improvements and enhanced demand flexibility.

- **For the 2020–2050 study period, the benefits of achieving the decarbonization scenarios far outweigh additional costs incurred.** Cumulative (2020–2050) power-system costs are one measure of the long-term economics of the decarbonization scenarios, helping to capture the impact of long-lived generating technologies. These costs are about $225 billion (10%) higher in the Decarb scenario than in the Reference scenario—reflecting the added cost of capital investments in clean generation, energy storage, and transmission; operations and maintenance of these assets; and the reduced fuel and other expenditures for fossil fuel technologies. Power-system costs are $562 billion (25%) higher in the Decarb+E scenario, but this higher estimate reflects the costs of serving electrified loads previously powered through direct fuel combustion. Using central estimates for electrification costs, the net incremental cost of the Decarb+E scenario is about $210 billion after factoring out offset fuel

expenditures. However, avoided climate damages and improved air quality more than offset those additional costs, resulting in net savings of $1.1 trillion in the Decarb scenario and $1.7 trillion in the Decarb+E scenario.

- **The envisioned solar growth will yield broad economic benefits in the form of jobs and workforce development.** The solar industry already employs around 230,000 people in the United States, and with the level of growth envisioned in the *Solar Futures Study's* scenarios, it could employ 500,000–1,500,000 people by 2035.

- **Challenges must be addressed so that solar costs and benefits are distributed equitably.** Low- and medium-income communities and communities of color have been disproportionately harmed by the fossil-fuel-based energy system, and the clean energy transition presents opportunities to mitigate these energy justice problems by implementing measures focused on equity. This study explores measures related to the distribution of public and private benefits, the distribution of costs, procedural justice in energy-related decision making, the need for a just workforce transition, and potential negative externalities related to solar project siting and disposal of solar materials.

- **Solar can help decarbonize the buildings, transportation, and industrial sectors.** In the Decarb+E scenario, electrification of fuel-based end uses enables solar electricity to power about 30% of all building end uses and 14% of transportation end uses by 2050. For buildings, rooftop solar can increase the value of batteries and investments in load automation systems; distributed batteries and load automation can, in turn, increase the grid value of solar. For transportation, rooftop solar could increase the value of electric vehicle adoption to consumers through a combination of low-marginal-cost electricity and managed charging—and thus could accelerate electrification of the transportation sector. The long-term role of solar electricity in industry is less certain, but industrial process heat from concentrating solar thermal plants can help decarbonize this sector as well. In all three sectors, solar can play a long-term role in producing zero-carbon fuels.

- **Diurnal energy storage enables high levels of decarbonization, but additional clean firm capacity is needed to achieve full grid decarbonization.** In the Decarb+E scenario, storage with 12 hours or less of energy capacity expands by up to 70-fold, from 24 GW in 2019 to more than 1,600 GW in 2050. This diurnal storage complements renewable energy deployment by storing energy when it is less useful to the grid and releasing it when it is more useful. However, because solar and wind occasionally provide insufficient supply for several days, advances in technologies that can provide clean firm capacity at any time are needed to reliably meet demand as full decarbonization is approached.

- **Maintaining reliability in a grid powered primarily by renewable energy requires careful power system planning**. In the decarbonization scenarios, the grid becomes increasingly reliant on weather-dependent inverter-based resources (IBRs) such as PV, representing a dramatic change from the current grid based primarily on synchronous electricity generators. A grid dominated by IBRs will require new approaches to maintain system reliability and exploit the ability of IBRs to respond quickly to system changes. New approaches may also be required for high-solar grids to maintain resilience (defined as the ability of grids to respond to critical events such as natural disasters). Small-scale solar, especially coupled with storage, can enhance resilience by allowing buildings or microgrids to power critical loads during grid outages. In addition, advances in managing distributed

energy resources, such as rooftop solar and electric vehicles, are needed to integrate these resources efficiently into electricity distribution systems.

- **Demand flexibility plays a critical role by providing firm capacity and reducing the cost of decarbonization.** Demand flexibility shifts demand from end uses, such as electric vehicles, to better utilize solar generation. In the Decarb+E scenario, demand flexibility provides 80–120 GW of firm capacity by 2050 and reduces decarbonization costs by about 10%.

- **Developing U.S. solar manufacturing could mitigate supply chain challenges, but different labor standards and regulations abroad create cost-competitiveness challenges.** Global PV supply chains can be constrained by production disruptions, competing demand from other industries or countries, and political disputes. A resilient supply chain would be diversified and not over reliant on any single supply avenue. To enhance the domestic supply chain, American solar technology manufacturers may improve competitiveness by increasing automation and exploiting the advantages of domestically manufacturing certain components. Policies can help promote domestic solar manufacturing.

- **Material supplies related to technology manufacturing likely will not limit solar growth in the decarbonization scenarios, especially if end-of-life materials displace use of virgin materials via circular-economy strategies.** Under the decarbonization scenarios, demands for important PV materials are small relative to global production of these materials, even when assuming use of virgin materials only and accounting for simultaneous growth in PV deployment worldwide. Displacing virgin material use through circular-economy strategies would enhance material supplies. However, breakthroughs in technologies and participation in what is currently a voluntary recycling and circular-economy landscape in the United States will be required to maximize use of recoverable materials—yielding benefits to energy and materials security, improved social and environmental outcomes, and opportunities for the domestic workforce and manufacturing sectors.

- **Although land acquisition poses challenges, land availability does not constrain solar deployment in the decarbonization scenarios.** In 2050, ground-based solar technologies require a maximum land area equivalent to 0.5% of the contiguous U.S. surface area. This requirement could be met in numerous ways including use of disturbed lands. The maximum solar land area required is equivalent to less than 10% of potentially suitable disturbed lands, thus avoiding conflicts with high-value lands in current use. Various approaches are available to mitigate local impacts or even enhance the value of land that hosts solar systems. Installing PV systems on waterbodies, in farming or grazing areas, and in ways that enhance pollinator habitats are potential ways to enhance solar energy production while providing benefits such as lower water evaporation rates and higher agricultural yields.

- **Water withdrawals decline by about 90% by 2050 in the decarbonization scenarios.** The water savings result from the low water use of solar and other clean energy generation technologies, compared with fossil fuel and nuclear generators.

- **Achieving the *Solar Futures Study's* vision requires long-term policy and market support in addition to continued innovation.** Decarbonization targets set by policy are critical to decarbonizing more quickly than would occur owing to market conditions alone. Policy also accelerates cost reductions and technological innovations through R&D

investments as well as through driving deployment and reducing costs through learning-by-doing. Even with significant cost and technology improvements, policy will be crucial for promoting decarbonization as the marginal costs of decarbonization increase. In addition, wholesale electricity markets must adapt to the increasingly dominant roles of zero-marginal-cost renewable energy, and retail markets must adapt with rates that reflect the changing grid and an increased role for distributed energy resources. Nascent markets such as those for demand-side services and enhanced energy reliability may need to evolve to optimize the roles of distributed energy resources, and efforts are needed to expand the use of these resources to traditionally underserved groups.

A dramatically larger role for solar in decarbonizing the U.S. electricity system, and energy system more broadly, is within reach, but it is only possible through concerted policy and regulatory efforts as well as sustained advances in solar and other clean energy technologies.

Table of Contents

List of Figures

List of Tables

1

Introduction and Summary of Results

1 Introduction and Summary of Results

The U.S. electric grid is one of the world's largest machines, comprising millions of miles of transmission and distribution lines that connect thousands of large-scale electricity generators to end users. The grid has undergone tremendous change in the past decades, in part due to innovations in the solar energy industry. However, in 2020, fossil fuel combustion continued to generate most U.S. electricity, emitting around 1.45 billion metric tons (gigatons, Gt) of heat-trapping carbon dioxide (EIA 2021b).[3] Rapid grid decarbonization is a key component of international measures to keep the global temperature rise below 2°C and prevent the worst impacts of climate change. Governments, businesses, and individuals worldwide are increasingly seeking the economic, social, and environmental benefits of clean, zero-carbon electricity.

The United States is the largest source of cumulative carbon emissions and the second-largest annual emitter. On its current trajectory, the United States is unlikely to meet its targets for keeping global temperature rise below 2°C as specified under the 2015 Paris Agreement (Liu and Raftery 2021). To help remedy this situation, the Biden Administration has set the ambitious goals of decarbonizing the U.S. electricity grid by 2035 and shifting the nation onto an irreversible path to a 100% clean-energy economy, reaching net-zero emissions by 2050—while strengthening the American economy, creating well-paying domestic jobs, conserving natural resources, and ensuring that the benefits and costs of the clean energy transition are equitably distributed. Reaching these goals will require transitioning existing fossil-fuel-based power plants to zero-carbon energy sources (Jenkins, Luke, and Thernstrom 2018; Larson et al. 2020; Denholm, Arent, et al. 2021; Bouckaert et al. 2021).[4] The result would be an unprecedented transformation of the grid and broader energy system over the next few decades—a challenging, but achievable, task.

Solar energy technologies—primarily photovoltaics (PV) and concentrating solar power (CSP)—will play a unique and central role in grid decarbonization. After decades of innovation and cost reductions, solar is rapidly maturing, and with continued research, development, and deployment, it could potentially serve 40% or more of U.S. electricity demand. Solar is already the lowest-cost form of electricity generation in an increasing number of locations around the globe (Nemet 2019; IEA 2020). It is uniquely modular, capable of being deployed cost-effectively at scales large enough to power cities and small enough to power individual households (Figure 1 - 1). Modularity means solar can play diverse roles, such as directly decarbonizing electricity end uses in buildings, industry, and—increasingly—transportation. Solar is also uniquely diurnal: it relies on daily and seasonal patterns of the rising and setting sun. Although the daily (e.g., related to cloud cover) and seasonal variability of solar poses challenges, the reliably diurnal nature of this variability means that grid operations and electricity demand can be proactively managed to maximize use of low-cost, zero-carbon solar energy.

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[3] Unless otherwise noted, all historical emissions estimates in this report are from (EIA 2021b). EIA emissions estimates vary slightly from other sources, such as (EPA 2018b).

[4] Throughout this report, the term "zero-carbon" refers to electricity generation technologies that do not increase atmospheric carbon dioxide concentrations; it does not imply zero emissions from a life cycle perspective.

Figure 1 - 1. Solar is uniquely modular, deployable at large scales (left) as well as small scales such as rooftop solar (right)

Photos by Reegan Moen, DOE (left) and Dennis Schroeder, NREL 45218 (right)

This *Solar Futures Study* explores the role of solar in decarbonizing the U.S. electric grid. The study is framed around a vision of largely decarbonizing the electric grid (relative to 2005 levels) by 2035.[5] In addition, the study explores how electrifying end uses in buildings, transportation, and industry could enable solar and the grid to play an expanded role in decarbonizing the broader energy system through 2050. Reaching these targets would be a monumental achievement. By our estimates, it will require annual solar deployment (in terms of GW installed per year) to double during the early 2020s and as much as quadruple during the late 2020s, compared with solar deployment in 2020. High deployment rates would be required for wind and energy storage as well. Grid decarbonization alone would eliminate up to about 60% of U.S. energy-based emissions by 2050 under our core decarbonization scenarios.[6] The estimated long-term benefits from climate change mitigation and avoided public health costs in the scenarios are on the order of trillions of dollars. The other half of remaining emissions reflects carbon-emitting fossil fuel combustion to directly power end uses in buildings, transportation, and industry. Other solar strategies that could be pursued to reduce the remaining emissions include using solar-produced fuels (such as solar-produced hydrogen) and directly using solar thermal energy from CSP.

The *Solar Futures Study* uses the state-of-the-art modeling capabilities of the U.S. National Renewable Energy Laboratory (NREL). We explore what it will take to achieve solar deployment at the pace and scale envisioned in our scenarios, including by exploring the synergies between solar technologies and energy storage, and the necessary transformations of the U.S. electric grid. We discuss key technological advances that could enable unprecedented solar deployment. We also explore the roles of solar in decarbonizing energy end uses in buildings, transportation, and industry. Finally, we explore the broader macroeconomic, energy justice, social, and environmental implications of a solar-centric clean energy transition.

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[5] The 2005 benchmark is based on U.S. goals set under the Paris Agreement. Unless otherwise noted, all decarbonization estimates are relative to 2005.

[6] Energy-based emissions are emissions that result directly from energy generation. Most non-energy emissions reflect CO_2 emitted as a result of chemical reactions in industrial processes, and agriculture is a primary source of other carbon emissions such as methane. While energy-based emissions from industry are in the scope of our study, all non-energy emissions are outside the scope. Total economy-wide emissions are about 5.3 Gt CO_2/year.

In this section, we briefly introduce each report topic and summarize key results. Additional details, results, methods, and references are in the body of the report. We begin with an introduction to the current U.S. energy system.

The Current U.S. Energy System

Most carbon emissions in the United States come from fossil fuel combustion to power end uses in buildings (36% of energy-based emissions), transportation (36% of energy-based emissions), and industry (29% of energy-based emissions), based on 2020 estimates. Burning fossil fuels to generate electricity emits around 1.45 Gt of carbon dioxide per year, or about 32% of the U.S. energy system's emissions. The other 68% of emissions comes from the direct use of combusted fuels, primarily to heat buildings, power vehicles, and fuel industrial processes.

The scale of this challenge is illustrated in Figure 1 - 2, which depicts existing fossil fuel shares in electricity and direct fuel use. Put simply, the task is to convert the dominant carbon-emitting fossil fuels (gray and dark blue flows) to mostly zero-carbon resources (green flows) by 2050. Our study focuses on the bottom third of these flows, those from the electric grid. However, the current contribution of the grid to U.S. energy-based emissions understates the role of the grid in energy system decarbonization. Our core scenarios envision grid expansion over time as more end uses are electrified, especially in transportation and industry. In effect, grid decarbonization coupled with electrification allows zero-carbon grid electricity resources—such as solar—to decarbonize loads that are outside the existing grid.
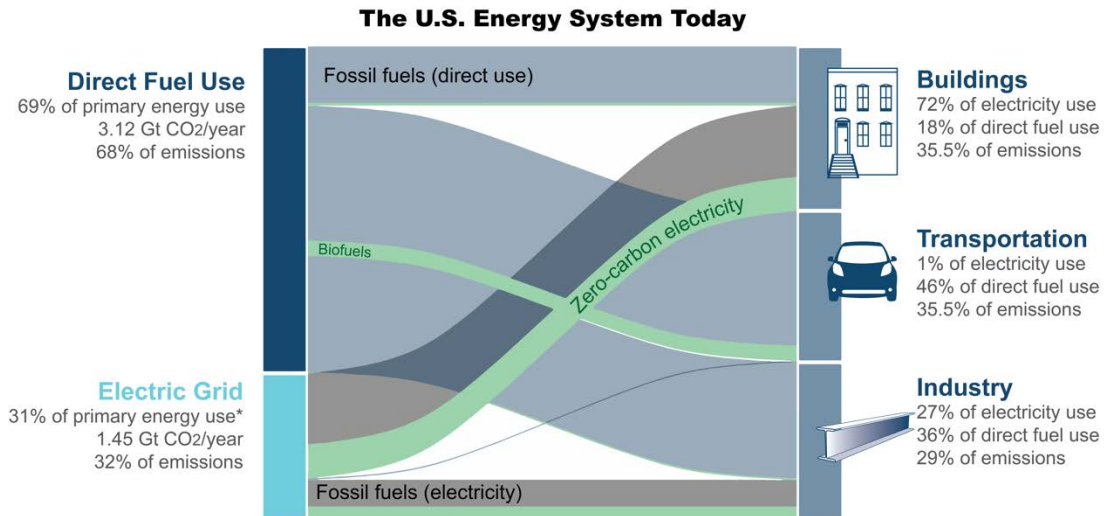
Figure 1 - 2. Primary energy flows in the existing U.S. energy system (2020 data)

This figure is based on energy use and emissions data from the U.S. Energy Information Administration.
*Electricity generation was converted to primary energy use assuming an average generator efficiency rate of 36% for all non-fossil generators. The plot maps energy output on the left to the end uses of that output on the right.

The *Solar Futures* Scenarios (Chapter 2)

Our study is based on three core scenarios (Table 1 - 1), all implemented using NREL's Regional Energy Deployment System (ReEDS) model. The "Reference" scenario represents a projection of solar deployment and grid decarbonization assuming ongoing, moderate technology cost reductions but without a required emissions-reduction target. In two decarbonization scenarios,

the ReEDS model is constrained to eliminate 95% of grid emissions by 2035 and 100% of emissions by 2050 (relative to 2005 levels). Both decarbonization scenarios assume more aggressive cost-reduction projections than the Reference scenario for solar (PV and CSP) as well as other renewable (biopower, geothermal, hydropower, onshore and offshore wind) and storage (batteries and pumped-storage hydropower) technologies.[7] These cost reductions affect projected decarbonization costs and the deployment trajectories of individual technologies, but they do not affect the decarbonization trajectory, which is determined by the emissions constraints. The key differences between the two decarbonization scenarios relate to electricity demand. In the "Decarbonization (Decarb)" scenario, we use standard future projections for electricity demand. The "Decarbonization with Electrification (Decarb+E)" scenario goes further by including large-scale electrification of buildings and transportation, meaning a significant increase in electricity demand and an expanded role for the grid in decarbonizing the broader U.S. energy system. Although electrification under the Decarb+E scenario is extensive compared to the other core scenarios, it does not represent complete electrification or emissions reduction for the energy system. In all three core scenarios, the model ensures the system can adequately serve hourly load, even during extended periods with limited sunlight. See Section 2.1 for scenario details.

Table 1 - 1. *Solar Futures* Scenarios Definitions

Scenario Name	Renewable Energy and Storage Technologies	Demand Flexibility	Electricity Demand	Policies
Reference	Moderate cost reductions	None	U.S. Energy Information Administration Reference	Existing policies* as of June 2020
Decarbonization (Decarb)	Advanced cost reductions	None	U.S. Energy Information Administration Reference	Existing policies* + 95% reduction in CO_2 emissions from 2005 levels by 2035, 100% by 2050
Decarbonization with Electrification (Decarb+E)	Advanced cost reductions	Enhanced	High electrification based on NREL Electrification Futures Study	Existing policies* + 95% reduction in CO_2 emissions from 2005 levels by 2035, 100% by 2050

* The existing policies assumed include state renewable and clean energy mandates, state and regional emissions limits, and federal tax incentives.

Even under the Reference scenario, installed solar capacity increases by a factor of eight by 2050, while grid emissions decline by 61% relative to 2005 levels. That is, even without a

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[7] The analysis does not consider all technologies that may be critical in decarbonized energy systems, including carbon dioxide removal (CDR) technologies, small modular nuclear reactors, fuel cells, and seasonal energy storage options.

binding emissions constraint, we project that market forces alone will drive significant deployment of solar and other clean energy technologies and eliminate significant grid emissions.[8] Grid decarbonization becomes more difficult and costly as the grid reaches higher levels of decarbonization (Cole et al. 2021; Denholm, Arent, et al. 2021). Eliminating the last 5%–10% of emissions poses particular challenges. The increasing difficulty of decarbonization affected our study design (see Text Box 1).

Text Box 1. Why 95% grid decarbonization by 2035?

The Biden Administration is targeting a 100% reduction in grid emissions by 2035. The *Solar Futures Study* focuses on scenarios achieving 95% decarbonization by 2035 and 100% decarbonization by 2050. Here, we explain why we did not constrain our models to eliminate the final 5% of emissions by 2035.

This study explores the role of solar in grid decarbonization. This role is essentially the same regardless of whether the goal is 95% or 100% by 2035 (see figure). However, achieving 95% or 100% grid decarbonization by 2035 entails substantial differences in costs and the need for other clean energy technologies.
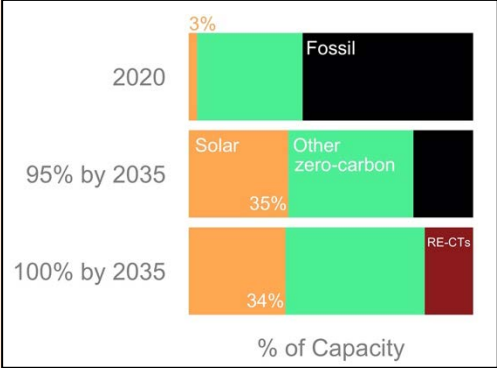
Grid decarbonization costs increase non-linearly; the cost to decarbonize the last 5% of emissions is much higher than the cost to decarbonize the first 5% (Denholm, Arent, et al. 2021). Further, the technologies needed to eliminate the last 5% of emissions are those that can provide clean, firm capacity, such as clean peaking capacity and carbon capture. These technologies are more difficult to model given their more uncertain cost and deployment trajectories. To maintain our focus on solar and avoid the significant uncertainties related to decarbonizing the last few percent, we exclude the results of a 100%-by-2035 scenario (presented in Appendix 2-B) from our core findings.

As we extend the model from 2035 to 2050, which has higher inherent uncertainty due to the longer timeframe, our core decarbonization scenarios do target a 100% carbon-free grid. This longer period provides an opportunity to explore the challenges and technology characteristics associated with decarbonizing the last 5%. However, the deployment and cost results for the post-2035 period entail greater uncertainties.

Finally, the Biden Administration set a long-term goal of achieving net-zero emissions in the U.S. economy by 2050. A net-zero economy implies substantial decarbonization of all energy sectors, including the grid and direct use of fuels (e.g., gasoline for vehicles), as well as non-energy emissions from industry and agriculture. We focus on grid decarbonization—for which

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[8] Under the Reference scenario, which uses moderate technology cost reductions, solar generation constitutes 18% of total generation (from 375 GW) in 2035 and 27% (674 GW) in 2050. With advanced technology cost reductions for all renewable and battery technologies (but without a national emissions target or increased electrification), estimated solar shares rise to 28% (562 GW) in 2035 and 36% (869 GW) in 2050.

solar has the most direct impact—while exploring potential roles for solar in decarbonizing the rest of the economy. We model how increased electrification of buildings, transportation, and industry could expand the role of solar beyond the existing grid in one of the core scenarios (Decarb+E). We also analyze a simplified scenario focusing on decarbonization of the energy system (the grid plus direct fuel use) by 2050 (see Section 2.3). Non-energy emissions are outside the scope of our study. Assessing pathways for achieving a net-zero economy, and the role of solar in this effort, is an area of ongoing research.

Clean Energy Deployment

Our decarbonization scenarios envision greater expansion of solar, wind, energy storage, and electric transmission infrastructure. In 2020, about 80 gigawatts (GW) of solar, on an alternating-current (AC) basis,[9] powered around 3% of U.S. electricity demand. By 2035, the decarbonization scenarios envision cumulative deployment of 760–1,000 GW,[10] serving 37%–42% of electricity demand (Figure 1 - 3). By 2050, those scenarios envision cumulative deployment of 1,050–1,570 GW, serving 44%–45% of electricity demand on an energy (MWh) basis. We estimate that roughly 80%–90% of that capacity will be utility-scale solar, with the remainder coming from smaller-scale distributed solar. Cumulative deployed solar capacity in the Decarb+E scenario is about 1.4 times greater than the capacity of the entire existing electric grid. Although the scale of this task is challenging, we show that these scenarios provide a realistic vision for a decarbonized grid. Further, we explore how this transition could be achieved with an equitable distribution of significant, long-term net benefits across the United States. See Section 2.2 for additional results, including deployment projections for other clean energy technologies.

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[9] Unless otherwise noted, capacity numbers in this report are reported in AC terms. We assume an inverter loading ratio (ILR) of 1.3 for utility-scale PV (UPV). ILRs for distributed PV (DPV) vary but are usually lower.

[10] In the core Solar Futures scenarios, PV constitutes the vast majority of solar capacity deployed. Less CSP capacity is installed, although CSP plays a significant role in the Decarb scenario by 2050.

Projected Solar Deployment (GW)
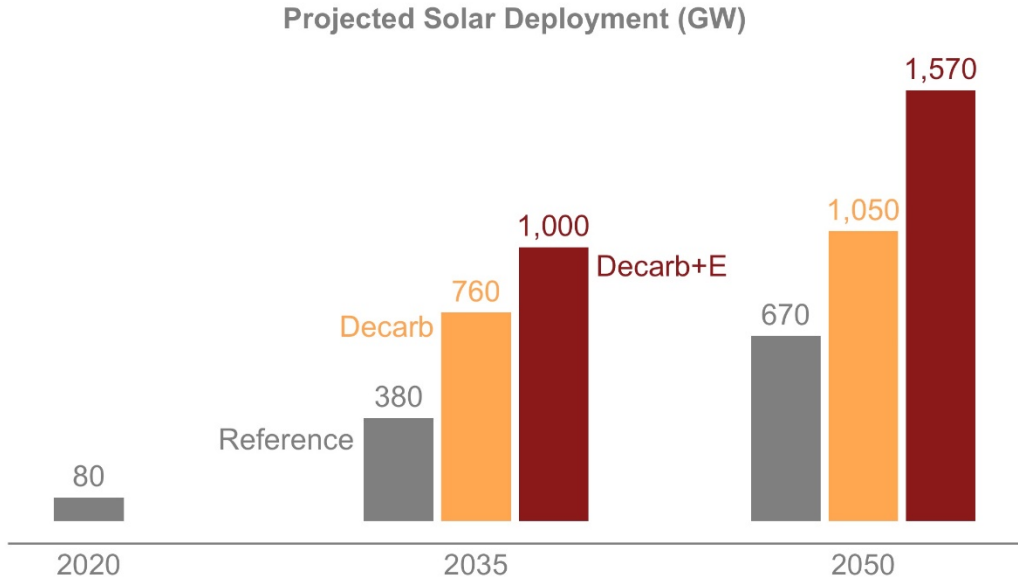
Figure 1 - 3. Projected solar deployment under the *Solar Futures* scenarios

Figure 1 - 4 compares the electricity generation mix of the U.S. grid in 2020 to the grid mix envisioned in the Decarb+E scenario in 2035. (The generation mix in the Decarb scenario shows a similar mix of resources, but they are scaled down to meet lower electricity demand.) The figure illustrates two key mechanisms for decarbonization: grid decarbonization and electrification. Grid decarbonization is depicted by the significant reduction in carbon-emitting fossil fuel flows in the Decarb+E grid mix in 2035. In 2020, about 60% of electricity came from carbon-emitting fossil fuel combustion in more than 1,000 coal and natural gas plants. By 2035, solar accounts for about 37% in the Decarb+E scenario, and the remainder is met largely by other zero-carbon resources, including wind (36%), nuclear (11%–13%), hydroelectric (5%–6%), and biopower and geothermal (1%) sources. The impact of electrification is illustrated by the overall growth of the grid: electricity demand grows by about 30% from 2020 to 2035 in the Decarb+E scenario, owing in part to the electrification of fuel-based building loads, vehicles, and some industrial processes.

The U.S. Electric Grid in 2020

Electric Grid in 2035
Based on Decarb+E Scenario
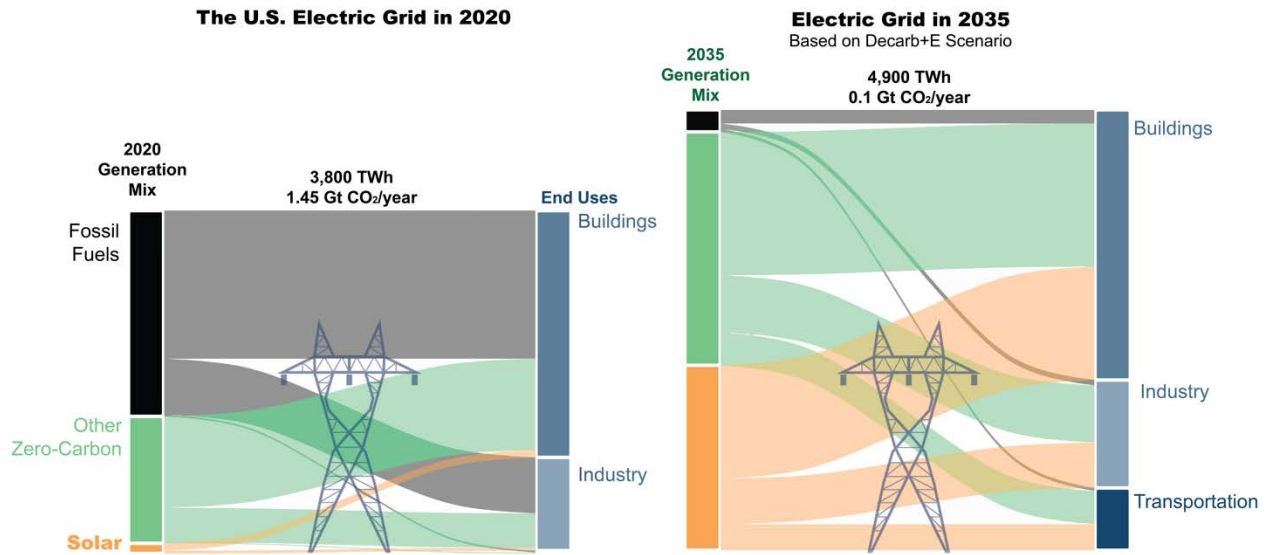
Figure 1 - 4. Grid mixes and energy flows in 2020 and 2035 under the Decarb+E scenario

The same trends from 2020 to 2035 depicted in Figure 1 - 4 continue from 2035 to 2050, as illustrated in Figure 1 - 5. The electricity demand increases by an additional 40%, largely due to the continued electrification of transportation. In 2050, in the Decarb+E scenario, all electricity generation is met by zero-carbon resources, mostly solar (45%) and wind (44%), as well as nuclear (4%), hydropower (4%), combustion turbines run on zero-carbon synthetic fuels such as hydrogen (2%), and biopower and geothermal (1%).

The U.S. Electric Grid in 2020   **95% Decarbonized Grid in 2035**   **Decarbonized Grid in 2050**
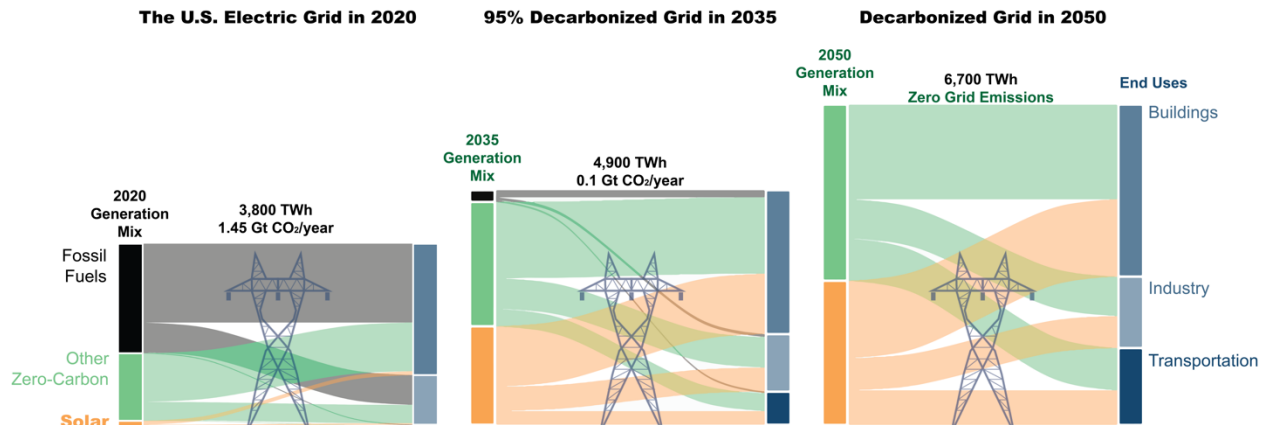
Figure 1 - 5. Grid mixes and energy flows in 2020, 2035, and 2050 under the Decarb+E scenario

Emissions Reductions

Figure 1 - 6 illustrates the impacts of the scenarios in terms of the abatement of grid emissions (i.e., emissions from combustion of carbon-emitting fossil fuels to generate electricity), relative to emissions levels in 2005. Grid emissions decline even in the Reference scenario, a reflection of the impacts of ongoing cost reductions in clean energy technologies. The Decarb scenario envisions a 95% reduction in grid emissions by 2035 and a 100% reduction in grid emissions by 2050. In the Decarb+E scenario, grid emissions are reduced by about 105% by 2035 and 155% by 2050 relative to 2005 levels. These extra abated emissions reflect the impact of electrification in the Decarb+E scenario. The zero-carbon grid in the Decarb+E abates not only the emissions of

today's grid, but also the emissions of formerly fuel-based end uses, particularly in transportation.
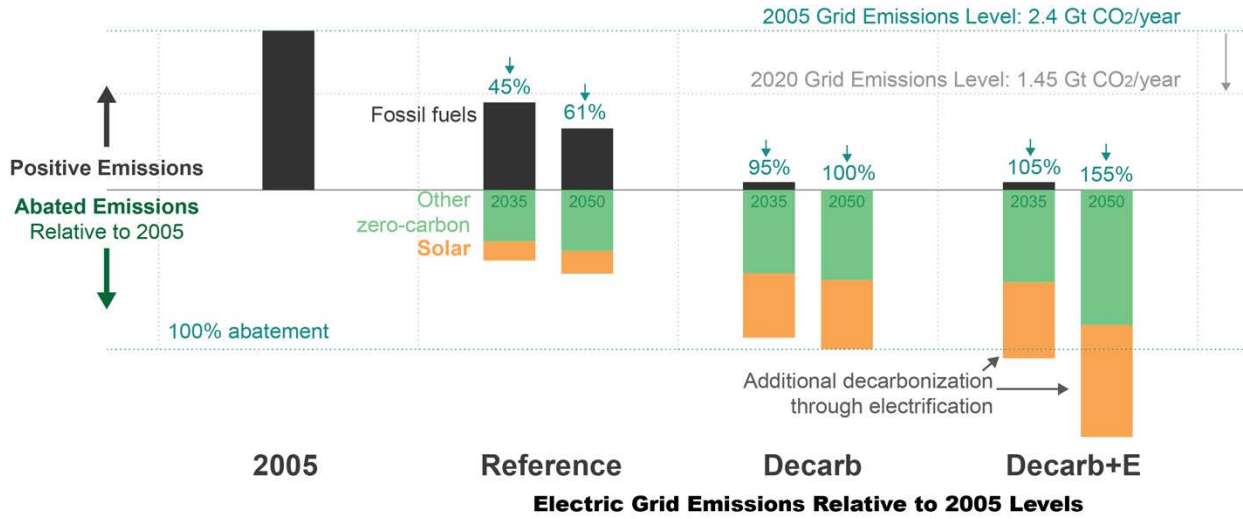
Figure 1 - 6. Grid emissions and abated grid emissions by scenario in 2035 and 2050, relative to 2005 grid emissions

The grid emissions reductions in the Decarb and Decarb+E scenarios result in 40% and 62% reductions in total U.S. energy system emissions by 2050 relative to 2005 levels, respectively, compared to a 24% reduction in the Reference scenario. The 38% residual in the Decarb+E scenario reflects emissions from direct carbon-emitting fossil fuel use, primarily for transportation and industry. A net-zero emissions energy sector may be achieved by 2050 through strategies including further electrification, energy efficiency, decarbonized fuels, renewable heat production including solar industrial process heat (SIPH), and the capture and sequestration of carbon. Although decarbonization of these fuel-based applications is not modeled in detail in this study,[11] solar technologies could play an important role in this effort. Using a simple sensitivity analysis to develop a first-order approximation of solar's role under a fully decarbonized 2050 U.S. energy system (i.e., grid and all fuels are decarbonized), we find that solar capacity doubles from the Decarb+E scenario, equating to about 3,200 GW of solar deployed by 2050. Thus, full decarbonization of the energy system could entail a substantially larger role for solar.

Energy Storage, Transmission, and Load Flexibility

In addition to an expansion of clean energy generation technologies, the *Solar Futures* vision relies on substantial expansions of four strategies to manage variable solar output. The first is to allow solar systems to generate according to variable solar profiles, curtailing solar when the grid cannot absorb that output. Solar curtailment can be a cost-effective way to integrate solar, particularly in the near term. Actively managed or planned curtailment can provide valuable grid services and enable additional solar deployment. The other three approaches are to temporally shift solar output, spatially shift solar output, or shift demand to better utilize solar output. These three approaches can be achieved through energy storage, transmission expansion, and demand

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[11] Full energy system decarbonization is being modeled in detail under other DOE initiatives.

flexibility, respectively, all three of which are projected to increase substantially based on the *Solar Futures* vision (Figure 1 - 7).
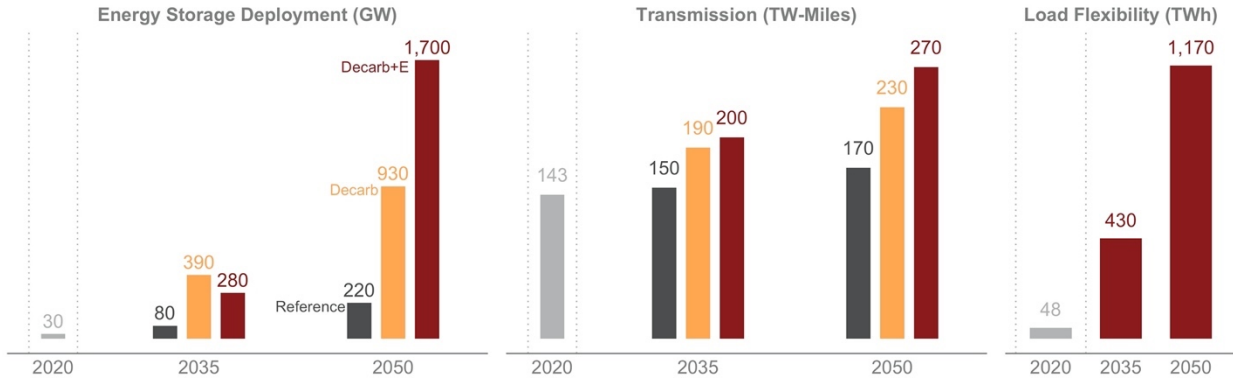
Figure 1 - 7. Projected deployment of storage (left), transmission (center), and load flexibility (right), under the *Solar Futures* scenarios

Load flexibility is not modeled in the Reference and Decarb scenarios. The load flexibility estimate in 2020 is based on the Decarb+E scenario. Only interregional transmission lines are reported here.

Transmission lines carry electricity—in some cases over hundreds of miles—from generators to load centers. Transmission expansions make the grid more flexible and enable solar integration. For instance, solar output is often curtailed because of an oversupply of solar at one location where there is not enough transmission capacity to move the output somewhere else. Transmission expansions alleviate these constraints. Through transmission expansions, abundant solar power in one location can be moved to satisfy demand in a geographically remote area. Further, transmission expansions can extend the grid to solar-rich regions that are geographically isolated from load centers. The Decarb+E scenario envisions a 90% expansion of the existing U.S. transmission network relative to the Reference scenario.

Load flexibility refers to the inherent capabilities of certain loads to be shifted over time or space. Load flexibility is a largely untapped grid resource. Large-scale electrification, advances in information and communication technologies, and system automation could create a significant future role for load flexibility as a grid resource. Load flexibility is a key ingredient to efficiently integrate solar in the Decarb+E scenario. Many building loads can be shifted to optimize solar use. Electric vehicle chargers can be controlled to maximize daytime charging. Some industrial loads can be similarly shifted over time, or even shifted geographically, to exploit different solar conditions at different points on the grid. In the Decarb+E scenario, load flexibility provides about 80–120 GW of firm capacity by 2050 and reduces the marginal power system costs of decarbonization by about 10%.

Costs and Benefits

In all scenarios, costs are incurred for capital investments in clean generation, storage, and transmission, and for operations and maintenance as well as fuel (where applicable) for these assets. These costs affect electricity costs. Figure 1 - 8 shows the national-average *marginal* system cost of electricity in 2035 and 2050 for the core scenarios, along with four factors—technology cost, emissions policy, electrification, and demand-side flexibility—that influence the

relative scenario costs.[12] In 2035, the marginal system cost of electricity in the Decarb scenario remains very similar to that of the Reference scenario, despite the emissions cap applied in the Decarb scenario. This is due to offsetting impacts of technology advancements and the emissions constraint.[13] In the Decarb+E scenario, demand flexibility offsets higher electrification-driven costs such that the 2035 electricity cost is slightly below the costs of the other two scenarios.[14] In other words, the combination of advancements in solar and other clean technologies and flexible demand could support substantial (95%) grid emission reductions with little or no increase in marginal electricity costs.
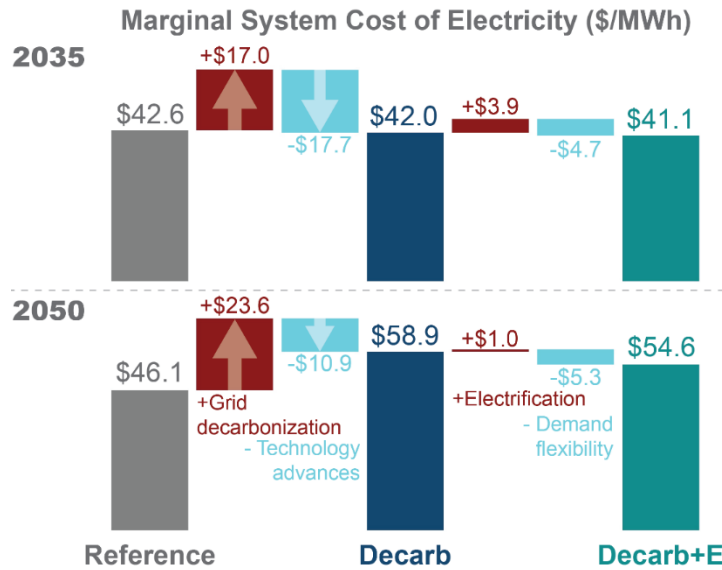
Figure 1 - 8. Marginal system cost of electricity estimates and drivers in 2035 (top) and 2050 (bottom) for the core scenarios

In 2050, incremental power system costs increase electricity costs in the Decarb and Decarb+E scenarios, relative to the Reference scenario, despite the greater renewable and storage technology advancements assumed in the decarbonization scenarios (Figure 1 - 8). This result highlights the challenges of 100% elimination of grid emissions, as well as the opportunities for innovation to create lower-cost decarbonization pathways that rely on technologies not modeled here (e.g., carbon dioxide removal technologies).

Cumulative power-system costs are another measure of the economics of the decarbonization scenarios, helping to capture the impact of long-lived generating technologies. We estimate the present value of incremental cumulative power-system costs (2020–2050, 5% real discount rate)

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[12] The marginal system cost of electricity is a measure that is similar to the electricity price from restructured power markets. The marginal system cost of electricity reflects the cost to serve the next increment of demand. See further details in Section 2.2. Unless otherwise noted, real 2018 dollars are used for all economic values reported.

[13] The Decarb and Decarb+E scenarios assume more technological progress in solar and other clean energy technologies than the Reference scenario. The R&D expenditures that may be required for these clean energy technology improvements are not captured in this metric or any other cost measure reported in this chapter.

[14] The cost to implement and operate demand flexibility, which would reduce the benefits of flexible loads to lower marginal costs, is not modeled.

for the Decarb and Decarb+E scenarios, relative to the Reference scenario. These incremental costs are $225 billion (10%) in the Decarb scenario, reflecting the added cost of solar and other zero-carbon and supporting capacity after factoring out the reduced fuel and other expenditures for fossil fuel technologies. The incremental power-system costs increase to $562 billion (25%) in the Decarb+E scenario because of the costs of serving electrified demand that was formerly powered by direct fuel combustion. Using a central estimate of electrification costs and fuel savings, the total incremental system cost (power and non-power sectors) of the Decarb+E scenario is about $210 billion. For context, these incremental system costs are about 0.05% of the present value of projected U.S. gross domestic product over the same period. These estimates are highly sensitive to underlying assumptions and potential cost-reducing innovations in clean energy technologies.

The estimated long-term benefits of achieving the *Solar Futures* vision far outweigh the costs (Figure 1 - 9). We estimate cumulative savings (2020–2050, 5% real discount rate) of about $1 trillion from avoided climate change damages and $300 billion from air quality improvements in the Decarb scenario, compared with the Reference scenario. As a result of electrification, in the Decarb+E scenario, these benefits increase to $1.6 trillion for avoided climate change damages and $400 billion for air quality improvements. Although these national climate change and air quality benefits are large, policies will be needed to monetize and distribute them equitably and in a way that incentivizes clean energy deployment.

Central estimates for net *savings* are $1.1 trillion and $1.7 trillion in the Decarb and Decarb+E scenarios (Figure 1 - 9). See Section 2.2.6 for additional details on estimated costs and benefits, as well as uncertainties.
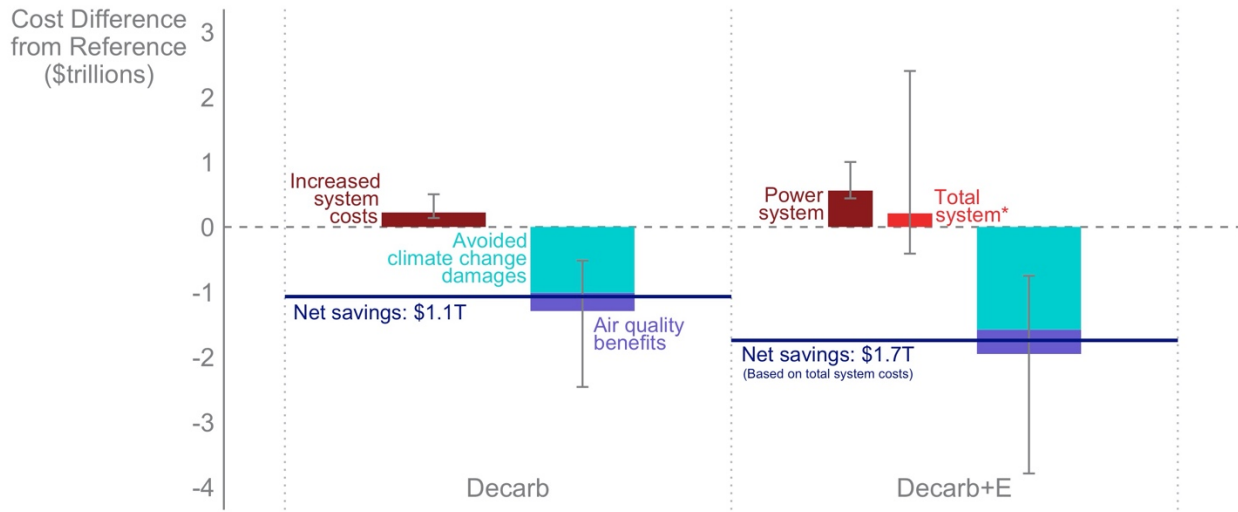
Figure 1 - 9. Estimated cost differences between decarbonization scenarios and Reference scenario, cumulative 2020–2050

Bars represent central estimates; lines represent estimates from sensitivity analyses. *Total system includes incremental power and non-power system costs.

Advances in Grid Technologies and Services (Chapter 3)

Solar is a proven technology, but effective widespread deployment also requires changes in grid operations and long-term planning. One key challenge is that the two primary generation sources in our scenarios, solar and wind, are variable, meaning that output depends on the availability of sunlight and wind. Variable renewable energy cannot, on its own, generate electricity to meet demand at all times and at all points on the grid. In addition, variable renewable energy sources deliver power to the grid via inverters—devices that convert direct current into the AC that is used by the grid. The *Solar Futures* vision relies on inverter-based resources for increasing shares of generation over time. It is likely that increasing shares of inverter-based resources will require changes to system operations. However, in the long run, inverter-based generation may entail several advantages over conventional generators that deliver AC generated through motors or turbines.

Maintaining grid resource adequacy (ability of the grid to meet aggregate electrical demand), reliability (ability of the grid to respond to unexpected events), and resilience (ability to withstand disruptive events) in a power system composed primarily of variable and inverter-based technologies requires careful system planning. Power system planners and operators must ensure sufficient zero-carbon capacity to meet demand and reserves at all hours and at all points on the grid. Completely decarbonizing the grid while maintaining reliability will require a diverse portfolio of zero-carbon generation sources, other grid assets (e.g., energy storage), and technological improvements (e.g., advanced inverters). Although our study focuses on solar—a variable resource—clean peaking capacity also plays a key role. Such capacity is not tied to a variable resource, so clean peaking generators can provide capacity on demand at any given time. In particular, we model renewable-energy-fueled combustion turbines as one path to providing this type of firm generation. These combustion turbines would use fuels, such as hydrogen manufactured using zero-carbon electricity, making the turbines themselves zero-carbon generation sources. Other potentially important sources of clean peaking capacity include CSP with thermal energy storage, hydropower, geothermal, long-duration storage, nuclear, and natural gas with carbon capture and storage. Such technologies can be called on to provide high-value power on demand to maintain system reliability. Maintaining reliability and ensuring affordability will also require strategic use of energy storage, demand response, and other assets to minimize risks. New approaches may also be required to maintain large-scale resilience on grids with large contributions from solar. Small-scale solar, especially when coupled with storage, can enhance resilience by allowing buildings or microgrids to continue to power critical loads during grid outages.

Around one third of solar capacity to date has been deployed by customers on distribution networks, often referred to as distributed solar. The rise of distributed solar and other distributed energy resources (DERs)—such as electric vehicles, batteries, and flexible loads—requires changes in distribution grid operations and planning. One key element will be adaptive interconnection processes that provide more grid operator control over DERs. Centralized software, such as distribution management systems, can also help grid operators maintain distribution grid reliability. Further, DERs can be co-optimized to minimize their impacts on distribution networks, such as by automating electric vehicle chargers to maximize charging from rooftop solar systems or from other renewable grid resources when there is surplus

generation. Finally, DERs can enhance resilience by providing reliable, local generation that can power critical assets (e.g., medical infrastructure) during grid outages.

Solar and Energy Justice (Chapter 4)

The fossil-fuel-based grid has yielded innumerable benefits for modern society, but also generates significant societal costs in the form of public health damages, environmental destruction, and climate change impacts. The benefits and costs of the existing energy system have not been equitably distributed. Under-resourced communities (e.g., low-income communities, communities of color, communities facing near-term climate change risks) have borne disproportionately large shares of the costs of the existing system, have enjoyed fewer benefits, and have been largely shut out of energy system planning and procedures.

In this study, we consider the role of solar not only through a techno-economic lens, but also through the lens of energy justice. Energy justice is a framework that explores the distribution of the costs and benefits of an energy system and the procedures that determine those distributions. Energy justice also recognizes historical inequities and finds measures to address those inequities. Like all energy resources, solar generates social benefits and costs at local, regional, national, and global scales. Our analysis suggests that the social benefits of solar far outweigh its social costs. Nonetheless, the distribution of these benefits and costs will not necessarily occur equitably, and addressing this challenge may require structural change. Although our exploration of these topics benefits from a growing energy justice literature, it is important to acknowledge all that we do not know. One of our objectives in discussing solar and energy justice is to prompt questions that will help inform public- and private-sector research agendas in the coming years.

The inequitable adoption of rooftop PV to date has garnered increasing attention as an energy justice issue. Households in under-resourced communities have been significantly less likely to adopt rooftop PV and enjoy its benefits, such as electricity bill savings and the satisfaction of participating in the clean energy transition. Rooftop solar adoption is becoming more equitable over time as costs decline, but a significant disparity remains (Figure 1 - 10). As a result, under-resourced communities have received disproportionately small shares of the private benefits of rooftop PV adoption. The inequitable adoption of rooftop PV may also drive cost shifting from high-income to low-income households via publicly funded incentives and utility rate structures. The adoption patterns in rooftop PV are comparable to similarly inequitable patterns for the adoption of other emerging technologies. Fortunately, research suggests that various interventions (financial, community engagement, siting, policy, regulatory, and resilience measures) can improve equity in rooftop PV adoption. Inequitable adoption of other forms of PV, such as community solar (solar projects where benefits flow to multiple subscribing customers), also need to be addressed. To date, only a small fraction of community solar has been dedicated to households in under-resourced communities.
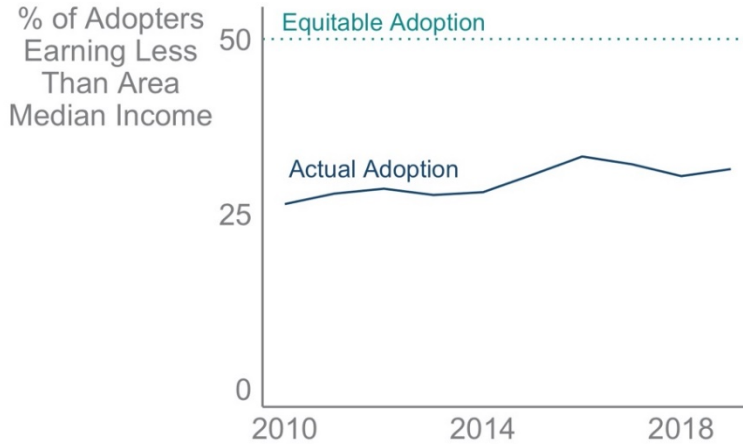
Figure 1 - 10. Percentage of rooftop solar adopters earning less than area median income over time

Based on data from (Barbose et al. 2021)

Another key energy justice issue involves the siting of the grid assets required to achieve the *Solar Futures* vision. Historically, grid infrastructure has been disproportionately sited in under-resourced communities, driving an inequitable distribution of the social costs of grid infrastructure (e.g., air pollution, impacts on property values). The energy justice implications of clean energy siting are more ambiguous. For instance, utility-scale solar projects may generate local wealth through land lease revenues without generating the negative externalities associated with fossil fuel infrastructure. Nonetheless, some communities are already resisting solar project development, suggesting that community engagement will be crucial for addressing local concerns and making equitable siting decisions. Similar concerns arise for complementary infrastructure such as transmission lines.

The grid transition will also entail an unequal distribution of economic opportunities. As we discuss further below, the transition will generate hundreds of thousands of jobs, but it will also displace jobs in fossil fuel industries. Solar is only one of several factors driving job displacement, and public retraining programs could help the rapidly growing solar industry absorb displaced fossil fuel workers. Available research suggests that the cost of addressing displacement of jobs related to fossil fuel industries is on the order of $10 billion (see details in Section 4.4), which is small relative to the hundreds of billions of dollars in benefits associated with the transition. However, the potential of such programs should not be overstated. Job loss is an acutely stressful experience that causes significant long-term hardships for individuals, families, and communities. A just transition considers the costs of these hardships alongside the benefits of new economic growth.

Synergies with Energy Storage (Chapter 5)

Energy storage is critical to achieving deep decarbonization with high solar penetrations. The Decarb+E scenario projects roughly equal cumulative deployment of solar and storage capacity by 2050. Most of this storage is intraday, capable of shifting energy over the course of a few hours, though long-duration storage plays a growing role from 2035 to 2050. Intraday storage can temporally shift solar output in ways that increase the value of solar to the grid. A simple example is using storage to shift midday solar to serve evening peak loads. Co-located solar-

plus-storage facilities can convert relatively inflexible PV plants into flexible facilities akin to some fossil generators.

Storage deployment goes through three distinct phases in the *Solar Futures* vision. The first phase, running through the late 2020s, is characterized by limited growth and installation rates of around 5 GW/year. The limited deployment reflects the limited need for storage capacity at low levels of cumulative solar deployment. However, as more solar comes online, grid peak demand will increasingly shift to later in the day, after solar output has declined. As a result, solar and storage will become increasingly synergistic over time, as storage can help shift solar output into the new peak period. The second phase, which runs from the late 2020s through the late 2040s, is marked by accelerating storage deployment. This second phase of rapid growth is due to the growing synergies between solar and storage, as well as declining storage costs and retirements of firm generation plants. Storage in the second phase is still primarily intraday. In the third phase, beginning in the late 2040s, long-duration storage becomes increasingly valuable; it represents most of the storage deployed in the final years of the study period.

Technology Advances (Chapter 6)

Technological innovations and cost reductions in PV have consistently outperformed expert projections. Particularly in the last decade, a confluence of technological, economic, and geopolitical factors drove a precipitous decline in PV costs. In some sun-rich parts of the world, solar is now the cheapest way to generate electricity. Still, ongoing cost reductions are required for solar and other enabling technologies. In 2010, the U.S. Department of Energy's (DOE's) Solar Energy Technologies Office set an ambitious target for an 80% reduction in the levelized cost of energy (LCOE) for utility-scale solar by 2020, a target that was met 3 years early. Now, DOE has established a new target, based on the need to allow for the cost of energy storage, additional power transmission, and infrastructure for shifting demand. This target calls for continued cost and performance improvements to drive PV LCOE from about $46/MWh in 2020 to $20/MWh in 2030.

This study explores scenarios in which solar technology follows cost and performance trajectories consistent with the 2030 LCOE target. All areas of solar technology can contribute to continued improvements that make solar electricity the cheap and ubiquitous foundation of a clean grid.

Dozens of incremental improvements have been combined to realize today's low costs. Continued evolution of existing PV technology is expected in the coming decade, thus improving efficiency, boosting lifetime energy yield, and reducing costs. New PV cell technology will increase efficiency and energy yield while making more effective use of smaller quantities of expensive materials. New scientific understanding of performance, degradation, and reliability will enable even more accurate predictions of energy produced over time, reducing contingency costs. Advances in manufacturing will move emerging ideas from the lab to the market faster than ever before. New solar technologies combining multiple types of solar cells (e.g., crystalline silicon and perovskites) could increase efficiency and push down the cost of all area-dependent parts of a PV system. Advances in the design and construction of PV systems and advances in non-module PV equipment will squeeze more energy out of the same space at lower cost. Substantial cost reductions have also been achieved in non-hardware or "soft" costs, such as installation labor, customer acquisition, and permitting costs. However, soft costs have not

declined as quickly as hardware costs and have, as a result, formed an increasing share of overall system costs. Further, soft costs remain high in the United States relative to other major solar markets. Soft cost reduction is an area of ongoing research as detailed in Chapter 6.

A new generation of CSP is also being demonstrated and could enable a step change in the cost of solar power plants that can store thermal energy to run night and day. Advanced CSP systems could operate above 700°C and use a supercritical carbon dioxide (sCO_2) power cycle that has potential for over 50% efficiency. Moving from a molten salt heat-transfer media to one using solid particles to collect sunlight could store more thermal energy at a lower cost. Improvements to the cost and performance of the collector field, the part of the CSP plant that collects sunlight, can yield significant reductions in electricity cost.

Low solar technology costs alone cannot drive the pace and scale of solar deployment envisioned in this study. In addition to the soft cost reductions mentioned above, rapid expansion of the solar market may require substantial reductions in the cost of solar manufacturing capacity, making it more practical to build solar factories. Further technology advances are needed in energy storage. These advances may include the maturation of thermal energy storage and battery energy storage systems.

Falling costs, technology advances, and growing experience will open opportunities to deploy solar technology in configurations that are only seen in limited demonstrations today—including installations associated with agriculture, buildings, waterbodies, and other parts of the built environment. Dual-use applications provide mutual benefits: farms can grow food and produce electricity on the same land, solar building materials do double duty, and PV on waterbodies reduces evaporation loss.

Role of Solar in Energy End-Use Sectors (Chapter 7)

The energy system ultimately powers end uses in buildings, transportation, and industry. Each end use relies on different combinations of electricity and direct fuel use and has different prospects for further electrification. The existing electricity/fuel balance and prospects for further electrification in each sector largely determine the near- and long-term role of solar in decarbonizing each end use.

The three end uses account for roughly even shares of energy use and emissions, and solar can play a role in decarbonizing all three sectors (Figure 1 - 11). Solar has the most immediate and largest long-term impact in the buildings sector, which in 2020 accounted for about 72% of electricity use. Electrification of remaining fuel-based building loads—mostly space and water heating—further increases the role of solar in buildings. In the Decarb+E scenario, solar electricity powers about 30% of all building end uses by 2050. The transportation sector relied almost exclusively on direct fuel use in 2020, but near- and long-term electrification of light-duty passenger cars and some medium- and heavy-duty vehicles will increase the sector's electricity use. As a result, the role of solar in decarbonizing transportation is projected to increase over time, with solar electricity serving around 14% of transportation end uses by 2050 in the Decarb+E scenario. The long-term role of solar electricity in industry is less certain, owing to the variety of potential pathways for decarbonizing energy-intensive industrial processes. An alternative to electrification is to use heat from concentrating solar thermal plants in place of fossil-generated heat in industrial processes. Previous research suggests that solar thermal could

meet about 25% of industrial heat demand. In all three sectors, solar can also play a long-term role as a power source for zero-carbon fuels to decarbonize fuel-based sectors.
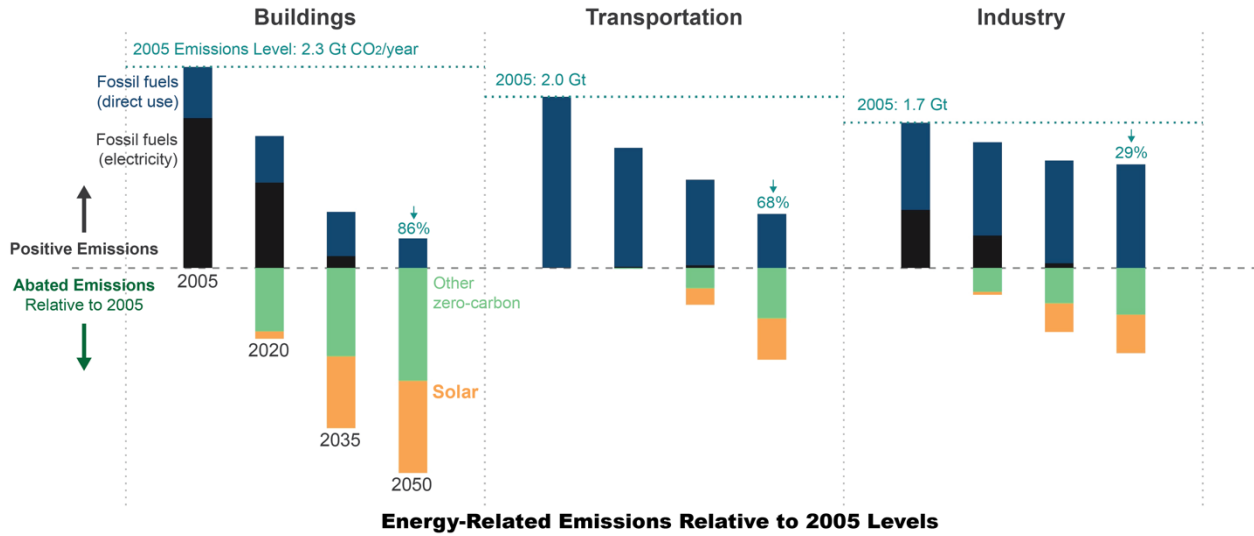
Figure 1 - 11. Emissions and abated emissions by end use in the Decarb+E scenario

In addition to its role as a zero-carbon power source, solar can enable greater adoption of other technologies in each end use. In buildings, rooftop PV adoption can increase customer bill savings from battery adoption and investments in load automation systems. Distributed batteries and load automation can, in turn, increase the grid value of solar, as noted in our discussion on the role of load flexibility. In transportation, rooftop PV adoption can reduce the cost of charging electric vehicles, thus increasing the value proposition of electric vehicle adoption and potentially accelerating the electrification of the transportation sector. In turn, electric vehicle adoption can drive rooftop PV adoption by significantly increasing a household's demand for on-site power. In industry, low-cost solar will increasingly compete with natural gas as an input to industrial processes, both as a source of electricity as well as heat, particularly from CSP. The economics of low-cost solar may drive electrification in a growing number of industrial applications over the long term.

Solar Supply Chain, Environmental Considerations, the Circular Economy, and Workforce (Chapter 8)

The *Solar Futures* scenarios are associated with challenges and opportunities related to the solar supply chain, the use of materials throughout the life cycle of solar technologies (including end-of-life material management), and land and water use. All these factors affect equity and environmental justice. The types and magnitudes of potential impacts depend in part on choices made by governments, businesses, and individuals.

Our analysis of potential U.S. and global material demands related to solar technology manufacturing suggests that material supplies likely will not limit solar deployment growth, especially if end-of-life materials are recovered and reused. The supply portion of this analysis is based on current global production of solar materials, but such estimates do not account for potential non-technical constraints, such as ethical and environmental concerns related to material production; these considerations could make end-of-life material use even more

important. Breakthroughs in technologies and participation in what is currently a voluntary recycling and circular-economy landscape in the United States are required to maximize use of recoverable materials—yielding benefits in energy and materials security, social and environmental impacts, and the domestic workforce and manufacturing sectors.

Developing the U.S. PV supply chain could mitigate challenges related to production disruptions, competing demand from other industries or countries, and global politics. However, lower labor costs and weaker environmental regulations outside the United States create challenges in matching costs from other countries. Overall, a resilient supply chain is diversified and not overly reliant on any individual supply avenue. The U.S. PV manufacturing industry may be able to improve its competitive position by increasing automation, exploiting the inherent advantages of domestically manufacturing particular components, and manufacturing products that require advanced technology or automation. Various policies can also help promote domestic PV manufacturing.

Land acquisition for solar development is a challenge, but land availability is not a constraint to the *Solar Futures* vision.[15] In 2050, ground-based solar technologies will require a maximum land area equivalent to 0.5% of the contiguous U.S. surface area, and this requirement could be met using less than 10% of potentially suitable disturbed lands, thus avoiding conflicts with high-value lands in current use. However, solar installations will affect local communities, ecosystems, and agricultural areas. Various approaches are available to mitigate such impacts or, in some cases, enhance the value of land that hosts solar systems. Because solar and some other clean energy generation technologies use so little water compared to fossil fuel and nuclear generation, power-sector water withdrawals decline by about 90% in the *Solar Futures* decarbonization scenarios.

Finally, in terms of workforce, the solar industry already employs around 230,000 people in the United States, and analysts estimate that it could employ 500,000–1,500,000 people by 2035.[16] Based on research on the existing clean energy industry, these jobs will tend to pay above-average wages and require less formal education than the average U.S. job. Further, clean energy experience can provide valuable on-the-job training in science and technical skills. The clean energy transition could drive job growth in more than 100 occupations to support the emerging solar industry.

The solar industry is taking measures to increase diversity and representation in its workforce. Racial diversity in the solar industry is comparable to racial diversity in the U.S. workforce overall, and interventions such as solar entrepreneurship programs have been shown to effectively increase workforce racial diversity. The workforce in the current solar industry is disproportionately male, but various initiatives aim to improve gender diversity. Transitioning to

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[15] In our analysis of land use and environmental impacts, we focus exclusively on solar infrastructure. The land-use and environmental implications of other technologies that generate electricity in the *Solar Futures* scenarios, as well as expanded electric transmission infrastructure, are outside the scope of this report.

[16] We did not perform a detailed economic impact or jobs analysis as part of this study. The economy-wide implications of the clean energy transition are an area of ongoing research.

a more even distribution could help advance high-paying job opportunities for women, thus helping to close the gender salary gap.

Policy and Market Support for Achieving a Solar Future

The Reference scenario, in which the electric grid continues to emit around 930 million metric tons (Mt) of carbon dioxide annually by 2050, represents our projection of the future grid under a business-as-usual trajectory. In addition to the factors described above, breaking away from business as usual and achieving the *Solar Futures* vision will require sustained policy and market support.

Decarbonization targets set by policy are critical to decarbonizing more quickly than would occur owing to market conditions alone. A growing number of states and utilities have committed to grid decarbonization by or before 2050. Achieving these targets will require unfaltering, long-term political support, given that the marginal costs of grid decarbonization increase as grids approach 100% decarbonization. Market dynamics alone are unlikely to abate the final 5%–10% of grid emissions. States and utilities with existing targets must adhere to their objectives, and remaining states and utilities must develop new policies to decarbonize the rest of the grid. Policy also accelerates cost reductions and technological innovations through R&D investments as well as through driving deployment and reducing costs through learning-by-doing. In addition, policies may be needed to ensure equitable distribution of the benefits of the clean energy transition.

On the market side, wholesale electricity markets must adapt to the increasingly dominant roles of zero-marginal-cost renewable energy, and retail markets must adapt with rates that reflect the changing grid and an increased role for DERs. Nascent markets such as those for demand-side services and enhanced energy reliability may need to evolve to optimize the roles of DERs, and efforts are needed to expand the use of these resources to traditionally underserved groups.

Significant work remains to decarbonize the grid and realize the associated benefits, and this work will require collaboration across many institutions and stakeholder (see Text Box 2). The *Solar Futures Study* provides a roadmap for solar's role in getting that work done.

Text Box 2. Collaborations for Achieving Decarbonization

Decarbonizing the nation's electric grid and energy system requires a wide range of technologies, and participation across industry, government, non-profit organizations, and other stakeholder groups. Within DOE, collaboration and coordination across technology offices is essential to maximizing the impact of the department's efforts; all the technology offices within the Office of Energy Efficiency and Renewable Energy (EERE) have a critical role to play in creating a zero-carbon future. The *Solar Futures Study's* focus on the role of solar in decarbonization implies various specific cross-office collaborations. For example, for transportation end uses, SETO collaboration with the Vehicle Technologies Office and Hydrogen and Fuel Cell Technologies Office can help spur innovation in approaches needed to maximize use of solar, such as large-scale managed EV charging and hydrogen fueling coordinated with PV. In buildings, joint research with the Building Technologies Office to advance building automation, coordination, and aggregation capabilities could help optimize use of distributed solar, alongside flexible loads and storage.

For grid integration, collaboration through DOE's Grid Modernization Initiative with the Office of Electricity; the Office of Cybersecurity, Energy Security, and Emergency Response; the Office of Fossil Energy and Carbon Management, the Office of Nuclear Energy; and other EERE offices will help ensure solar and other renewable energy technologies are deployed in a resilient and secure manner. EERE's collaboration with various other DOE offices will be important as well, including the Office of Indian Energy Policy and Programs, Office of Economic Impact and Development, Advanced Research Projects Agency–Energy (ARPA-E), Loan Programs Office, and Office of Science.

Renewable Power	Sustainable Transportation	Energy Efficiency
• Solar • Wind • Water • Geothermal	• Bioenergy • Hydrogen and fuel cells • Vehicles	• Advanced manufacturing • Buildings • Federal Energy Management • Weatherization and Intergovernmental

EERE technology divisions and offices

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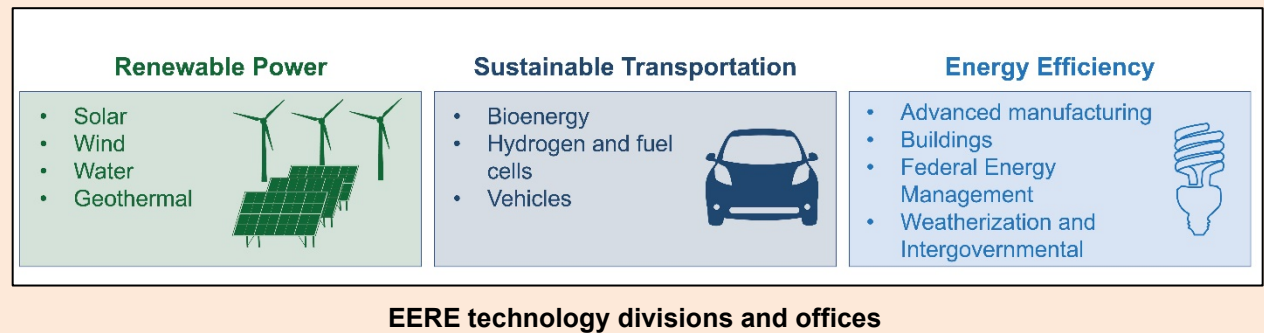
Solar Futures
Scenarios

2 *Solar Futures* Scenarios

At the end of 2020, U.S. installed solar capacity reached 76 GW: 46 GW of UPV, 28 GW of distributed photovoltaics (DPV), and 2 GW of concentrating solar power (CSP). Rapidly growing deployment of solar during the past decade was driven by a combination of cost reductions (Feldman et al. 2021), federal tax incentives (e.g., the investment tax credit), and state policy support (e.g., renewable portfolio standards and net metering). Despite this growth, solar generation constituted only 3% of U.S. electricity generation in 2020—highlighting the substantial opportunities for future deployment. The role of solar in mitigating greenhouse gas (GHG) emissions in the power sector and beyond has important ramifications for energy planning, R&D strategies, policymaking, and broader decision making. In this chapter, we inform such strategic considerations by exploring the role of solar energy in decarbonization scenarios for the U.S. electricity system.

This work builds on a decade of solar analysis by researchers from NREL, other national labs, the federal government, academia, and other research institutions. The *SunShot Vision Study* (DOE 2012) assessed scenarios in which solar technologies achieved cost targets that were optimistic at the time, but have since largely been met (Feldman et al. 2021). The study projected that achieving these cost goals would enable solar to reach 27% of total U.S. electricity generation by 2050. The *On the Path to SunShot* report series (DOE 2016) evaluated the technology and market advances needed to reach the cost goals as well as the broader impacts of the *SunShot* scenarios. Cole et al. (2018) envisioned scenarios with PV cost reductions beyond the *SunShot* goals, as well as the implications of combining low-cost solar with low-cost storage, and thus projected even greater PV deployment. Murphy et al. (2019) focused on CSP deployment potential. As solar technology costs have declined, optimism for further technology advancements has grown, along with expectations for increasingly high levels of solar deployment.

More recently, a growing focus on decarbonization, coupled with unprecedented energy storage cost reductions, has expanded the drivers and potential opportunities for solar energy. Phadke et al. (2020) showed how combining solar, wind, and battery technologies could yield 90% clean electricity by 2035 with low incremental costs. In particular, the synergies between solar and low-cost grid storage are now well established (Frazier et al. 2020; Denholm et al. 2019; Gorman et al. 2020) and have reset expectations about solar's deployment ceiling. Moreover, lower-cost batteries have spurred interest in electric vehicles (EVs). Expanded EV adoption—plus electrification of other end uses traditionally reliant on fossil fuels—could influence the demand for solar and other generation technologies (Murphy et al. 2021). Decarbonization goals could accelerate clean electricity generation, electrification, low-carbon fuel production, and direct displacement of end-use emissions—which could correspondingly increase solar technology adoption (Larson et al. 2020; Williams et al. 2021).

In this work, we examine the role of solar energy in scenarios with decarbonized U.S. electricity grids, including under high-electrification futures. The analysis examines the necessary changes to the power system, interactions between solar and other clean energy technologies, cost and emissions implications, and grid-integration challenges and opportunities under decarbonized systems. Links between the power-sector scenarios presented in this chapter and other topics in the report are identified throughout. We also go beyond the power-sector analysis to examine the

role of solar in comprehensive decarbonization of the U.S. energy system, although the broad nature of this analysis entails significantly more uncertainty.

2.1 Modeling Approach and Scenario Framework

2.1.1 Power-Sector Models

The *Solar Futures* scenarios are modeled using the Regional Energy Deployment System (ReEDS) capacity-expansion and dispatch model of the U.S. electricity sector (Ho et al. 2021; Cole, Corcoran, et al. 2020). ReEDS identifies the optimal power system portfolio from a mix of renewable (biopower, CSP, geothermal, hydropower, onshore and offshore wind, PV, and renewable energy combustion turbine [RE-CT]) and non-renewable (nuclear, coal, and natural gas [NG]) generation technologies, bulk energy storage (batteries with 2–10 hours of duration, pumped-storage hydropower [PSH] with 12 hours) options, and transmission expansion. CSP options with 10 and 14 hours of thermal energy storage (TES) are modeled by default.[17] For PV, ReEDS models ground-mounted urban and rural options, where the former represents smaller systems located closer to load centers and the latter represents larger utility-scale plants. DPV adoption is modeled based on exogenous projections (see Appendix 2-A). Major constraints considered in the optimization model include load balance, planning reserves, operating reserves, transmission and resource constraints, and policies (e.g., state clean energy standards). Investment decisions are based on 20-year present-value costs for all capital and operating expenditures (Ho et al. 2021). ReEDS also models capacity retirements within its economic optimization, constrained by maximum lifetimes that vary by technology.

ReEDS is uniquely designed to represent the characteristics of renewable energy (RE) resources and technologies (Mai, Bistline, et al. 2018). Location dependence and spatial variability of RE resources are captured by disaggregating the continental United States into 356 wind and CSP resource regions and 134 model balancing areas (BAs) where PV and all other technologies are represented (Figure 2 - 1). Further technology detail is represented using multiple resource classes and technology types. Interregional power transfers and transmission expansion are also modeled based on the 134-BA network.[18]

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[17] CSP configurations with 6 and 8 hours of storage can also be modeled but are not considered in the core scenarios.

[18] Grid connection supply curves (representing costs for intraregional spur lines) are also modeled for solar and wind.
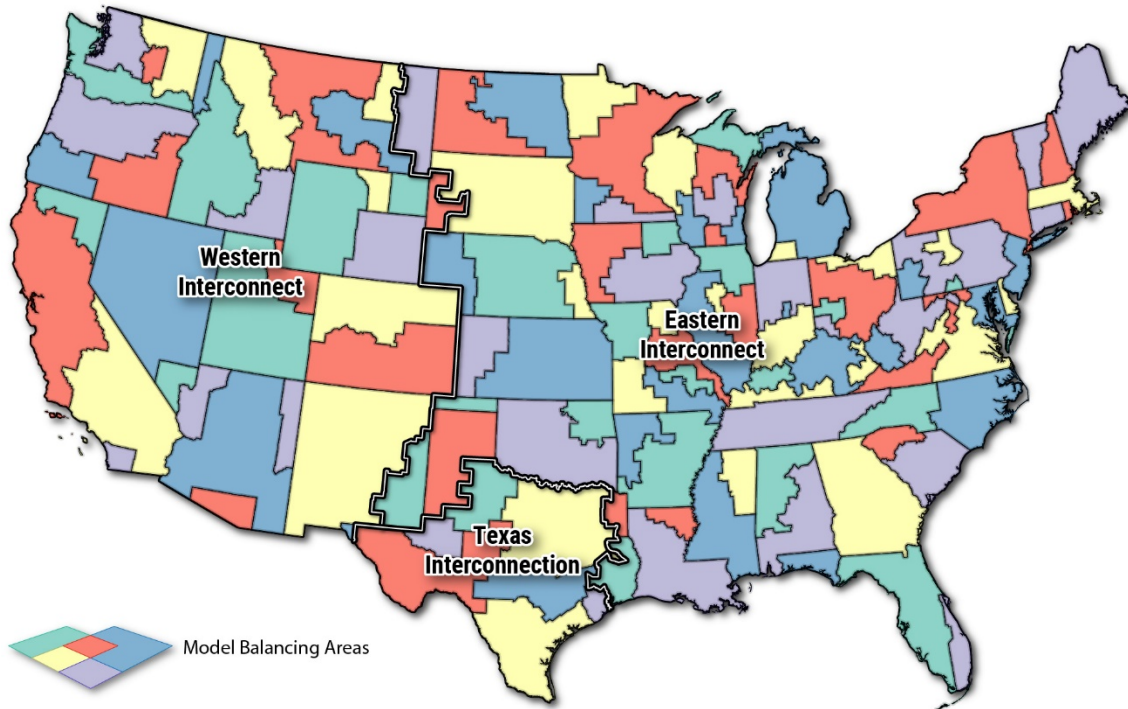
Figure 2 - 1. ReEDS model balancing area regions

Investment and dispatch decisions are co-optimized in ReEDS and modeled in conjunction with a suite of grid services and existing policies. Generation and dispatch estimates are modeled using a combination of a 17 time-slice aggregated dispatch, which reflects seasonal and diurnal changes to load and variable RE (VRE) availability, and chronological hourly dispatch to inform the value of storage operations and VRE curtailment (Frazier et al. 2020; Gates et al. In review). ReEDS uses hourly data for 7 weather years (2007–2013) to dynamically estimate capacity credit—the fraction of nameplate capacity that contributes to resource adequacy—for PV, wind, CSP with and without TES, and storage. These calculations help ensure that the portfolios generated by ReEDS meet resource adequacy requirements.[19]

Although ReEDS is designed to model economic dispatch and consider resource adequacy endogenously, the large scope of the model necessitates simplifications. To supplement ReEDS and better assess the operability and adequacy of the scenarios, the *Solar Futures* analysis uses the PLEXOS and Probabilistic Resource Adequacy Suite (PRAS) models to further evaluate a subset of the 2050 power systems from the scenarios. Results from the high-fidelity grid-modeling analysis are detailed in Chapter 3. Another important limitation of ReEDS is that its scope is limited to the bulk power system, thus requiring exogenous assumptions for electricity demand and demand flexibility, and distributed generation. ReEDS also does not represent all possible technologies that may be critical in decarbonized energy systems, including carbon dioxide removal (CDR) technologies, small modular nuclear reactors, fuel cells, and seasonal

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[19] Due to data limitations, scenarios with high electrification rely only on a single weather year (2012). The models rely on historical weather years only and do not consider the effects that climate change might have on electricity demand and technology performance. Further study is needed to assess such impacts.

energy storage options. Lastly, the model applies a system-wide planning approach that does not fully reflect local or regional factors.

2.1.2 Scenarios and Assumptions

The *Solar Futures* scenarios assess the potential role of solar as the U.S. power system transitions to low-carbon electricity. This chapter focuses on three core scenarios—Reference, Decarbonization (Decarb), and Decarbonization with Electrification (Decarb+E)—summarized in Table 2 - 1. Given the substantial uncertainties over the 2020–2050 study period,[20] a larger set of sensitivity scenarios are also modeled and described in Appendix 2-B. These scenarios encompass multiple dimensions, including renewable and storage technology costs, availability of flexible loads, decarbonization targets, and electrification.

Table 2 - 1. Framework for the Core *Solar Futures* Scenarios

Scenario Name	Renewable Energy and Storage Technologies	Demand Flexibility	Electricity Demand	Policies
Reference	Moderate cost reductions	None	U.S. Energy Information Administration Reference	Existing policies* as of June 2020
Decarbonization (Decarb)	Advanced cost reductions	None	U.S. Energy Information Administration Reference	Existing policies* + 95% reduction in CO_2 emissions from 2005 levels by 2035, 100% by 2050
Decarbonization with Electrification (Decarb+E)	Advanced cost reductions	Enhanced	High electrification based on NREL Electrification Futures Study	Existing policies* + 95% reduction in CO_2 emissions from 2005 levels by 2035, 100% by 2050

* The existing policies assumed include state renewable and clean energy mandates, state and regional emissions limits, and federal tax incentives.

The Reference scenario assumes Annual Technology Baseline (ATB) 2020 Moderate cost projections (NREL 2020), no demand-side flexibility, electricity demand growth from the Annual Energy Outlook (AEO) 2020 Reference case, and existing policies as of June 2020. The AEO 2020 Reference case (EIA 2020a) considers a relatively limited amount of electrification, with annual demand from 2020 to 2050 growing 0.9%/year (on a compounding basis) and 2050

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[20] The modeling analysis was conducted in 2020 and using data available at the time. This data did not comprehensively include historical data for all of 2020 and, therefore, did not capture the effects of the pandemic.

load reaching nearly 5,000 TWh. The existing policies assumed include state renewable and clean energy mandates, state and regional emissions limits, and federal tax incentives.[21]

The Decarb scenario differs in terms of cost projections and policies. It uses the ATB Advanced cost projections for solar, which are consistent with SETO's 2030 PV and CSP cost targets, and all other RE and storage technologies.[22] It includes existing policies but adds an annual power-sector emissions cap applied nationally that ramps linearly to 120 Mt of CO_2 (95% below 2005 levels) in 2035–2036.[23] After this period, the cap ramps linearly to zero by 2050. The orange line (labeled "95%-by-2035") in Figure 2 - 2 shows the emission trajectory for this scenario. This requirement prohibits any emitting *capacity* to remain by 2050 as well.[24] The emissions reduction trajectory in this scenario is directionally aligned with but falls slightly short of the Biden Administration's "100% carbon pollution-free power sector by 2035" target. This difference is due to our principle focus on the role of solar technologies, which is similar whether the target is 95% or 100% reduction, and the significant uncertainties associated with the last 5%. Further research is underway to assess the specific pathways to achieve full emissions reduction, but such a comprehensive assessment is outside of our scope in this report. Note that we include sensitivities that achieve 100% emissions reductions by 2035 in Appendix 2-B. See Text Box 1 in Chapter 1 for additional discussion.

The Decarb+E scenario uses the same technology cost and power-sector policy assumptions as the Decarb scenario. However, it assumes end-use electrification beyond the level in the AEO 2020 Reference case, reaching the level envisioned in the *Electrification Futures Study* (EFS) "High Electrification" scenario (Mai, Jadun, et al. 2018; Murphy et al. 2021).[25] In this case, annual demand grows 1.9%/year and reaches about 6,700 TWh by 2050. The Decarb+E scenario also includes exogenously specified flexible loads from the EFS "enhanced" flexibility case (Y. Sun et al. 2020; Murphy et al. 2021). Demand-side flexibility is modeled as diurnal shiftable load

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[21] Federal tax credits decline over time and include a safe harbor provision. The solar investment tax credit is assumed to be 30% for projects installed in 2020, ramping down to 10% for all capacity installed after 2026.

[22] Appendix 2-E includes tables with cost and performance assumptions for solar and battery technologies used in the scenarios, and the ATB (NREL 2020) includes a more complete set of technology assumptions. The ATB "provides a consistent set of technology cost and performance data for energy analysis" and relies on technology experts for each option included. Chapter 6 details the cost and performance improvements for solar technologies.

[23] ReEDS models 2-year solve periods, so the "2036" period refers to 2035 and 2036. These 2 years are used interchangeably in this chapter. The benchmark 2005 U.S. power system emissions level of 2,400 Mt CO_2 used throughout is based on estimates from the U.S. Environmental Protection Agency's Greenhouse Gas Inventory (EPA 2018c). The emissions cap is applied starting in 2020 and is set at 1,600 Mt CO_2 for that year, but it is not binding for that historical year. The emissions cap is an upper limit and may not be binding in all years.

[24] In the model, retirement decisions are based on maximum lifetime assumptions and economic decisions, where the latter weighs ongoing costs (including fixed O&M costs) with potential revenues from providing the various grid services. This could result in plants having shorter lifetimes than the design life and/or shorter than the anticipated cost recovery period at the time of investment. Further study is needed to assess the impacts to owners of stranded assets or to others who may be economically affected.

[25] We use the "Moderate" end-use technology advancement case from the EFS (Jadun et al. 2017). The EFS data (for demand growth, emissions, and final energy consumption) are adjusted from those used originally to calibrate with the more recent AEO 2020 used in the present analysis.

that is constrained in timing, direction, and magnitude.[26] The amount of flexible load varies over time, constituting 17% of total load in 2050 under the Decarb+E scenario.
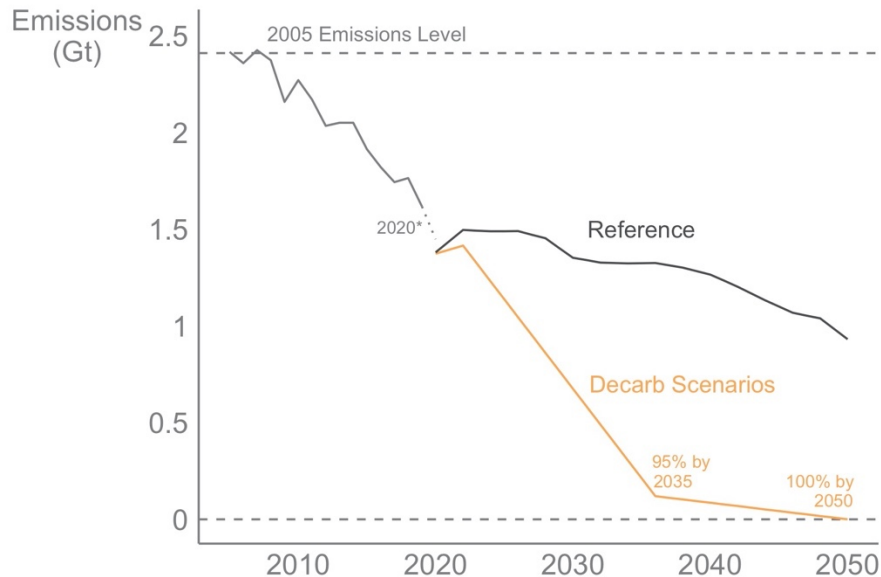
Figure 2 - 2. Historical power-sector emissions and modeled *Solar Futures* carbon cap

Historical data from (EPA 2018c) and (EIA 2021d). * Emissions fell by about 11% from 2019 to 2020, in part due to demand changes from the Covid-19 pandemic.

The Decarb+E scenario includes much greater electrification than the other two core scenarios doe; however, it does not reflect the full technical potential of electrification or complete decarbonization. Section 2.3 provides approximations for a more completely decarbonized 2050 energy system, although such a scenario was not modeled in detail and, thus, is not included in our core scenarios. Moreover, in addition to the core scenarios shown in Table 2 - 1, the analysis includes four sets of sensitivity scenarios related to the rate and extent of grid decarbonization, solar and clean technology cost and performance, RE-CT costs, and perturbations to the optimal scenario mix. Appendix 2-B describes the sensitivity analysis and findings.

Other ReEDS assumptions are from the Standard Scenarios Mid-case (Cole, Corcoran, et al. 2020). For example, fossil fuel and uranium prices are from the AEO 2020 Reference case, although ReEDS represents NG supply curves that vary NG prices with electric-sector consumption.[27] Model representation and assumptions for RE-CTs are described in Appendix 2-C.

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[26] The constraints to demand flexibility are considered separately by subsector within the four end-use sectors—residential and commercial buildings, transportation, and industry—but are aggregated to reflect a single demand response capability for each region in the ReEDS model. ReEDS endogenously dispatches the flexible load in its economic decision making, e.g., electricity serving the flexible load is consumed during low-price periods and deferred or delayed during high-price periods. No implementation or operational costs for the flexible loads are assumed and no mechanism (e.g., distributed energy resource aggregator, tariff design, utility control) to enable demand-side flexibility is explicitly represented (Y. Sun et al. 2020).

[27] For scenarios with high electricity demand, NG prices are also influenced by changes to non-power-sector consumption (Y. Sun et al. 2020).

2.2 *Solar Futures* Core Scenario Results

The U.S. electricity sector was responsible for about 1,450 Mt (or 32% of U.S. energy-related) CO_2 emissions in 2020, representing a 40% reduction from 13–15 years ago when annual emissions peaked (EIA 2021d). These reductions were driven by a suite of factors—energy efficiency and structural changes to the economy, fuel-switching from coal-fired to NG-fired generation, and RE growth (Wiser et al. 2021). However, a majority of U.S. power generation continues to rely on fossil fuels, and emissions reductions in other sectors have been slower to materialize. Here we describe generation portfolios that could facilitate power-sector decarbonization through 2035 and 2050 as well as the challenges and opportunities of fully decarbonizing the grid and leveraging zero-emissions electricity to serve a broader set of energy demands through electrification.

This section focuses on results from the three core *Solar Futures* scenarios only. Key sensitivity analyses are presented in Appendix 2-B, and some results from these sensitivities are included in this section for additional context. The ReEDS model identifies a single, least-cost portfolio for each scenario, but there may be other portfolio mixes with very similar costs. The sensitivity analysis includes a set of near-optimal portfolios with greater deployment of CSP, geothermal, offshore wind, nuclear, and PSH to highlight the existence of multiple clean electricity pathways beyond those presented in the core scenarios. These scenarios are intended to capture some of the uncertainties associate with the modeling and assumptions.

2.2.1 *Portfolios for a Decarbonizing Grid*

Figure 2 - 3 and Figure 2 - 4 show generation and capacity mixes for the core scenarios in 2020, 2035, and 2050. Appendix 2-G provides tabulated data. Under the Reference scenario, growth in solar technologies—particularly PV—exceeds growth of all other options; solar capacity reaches 375 GW by 2035 and 674 GW by 2050, resulting in 27% of total 2050 generation from solar technologies, compared to about 3% in 2020. Overall, RE generation grows to 38% in 2035 and 56% in 2050 (compared with 20% in 2020).[28]

The Reference scenario results show that, even with moderate RE technology assumptions and no new policies, a transition away from nuclear and coal-fired generation and toward RE—especially solar energy—is anticipated.[29] Because of retirements, coal and nuclear capacities steadily decline and constitute a similar share of 2050 generation (6.6% and 7.2%, respectively).[30] The share of total generation from NG-fired plants declines from 40% in 2020 to about 30% by 2030, remaining approximately at that level for all years thereafter. Growth in

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[28] Generation from zero-carbon sources (i.e., renewable and nuclear energy) reaches 52% in 2035 and 63% in 2050, compared with 40% in 2020. Nuclear generation declines over time owing to age-based retirements, and no new nuclear capacity is deployed in any of the core scenarios. In all core scenarios, nuclear constitutes 4%–7% of 2050 generation. Appendix 2-B includes a sensitivity analysis with a prescribed amount of nuclear generation.

[29] Under the Reference scenario, which uses moderate technology cost reductions, solar generation constitutes 18% of total generation (from 375 GW) in 2035 and 27% (674 GW) in 2050. With advanced technology cost reductions for all renewable and battery technologies (but without a national emissions target or increased electrification), estimated solar shares rise to 28% (562 GW) in 2035 and 36% (869 GW) in 2050.

[30] Growth in nuclear generation is observed in some scenarios in another study focused on economy-wide decarbonization (Larson et al. 2020). In addition, various visions for renewable technology growth have been examined, including for geothermal (DOE 2019), hydropower (O'Connor et al. 2016), and CSP (Murphy, Sun, Cole, Maclaurin, Mehos, et al. 2019).

bulk energy storage capacity is also anticipated under this scenario, with 82 GW of PSH and battery capacity combined by 2035, and 220 GW by 2050.

The scenario results are striking in the context of results from earlier studies. For example, the SunShot Scenario from the 2012 *SunShot Vision Study* yields 2050 solar generation similar to that in the *Solar Futures* Reference scenario (27%) based on policy and market conditions at the time the analysis was completed *and* the most optimistic solar cost trajectory in the *SunShot Vision Study*. Yet, the *Solar Futures* Reference scenario achieves that same solar generation level despite being the most conservative of this study's scenarios.[31]
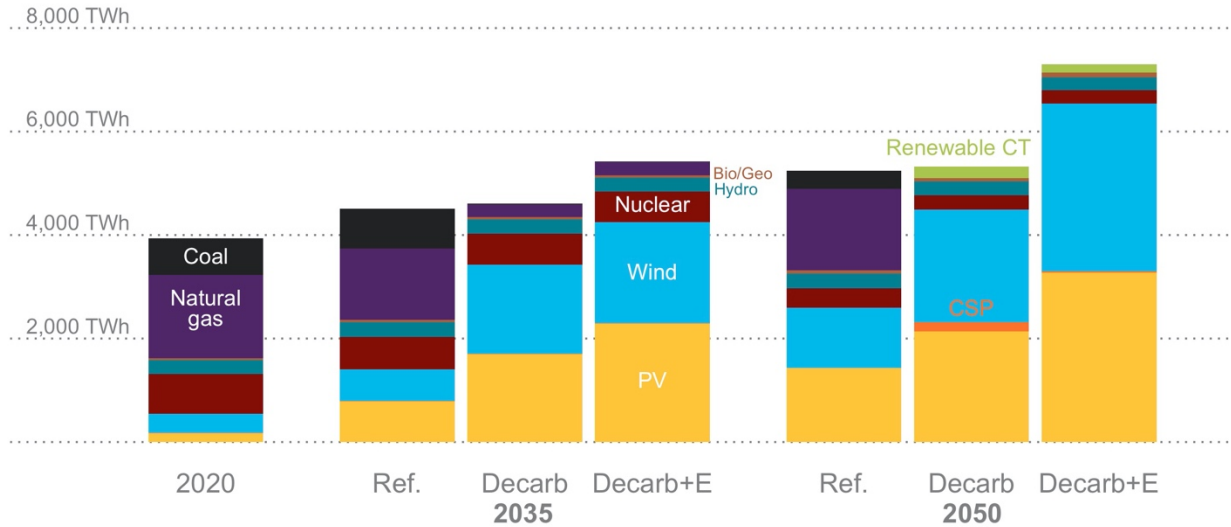
Figure 2 - 3. Generation by technology in 2020, 2035, and 2050 in core scenarios

Bio = biomass, Geo = geothermal, Hydro = hydropower, CT = combustion turbine. Hydro includes pumped hydro-storage.

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[31] Note that this comparison is complicated due to numerous changes since the 2012 *SunShot Vision*, including cost projections for solar, wind, batteries, and natural gas; changes to state and local policies including increased renewable and clean energy standards; extensions to federal tax credits; and more-accelerated coal plant retirements than anticipated in 2012. In a current-policies scenario using ATB advanced technology projections, solar contributes 27% of generation in 2035 and 36% in 2050.
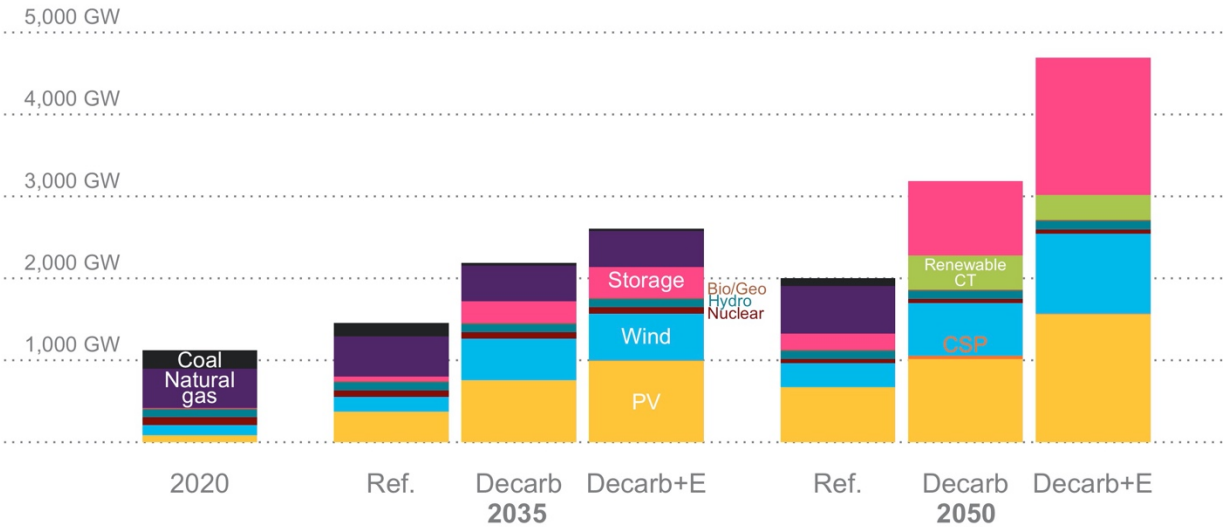
Figure 2 - 4. Capacity by technology in 2020, 2035, and 2050 in core scenarios

Unsurprisingly, clean electricity grows more quickly in the Decarb scenario, which assumes a declining power-sector emissions cap (Figure 2 - 3). New RE capacity—along with existing clean energy technologies (e.g., nuclear and hydropower)—is used to achieve the 95% emissions-reduction target by 2035.[32] Under the Decarb scenario, solar energy technologies provide about 37% of total 2035 generation from 759 GW of installed capacity. Generation shares from renewable and zero-carbon energy sources are about 80% and 94%, respectively, in the same period. Energy storage plays a sizeable role under this scenario, with installed storage capacity reaching 285 GW by 2035, reflecting over an order of magnitude growth in U.S. storage capacity over the next 15 years.

Combining electrification with decarbonization in the Decarb+E scenario increases the deployment of solar and other clean energy technologies. For example, nearly 1 TW of solar deployment is observed under the Decarb+E scenario by the mid-2030s, and storage capacity reaches 400 GW. In fact, solar meets an even larger fraction of the incremental amount of demand from electrification such that 42% of 2035 generation is from solar.[33] The synergies between solar and new electrified loads, such as EVs, are discussed in Chapter 7.

Transmission expands in the core scenarios, although near-term expansion is modest relative to changes in generation and storage capacity (Figure 2 - 5). In the Reference scenario, U.S. interregional transmission capacity expands by 7% (10 TW-miles) from 2020 to 2035. The level of transmission expansion is correlated with solar and RE development, resulting in a 33% (46

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[32] No new nuclear capacity or fossil generation capacity with carbon capture and sequestration (CCS) are deployed in the core scenarios. The modeling does not include biomass with CCS or other negative-emissions technologies.

[33] Emissions intensities are lower in the Decarb+E scenario compared with the Decarb (without electrification) scenario owing to the same absolute CO_2 cap applied. As a result, solar and other zero-carbon resources are even more incentivized with high electrification.

TW-miles) and 39% (56 TW-miles) increase in transmission over this same period under the Decarb and Decarb+E scenarios, respectively.
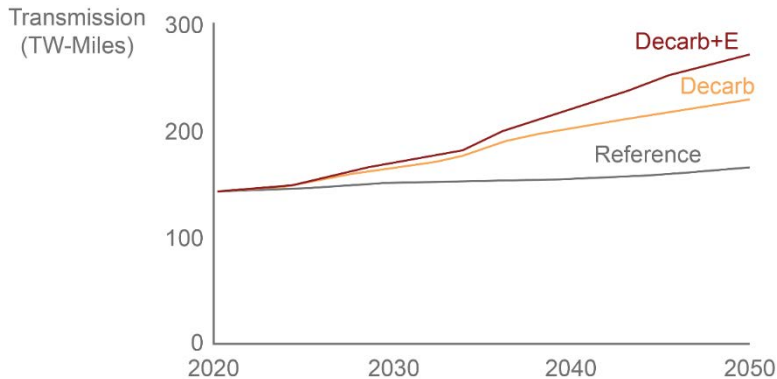
Figure 2 - 5. Interregional transmission expansion under the core scenarios

Interregional transmission refers to transmission between the 134 model BAs.

After 2035, solar and complementary technologies—including wind, energy storage, and transmission—continue to grow under the Decarb and Decarb+E scenarios as emission targets tighten, electricity demand continues to grow, and existing capacity (including zero-carbon nuclear capacity) retires (Figure 2 - 3). By 2050, solar energy is used to meet 44%–45% of total generation from 1,050 GW under the Decarb scenario and 1,570 GW under the Decarb+E scenario. Although most solar capacity growth is from PV technologies, CSP deployment is found as well. Under the Decarb scenario, 39 GW of CSP with TES are deployed by 2050. The dispatchability and high capacity credit (see Section 2.2.2) of CSP with TES are highly valued in this timeframe, especially with the levels of PV and wind generation envisioned. Figure 2 - 6 shows the increasing solar capacity across core scenarios over the 30-year study period.
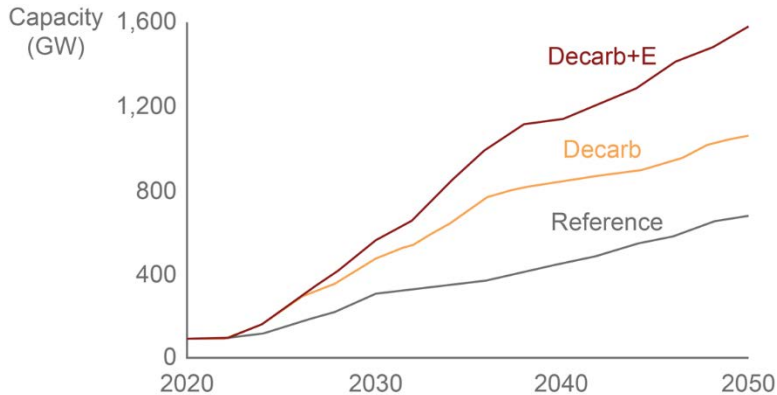
Figure 2 - 6. Installed solar capacity (DPV, UPV, and CSP combined) in the core scenarios

Solar technologies are deployed in all states under the Decarb and Decarb+E scenarios. Figure 2 - 7 shows regional installations by Census division, with growth increasingly spread across the country over time. Chapter 8 describes the land-use implications of these scenarios. The geographic distributions of solar and, especially, wind require more transmission expansion after 2035 (Figure 2 - 5). Achieving grid decarbonization along with high electrification (Decarb+E) would increase interregional transmission expansion by 90% (129 TW-miles) from 2020 to

2050. Transmission expansion is more limited without electrification; U.S. transmission capacity grows by 60% (86 TW-miles) over 30 years under the Decarb scenario.
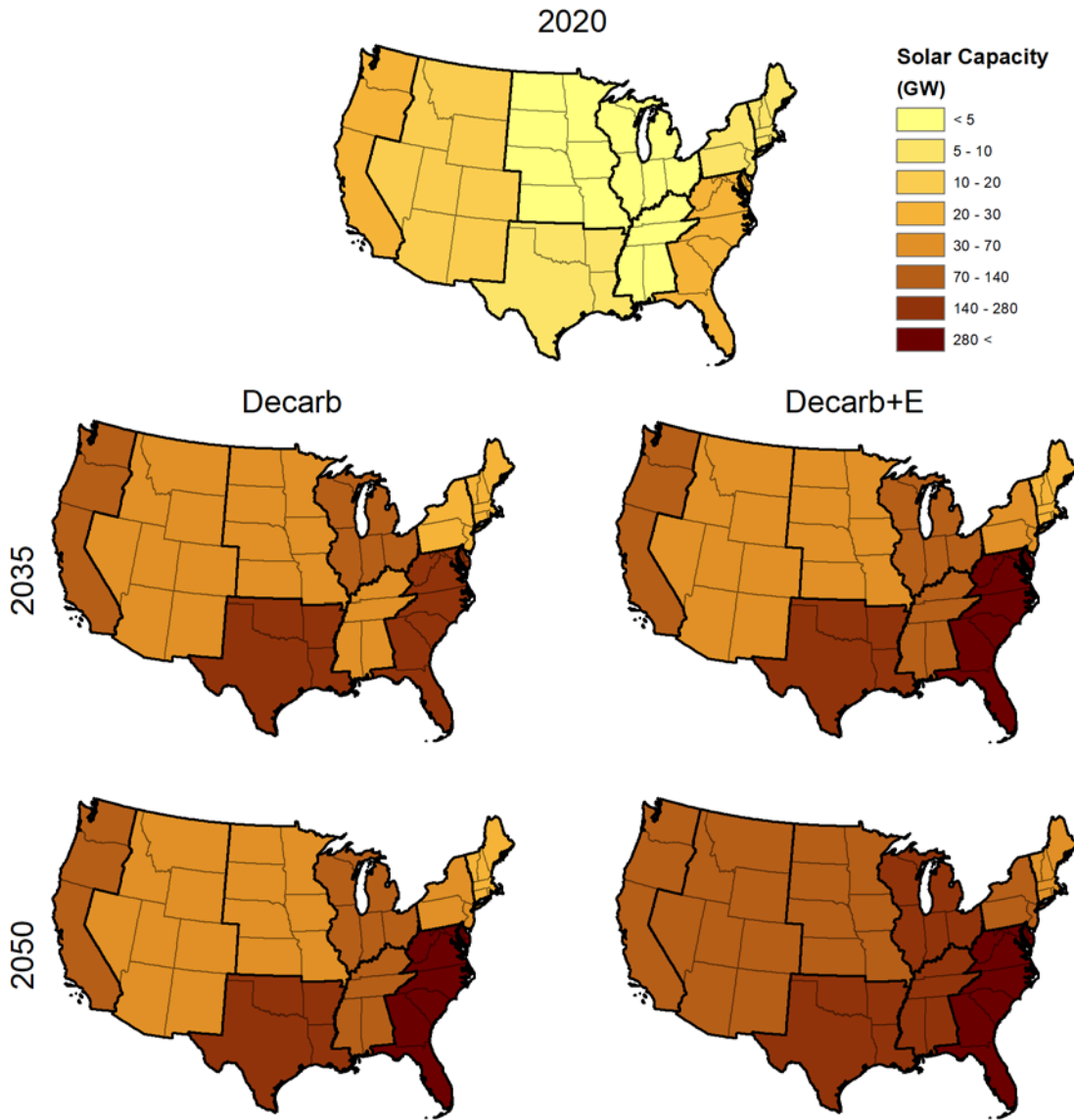
Figure 2 - 7. Solar capacity by Census division in 2020, 2035, and 2050, with future years depicted for the Decarb and Decarb+E scenarios

Modeled solar deployment is based on numerous factors—including the solar resource quality, cost and performance of other resources, land availability and exclusions, transmission topology, grid interconnection costs, and regional differences in installation costs that depend on labor rates and other factors—and can be highly sensitive to how these factors are parameterized; slight changes to these uncertain factors can yield substantial differences in the spatial distribution of future solar deployment outcomes in the scenarios. Given these sensitivities, the state-level deployment estimates shown in the figure should be interpreted as indicative only and not predictive.

Achieving the decarbonization scenarios requires significant acceleration of clean energy deployment. Compared with the approximately 15 GW of solar capacity deployed in 2020, annual solar deployment doubles in the early 2020s and quadruples by the end of the decade in

the Decarb+E scenario (Figure 2 - 8). The average solar deployment rate remains similar during the 2031–2035 period, at around 70 GW/year. Between 2036 and 2050, the rate is about 50 GW/year.[34] The solar deployment rates in the Decarb scenario are 30%–40% lower than in the Decarb+E scenario in all the periods after 2025.

Deployment rates accelerate for wind and energy storage as well. Wind experiences its most rapid growth during the 2031–2035 period, reaching about 50 GW/year in the Decarb+E scenario and 40 GW/year in the Decarb scenario and representing 3–4 times more than the 14 GW of wind deployed in 2020. Between 2036 and 2050, the rate is about 40 GW/year in the Decarb+E scenario and 20 GW/year in the Decarb scenario. Energy storage deployment rates increase across the entire study period, reaching about 110 GW/year in the Decarb+E scenario and 60 GW/year in the Decarb scenario during the 2036–2050 period.[35]

The lower solar and wind deployment rates during the second half of the study period are driven in part by a slowing decarbonization rate after 2035, but also by the increasing need for firm capacity (rather than energy) as the grid is nearly decarbonized and VRE shares reach very high levels.[36] Firm capacity is needed to ensure system resource adequacy and, under the conditions of these scenarios, the technologies that provide firm capacity offer greater value to the grid. As a result, batteries with increasing duration, RE-CTs, CSP with TES, and geothermal all increase considerably during the 2040s in the Decarb and Decarb+E scenarios, in which power-sector emissions are eliminated by 2050. For example, nearly 3 GW of the 28 GW of annual solar capacity additions during the 2040s are for CSP with TES under the Decarb scenario.[37]

Although the envisioned clean energy deployment rates are unprecedented, clean energy growth during the past decade—along with record deployment in 2020 for solar and wind under pandemic conditions—indicate the scalability of clean technology industries. Furthermore, global solar deployment rates have exceeded those shown in Figure 2 - 8, and very high annual deployments of other technologies have occurred historically. For example, 54 GW of NG capacity were installed in 2002. Nonetheless, increased and sustained deployment of solar and other clean technologies would require substantial scaleup of solar manufacturing, supply chains, and the workforce. These changes would also have implications for siting, permitting, and interconnection processes and policies. Chapter 6 and Chapter 8 discuss these implications in greater detail.

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[34] New capacity is also needed to replace retiring facilities. We assume physical lifetimes of 30 years for solar and wind capacity and 15 years for battery storage.

[35] Figure 2 - 8 shows stationary grid storage capacity only. EVs in the Decarb+E scenario would further increase demand for batteries.

[36] Solar and wind, together, constitute about 74%–78% of total generation by 2035 under the Decarb and Decarb+E scenarios. This share increases to 84%–90% by 2050.

[37] Chapter 5 discusses the increasing reliance on longer-duration storage.
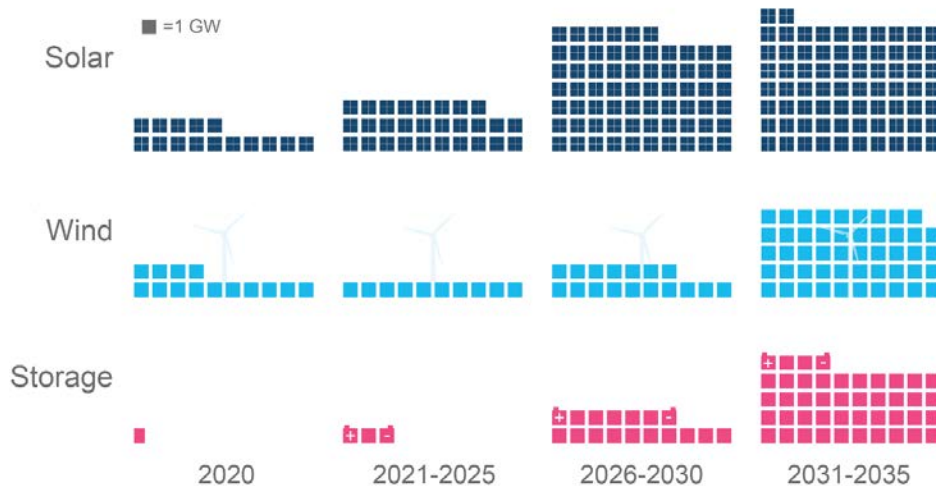
Figure 2 - 8. Historical annual technology deployment rates vs. projected average annual deployment rates during 5-year periods under the Decarb+E scenario

2.2.2 Resource Adequacy Under the Solar Futures Scenarios

Resource adequacy is the "ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)" (NERC 2017b). Adequacy reflects whether the system includes enough installed capacity from various resources—including generation, storage, transmission, and demand-side capacity—to meet a specified tolerance or expectation of unserved load as determined by regulators or utility planners. Increasing solar, wind, and storage complicates adequacy assessments owing to the variability of the renewable resources and the state-of-charge complexities with storage.

The ReEDS model represents system resource adequacy needs through seasonal planning reserve requirements[38] and endogenously estimates capacity credits[39] for VRE and storage (Ho et al. 2021; Cole, Greer, et al. 2020). Solar technologies contribute to planning reserve requirements despite their reliance on a variable solar resource, but these contributions typically decline with increasing solar deployment. Diurnal storage, such as the 2- to 10-hour battery options modeled, can also contribute to resource adequacy. The complementary nature of PV and batteries for peaking needs is well established (Denholm et al. 2019; Frazier et al. 2020).[40] Despite these synergies, the marginal capacity credit of diurnal storage can also decline with increasing storage deployment as peak of demand minus VRE and storage widens beyond the storage duration. Similar relationships exist for CSP, but the longer TES duration of the CSP configurations modeled (10 and 14 hours) typically leads to higher capacity credits for these options.

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[38] ReEDS uses the North American Electric Reliability Corporation reference reserve margin (NERC 2017a) by region.

[39] Capacity credit is the fraction of a technology's nameplate capacity that can be counted on for resource adequacy needs. In this chapter, "firm capacity" refers to the product of the capacity credit and the nameplate capacity, and has units of capacity (e.g., MW or GW).

[40] As net peak hours move towards the evening hours, diurnal storage can shift solar generation towards those periods of need. On the other hand, solar deployment can narrow demand peaks, which can increase the ability of energy storage to provide peaking reserves.

Declining solar capacity credits and thermal capacity retirements drive increasing deployment of the longer-duration storage, RE-CTs, and non-VRE generation options described in Section 2.2.1. Figure 2 - 9 shows summer and winter firm capacity contributions from all technologies in 2035 and 2050 under the core scenarios. In the Decarb scenario in 2050, battery storage contributes 251–326 GW of *firm* capacity from 910 GW of nameplate capacity installed by 2050 (see Figure 2 - 3).[41] PV's contributions are even more modest, providing 160 GW of firm capacity in summer, out of 1,020 GW of installed capacity. Firm capacity contributions from wind and non-dispatchable hydropower are also less than their nameplate capacity ratings. Demand flexibility can contribute to resource adequacy by decreasing the need for firm capacity services from other technologies. In the Decarb+E scenario, flexible loads provide 77–120 GW of firm capacity in 2050.

Figure 2 - 9 shows how solar's firm capacity contributions are even more limited in the winter. Most U.S. regions currently have summer demand peaks, which often establish system capacity needs. Under the *Solar Futures* scenarios, winter periods grow in importance as large-scale solar adoption can shift *net* demand peaks to evening periods and *seasonally* shift net peak demand to winter periods. Electrification—especially for space heating (Mai, Jadun, et al. 2018)—can also shift demand peaks to colder periods. These winter low-solar periods highlight some of the potential challenges with integrating high shares of solar energy under a decarbonized energy system.[42]

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[41] Attributing firm capacity to individual technologies is imperfect because the capacity credit for one technology is influenced by the deployment of another owing to impacts on net demand (Denholm et al. 2019; Frazier et al. 2020).

[42] For most regions, the summer planning reserve constraints are binding in all years after the mid-2020s in all scenarios modeled. Before the mid-2030s, the winter requirement is only binding for a small number of winter peaking regions; however, under the Decarb and Decarb+E scenarios, the winter planning reserve constraints become binding for nearly all regions.
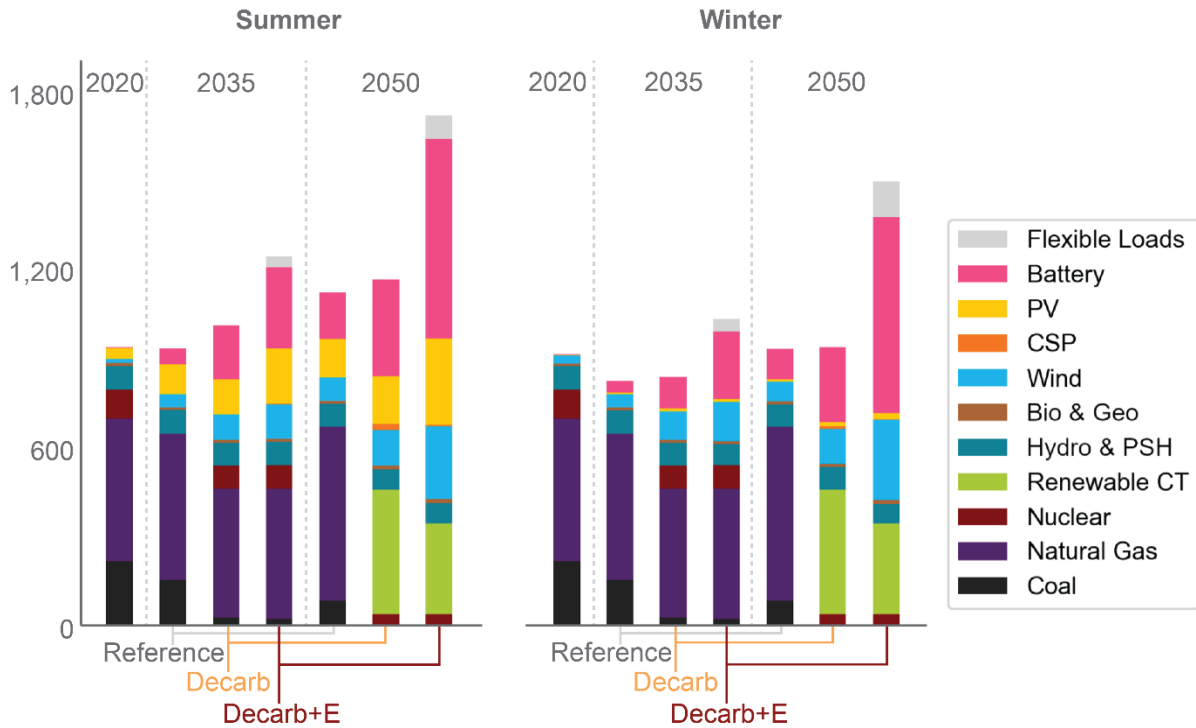
Figure 2 - 9. Summer (left) and winter (right) firm capacity contributions in 2050 under the core scenarios

The detailed analysis presented in Chapter 3—which uses chronological hourly unit commitment and economic dispatch grid simulations—shows how a mix of resources is used to maintain resource adequacy across the core *Solar Futures* scenarios in 2050, particularly during high net load (load minus VRE generation) periods. The diverse mix of resources includes energy storage, flexible demand, transmission (enabling greater spatial and technological diversity in resources), and RE-CT generation—to address periods of high net demand.

Much of the diurnal mismatch between supply and demand during high net load periods is addressed via energy storage with 10 or fewer hours of duration. Storage is typically used to meet the net load peaks that occur in the morning and early evening. Flexible demand supplements storage to address the diurnal mismatch in the Decarb+E scenario. It is predominantly used during the net-load ramp in the evening as PV generation declines, displacing output from shorter-duration storage during this time. Some load is shifted into the midday hours of PV output, directly using overgeneration during these hours when available.

In some regions, expanded transmission is a key aspect of resource adequacy as diverse resources from across the country are used to meet demand. Such power trading can help lower costs by reducing the excess capacity required for a few hours of the year, although this also could yield reliability challenges if certain regions rely on transmission in times of grid stress. Relatedly, transmission enables generators and storage to provide capacity services to multiple regions that have non-coincident demand peaks.

Unlike PV and wind technologies, RE-CTs use a stored fuel source to provide generation when needed throughout the year, which is critical to maintaining resource adequacy in 2050 in the Decarb and Decarb+E scenarios. Use of RE-CTs in those scenarios varies substantially based on

weather conditions: When solar and wind generation is low, the RE-CTs fill the gap. Overall, RE-CT use is lower in spring and fall (when VRE is sufficient to meet the diurnal mismatch almost entirely with storage and demand response) and higher in summer and winter. Annual RE-CT capacity factors in 2050 vary across regions, but are similar to the capacity factors of current NG-CTs (e.g., 8%–12% during 2011 to 2020 for the U.S. fleet average (EIA 2021c).

Chapter 3 provides more detailed analysis of resource adequacy in the *Solar Futures* scenarios. That chapter also examines how a mix of resources, including RE-CTs, can work together with diurnal storage during extreme events when VRE output is low for extended periods. In addition, it discusses operating reserves and other grid reliability issues that arise from increased variable and inverter-based generation.

2.2.3 Curtailment

Curtailment is the practice of foregoing available RE output (O'Shaughnessy, Cruce, and Xu 2020) due to transmission congestion constraining RE delivery, other system inflexibilities such as minimum generation limits, and mismatches between generation and demand profiles. Figure 2 - 10 shows estimated annual curtailment through 2050 under the core scenarios. Annual curtailment reaches 274 TWh (8.0% of available PV and wind generation) in 2035 and grows to 398 TWh (9.2%) by 2050 under the Decarb scenario. With electrification and decarbonization, curtailment is greater in absolute and relative terms by 2050; 2035 and 2050 annual curtailment are 298 TWh (7.0%) and 826 TWh (13%) under the Decarb+E scenario.
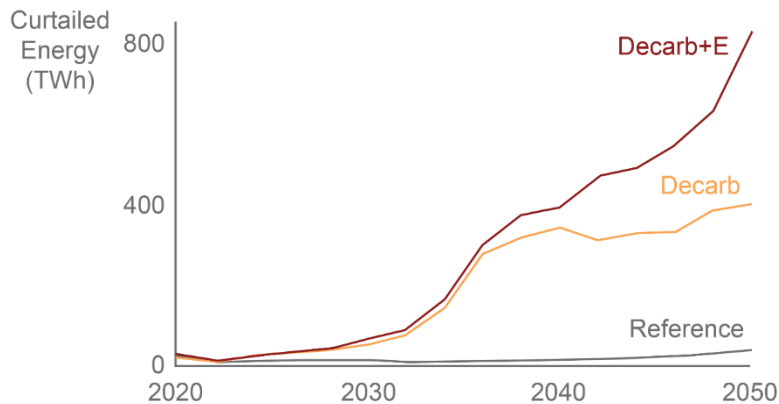
Figure 2 - 10. Annual curtailment under the core scenarios

Curtailment is one of several ways to manage variable solar and wind output. Other approaches include temporally or spatially shifting generation or demand through energy storage, transmission, or demand flexibility as described in Section 2.2.2. The modeled least-cost scenarios rely on a mix of all these approaches. Increased reliance on curtailment is found in the Decarb and Decarb+E scenarios because diurnal storage and demand flexibility cannot manage the seasonal oversupply of solar and wind. Figure 2 - 11 shows how curtailment predominantly occurs in the spring under these scenarios. Curtailed solar and wind represents low-cost, zero-carbon output that is available to power new end uses or as an energy source for low-carbon fuel production, which could help reduce emissions and/or costs. Low-carbon fuel produced via curtailed energy could also be used in RE-CTs. However, tapping into this curtailed output will require co-location or adequate transmission connection as well as new demands that can make economic use of the seasonal and diurnal variability of curtailed solar.
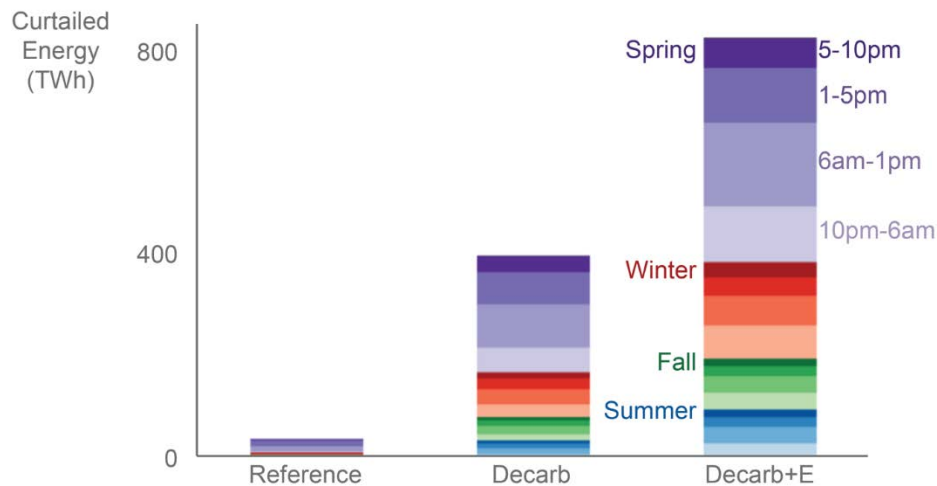
Figure 2 - 11. Annual curtailment under the core scenarios

Storage and transmission losses also increase over time and relative to the Reference scenario in the Decarb and Decarb+E scenarios. Roundtrip efficiency losses from storage in 2050 are 117 TWh and 224 TWh under the Decarb and Decarb+E scenarios, respectively. Transmission losses total 54 TWh in 2050 under the Decarb scenario and 73 TWh under the Decarb+E scenario.[43] In comparison, 2050 storage and transmission losses under the Reference scenario are about 50 TWh each.

2.2.4 *CO$_2$ Emissions*

The changes to electricity generation described in Section 2.2.1 result in reduced power-sector emissions over time in all *Solar Futures* scenarios. In the Reference scenario, declining coal-fired generation and a corresponding increase in generation from lower-emissions sources result in power-sector emissions of 1,330 Mt CO$_2$ (45% below 2005 levels) in 2035 and 931 Mt CO$_2$ (61% below 2005 levels) in 2050.[44] In contrast, power-sector CO$_2$ emissions under the Decarb and Decarb+E scenarios reach 120 Mt by 2035 and 0 Mt by 2050, as specified by the scenario designs.

Figure 2 - 12 combines the estimated power-sector emissions with emissions from U.S. end-use sectors—residential and commercial buildings, industry, and transportation—to estimate total energy-related CO$_2$ emissions. In the Reference scenario, reduced power-sector emissions are offset in part by increased emissions in the end-use sectors. As a result, annual energy-related CO$_2$ emissions are 21% below 2005 levels in 2035, declining only slightly to 24% below in 2050. In contrast, the Decarb scenario—which has the same end-use sector emissions as the

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[43] Combined transmission and distribution losses together are estimated to be 314 TWh and 426 TWh in the Decarb and Decarb+E scenarios, respectively.

[44] Only CO$_2$ emissions from direct combustion are reported in this chapter. The NREL Life Cycle Assessment Harmonization project (NREL n.d.) includes a series of papers with estimated full life-cycle emissions—including non-CO$_2$ GHG emissions—of solar and other generation technologies. Chapter 8 of the Los Angeles 100% Renewable Energy Study (Cochran et al. 2021) includes a recent application of these estimates to future scenarios. Heath et al. (Forthcoming) discuss the circular economy, health, and environmental aspects of solar development.

Reference scenario—reduces energy-related emissions to 42% below 2005 levels in 2035. The rate of *energy*-related CO_2 reductions between 2020 and 2035 is similar to reductions experienced during the prior 15 years (Wiser et al. 2021). Energy-related emissions rise slightly between 2035 and 2050 as increased emissions from end uses outpace power-sector emissions reductions. Although the grid transformation suggested by this scenario is unprecedented, the significant remaining CO_2 emissions from the end-use sectors show the limits of grid decarbonization alone as a GHG abatement measure.
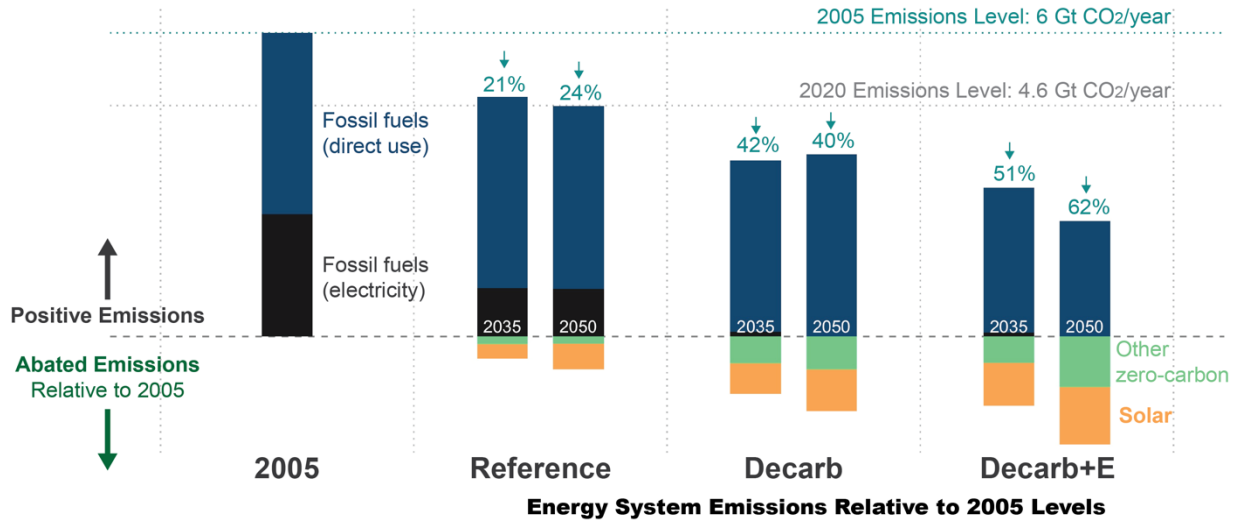
Figure 2 - 12. Energy-related CO₂ emissions in the core scenarios

Percent reductions are relative to 2005 CO_2 emissions. Direct emissions from the end-use sectors for the Decarb+E scenario are based on the high electrification scenario from the EFS study, which did not project complete electrification or decarbonization for all subsectors.

Combining grid decarbonization with electrification provides larger emissions reductions. The Decarb+E scenario shows that increasing use of low-carbon electricity in the end-use sectors can lower energy-related CO_2 emissions to 2,950 Mt by the mid-2030s (51% below 2005 levels) and 2,280 Mt by 2050 (62% below 2005 levels).[45] Here, electrification reduces transportation-related emissions 59% from 2005 levels by 2050, primarily by reducing gasoline use in light-duty vehicles. Direct emissions from the buildings sector (residential and commercial combined) decline 42% below 2005 levels largely through adoption of electric (heat pump) space and water heating. Industrial emissions remain above 2005 levels (by 11% in 2050), but they are lower than in the other scenarios owing to incremental adoption of electro-technologies. The declining total and sector emissions occur in this scenario despite increased service demand, population, and gross domestic product (EIA 2020a).

Although the Decarb+E scenario leaves 2,280 Mt of energy-system CO_2 unabated in 2050, the deep emissions reductions—relative to historical emissions and to the Reference scenario—show how electrification and grid decarbonization are key pillars to achieving economy-wide

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[45] Direct emissions from the end-use sectors are based on estimates from the High Electrification Moderate technology scenario in the EFS (Murphy et al. 2021), but calibrated using the AEO 2020 Reference case (EIA 2020a). The calibration applies sector-specific relative emissions reductions from the EFS to the 2020 end-use sector emissions from AEO 2020. Note that the AEO 2020 data did not consider the full effects of the pandemic which caused much lower emissions in 2020 than expected.

decarbonization. Further emissions reductions would require additional electrification and a transition to low-carbon fuels, primarily in the transportation and industrial sectors. These strategies could rely on more solar technology deployment for electricity production and solar thermal applications. Section 2.3 explores the potential role of solar in decarbonization efforts beyond those modeled in the *Solar Futures* scenarios.

2.2.5 *Electricity Prices and CO$_2$ Abatement Costs*

Multiple factors influence the cost of electricity and emissions abatement cost in the scenarios. Figure 2 - 13 shows the national-average *marginal* system cost of electricity in 2035 and 2050 for the core scenarios, along with four factors—technology cost, emissions policy, electrification, and demand-side flexibility—that influence the relative costs between scenarios. The marginal system cost of electricity is a measure that is similar to electricity prices from restructured power markets.[46] In all scenarios, the marginal system cost of electricity starts around $30/MWh in 2020 and rises during the early 2020s as reserve margins tighten owing to demand growth and power plant retirements, as well as the emissions constraints in the Decarb and Decarb+E scenarios. Unless otherwise noted, real 2018 dollars are used for all economic values reported.

In the mid-2030s (Figure 2 - 13, top), the marginal system cost of electricity of the Decarb scenario remains very similar to that of the Reference scenario despite the emissions cap applied in the former. This is due to offsetting impacts from technology advancements and the emissions constraint.[47] For example, the grid decarbonization policy alone raises the 2035 electricity price of the Reference scenario by about $17/MWh, but RE technology advancements assumed in the Decarb scenario fully offset this incremental cost. Additionally, electrification raises electricity costs by nearly $4/MWh as more expensive resources are used to meet the higher demands. This low incremental impact suggests there are sufficient low-cost clean electricity resources, including solar energy, in the United States to serve new electrified loads (Murphy et al. 2021). Furthermore, demand flexibility offsets the higher electrification-driven costs such that the 2035 electricity cost for the Decarb+E scenario (right green bar) is slightly below that of the other two scenarios.[48] In all core scenarios, electricity prices are estimated to be about $41–$43/MWh during the mid-2030s.

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[46] The marginal system cost of electricity reflects the cost to serve the next increment of demand and considers the combined costs of all major grid services modeled—including for load balancing, planning reserves, operating reserves, and clean energy policies. Both long-run capital expenditures and variable operating costs are considered in this measure of electricity prices. Specifically, the marginal system cost of electricity is calculated from the sum of the products of the shadow prices of all the constraints reflecting these grid services and the grid service requirements, divided by the delivered electricity. This price excludes distribution system and administrative costs that are included in retail prices. Additional study is needed to assess costs for needed distribution system upgrades for distributed energy resources and new electrified loads as well as costs for sensing, communications, and control infrastructure to enable demand-side flexibility. Appendix 2-F defines various cost metrics.

[47] The Decarb and Decarb+E scenarios assume more technological progress in solar and other clean energy technologies than the Reference scenario. The R&D expenditures that may be required for these clean energy technology improvements are not captured in this metric or any other cost measure reported in this chapter.

[48] We assume demand flexibility is available at zero cost in the scenarios. Including costs or other constraints to demand flexibility would reduce its ability to lower electricity costs.

Marginal System Cost of Electricity ($/MWh)
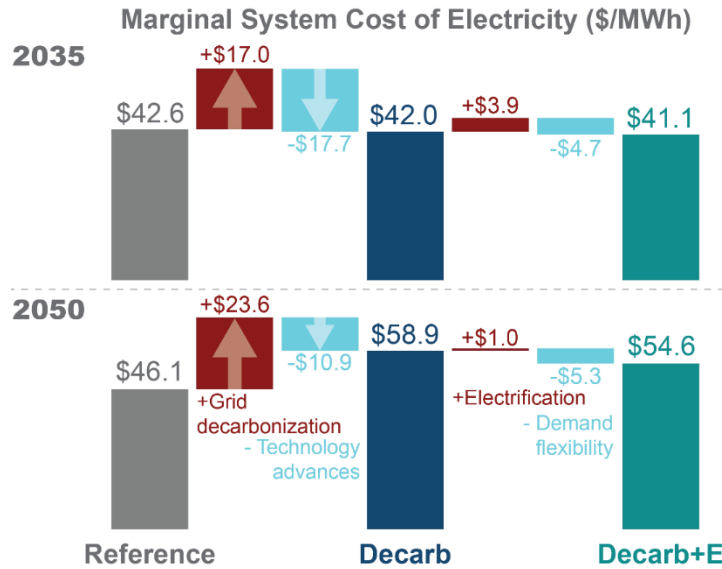
Figure 2 - 13. Marginal system cost of electricity estimates and drivers in 2035 (top) and 2050 (bottom) for the core scenarios

The isolated effects shown in the waterfall chart are estimated by simulating additional scenarios beyond the three core scenarios. For example, the leftmost increase in prices from "grid decarbonization" alone are based on the difference between a decarbonization scenario that uses the ATB Moderate cost projections and the Reference scenario, while the adjacent light blue reduction in prices reflects the difference between the Decarb scenario and this ATB Moderate decarbonization scenario. Similarly, the increase in prices from electrification uses a scenario without any assumed demand-side flexibility.

The results from Figure 2 - 13 highlight how power-sector CO_2 emissions reductions of around 95%—and additional emissions reductions in the end-use sectors via electrification—are possible by the mid-2030s without increasing electricity prices. Achieving these emissions reductions without raising electricity prices requires continued improvements in clean energy technologies, such as through R&D and learning-by-doing. Ultimately, the affordability of grid decarbonization—from an electricity price perspective—is determined by these two counteracting effects.

Figure 2 - 13 (bottom) shows the comparisons for 2050, when the power systems under the Decarb and Decarb+E scenarios are emissions free; the longer timeframe adds uncertainty to this analysis compared with the 2035 analysis. Again, technology advancements and demand flexibility reduce costs substantially, but the incremental cost to completely eliminate emissions from power generation outstrips these benefits under the assumptions used. The 2050 marginal system cost of electricity is $8.50/MWh–$13/MWh greater under the Decarb and Decarb+E scenarios, relative to the Reference scenario. A combination of greater technology advancements beyond those modeled in the scenarios and deployment of other decarbonization options that were not included in the modeling (e.g., CDR technologies) are needed to offset the cost of fully decarbonizing electricity, especially given the need to replace carbon-emitting fossil fuel capacity with zero-emission options. Furthermore, changing electricity prices can have unequal impacts across households and businesses in part due to different impacts of energy expenses on budgets—and these effects are not captured in the electricity price estimates here. Chapter 4 discusses distributional impacts and mechanisms to increase equity from potential changes to electricity prices.

Another measure of the difficulty of reducing emissions is the *marginal* abatement cost, which is the incremental cost to avoid the next metric ton of CO_2.[49] Figure 2 - 14 shows how the marginal abatement costs in the power sector for the Decarb and Decarb+E scenarios are very low during the first decade of the study period, remaining below \$20/t CO_2 in the scenarios until the early 2030s. These costs remain below \$100/t CO_2 through the mid-2030s even as power-sector emissions fall to 120 Mt/year.

Marginal abatement costs can be compared with the social cost of CO_2 (SCC), which is the estimated monetary damage associated with releasing a metric ton of CO_2 (IWG 2021). Figure 2 - 14 shows the central SCC estimate (green line) and the full range of SCC estimates (green shading) from the U.S. interagency working group on social cost of greenhouse gases (IWG 2021).[50] The intersection of the SCC and the marginal abatement costs reflects the point at which the cost to reduce emissions matches the social benefits of that reduction. The cost-benefit comparison here is based on CO_2 only and does not consider impacts from other GHGs, air pollution and health co-benefits, or other social impacts. Within this narrow scope and for the two scenarios shown and the central SCC trajectory, marginal abatement costs are lower than the social benefits of avoided climate damages until the mid-2030s, when annual power-sector emissions are about 95% below 2005 levels. With the lowest SCC estimate (5% discount rate), the intersection occurs when power-sector emissions are about 80% below 2005 levels.[51] These findings highlight the substantial low-cost CO_2 abatement opportunities in the power sector.

After the mid-2030s, marginal abatement costs rise in a highly nonlinear fashion and exceed even the highest SCC estimates. Marginal abatement costs reach several thousand dollars per metric ton of CO_2 during this period. These results reveal the challenge of eliminating the last 5%–10% of power-sector emissions, in part due to the need for clean peaking capacity. They also highlight opportunities for further innovation—including for options not modeled here, such as negative-emissions technologies—to play a larger role in decarbonizing electricity. Moreover, the results indicate that emissions abatement outside the power sector may be more cost-effective than focusing solely on electricity. Cross-sectoral integration can help lower abatement costs across the energy system.[52]

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[49] Specifically, the marginal abatement cost is the shadow price on the national annual emissions constraint.

[50] The SCC reflects global damages from emissions in a year by estimating the monetized impacts that those future emissions have over a long (multi-century) period. The present value of the monetized damages is sensitive to assumed discount rate, which is one driver of the range of SCC estimates. The central estimate uses the 2.5% discount rate as recommended by the IWG (2021).

[51] The use of the higher (5%) discount rate for the SCC has been under question (National Academies of Sciences 2017; IWG 2021).

[52] The reported metric imperfectly measures abatement costs for the Decarb+E scenario because demand from new electrified loads is exogenously specified in ReEDS. However, the system cost analysis (Section 2.2.6) considers demand-side expenditures and benefits from avoided emissions across the *energy* system.
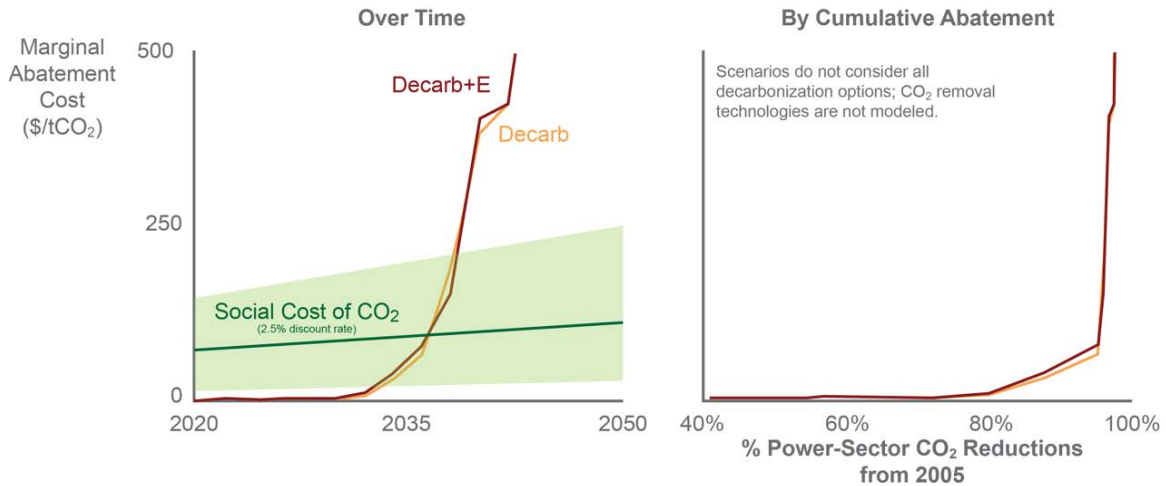
Figure 2 - 14. Marginal CO₂ abatement costs and SCC by year (top) and marginal abatement costs by percentage of power-sector CO₂ reductions relative to 2005 CO₂ emissions (bottom)

Marginal abatement costs are highly uncertain as the power system approaches full decarbonization (i.e., after 2035). The scenarios do not include all decarbonization options—including CDR technologies—which could lower the abatement costs shown.

2.2.6 System Costs and Benefits

Figure 2 - 15 shows the present value of total bulk power system costs—including capital, operations and maintenance (O&M), and fuel expenditures for generation, storage, and transmission—over the 30-year study horizon, assuming a 5% real discount rate.[53] Compared with the Reference scenario system cost, the cost for the Decarb scenario is 9.9% ($225 billion) higher, reflecting the added cost of solar and other zero-carbon and supporting capacity after factoring out the reduced fuel and other expenditures for fossil fuel technologies. The incremental power-system costs increase to $562 billion (25%) in the Decarb+E scenario because of the costs of serving electrified demand that was formerly powered by direct fuel combustion. For context, U.S. gross domestic product (GDP) was about $20 trillion in 2020 and is projected to grow (in real terms) through 2050 in the Annual Energy Outlook Reference case (EIA 2021a). Using these projections, the incremental power system costs for the Decarb and Decarb+E scenarios are estimated to be less than 0.05% and 0.14%, respectively, of the present value of U.S. GDP over the same period and using the same discount rate.

As with the marginal system cost of electricity, the magnitude of incremental system costs depends on multiple factors, several of which are explored in the sensitivity analysis presented in Appendix 2-B. For example, absent clean electricity technology advancements, the incremental system costs for the Decarb scenario would be over twice as high ($500 billion).

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[53] System costs are estimated for the bulk power system only. Electric distribution system costs are not estimated for any of the scenarios. Costs for distributed energy resources, including rooftop PV, are also not accounted for in this metric. However, the differences in capital and O&M expenditures for distributed PV between the Reference and Decarb (and Decarb+E) scenarios are modest relative to the difference in bulk power system costs. Appendix 2-F defines various cost metrics.
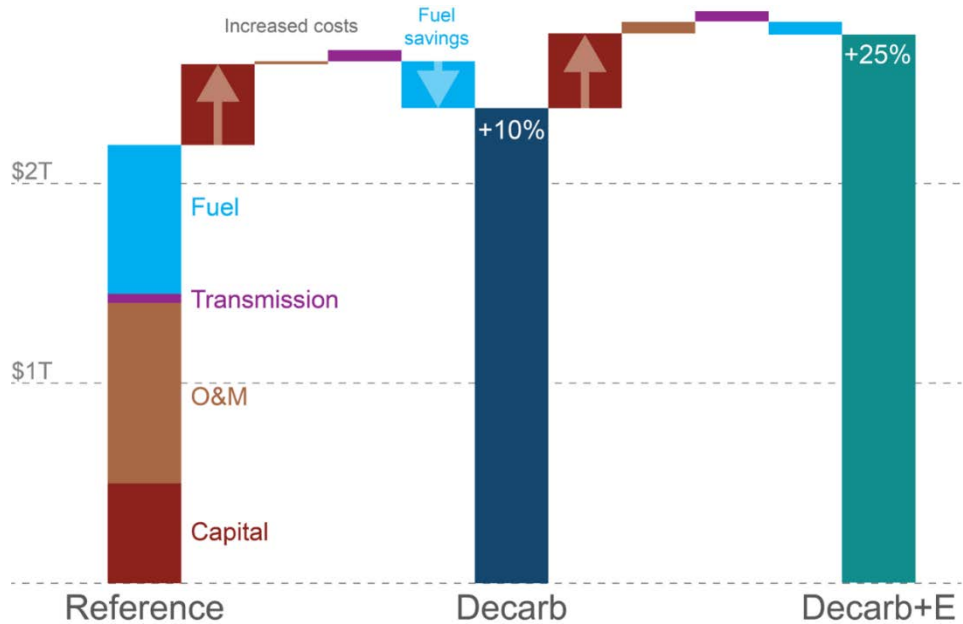
Figure 2 - 15. Electricity system costs in the core scenarios

System costs are on a present-value basis for 2020–2050 using a 5% real discount rate.

Moreover, the higher incremental electricity system cost for the Decarb+E scenario must be weighed against differences in non-electric capital, fuel, and operating expenditures by end users. For instance, EV adoption increases electricity system costs by increasing demand for EV charging, but it reduces end-user expenditures on gasoline. The incremental Decarb+E power system cost estimate ($562 billion) accounts for the former but not the latter. We used data from the EFS (Jadun et al. 2017) to estimate a range (slow, moderate, and rapid) of incremental costs for electrified technologies (e.g., EVs, heat pumps) and reduced end-user expenditures on fuels (e.g., gasoline for vehicles, natural gas for building heating). Using the central (moderate) projections, differences in end-user costs result in net system savings of $350 billion,[54] partially offsetting the greater electricity system expenditures. Accounting for changes in end-user costs, the incremental cost of the Decarb+E scenario declines to $210 billion; this is similar to the incremental cost in the Decarb scenario, which assumes the same rate of electrification as the Reference scenario.

The SCC can also be used to compare power-system costs versus monetized benefits from avoided climate damages across the 30-year study period. Figure 2 - 16 shows how these benefits—when using the central technology and SCC assumptions—outweigh incremental electricity system costs in the decarbonization scenarios. We estimate cumulative (2020–2050, 5% real discount rate) savings of about $1 trillion from avoided climate change damages plus $300 billion from air quality improvements in the Decarb scenario, compared with the Reference scenario. As a result of electrification, in the Decarb+E scenario these benefits increase to $1.6

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[54] To be clear, the adoption of electrified technologies increases end-user electricity bills, but these increases are already reflected in the incremental power system cost of $562 billion. The estimated net savings reflect an adjustment to account for the impacts of electrification on non-electricity costs.

trillion for avoided climate change damages and $400 billion for air quality improvements. Estimated avoided climate damage benefits vary widely depending on choice of SCC.
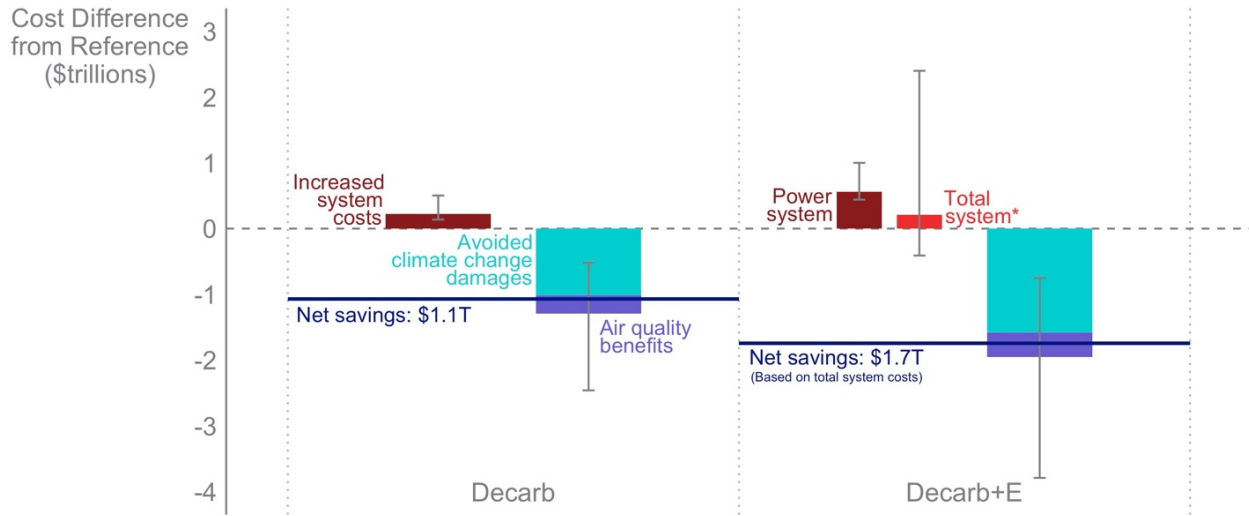
Figure 2 - 16. Estimated cost differences between decarbonization scenarios and Reference scenario, cumulative 2020–2050

System costs and climate damages are on present-value basis for 2020–2050 using a 5% real discount rate. Positive values represent higher incremental costs, whereas negative values represent lower costs or climate benefits (i.e., less damage), both relative to the Reference scenario. Colored bars represent central estimates: ATB Advanced RE and storage technologies, EFS Moderate end-use technologies, and SCC using a 2.5% discount rate. Ranges for electricity system costs correspond to the ATB Moderate and Breakthrough PV and battery scenarios (see Appendix 2-B). Ranges for demand-side electrification costs correspond to the EFS Rapid and Slow projections. Ranges for climate damages correspond to the 5% and 3% 95th percentile SCC trajectories. * Total system cost includes adjustment for the difference in end-user non-electricity expenditures.

Central estimates for net *savings* are $1.1 and $1.7 trillion in the Decarb and Decarb+E scenarios. The findings suggest that the benefits from avoided climate and air pollution damages are expected to outweigh incremental costs from decarbonizing electricity and electrifying end uses to the extent considered in the scenarios, although with substantial uncertainty across several dimensions. Advancements in technologies—both for power generation and those used directly by consumers—can influence the costs, but uncertainties with respect to damages from future emissions can be even greater. Beyond these uncertainties, the analysis does not address all social impacts, including the social costs of other GHGs. Heath et al. (Forthcoming) describe the methods and assumptions behind the air quality benefits and discusses land and water use impacts from the scenarios; Text Box 3 summarizes the air quality estimates. Future work is needed to evaluate these and other effects, including the distribution of costs and benefits by region and populations.

Text Box 3. Order-of-Magnitude Estimate of Air-Quality Benefits

Often accompanying GHG emissions abatement are reductions in other air emissions that can reduce health-related damages such as premature mortality and incidences of heart attacks, asthma, hospitalizations, and corresponding negative impacts on productivity. These avoided health damage "co-benefits" can be sizeable and, historically, can even outstrip climate benefits and other social impacts (Wiser et al. 2021). In addition, given that historically the negative impacts have been disproportionately borne by underserved communities, due to proximity with existing plants, reducing emissions could help address equity concerns. Here we present initial and approximate estimates of the potential air-quality benefits of the Solar Futures scenarios based on a simplified approach.

We estimate the air-quality benefits from avoided emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) in the power and transportation sectors—through displacement of fossil fuel combustion sources by solar and other clean electricity technologies—for the Decarb and Decarb+E scenarios. Following historical reduction trends, power-sector SO_2 and NO_x emissions continue to decline significantly under the Decarb and Decarb+E scenarios such that emissions fall below 100,000 t/year of each pollutant by 2035 and are essentially eliminated by 2050. As shown in the figure below, the monetized benefit from these avoided emissions totals roughly $300 billion on a present-value basis (over the 30-year study horizon, using a 5% real discount rate, and relative to the Reference scenario). Under the Decarb+E scenario, electrified transportation further reduces petroleum use, thereby lowering NO_x and PM emissions. These reductions save an additional nearly $100 billion in health damages from reduced vehicle emissions.
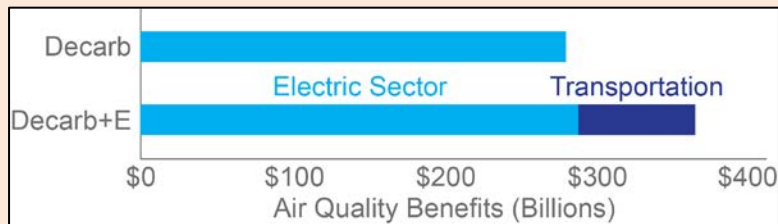
Quantifying air-quality and health impacts—especially on a prospective basis to 2050—can be challenging owing to the highly localized nature of pollution exposure, background air quality, atmospheric chemistry, and uncertainties associated with factors relating health damages to marginal changes in emissions. National average emissions and damage estimates are used here. Emissions factors are based on historical trends but could differ in the future, especially through emissions-control equipment that could be adopted separately from GHG reductions, thereby possibly lowering the air-quality benefits estimated here. Conversely, only power- and transportation-sector emissions reductions are considered in these estimates, whereas the Decarb+E scenario includes reduced fossil fuel use in buildings and industry as well. Including these effects would increase the air-quality benefits in that scenario. Other uncertainties, assumptions, and methodological limitations are described in Heath et al. (Forthcoming). Notwithstanding these limitations, the approximate preliminary estimates presented here highlight that air-quality benefits from the *Solar Futures* scenarios are sizeable and within the same order of magnitude as the incremental direct system cost and climate benefits quantified for these scenarios.

2.3 Solar Deployment for Deeper Decarbonization

The results of the core *Solar Futures* scenarios presented in Section 2.2 show possibilities for substantial power-sector CO_2 emissions reductions through increased deployment of solar and other clean electricity technologies. With high electrification, low-carbon electricity is used to mitigate emissions from end-use sectors as well, in large part through greater solar adoption. Solar capacity reaches nearly 1,600 GW, providing 45% of total generation needs, in 2050 under the Decarb+E scenario. However, even under this scenario with full grid decarbonization and high electrification, substantial residual annual energy-related emissions (2,280 Mt CO_2 in 2050, Figure 2 - 12) from carbon-emitting fossil fuel use remain. Reducing or eliminating these emissions requires additional clean energy deployment.

Several abatement strategies could help achieve deeper emissions reductions, which fall into four broad categories: (1) energy efficiency, (2) additional electrification with low-emissions electricity, (3) zero-carbon gas or liquid fuels, and (4) carbon capture or negative-emissions technologies (e.g., biomass with CCS, direct air capture). We consider a single possible set of market shares for these options[55]—applied to the residual carbon-emitting fossil fuel energy consumption after the Decarb+E scenario is achieved in 2050—and we calculate the associated energy and electricity demands. These assumptions are not derived based on economic competition; they are used only to enable a rough estimate of the potential impact on solar deployment of additional decarbonization. The incremental solar deployment is estimated based on the generation and capacity mix in 2050 from the Decarb+E scenario. Section 2.3.1 presents our estimates, and Appendix 2-D describes the method and assumptions used. Section 2.3.2 discusses the limitations of this analysis and the qualitative impact of different assumptions.

2.3.1 Energy System Decarbonization and Solar Deployment

Residual emissions in 2050 under the Decarb+E scenario are from continued reliance on carbon-emitting fossil fuels in the buildings, industrial, and transportation sectors—even after the increased electrification modeled in the scenario. Figure 2 - 17 shows the final energy consumption under that scenario by sector and fuel type. Electricity constitutes 36% of total final energy consumption by 2050, which approximately doubles electricity's 2020 share and is much higher than the shares for 2050 under the Reference and Decarb scenarios. In addition, because *electricity* is fully decarbonized by 2050, remaining fossil fuel use is through direct consumption in the end-use sectors only.

Residual fossil fuel consumption totals 40.6 quadrillion Btus (quads) in 2050 under the Decarb+E scenario, over half (22.7 quads) for industrial applications. The construction, industrial boilers, agriculture, industrial process heating, and bulk chemicals subsectors each consume 2.5–4.1 quads of fossil fuels (petroleum and NG) in 2050. Fossil fuel consumption in the transportation sector totals 12 quads in 2050 and is almost exclusively from petroleum products such as jet fuel for aviation (2.5 quads) and diesel and other bunker fuels for freight rail and marine shipping. Even with significant electrification of on-road transportation, 2.9 quads,

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[55] CDR technologies are not considered in our analysis. Their inclusion could lead to increased solar deployment due to the electricity demand to operate some of these technologies. Conversely, these technologies could allow continued use of fossil fuels and thereby reduce the need for solar and other clean energy technologies. Additional research is needed to assess these net effects.

1.1 quads, and 2.8 quads of fossil fuel consumption remain for light-, medium-, and heavy-duty vehicles, respectively. Fossil fuel consumption in the commercial and residential buildings sectors totals about 3 quads for each sector, primarily in the form of NG consumption for space and water heating—again even after significant electrification through heat pump adoption assumed in the Decarb+E scenario.
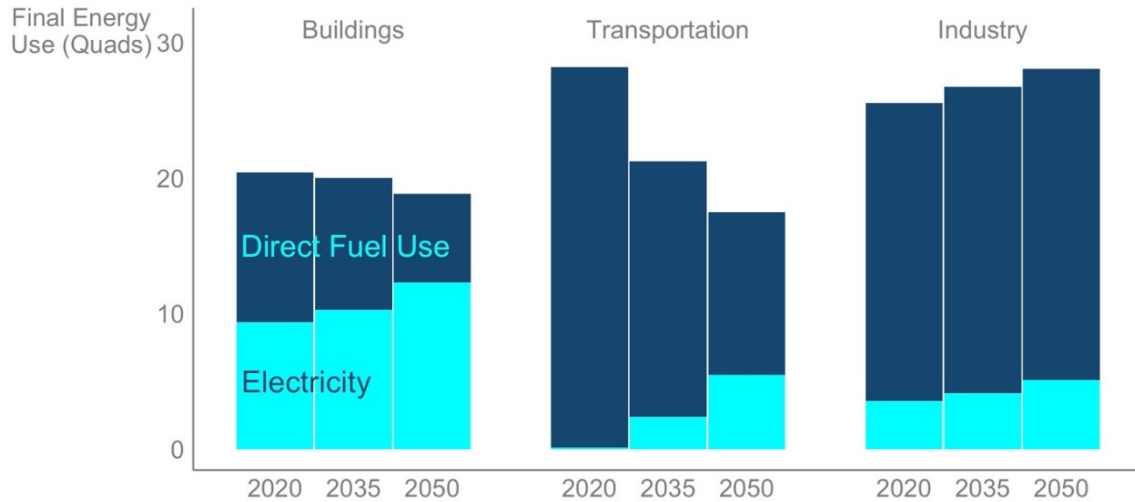
Figure 2 - 17. Final energy consumption by sector for the Decarb+E scenario

See Chapter 7 for details on energy consumption by sector, including discussion of direct fuel vs. electricity use.

To calculate a first-order estimate of additional solar demand associated with eliminating CO_2 emissions across the energy system, we develop an Energy Decarbonization (Energy Decarb) scenario starting from the residual carbon-emitting fossil fuel consumption in the Decarb+E scenario. We assume market shares for energy efficiency, increased electrification, and substitution of fossil fuels with low-carbon fuels that result in very little carbon-emitting fossil fuel consumption (~4 quads) by 2050. For example, space and water heating are fully electric under the Energy Decarb scenario. On-road transportation needs are met by a combination of further electrification (particularly for light-duty vehicles), adoption of hydrogen fuel cell electric vehicles (FCEVs), and biofuels. Other transportation energy demands (e.g., marine, rail, aviation) are met through a broad portfolio of fuels, including electricity, hydrogen, biofuels, synthetic hydrocarbons, ammonia, and methanol. Pathways for decarbonizing industry are even more varied and speculative given the heterogenous nature of industrial energy use. To estimate 2050 electricity demand under the Energy Decarb scenario, we simply assume electrification for many industrial applications, with some deployment of carbon capture, utilization, and sequestration (CCUS, for the cement industry), biofuels (for construction and agriculture), and synthetic hydrocarbons (for glass). Solar thermal is also used for industrial boilers (McMillan et al. 2021). Appendix 2-D summarizes these market share assumptions.

The analysis accounts for the greater efficiency of low-emissions technologies (e.g., fuel economies are higher for EVs and FCEVs than for internal combustion engine vehicles) and the potential for other energy-efficiency measures (e.g., insulation for buildings). Thus, final energy demand is substantially lower under the Energy Decarb scenario than under the core scenarios. Final energy consumption in 2050 totals 47 quads under the Energy Decarb scenario, 64 quads under the Decarb+E scenario, and 79 quads under the Reference and Decarb scenarios. The

Energy Decarb scenario also has the largest share of final energy from electricity owing to the largest amount of electrification.

Estimating electricity and solar demand in the Energy Decarb scenario requires accounting for the electricity needed to produce low-carbon fuels. We assume electrolytic hydrogen production and consider the electricity and hydrogen fuel inputs needed to produce biofuels, synthetic hydrocarbons, ammonia, and methanol. Although multiple pathways exist to develop these fuels, we use a single set of pathways as described in Appendix 2-D. In addition, we assume hydrogen is used for electricity generation from RE-CTs for the core scenarios in Section 2.2. Accounting for these direct and indirect uses of hydrogen, we estimate 7 quads of hydrogen use in 2050 under the Energy Decarb scenario. Hydrogen use would be substantially higher if additional hydrogen applications were considered (steel refining, ammonia for fertilizer, chemical synthesis, etc.), and clean electricity could be used to synthesize other products not considered here; see (Badgett, Xi, and Ruth 2021) for details on electrons-to-molecules pathways. In combination with the 37 quads of electricity consumption, these low-carbon fuel assumptions result in 13,600 TWh of electricity demand in 2050—twice the demand in the Decarb+E scenario and 2.75 times the demand in the Reference and Decarb scenarios (Figure 2 - 18).

We assume the additional electricity demand is met in part by increased solar deployment. Assuming the same 2050 generation share as under the Decarb+E scenario, solar electricity generation would total nearly 7,000 TWh under the Energy Decarb scenario (Figure 2 - 18), corresponding with over 3 TW of installed solar capacity assuming the same capacity factor and curtailment rates as in the Decarb+E scenario (for additional details, see Appendix 2-D). For comparison, (Larson et al. 2020) modeled a combined high electrification and 100% renewable (E+ RE+) scenario, with 2050 solar capacity reaching 2.6 TW and helping serve nearly 16,000 TWh of electricity demand. (Williams et al. 2021) modeled similar scenarios, including one with over 5,000 TWh of solar generation by 2050. Our Energy Decarb scenario is broadly aligned with these other estimates.
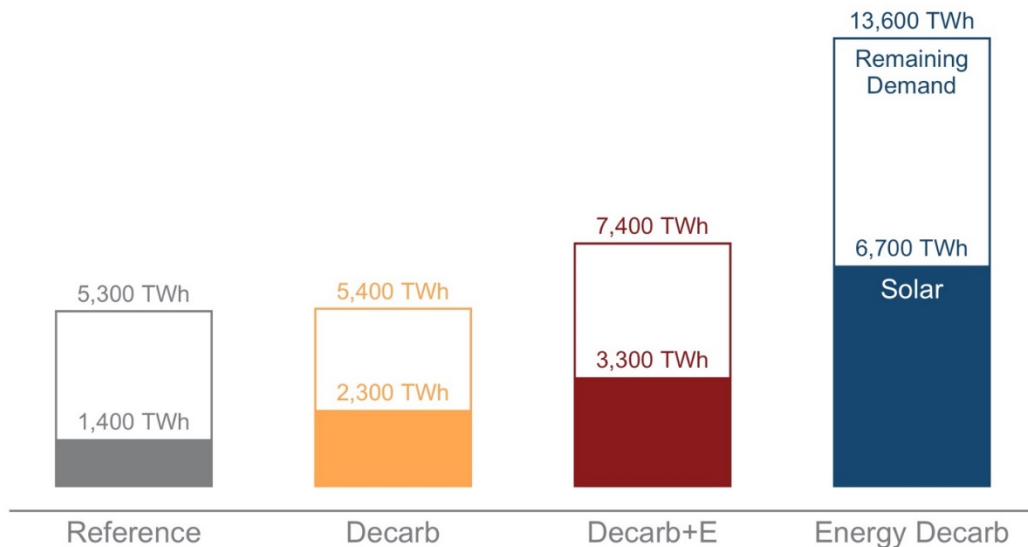
Figure 2 - 18. Electricity and solar demand from decarbonization

The substantial solar deployment estimated for our Energy Decarb scenario and in other recent studies would heighten many of the impacts and challenges raised in Section 2.2, including supply chain and siting considerations, transmission expansion, maintenance of grid reliability and resource adequacy, and increased electric system costs—while producing further emissions reductions and associated benefits. These effects are not quantified here owing to our limited analysis of the Energy Decarb scenario, but the large increases in electricity demand and solar development highlight potential opportunity for solar growth beyond what is modeled in our core scenarios.

2.3.2 Limitations and Discussion

The Energy Decarb scenario is designed to provide initial estimates of how further decarbonization—beyond the core *Solar Futures* scenarios—might impact U.S. solar deployment. In contrast with the core scenario analysis based on detailed power-sector models, only approximate and simple accounting calculations are used to develop this scenario.[56] Owing to the simplifying assumptions, the analysis focuses primarily on the incremental impacts on solar and excludes any cost estimates or detailed analysis of infrastructure or stock turnover requirements.

Different assumptions could yield significantly different outcomes. For example, greater reliance on energy efficiency or CCUS would likely lower demand for electricity and solar technologies. Conversely, greater reliance on electrolytic hydrogen and synthetic fuels could increase electricity and solar demand owing to the substantial amount of energy needed for low-carbon fuel production. In addition, we rely on approximate relative differences in efficiencies between fossil-based and low-carbon technologies based on current estimates, but there are significant regional variations in these efficiencies and uncertainties surrounding future technological progress. Lower-efficiency options would increase demand for electricity and solar energy and vice versa.

The same generation mix from the Decarb+E scenario is used to estimate the amount of solar needed to meet higher electricity demands in the Energy Decarb scenario; solar contributed to a larger share of the incremental electricity demand from electrification under the Decarb+E scenario, relative to the Decarb scenario, suggesting that even higher electricity demand from the Energy Decarb scenario might be satisfied to an even greater extent by solar technologies. Conversely, regional constraints on solar development—such as from resource limits, transmission, or land-use considerations—could challenge further solar expansion. Moreover, the value of solar electricity would depend on the future temporal profile (and flexibility) of incremental electricity demand. Electricity demand for fuel production could reduce curtailment rates and help support efficient integration of PV and wind. Alternatively, new load profiles could be highly uncorrelated with solar production, such as demand for space heating needs during winter nights.

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[56] Simple calculations are used because an economy-wide model with a level of detail similar to the power-sector tools used to analyze the core scenarios is not available. Moreover, the lack of commercial availability and experience with new technologies and fuels needed to fully decarbonize the energy sector would create significant uncertainty.

Additional data and modeling capabilities are necessary to assess full energy-system decarbonization scenarios robustly. Nonetheless, our initial analysis highlights the potential for much greater solar energy demand—approximately double the amount in the Decarb+E scenario—due to deeper decarbonization of the U.S. energy system.

2.4 Study Limitations, Uncertainties, and Risks

Like all future-looking studies, the *Solar Futures Study* is subject to numerous quantitative and qualitative limitations. Our quantitative analyses rely on uncertain assumptions and modeling methods. We explore these uncertainties by quantifying ranges along key cost and benefit drivers where possible and presenting results for several sensitivity analyses in Appendix 2-B. For specific limitations of the ReEDS model, the basis for the decarbonization scenarios, see (Ho et al. 2021). Further, the models are techno-economic focused and thus do not account for many socioeconomic considerations such as equity. Our qualitative discussions are limited based on our extrapolation of future conditions from historical trends and the existing literature. We mitigated these limitations by collecting input from dozens of subject matter experts throughout the drafting of this report.

Any number of uncertain and unforeseen developments could substantially alter the future role of solar and other technologies in a decarbonized grid. Our projections of the cost and performance of individual technologies are uncertain. Overperformance or underperformance of these projections could reshape the relative contributions of different technologies. Further, uncertain future developments might create significant roles for technologies that play minor roles in our core scenarios, especially in the longer term. In particular, we did not model all potential decarbonization options, including carbon dioxide removal technologies. Emergence of such options could reduce long-term decarbonization costs or help lower emissions beyond the levels estimated in our core scenarios. Much research is needed to understand the potential role of these technologies and their interactions with solar in a low-carbon energy system.

In addition to limitations and uncertainties, the *Solar Futures* vision entails several risks. One key risk is path dependence or lock-in: the risk that the system adapts to large capacities of solar in ways that disadvantage, or lock-out, other potentially effective technologies. Another key risk is that certain elements of the *Solar Futures* vision become incompatible with competing objectives. For instance, the decarbonization scenarios rely on converting significant amounts of land to solar and supporting infrastructure (e.g., transmission lines). Siting the infrastructure required for the scenarios is technically possible, but project siting in practice must overcome social and political challenges as well as tradeoffs regarding equity and justice. We do not account for these risks in our modeling.

The results of all future-looking studies should be interpreted in the context of their limitations, uncertainties, and risks. Many aspects of the *Solar Futures* scenarios will not materialize in the real world as envisioned in our analysis. However, the *Solar Futures Study* is firmly grounded in the scientific literature and was vetted through technical reviews by a broad mix of subject matter experts. It provides the most rigorous and authoritative exploration to date of the potential role of solar in decarbonizing the U.S. electric grid.

3

Reliably Integrating More than a Terawatt of Solar onto the Grid

3 Reliably Integrating More than a Terawatt of Solar onto the Grid

The *Solar Futures* vision represents a dramatic change in the composition and operation of the U.S. electric power system. With terawatt-scale deployment of solar, wind, and battery storage technologies by 2050, the grid becomes increasingly reliant on weather-dependent variable renewable energy (VRE) inverter-based resources (IBRs). In addition, a significant share of photovoltaics (PV) and storage may be installed as distributed energy resources (DERs), sited at residential and commercial properties. This combination of factors raises important questions about maintaining the reliability of the electricity grid.

Reliability encompasses many factors, which can be expressed as the three Rs: resource adequacy (RA), operational reliability, and resilience. The first two terms have well established definitions (NERC 2007). RA represents planning for the system's ability to supply enough electricity—at the right locations—to keep the lights on, even during extreme-weather days and when "reasonable" outages occur. All power plants, transmission and distribution lines, and other grid equipment occasionally experience outages, and an adequate system has sufficient spare capacity and reconfigurability to replace capacity that fails or is out of service for maintenance. An important element of maintaining adequacy is estimating the availability of variable resources, such as solar and wind, particularly during times of expected system stress. The second component, operational reliability, ensures the lights stay on even when unexpected things happen. There is overlap between RA and operational reliability. RA is intended to ensure sufficient capacity is available during events such as an outage. Operational reliability enables the system to operate in the seconds during an abnormal event and minutes after the event. Resilience is less distinctly defined; the Federal Energy Regulatory Commission (FERC) proposes it is "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event" (FERC 2018). This definition has potentially significant overlap with the other aspects of reliability, particularly related to the ability of a grid to "absorb" an event. However, several aspects of this definition are unique, particularly related to system recovery, or how quickly power can be restored after an outage. Resilience also typically includes more extreme events that go beyond the "reasonable" outages excluded from RA and traditional operational reliability.

In this chapter, we discuss the three Rs in terms of their role in realizing the terawatt-scale deployment of solar envisioned in the core scenarios. We also identify and discuss potential research priorities related to maintaining RA, operational reliability, and resilience of the grid as it evolves in these scenarios.

3.1 Resource Adequacy

Increased VRE deployment complicates the ability to assess RA (Stenclik 2020). Furthermore, evaluating the impacts of seasonality and interannual variability becomes increasingly important to ensuring these systems can serve demand under various weather conditions. In addition, the grid itself is critical for connecting these resources to loads, particularly as solar and flexible load resources are increasingly located throughout the transmission and distribution (T&D) system.

3.1.1 Maintaining Resource Adequacy in the Solar Futures Scenarios

In the following subsections, we model resource adequacy in the *Solar Futures* vision by simulating the system as built out in 2050.[57] To provide a wide range of operating conditions, we simulate the system using 7 years of weather data (2007–2013). The range of weather years provides a wide variety of operating conditions for examining potential RA or operational concerns, as well as analysis of typical operations throughout the year. Our examples use a specific weather year to illustrate key points; under this approach, the weather in 2050 is the same as the weather in the example year, though we do explore specific extreme weather events to analyze the impacts of changing weather patterns due to climate change.

Evaluation of RA Under Shifting Net Demand Peaks

RA performance has historically been driven by generator availability during hours of annual peak demand, which typically occur during hot summer afternoons in much of the United States. In the *Solar Futures* scenarios, peak load periods typically correspond to times of high solar output. Figure 3 - 1 shows periods of peak demand in two regions—the Electric Reliability Council of Texas (ERCOT) and Virginia-Carolinas (VACAR)—for 2050. The results for ERCOT (using 2009 weather) illustrate how high solar contributions facilitate meeting demand during the traditional peak. The results for VACAR (using 2012 weather) illustrate how, with a high solar contribution combined with storage, excess solar generation can be used to meet peaks later in the day. The figures also illustrate that on a regional basis supply and demand do not need to match in every hour due to imports and exports.
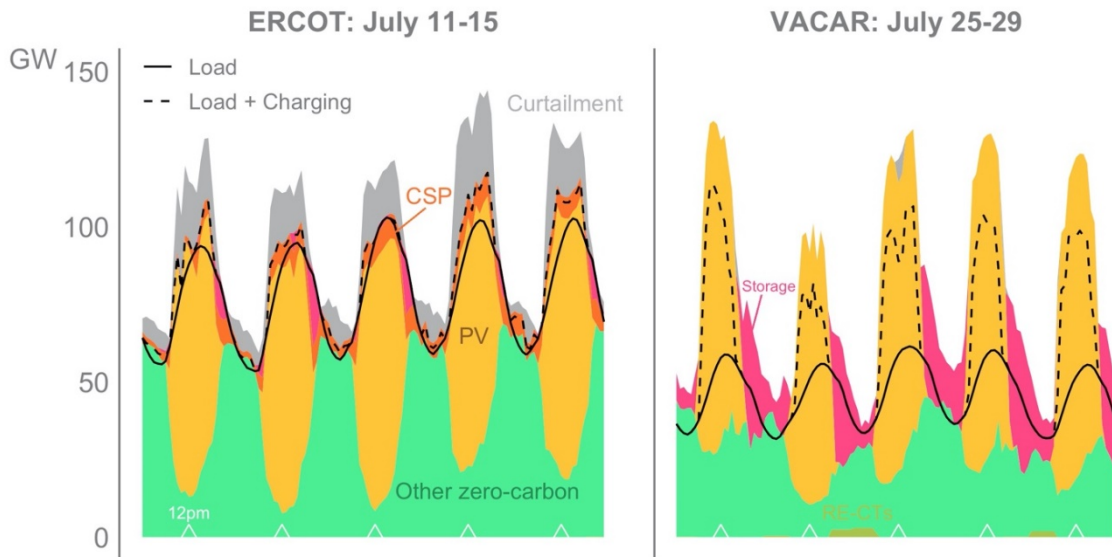
Figure 3 - 1. Peak load periods for two regions in the Decarb scenario in 2050, showing examples of high VRE output during peak periods

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[57] The *Solar Futures* scenarios were generated using the Regional Energy Deployment System (ReEDS) model, which includes an RA constraint to ensure the generation mix can meet load. However, given the limited temporal resolution of ReEDS, the study supplements these results with two additional models: a production cost model (PLEXOS) and a probabilistic RA model (Probabilistic Resource Adequacy Suite [PRAS]). These tools provide a more detailed analysis that is suitable for evaluating RA in specific scenarios.

The coincidence between PV and demand in much of the United States means initial PV deployments benefit RA significantly, as reflected in a high capacity credit,[58] typically measured by the fraction of a generator's nameplate capacity expected to be available during hours of highest demand (Awara, Zareipour, and Knight 2018; Mills and Wiser 2012). However, increasing PV levels reduce PV's incremental capacity credit (Cole, Greer, et al. 2020; Mills and Wiser 2012), as the peak net load (load minus VRE generation) shifts from times when PV is available to times when it is not. Figure 3 - 2 shows the median capacity credit values from the three core scenarios. Initial PV deployments provide about 50% capacity credit on average, but this declines as PV deployments increase over time. The sharp drop in marginal capacity credit occurs after PV shares exceed about 16% of total annual generation, which occurs during the late 2020s under the Decarb and Decarb+E scenarios and during the early 2030s under the Reference scenario. Note that the capacity credit can vary significantly by region, although only median values are shown in Figure 3 - 2.
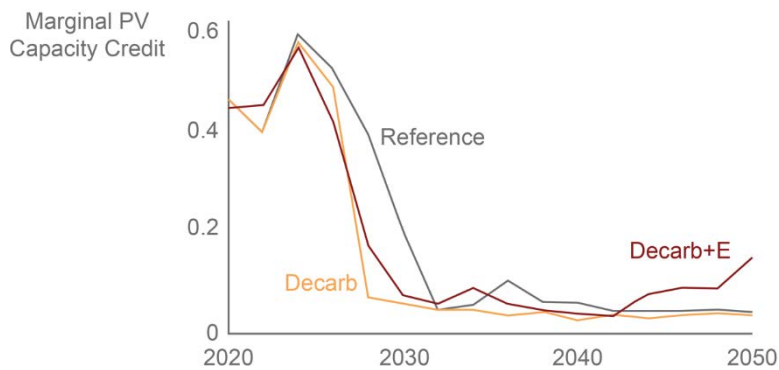
Figure 3 - 2. Declining marginal capacity credit of PV as PV levels increase over time

Ensuring RA in systems with high VRE requires analyzing periods of high net load. Figure 3 - 3 compares load and net load for three regions: ERCOT, the Southwest Power Pool (SPP), which covers a large area in the southern Midwest, and the Florida Reliability Coordinating Council (FRCC), which comprises most of Florida. In two regions (ERCOT and SPP), the peak net load period shifts from summer to winter. Several regions (not shown) do not experience a large seasonal shift in peak net load compared to normal load, but peak net load shifts to a day with lower VRE output. FRCC is the only region where peak load and peak net load occur within the same week.

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[58] Capacity credit can also be called qualified capacity or capacity value, though the latter is sometimes used to refer to the monetary value that capacity provides to the system (Mills and Wiser 2012).
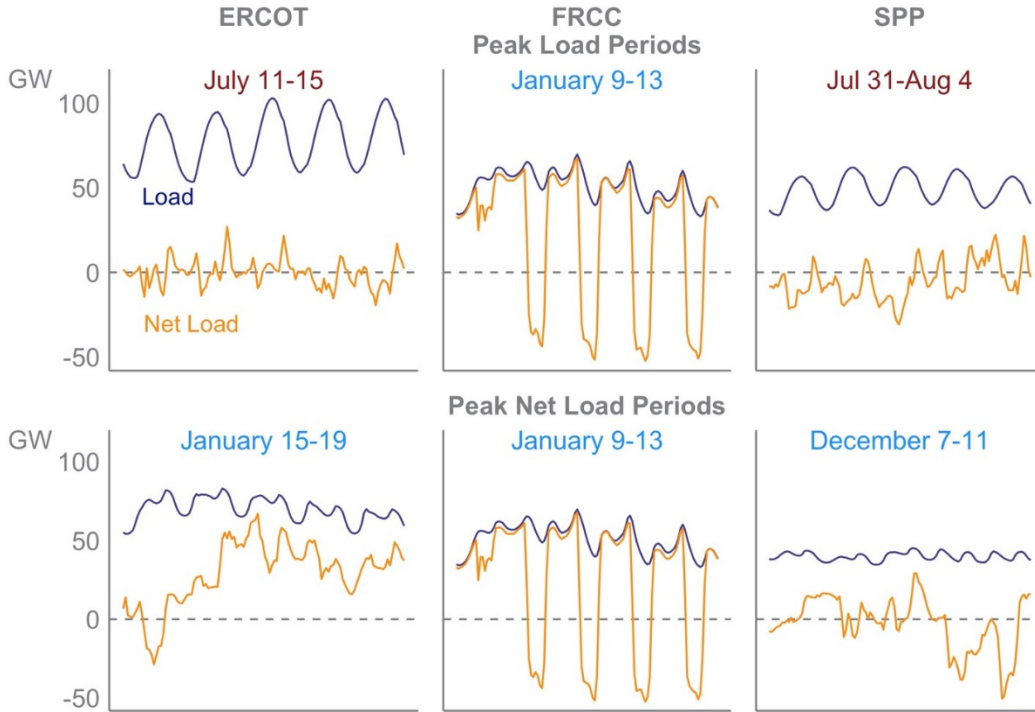
Figure 3 - 3. Peak load and peak net load in ERCOT, FRCC, and SPP for the Decarb scenario in 2050

At high VRE levels, grid conditions leading to RA challenges may shift to new times of the year. These regions have potentially challenging net-load periods across the 7 weather years analyzed for the Decarb scenario in 2050.

Addressing periods of high net demand requires a diverse mix of resources. Figure 3 - 4 shows the same regions as in Figure 3 - 1 but for the peak net load period across all weather years analyzed. Compared with the peak load period, the peak net load period of these regions experiences lower wind and solar generation—requiring reliance on additional resources, including greater use of energy storage (potentially including CSP/TES), imports, flexible loads, and RE-CT generation. The importance of these resources is detailed in the following subsections.
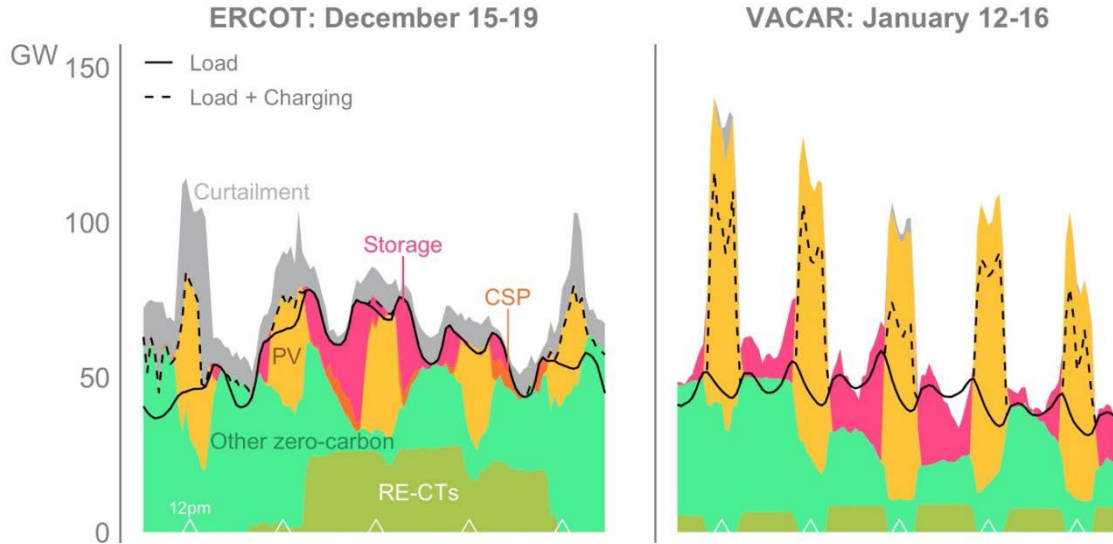
Figure 3 - 4. Peak net load for two regions in the Decarb scenario in 2050

Role of Energy Storage

Meeting RA requirements involves addressing diurnal and longer-term supply-demand mismatches. Much of the diurnal mismatch is addressed via storage with 10 or fewer hours of capacity. Storage and its role in the *Solar Futures* scenarios are detailed in Chapter 5. Figure 3 - 1 and Figure 3 - 4 show how storage addresses the diurnal mismatch and shifts PV generation to periods of lower output, highlighting contributions of various battery storage durations from 2 to 10 hours. Figure 3 - 5 illustrates this more clearly, showing how storage is typically used to meet the net load peaks that occur in the morning and early evening. These correspond to periods of highest net load, particularly during the hours around sunset when demand can be relatively high. Results are the average hourly output over the entire month. Much greater use of storage occurs during the high-demand months in winter and summer, with less use in the spring and fall. Several regions, including ERCOT, also deploy CSP with TES, which can help meet the RA requirements.
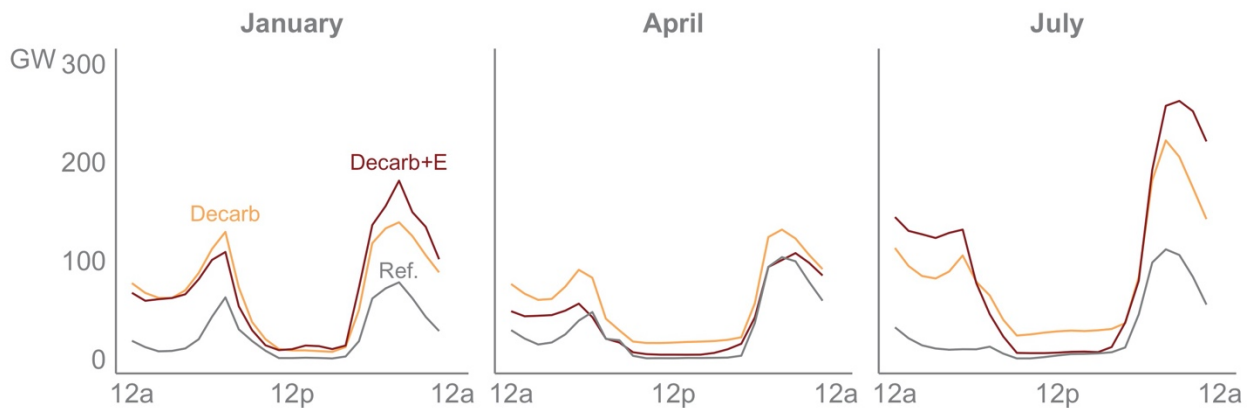
Figure 3 - 5. Storage generation across the core scenarios analyzed in PLEXOS in 2050

Storage shifts energy in all scenarios, with increasing storage use in the higher electrification and decarbonization scenarios

Role of Flexible Demand

Flexible demand can also be used to supplement storage and address the diurnal mismatch. An expanded role for flexible loads is included in the Decarb+E scenario, allowing certain loads to shift demand over short periods (typically less than 4 hours). Figure 3 - 6 shows two regions during their peak net-load periods for this scenario. Of particular importance is how PV narrows the peak demand period, meeting the load during much of the middle of the day, but leaving a very short, sharp peak in net demand (illustrated by the black solid line). This short peak is well suited to demand response (DR) applications that can only defer use for a few hours. As a result, the DR is predominantly used during the net-load ramp in the evening as PV declines, displacing output from shorter-duration storage during this time. Some load is shifted into the hours of PV output, directly using energy that would otherwise be curtailed during these hours.
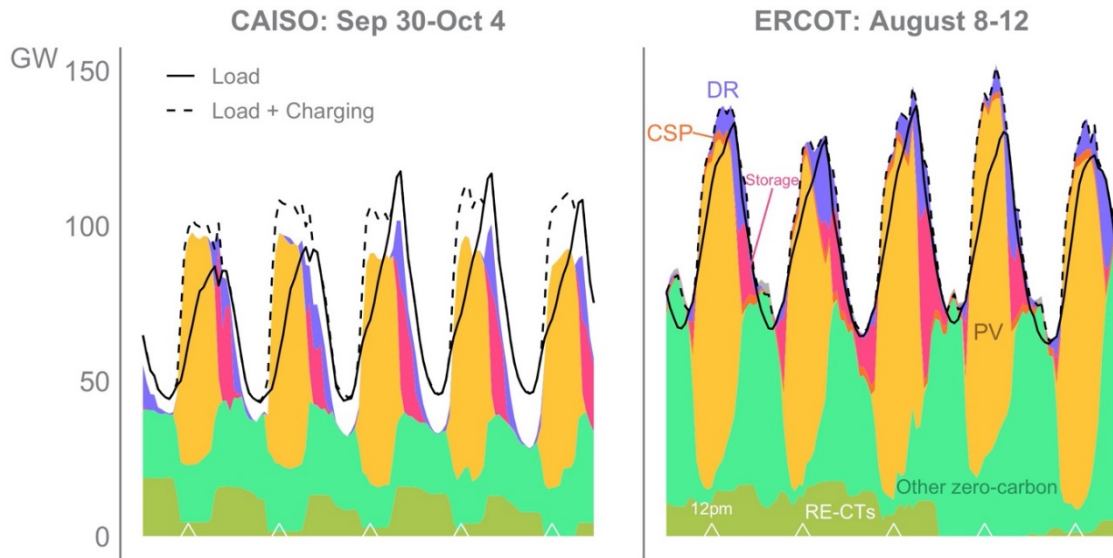
Figure 3 - 6. Dispatch during peak net load periods for two regions in the Decarb+E scenario in 2050

DR typically displaces storage in addition to increasing load during hours of excess PV

Role of Transmission

Transmission is useful for improving RA, because electricity can be better shared between parts of the power system. Substantial upgrades to the transmission grid to support the *Solar Futures* scenarios are described in Chapter 2. As an example, Figure 3 - 7 illustrates the role of transmission in Florida (FRCC), showing a 9-day period presenting one of the greatest RA challenges in the Decarb scenario. Cloudy weather on January 8–9 (using 2010 weather) results in the highest peak net load among all weather years. Figure 3 - 7 (top) shows the dispatch of the in-state resources. Although RE-CTs and storage typically operate in this region in a diurnal cycle to complement PV output, the cold front during this period drastically reduces PV output for 2 days, requiring RE-CT use at a nearly constant output (discussed in more detail in the following section). The energy not met by in-state resources (shown in the white area under the load line) is met with imports from neighboring areas and the use of the transmission (Figure 3 - 7, bottom) reaches full capacity during these periods.
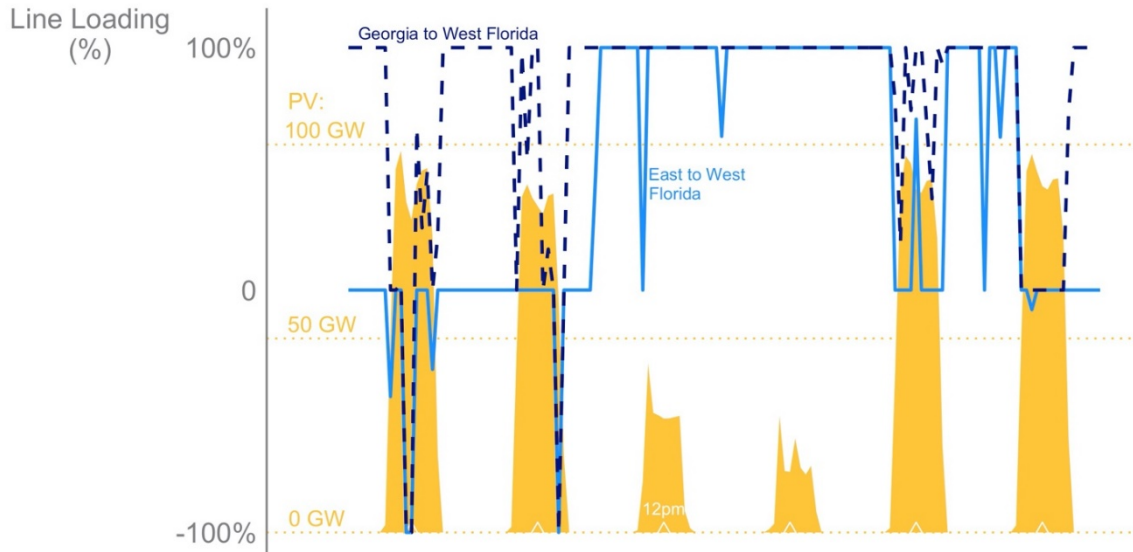
Figure 3 - 7. Grid operations in Florida during a challenging period for the Decarb scenario in 2050 using 2010 weather

Overall, use of transmission can reduce costs by reducing the excess capacity required for a few hours of the year. However, this also could yield reliability challenges if certain regions rely on transmission and imported energy in times of grid stress. Previous studies provide additional examples of how properly designed interregional transmission can increase overall reliability and decrease costs (Brinkman et al. 2021; Bloom et al. 2020).

Role of Firm Renewable Capacity (RE-CTs)

Dispatchable generation (capacity that can run for extended periods) is a critical contributor to RA. In high-decarbonization or electrification scenarios, much of the dispatchable power comes from RE-CTs, with their use varying significantly based on weather conditions. Figure 3 - 8 shows the 2050 simulations during the week of January 15 for two weather year simulations, 2007 and 2013, in ERCOT. The 2007 weather year results in the highest net-load period in ERCOT across all 7 weather years; as VRE decreases during the week, RE-CTs are used to fill the gap. In comparison, the 2013 weather year results in very little RE-CT use during this week, because there is adequate wind and solar. This shows the variation in VRE output for the same period across years and that there will be increased uncertainty over when dispatchable RE-CTs will need to operate.
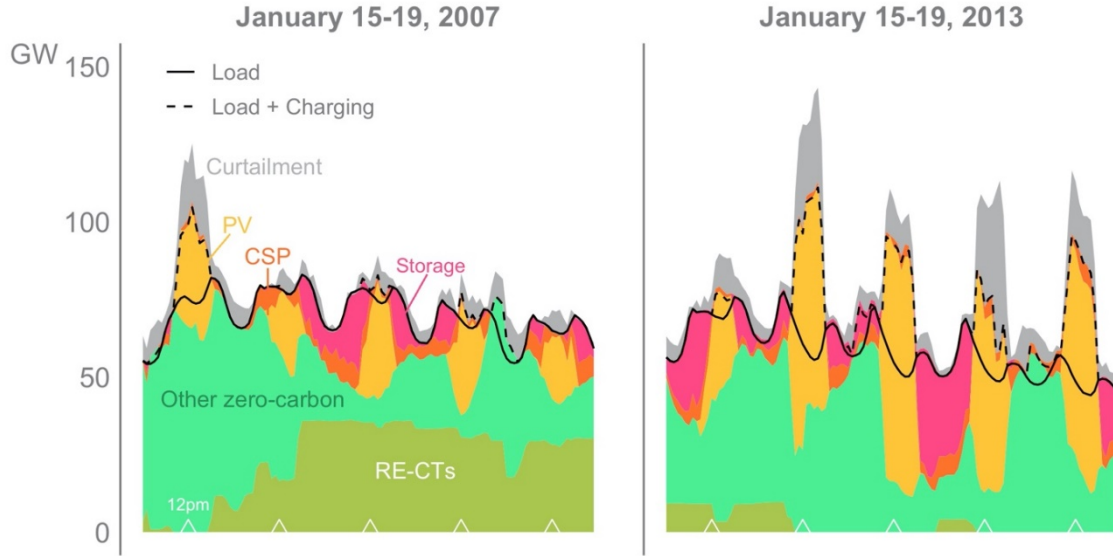
Figure 3 - 8. ERCOT dispatch for the same week in 2050 using 2 different weather years for the Decarb scenario

Overall, RE-CT use varies hourly and seasonally. Figure 3 - 9 shows average hourly patterns for 3 months. Operation in the spring is very limited, because the VRE supply is sufficient to meet the diurnal mismatch almost entirely with storage and DR. During some periods in the summer and winter, RE-CTs remain online to charge energy storage when the amount of other RE resources is insufficient. Seasonal use is shown more clearly in Figure 3 - 10, which provides monthly capacity factors for RE-CTs across all regions.
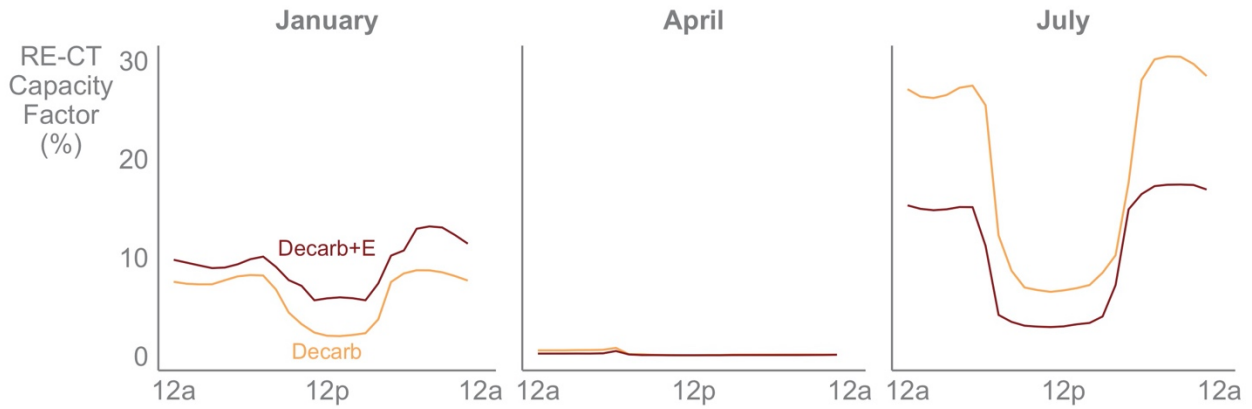
Figure 3 - 9. RE-CT operation across scenarios including that technology option in 2050
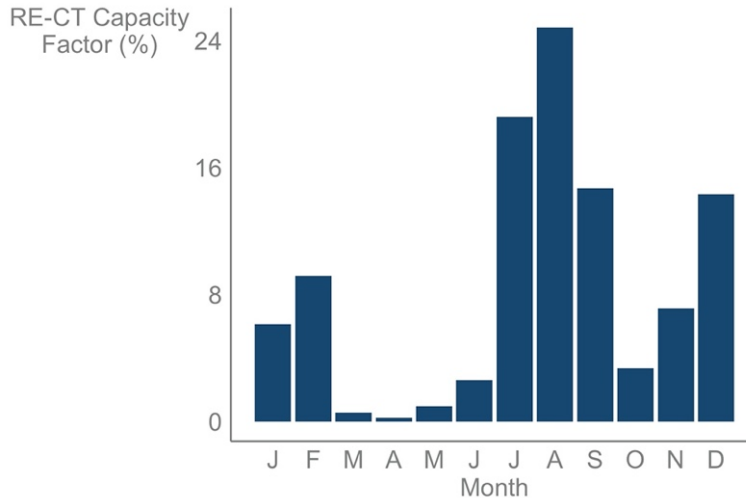
Figure 3 - 10. Monthly national average RE-CT capacity factors for the Decarb scenario for 1 weather year in 2050

The overall annual capacity factors of RE-CTs in 2050 are 4%–5% across the various scenarios. Because RE-CTs use synchronous generators, they provide several other benefits to operational reliability (see Section 3.2). Further discussion of the RE-CT concept is provided in Chapter 5.

Additional Examination of Extreme Events

The above exercise uses historical weather patterns to test system performance under the modeled scenarios. However, weather patterns are projected to become more extreme and volatile due to climate change. Using multiple years of historical weather, it is possible to identify periods of extreme conditions and simulate those conditions in the 2050 scenarios. In addition to the Florida 2011 weather case, another example is the ERCOT cold and heat waves of 2011 (Figure 3 - 11). The cold wave was a significant grid reliability event and a precursor to the catastrophic events of February 2021. In the 2011 event, cold temperatures triggered outages of gas plants as demand spiked from increased heating demand, leading to load-shedding events. Applying 2011 weather conditions to our 2050 Decarb scenario, good wind availability allows for storage charging prior to the cold weather event. However, even with some solar generation, there is insufficient VRE supply, leading to use of RE-CTs.

The heat wave occurring later that year also requires RE-CT use, but this period is associated with significant PV availability. Curtailment occurring while expensive RE-CTs are operating is associated with transmission congestion, indicating the critical role of transmission in ensuring a least-cost mix of resources.

Examining extreme weather events will become increasingly important to ensure adequate reliability and resilience (see Section 3.3) of the grid. Future research could use purely synthetic weather patterns (rather than observed historic patterns) to model grid operations under more extreme conditions.
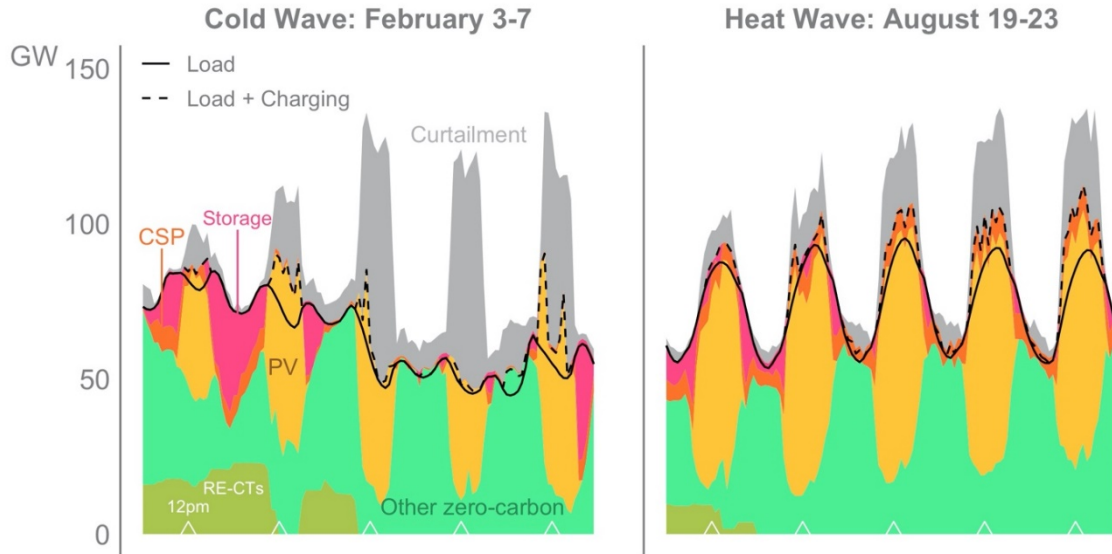
Figure 3 - 11. Simulations of cold and heat waves in ERCOT in 2050 in the Decarb scenario using 2011 weather data

3.1.2 Additional Considerations and Research Needs Associated with Resource Adequacy in a High-Solar Future

Ensuring RA under increased VRE deployments requires changes to how the power system is planned and operated. Many of these changes are assumed in the *Solar Futures* scenarios, and this section provides further discussion of these issues.

Participation of DERs in Bulk System RA

DERs can provide the same services as utility-scale PV, offsetting the need for generation and transmission resources to ensure RA. As a result, DERs in the *Solar Futures* scenarios are assumed to contribute to overall system RA based on their output profiles. However, there are multiple real-world challenges to enabling this support. One is the need for a better understanding of the constraints and opportunities associated with the distribution system. For instance, the ability of DERs to directly serve nearby loads without involving the transmission system suggests a need to not only accurately capture spatially resolved DER deployments and loads, but also to consider distribution capacity constraints or corresponding upgrades to the distribution system to ensure DERs can serve local loads and/or deliver any additional generation to the bulk system. This may also involve capturing additional engineering factors including the impact of potentially significant voltage differences throughout the distribution system on the power production and voltage support available from DERs. For instance, DER capacity that is curtailed to avoid high local voltage would not be available to provide primary frequency response (PFR), while other situations might encourage increased DER production to manage distribution needs.

Another key challenge is ensuring equitable treatment and compensation for DERs when providing RA services. In 2020, FERC issued Order 2222, which requires that all regional transmission organizations allow DER aggregators to participate in wholesale markets (Cano 2020). Additional efforts may be needed to develop and identify participation models for DERs to provide energy, capacity, and ancillary services to the grid with appropriate compensation.

This includes new approaches to compensate DERs for potential ability to provide alternatives to new T&D infrastructure, sometimes referred to as non-wires solutions (NWS). Given the newness of NWS projects, utilities and system operators may not consider them during the planning process, potentially ignoring a lower-cost alternative to traditional investments. Regulators in New York and California have mitigated this potential issue by mandating that utilities consider NWS alongside other investments when conducting planning exercises.

Future efforts to increase DER deployment could focus on encouraging utilities to consider DER in traditional planning processes. This may require additional modeling capabilities for comparing the performance of DERs and traditional investments. Such tools should be able to account for fluctuating availability of DER services given consumer behavior behind-the-meter as well as constraints and opportunities imposed by the distribution system.[59]

Visibility and Communications for DERs

Utilities and power system operators often do not have direct visibility of DER output, making it difficult to fully include DERs in system planning and especially operations. Future DER integration should include improved visibility, analytics, and controls to achieve economic integration and ensure maximum utilization of PV resources for energy and ancillary services (Letendre 2014). Currently, most PV systems operate autonomously without any communication to the grid operator. To ensure reliable operation of the grid with high levels of DERs, advances in sensing, communications, and controls will be needed to manage highly distributed deployments spread out over cities and communities. To optimize performance, PV systems will increasingly communicate with entities such as DER aggregators and grid management systems. From the utility perspective, DER management systems (DERMS) are a possible platform for communicating with distributed PV (DPV) systems to manage aggregated DER response. These platforms can also be integrated into higher-level grid-management tools used by utilities, such as distribution management systems (DMS) and supervisory control and data acquisition (SCADA). However, the capabilities and approaches to DERMS currently vary widely, potentially complicating widespread adoption. To help address this, IEEE standard P2030.11 is under development to establish functional specifications for DERMS.

Advanced Forecasting

Forecasting at multiple spatial and temporal resolutions is critical for ensuring RA by providing a predictive measure of VRE output and loads. This goes beyond traditional forecasting requirements to add considerations for evaluating localized or regional impacts on PV generation such as snow cover, wildfires, or smoke (Cole, Greer, et al. 2020; Gómez-Amo et al. 2019). Forecasting over periods of days or longer is needed for careful management of the state of charge of storage resources under increasing uncertainty. Future PV forecasting will require collaboration involving balancing authorities, power system researchers, meteorologists, and data scientists. Possible research directions include the following:

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[59] This may only apply to NWS incorporating behind-the-meter resources, as opposed to those with only front-of-the-meter resources connected to the distribution system, because the former may be operated to meet customer needs and only offer *excess* power to utilities and power system operators, complicating the task of estimating NWS performance.

- Development of physics-based forecasting models (advancing Weather Research and Forecasting [WRF] solar and other products for the contiguous United States as well as individual PV sites).

- Development of probabilistic forecasting models and methods to increase the impact of forecasting on real-time grid operations.

Improving and expanding low-cost weather networks will improve the ability to make informed real-time decisions and conduct long-term planning on projects pertaining to VRE forecasting. Integrating innovative technologies can help achieve this goal in several ways, including applying technologies from other fields such as agricultural sensing.

Impact of Distributed Resources on Distribution System RA

RA traditionally considers adequacy of the bulk power system, including generation and transmission, but the distribution system also requires adequate capacity to deliver energy. The *Solar Futures* scenarios do not directly analyze the distribution system; however, considerable previous analysis provides insights into distribution system hosting capacity and other aspects of distribution RA.

A key element of ensuring cost-effective DER deployment will be flexible and adaptive interconnection processes. In addition to streamlining traditional interconnection approaches, such as by publishing hosting capacity maps, additional innovations in ease of distribution integration and evolved interconnection approaches can further support cost-effective DER deployment. For instance, DER interoperability efforts aim to provide seamless, "plug-and-play," or integration of DERs and corresponding communication systems (Widergren et al. 2018). Another approach, known as active network management (ANM), uses flexible interconnection agreements, sophisticated communication infrastructure, and information on local power system conditions (forecasted load, constraints, etc.) to automatically adjust the behavior of DERs. In exchange for allowing the utility limited control over the DER and accepting limited curtailment throughout the year, interconnecting customers endure shorter interconnection processes and avoid paying for prohibitively expensive distribution upgrades. ANM has demonstrated substantial reduction in interconnection costs for DER projects (Horowitz, Jain, et al. 2020; NYSEG and RG&E 2019). ANM could aid in coordination of transmission system planning and improve the ability of DERs to provide RA services on the bulk system as well.

Supporting RA Under Increased Electric Vehicle Deployment

Electric vehicle (EV) charging is a substantial new source of load, potentially creating new challenges for distribution system RA. PV generation and EV charging co-simulations are needed to evaluate the effects of widespread adoption.

Distribution system capacity is expected to create limitations in areas without local generation and coordinated control. Several studies have evaluated the impacts of EV charging on localized distribution systems, a few in conjunction with onsite PV. These studies could be extended to capture wider transit areas and evaluate scenarios with higher levels of PV and EV adoption to allow implementation of mutually beneficial infrastructure and control adaptations.

Advances in Retail Tariff and Compensation Mechanism Design

Load flexibility and optimized dispatch of DERs including storage likely will be important for maintaining system RA. Yet many current retail rate designs poorly reflect the need for customer response during periods of system stress. Several retail tariff elements that can better align customer behavior with power system needs have already been implemented for larger customers and in select U.S. jurisdictions. These elements include demand charges, which charge customers based on their maximum instantaneous demand in a given period, and time-of-use rates, which charge different rates for electricity consumption in different hours. Rates can also vary by location. Additional elements such as critical peak pricing or real-time pricing can further influence customer load patterns. Regulators have historically hesitated to subject retail customers to complex tariffs owing to concerns about the customer's abilities to interpret and respond to more complex tariff structures.

Creating DERMS that can translate customer load patterns, PV availability, and retail tariff structures into grid operations that minimize customer bills while ensuring system reliability can benefit both the customer and, assuming appropriate economic signals through retail tariffs are in place, the power system. Providing a wide range of available cost-reflective tariffs can ensure that adopting customers can select the tariff best suited to their DER capabilities and load patterns. Further research on how best to design retail tariffs for particular customer classes and DER technologies, how best to communicate tariff options to customers, or how to incentivize the most desired response may be required. Furthermore, as distributed energy storage becomes more prevalent, the interaction between hybrid DPV-plus-storage systems and retail tariffs and compensation mechanisms originally designed for DPV systems must be better understood.

Overall, regulations and policies may lag improvements in technical standards and manufacturing innovation, barring PV—and especially DPV—systems from providing services of which they are otherwise technically capable. Likewise, without appropriate incentives or adequate access to compensation, DPV system operators may not be motivated to provide certain services.

PV and Natural Gas Co-Simulation and the Transition to Winter Peaks

The *Solar Futures* scenarios demonstrate that electrifying heating loads could shift net peak loads to the winter for more U.S. power systems (Mai, Jadun, et al. 2018). Given the lower availability of PV during winter periods, this increases pressure on other generation resources to provide energy. Depending on the rate of this transition, increased dependence on natural gas (or RE-CTs) for generation during cold periods may increase.

This interdependence can pose new operational challenges. For example, limitations in gas deliverability during the 2014 U.S. polar vortex due to pipeline constraints and high gas demand for residential heating led to generator outages. Similarly, widespread winter outages in Texas in 2021 were caused in part by natural gas systems that failed during unusually cold weather. Additional study is needed to evaluate this interdependence to ensure RA is not compromised during the transition to less reliance on carbon-intensive sources of generation.

Power Flow Considerations for RA

In addition to ensuring sufficient generation and transfer capacity, high levels of PV and IBRs may require increased attention to AC power flow considerations while considering RA in

addition to its traditional role in operational reliability. This includes capturing potential transfer limits imposed by voltage and reactive power, requirements of managing low inertia, stability considerations for contingencies, and consideration of how distribution-connected resources impacts on power flow affect RA. Doing so may require new tools and practices to capture these effects during the RA analysis and/or the integration of additional operations analysis during planning-phase RA assessment.

3.2 Operational Reliability

While RA addresses supply/demand balance at time scales of minutes and longer, operational reliability typically deals with events that occur at shorter timescales. Many of the concerns focus on increased use of inverter-based resources, which differ from the synchronous generators currently used for most generation.

Figure 3 - 12 frames this concern, using duration curves for the fraction of load met by IBRs across three scenarios in each of the three North American interconnections. Although none of the interconnections reaches 100% inverter-based generation in the study period because of the inclusion of nuclear, concentrating solar power, geothermal, and hydropower resources, each interconnection has a large number of hours of the year with very high fractions of inverter-based generation. This increasing fraction raises the question of whether there may be some threshold at which the IBR contribution decreases operational reliability or will require changes to system operation to maintain or increase current levels of reliability.
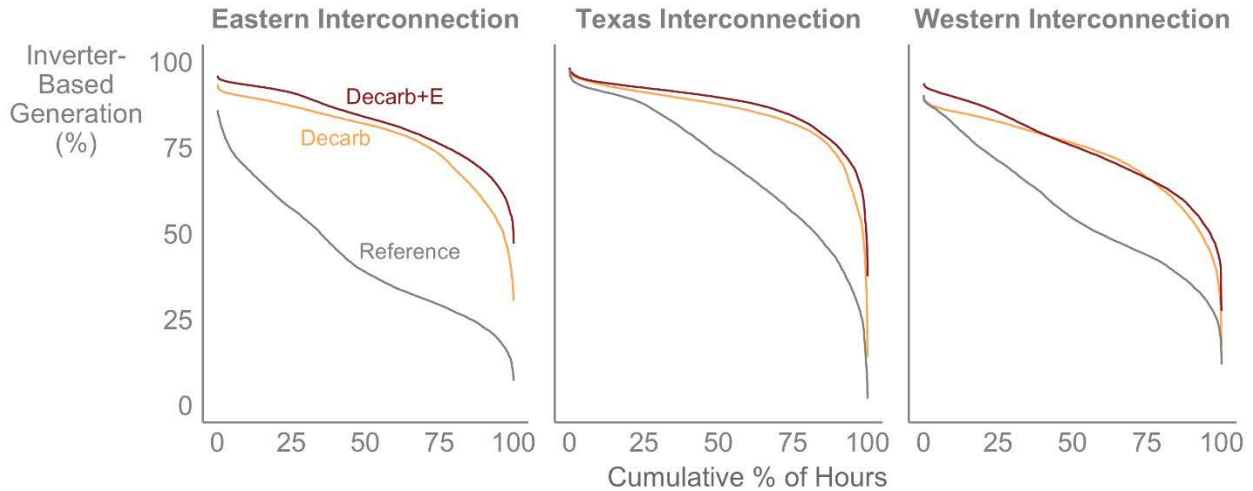
Figure 3 - 12. IBR generation duration curves by interconnection and scenario in 2050, for weather year 2012

There are three components to maintaining operational reliability: (1) frequency, (2) voltage, and (3) system strength and protection. The ability to provide these components is mostly based on inherent characteristics of synchronous generators. Moving to IBRs means the grid loses some of these inherent characteristics (such as inertia). However, it gains new capabilities, because IBRs can respond more quickly than synchronous generators to system changes. The next section discusses grid reliability problems and solutions at VRE levels envisioned in the *Solar Futures* scenarios.

3.2.1 Three Components of Maintaining Operational Reliability

Maintaining Real-Time Balance and Stable Frequency

Maintaining frequency within specified tolerances is important to operational reliability. In the current grid, system frequency is a measure of the balance between generation and load at any particular point in time. The greatest challenge to maintaining steady system frequency is associated with large power plant or transmission line failures (often called a contingency event), which produce a nearly instantaneous imbalance of supply and demand and change in frequency. The system's ability to arrest this change and restore frequency is key to its ability to resist breaking apart and losing synchronism, making it an important performance metric. Until the system transitions to an alternative means of measuring and maintaining supply and demand balance, the use of IBRs to support stable frequency will be important.

The initial response to a contingency event is via inertia and primary frequency response (PFR). Within the bulk power system, inertia is the tendency of a given interconnection to resist changes in frequency when an imbalance between generation and load occurs. In response to a sudden generation loss, the kinetic energy stored in the spinning masses of operating synchronous generators is automatically and instantaneously converted into real electrical power, slowing the generators and slowing the change in grid frequency (Denholm et al. 2020). This inertial response is important for power system reliability because it provides additional time, on the scale of a few seconds, for interventions to respond to contingency events that may otherwise cause grid frequency to fall outside of acceptable bounds and result in system instability. This inertial buffer allows for PFR, which automatically detects changes in frequency and instructs generators providing PFR to increase output. Following PFR, system operators deploy secondary frequency control (automatic generation control) and spinning contingency reserves to restore the frequency to 60 Hz. IBRs do not inherently provide inertial response, so increasing displacement of conventional generation with IBRs has increased concerns over maintaining adequate inertia in the system to respond to contingency events.

Significant work has been done in recent years to address frequency stability concerns. Many solutions have been deployed, including deriving fast-frequency response (FFR) from IBRs (EirGrid and SONI 2016; Everoze 2017; Fairley 2016; Rahmann and Castillo 2014; Singhvi et al. 2013; Spahic et al. 2016; Yingchen Zhang et al. 2013). IBRs can rapidly detect frequency changes and increase output, if operating below maximum output. The lack of mechanical or thermal components enables IBRs to respond faster than synchronous generators. Rapid and accurate response from PV has already been demonstrated, and FERC requires all new IBRs to have frequency-responsive capabilities (Loutan et al. 2017).

Voltage Support and Stability

For loads and grid equipment to work properly, it is important to maintain voltage at acceptable levels on all parts of the T&D systems. A closely related concept is the need to provide sufficient reactive power to maintain grid voltage. Reactive power is required on transmission to overcome reactive power loss on transmission lines and on distribution to serve non-unity power factor loads such as motors. PV inverters already provide some voltage control and reactive support by using power electronics to adjust the phase angle between voltage and current, thereby providing or absorbing reactive power (Palmintier et al. 2016). At the distribution level, updates to IEEE 1547-2018 now expect distribution-connected DERs to provide local volage control. The

forthcoming IEEE Standard P2800 is the bulk grid corollary to IEEE 1547. Expected to be released in 2021, it will help to standardize the way transmission-connected IBR provides voltage support and other grid support. Additional information on these two standards can be found in Section 3.2.2.

In addition to providing voltage support during regular operations, it is critical with high deployments of solar and storage to ensure these resources can continue to provide power during grid challenges, which can create excursions in frequency and voltage. The ability to continue to operate, or "ride-through," these conditions is key to limit cascaded tripping of IBRs and DERs following grid faults. Voltage and frequency ride-through capabilities have been required in transmission-connected PV resources by industry standards and FERC (Achey and Farrar 2020) in the United States for some time and will be further standardized through IEEE P2800. At the distribution level, IEEE 1547-2018 also now specifies and requires ride-through settings for DERs.

System Strength and Grid Protection

Existing protection schemes rely on the inherent ability of synchronous generators to inject high amounts of current under fault conditions, such as a short circuit (B. Kroposki et al. 2017). This current is detected by devices that open circuits to prevent damage to the grid components. The ability of a system to respond to these types of faults is measured in terms of system strength or short-circuit ratio (Y. Zhang et al. 2014). As currently designed, IBRs have little ability to inject current above their continuous operational rating—so if they replace synchronous generators, they will reduce the system strength. With large amounts of VRE there may be insufficient current for protection equipment (as currently configured) to react (Denholm, Arent, et al. 2021).

In distribution systems, reduced fault currents under high IBR levels and bidirectional current flow also pose protection challenges (Matevosyan et al. 2019). Legacy protection systems use the magnitude and direction of the fault current to detect and locate faults in distribution systems. High levels of DER can affect legacy protection settings and coordination of protective devices.

3.2.2 Solutions and Research Agenda

Grid operators and planners have already started to address the need to maintain operational reliability under increased IBR deployment. Some measures are specific to one of the three components of operational reliability, but there are many common themes across these issues. These include time variance and uncertainty of PV output, the limited overcurrent capacity of PV inverters, visibility and controllability of DERs, and the need to maintain headroom for real power response to system disturbances. The following subsections discuss the general approaches to addressing these issues and outstanding issues that require additional research and engineering.

Evolving (Grid-Following) Inverters

Inverters are the interface between PV and the grid, so all changes to the way PV provides services occur via changes to how the inverter is designed and operated. Most inverters deployed to date are "grid following" inverters, meaning they rely on the presence of an externally regulated 60-Hz (in the United States) voltage waveform provided by the grid. Grid-following inverters continue to evolve, providing new capabilities beyond converting PV direct-current power to grid-compatible AC power (Matevosyan et al. 2019).

Advanced inverters now being deployed can provide additional grid services by controlling real power output in response to grid conditions, and they can independently control real and reactive power outputs to the grid in response to local voltage measurements via volt/VAR control and volt/watt control (Giraldez et al. 2018). In California, Pacific Gas and Electric forecasts that, by 2021, roughly half of all behind-the-meter PV will be equipped with advanced inverters, and nearly 100% will be equipped with advanced inverters by 2028 (PG&E 2019).

Interconnection standards and DER interoperability are critical, allowing for DERs and associated technologies that communicate with DERs to minimize cost and ease integration (Palmintier et al. 2016; Widergren et al. 2018). Standards must continue to be updated in response to changing grid conditions. The main standard for DER inverters is IEEE 1547, which underwent a major update in 2018 that allowed a variety of new advanced inverter functionalities including voltage and frequency support functions. This and other standards will continue to need updates to allow DER to provide increasing benefits to both the distribution and transmission systems. Standards must be updated to ensure inverters help improve overall grid reliability during abnormal events. Better specifications of IBR and DER behavior under fault conditions are needed, and new standards (such as the IEEE P1547.9 Guide to Using IEEE Standard 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems, which is under development) are needed for DER operation with storage.

Similarly, standards for utility-scale IBR-based systems need regular updating. The IEEE Standard P2800 for transmission-interconnected systems is expected to be released in late 2021 after industry and stakeholder review. This standard will describe the performance ranges and control interactions as well as power system services required and allowed, including frequency response, reactive power and voltage control, power quality, system protection, and performance validation. It likely will require reactive power supply and automatic voltage regulation even with zero active power output. Power-quality requirements will likely range from basic limits preventing flicker to more advanced requirements preventing harmonics or transient overvoltages. Additional protection requirements will also likely be included. Similar to IEEE 1547, P2800 is expected to include functions such as frequency and voltage ride-through capabilities, but given the greater focus on bulk systems these capability requirements will likely extend to include balanced and unbalanced current injections. Finally, this standard will have some description of system status monitoring and validation to assure system performance can be accurately controlled and reported.

This range of requirements and allowances will enable transmission-connected IBRs to participate in ancillary service markets while assuring stable transmission operations. IEEE P2800 pertains to all inverter-based transmission-connected systems, so it will encompass PV generation as well as hybrid plants including storage and may need modification as new sources of bulk inverter-based generation become prevalent and begin interacting with the market.

Grid-Forming Inverters

Advanced grid-following inverters have already addressed many challenges with continued IBR deployment, and a number of technologies would allow nearly 100% or even 100% IBR-based systems (B. Kroposki et al. 2017). Grid-forming inverters (GFMs) are considered a promising solution to many technical challenges associated with increased IBR deployment (Y. Lin et al. 2020). In contrast to grid-following inverters, GFMs do not require an external 60-Hz waveform

from the grid, which also enables them to produce such reference signals that other grid-following inverters can use. While GFMs have been used on small island power systems, they must be fully validated at scale to be employed as reliable solutions for larger grids. GFMs have shown promise in improving frequency response and overall system stability in small island systems (Hoke et al. 2021) and in some studies (Matevosyan et al. 2019). However, they are still a new technology without widespread operational deployment and resulting operational experience when interconnected to large grids. Research exploring system-wide impacts of deploying GFMs, at what point GFMs may be needed, the number of GFMs needed, and evaluation of their interactions with grid-following inverters and synchronous generators is critical.

Potential alternatives to including substantial amounts of GFMs include running RE-CT generators on a more continuous basis (thereby using fuel and potentially increasing VRE curtailment and emissions) or operating them as synchronous condensers.

Programmed Response of IBRs to Faults and Frequency Events

Synchronous generators can respond autonomously to changes in the power system due to the physics of their electro-magnetic coupling, but PV plants must be programmed for their controllers to respond in the desired manner. That said, PV system controls can respond quickly to grid disturbances, often more quickly than the response of synchronous generator controllers.

Significant work has already been done to enable IBRs to provide FFR. However additional research is needed to evaluate (1) the most appropriate shape and speed of response to improve and not adversely impact system stability, and (2) the impact of measurement approaches, measurement errors, and loss of measurement on FFR and system stability (Kuga et al. 2019; EirGrid and SONI 2016; Spahic et al. 2016). It will be important to ensure grid-wide standards allow the capabilities of IBRs to respond in times of need.

Accurate measurements are important when using inverters to respond to grid conditions. Unlike physics-based inertial response from synchronous generators, FFR will always be based on grid parameter measurements. Therefore, how grid frequency is measured and the measurement noise will impact inverter response. This problem is particularly pronounced under fast events such as faults, where frequency measurements may be erroneous for a few seconds after the event, and an unexpected and incorrect response may be detrimental to system stability (Kuga et al. 2019; Pourbeik et al. 2018). New sensing technologies could improve measurements of voltage and current waveforms and capture fast inverter dynamics (IEEE 2018).

Protection and Relaying

Some forms of protection in the grid rely on the ability of generators to inject large amounts of current during fault conditions, which can be detected by protection equipment. Increased deployment of IBRs and retirement of synchronous generators can reduce fault current available from the power system, eventually requiring new methods to ensure system protection such as higher fault current inverters, new sources of fault current, or new adaptive protection and relay coordination schemes (Y. Lin et al. 2020). High-fault-current inverters can be deployed with new IBR generators, or potentially retrofitted, while new sources of fault current include synchronous condensers (including retrofits of existing generators). New adaptive protection schemes may be devised for future grids to fully benefit from the superior control performance of power

electronic grid interfaces. These approaches include using adaptive overcurrent settings for protection, communication infrastructure for direct transfer trip, traveling wave, and current and voltage time-domain signatures (non-magnitude) to detect and locate faults.

These approaches require detailed modeling and simulation to clarify how they can protect the equipment and the power system as a whole, as well as when these approaches are needed and how much they will cost. Research aimed at better understanding the extent and regional variations of the protection challenges is important to develop solutions that serve the needs of various utilities without imposing the high costs of overhauling the entire protection infrastructure.

Advanced Simulation Tools

Achieving high reliability with IBRs requires improved modeling of grid interactions across multiple timescales including dynamic (millisecond) and/or transient (microsecond) modeling and simulation of inverters, energy storage devices, PV, and DERs (NERC 2017c; Matevosyan et al. 2019; Q. Huang and Vittal 2016). The behavior of these resources during grid changes depends on the specific implementations of hardware and control designs that occur at much faster speeds than those for traditional generation. In addition, newer technologies such as grid-forming technologies and the roles of coordinated controls schemes such as DERMS require development to be appropriately captured in simulations.

These models should be integrated with both T&D power system models for large-scale analysis of future grids with widespread IBRs and millions of DERs. More widespread use of DERs also requires adapting grid models to encompass two-way T&D interactions (Q. Huang et al. 2018; Jain 2017; Palmintier 2019; Yuan 2020). Additional modeling to capture the interactions with non-grid infrastructure may also be important, such as to consider transportation constraints on the ability of EVs to support the grid and communications impacts on controls.

In addition, widespread IBR, PV, and DER use requires evolved tools to consider additional aspects of power grid operations. For instance, the effects of inverters on power quality—including harmonics, flicker, and voltage sag or swell—require further understanding and tool development to mitigate their effects on other equipment in the power system. Advanced signal processing or machine-learning techniques may also be needed to identify and characterize unexpected energization, low current, high impedance, or incipient faults and cyberattacks.

Although much work has been done to develop new tools to better model power systems with increasing IBR levels, there is a need for research that can identify the best and most computationally efficient modeling practices that can be readily adopted by industry. The recently published Grid Modernization Strategy (Grid Modernization Initiative 2020) begins to lay out the path for the evolution of modeling approaches as PV adoption increases. Extending this effort further would help utilities and software vendors plan and prepare for this transition.

Co-Simulation of T&D Interactions

As the grid evolves along with increased PV deployment, system modeling will increasingly require co-simulation to capture increased complexities including interactions between T&D systems. This will allow greater understanding of how the capacity and energy requirements of both systems might evolve and can drive investments more efficiently and more intelligently,

compared with isolated simulations for planning. More broadly, understanding how actions taken by either operator will impact the other is crucial to accessing the full value of DERs without compromising reliability. For instance, if a transmission system operator (TSO) calls on aggregated DPV-plus-storage systems to reduce peak demand, some DER systems in the aggregation may exacerbate local voltage or congestion issues on the distribution system for a distribution system operator (DSO). Likewise, a DSO may need to operate DERs to manage distribution needs or achieve NWS goals such that the TSO would need to adjust the dispatch of resources elsewhere. Clear protocols for orders of operation and hierarchy as well as established channels for communication between the TSO and DSO can minimize any potential negative impacts of DERs.

Enabling increased TSO-DSO interaction will rely in large part on improved communication and data sharing between the two entities. Determining the appropriate tradeoff between coordination efforts, communication infrastructure, and efficiency gains will be a key factor in developing the appropriate coordination scheme for enhanced TSO-DSO interaction.

Market Design for Providing Reliability Services

Although PV may be technically capable of providing reliability services, regulatory or market structures designed for conventional generators may explicitly prevent or hinder PV participation. Even when allowed, compensation for ancillary service provision may not take the quality or speed of response into consideration, which may disadvantage PV's potential performance. Markets often do not consider the difference in costs or ability of resources like PV to provide "upward" versus "downward" reserve products. Ensuring better-performing resources are better compensated, by tracking the accuracy and speed of response, can help encourage PV to participate in ancillary markets as well as improve overall system reliability and efficiency.

Operating PV plants to provide inertial response and FFR may require a change in current practices that focus on maximizing PV generation. Although PV could maintain headroom to provide valuable FFR, without proper financial compensation, consistently generating below maximum potential would represent expensive curtailment that may discourage provision of such a service (Chernyakhovskiy et al. 2019; Loutan et al. 2017). Research aimed at developing market-based mechanisms to incentivize the maintenance of headroom for frequency response provision from IBRs will help improve system stability as more PV is integrated onto the grid.

3.3 Grid Resilience and Security

3.3.1 PV and Resilience

Resilience addresses the risk of an undesired outcome to a system, such as the failure of the power grid, which is a function of hazards faced by a system, its vulnerabilities, and the consequences inherent to each vulnerability (Anderson et al. 2019). The electric grid faces a broad range of hazards, from natural (e.g., hurricanes, floods, wildfires, and extreme temperature events), to adversarial (e.g., physical and cyber attacks), to technological (e.g., component/operator failure).

Increasing resilience can mean intervening to reduce the likelihood of a hazard, the exposure of a specific vulnerability, or the consequence of a vulnerability being exploited (Anderson et al. 2019; Petit and Vargas 2020). Although no one set of characteristics makes a system "resilient,"

common attributes include diversity, redundancy, decentralization, the ability to fail gracefully, flexibility, and foresight (Hotchkiss and Dane 2019). The consequences of system failure must be weighed against the cost of building resilience into a system.

Distributed PV offers opportunities to enhance resilience by allowing buildings to continue to power critical loads during grid outages. For example, during Hurricane Sandy, Midtown Community School maintained power using PV during the day to reduce diesel generator use and conserve fuel supplies, and it served as a community shelter during the aftermath (NREL 2019). The resilience value of solar can be augmented through storage and load flexibility. Further, groups of resilient buildings can be integrated into microgrids: clusters of buildings that are interconnected to the grid but capable of operating independently. Solar-based microgrids could ensure uninterrupted provision of critical services during natural disasters and other grid outage events.

PV itself is vulnerable to hazards. For example, during hurricanes PV output can drop to 18%–60% of clear-sky production due to cloudy conditions, and the high winds can destroy PV modules (Belding, Walker, and Watson 2020; Cole, Greer, and Lamb 2020); installation techniques to mitigate against high winds also add expense (Elsworth and Geet 2020). While these vulnerabilities are in some ways extensions to RA, their extended duration, potential for protracted recovery, and connection to extreme weather events brings them into resilience considerations.

3.3.2   Research Priorities for Grid Resilience

Support for Resilience Planning and Valuation

Many utilities, consumers, and decision makers lack the institutional tools and practices needed to evaluate resilience needs and preferences and the use of PV for resilience. Although a robust resilience-planning community exists, linking conclusions from that research to grid operators, utilities, or consumers considering PV investments will be needed to improve resilience outcomes. As utilities or other decision makers consider resilience investments, insights from social science research on how to value preferences for avoiding disruptions likely will be critical. Valuing PV and grid resilience is challenging. For example, because advanced inverters and controls to enable grid islanding may entail a cost premium over less resilient alternatives, regulated utilities may have difficulty gaining approval for their use without a clear mandate to invest in resilience. The current regulatory environment also limits the ability of non-utility entities to develop microgrids that serve multiple customers. There is a growing effort to characterize the willingness of individuals, companies, or grid operators to pay for resilience, but it is not always clear how payments for resilience should be spread across consumers who benefit from resilience differently (Baik et al. 2020; NREL 2019). In addition, many of the PV upgrades that would provide resilience would also benefit reliability. Understanding the interactions between resilience and reliability is important.

Improved Forecasting

Improving the resolution and accuracy of solar forecasts—during normal conditions and extreme events—likely will help grid operators and planners determine how to assess the resilience contribution of PV. These forecasting methods should be adapted to include fire smoke forecasting and evaluation of the effects of wildfires on PV generation. Forecasting is discussed

in Section 3.1.2. Another need is real-time situational awareness and visualization tools that can translate the uncertainty of weather and solar forecasts into grid impacts, overlaying the evolution of severe weather events on the geographic information systems (GIS) data of distribution and transmission grids, critical loading facilities, and emergency shelters.

Solar Blackstart

Blackstart refers to the process of a generating resource restarting itself and initiating grid restoration after an outage. Traditionally, synchronous generators such as natural gas turbines have been used for blackstart (Jain et al. 2020). Providing blackstart with PV alone would be difficult but likely possible with careful coordination with load and solar forecasts. PV in combination with resources that can sustain power output for long periods, such as battery storage, could be an important capability in the future. The use of IBRs for blackstart also requires careful management of "surge" current capability to supply increased power for a short duration as new loads, and in particular inductive loads such as motors, are brought on-line. Because IBRs can start almost instantly without requiring a minimum load, the restoration process can be sped up. At the same time, having more diverse and widely dispersed resources can improve the reliability of blackstart. The U.S. Department of Energy (DOE) has funded several efforts to understand the role of IBRs in blackstart and develop the capabilities required to make IBRs act as blackstart resources. An approach to using feeders with PV and wind resources is being developed to facilitate blackstart (Feller 2019). Research on market-based approaches to incentivize and compensate IBRs to provide blackstart support is also needed.

Microgrids

With advanced inverters and control systems, PV can help form microgrids—from the household level, to critical facilities such as hospitals, to sections of the grid—that provide resilience benefits during failure of the broader grid.[60] Microgrids would be designed to interact with the grid during normal operations but operate as an island during a blackout or other emergency event. IEEE Standard 1547.4 provides guidance on the design and operation of microgrids as part of larger grid infrastructures. Although microgrids are relatively rare—as of 2019, less than 4 GW of microgrid capacity was installed in the U.S. (Maze-Rothstein 2020)—interest in PV-based microgrids is growing rapidly.

As microgrid technology improves and experience with operating islanded systems grows, there may be opportunity to move from a traditionally integrated system with microgrids at select locations to a grid that can flexibly isolate different segments. Although fault isolation is widespread in U.S. grids, a grid that can reorganize around distributed generation like PV could provide additional benefits. For example, in the event of a widespread blackout, sections of the grid close to generation might be able to isolate themselves and use available power, even if those loads are not in an established microgrid with that generation. As systems and devices become increasingly interconnected, there may be additional opportunities to extract resilience by coordinating DPV in such an isolated system during a disaster in a way not feasible today. Such a vision would represent a radical departure from current grid operations but would offer

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[60] For example, SMA markets inverters with a "Secure Power Supply" feature allowing individuals to access up to 1.5–2 kW of power from their PV system using a dedicated outlet during a grid outage (Dyke 2016; SMA 2020). These inverters were demonstrated successfully in Hawai'i during Hurricane Iselle (Shinogawa 2014).

additional system resilience. DOE's Solar Energy Technologies Office is currently funding several Resilient Community Microgrids Projects that are developing community-scale microgrids with high solar generation that can disconnect from the traditional grid to operate autonomously when the main grid is down.[61]

3.3.3 Cybersecurity in the Future Grid

Modern grids measure and collect large amounts of data and use a variety of advanced control systems in the information technology (IT) and operational technology (OT) spaces, but each innovation opens doors for new vulnerabilities and cyber threats that could disrupt grid operation. Addressing cybersecurity concerns requires all energy stakeholders—electric utilities, aggregators, grid operators, vendors, and state and federal government agencies—to understand the threats, cooperate on cybersecurity strategies, develop policies and functions that protect the grid, and develop cyber incident response plans to ensure business continuity.

Standards, guidelines, and procedures around different aspects of cybersecurity are evolving quickly. Currently, the National Institute of Standards and Technology Cybersecurity Framework (National Institute of Standards and Technology 2018) is the most thorough and holistic approach to cybersecurity. This framework covers 900 controls over five major functions: identify, protect, detect, respond, and recover. DERs such as PV present particular issues, which are discussed below.

Cybersecurity for DERs

National laboratories have started working with standards development organizations, certification labs, and other energy stakeholders to develop general DER cybersecurity policies, secure network architectures (EPRI 2019), certification procedures data and DER communication security (Saleem and Carter 2019), recommendations for trust and encryption in DER interoperability standards (Obert et al. 2019), and data-sharing requirements for DERs. There are now several examples of key cybersecurity guidelines, standards, and best practices that could be used to enhance the grid's cybersecurity (J. Henry et al. 2015).

The following are a few cybersecure functionalities that could be considered by PV aggregators, electric utilities, vendors, and manufacturers to secure grid-edge devices (Saleem and Carter 2019):

- Using authentication to ensure the identity of personnel, customers, and vendors, and to ensure that different systems have different privileges for accessing the DER monitoring and control systems. This also helps enforce the least-privilege rule for DERs.

- Using transport layer security (TLS) to ensure encryption, authentication, and data integrity. Use of TLS helps protect the system against man in the middle, eavesdropping, and replay attacks.

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[61] See (DOE 2020).

- Using certificate revocation lists to revoke expired certificates that can no longer be used to authenticate a network session. This helps protect the system from data spoofing cyberattacks.

- Instituting adequate physical security to protect hardware from malicious physical actions and prevent unauthorized access.

- Implementing the ability to perform firmware "rollbacks" to help systems recover from malware embedded in the firmware updates or software files pushed out by DER manufacturers or vendors.

- Instituting effective password management to ensure devices cannot be easily undermined by brute-force cyberattacks.

- Using logging to record observable events on a system. Logs can be generated by security devices (which issue alerts) or other devices (for instance, an OT device may have its own log file).

3.3.4 Research Priorities for Cybersecurity

As outlined in DOE's Multiyear Plan for Energy Sector Cybersecurity, "game-changing" technologies are needed to enable a fully distributed grid while protecting national security (Walker 2018). Basic research questions revolve around how to use redundant communication paths (to eliminate the impacts of losing one path), how to actively monitor and alarm if redundant communication paths are lost, how to maintain a trusted "gold copy" of system device configuration files to expedite recovery after an attack or ransom situation, how to securely update software/firmware using code signing and boot loader process, and so on. The following are specific game-changing topics that could help enable a fully distributed grid.

- Name data networking: enables secure end-to-end communications without dependence on the security or topology of underlying channels (Chen et al. 2016).

- Zero-trust networks for grid operations and management: recognizes the information, devices, applications, and frameworks that must be protected with the assumption that the network is potentially compromised (Rose et al. 2020).

- Quantum-resistant cryptographic algorithms: requires development of cryptographic schemes resistant to the impacts of quantum computers (Cheng et al. 2017; Farik and Ali 2016).

- Use of fifth-generation (5G) cellular technology in the modern grid for power communications: provides significantly higher throughput, better coverage, and better reliability (5G ACIA 2020; Cosovic et al. 2017).

4

Understanding the Role of Solar Through the Lens of Equity

4 Understanding the Role of Solar Through the Lens of Equity

Fossil fuels underpin many of the benefits we take for granted in modern society (Smil 2017). However, the fossil-fuel-based energy system has numerous costs, particularly due to the immediate public health and environmental harms from fossil fuel extraction, processing, and combustion, and the long-term harms from climate change (Millstein et al. 2017). The benefits and costs of the energy system have not been equitably distributed (Sovacool and Dworkin 2014). Under-resourced communities[62] have borne disproportionately large shares of the costs of the existing energy system, as evidenced by the disproportionately poor air quality and health outcomes in under-resourced communities (Figure 4 - 1, left) (Carley and Konisky 2020)—though energy generation is only one among many factors driving these inequities (Tessum et al. 2021). Several factors contribute to this disparity, including environmental racism, lack of local representation in energy project development, and the structural inequalities of today's energy system (Baker 2021). Further, under-resourced households bear disproportionately large energy burdens in the existing system: they dedicate greater shares of household income toward energy expenses than do high-income households (Bednar and Reames 2020; Drehobl, Ross, and Ayala 2020; Memmott et al. 2021) (Figure 4 - 1, right). Finally, many under-resourced households are energy insecure, meaning they cannot afford to buy enough energy to meet basic needs (Memmott et al. 2021). Large energy burdens and energy insecurity have direct impacts on health and wellbeing, causing energy-burdened households to make difficult decisions between paying for energy expenses and other necessities such as food and medicine (Reames, Daley, and Pierce 2021).
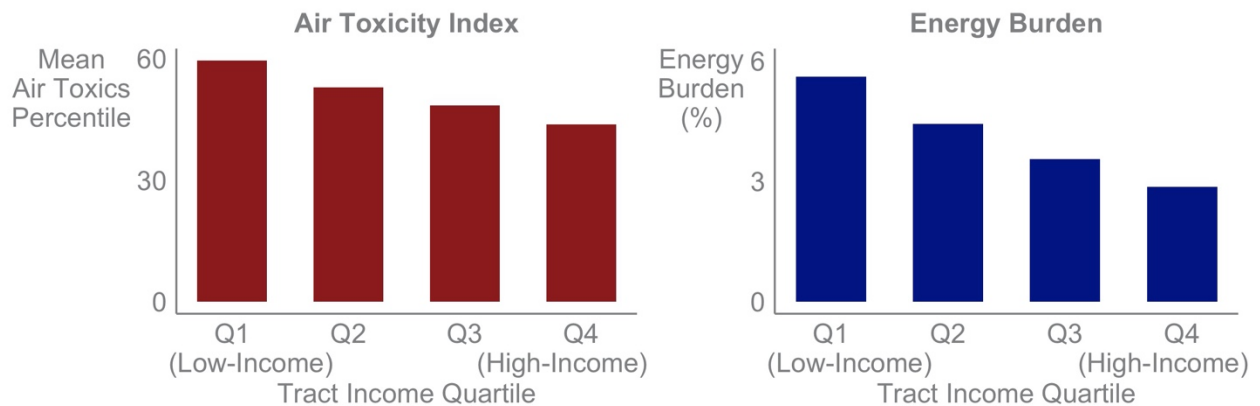
Figure 4 - 1. Air toxicity index (left) and average energy burden (right) based on Census tract income levels

The figures are based on tract-level data from the U.S. Environmental Protection Agency's EJSCREEN and DOE's Low-Income Energy Affordability Data tool. The left pane is based on percentile scores for EJSCREEN's index for air toxics cancer risk. Electricity-based emissions are only one of many factors contributing to local air toxicity.

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[62] The Clean Energy States Alliance defines "under-resourced communities" as communities that have high proportions of low-to-moderate income (LMI) residents and generally receive below-average services and financial resources from government. Many, but not all, comprise an above-average number of people of color and immigrants. This report references under-resourced, LMI, and front-line communities as well as communities of color.

Solar deployment—at the scale envisioned in the *Solar Futures Study*—presents an opportunity to maintain the benefits of the modern energy system while mitigating the costs and distributing costs and benefits more equitably. This growth in the use of solar technologies presents many potential benefits including climate change mitigation, improved air quality, job creation, and local wealth building. New approaches to energy policy and development may be needed to ensure that the benefits of the zero-carbon system are equitably distributed.

The benefits and costs of solar have generally been analyzed through techno-economic frameworks. These benefits and costs can also be analyzed through equity frameworks such as energy justice. Energy justice is an emerging framework with a variety of meanings and working definitions. For the purposes of this chapter, we use the term energy justice consistently with its use in academic literature, which defines energy justice as a framework that evaluates the distribution of benefits and costs and how that distribution is determined (Sovacool and Dworkin 2014). In a just energy system, all individuals can secure reliable, affordable, safe, and sustainable energy. Most scholars identify several tenets of energy justice, including but not limited to distributive justice (achieving a fair distribution of benefits and costs), procedural justice (fair procedures to determine those costs and ensuring that marginalized communities are provided opportunities to participate), and recognition justice (recognition of historic and ongoing inequalities and restorative justice redressing historic injustices) (Carley and Konisky 2020).

In this chapter, we explore the role of solar in deep decarbonization through the lens of equity. We organize our discussion around four themes of energy justice (Sovacool and Dworkin 2014):

- *Equitable distribution of benefits*: A just energy system fairly distributes the benefits of energy technologies and services. We explore the distribution of the public and private benefits of solar in Section 4.1.

- *Equitable distribution of costs*: A just energy system fairly distributes the costs—including hazards and negative externalities—of energy technologies and services. We explore the distribution of the costs of solar in three categories in Section 4.2.

- *Procedural justice*: All just energy systems have procedures, rules, and policies that ensure representative and impartial decision making. We explore procedural justice in solar in Section 4.3.

- *Just transition*: Energy transitions create benefits and costs that are not equally distributed. A just transition accounts for the costs of the transition and seeks ways to mitigate adversities. We explore just transition issues in the context of solar in Section 4.4.

For each theme, we explore the existing literature to establish what we know. We then discuss what could be done in the near term to augment the energy justice benefits of solar, redress historical inequities of solar deployment, and mitigate future harms where these may exist. After reviewing these themes, we discuss how solar could fit into the energy justice vision of the Biden Administration. Lastly, we offer conclusions and identify priority areas for future research.

What do we know?	**What can be done?**
We review how the benefits and costs of solar have been distributed to date.	We review potential measures to maximize the benefits of solar, redress historical inequities, and mitigate potential future energy justice issues.

Before discussing what we know and what can be done, it is important to acknowledge what we do not know. Energy equity and justice are emerging topics in the literature that benefit from a growing body of empirical and theoretical research. Still, particularly related to solar, there are many unanswered questions. We need to acknowledge our uncertainty in each of the four areas to be discussed in this section:

Distribution of benefits: While we know that certain benefits of solar have been inequitably distributed, we do not know whether the aggregate benefits of solar have been equitably distributed with respect to income and other demographic factors. The long-term public benefits of solar (e.g., climate change mitigation, air-quality benefits) are several orders of magnitude larger than the historical private benefits of photovoltaic (PV) adoption. Without a clear picture of the distribution of these public benefits, we cannot make reliable conclusions about the equitable distribution of the aggregate benefits of solar.

Distribution of costs: We do not know whether the aggregate costs of solar have been equitably distributed with respect to income and other demographic factors. In Section 4.2, we review the costs of solar and what the literature suggests about the distribution of those costs. While some of these costs may have been inequitably distributed (e.g., potential cost shifting in rate structures), others may have been progressively distributed (e.g., through programs funded through progressive taxation). The historical distribution of aggregate costs is ambiguous and is an area for further research. It is worth contrasting the ambiguous distribution of solar costs with the systematically inequitable distribution of costs in the existing energy system.

Procedural justice: We do not know which measures maximize procedural justice. As we discuss in Section 4.3, numerous measures have been proposed and implemented to increase representation in energy decision making. Additional data collection and analysis to understand the efficacy of various measures are needed. Understanding ways to maximize procedural justice and evaluate the impacts of different procedures is a key area for future research.

Just transition: We do not know the long-term impacts of the clean energy transition on workers in displaced industries. We know the transition will displace thousands of workers, resulting in acute hardships for individuals and communities. Beyond this basic projection, we have little certainty about the longer-term impacts of the transition on these individuals and communities. It is possible that healthy economic conditions and worker transitions into growing clean energy industries will mitigate the adversities of displaced industries. It is also possible that these adversities will persist and require more significant and long-term restorative measures.

4.1 Distribution of Benefits

We distinguish between *public* benefits, which accrue to broad groups of people regardless of whether they themselves adopt solar, and *private* benefits, which only directly accrue to solar adopters. The public benefits of solar (e.g., climate change mitigation) are public goods in the traditional economic sense. The public benefits are inclusive and non-rivalrous: they are enjoyed by all (or broad groups of people) regardless of which individuals bear the costs. In contrast, the private benefits of solar adoption are exclusive and rivalrous: they are enjoyed by the adopters but not by others. Public policy has a clear and direct role in ensuring an equitable distribution of the public benefits, while the role of policy in the distribution of private benefits is more nuanced. We explore these nuances in the following sections.

4.1.1 Public Benefits: Climate Change Mitigation, Local Air Quality, and Economic Benefits

What do we know?	**What can be done?**
Under-resourced communities bear disproportionate shares of the air-quality and public-health damages of the existing system. Solar plays a central role in eliminating these inequitably distributed harms.	Incentive programs can maximize the air-quality benefits of solar by incentivizing vehicle electrification in under-resourced communities.

What Do We Know?

The primary public benefits of solar and clean energy more broadly are emissions reductions, climate change mitigation, and air-quality improvements from the displacement of emitting electricity generators (Outka 2012; Millstein et al. 2017; Fell and Johnson 2021; Wiser et al. 2021). Fossil fuel combustion emits a suite of hazardous air pollutants that pose direct and immediate threats to public health as well as greenhouse gases that pose long-term threats from climate change. Across the population in 2011, around 15,000 people died owing to poor air quality related to electricity generation, with public health expenditures of around $120 billion (Goodkind et al. 2019).[63] However, the air quality impacts of electricity generation have already declined substantially, due largely to the ongoing reduction of coal-fired generation (Fell and Johnson 2021). By displacing fossil sources of power generation, solar energy can directly mitigate the near-term public health threats and the long-term climate change damages associated with electricity production. We estimate that the grid transformation envisioned in the *Solar Futures Study* will yield about $300 billion of air-quality and health benefits in the Decarb scenario, largely due to reduced emissions of sulfur dioxide from coal plants (see Section 2.2.6). With respect to climate change mitigation, power-sector CO_2 emissions under the Decarb and Decarb+E scenarios reach 120 Mt by 2035 and 0 Mt by 2050, as specified by the scenario designs. In contrast, under the Reference scenario, power-sector CO_2 emissions reach 1,330 Mt (45% below 2005 levels) in 2035 and 931 Mt (61% below 2005 levels) in 2050. These long-term

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[63] Specifically, Goodkind et al. estimate that poor air quality resulted in 107,000 deaths at a cost of $886 billion/year, of which 14% is attributed to energy generation. For additional studies on air quality impacts of electricity generation, see (National Research Council 2010; Millstein et al. 2017; Fell and Johnson 2021).

benefits far outweigh the incremental system costs estimated for the *Solar Futures* vision (see Section 2.2.6).

Owing to the interconnected nature of the grid, the complexities of electricity dispatch, and the broad geographic dispersal of power plant emissions, the air-quality benefits of solar are generally measured at a regional or national scale (Fell and Johnson 2021). Similarly, the climate change mitigation benefits of offset carbon emissions accrue at regional, national, and global scales (Martinich and Crimmins 2019). As a result, though we know solar yields broad population-wide air-quality and health benefits, it is inherently challenging to analyze the *distribution* of those benefits with respect to income and other demographic factors. Further research is required to identify potential strategies to maximize the local air-quality and health benefits of solar deployment, particularly in under-resourced communities.

In addition to mitigating air-quality impacts of electricity generation, solar can help mitigate air-quality impacts from transportation, which accounts for around 28% of public health damages related to air quality (Goodkind et al. 2019). Unlike the broad regional impacts of emissions-intensive electricity generators, transportation can have highly localized impacts on air quality, such as local ozone formation due to emissions from vehicle tailpipes. As a result, displacing transportation emissions can have localized air-quality and health benefits. Solar can accelerate these localized benefits by enabling EV adoption. Households and businesses that adopt rooftop solar or have access to low-cost midday solar electricity are more likely to convert to EVs (Kaufmann et al. 2021). High rates of local PV adoption could therefore accelerate localized air-quality benefits across the transportation sector. We estimate that the vehicle electrification envisioned in the Decarb+E Scenario will yield nearly $100 billion in additional air-quality and health benefits due to offset emissions from transportation (see Section 2.2.6).

Solar might also mitigate the local air-quality impacts from industrial emissions by serving as an alternative energy input to certain industrial processes, though this concept has yet to be rigorously tested. In this capacity, solar can similarly serve as a tool for restorative justice by reducing harmful emissions from facilities that have been disproportionately sited in LMI and communities of color. Further research is required to understand this potential role.

Finally, energy abundance is a key potential future public benefit of solar. Abundant solar can drive the effective marginal cost of energy to zero. Lower-cost electricity benefits consumers if the lower costs are reflected in rates. It is possible, though far from guaranteed, that zero-marginal-cost solar could reduce LMI energy burdens in the long term. However, the long-term effects of zero-marginal-cost solar energy on end-user prices are uncertain (Antweiler and Muesgens 2021). The electricity customer benefits of abundant, low-cost solar are potentially substantial, but further research is required to understand how such benefits could be equitably distributed.

What Can Be Done?

The *Solar Futures Study* envisions a significant role for solar in eliminating emissions from the electricity sector by 2035 and from direct fuel combustion by 2050. The Decarb scenario would eliminate 85% of power-sector emissions of sulfur dioxide and nitrogen oxides (ozone precursors) by 2035, and 100% of these emissions by 2050. These emissions reductions yield broad public health benefits, with estimated public health savings of about $300 billion from

2020 to 2050. It may also be possible to strategically deploy solar, storage, and other clean energy technologies to displace output from specific generators and achieved localized health benefits. For instance, strategically deployed assets could reduce output from urban peaking plants that are disproportionately sited in under-resourced communities (Clean Energy Group et al. 2020).

For the transportation sector, realizing the local air-quality benefits of vehicle electrification in under-resourced communities will require EV adoption and access to vehicle charging infrastructure that have not kept pace with affluent and white communities (Muehlegger and Rapson 2018; Hsu and Fingerman 2021). Emerging solutions include income-qualified incentives and rebates for EV purchases and state mandates for infrastructure investment in under-resourced communities (Hsu and Fingerman 2021). Meanwhile, using solar electricity directly for public vehicle charging and hydrogen fuel production may provide benefits associated with increasing access to zero-carbon charging. Some of these benefits can be difficult to measure and vary across communities, but may include a sense of satisfaction in living in a community that prioritizes environmental stewardship. New business models and programs that bundle charging infrastructure with dedicated local solar projects could increase access to zero-carbon EV charging and hydrogen fueling. In addition, expanding vehicle electrification beyond single-occupancy, owner-occupied vehicles to transit vehicles and rideshare fleets can enable broader use of clean transportation options. Finally, co-locating charging infrastructure and PV in under-resourced communities, including at multifamily housing locations and public spaces, can increase opportunities for vehicle charging and zero-carbon charging with PV (Baldwin, Myers, and O'Boyle 2020). The level of vehicle electrification in the Decarb+E scenario results in nearly $100 billion in avoided health damages from reduced vehicle emissions.

For the industrial sector, the siting of polluting facilities near LMI and communities of color is a priority environmental justice challenge (Tessum et al. 2021). Further research is needed to understand the role of solar in helping address this challenge. In theory, displacing polluting sources of electricity and heat with solar could help improve local air quality and neighborhood wellbeing. In practice, today, there are few examples of government incentives and other measures aimed at increasing use of solar in industrial processes or directly addressing the inequitable siting of industrial facilities. For those programs that do exist, incentives for using solar process heat systems are more common than for using solar electricity.

4.1.2 Private Benefits: Economic and Local Resilience Benefits of Solar Adoption

What do we know?	What can be done?
The private benefits of rooftop PV adoption have been inequitably distributed, though this inequitable adoption largely reflects broad social and economic factors.	PV adoption equity can be improved through financial, community engagement, siting, policy and regulatory, and resilience measures.

What Do We Know?
Rooftop PV adopters make upfront or ongoing payments to buy PV output. In return, PV adopters earn a variety of private benefits, including financial benefits, resilience benefits, and

less tangible benefits such as social status and the satisfaction of feeling more sustainable (Moezzi et al. 2017; Wolske, Stern, and Dietz 2017). These benefits have been inequitably distributed with respect to income, race, and other demographic factors, as a result of inequitable PV adoption patterns. With respect to income, LMI households have adopted rooftop PV at lower rates than high-income households (Barbose et al. 2021). Rooftop PV adoption has become more income-equitable over time, but in 2019, only about 31% of adopters earned less than their area's median income (Barbose et al. 2021) (Figure 4 - 2). With respect to race, when controlling for income, Census tracts with majority Black and Hispanic populations exhibit 30% and 69% less rooftop PV adoption, respectively (Sunter, Castellanos, and Kammen 2019). Inequitable PV adoption reflects a variety of adoption barriers faced by LMI households and households of color, including cash constraints, lower rates of home ownership, and language barriers (Lukanov and Krieger 2019; M. Brown et al. 2020). PV adoption inequity also reflects historical patterns of PV deployment that cause PV systems to cluster in high-income areas, such as installer marketing patterns and peer effects (O'Shaughnessy et al. 2020).
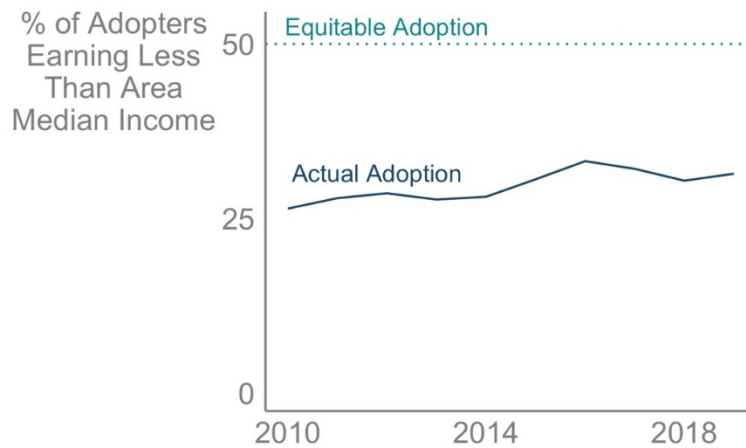
Figure 4 - 2. Percentage of PV adopters earning less than their area median income over time

Based on data from (Barbose et al. 2021)

The historically inequitable distribution of the private benefits of rooftop PV adoption is beyond dispute, but it is critical that this observation not be interpreted as a condemnation of solar as an inequitable technology. In this regard, solar is not unique: most products are inequitably adopted with respect to income, particularly in emerging markets for new technologies (Attanasio and Pistaferri 2016). The inequitable adoption of solar and other technologies is largely a consequence of free markets in an income-unequal society, not innately inequitable characteristics of these technologies (Attanasio and Pistaferri 2016). Inequitable PV adoption needs to be understood in this broader context. This context surrounding diffusion of new technologies is important for understanding PV adoption patterns and mechanisms to enable more equitable distribution of the benefits that PV provides.

For the purposes of this report, we identify three specific energy justice implications of inequitable PV adoption. The first is the cross-subsidization stemming from the accrual of private benefits from public funds. The second is the potential role of solar in addressing LMI energy burdens. The third is the inequitable distribution of resilience benefits that blur the lines between public and private.

Cross-Subsidization

Nearly all rooftop PV adopters in the United States received financial incentives in the form of state and local rebates, tax credits, or ongoing production-based incentives, as well as federal investment tax credits. According to data from Barbose, Forrester, et al. (2020), state incentive programs have distributed around $4 billion in rebates, and total foregone tax revenues from the federal investment tax credit are around $15 billion.[64] These rebates and tax credits are supported by public funds and reduce the up-front costs of adopting PV. As a result of inequitable PV adoption, these incentives flowed disproportionately to high-income households (Borenstein and Davis 2016). Meanwhile, Tribal and other non-profit organizations that may be well positioned to serve LMI communities are ineligible to receive tax incentives, and thus must partner with a third-party tax-equity investor to take advantage of the federal investment tax credit (Ardani, Hillman, and Busche 2013).

While state and local financial incentives have largely phased down and the federal credit is scheduled to phase out by 2023, incentives played a key role in catalyzing early PV deployment. The rationale for these incentives was the promotion of public benefits, namely, to support emerging PV markets and accelerate PV cost reductions, both of which will yield long-term public benefits for PV adopters and non-adopters alike. Incentives are broadly credited with fulfilling these functions and driving the cost reductions that have made solar increasingly cost-accessible to more households (Nemet 2019). Nonetheless, these incentives used public funds to enable private financial benefits, equating to non-adopters subsidizing adopters. Owing to income-inequitable adoption patterns, this subsidization may have occurred across income groups: LMI households may have subsidized high-income households (Borenstein and Davis 2016).

LMI Energy Burden

As already noted, LMI and households of color bear disproportionately large energy burdens: they dedicate greater shares of household income to energy expenses than high-income households do (Drehobl, Ross, and Ayala 2020; Memmott et al. 2021). Energy burdens have direct impacts in terms of adverse impacts on health and wellbeing (Reames, Daley, and Pierce 2021; Memmott et al. 2021). Targeted solar deployment could alleviate LMI energy burdens by reducing LMI household energy bills for PV adopters (Bednar and Reames 2020). However, as a result of inequitable PV adoption, the market has not realized the full potential for solar to mitigate LMI energy burdens (Borenstein 2017; O'Shaughnessy et al. 2021). The underperformance of solar in LMI markets represents a missed opportunity to alleviate LMI energy burdens and their direct impacts on health and wellbeing.

Local Resilience

Climate change increases the frequency and intensity of natural disasters and extreme weather events. As a result, power outages are becoming more common and are having a disproportionate impact on frontline communities, which are often LMI and communities of color (Krause and Reeves 2017; Leon et al. 2019). Several factors contribute to this disparity, including less

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[64] The rebate estimate is based on the total value of all state rebates distributed and reported in Lawrence Berkeley National Laboratory's Tracking the Sun data set. Foregone tax revenues are based on the sum of all system costs in the same data set, assuming that most systems monetize approximately the full value of the tax credit (30% of system cost).

durable and aging grid infrastructure, lack of informational and financial resources to aid in recovery, and a higher share of the population residing in coastal and other disaster-prone areas (Leon et al. 2019). Repeated exposure to disasters and power outages compounds financial insecurity, further exacerbating the energy burden borne by LMI communities (Sanders 2020).

In Chapter 3, we discuss the role of solar in maintaining grid resilience. Solar can also provide local resilience at the level of individual facilities or clusters of facilities in "microgrids" (Mullendore and Milford 2015; Anderson et al. 2017; Hirsch, Parag, and Guerrero 2018). Local resilience can be vitally important for maintaining public health and economic activity during natural disasters (Gundlach 2018). To our knowledge, the geographic distribution of the resilience benefits of solar have not been studied. However, it is possible that inequitable PV adoption will, in the long run, yield similarly inequitable geographic disparities in resilience. The geographic distribution of the resilience benefits of solar is an area for further research.

What Can Be Done?

The unequal adoption of rooftop PV reflects socioeconomic factors that are much larger than the rooftop PV market, particularly income inequality and structural racism. Like other emerging technologies, rooftop PV adoption is and will become more equitable over time as costs decline. Further, research suggests that the transition toward more equitable PV adoption can be accelerated through policy interventions, business model reforms, and other measures (O'Shaughnessy et al. 2021). We organize these potential measures into five categories: financial, community engagement, siting, policy and regulatory measures, and resilience measures. These measures can be aimed at increasing PV adoption in frontline, LMI, and communities of color to help ensure that these communities have equitable access to the benefits of solar. While a comprehensive discussion of all potential measures is outside the scope of this chapter, we briefly discuss each type of potential solution, in turn. See the accompanying *Solar Futures* technical report by Heeter et al. (2021) for more detail on the many LMI adoption barriers and solutions.

Financial

Implementing incentives and financing mechanisms that provide easier access to capital or allow households to adopt solar with minimal or no upfront cost can expand solar access to LMI customers (O'Shaughnessy et al. 2021; Paulos et al. 2021). A number of short- and long-term solutions have been explored to address financing and funding barriers, including leasing and other zero-down solar products, provision of increased state and federal funding for LMI solar programs, and refundable tax credits.[65] Other potential mechanisms could include state and federal programs that automatically provide an onsite or offsite solar option for customers meeting certain eligibility criteria, thereby providing an immediate reduction in utility bills. The

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[65] Also referred to as a direct-pay option, refundable tax credits typically allow for direct cash refunds up to the full amount of credit available, after accounting for the amount of credit a recipient has claimed in tax credit form, as determined by tax liability. Senate legislation introduced in March 2021, Save America's Clean Energy Jobs Act, would allow for temporary refundability of the investment tax credit for projects that begin construction before January 1, 2023, and are placed into service after March 25, 2021. Proposals for direct-pay options are also included in the Biden Administration's $2 trillion American Jobs Plan announced March 31, 2021.

success of such programs may hinge on measures to streamline the qualification process, which if too lengthy or cumbersome could deter participation.

Community Engagement
Increasing under-resourced community participation in energy decision-making processes can help ensure that outcomes reflect community priorities (Bidwell 2016). Example measures to increase community engagement in solar development decisions include education and outreach efforts that focus on community organizations working directly with solar developers, more inclusive and participatory regulatory and utility processes, and greater transparency in community energy planning and decision making. Community engagement is a core tenet of the Biden Administration's vision for energy justice (see Section 4.5). See further discussion of community engagement as a means for procedural justice in Section 4.3.

Community engagement encompasses not only participatory, inclusive processes, but also the ability to create new wealth in communities. For example, some communities may want a more active role in investing in renewable energy technologies so they can also receive the benefits of owning the technology. Some emerging models prioritize community development, control, and ownership of solar systems and programs, such as by providing technical assistance and raising incentive levels for project development by community-based nonprofits or cooperatives.

Siting
Lower rates of home ownership among households are a key barrier to PV adoption in under-resourced communities. To address this, policies can support offsite solar business models. Offsite solar options, such as community solar, can mitigate the need for individuals to secure their own financing and host a solar system, while still providing bill credits to LMI customers. State-level community solar programs with carveouts or other measures to support LMI subscribers have been implemented in at least 17 states and Washington, DC (Paulos et al. 2021).

LMI adoption could be accelerated by integrating solar installation with other LMI services. These services could be energy related, such as weatherization efforts, or even more broadly focused on other LMI housing services or other benefits, such as financial assistance for families. Packaging solar with other service delivery options can provide additional savings for tenants and streamline the customer-adoption process. Packaging solar with service delivery targeted to LMI customers could be a way to expand solar access in LMI communities. Service delivery of onsite solar via the Weatherization Assistance Program has been demonstrated, and renewable energy is considered a weatherization measure. The December 2020 Stimulus Bill provides $1.7 billion for the Weatherization Assistance Program and formally considers renewable energy installations as an eligible weatherization measure.

Another potential siting measure is providing incentives to site wealth-building PV in under-resourced neighborhoods or on land owned by members of under-resourced communities. PV systems can build wealth in several ways depending on ownership structures. For PV systems owned or leased by members of under-resourced communities, the systems provide a stable stream of low-cost electricity and can increase the resale value of buildings or land. In other cases, PV developers can lease rooftop space or land from under-resourced communities while selling the power to a utility or into wholesale electricity markets. In those cases, the developer leases the rooftop space or land, and that lease provides a new, stable revenue stream to the

under-resourced communities. In both cases, siting PV in under-resourced communities can convert those PV systems into wealth-building assets.

Policy and Regulatory
Many barriers may be addressed by policy and regulatory reforms. Reforms could include measures to eliminate the landlord-tenant split-incentive problem, such as on-bill financing options, green leases, and building standards. Solutions could also include incentives or mandates for including solar on new construction or as a condition of receiving or retaining federal assistance.

LMI households could be allowed to size their PV systems to accommodate contemporaneous or future electrification of their homes, appliances, and (if applicable) vehicles, rather than being limited by historical use. Co-marketing would help enable more one-time installations of solar along with other technologies.

Ensuring the success of these reforms may require program harmonization across the local, state, and federal levels, because oftentimes solar policies can be piecemeal, inconsistent over time, and not well integrated with other programs and incentives. In addition, energy programs for LMI households often are siloed in separate agencies, resulting in inefficiencies and lack of holistic energy offerings that would include solar and other solutions as a package. For example, tighter coordination of solar incentives and policies with energy assistance programs, home and vehicle electrification efforts, and disaster planning and mitigation may be helpful.

Resilience
Pairing solar with storage can help support LMI customer resilience. Communities considering deploying resilience projects could plan for infrastructure to support critical needs, not only facilities such as hospitals, but also facilities that serve LMI populations in cases of grid outages. The positive health and safety impact would be especially significant in areas, such as some Tribal communities, that do not presently have reliable access to electricity.

As noted above, research has shown that LMI households and communities suffer disproportionately from disasters, yet many disaster mitigation and recovery programs may fail to help the most vulnerable people get back on their feet (Jerolleman 2019). Many LMI households do not qualify for disaster loans, and they are especially affected by funding delays or shortfalls. Ensuring that LMI households receive effective assistance that includes solar can help LMI communities suffer less damage and recover more quickly and fully.

4.2 Distribution of Costs

4.2.1 Costs to Fund Federal and State Solar Programs

What do we know?	**What can be done?**
Billions of federal and state dollars have supported solar R&D and incentive programs. State clean energy mandates slightly increased electricity costs.	Local funding may drive more equitable distributions of costs. The costs of clean energy mandates can be mitigated through discounted electricity rates for LMI customers.

What Do We Know?

Federal expenditures for solar include several billion dollars for R&D and foregone tax revenue from the federal investment tax credit (Nemet 2019). States have spent several billion dollars on PV adoption incentives, with the California program alone spending about $3 billion on incentives. The distribution of R&D and most incentive costs depend on federal and state taxation and funding policies. Similarly, the question of whether these costs have been equitably distributed is fundamentally a question of whether public taxation and funding systems are equitable—a question that is outside the scope of this report.

Clean energy mandates are another key category of state solar programs. Clean energy mandates vary by state, but the most common model is known as a renewable portfolio standard, wherein load-serving entities are required to procure a minimum amount of renewable energy. Fifteen states require or incentivize a minimum amount of solar, specifically.[66] State renewable portfolio standards—including mandates for solar but also other renewable energy sources—have increased grid costs by around 3%, though the full value of that increase is not necessarily passed through to ratepayers (Barbose 2021). In the Decarb scenario, we project that power-system costs could increase by around 10% (see Chapter 2). However, owing to electrification, the net impacts on end-user energy costs are ambiguous. All else equal, an increase in retail electricity rates will disproportionately affect LMI households, who already dedicate larger shares of household income to energy expenses (Bednar and Reames 2020; Drehobl, Ross, and Ayala 2020).

What Can Be Done?

Federal and state solar programs are financed through federal and state funds; the equitable distribution of the costs of such programs depends on tax policy and is outside the scope of this report. However, one way to address potential equity concerns for publicly funded programs is to shift funding to a more local level. Local authorities such as towns, municipal utilities, and community choice aggregations can finance their own incentives and make decisions about how to distribute the costs of those programs at a local level. For instance, MCE, a community choice

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[66] According to the Database of State Incentives for Renewables & Efficiency, 22 states and Washington, DC have renewable portfolio standards with specific provisions for solar or distributed generation. Of those, 15 refer specifically to solar.

aggregation in California, provides solar rebates to income-qualifying customers. MCE finances the program through internal funds set aside for the purpose.

In terms of impacts of clean energy mandates on electricity costs, measures can be taken to mitigate the impacts on LMI ratepayers. Some states already require utilities to offer discounted electricity to income-qualifying households, as the California Alternate Rates for Energy (CARE). Rates such as CARE could be expanded to mitigate or offset the energy burden impacts of clean energy mandates.

4.2.2 Costs for Rate-Based Rooftop Solar Deployment

What do we know?	**What can be done?**
Utilities are required to charge rates that equitably distribute system costs. Solar deployment may affect cost distributions and has sparked an ongoing conversation about how to implement equitable rates in a future with high solar penetration.	Special solar rate structures can be created for LMI customers. Broad rate reforms can yield more equitable cost distributions. Procedural reforms could increase stakeholder participation in rate design.

What Do We Know?

Distributed PV adoption poses new challenges to electricity rate design. The crux of the question is how PV adopters can equitably and efficiently pay for grid electricity and be compensated for the output they deliver to the grid. In most major PV markets, the initial solution to the question of PV rate design was net metering, under which customers were compensated for exported PV output at the same rate they paid for purchased grid electricity. Under typical rate structures, net-metered customers pay less for electricity than the costs that those customers impose on the grid (Verdant 2021). As a result, net metering could drive electricity cost shifting between PV adopters and non-adopters (A. Brown and Bunyan 2014). While the magnitude of potential cost shifting is still disputed and is likely negligible for the foreseeable future (Barbose 2017), the threat of cost shifting has already affected rate design and public acceptance of rooftop solar (Welton and Eisen 2019). Several states and utilities have implemented rate reforms that significantly diminish the value proposition of solar adoption. Other states and utilities have implemented more modest reforms, such as value-of-solar tariffs that seek to address cost shifting (among other objectives) while retaining incentives for beneficial rooftop solar adoption (O'Shaughnessy and Ardani 2020).

The central role of equity in ratemaking means that rate structures should, in the long run, adjust to address any perceived inequitable distributions of costs. However, as argued by Baker (2021), rate adjustments do not necessarily redress historical inequities. Specifically, pivots away from net metering imply that future adopters will not receive the same bill savings benefits as previous adopters. Given that future adopters will be increasingly LMI households, whereas previous adopters were primarily high-income households, these rate reforms could solidify the inequitable distribution of the benefits of net metering.

What Can Be Done?

Rate structure-related equity issues can be broadly addressed through three pathways: (1) general rate reforms, (2) rate design for income-qualifying customers, and (3) rate design procedures. We discuss each of these pathways without evaluating tradeoffs between different approaches. Further research is required to identify optimal pathways for rate structure-related equity issues, particularly via general rate reform. Given that the vast majority of electricity customers are served by regulated utilities, we frame this discussion of the pathways around utility regulations. However, it is worth noting that the regulated utility model is likely to undergo significant changes in the coming decades and a growing number of customers may be served through alternative models such as community choice aggregation.

General Rate Reform

States and utilities have proposed and implemented various rate reforms in response to increasing penetrations of rooftop PV. Some of these rate reforms were designed, ostensibly, to address potential cost shifting. These rate reforms can be broadly grouped into four categories:

- *Net billing*: Under net billing (as opposed to net metering), PV adopters save the equivalent of the retail rate for each unit of demand directly met by the PV system, but PV grid exports are compensated at a separate rate. Different states and utilities have taken different approaches to determine this rate. One approach is commonly known as a value-of-solar tariff, which is designed to compensate rooftop PV output according to the value that output provides to the grid. Although structures vary, a common approach is the value "stack," where each component of the value of solar (e.g., energy, capacity, environmental) is separately calculated then "stacked" to estimate a bill credit for rooftop PV customers. In theory, an accurate value-of-solar rate prevents cost shifting by ensuring that rooftop PV customers pay for their share of grid costs.

- *Buy-all sell-all*: Under a buy-all sell-all agreement, PV customers buy all of their electricity from the grid at the grid retail rate and sell all of their PV system's output to the grid at a separate defined rate. The "buy all" component prevents cost shifting by ensuring that utilities can recoup all of their costs from rooftop PV customers. Similar to net billing, the sell-all rate can be set according to the value of solar.

- *Fixed charges/minimum bills*: Several states and utilities have proposed increasing fixed ($/month) charges while reducing volumetric ($/kWh) charges. Fixed charges prevent cost shifting by effectively guaranteeing that utilities can recoup their costs from customers. A variation is a minimum bill, which effectively establishes a cap on how much PV customers can save without forcing those customers to pay fixed charges. Fixed charges tend to be regressive with respect to income. To address this issue, fixed charges could be designed on a progressive scale, such that LMI households pay lower fixed charges in proportion to their income (Borenstein, Fowlie, and Sallee 2021).

- *Demand charges*: Several states and utilities have proposed increasing demand charges, which typically take the form of a fee ($/kW) based on a customer's energy use during peak demand periods. Some utilities and regulators argue that demand charges better align customer payments with their contribution to grid costs, thus preventing cost shifting.

There is still no consensus on how to design equitable and efficient rates in the context of increasing penetrations of rooftop PV (Rábago and Valova 2018). No single approach provides a perfect solution, and each approach poses new and unique challenges. An optimal approach may include elements of multiple pathways. For instance, value-of-solar tariffs could be structured as buy-all sell-all agreements and include both fixed and demand charges. An optimal balance of these different elements could ensure an equitable distribution of grid costs while also maintaining appropriate incentives for rooftop PV adoption. Further research and pilot rate implementation are required to understand the tradeoffs between different rate designs in terms of equity, efficiency, and appropriate incentives for rooftop PV adoption.

Rate Designs for Income-Qualifying Customers

Many states already require utilities to offer discounted rates to income-qualifying customers. Similar approaches could be taken in the context of rooftop PV adoption. Potential designs include the following:

- LMI households could remain eligible for net metering while all other households are shifted onto net billing or other alternative rates. Such an approach would have the added benefit of ensuring that LMI households receive the same financial benefits from PV adoption as early high-income adopters received.

- Value-of-solar "stacks" could include an additional credit for LMI households.

- Buy-all sell-all agreements could be structured with higher sell-all rates for LMI customers.

- LMI PV customers could be exempt from fixed charges, minimum bills, or demand charges.

Procedural Reform

One way to ensure more equitable rate structures is to ensure broader public participation in rate design, specifically by historically underrepresented groups such as LMI and communities of color (Baker 2021). Rate design procedures could be reformed to address barriers to participation, such as by compensating organizations that represent disadvantaged stakeholder groups. See further discussion of procedural justice in Section 4.3.

4.2.3 Negative Externalities

What do we know?	What can be done?
Solar manufacturing and end-of-life disposal could yield negative externalities that disproportionately affect LMI and communities of color. These potential externalities are trivial relative to the existing energy system.	Circular economy principles—repairing, reusing, recycling—as well as standards and certifications can mitigate negative externalities.

What Do We Know?

Like all energy technologies, solar generates negative externalities throughout its life cycle. We discuss these negative externalities in our effort to develop a comprehensive list of solar benefits and costs. However, the negative externalities of solar are trivial compared to the externalities of conventional energy technologies that solar displaces (Outka 2012; Carley and Konisky 2020). Most solar materials mining (primarily silicon) and parts manufacturing (modules, inverters) occur in countries with less rigorous environmental and labor standards than the United States (Curtis, Buchanan, Smith, and Heath 2021). Use-phase externalities include aesthetic impacts, land-use impacts from large-scale PV deployment, and wildlife losses from concentrating solar power (Outka 2012). Finally, end-of-life disposal of solar materials entails externalities common to the disposal of other toxic materials, such as the potential releases of toxic metals including cadmium and lead (Curtis, Buchanan, Smith, and Heath 2021). From a global energy justice perspective, the supply chain concerns of solar module manufacturing may pose the most significant challenge to achieving energy justice in solar deployment. From a domestic perspective, end-of-life disposal and the inequitable siting of landfills in LMI communities may pose the most significant challenge.

Some externalities may accrue from the siting of the large-scale grid infrastructure required for the *Solar Futures* vision. The implications of utility-scale solar siting patterns are not yet well understood. In some cases, utility-scale solar can provide extra revenue (e.g., through land leases) without affecting other land uses (e.g., certain types of agriculture). Nonetheless, utility-scale project development is already facing local opposition. The potential negative externalities of utility-scale solar projects include aesthetic impacts, impacts on property values surrounding the project, and the implications of committing land to a specified use over the project term, typically over 20 years.

A potentially significant indirect externality of solar and other remote clean energy sources such as wind are the externalities associated with large-scale transmission projects. The *Solar Futures Study*—like other deep-decarbonization studies—envisions substantial expansion of the nation's transmission infrastructure, in part to connect load centers to remote solar resources. Under the Decarb+E scenario interregional transmission expands by 90% (128 TW-miles) from 2020 to 2050. Transmission expansion is more limited without electrification; U.S. transmission capacity grows by 60% (86 TW-miles) over 30 years under the Decarb scenario. Transmission towers and lines generate negative externalities such as aesthetic impacts, local habitat destruction, wildlife impacts, noise, and radio interference (Sovacool and Dworkin 2014). That infrastructure must be sited over tens or hundreds of miles, raising the prospect of local opposition (Sovacool and Dworkin 2014; Carley et al. 2020). From an energy justice perspective, a key question is whether local opposition and local politics result in inequitable transmission siting. History would suggest that the priorities of relatively affluent communities will dominate the priorities of marginalized communities (Sovacool and Dworkin 2014), potentially resulting in an inequitable distribution of the costs of transmission network expansion.

What Can Be Done?

The negative externalities of solar can be mitigated through measures to promote circular economy in solar manufacturing, installation, and disposal. Circular economy is a framework that emphasizes long resource lifetimes, high performance, and the reuse and recovery of

products and materials (Heath et al. 2020; Curtis, Buchanan, Smith, and Heath 2021). Applied to solar, circular economy principles can prevent negative externalities by increasing repair, reuse, and recycling of PV modules (Curtis, Buchanan, Smith, and Heath 2021). Periodic repairs can extend solar system lifetimes beyond the conventional useful life of 20–30 years. Degraded solar panels can also be transferred and reused in applications compatible with lower system output. By extending useful lifetime, repair and reuse can delay the need for new resource extraction and manufacturing and delay end-of-life disposal. Certain solar system components and materials can be recycled, avoiding raw material extraction and disposal.

PV module repair, reuse, and recycling are rare in the United States, largely owing to cost barriers (Curtis, Buchanan, Smith, and Heath 2021). One option is to mandate PV module recycling, as is currently done in some European countries. One pathway is to require PV manufacturers to contractually agree to take back modules at the end of life, as required in Washington State. Policymakers could also incentivize recycling by prohibiting disposal or reducing the regulatory burdens currently associated with module recycling (Curtis, Buchanan, Smith, and Heath 2021). Such requirements could have knock-on environmental justice benefits by keeping PV materials out of landfills, which are disproportionately sited in LMI and communities of color. Measures to increase the circular economy of the U.S. solar industry are an area for further research (Heath et al. 2020; Curtis, Buchanan, Smith, and Heath 2021). See Chapter 8 for more information.

Standards and certifications offer another pathway to mitigate negative externalities in solar manufacturing, installation, and disposal. Policymakers could support the development of new standards, such as the American National Standards Institute's Sustainability Leadership Standard for Photovoltaic Modules and Inverters. The Standard certifies modules that meet criteria in several dimensions, including end-of-life management and corporate responsibility.

In terms of externalities from transmission expansions, measures to ensure equitable representation in transmission planning and siting are critical. Local opposition to transmission expansions is nearly inevitable. Policies could be implemented to ensure that opposition from well-resourced groups (e.g., affluent communities) does not override the concerns of under-resourced groups (e.g., LMI and communities of color). Such policies relate to a broader need for procedural justice in solar and energy system decision making, the topic of the following section.

4.3 Procedural Justice

What do we know?	**What can be done?**
The existing energy system is characterized by a lack of procedural justice.	Shift decision making to the community level and implement inclusive planning methods.

What Do We Know?

Procedural justice refers to a system of procedures, rules, and policies that ensure due process and representation in energy system decision making (Sovacool and Dworkin 2014). Based on this characteristic, the existing energy system can largely be defined by the absence of procedural justice (Sovacool and Dworkin 2014; Baker 2021). Communities generally have

limited input into decisions about which energy assets will be deployed in a given location. Where communities do intervene, politically powerful and well-resourced groups tend to override the concerns of LMI and communities of color (Sovacool and Dworkin 2014; Baker 2021). The lack of representation and unequal power of stakeholder groups may exacerbate environmental justice issues such as the inequitable siting of emitting facilities (Sovacool and Dworkin 2014). Procedural justice issues have been raised in relation to solar siting, particularly for potential projects near cultural artifacts and landscapes (Outka 2012).

What Can Be Done?

A key theme in procedural justice is ensuring that diverse interests are represented in decision making (Bidwell 2016). Engaging diverse stakeholders could ensure better outcomes and reduce the possibility of opposition resulting in project cancellations (Bidwell 2016). Baker (2021), among others, argues that existing energy decision-making frameworks exclude or mute these diverse interests. One barrier is the top-down model, in which most decision authority lies with state-level public utilities commissions and large regional electric utilities. Baker proposes inverting this model by shifting more decision-making authority to the customer and community level; several pathways could enhance procedural justice in electricity systems, including utility reform and embracing community-based procurement models such as community choice aggregation and community solar. Community-centered models may ensure broader representation of diverse interests, though Baker notes that not all community-centered models have been successful in doing so to date.

There are several approaches to advancing procedural justice in the energy decision-making process, many of which may begin by developing a community energy plan. For example, ongoing efforts by the U.S. Department of Energy (DOE) and NREL have focused on community energy planning and increasing stakeholder participation in the strategic energy planning process. Through development of an inclusive planning method and workshops held in collaboration with local organizations, DOE and NREL have worked to advance participatory energy planning processes at the local level. The method begins by identifying and convening stakeholders to understand the various interests across a community. Stakeholders are diverse and may include utilities, government entities, local businesses, nonprofit organizations, residents, and more. The method used by DOE and NREL is similar to other community energy planning approaches in that it focuses on devising a common energy vision that reflects the unique priorities of the community. Other example resources include the following:

- The American Planning Association developed a guide with strategies to engage community partners on solar development (APA 2012).

- The Clean Energy States Alliance developed a guide on community outreach and solar equity (Ramanan et al. 2021).

- The Low-Income Solar Policy Guide, a collaborative effort led by multiple non-profits, provides guidance on solar engagement (see lowincomesolar.org).

Ultimately, community energy plans can guide local energy development and be a useful resource for community representatives throughout various legal, regulatory, and political processes.

4.4 Just Transition Issues

The realities of climate change require a transition away from carbon-emitting energy sources and toward zero-carbon resources. Scholars and policymakers have increasingly recognized the adverse impacts that this transition will entail for thousands of individuals whose livelihoods directly or indirectly depend on the existing energy system (Carley and Konisky 2020). A "just transition" recognizes the economic adversities that specific communities may experience and manages the shift from a fossil-fuel-based system to a clean energy system (M. S. Henry, Bazilian, and Markuson 2020).

What do we know?	**What can be done?**
The clean energy transition will cause adversities in industries that depend on a fossil-fuel-based system. Solar could create thousands of jobs and new companies, but the existing solar industry is not representative in terms of race and gender.	Workforce development (e.g., retraining programs) and compensatory measures can mitigate the adversities experienced by displaced workers.

What Do We Know?

The clean energy transition will drive broad economic changes that create new jobs in clean energy industries (see Section 8.4) while displacing jobs in fossil fuel industries. Pollin and Callaci (2019) estimate that the transition will generate around 3 million new jobs while displacing thousands or a few tens of thousands of jobs in fossil fuel industries (after accounting for retirements).[67] However, a simple comparison of jobs created and jobs lost belies the hardships of the transition. Job losses are acutely stressful experiences at the personal, family, and community levels (Brand 2015). At the personal and family levels, job losses can cause lost wages, psychological distress, loss of social status, forced migration (i.e., moving to find new employment), and impacts on childhood wellbeing (Brand 2015; Carley and Konisky 2020; M. S. Henry, Bazilian, and Markuson 2020). At the community level, job losses can cause lost tax revenue, reduced social engagement, and reduced community wellbeing (Brand 2015; Carley and Konisky 2020; M. S. Henry, Bazilian, and Markuson 2020; Jolley et al. 2019). Given that fossil fuel facilities tend to cluster in specific areas, these community-level impacts will be acutely experienced by a small number of communities whose local economies currently depend on fossil fuels (Pollin and Callaci 2019).

What Can Be Done?

Just transitions ensure that adverse consequences are mitigated and that new economic opportunities are equitably distributed. We separately explore these two outcomes.

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[67] Pollin and Callaci estimate that a 60% reduction in coal industrial activity and a 40% reduction in oil and gas activity would displace 2,700 jobs after accounting for retirements. The *Solar Futures* vision requires a nearly 100% reduction in coal activity and much more aggressive reductions in oil and gas activity, suggesting that job displacement would be higher than the 2,700 point estimate. However, Pollin and Callaci still estimate job losses only on the order of tens of thousands even under more aggressive contractions in fossil fuel industrial activity.

A just transition for displaced industries

Workforce-development programs support transitions to new jobs and retraining of displaced workers (Carley and Konisky 2020). Such programs could help displaced workers find new employment in any sector. Given overlapping skills and the pace of growth in the clean energy industry, programs could be designed to prepare displaced fossil fuel workers for new careers in the clean energy industry. Displaced workers could be compensated for lost wages while attending training programs to develop new skills for the clean energy industry. Pollin and Callaci (2019) estimate that retraining the displaced workforce would cost around $55 million—based on the costs of supporting community college tuitions for displaced workers—a budget comparable to that of other federal retraining programs.

Compensatory measures refer to policies that directly mitigate economic harms of the clean energy transition. Pollin and Callaci (2019) estimate costs for three compensatory measures:

- *Compensation insurance*: Just-transition programs could provide compensation for displaced workers while they look for new jobs. Pollin and Callaci estimate that a program with 5-year compensation insurance would cost around $200 million/year throughout the clean energy transition.

- *Relocation costs*: Displaced workers may not be able to find new work near their current home. Just-transition programs could compensate displaced workers for costs incurred to relocate to new jobs. Pollin and Callaci estimate that a relocation program would cost around $27 million/year throughout the clean energy transition.

- *Pension guarantees*: Throughout the transition, certain fossil fuel companies may come under increasing financial distress, increasing the risk that companies default on their employee pension obligations (Pollin and Callaci 2019). The federal government has authority to enforce pension obligations through the Pensions Benefit Guaranty Corporation. That authority may be critical in ensuring that the transition does not put fossil fuel industry retirees at risk of losing retirement benefits.

In total, Pollin and Callaci estimate that a just-transition program with workforce-development and compensatory measures would cost around $12 billion over 20 years, or about 1.2% of the authors' estimated total budget needed to meet U.S. climate targets.

A just distribution of new economic opportunities

The clean energy transition will create thousands of new jobs and opportunities for entrepreneurship (see Section 8.4). Workforce development could be critical for achieving a more equitable clean energy workforce. Workforce development opportunities could be targeted at under-resourced communities. California apprenticeship programs provide a successful early example of this type of initiative. Apprenticeship programs are public-private partnerships that help apprentices prepare for careers in skilled labor, primarily construction. Participants in the California apprenticeship program are more racially diverse than the state's workforce (Luke et al. 2017). That diversity reflects, in part, active efforts by California unions and other stakeholders to increase diversity in the construction workforce. Similar measures could be taken to ensure that members of under-resourced communities benefit from clean energy economic opportunities.

Measures could also be taken to ensure that the new workforce operates under fair standards. In a working paper, Mayfield and Jenkins (2021) explore the implications of encouraging "high road" labor practices in the clean energy industry. High-road labor practices include measures that promote fair pay, equitable hiring, local hiring, and workforce development. Policymakers could implement tax credits, workforce-development funding, and other measures to incentivize employers to implement high-road labor practices. The authors find that implementing high-road labor requirements would have modest impacts on solar and other clean energy costs and similarly modest impacts on the long-term decarbonization trajectory.

Further, PV installation presents unique opportunities for entrepreneurship. In contrast to other energy generation industries, PV installation can be conducted on very small scales. The vast majority of PV installers in the United States install fewer than a dozen systems per year, often as a side business for other services such as electrical work and roofing. Entrepreneurship programs could help train members of under-resourced communities in the skills required to start and run small PV installation businesses. Historically, PV installation businesses tend to be headquartered in relatively affluent areas (O'Shaughnessy et al. 2021)—consistent with patterns in other industries. Targeted entrepreneurship training and subsidies for siting businesses in under-resourced communities could break that pattern and drive more small PV businesses into those communities.

4.5 Solar and the Justice40 Vision

The Biden Administration issued an executive order requiring that 40% of the benefits of certain federal climate investments flow to disadvantaged communities,[68] commonly known as the Justice40 order. Prompted by that order, the White House Environmental Justice Advisory Council (WHEJAC) issued a series of recommendations that more clearly define the Justice40 vision (WHEJAC 2021). The Justice40 vision comprises structural changes throughout the U.S. economy, including in energy, industry, agriculture, health, and education. The WHEJAC makes several specific recommendations with respect to solar:

- Offer grants to incentivize community solar projects with discounted subscriptions for low-income households.
- Establish a green bank to provide low-interest loans for rooftop and community solar, with at least 40% of funds dedicated to under-resourced communities.
- Perform research to identify key barriers to solar access in federal housing.
- Ensure that 40% of DOE incentives and programs funds support clean energy development in under-resourced communities.
- Prioritize emergency federal funds for rooftop solar and distributed battery storage.
- Revise the federal investment tax credit to clarify that tax-exempt entities are eligible for direct cash grants.

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[68] Justice40 generally uses the term "disadvantaged communities." The White House Environmental Justice Advisory Council (2021) makes various recommendations for criteria for disadvantaged communities, including communities with majority minority populations, high rates of health disparities, and non-attainment of clean air and water standards. We continue to use the term "under-resourced" to be consistent with the rest of this chapter.

- Support clean energy workforce initiatives, such as the development of Green Worker Cooperatives to help clean energy workers own and develop their own businesses and associations.

The Justice40 vision focuses on community-driven approaches to clean energy development. The WHEJAC refines that vision, stating that all federal investments should incorporate community-driven and controlled approaches. The WHEJAC calls for a dedicated role for community-based organizations that provides "a direct line of responsibility and accountability" and effective veto power over federally supported clean energy projects.

The Justice40 initiative is a working project with many unresolved questions. One key unresolved question affecting the role of solar is what constitutes a "benefit" and how benefits are directed specifically to disadvantaged communities. The WHEJAC proposes definitions of benefits at several levels. Table 4 - 1 defines these levels and explores how solar can play a role at each level.

Table 4 - 1. Justice40 Benefit Levels and Roles of Solar

Benefit Level	Definition	Roles of Solar
People	Specific members of under-resourced communities	Rooftop and community solar can be prioritized for specific households.
Geography	Frontline geographies (e.g., Census tracts)	Solar project development can be targeted to specific areas.
Community	Communities and community organizations	Community groups can be prioritized for solar project development.
External direct investment	Investments outside of under-resourced communities that directly benefit these communities	Solar projects yield broad benefits that benefit all communities regardless of where projects are sited, such as air-quality benefits and climate change mitigation benefits.

Further research is required to understand the optimal roles for solar at each of the levels defined in Table 4 - 1. A key question is how solar will be considered at the level of "external direct investment": investments made outside of under-resourced communities that "provide essential services to environmental justice such as water, energy, and sanitation." Solar, deployed anywhere, yields broad benefits that will benefit under-resourced communities, such as air-quality improvements and climate change mitigation. As a result, achieving the Justice40 vision in solar may not be as simple as steering 40% of solar investments into under-resourced communities. Further research is required to understand tradeoffs between large external investments and targeted, localized investments in under-resourced communities.

4.6 Conclusions and Areas for Future Research

Because of a variety of societal issues stemming from a long history of income and racial inequality, LMI and communities of color have been disproportionately harmed by the modern energy system reliant on carbon-emitting fossil fuels. The clean energy transition presents

opportunities to mitigate energy justice issues. In particular, replacing emitting generators with zero-carbon power sources such as solar could restore local air quality in affected communities and mitigate upstream environmental justice issues associated with materials extraction. However, the literature has identified one area in which the benefits of solar have not been equitably distributed: the private benefits of distributed solar adoption. LMI and communities of color have received a disproportionately small share of the private benefits of distributed PV. There are approaches that may help ensure a more equitable distribution of the benefits of the energy transition and that the energy system evolves justly and equitably. We explore measures to help address the distribution of public and private benefits, the distribution of costs, potential negative externalities, procedural justice, and the need for a just transition. These measures can be broadly summarized as follows:

- **Public benefits**: Provide state, local, and federal government incentives and policy interventions to target public benefits in under-resourced communities.

- **Private benefits**: Provide financial incentives, community engagement, siting, policy and regulatory measures, and resilience measures aimed at increasing PV adoption in under-resourced communities.

- **Distribution of costs**: Shift funding to the local level for publicly funded programs, mitigate the electricity cost impacts of clean energy mandates on LMI ratepayers, and reform electricity rates and procedures.

- **Negative externalities**: Promote circular economy in solar manufacturing, installation, and disposal.

- **Procedural justice**: Increase community representation in energy planning processes and decisions to ensure local energy development reflects unique and varied community priorities.

- **Just transition:** Provide workforce development and compensation for those negatively impacted by the energy transition.

We conclude this section by reiterating that research is lacking in this space. The emerging energy justice literature has produced a wealth of empirical data on the inequitable distribution of the costs and benefits of the *existing* system, but much remains unknown about the energy justice implications of the transition to a *new* system. Much more research is needed to identify effective restorative measures, maximize the benefits of the transition, and mitigate potential future harms. In addition, further research to understand and account for the intangible costs and benefits that cannot be readily quantified (e.g., the value of community empowerment) is needed to inform future policy and other proposals aimed at addressing energy justice challenges. Potential areas for future research include the following:

- Modeling on pathways to directly address equity.

- Identification and characterization of traditional vs. nontraditional costs/benefits of solar to derive consistent accounting methods for traditional and nontraditional costs/benefits.

- Methods to distribute costs and benefits from the clean energy transition across demographic groups. In particular, further research is required to disaggregate broad public benefits such as air-quality improvements and climate change mitigation.

- Research on targeted solar interventions that could yield immediate, localized impacts in environmental justice communities.

- Methods to baseline and track outcomes of measures aimed at increasing procedural justice and ensuring a just energy transition.

- Deep-dive analysis of potential job growth and job creation across the solar value chain and potential differences based on various demographic indicators (e.g., income, race, education level).

5

Synergies Between Solar and Storage

5 Synergies Between Solar and Storage

Energy storage is key to enabling large-scale solar deployment. The core *Solar Futures* scenarios deploy hundreds of gigawatts (GW) of storage capacity. Compared to a 2019 installed base of about 24 GW, mostly in the form of pumped storage hydropower (PSH) (EIA 2020b), adding hundreds of GW of new storage would enable a significant shift in how the nation's electric grid is operated. This chapter focuses primarily on the role of diurnal energy storage (storage with capacity of 12 hours or less) in the core scenarios and how this role changes with increased solar and storage deployment.

As shown in Figure 5 - 1, about 23 GW of PSH have been deployed in the United States, mostly before 1990 to provide peaking capacity in an era of higher-cost peaking generation and to time-shift energy from less flexible resources (EIA 2020b; Denholm et al. 2010). A combination of factors, including lower natural gas prices and availability of easily sited and constructed gas peaking plants, resulted in a two-decade hiatus of significant storage deployment from roughly 1990 to 2010 (Denholm, Cole, et al. 2021). Since 2010, several factors have revived interest in storage.
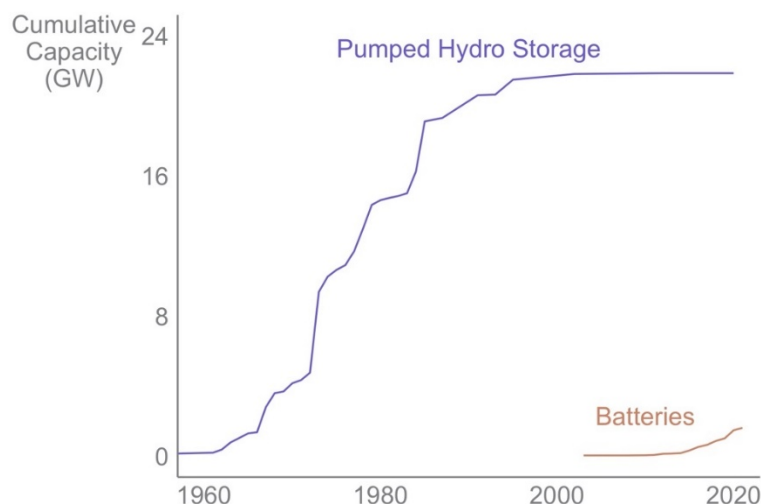
Figure 5 - 1. Cumulative electricity storage deployment, 1960–2020

The figure does not include plants that were not operational at the beginning of 2021, nor does it include the 110-MW compressed air energy storage facility, concentrating solar power (CSP) with thermal energy storage, or flywheels. Data from (EIA 2020d).

One factor was the creation of wholesale market products enabling cost-competitive short-duration storage. A key opportunity associated with introducing wholesale electricity was creation of regulating-reserves markets paying for capacity that can rapidly vary output in response to random variations in supply and demand (Denholm, Sun, and Mai 2019; FERC 2020). Storage has several attributes enabling cost-competitive provision of regulating reserves

(sometimes referred to as frequency regulation).[69] Most storage technologies respond more quickly than traditional thermal power plants.[70] Storage also has an advantage over thermal generators that must be synchronized to the grid (spinning) and operating at partial output to provide operating reserves, which reduces their efficiency (Hummon et al. 2013). In addition, regulating reserves require a relatively short response duration, so lower-cost, short-duration storage can provide this service. In many regions, this may be as short as 15–30 minutes (EPRI 2016). These attributes created a cost-effective entry point for storage and allowed technologies with lower power-related costs (but higher energy-related costs), such as flywheels, to be competitive.[71]

The declining costs of lithium-ion (Li-ion) batteries also contributed to renewed interest in storage. Creation of wholesale markets for regulating reserves occurred at roughly the same time as initial deployments of electric vehicles (EVs), significant increases in Li-ion battery manufacturing capacity, and lower battery costs.

Finally, interest has grown in using storage to improve grid reliability and solar and wind integration, and several regions have implemented storage mandates and incentive programs. These policies have encouraged utilities to explore storage for applications requiring longer duration, such as providing firm capacity and local transmission and distribution benefits. All these factors have resulted in new U.S. storage deployments (Figure 5 - 1) (DOE and EIA, n.d.).

Although the cumulative U.S. stationary battery capacity remains relatively small, deployments to date have improved utilities' understanding of battery capabilities, increased the number of battery suppliers, and enabled cost reductions for the balance of system including the power electronics. With the help of continued EV-related reductions in Li-ion battery costs, the stage is set for rapid growth of storage as a cost-competitive alternative to new peaking capacity and other conventional resources (DOE and EIA, n.d.; BNEF 2019).

5.1 Storage in the *Solar Futures* Visions

The *Solar Futures* scenarios project significant growth of storage due to declining costs and storage's ability to provide multiple services (Figure 5 - 2).[72] The scenarios show a large range of deployments, but even the more conservative scenarios result in hundreds of GW of storage capacity. This section details the trends related to deployment of diurnal storage, including the drivers and limits of storage deployment before 2028, accelerated storage deployment in the late 2020s, the limits of diurnal storage, and the transition to longer-duration diurnal storage. The potential role of multiday to seasonal storage is discussed in Section 5.1.5.

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[69] Regulating reserves are sometimes referred to as "frequency regulation," but the North American Electric Reliability Corporation defines frequency regulation to include both governor response (frequency response) and the service described in this section (NERC 2017b). To avoid potential confusion, we use the term regulating reserves.

[70] Regulating-reserve prices may vary based on the speed and accuracy of a plant following a regulation signal; for example, PJM has two regulating-reserves markets separated by speed of response (Denholm, Sun, and Mai 2019).

[71] The total requirement for regulating reserves in the United States is small compared to other services, so opportunities are inherently limited.

[72] See Appendix 5-A for additional methodological details on storage modeling in the scenarios.
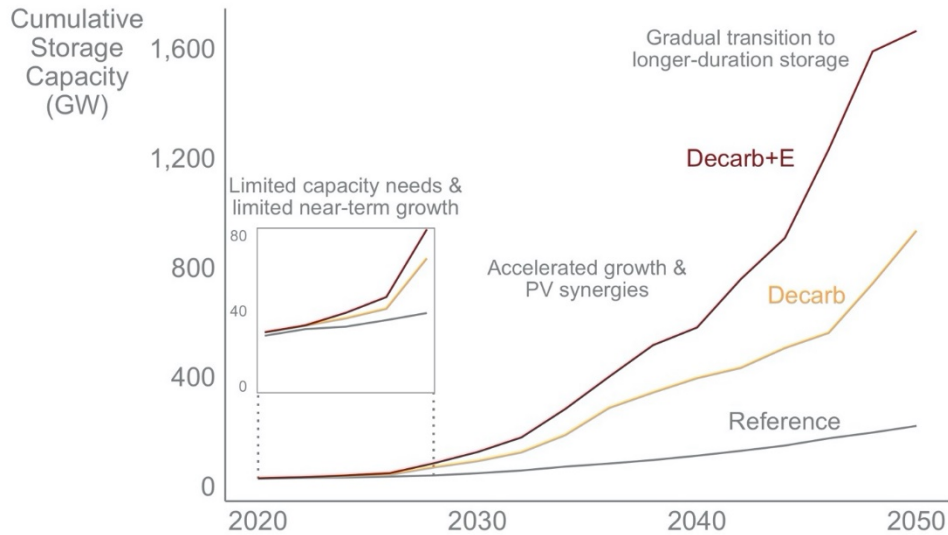
Figure 5 - 2. Total storage deployment by *Solar Futures* scenario

5.1.1 Drivers and Limits of Storage Deployment Before 2028

During the period 2020–2026, all three core scenarios show installation rates below 5 GW/year with limited growth relative to the remainder of the study period (see Figure 5 - 2). Although batteries are projected to be increasingly cost-competitive against conventional peaking capacity during this period, near-term growth is limited by the low need for new capacity. The U.S. power system currently has capacity that exceeds planning reserve margins in many regions (North American Electric Reliability Corporation 2020). There are some retirements due to plants reaching their design life, or policies such as air-quality and cooling-water regulations (Mills, Wiser, and Seel 2017). However, a significant amount of this capacity is being replaced by PV and other RE resources.

PV initially has a high capacity credit in much of the United States. Initial PV deployments can significantly reduce peak demand. However, as deployment increases, the net load peak shifts to periods of low solar output, and the PV capacity credit drops. This has already occurred in California, but limited PV deployment in many other U.S. regions has kept the PV capacity credit high. Chapter 3 discusses how the marginal capacity credit values from the *Solar Futures* scenarios change, with values around 50% on average before the drop in 2028 due to shifting of the net load peak.

Without the need for new capacity, storage is limited to energy time shifting, which has insufficient value in most cases to justify its costs (Frazier et al. 2021). Combined, these factors limit storage deployment before 2028. However in the following decades, an increasing fraction of existing generation capacity retires owing to age, including much of the 260 GW of dedicated peaking capacity (Denholm et al. 2019). A consistent theme of many RE transition studies is the challenge associated with competing against the variable costs of depreciated assets, particularly without aggressive decarbonization goals or other policies that incentivize early retirements of carbon-emitting fossil fuel assets.

5.1.2 Accelerated Storage Deployment in the Late 2020s

The storage growth rate generally increases in all scenarios after the late 2020s because of continued cost reductions, plant retirements (resulting in the need for new physical capacity), and increased synergies between PV and storage (Denholm et al. 2019). A major element of this synergy is the change in net load shape resulting from PV deployment, which increases storage's ability to contribute to meeting load during summer peak periods. Figure 5 - 3 illustrates this concept using simulated data for California for cases with 0% and 20% annual contribution of PV. PV changes the net load shape in a way that benefits storage. Assuming deployment of 10 GW of storage, in the 0% PV case, an average storage duration of about 7.2 hours is needed to reduce the net demand peak by 10 GW, meaning a total of 72 GWh of stored energy. In the 20% PV case, the required duration declines to about 3.9 hours (39 GWh), which would substantially reduce costs while providing an equivalent system capacity contribution.
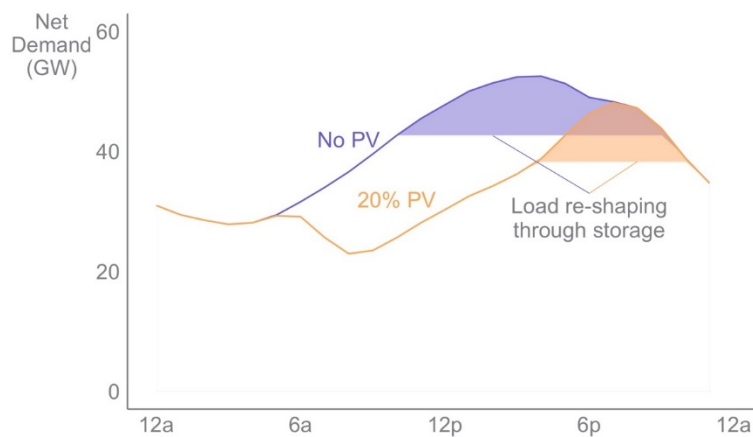
Figure 5 - 3. Change in net load shape from deploying PV with or without storage

The cost, required capacity, and PV-storage synergy trends accelerate storage growth in 2028 and beyond (Figure 5 - 4). Shorter-duration storage tends to be deployed in the scenarios, particularly before 2040. The incremental value of additional duration typically does not justify the additional costs, especially when shorter durations capture all of the capacity value and much of the energy time shifting value (Denholm, Cole, et al. 2021). However, changing net load patterns incentivize larger proportions of longer-duration storage starting around 2040 and particularly around 2050.
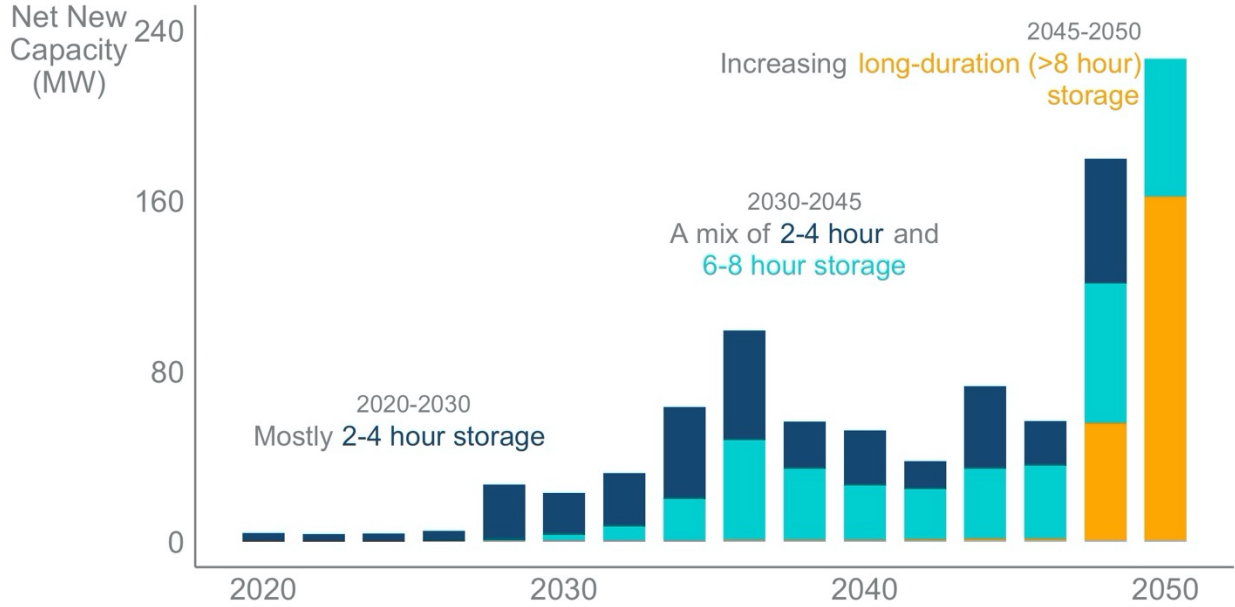
Figure 5 - 4. Storage by duration in the Decarb scenario

Shorter-duration storage is deployed for most of this period because the incremental value of additional duration typically does not justify the additional costs, especially when shorter durations capture all of the capacity value and much of the energy time shifting value. However, changing net load patterns incentivize larger proportions of longer-duration storage starting around 2040 and particularly around 2050 as full decarbonization is approached. Long-duration storage and RE-CTs help fill the firm capacity gap left by retiring fossil fuel generators.

The *Solar Futures* scenarios show that the post-2028 period is characterized in part by PV increasing the value of storage (increasing its ability to provide capacity) and storage increasing the value of PV (increasing its energy value by shifting its output to periods of greater demand). All scenarios demonstrate a correlation of deployments, as illustrated in Figure 5 - 5, which plots national PV and storage deployments for all years 2020–2050. In the Decarb+E scenario, which includes increased electrification and associated flexible demand, storage competes against other technologies to provide grid flexibility.
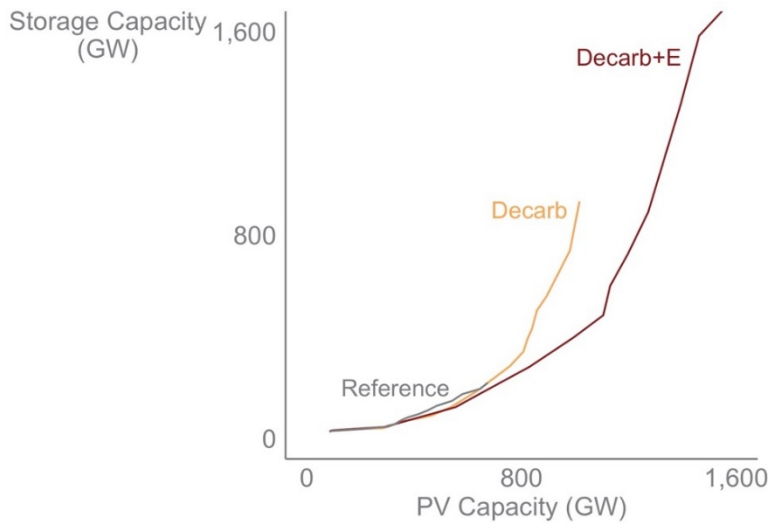
Figure 5 - 5. Overall relationship between storage and PV across *Solar Futures* scenarios and years

5.1.3 Limits of Diurnal Storage

As deployments of solar, wind, and diurnal storage increase, it becomes increasingly costly to meet the residual demand with these technologies—especially as the 95% emissions-free grid (in 2035) transitions to the 100% emissions-free grid (in 2050). The residual demand occurs increasingly during periods of low solar and wind output, meaning an increasing amount of capacity is required per unit of residual demand met. Most generation from these additions is unusable owing to saturation of demand during most of the year. As a result, the incremental utilization (capacity factor) of resources added to meet the residual demand drops.

Figure 5 - 6 and Figure 5 - 7 exemplify the challenge of meeting load with RE and diurnal storage during some periods of the year as the system approaches 100% RE in the Decarb scenario, using the 2050 results. Figure 5 - 6 (left) shows results from ERCOT during a period when the supply of RE is insufficient to meet demand. Figure 5 - 6 (right) shows results from the Florida Reliability Coordinating Council (FRCC) during a high net load period when the PV supply is insufficient to satisfy a large fraction of the demand, and other resources must be used. The energy limits in Figure 5 - 6 could be addressed in part by additional PV (or wind in the ERCOT scenario), because the supply of RE is not zero. However, this would come at considerable cost, because the system already has too much energy during much of the year.

Figure 5 - 7 shows the same scenarios, but during a spring week with lower demand and higher wind and solar output. Demand is saturated during this week, meaning no residual load must be met with non-RE resources. Much of the RE generation is curtailed because the storage is completely full during periods of overgeneration. In fact, there is no net load during the 31-day period from March 3 to April 4 in ERCOT, so additional PV or diurnal storage would have no value during this period.
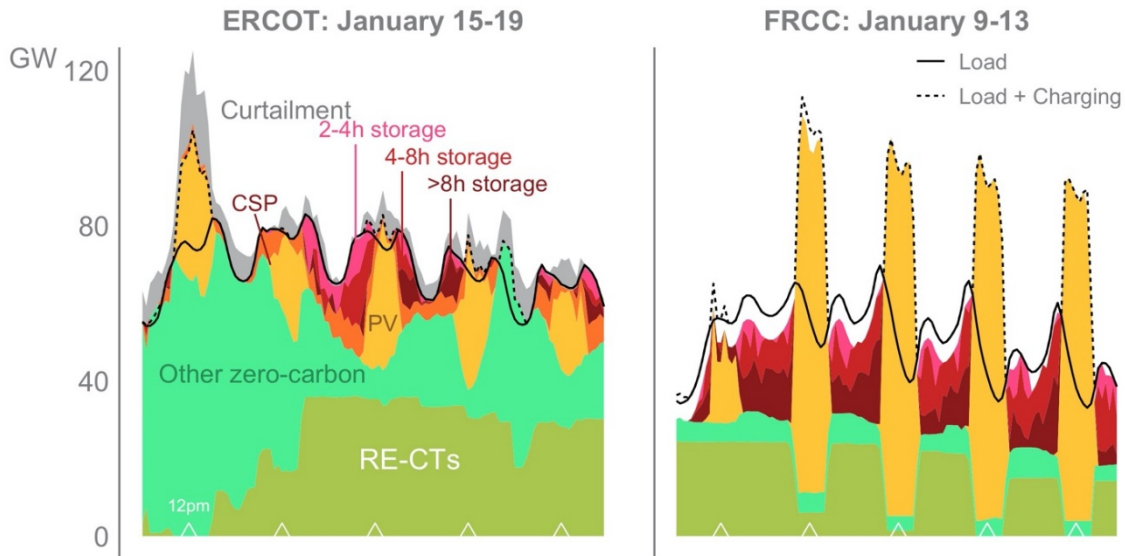
Figure 5 - 6. Use of RE-CTs for firm capacity during periods of peak net demand in 2050 in the Decarb scenario
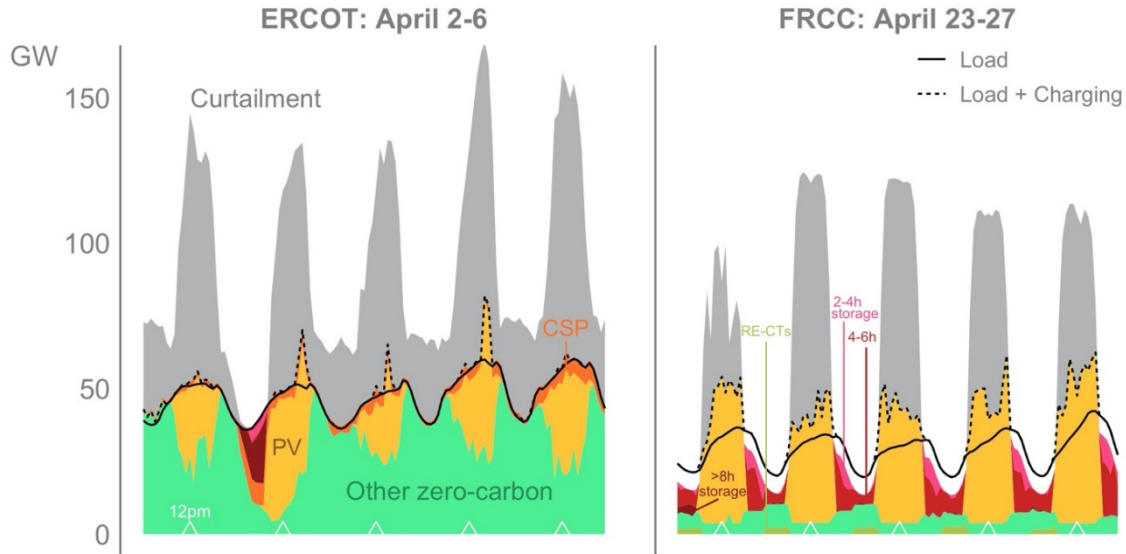
Figure 5 - 7. Spring period with oversupply in 2050 in the Decarb scenario

These patterns are characteristic of the economic limits of RE with diurnal storage that occur in scenarios with 80% or more RE contribution, suggesting opportunities for seasonal storage (Frazier et al. 2021). Seasonal storage could use otherwise-curtailed energy to meet residual demand.

5.1.4 Transition to Longer-Duration Diurnal Storage

As PV and storage deployments increase, the proportion of storage with 6, 8, and 10 hours of capacity increases owing to two factors. First, storage continues to widen the summer net load peak, even after accounting for the PV-driven peak narrowing. Second, the combined benefits of solar and storage tend to shift the net load peak to other seasons, including winter, which features longer peak periods.

Longer-duration peaks resulting from increased storage deployment result in lower realized value for shorter-duration storage (i.e., each increment of duration has a lower marginal value). However, growing net peak periods do not inherently require longer-duration storage. Storage with 6 hours or less of duration can still provide capacity, just with a reduced capacity credit that requires reduced cost to offset the lower value. Alternatively, reducing the energy component (duration) costs could enable deployment of longer-duration diurnal storage (8–12 hours) to continue providing full capacity, while further increasing the energy time shifting value.

The choice between shorter-duration storage with lower capacity credit or longer-duration storage with full capacity credit is driven by many factors, including the value of other services such as energy time shifting (Denholm, Cole, et al. 2021). For example, to reduce the net load by 100 MW when the peak net load period is 8 hours, 800 MWh of stored energy are needed. This could be achieved by adding a 100-MW device with 8 hours of capacity or adding a 133-MW device with 6 hours of capacity (which would operate at less than full power output to reduce the peak by 100 MW). Both options provide the same amount of stored energy. For the same technology and given that both plants have the same energy capacity, the 133-MW plant will almost certainly cost more than the 100-MW plant, because the higher power capacity of the

133-MW plant increases the costs of the inverters and other grid-interconnection equipment. The additional 33 MW of power-related costs provide no additional capacity-related value. However, this additional power capacity may provide additional energy-shifting opportunities; thus, depending on the value of energy shifting or other value streams, different configurations may be cost-effective. Emerging technologies that enable decoupling of storage duration and power capacity offer potential advantages over current battery technology (see Section 5.3).

Figure 5 - 8 illustrates how shorter-duration (higher-power) storage enables greater capture of curtailed energy and potentially higher energy-shifting value. The figure shows periods in the 2050 simulations in Electric Reliability Council of Texas (ERCOT) territory (Decarb scenario) with both significant curtailment and long net load peaks. Adding shorter-duration storage, with its higher power capacity per unit of energy stored, could absorb more curtailed energy. As a result, the higher power capacity is better aligned with the higher power associated with PV overgeneration events.

This result shows the tradeoff between power and energy for the two applications. For provision of peaking capacity, the long peaks result in energy limits, better suited for longer durations of storage. However, for energy shifting, particularly in high-PV scenarios, storage may be power limited. With a sufficiently high value of energy shifting, this could justify the additional power-related costs associated with the shorter-duration storage. As a result, shorter-duration storage may still be deployed to capture the high-power curtailment events in the high-PV scenario. In the *Solar Futures* scenarios, 2-, 4-, and 6-hour storage continue to be deployed, even when these durations do not receive full capacity credit. This is likely due to the ability of these durations to respond to periods of high overgeneration driven more by power than energy. However, there is an overall trend toward longer durations as storage widens periods of peak demand.
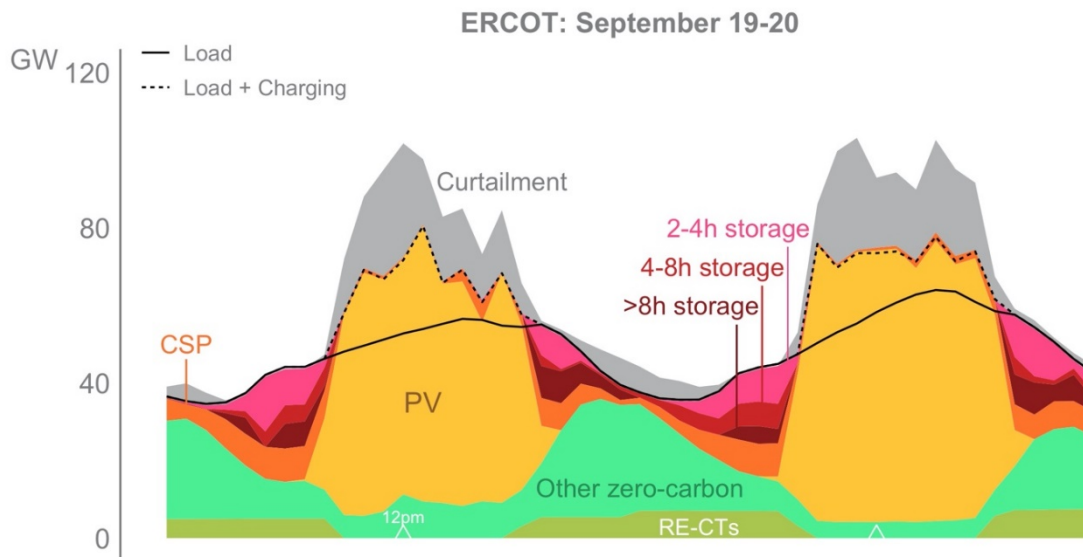
Figure 5 - 8. Residual curtailment in the Decarb scenario in ERCOT in 2050, showing the potential role of short-duration storage, even when net load periods are longer

Figure 5 - 9 shows the increase in system-wide average duration over time. This is the average duration of all (cumulative) storage deployed in each scenario, so the average duration of incremental storage is much higher, as shown in Figure 5 - 4.
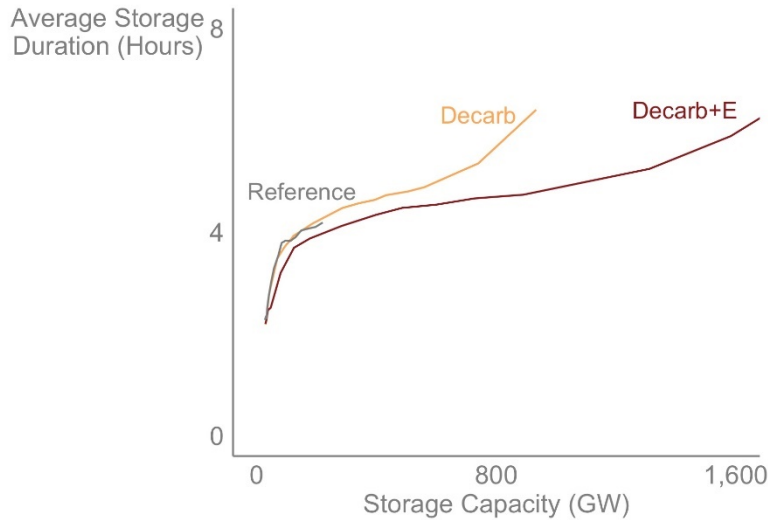
Figure 5 - 9. Average storage duration over time

5.1.5 Addressing Residual Demand and Options for Seasonal Storage

The residual demand after contributions from RE and diurnal storage is one of the most significant challenges to full decarbonization of the grid. In the *Solar Futures* scenarios, the residual demand is met by RE-CTs—essentially conventional gas turbines with modifications enabling them to burn liquid or gas fuels from renewable resources—with low utilization (capacity factors). The RE-CTs play a role similar to the role of conventional peaking capacity in the current system, which often runs with capacity factors below 10%.

Figure 5 - 10 illustrates several possible fuel pathways for renewably fueled peaking generators. The two main pathways are biomass and renewable hydrogen. Solid biomass (such as forest waste) and organic trash (such as paper) can be burned directly to produce steam. The *Solar Futures* scenarios do not consider further deployment of solid biomass fuels. The alternative pathway is production of liquid or gaseous fuels. This process includes biofuel refining, which can produce products such as ethanol or biodiesel. Another process results in biogas, typically produced by anaerobic decomposition of municipal solid waste in landfills or from livestock manure. Biogas is primarily methane. Both biofuels and biogas can then be combusted in a CT. Biofuels are limited by resource availability and competition for use in transportation. In addition, these fuels cannot be used as a form of seasonal electricity storage, to exploit RE oversupply. The second potential source of RE-derived fuels is based on renewable hydrogen, either used directly or converted into a fuel that is easier to store and transport.
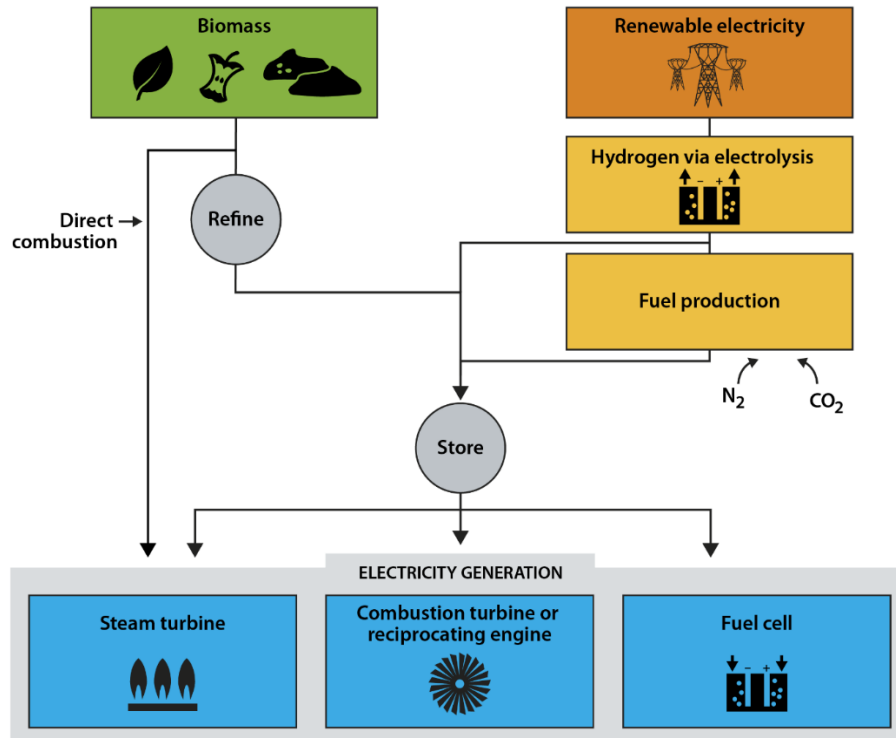
Figure 5 - 10. Possible fuel pathways

Gaseous fuel can be stored seasonally in underground formations, while liquid fuels can be stored underground or in large tanks similar to how petroleum products are stored. Stored fuels can be used to generate electricity via various technologies. Conventional steam turbines are not considered here. CTs are more efficient, already burn a variety of fossil fuels, and have demonstrated use of several renewably derived biofuels.

Required modifications to existing turbine technology vary by fuel type. Because biogas is primarily methane, it can be burned with little to no modifications of existing CTs. It can also be injected into the existing natural gas pipeline network if sufficiently processed to remove contaminants. Other biofuels, such as biodiesel, can also be burned in CTs with fairly minimal modifications. Overall, use of biofuels in RE-CTs presents modest technical challenges but is limited by fuel availability.

The ability to use hydrogen-based fuel in existing generation equipment varies by fuel type. Synthetic methane is chemically the same as natural gas, so it can be burned in conventional gas turbines without modification. Turbines that can burn natural gas/hydrogen blends are available but not yet widely deployed, particularly when burning a large fraction of hydrogen on an energy basis. Using 100% hydrogen in CTs has yet to be demonstrated at scale.

Other combustion-based pathways include reciprocating engines. A number of internal-combustion generators have been deployed, burning a variety of renewably derived fuels including biogas and hydrogen-based fuels.

Using RE-CTs or reciprocating engines in high-RE scenarios may provide several additional advantages. They can use existing infrastructure, especially if retrofits of existing CT and

combined-cycle plants are possible. They use synchronous generators that provide frequency-responsive services including physical inertia, and they can inject large amounts of fault current, which helps maintain system protection. These plants can provide these services even without operating by using clutches that enable the generator to act as a synchronous condenser, which is a relatively low-cost and proven capability of existing turbines. These capabilities can reduce concerns regarding overdependence on inverter-based resources.

Fuel cells, which convert chemical energy in a fuel to produce electricity (similar to a battery), are an alternative generation pathway. Fuel cells may use a number of renewably derived fuels (e.g., hydrogen) or a limited number of biofuels. Potential advantages include zero emissions and very little noise, which eases siting concerns. Although fuel cells are currently more expensive than combustion options, pathways exist to achieving costs below those of combustion plants.

Although the *Solar Futures* scenarios do not include detailed representation of specific technology pathways, the results indicate the need for capacity and fuel production. Figure 5 - 11 illustrates the total capacity needed to meet the residual demand not met by other RE resources. For context, the United States currently has about 400 GW of natural gas combined-cycle and simple-cycle gas turbine capacity (EIA 2020c).
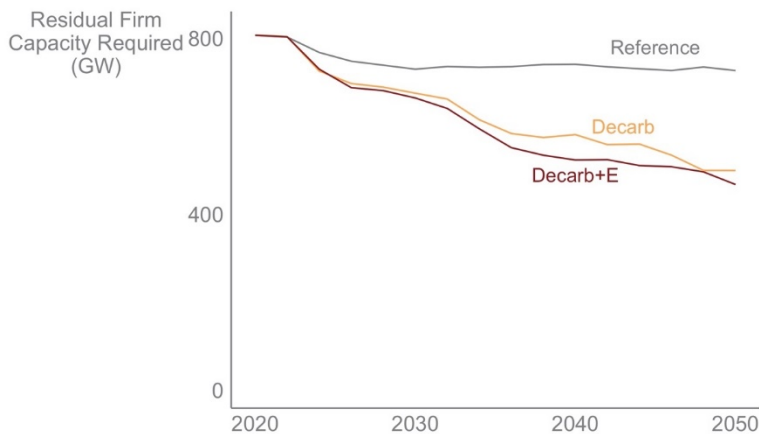
Figure 5 - 11. Residual capacity requirements in the *Solar Futures* scenarios

5.2 Solar-Based Fuels

In the *Solar Futures* vision, significant portions of the U.S. energy system still rely on the direct use of fuels, particularly in transportation and industry. The continued use of fuels reflects the challenges of electrifying certain end uses, as discussed in Chapter 7. Decarbonizing these fuel-based end uses is critical for achieving deep decarbonization.

Electrochemical fuel manufacturing provides a most promising pathway toward decarbonizing fuel-based end uses (Tuller 2017; De Luna et al. 2019; IEA 2019; Ruth et al. 2020). Through this process, zero-carbon electricity is used to manufacture synthetic carbon- or hydrogen-based fuels. Synthetic carbon-based fuels still release emissions when combusted. Carbon-based fuels can be electrochemically manufactured using "recycled" carbon captured from emitting facilities, which can significantly reduce though still not eliminate emissions at point of use (Tuller 2017). In the case of industry, recycled carbon-based fuels can be equipped with carbon capture to make such processes truly net zero. In contrast, hydrogen fuels need not emit carbon at

the point of combustion. Combustion of pure hydrogen, for instance, produces water vapor, although combustion in air can produce nitrogen oxides as well.

Electrochemical fuel manufacturing is currently a niche industry. Electrochemically manufactured fuels cannot currently compete with fossil fuels at scale to power fuel-based end uses such as building heating, transportation, and industrial processes. Scaling electrochemical fuel manufacturing will require significant cost reductions (Bataille et al. 2018; IEA 2019). Even under assumptions for aggressive cost reductions, Ruth et al. (2020) estimate that around 41 Mt of hydrogen fuels could be electrochemically manufactured by 2050, equating to only around 16% of fuel demand in those sectors in the Decarb+E scenario.

Solar, by providing an abundant, low-cost electricity source, can play a crucial role in scaling electrochemical fuel production (Rodriguez et al. 2014). Electrochemical production plants can be sited in solar-rich areas or co-located with solar to take advantage of low-cost electricity available during the day. In turn, by providing a steady source of demand, electrochemical production may drive better utilization of solar output and reduce curtailment. Similarly, electrochemical production might enable nuclear base load at times of high solar production. We do not model electrochemical production in our core scenarios. However, in Chapter 7 we explore the potential role of solar-based fuels in powering specific end uses.

In the longer term, solar energy technologies can be more directly integrated into fuel production. Solar absorbers can be integrated into devices used to split hydrogen out of water via photoelectrochemical water splitting (Tuller 2017). This process eliminates efficiency losses associated with the two-step process involved in conventional electrolysis: first generating electricity in a PV panel then delivering that electricity to a conventional electrolyzer. Combining both processes in a single device could yield more efficient and lower-cost solar-based fuels. Another option is using concentrated solar fluxes to heat active materials and drive thermochemical rather than electrochemical splitting of water to produce hydrogen (Tuller 2017). In this process, a metal oxide absorbs the solar heat, reaches a high temperature (1,000°–1,500°C), and, if properly designed, releases oxygen. When exposed to water, these reduced metal oxides recover oxygen from gaseous water (steam), leaving a mixture of hydrogen and steam, which must then be separated. The conversion efficiencies of thermochemical hydrogen production are, theoretically, much higher than those of photoelectrochemical hydrogen production. Finally, solar thermal heat could be used in high-temperature electrolysis, which increases efficiencies by up to 25%—compared with low-temperature electrolysis—by operating at temperatures above 600°C (Ruth et al. 2020; DOE 2021b). All of these processes have low technical maturity levels.

5.3 Opportunities for Storage Research and Development

The *Solar Futures* scenarios assume cost improvements for energy storage due to research, development, and deployment activities. This section describes R&D pathways that could contribute to declining costs, focusing primarily on those particularly compatible with activities potentially supported by DOE's Solar Energy Technologies Office (SETO), or via collaboration between SETO and other DOE offices.

5.3.1 Alternative Technology Pathways

Many energy storage technologies are in various stages of research, development, and commercialization. EV applications have been a major focus of storage development, and as EV technologies continue to evolve their use in stationary applications may accelerate. R&D could address how to optimize EV batteries for stationary applications. Conversely, EV and stationary battery technologies may diverge as longer-duration storage proliferates or the needs of stationary storage call for alternatives without the constraints of mobile applications. Specifically, factors such as weight or volume may be less critical in stationary applications, which could use lower-energy-density, lower-cost materials. For example, alternative battery chemistries, such as liquid electrolyte flow batteries, feature decoupled energy and power components and potentially low-cost electrolytes, which can reduce per-unit energy costs. Thermal, chemical, and mechanical storage technologies are under various stages of development, including pumped thermal storage, liquid air energy storage, novel gravity-based technologies, and geological hydrogen storage (Augustine and Blair 2021; Albertus, Manser, and Litzelman 2020). The DOE Energy Storage Grand Challenge has set aggressive storage cost goals, potentially exploiting technologies better suited for stationary applications (DOE 2021a).

As new storage technologies are developed, it may be increasingly important to examine decoupling of the charge and discharge components, particularly with increased PV deployment. Decoupling could help optimize the system to address high-power curtailment events (see Section 5.1.4) or integrate storage in hybrid systems as described in the next subsection.

5.3.2 PV Storage Integration

Synergies between PV and storage include shorter net load peaks and storage's ability to shift low-value PV generation to higher-value periods. Storage may be located where it provides the highest overall benefits, including supporting PV sited at a different location. However, as PV deployment increases, a larger fraction of energy stored will be generated from PV, further incentivizing co-location or hybridization. Systems coupled on the DC side of the inverter can incur lower losses and capture otherwise-clipped energy (Denholm, Margolis, and Eichman 2017). This also enables systems with higher DC-to-AC ratios, which could further lower interconnection costs and the overall cost of energy produced by the system.

PV-plus-storage systems, particularly those with DC-coupled architectures, are still in early stages of deployment, so the lowest-cost system architectures are not well understood. Unknowns include the optimal DC-to-AC ratio and storage system configuration, including input and output power and overall duration. Differences in input and output power could reduce the cost of mitigating short-duration curtailment events followed by longer periods of zero solar output. Furthermore, the current interest in co-located and hybrid PV-plus-storage power plants demonstrates that the industry may see value propositions that are not fully reflected in system-wide modeling results. R&D and demonstration projects could help identify optimal configurations and explore whether those configurations may vary as a function of solar resource quality or regional grid mix.

5.3.3 Integration of PV with Storage, Wind, and Transmission

New transmission development is important for increased solar energy use. Benefits include enabling regions with lower solar resources or limited land availability to access higher-quality

sites that are easier to develop. It is also important to deliver solar energy into urban areas with limited land area. The highest-quality U.S. solar resources (and those with the lowest competition for alternative uses) are often in relatively remote locations that may require new long-distance transmission lines to high-population load centers.

A challenge with transmission development for solar is the relatively low utilization of transmission, limited by solar's capacity factor, which increases costs per unit of energy delivered. Storage can increase transmission utilization, similar to how higher DC-to-AC ratios can increase utilization of a shared inverter or interconnection. Thus, storage can offer a partial alternative to transmission upgrades (Jorgenson, Mai, and Brinkman 2017).

This transmission challenge is potentially greater for wind energy, and further analysis is needed to explore how remote solar resources can be used in conjunction with wind, and potentially shared storage. In some regions, such as West Texas, locations with high-quality wind and solar resources could greatly increase transmission line utilization. Because wind generation is often anticorrelated with load and solar on a diurnal basis, storage can be used to increase transmission utilization (increasing the amount of energy delivered per unit of transmission capacity) while providing system capacity and time shifting (Denholm and Mai 2019).[73] Even when solar and wind generators are not geographically coincident, there may be shared opportunities. For example, wind electricity from windy Wyoming could be delivered to southern California via new transmission, and solar electricity from sunny southern Utah and Nevada could share part of this transmission. Analysis of corridors that would enable shared wind, solar, and storage transmission could reveal larger regional benefits and the ability to reduce overall costs.

5.3.4   PV with Existing and Next-Generation Pumped Storage Hydro

PSH has the largest installed capacity among storage technologies, with about 23 GW in the United States and over 100 GW worldwide. DOE is pursuing R&D on next-generation PSH with reduced costs and improved performance (Huertas Hernando et al. 2016). This includes deployment of closed-loop PSH plants that reduce siting constraints and new pump/turbine systems that provide higher efficiency and faster response (O'Connor et al. 2016). Improving the efficiency and response time of existing PSH plants is also possible (O'Connor et al. 2016). In addition, DOE is exploring new mechanisms to reduce permitting times, particularly for new PSH systems that have little to no interaction with existing water systems or sensitive habitats.

New PSH could help integrate solar by providing cost-effective storage with longer duration. This becomes increasingly important as short-term peaking applications are saturated. New PSH in less ecologically sensitive regions could feature floating PV deployment with shared infrastructure and lower transmission losses, given the proximity of generation and storage.

5.3.5   Electrification and Flexible Demand

The *Solar Futures* scenarios envision a power system designed largely to vary electricity supply to match time-varying (but mostly inelastic) demand. This paradigm may be altered by new

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[73] Transmission deferral is one application that can be partially additive ("stacked") with other services, but careful analysis is required because this application inherently limits the flexibility of the storage device to charge and discharge independently of transmission constraints.

technologies, market mechanisms, and loads created by electrification. Flexible loads have always been part of the power system, with time-varying and demand-based rate structures and interruptible load programs applied largely to industrial customers, plus limited residential applications via water heater and heating, ventilation, and air conditioning (HVAC) load-control programs. Much greater load flexibility is possible with greater deployment of time-varying (including real-time) price tariffs, enabled by Internet-of-things appliances and communications. Some of the hundreds of GW of utility-scale electricity storage deployed in the *Solar Futures* scenarios might be replaced with load flexibility, which could include end-use electricity storage or thermal storage. Chapter 7 discusses flexible loads from buildings and EV charging. R&D on integrated systems could enable further PV deployment with improved and integrated forecasting of supply and demand at spatially disaggregated locations, minimizing flows on the transmission and distribution networks during periods of high PV supply or high "normal" electricity demand.

5.3.6   Soft Costs and Regulatory Barriers

Previous studies have demonstrated the role of reducing soft costs and regulatory barriers to deployment of solar energy and storage (Cook et al. 2018; Feldman et al. 2021). The ongoing challenges of value capture for energy storage, particularly when providing services at multiple locations on the power system, will require regulatory reform. While some of these activities are ongoing—such as modifications to market rules associated with Federal Energy Regulatory Commission orders 841 and 2222 (Chernyakhovskiy et al. 2021)—some challenges may be particularly difficult to address. These include capturing value on parts of the system that are operated by entirely different entities, such as providing benefits to both the distribution system and transmission system.

5.3.7   Solar-Based Fuels

The fundamental technologies exist for solar-based fuels, but significant cost reductions are required for these fuels to compete with fossil fuels to power building heating, transportation, and industry. Some research suggests that PV cost reductions are the most important factor in the long-term trajectory of solar-based fuels (Rodriguez et al. 2014). R&D on electrolysis components and processes could further reduce costs and increase the competitiveness of solar-based fuels. Further research could explore opportunities for photoelectrochemical and thermochemical production to yield more efficient solar-based fuels. An accompanying report (Badgett, Xi, and Ruth 2021) provides more discussion on R&D challenges and opportunities related to solar-based fuels.

6

Technology Advances for Increased Solar Deployment

6 Technology Advances for Increased Solar Deployment

This chapter focuses on the improvements to solar technologies needed to achieve the solar deployment envisioned in the *Solar Futures* scenarios. Much of this deployment will be in forms familiar today: large utility-scale power plants, commercial rooftop systems, and residential rooftop systems. However, falling costs, technology advances, and growing experience will open opportunities to deploy solar technology in configurations only seen in limited demonstrations today. Solar technology will appear everywhere when it is possible to cost-effectively deploy with agriculture, on buildings, on waterbodies, and combined with other parts of the built environment. These dual-use applications provide mutual benefits: farms can grow food and produce electricity on the same land, solar building materials do double duty, and PV on waterbodies reduces evaporation loss. In our vision of the solar future, solar technology is ubiquitous.

6.1 Photovoltaics

6.1.1 Background

Photovoltaic (PV) technology uses a solar cell to convert sunlight directly into electricity. At first, PV was deployed where there were few alternative sources of electricity, such as on spacecraft or in remote terrestrial locations. Cost reductions and efficiency improvements made it practical to supply the grid with PV electricity. Solar panels, also called PV modules, consist of multiple, interconnected solar cells in a weatherproof package (Figure 6 - 1). Additional equipment, primarily an inverter, collects direct current (DC) electricity from the modules, converts it to AC electricity, and feeds this energy to the grid. PV capacity is often expressed in watts DC (W_{DC}), because this reflects the physical size of the power plant. Watts AC (W_{AC}), used by all other generation technologies, refers to the size of the plant's connection to the grid. PV systems can be designed for residential, commercial, and utility-scale applications (Figure 6 - 2).
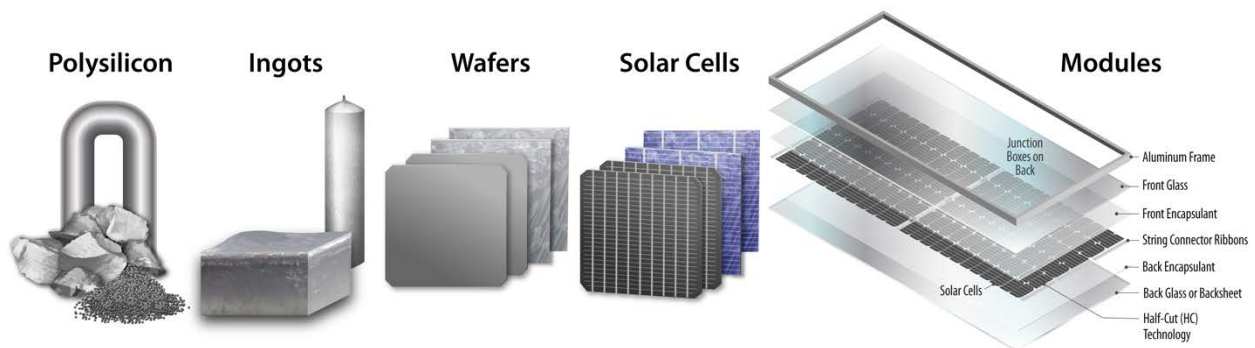
Figure 6 - 1. Main elements of a PV module, including a typical module design for 2020
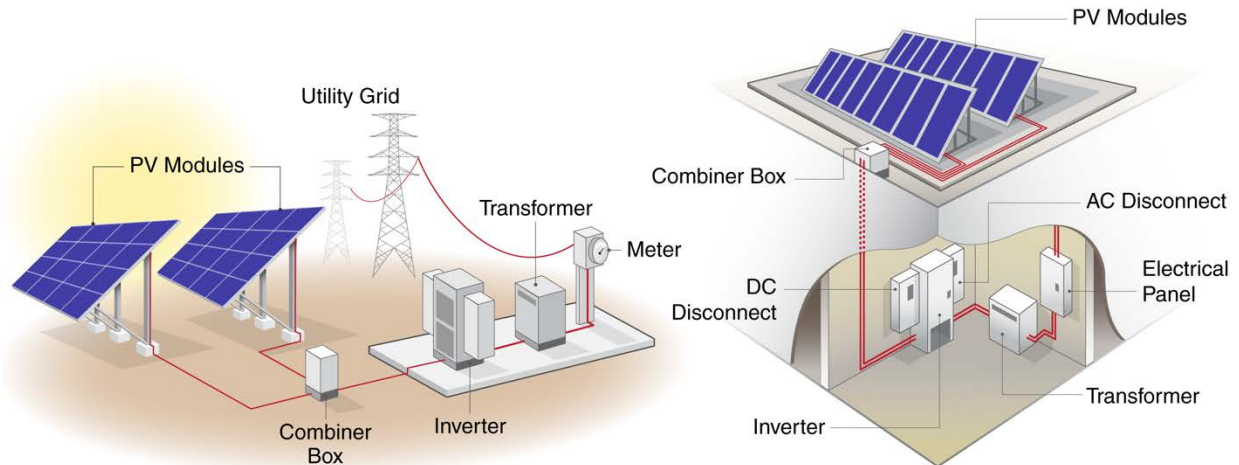
Figure 6 - 2. Illustrations of a utility-scale PV system (left) and a commercial rooftop system (right)

PV systems have been connected to the grid since the 1980s. Cumulative PV capacity in the United States reached 1 GW_{DC} in 2009 and 2 GW_{DC} in 2010 (SEIA/GTM 2016). In 2020 alone, 20 GW_{DC} were installed, bringing cumulative capacity to about 95 GW_{DC}. Although 80% of this capacity is in medium-sized commercial or large utility-scale PV (UPV) systems, 96% of the nation's 3 million PV systems are relatively small residential rooftop systems (SEIA/Wood Mackenzie 2021).

The cost of PV electricity is set by the upfront cost of a system, operations and maintenance (O&M) costs, the cost of capital,[74] the amount of energy the system produces, and the system's expected service life (NREL 2020). The times of day when the system can deliver energy also affect the decision between building PV and other types of power plants.

The unsubsidized upfront cost of a typical UPV system declined more than 80% between 2010 and 2020. In 2020, a typical UPV system cost about $1/$W_{DC}$. Higher efficiency and lower module cost were the primary reasons for these system cost declines (Feldman et al. 2021). Dramatic module cost reductions have resulted from technology improvements, global economies of scale, and learning by doing (Figure 6 - 3).

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[74] Cost of capital is the expected return to investors in a project. It is not to be confused with capital cost, which is another term for upfront cost.
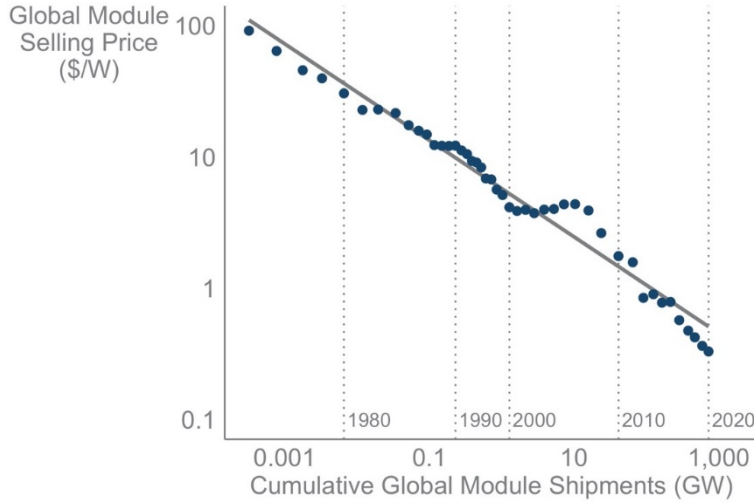
Figure 6 - 3. Global module average selling price vs. cumulative global module shipments

The gray line shows an experience curve fitted to the data points, indicating a 20.5% cost reduction for every doubling of cumulative shipments. Costs are shown in 2020 real U.S. dollars. Sources: (Strategies Unlimited 2003; Navigant Consulting 2006; 2010; Mints 2015; 2021).

About 94% of the global PV market in 2019 consisted of modules based on crystalline silicon (c-Si) (SPV Market Research 2020). In the United States, about 17% of the total PV market in 2020 was cadmium telluride (CdTe) technology, and the remaining 83% of the market was c-Si. Commercial and residential PV systems are virtually all c-Si (Barbose, Darghouth, et al. 2020). CdTe and c-Si are expected to remain the mainstream PV technology options in the near term.

6.1.2 Solar Futures *Scenario Assumptions*

In the *Solar Futures* scenarios, PV technology is deployed based on assumptions about cost and performance. These assumptions are summarized for the UPV example in Figure 6 - 4 and are documented in greater detail in NREL's Annual Technology Baseline (ATB). Costs fall to 50% of their 2020 values and capacity factor rises by about 15% by the early 2030s.
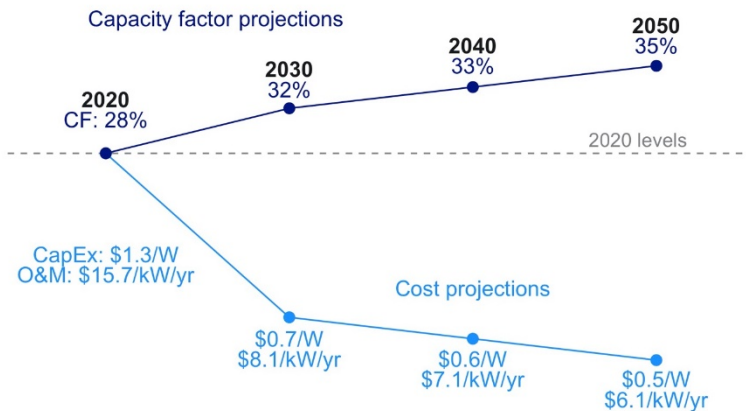
Figure 6 - 4. CapEx, O&M cost, and capacity factor for utility-scale PV based on 2020 ATB Advanced projections

Capacity factor increases come from improvements to module energy yield, tracking, bifacial energy production, reduced system losses, and reduced degradation (NREL 2020)

In 2021, the U.S. Department of Energy's (DOE's) Solar Energy Technologies Office (SETO) set a formal target for the LCOE of UPV to reach $20/MWh in 2030 (DOE SETO 2021). The Decarb and Decarb+E scenarios make assumptions consistent with achieving this target.[75] LCOE varies by location because it depends on the amount of solar resource available. The target is for Kansas City, which has an average solar resource for the United States. LCOE targets for commercial and residential PV systems are $40/MWh and $50/MWh, respectively (DOE SETO 2021).

The same LCOE target can be reached through multiple combinations of improvements to upfront cost, O&M cost, and energy output. Figure 6 - 5 shows multiple paths to the 2030 SETO target for utility-scale PV LCOE based on module cost, balance of system (BOS) cost, reliability characteristics, and energy yield.[76] The Decarb and Decarb+E scenarios use technology assumptions that result in an LCOE similar to this 2030 target. The module, BOS, and O&M costs are normalized to a system's nameplate power, so an increase in module efficiency decreases all three of these cost components.

Figure 6 - 5. Two example cases that achieve the 2030 target for utility-scale PV LCOE. Many possible technology trajectories can reach the same cost target.

The high-performance case uses module efficiency of 25%, module cost of $0.24/W, energy yield of 2,022 kWh$_{AC}$/kW$_{DC}$ year, service life of 50 years, annual degradation rate of 0.4%/year, 20% reduction of BOS cost compared to 2020, 35% reduction in initial O&M cost compared to 2020, and 2%/year O&M escalation rate. The low-cost case uses module efficiency of 20%, module cost of $0.168/W, energy yield of 1,916 kWh$_{AC}$/kW$_{DC}$ year, service life of 40 years, annual degradation rate of 0.5%/year, 30% reduction of BOS cost compared to 2020, 44% reduction in initial O&M cost compared to 2020, and 3%/year O&M escalation rate.

Upfront PV system cost includes hardware and soft (non-hardware) costs. PV modules, structural BOS, and electrical BOS are the components of hardware cost. Soft costs include installation labor; permitting, inspection, and interconnection (PII); customer acquisition; and overhead and

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[75] The scenarios use different assumptions than the ATB about capacity factor, losses, financing, incentives, and O&M. New operating cost categories were added to O&M in late 2020. The LCOE calculated for the ATB advanced scenario is even lower than the 2030 SETO target.

[76] Degradation effects are included in calculating energy yield and capacity factor, but system degradation is considered a second-order effect and is neglected in ReEDS capacity-expansion decisions and subsequent grid simulations.

profit. Figure 6 - 6 shows the main contributors to 2020 benchmark PV system capital cost (Feldman et al. 2021). Figure 6 - 7 shows the components of O&M cost for 2020 benchmark PV systems (Feldman et al. 2021). In this section, we focus on hardware costs. See Section 6.3 for a discussion of solar soft costs.
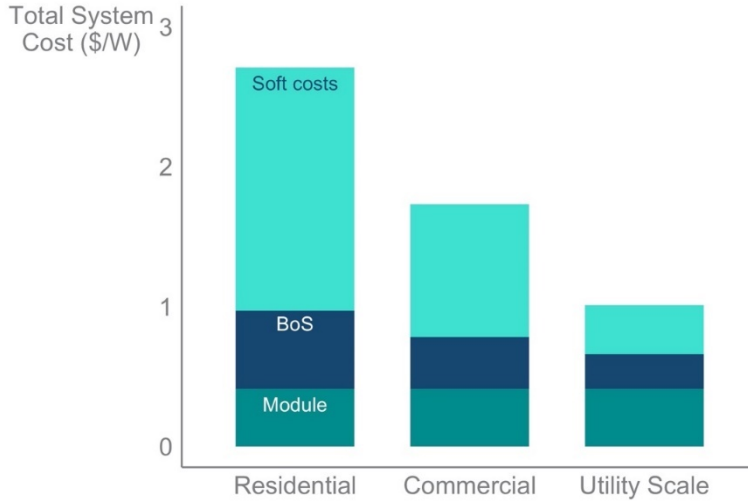
Figure 6 - 6. 2020 benchmark upfront system cost for the main PV market segments
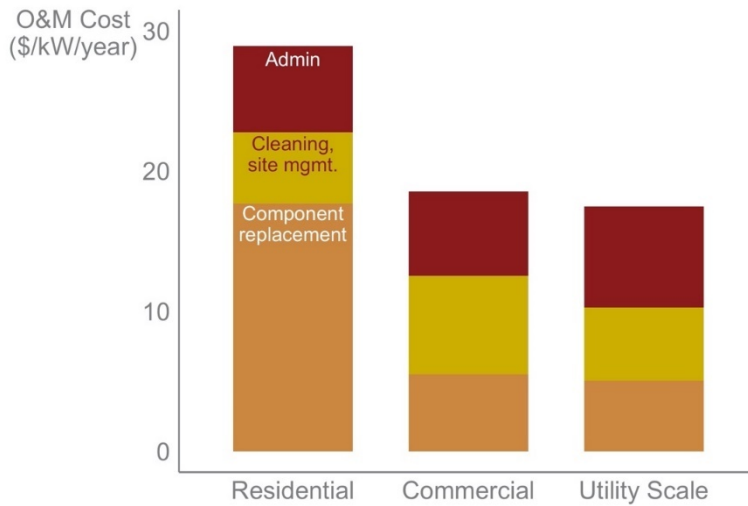
Figure 6 - 7. 2020 benchmark O&M costs for the main PV market segments

Costs are split between component replacement (module, inverter, and component part replacement), cleaning and site management (cleaning, vegetation management, pest management, system inspection, and monitoring), and administrative costs (land lease, property tax, insurance, asset management, security, and operations administration).

The following subsections explore ways for mainstream and emerging PV technology to achieve the improvements needed to realize the *Solar Futures* scenarios.

6.1.3   PV Improvements to Achieve the Solar Futures Scenarios

Cell and Module Technology

Efficiency

One of the most important areas of improvement for PV technology is efficiency. Efficiency is the ratio between a PV module's electrical power output and its solar power input. For a module of a certain size, higher efficiency means more power output under the same conditions. For a PV power plant, using higher-efficiency modules means using a smaller area to produce the same power. This reduces the amount of space and material a system uses, the labor required to perform the installation, and the costs associated with the land area the system occupies.

Modern c-Si PV is the culmination of many incremental improvements (Figure 6 - 8). Average commercial module efficiency has increased by approximately 2% each year since before 2010 (Feldman et al. 2021). Commercial c-Si products routinely exceed 21% efficiency in 2021. These improvements cannot continue indefinitely: the physical limit of efficiency for single-junction, non-concentrating c-Si solar cells is 29% (Figure 6 - 9) (Kerr, Campbell, and Cuevas 2002). However, because of its low-cost, mature supply chain and extensive manufacturing experience, c-Si is expected to play a major role in PV deployment for years to come—particularly if the gap between actual and maximum efficiency continues to close.

Multiple types of c-Si cell exist. The monocrystalline p-type passivated emitter and rear cell (PERC) type showed high efficiency in the laboratory in the 1980s. In 2019, after the right combination of mass-production technology and market conditions occurred, it became the dominant commercial solar cell type (Blakers 2019). Using PERC technology, minor changes in production equipment led to substantial increases in cell efficiency. PERC uses extra layers of material to reduce recombination, a cause of efficiency loss, and increase the effectiveness of light collection. Further improvements to PERC performance may push its efficiency to 24% in mass production (Min et al. 2017).

The mainstream successor to PERC technology has not yet been identified, but could be one of several c-Si cell types. Tunnel oxide passivated contact (TOPCon) cells use a different type of thin layer to reduce recombination beyond the PERC reduction, but they use much of the same production equipment. TOPCon is conventionally applied using n-type wafers, which are currently more expensive and difficult to produce than the p-type wafers on which PERC is based. However, portions of the TOPCon technology, or similar polycrystalline silicon on oxide (POLO) technology, can be implemented in p-type cells. High-efficiency alternatives to PERC and TOPCon/POLO include the interdigitated back contact (IBC) cell and the silicon heterojunction (SHJ) cell. These cell types have been commercially available for decades, but they have not reached market dominance. Both are based on n-type wafers and carry the associated cost premium. The passivation layers in SHJ cells have a temperature limitation that requires more expensive metallization paste.

		1980	2000	2010	2015	2018	2020
Relative Wafer Shape and Thickness		106 mm dia. / 500 μm / Cylinder	125 mm / 300 μm / Psuedo-square	156 mm / 180 μm / Full Square	156 mm / 180 μm / Full Square	156 mm / 160 μm / Pseudo-square	166 mm / 170 -180 μm / Half-cut Pseudo-square
Relative Ingot and Cell Size and Shape		106 mm / Cylinder	125 mm / Psuedo-square (cut from circle)	156 mm / Full Square	156 mm / Full Square	156 mm / Pseudo-square (less corner losses)	166 mm / Pseudo-square (less corner losses)
Module Format, Dimensions, Cell Count, and Power Rating / *Commercial Module Efficiencies* / Figure by Alfred Hicks and Michael Woodhouse, NREL		8 - 12% / 30 - 40 cells, 0.5 - 1.0 m² / 40 - 100 W	9 - 15% / 72 cells, 1.2 - 1.5 m² / 140 - 180 W	12 - 17% / 72 cells, 1.8 - 2.0 m² / 250 - 300 W	14 - 18% / 72 cells, 1.8 - 2.0 m² / 280 - 340 W	18 - 21% / 72 cells, 1.9 - 2.1 m² / 380 - 420 W	19 - 22% / 72 cells, 2.1 - 2.5 m² / 400 - 550 W

Figure 6 - 8. Changes to mainstream c-Si wafer, cell, and module technology over time
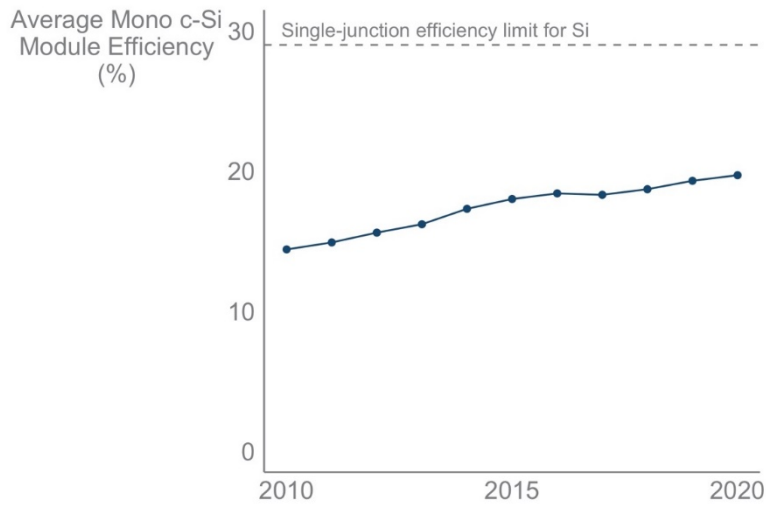
Figure 6 - 9. Steadily increasing average monocrystalline Si module efficiency in the California net energy metering program (CaliforniaDGStats 2021)

The plot shows the average of all 60- and 72-cell modules installed in the indicated year. Some less common modules with even higher efficiency have different numbers of cells. The red line shows the 29% physical limit of efficiency for single-junction c-Si in unconcentrated sunlight (Kerr, Campbell, and Cuevas 2002).

Commercial CdTe modules reached 19% efficiency in 2021. Efficiency improvements have resulted, and are expected to continue, from adjustments to the CdTe module's complex stack of materials and the processes for depositing and treating them. Mass-produced CdTe is a polycrystalline material, and many advances in CdTe technology deal with reducing losses that occur at the boundaries between crystal grains. This helps to close the gap between the CdTe cell's voltage and its maximum theoretical voltage, which is much higher than the voltage of a c-Si cell (Wilson et al. 2020).

Single-junction c-Si technology is approaching the physical limit of maximum efficiency (Figure 6 - 9), but researchers and manufacturers have long considered ways to surmount this limit. The limit is substantially higher for materials with a different bandgap energy compared to silicon. These materials include the mainstream CdTe, but also some III-V absorbers (named after the old labels for two columns of the periodic table of elements) and perovskite absorbers (named after a natural mineral for their shared crystal structure).

III-V solar cells are the most efficient ever made and have a long history of use on spacecraft. These cells are made from expensive materials using expensive processing, so they are rarely used on earth under unconcentrated sunlight. Perovskite solar cells may reach or exceed the efficiency of c-Si solar cells, because they can be made with a bandgap energy that accesses a higher efficiency limit (Wilson et al. 2020).

The efficiency limit for any simple, single-junction solar cell can be surmounted by stacking multiple solar cells on top of each other to form a tandem cell. Each subcell then collects a different part of the incident light so electricity is converted more efficiently (Figure 6 - 10). Tandems made of multiple III-V cells have long had world-record efficiency, but making large-area, low-cost tandem modules will require new designs, material combinations, and manufacturing techniques. Subcells in low-cost, large-area, high-efficiency tandems may include cell technology that is already in mainstream use (as in CdTe-Si tandems), they may be made entirely from emerging technology (as in perovskite-perovskite tandems), or they may be combinations of the two (as in perovskite-Si tandems) (Wilson et al. 2020). Figure 6 - 11 shows possibilities for future PV modules.

Single-Junction Cell

Double-Junction Cell
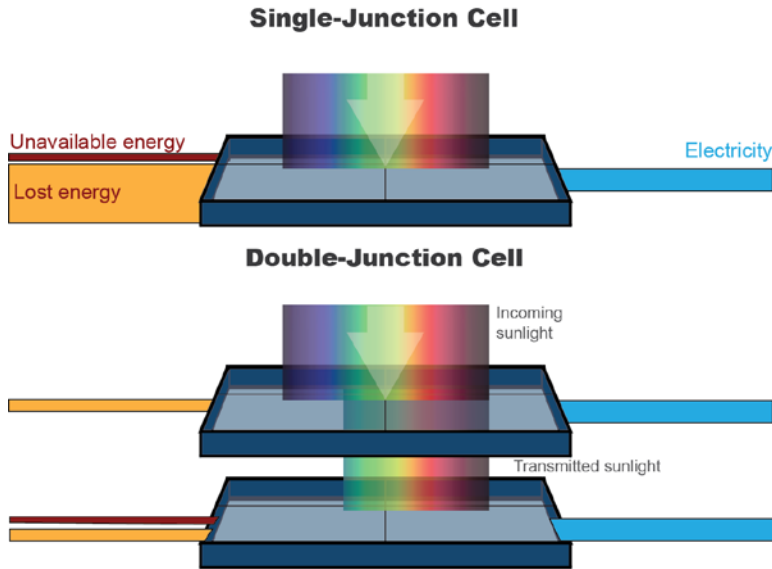
Figure 6 - 10. Single-junction cell with a single device converting sunlight to electricity (top) and tandem cell with some light passing through a top cell for conversion to electricity by a bottom cell (bottom)

Tandem cells can produce more electricity when they effectively minimize energy losses. Unavailable energy, which is impossible for the cell to convert to electricity because it is below the bandgap energy, is reduced in tandem cells.
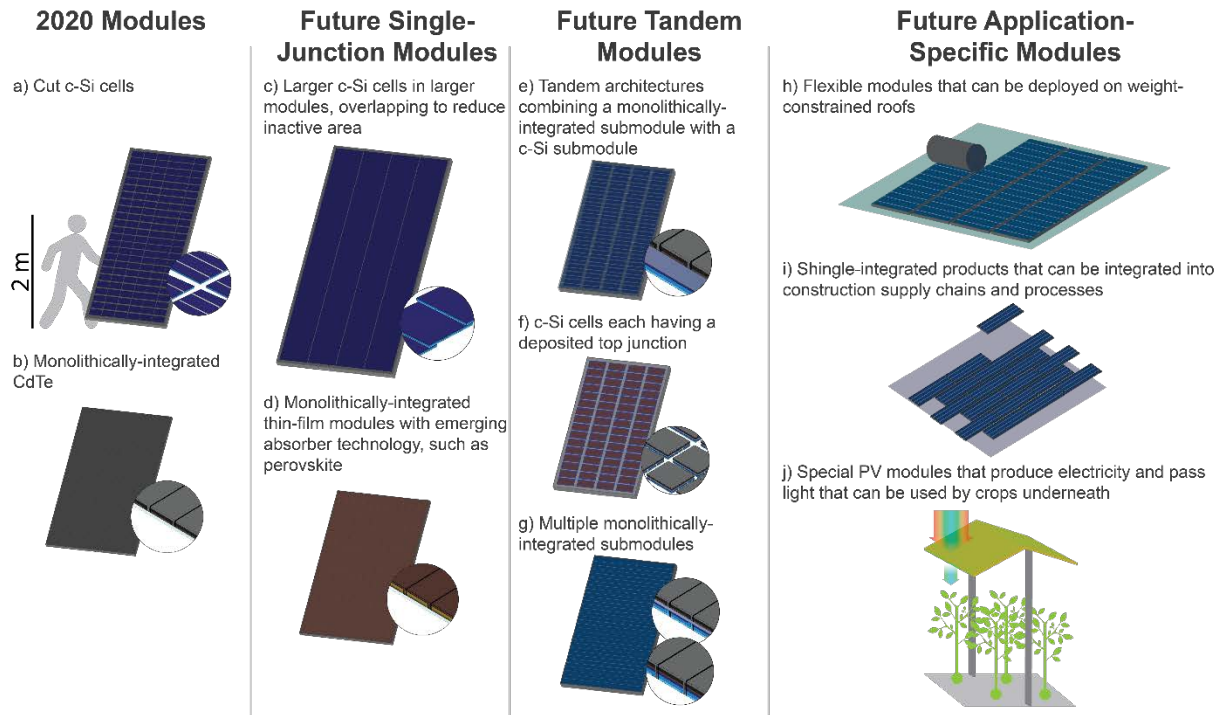
Figure 6 - 11. Possible future PV modules are expected to have increased size and improved efficiency, integrate emerging materials like perovskites, implement tandem architectures, and expand into more application-specific form factors

Module efficiency can be increased independently from cell efficiency. Some of the light collected by a PV module can be lost before delivery to the cells inside, and some power

generated by the cells is lost as it is delivered to the module's leads. This cell-to-module loss has many small contributors, including optical and electrical losses (Haedrich et al. 2014). Reducing these losses is a main objective of the module format changes shown in Figure 6 - 8. Incremental changes to existing module designs and materials can continue reducing losses—increasing module efficiency even without increasing cell efficiency.

Module improvements that reduce optical and electrical loss include changes to module form factor, cell form factor, interconnection, and packaging materials. Module efficiency increases when inactive area is reduced. Inactive area does not directly produce electricity and includes borders, gaps between cells, metallization, and interconnection. Larger modules reduce the area fraction that is occupied by borders. Gaps between cells can be reduced through improved assembly precision or by adopting seamless or overlapping interconnection technology. Metallization and interconnection area can be reduced by changing to a larger number of smaller interconnects, switching to overlapping interconnection technology where interconnect area is on the rear of the cell, or using IBC cells, which have no front-side interconnects at all. Special interconnection and packaging materials can counteract the effects of inactive area, trapping more light in the module and increasing module efficiency.

Perovskite solar cells have reached record laboratory-cell efficiencies that compete with those of c-Si cells. If certain challenges are resolved, this technology could mature to serve as an alternative to mainstream cell technology. The principal challenge is long-term durability. Compared to conventional solar cells, perovskite cells are more susceptible to damage from moisture and ultraviolet light. The scientific basis for long-term durability testing of perovskite modules is still developing.

Energy Yield

Energy yield describes the annual energy produced by a PV system with a given DC nameplate rating. Efficiency is measured instantaneously under fixed, standard conditions. This standard efficiency does not directly affect energy yield, but *operating* efficiency does. Operating efficiency depends on temperature and the details of incident light, which module design can influence. System design factors that can also affect energy yield are described in a later section.

Most U.S. UPV systems are now installed with single-axis trackers, which point modules at the sun as it moves across the sky (Bolinger et al. 2020). Trackers boost the amount of light reaching modules without much cost increase. Increased adoption of trackers and improved tracker performance can raise the energy yield of the nation's PV fleet.

Bifacial modules collect light on both sides and enable major increases to energy yield. Bifacial technology is mainstream, but not dominant, in UPV systems (Wilson et al. 2020). Some bifacial gain is also available on flat-roof installations typical of commercial PV systems. No bifacial gain is available on ordinary sloped-roof residential rooftop PV systems, so adoption of bifacial technology is not expected there. In UPV and commercial PV systems, increased adoption of bifacial modules and continued optimization of the back-side performance of these modules can continue driving energy yield up.

Like most power plants, PV systems slowly degrade during their service life. Eliminating causes of power degradation is an objective of PV module and system reliability research. As module

technology changes, new degradation pathways become possible. These must be discovered and eliminated to continue reducing the degradation rate.

PV modules produce less energy when they are hot. Low temperatures can also slow down some degradation mechanisms, allowing modules to last longer. Technology for reducing operating temperature and boosting energy output has been demonstrated in the laboratory but has not been successfully commercialized.

Anti-reflective coatings are in mainstream use and boost module efficiency by reducing reflections, especially when light strikes a module at a glancing angle. Additional improvements to module optics can boost energy yield by increasing the amount of light a module can absorb under operating conditions.

Optimal cleaning of dirty modules can balance cost and energy yield, but development of anti-soiling glass coatings, treatment of land to reduce dust production, and soiling-aware site selection may eliminate soiling loss before it occurs.

Cost

Crystalline-silicon solar cells have followed a steady trajectory of cost reduction from reduced materials use and increased equipment productivity. These improvements are expected to continue (Woodhouse et al. 2019). Figure 6 - 12 shows module cost progress through 2020 and projected changes through approximately 2030.

Solar silicon is an extremely pure substance made in a complex and energy-intensive process. The cost contribution from the use of silicon material can be reduced by making this process more efficient, but also by reducing how much silicon is used in each cell and how much is wasted during the wafering process. Thinner wafers and smaller kerf loss lead to lower silicon use per wafer. Kerfless wafer technology, which produces wafers without needing to saw them from ingots, eliminates kerf loss entirely. While kerfless solar cells have not achieved commercial success, new methods for producing wafers are still being demonstrated in the laboratory and could someday compete with conventional wafers.

After wafers are produced, each one must pass through a series of machines that convert the wafer into a solar cell. For machines that process wafers at a certain rate, shifting to larger wafers leads to higher equipment throughput. The dominant wafer size has increased several times, as shown in Figure 6 - 8, and 210-mm wafers are now available.

Metals are applied to the front and rear of processed silicon wafers to form electrical contacts. These metallization materials usually include silver and are a major contributor to the wafer-to-cell cost. Metallization cost can be pushed down by reducing the amount of metal used or by changing to lower-cost metals. Busbarless cells use less metallization and rely more heavily on separate copper ribbons, which are usually present anyway, to carry electricity. The silver in conventional metallization paste may also be replaced with lower-cost metals such as copper, as long as detrimental effects on cell performance can be mitigated.

Module cost historically was dominated by cell cost. However, in 2020, the cells constituted less than half of the module cost. Reductions to non-cell module costs are as important as cell cost

reductions. Finding lower-cost module materials that do not sacrifice safety or reliability can reduce the balance-of-module materials cost. Increasing automation and increasing module size enable productivity improvements that reduce module assembly costs (Horowitz et al. 2017). Figure 6 - 12 shows the effects that cell and non-cell factors have on modeled module cost. The processing advancements depicted in the figure include improvements that are anticipated by 2025: larger wafers, thinner wafers, smaller kerf loss, larger ingots, reduced silver use, and higher wafer-to-cell and module assembly throughput (ITRPV 2021).

Consistent with the experience curve shown in Figure 6 - 3, continued maturation of the industry and supply chains combined with the incremental technology improvements described here are continuing to drive cost reductions in conventional technology.
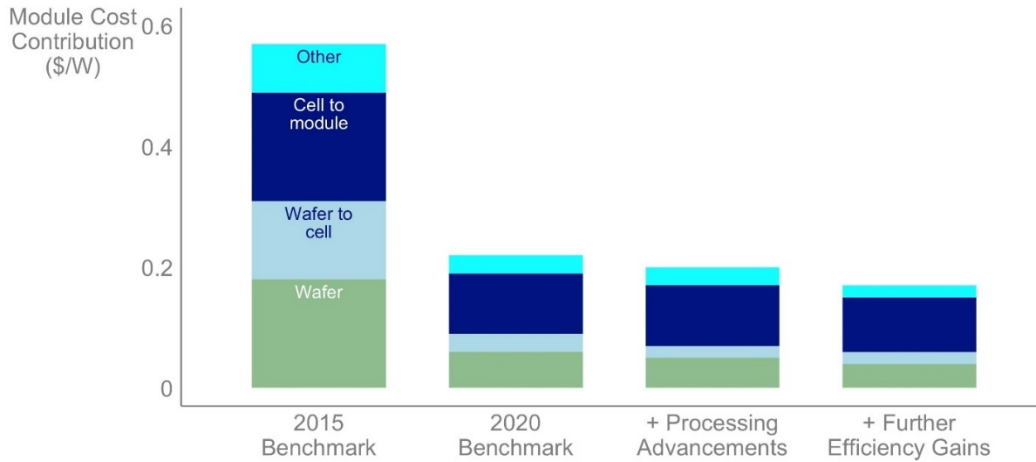
Figure 6 - 12. Monocrystalline Si PV module manufacturing benchmark showing a pathway to $0.17/W module cost

Other costs include research, development, sales, general, and administrative costs. Wafer, wafer to cell, and cell to module include materials and processing costs. Costs are shown in 2020 real U.S. dollars per nameplate DC watt and do not include profit, shipping, or tariffs

Crystalline silicon is the incumbent technology against which alternatives are compared. CdTe has been a successful competitor, especially in the United States. CdTe modules are made all at once, from cells deposited directly onto glass. CdTe technology has a path to cost reductions and performance improvements that is similar to the path for c-Si. Costs can be improved through efficiency improvements, film thickness reduction, and higher productivity from workers and machines (Wilson et al. 2020).

Although mainstream solar cell technology has a roadmap for further cost reduction, a shift to new solar cell types or to tandem architectures could provide a path to even lower cost. Crystalline silicon and CdTe absorbers are manufactured using expensive equipment, requiring extensive upfront investment. Reducing the capital intensity of new manufacturing facilities is essential for cost-effectively growing the PV industry in support of power-sector decarbonization. Solution-processed solar cells, such as perovskite cells, can be made from wet inks on low-cost and high-throughput equipment that is similar to a printing press. Factories based on this roll-to-roll technology could be simpler and faster to build than the facilities that produce conventional PV modules. If solution-processed cells can be made with efficiency and

longevity that competes with mainstream incumbents, the low upfront cost of manufacturing equipment could enable major cost reductions.

The parts of a PV module other than the solar cell include mainly glass and polymers. Although these materials are already low in cost, further cost reductions are possible. Thinner glass or substitution of glass could reduce material and shipping costs. Replacement of sophisticated polymers with simpler ones, without sacrificing performance, could also cut costs.

System Technology

Energy Yield

Systems are not always designed to maximize the output of bifacial modules. Row spacing, height above the ground, tracker design, module layout, and ground cover reflectivity (albedo) all affect the energy output of bifacial systems (Pelaez et al. 2018). Optimizing these parameters in tandem with module selection can further boost the output of bifacial systems.

Availability loss occurs when a system is turned off because of a fault, repair, or maintenance. Improving component reliability can reduce this loss by eliminating faults and reducing the need for repairs. Inverters can trip off when they detect a ground fault or an arc fault. Decreasing the incidence of ground faults and arc faults further increases availability. Improving inverters and system design to eliminate false trips also reduces availability loss.

PV modules can become mismatched because they have different initial performance, undergo different degradation, or are receiving different amounts of sunlight. This mismatch results in an energy loss when interconnected modules are forced to operate at the same electrical condition. In residential PV, module-level power electronics (MLPE)—including microinverters or DC power optimizers—resolve this problem by running each module at its optimal operating point. Mismatch loss may be reduced in larger systems using MLPE or by reducing mismatch in the first place (MacAlpine, Erickson, and Brandemuehl 2012).

When dust accumulates on PV modules, it blocks some of the incident sunlight. Soiling loss is often low where occasional rain cleans the modules. In other areas, reducing soiling loss is a key way to increase energy yield (Micheli, Deceglie, and Muller 2019). Manual or mechanized cleaning removes soiling but adds to O&M cost and can sometimes damage module surfaces. Optimization and automation of cleaning can increase energy output.

It may be possible to design PV systems to operate at lower temperature. Different arrangements of PV system components can affect the way that air naturally cools the modules (Stanislawski et al. 2020). These approaches can boost energy output on top of other yield improvements.

O&M Cost

Replacing components, mainly modules and inverters, when they fail is an anticipated recurring expense in all PV systems (Feldman et al. 2021). Improved component reliability reduces the need for these replacements and reduces O&M cost. Module, inverter, and tracker reliability can all be advanced to reduce component replacement costs. As important as increased reliability are test procedures and field data proving that better reliability has been achieved.

Managing vegetation growth and animal activity around ground-mounted PV systems is a labor-intensive O&M task. Optimizing or reducing the need for these practices helps PV systems operate in harmony with their surroundings and reduces costs.

Increasing O&M sophistication can help target maintenance by place and time such that wasted effort is minimized. For example, cleaning can be done less often if it is coordinated with actual and forecasted soiling and precipitation. This requires improvements to existing monitoring, communication, and field data analysis technology. A shift from reactive to proactive maintenance practices can further reduce the total amount of maintenance required by catching problems at an early stage.

More reliable hardware leads to less effort and expense spent replacing components. Warranties and plans for replacing components are set by a combination of experience and durability test results, but technology to predict the service life of a PV module does not exist. Service life prediction would allow for components with long, predictable lives to be used, minimizing component replacement costs.

Diagnostic techniques to target maintenance effort are increasing in sophistication, but they still involve a great deal of labor and judgment. Automated monitoring and diagnostics could enable optimal maintenance or even predictive maintenance, where problems are solved at optimal cost or prevented entirely.

BOS Hardware Cost

The c-Si and CdTe modules used in UPV systems have become larger since 2010, driving reductions in installation cost and complexity. The size increase is expected to continue for c-Si technology, partly because changes to cell size and interconnection schemes dictate new module sizes (Horowitz et al. 2017; Feldman et al. 2021).

Structural BOS costs can be reduced through use of low-cost materials, simplified designs, increased use of automation, and economies of scale from increased mass production. Building-integrated PV (BIPV) eliminates some elements of structural BOS entirely and offsets building material costs. BIPV products tend to be small modules with high operating temperatures, and these factors can be barriers to cost competitiveness.

Increasing system voltage has led to reduced electrical BOS cost and complexity. Higher system voltage allows for more modules per string and fewer strings. This reduces the number of system components—such as fuses, wiring home runs, and combiner boxes—that scale with the number of strings.

It is increasingly routine to combine PV systems with battery storage. PV-plus-storage systems can be configured with AC-coupled or DC-coupled storage. These architectures can realize different levels of BOS cost savings over PV-only or storage-only system configurations (Feldman et al. 2021).

6.2 Concentrating Solar Power

6.2.1 Background

Concentrating solar power (CSP) uses reflectors to concentrate sunlight onto a surface, where it is converted to heat. This heat can be used, via a heat-transfer medium, to produce electricity or run an industrial process, or it can be stored for later use. A steam turbine system, similar to those used in conventional power plants, is used to convert the heat to electricity. Thermal energy storage (TES) makes it possible for CSP to deliver energy in times of low solar resource, including at night. Only direct sunlight can be effectively concentrated, so CSP works best in areas with high direct solar irradiance, such as the southwestern United States.

The first CSP plants were built in the 1980s in the United States, and some of these were still operational as of 2020. The United States and Spain have over 1 GW of operational CSP capacity each, and Chile, China, and the Middle East/North Africa region each have over 1 GW of capacity planned or under construction. In 2020, a total of 6 GW of CSP were operational worldwide (NREL 2021a).

The majority of currently operating CSP systems take two main forms, depending on how they concentrate light. Parabolic trough systems use a long, curved reflector to focus light onto a tube containing a heat-transfer medium. Power tower systems use a field of reflectors to reflect light onto a central tower, where a receiver uses it to heat a heat-transfer medium (Boretti, Castelletto, and Al-Zubaidy 2019). Of the 1.7 GW of operational U.S. CSP capacity, parabolic trough systems account for 1.3 GW, and power tower systems account for the rest. Since 2015, no new U.S. CSP plants have been built, but multiple gigawatts of new capacity have been built overseas, and more are planned. Lessons learned from these existing plants have provided important data to reduce development and operational costs and improve performance (Mehos et al. 2020).

CSP plants can store thermal energy by heating molten salt and converting the stored thermal energy to electricity later. TES can be scaled independently of the power block, allowing plants with short- or long-duration storage to be implemented. Increasing the duration of TES only requires that larger volumes of storage medium be used, so TES can have lower marginal cost than battery storage. CSP can also use supplemental, renewably derived fuels to provide firm capacity even during periods of low solar output, potentially replacing some of the RE-CT capacity (Yagi, Sioshansi, and Denholm 2019).

The global capacity-weighted average cost of a CSP power plant declined from about $8.99/W in 2010 to $5.77/W in 2019 (IRENA 2020). This occurred despite the increasing prevalence of TES, which increases system cost. Figure 6 - 13 shows that the LCOE of CSP plants has also declined. Different CSP plants have different capacity factors, and these capacity factors are often higher than those of PV power plants. Comparing the LCOE between different CSP plant configurations or between CSP and PV can be misleading, because different plants have varying capabilities for delivering electricity on demand.
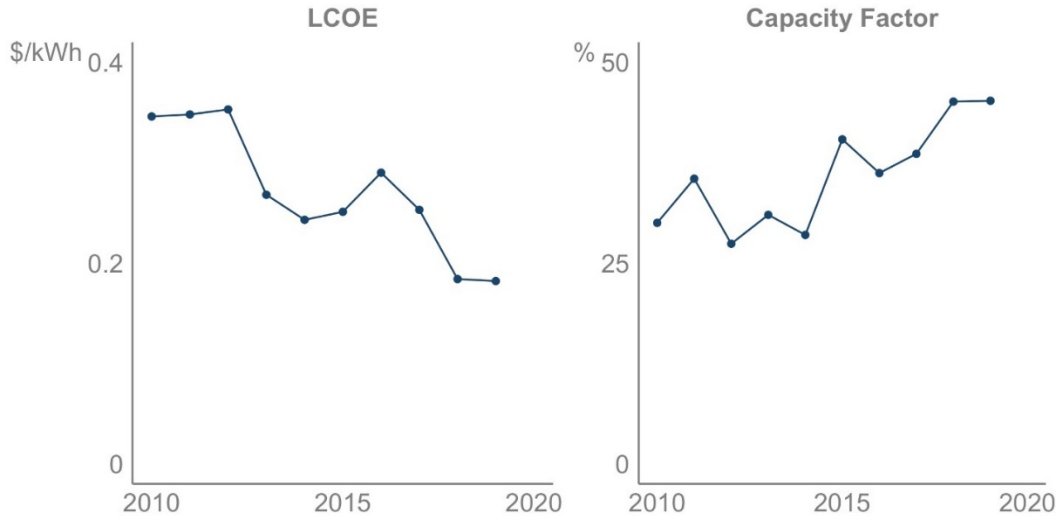
Figure 6 - 13. Global average LCOE and capacity factor for CSP systems, 2010–2019 (IRENA 2020)

Costs are shown in 2019 real U.S. dollars. Two unusual projects in Israel are excluded from the 2019 data point.

New CSP power plants use one of the two dominant designs, parabolic trough or power tower. Power tower systems and TES are increasing in prevalence. When plants include TES, the storage medium is usually solar salt, a mixture of sodium nitrate and potassium nitrate. This salt is stable up to 565°C, and this limit sets the temperature and efficiency limits of the rest of the power plant (Mehos et al. 2017).

In 2018, SETO launched its CSP Gen3 program to overcome the temperature and efficiency barriers associated with conventional solar salt, addressing the thermal transport system from receiver to heater. Gen3 CSP systems are being designed to deliver heat exceeding 700°C to advanced supercritical carbon dioxide (sCO_2) power cycles, which are expected to have over 50% net thermal-to-electric efficiency. Among multiple solid, liquid, and gas heat-transfer media explored, in 2021 a system using solid particles to collect sunlight and store thermal energy was selected to proceed to pilot scale. Future CSP plants may unlock higher efficiency and lower cost using this technology (Mehos et al. 2017).

Many industrial facilities use fossil fuel combustion to drive a process using heat. SIPH can replace some or all of this combustion with heat from a CSP system. SIPH systems are already in use in the United States to offset a small portion of total industrial process heat emissions. SIPH is not explicitly considered in the *Solar Futures* scenarios, but it could be a key technology for decarbonizing parts of the energy system that are difficult to electrify (Schoeneberger et al. 2020; Augustine, Turchi, and Mehos 2021).

6.2.2 Solar Futures *Scenario Assumptions*

In the *Solar Futures* scenarios, CSP is deployed based on assumptions about cost and performance. In the Decarb and Decarb+E scenarios, those assumptions are consistent with Gen3 CSP technology being successful, bringing >700°C CSP systems with over 50% net thermal-to-electric efficiency into mainstream use by 2030, with substantial cost reductions compared to existing systems. These assumptions are documented in greater detail and for years beyond 2030 in NREL's ATB (NREL 2020).

ReEDS does not make deployment decisions based on LCOE, but our technology and cost assumptions correspond to achieving certain LCOE values. The Decarb and Decarb+E cost and performance assumptions are consistent with meeting the SETO CSP LCOE target of $50/MWh in 2030, set in 2016 (Murphy, Sun, Cole, Maclaurin, Turchi, et al. 2019). This target is for a system with 12 hours or more of TES in Daggett, CA, a location with a very high direct solar resource (class 12).

The cost and performance assumptions of the Decarb and Decarb+E scenarios are based on improvements to capacity factor, upfront capital cost, and O&M cost. Many combinations of improvements can reach the same LCOE as the case used to set our assumptions. One possible path to reducing LCOE is shown in Figure 6 - 14.
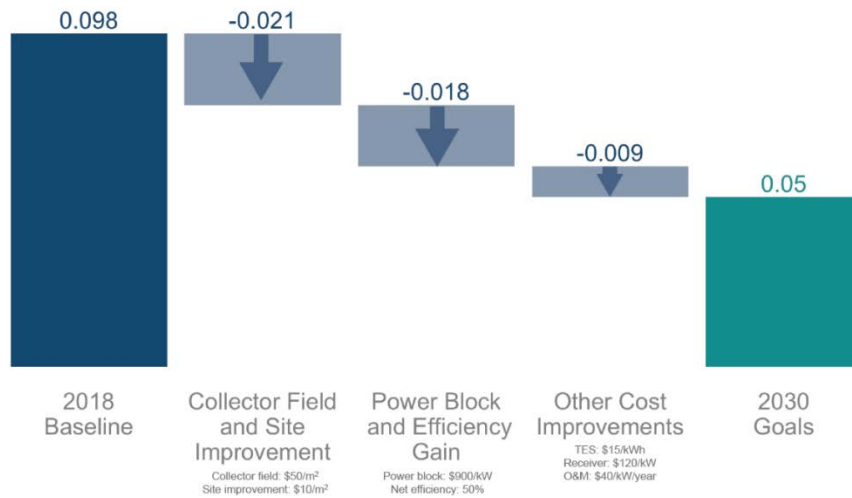
Figure 6 - 14. One possible pathway to an LCOE of $0.05/kWh from CSP in 2030 (Silverman and Huang 2021)

Costs are shown in real 2018 U.S. dollars. The 2018 benchmark LCOE in this figure and the global average LCOE given in Figure 6 - 13 differ. The benchmark LCOE represents what is achievable using a simulated system. The real-world systems captured in Figure 6 - 13 may have a different LCOE owing to departures from the simulated system, including plant-specific factors such as solar resource and system availability.

We simulated an additional scenario with a special set of CSP assumptions to explore an expanded role for CSP. We varied the Decarb scenario assumptions to ensure that CSP's share of generation reaches 10% by 2050 (requiring 98 GW of CSP capacity). The power-system costs resulting from this scenario are only slightly higher than the costs for the core (least-cost) Decarb scenario, indicating the potential of CSP to play a larger role if future conditions vary from the Decarb scenario's assumptions. Details of this scenario are given in Appendix 2-B.

6.2.3 CSP Improvements to Achieve the Solar Futures Scenarios

Improvements to the cost and performance of the collector field, the part of a CSP plant that collects sunlight, can yield major reductions in electricity cost. The collector field is the largest contributor to upfront cost. It includes reflectors and heliostats, the equipment that moves the reflectors to follow the sun. Collector field cost can be reduced through improved performance or through reduced hardware cost. About 45% of incoming radiation is lost before it reaches the receiver, and some of these losses can be reduced through technology advances. Low-cost materials can help drive down hardware costs. Increased standardization and economies of scale

would also drive down collector field costs, as they have driven down PV module and structural BOS costs. Low-cost reflectors and heliostats make it cost-effective to build a larger collector field, increasing a plant's solar multiple and enabling the use of long-duration TES. These factors increase a plant's capacity factor, reducing the cost and raising the value of the electricity it produces (Mehos et al. 2017).

Sunlight is converted to heat in the CSP receiver. While the current generation of CSP plants uses a tubular receiver containing a heat transfer fluid, Gen3 receivers will use a curtain of sand-like particles falling through open air. Particles are not bound by the same temperature limits of existing heat transfer fluids, unlocking higher power cycle efficiency. The particles are stored in insulated bins, where they also act as thermal energy storage. Optimizing the equipment for moving the particles, the formation of the curtain in the receiver, and the properties of the particles themselves can boost the performance and cost-effectiveness of Gen3 CSP plants. Hot particles transfer their thermal energy into a power cycle's working fluid using a heat exchanger. Solid-to-sCO$_2$ heat exchangers that operate at Gen3 temperatures will require new designs and materials.

CSP TES is attractive because it is simple: a larger tank or bin holds more storage medium, increasing a plant's capacity factor. Keeping the costs of storage low while resolving durability and corrosion concerns will support increased adoption of CSP plants with TES (Mehos et al. 2017). Gen3 systems using solid particles should unlock lower storage system costs by adopting similar technology from other industries.

Heat is converted to electricity in a CSP plant's power block. Increasing the efficiency and reducing the cost of the power block are important areas of CSP technology improvement (Mehos et al. 2017). Conventional power blocks use a steam Rankine power cycle and are limited in temperature to the 565°C limit of solar salt. For example, the ATB assumes that in 2020 a CSP plant had a 41.2% power cycle efficiency (NREL 2020). A crucial emerging development is the use of a sCO$_2$ Brayton power cycle, which, in combination with the higher operating temperature of Gen3 TES, can deliver net thermal-to-electric efficiency of greater than 50%. Supercritical CO$_2$ Brayton turbines are also physically smaller than steam Rankine turbines, saving on capital costs. These turbines also maintain their high efficiency even at small capacity, enabling demonstration and learning to occur at smaller scale. Additional technical details on CSP improvements are provided in an accompanying report (Augustine, Turchi, and Mehos 2021).

6.3 Solar Soft Costs

Solar soft costs include all non-hardware costs that directly affect the prices of installed systems. Key categories of soft costs include installation labor, permitting costs, interconnection costs, land acquisition, customer acquisition, and installer profits. While soft costs have decreased over time, they remain higher than hardware costs in the residential sector (Figure 6 - 15) and represent a constant or growing proportion of total system cost, depending on the market segment (Figure 6 - 16). For instance, soft costs have remained higher in the residential and commercial market segments, in contrast to the utility market segment. Residential soft costs, as a share of total system cost, increased from 50% in 2010 to 64% in 2020, while the commercial market segment experienced an increase from 33% to 55% over that same period (Feldman et al.

2021). As a result, soft cost reduction has emerged as a key area of policy and research attention (Ardani et al. 2018).
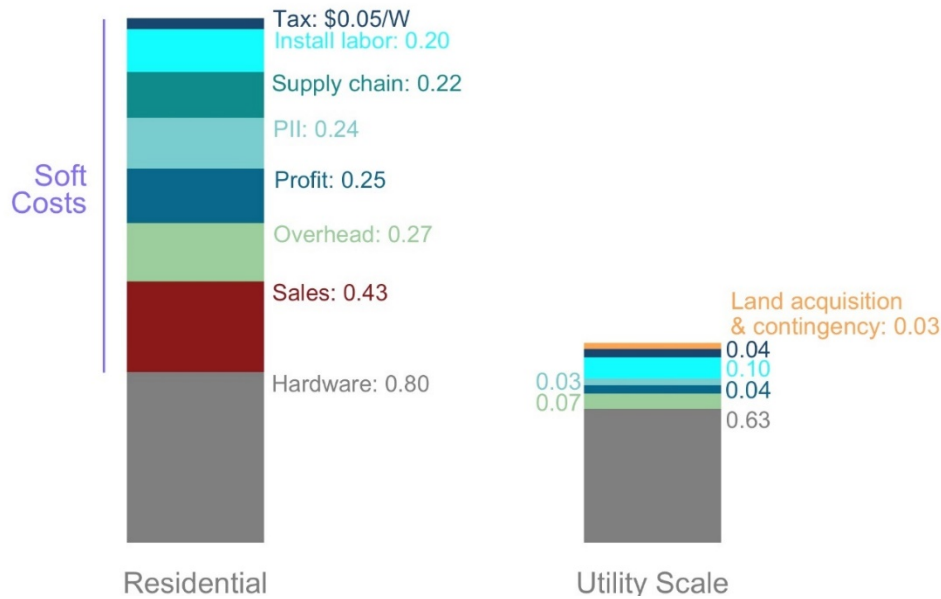
Figure 6 - 15. Residential and utility-scale PV cost benchmarks

Based on data from (Feldman et al. 2021)
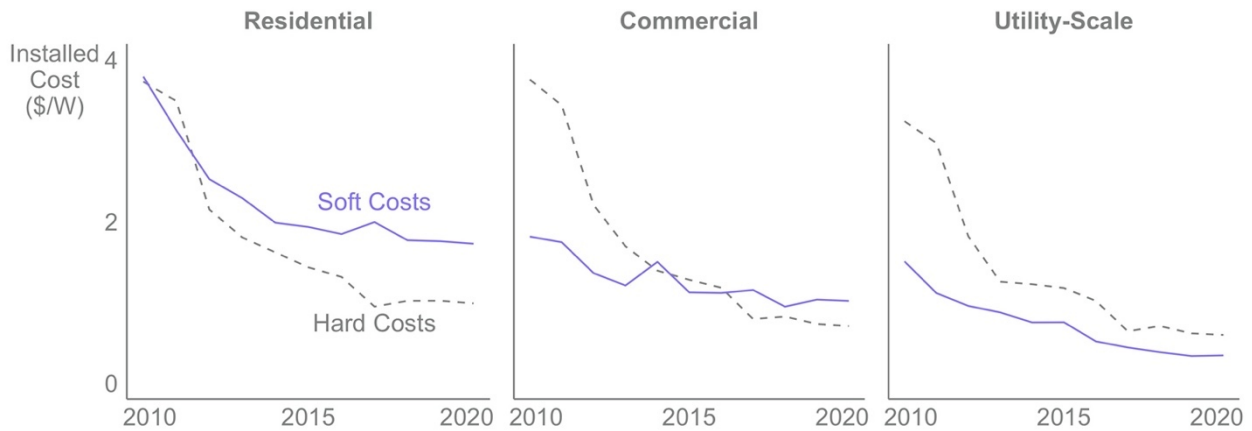
Figure 6 - 16. Hardware and soft costs by customer class, 2010–2020

Based on data from (Feldman et al. 2021)

Solar soft costs can be broken down into five areas (O'Shaughnessy et al. 2019): system-level, installer-level, market-level, financing, and jurisdiction-level soft costs. Here, we review historical trends in soft costs and prospects for future soft cost reductions at each level. We focus our discussion on PV soft costs because that is the focus of much of the literature. Further, the literature generally focuses on residential soft costs, because soft costs are relatively high in that sector. Many key soft cost takeaways from the residential PV literature can be extrapolated to commercial- and utility-scale PV.

6.3.1   System-Level Soft Costs

Two key system-level soft cost drivers are economies of scale and economies of scope (O'Shaughnessy et al. 2019). In terms of economies of scale, per-unit ($/W) PV system prices are smaller for larger systems, all else equal (Gillingham et al. 2016; Burger et al. 2019). Increasing system sizes have therefore contributed to reductions in system prices on a $/W basis: from 2000 to 2019, the median residential PV system increased from 2.4 kW to 6.5 kW, the median commercial system increased from about 11 kW to 40 kW, and the average utility-scale system grew from around 17 MW in 2010 to around 44 MW in 2019 (Barbose, Darghouth, et al. 2020; Bolinger et al. 2020).

In terms of economies of scope, installed PV system prices tend to be lower when PV is installed in tandem with another construction project, such as rooftop PV installed during new home construction (Gillingham et al. 2016; Ardani et al. 2018). When residential rooftop PV installation is combined with new house construction or retrofit work such as reroofing, major savings may be realized; one study showed potential system price reductions of about 60% due to implementing either strategy (Ardani et al. 2018). For example, combining reroofing or new construction with PV installation activities creates synergies and logistic efficiencies that reduce truck rolls, crew-hours spent on site, and other direct transportation costs, such as fuel. Regulatory and permitting processes can also be coordinated to reduce overall PII costs (Ardani et al. 2018). Utility-scale PV projects can be codeveloped with utility-scale storage projects to leverage economies of scope for land acquisition and PII (Gorman et al. 2020). Planning PV installation into construction projects can also yield additional economies of scale, such as by installing rooftop PV on many homes at once as part of new neighborhood development. Labor-saving innovations—such as standard system configurations, preassembled systems, and process automation—can also push installation costs down.

From a policy perspective, it is possible to reduce PV system prices by supporting larger systems, such as through policies that incentivize community solar rather than residential rooftop solar. However, such gains in soft cost reductions must be weighed against potential tradeoffs between small- and large-scale PV systems (Clack et al. 2020). Further, policies could enable economies of scope by incentivizing PV installation in tandem with other activities. An example is building codes that require new buildings to be solar ready or installed with rooftop solar, such as in the California building code. The impacts of such codes on system prices are an area for further research.

6.3.2   Installer-Level Soft Costs

Different PV installers charge significantly different prices for installed rooftop PV systems. Differences in installer prices can be explained by differences in installer efficiency, installer business models, and profit margins (which are constrained by market dynamics and discussed in Section 6.3.3). In terms of efficiency, it is well established that PV prices decline as installers "learn" through experience (van Benthem, Gillingham, and Sweeney 2008; Gillingham et al. 2016; Bollinger and Gillingham 2019). As a result, more experienced installers tend to charge lower prices than novice installers, all else equal.

In terms of business models, available research suggests that a variety of business models can result in relatively low system prices. High-volume installers can use learning and economies of scale to reduce installation costs and charge lower prices, though the gains from learning and

volume can be partly offset by market power (O'Shaughnessy 2019). Further, high-volume installers have historically been more likely to offer complementary products such as storage or building load control technology installation. High-volume installers may therefore achieve lower prices through economies of scope and play key roles in driving solar-plus-storage markets. At the same time, some research suggests that small-scale installers are associated with lower prices (Nemet et al. 2017; O'Shaughnessy 2019), possibly because small-scale installers offer PV as a side business to other services and are able to reduce prices through economies of scope (O'Shaughnessy and Margolis 2018).

Policymakers could explore measures that leverage the cost-reducing benefits of specific installer characteristics. For instance, entrepreneurial training and workforce development could help new installation businesses learn more rapidly and translate that learning to lower system prices. State contractor licensing could be reformed to incentivize more contractors in related industries to explore rooftop PV installation as a side business, such as by explicitly allowing licensed electricians to install PV (as is already done in many states). Finally, policymakers could consider how regulatory environments affect the formation of new PV businesses (Gao 2021).

6.3.3 Market-Level Soft Costs

Market-level soft costs can be broken down into supply- and demand-side factors. On the supply side, competition between installers can reduce prices by forcing installers to lower their profit margins (Gillingham et al. 2016; O'Shaughnessy and Margolis 2018). At the same time, highly competitive markets may blunt the efficiency gains of installer experience, given that that experience is distributed among a larger number of installers. As a result, research suggests that installed prices are minimized in markets with an optimal balance of competition and concentration (i.e., accumulation of market shares by high-volume installers) (O'Shaughnessy 2019).

On the demand side, consumer demand for PV determines customer acquisition costs. Unlike other categories of soft costs, customer acquisition costs are not declining and may even be increasing in the residential sector (Mond 2017; EnergySage 2020). Increasing residential customer acquisition costs partly reflect increasing installer competition for customers. Rising customer acquisition costs may also reflect the challenges of pursuing later adopters that require more persuasion and better returns to be convinced to adopt PV than early adopters.

Demand-pull policies are one potential way to address high residential customer acquisition costs. Demand-pull policies, such as upfront incentives and tax credits, have been the primary ways that federal and state jurisdictions have supported PV. Demand-pull policies yield long-term societal net benefits by driving PV scaling and reducing PV costs through learning (Tibebu et al. 2021). In most cases, incentives are phasing out by policy design, partly under the assumption that such incentives are no longer necessary as PV prices decline (Nemet 2019). Rising customer acquisition costs suggest that demand-pull policies may still be effective. One option is to target demand-pull policies at specific customer segments that pose the greatest customer acquisition challenges. For instance, incentives could be dedicated to promoting adoption in historically under-served areas, such as low-income neighborhoods and communities of color (see further discussion in Chapter 4).

6.3.4 Financing Soft Costs

Financing soft costs refer to the price premiums that financiers charge to bear financial risks and incur administrative costs on behalf of PV customers. Financing soft costs manifest in the higher levelized costs that customers pay for financed PV systems relative to systems purchased outright (Davidson, Steinberg, and Margolis 2015). Further, when a system is financed via third-party ownership, the third-party owner receives the associated PV incentives rather than the PV adopter. Financiers hold onto the value of these incentives to various degrees, though research suggests that financiers pass most of the value of incentives through to customers in the form of lower prices (Pless and van Benthem 2017; Dong, Wiser, and Rai 2018; Bielen et al. 2019).

Solar financing is constantly evolving. For residential solar, financing has become slightly less prominent over time as more and more customers buy their systems outright. Nonetheless, financing remains particularly important for low- and moderate-income customers (O'Shaughnessy et al. 2021). Green banks offer one potential approach to improving access to solar financing. An expansion of green banks has been proposed under the Justice40 initiative (see Section 4.5). For commercial and utility-scale solar, a variety of financing options have emerged, including power-purchase agreements, leases, and contracts for differences. Many opportunities to improve utility-scale PV financing are associated with reducing technical risk (Feldman, Jones-Albertus, and Margolis 2020); these improvements to financing costs are limited, however, because PV already enjoys the lowest rates in the industry (Feldman, Bolinger, and Schwabe 2020).

6.3.5 Jurisdiction-Level Soft Costs

In the United States, individual jurisdictions (e.g., cities, counties) have authority over PV permitting and inspection, and individual utilities over PV interconnection; collectively, these three processes are known as PII. PII processes ensure safe PV system installation, particularly on buildings. At the same time, onerous or inconsistent PII requirements can increase PV installation costs, which are ultimately passed through to customers in the form of higher prices (Dong and Wiser 2013; Burkhardt et al. 2015). Further, inconsistent PII across jurisdictions can force installers to learn new requirements in each jurisdiction, a challenge that increases PII costs in the United States relative to other large PV markets such as Germany (Seel, Barbose, and Wiser 2014).

In the near term, policymakers can reduce PII costs by implementing measures to streamline PII processes. For instance, many jurisdictions already exempt PV systems under threshold capacities from certain PII requirements. The DOE SolSmart program recognizes local jurisdictions that have implemented measures to streamline PII. SolSmart-certified programs have quicker-than-average turnaround times on PV permit applications, suggesting that streamlining policies work and can save time and money (O'Shaughnessy, Barbose, and Wiser 2020). Ongoing NREL research suggests that measures such as online permitting, automated permitting platforms such as SolarAPP, and online interconnection portals can similarly reduce PII process durations and yield cost savings. Policymakers could also look to other countries for proven best practices to streamline PII. For instance, PII costs for residential systems are negligible in Germany owing to the country's higher degree of standardization, the use of online portals, and exemptions for permit inspections (Seel, Barbose, and Wiser 2014).

In the long term, as jurisdictions gain greater familiarity with PV and it becomes a mainstream technology, PII requirements could be significantly reduced or even eliminated for certain PV systems. For example, PV-plus-storage systems designed to minimize grid export could be subject to more streamlined interconnection. As of 2021, certain utilities, such as the large IOUs in California, are already moving towards interconnection processes that can be completed in as little as one business day for standard systems. In addition, PII requirements could become nearly obsolete with certain technology advancements, such as plug-and-play systems.

Project siting entails additional jurisdiction-level soft costs, primarily for utility-scale PV. Identifying a viable project site for large-scale projects can require numerous permits from multiple jurisdictions, costs for studies such as environmental impact analyses, and costs for measures to comply with local requirements such as measures to mitigate impacts on local wildlife. These costs may initially be low owing to the broad availability of viable sites, but they may increase over time as low-cost sites are exploited. Further, project siting may increasingly encounter local resistance from community groups, environmental groups, or other stakeholders opposed to project development at specific sites. This resistance ultimately translates to additional costs for negotiation, potential litigation, and in some cases project cancellation.

6.4 Other Technologies

Solar technology alone cannot decarbonize the electricity system. This section refers to resources with more about the future of storage and generation technology.

6.4.1 Energy Storage

Energy storage deployed to provide peaking capacity can also store low-cost PV electricity generated outside of peak demand times. As more PV is deployed, the value of storage increases because of changes to the timing of peak net load (electricity demand minus variable renewable energy supply). The resulting increase in storage capacity increases the value of PV electricity, because it can increasingly be stored and used later (Denholm et al. 2019). This strong synergy means that storage is an essential technology for the cost-effective and massive PV deployment envisioned in the *Solar Futures* scenarios. See Chapter 5 for more information.

The *Solar Futures* scenarios assume the trajectory of cost reduction for batteries summarized in Figure 6 - 17. Costs fall to half of their 2020 values by 2030.

2020 levels

2020
CapEx: $1.2/W
O&M: $30.1/kW/yr

Storage cost projections

2030
$0.6/W
$14.1/kW/yr

2040
$0.5/W
$11.4/kW/yr

2050
$0.3/W
$8.6/kW/yr
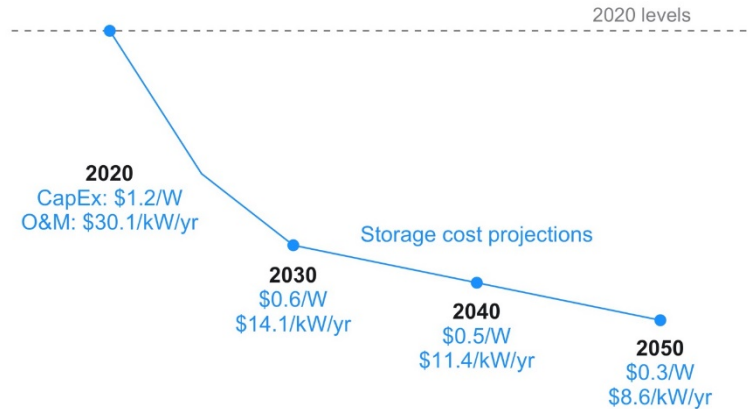
Figure 6 - 17. 2020 ATB Advanced projections of 4-hour battery storage upfront cost and O&M cost

There are also opportunities to leverage new TES technologies, in addition to its use in CSP. TES can be deployed for electricity storage, potentially achieving roundtrip efficiencies of greater than 60% at low costs, making it particularly useful for longer-duration storage of 8 hours and beyond (Olympios et al. 2021). DOE's Energy Storage Grand Challenge is a strategy for creating and maintaining American leadership in energy storage technology. The challenge seeks a 90% reduction in the cost of stored energy from 2020 to 2030 and aims to develop and domestically manufacture technologies meeting all of U.S. demand by 2030 (DOE 2021a).

The NREL Storage Futures Study considers the role of storage in the future energy system. More details are available in the publications associated with that study (NREL 2021b; Denholm, Cole, et al. 2021).

6.4.2 Other Generation Technologies

Realizing the *Solar Futures* scenarios depends on major advances in non-solar generation technologies as well. In the Decarb and Decarb+E scenarios, major energy contributions from wind are necessary by 2035. The scenarios' assumptions about the cost of wind technology are shown in Figure 6 - 18. Demand flexibility and electrification rely on advances in building and vehicle technologies. More information about wind, building, and vehicle technologies can be found on the websites of the respective DOE technology offices: Wind Energy Technologies Office, Building Technologies Office, Vehicle Technologies Office.
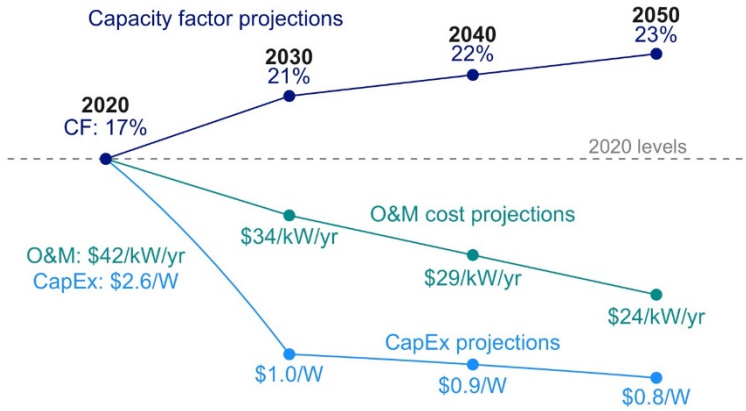
Figure 6 - 18. 2020 ATB Advanced projections for land-based wind upfront cost, O&M cost, and capacity factor

By 2050, when the power sector is completely free of emissions, substantial capacity contributions from RE-CT technology are necessary. RE-CTs may be fueled by hydrogen. Information about hydrogen can be found on the DOE Hydrogen and Fuel Cell Technologies website.

The NREL ATB provides more details about cost and technology advances in these and other generation technologies (NREL 2020).

7

The Role of Solar
by End-Use Sector

7 The Role of Solar by End-Use Sector

The energy system exists to generate and deliver power for end-use activities. These end uses are often categorized into three sectors: residential and commercial buildings, transportation, and industry. In this chapter, we analyze the role of solar in decarbonizing each of these end uses. Taking an end-use approach makes sense for four reasons. First, each end-use sector relies on a different combination of grid electricity and direct fuel use. By exploring and understanding existing end-use energy profiles and near- and long-term prospects for electrification, we can analyze the role of solar as a zero-carbon resource in each sector (Figure 7 - 1). Second, solar can enable technologies in each end-use sector. That is, owing to the unique characteristics of solar— namely its modularity, predictability (diurnal cycles), and future position as the lowest-cost power source—solar can enable key decarbonization technologies and approaches in each end use, such as load flexibility in buildings, vehicle electrification in the transportation sector, and growth of electrochemical manufacturing in industry. Third, each end use can enable solar in different ways. For instance, shifting flexible building loads to midday can increase the value of rooftop photovoltaics (PV). Understanding and leveraging these synergies is critical for evaluating and optimizing the role of solar in deep decarbonization. Fourth, the industrial sector will be responsible for manufacturing key inputs for deep decarbonization, such as silicon refining and glass manufacturing for PV, so finding ways to decarbonize these end uses could reduce the life-cycle emissions of zero-carbon technologies.
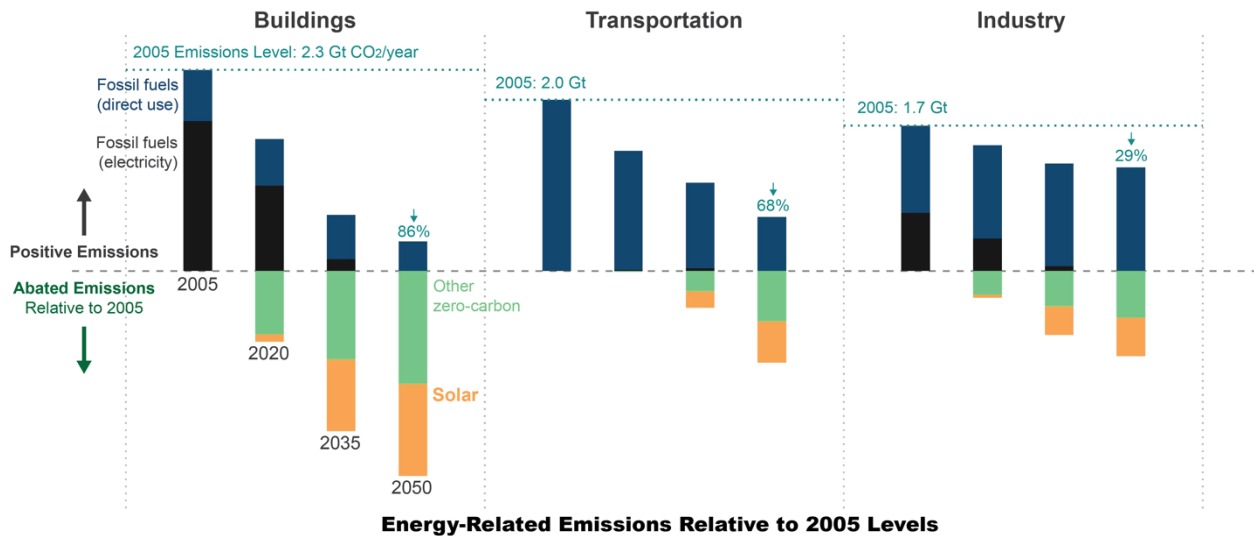
Figure 7 - 1. Emissions and abated emissions by end use in the Decarb+E scenario

For each end use, we begin by discussing the current energy use profiles (electricity and fuels) and prospects for further electrification. We then discuss the roles of solar as a zero-carbon resource and enabling technology and explore synergies between the end uses and solar deployment. We discuss the specific equity implications of solar-based decarbonization of the end uses. We also suggest priorities for R&D agendas related to the roles of solar in decarbonizing the end uses. We conclude this chapter with a discussion of barriers to and opportunities for maximizing the roles of solar in decarbonizing the end uses.

Text Box 4. Comparing electricity and direct fuel use

Throughout this chapter, we discuss end-use energy profiles in terms of relative shares of electricity and fuel use based on the Decarb+E scenario. We use this approach to discuss the relative near- and long-term roles of solar in decarbonizing each end use, primarily by decarbonizing electrified loads. However, relative *energy* shares of electricity and direct fuel use may misrepresent the roles of these two energy carriers in powering each sector. End-use electric technologies are generally more efficient, such that a unit of electricity generally translates to more end-use activity than a unit of direct fuel use. That is, the estimated share of electricity in each end use is less than the share of electrified loads and activities.

As a general rule, solar can play the most immediate role in decarbonizing end uses that are already electrified or can be electrified in the near term. We therefore begin this chapter in the buildings sector, where solar can make the most immediate and significant impacts owing to already high electricity use and strong prospects for further electrification.

7.1 Buildings

About 120 million residential and 6 million commercial buildings are in the United States (EIA 2018; 2020a). These buildings require energy to maintain comfortable living and working conditions through space heating, ventilation, air conditioning, and water heating (HVAC+WH). Building HVAC+WH accounts for about 60% of building energy use. The rest of building energy use reflects the electrical appliances housed within buildings, with key loads including refrigeration, lighting, and computing. Building energy use is characterized by relatively high electricity use and good prospects for further electrification (Figure 7 - 2). The prominent role of electricity translates into a similarly prominent near-term decarbonization role for solar. Solar could help decarbonize the remaining fuel-based sectors (mostly HVAC+WH), first in the near term by blending solar-based fuels (e.g., hydrogen, synthetic hydrocarbon fuels) into existing building heating systems, then—if any fuel-based sectors remain—eventually by supplying hydrogen to hydrogen-based heating systems.

ELECTRICITY

About 2.7 PWh/year today projected to rise to 3.6 PWh/yr in 2050, due partly to large-scale electrification

2020	72%
2050	54%
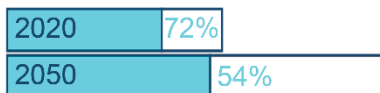
FUELS

About 11 quads/year today projected to fall to 7 quads/year in 2050, mostly for space and water heating

	18%
	16%

EMISSIONS

About 1.6 billion tons of CO_2/year in 2020, declining to 0.3 billion tons in 2050.

	36%
	15%
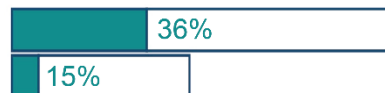
Sector shares of economy-wide electricity and fuel use. Buildings account for around 72% of electricity use and 18% of direct fuel use today. Though building electricity use increases, the sector's share of electricity use falls by 2050 due to electrification in other sectors.

Sector share of energy-based emissions

Figure 7 - 2. Key energy and emissions statistics for the buildings sector

Based on the Decarb+E scenario. PWh = petawatt-hour.

7.1.1   Electricity

Building electricity use roughly doubled from 1980 to 2018 (EIA 2020a). The increase can mostly be attributed to the growth of the U.S. building stock, primarily from new home construction. Secondary factors driving increased building electricity use include the proliferation of small high-tech devices (e.g., laptops, smart phones) and demographic shifts to warmer climates with larger air-conditioning loads (EIA 2020a). The electrification of fuel-based building loads will further increase building electricity use in the near and long terms (EIA 2020a; Larson et al. 2020). Fuel-based building loads mostly represent natural gas burned to heat building spaces and water. Electrification of these loads is being actively pursued as a way to reduce building energy-driven emissions (Dennis, Colburn, and Lazar 2016). Some electric alternatives are already competitive in 2021. For instance, many conventional HVAC+WH systems can be cost-effectively replaced with heat pumps, which use electricity to heat and cool buildings by leveraging differentials between air and near-surface temperatures underground.

7.1.2   Fuels

Under the Decarb+E scenario, about 35% of building load remains unelectrified in 2050. This remaining fuel-based portion largely represents space and water heating as well as gas cooking and gas- or wood-burning fireplaces. This assumption is, if anything, conservative. Many studies suggest that all building loads could be electrified, and that most can be cost-effectively electrified in the near term (Steinberg et al. 2017b; Deason et al. 2018; Larson et al. 2020).

7.1.3   Solar as a Zero-Carbon Input

Under the Decarb+E scenario, solar constitutes about 42% of annual grid output by 2035 and 45% by 2050. Under the same scenario, building energy use is 51% electrified by 2035 and 65% electrified by 2050. Assuming, imperfectly, that buildings consume proportional shares of solar electricity, we project that solar electricity powers 22% of building loads by 2035 and 30% by 2050.[77]

Solar plays a limited near-term role as a source of zero-carbon fuels for fuel-based building loads. In the near term, solar water heating[78] could displace fuel combustion for building water heating. Solar could also power the production of hydrogen fuels or synthetic hydrocarbons, which can be blended into existing fuel infrastructure, such as steam heating networks. Existing systems could incorporate blends composed of around 3%–20% hydrogen by volume and higher quantities of synthetic hydrocarbon fuels without needing significant upgrades (IEA 2019). We did not model the long-term contribution of solar to fuel-based building loads as part of this study. One possibility is that fuel-based building loads are completely electrified in the long term, as envisioned in the Energy Decarbonization scenario. Assuming some fuel-based building

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[77] Throughout this section, we assume that each end use consumes a share of solar electricity proportional to the sector's share of electricity demand. This assumption is imperfect in two senses. First, differences in applications of distributed solar (e.g., residential rooftop PV, PV at electric vehicle [EV] charging stations, PV at industrial facilities) may drive differences in each sector's use of solar. Second, differences in load flexibility may allow each sector to reshape load profiles in order to consume more solar than other sectors. However, lacking strong assumptions about how to project these highly uncertain factors, the proportional use assumption provides the best first-order approximation of each sector's use of solar electricity.

[78] Small-scale solar systems can heat water in two ways. The first, most common way, is a rooftop system dedicated to heating water instead of generating electricity. Solar water heaters are a mature technology and provide a cost-effective way of water heating in many buildings. The second way is to use rooftop PV to power an electric water heater in the building.

loads remain, as envisioned in the Decarb+E scenario, we estimate that solar-based hydrogen could meet around 7%–20% of those remaining fuel-based sectors by 2050, accounting for about 2%–7% of all building energy use by 2050, as a first-order approximation (see Section 7.6 for assumptions). Together with solar electricity, these estimates suggest that solar could power around 37% of building loads by 2050, the highest estimated contribution among the three sectors.

7.1.4 Solar as an Enabling Technology

The unique characteristics of solar could accelerate building electrification while enabling the broader utilization of flexible loads, the broader deployment of distributed storage, and a more substantial role for solar in fuel-based sectors.

Solar deployment could accelerate building electrification. As solar costs decline, low-cost solar electricity will increasingly compete with natural gas as the primary fuel source for building space and water heating (Victoria et al. 2021). Over time, more building owners will find that electrified heating powered by low-cost solar electricity is cheaper than fuel-based heating powered by natural gas. Distributed solar deployment could accelerate building electrification by improving the economics of converting from fuel-based to electrified infrastructure. Given that electrified alternatives, especially electric heat pumps, are often several times more efficient than fuel-based devices, the solar-driven acceleration of building electrification will improve the overall efficiency of the U.S. energy system.

Solar could enhance the value proposition of building energy automation and load flexibility. Several building end uses are emerging as key sources of demand flexibility (see Chapter 3), with estimated grid cost savings around $10 billion per year (Dyson et al. 2015). While many loads are inherently flexible, leveraging these loads reliably and cost-effectively requires information and communication technology systems that automate and coordinate flexible loads (Teplin et al. 2019). Today, the value of load flexibility is limited by the fact that most buildings lack such automation systems (Sofos et al. 2020), in addition to a host of regulatory barriers (see Chapter 3). Solar can enable load flexibility by enhancing the value proposition of investments in building automation (O'Shaughnessy et al. 2018). The enhanced value of building automation could lead to broader deployment and more significant potential to leverage flexible loads for grid services. Distributed solar could play a particularly important role in residential buildings, where automation remains extremely rare. The value proposition of optimizing on-site solar output could enable markets for smart thermostats and home automation devices (e.g., Amazon Alexa, Google Nest) that could significantly increase the load-flexibility capabilities of residential buildings in the near term (Kellison et al. 2020). All of these capabilities could be deployed to provide grid services, such as by aggregating solar, storage, and flexible loads into virtual power plants.

Solar could drive broader distributed storage deployment. In addition to backup power, using batteries to store and shift rooftop solar output has been a key value proposition in the emerging distributed battery storage market. Building-site battery capacity could grow from around 1 GW in 2020 to around 7 GW by 2025, much of it co-located with rooftop solar (Holden et al. 2020; Kellison et al. 2020). The synergistic relationship between distributed solar and storage could drive continued growth in the distributed storage market. Distributed solar and batteries could be

aggregated and coordinated—along with flexible loads—as virtual power plants, providing a valuable alternative to upgrades to grid infrastructure (Clack et al. 2020).

The distributed solar industry could serve as a platform for other building energy technologies. The U.S. distributed solar industry comprises several thousand professional system installers. Some of these installers have incorporated other building energy technologies into their business models. Some PV installers now offer broader home energy packages, including batteries and load-automation devices. PV installer-customer interactions could serve as touchpoints to educate building owners and operators about other beneficial building energy technology upgrades, such as energy efficiency and building automation.

Solar, storage, and load flexibility can enhance building resilience. As costs decline, batteries have emerged as a substitute for fuel-based generators as a source of building backup power. Solar can further enhance building resilience by providing a source of generation to power batteries during prolonged grid outages. Load flexibility can augment resilience by automating critical loads to ensure the optimal use of limited supplies of on-site solar power (Dyson and Li 2020).

7.1.5 Synergies

One of the key challenges in the grid integration of solar is the temporal mismatch between solar output peaks (midday) and grid demand peaks (early evening) (see Chapter 3). This mismatch requires measures to enhance grid flexibility to respond to the resulting swings in net grid demand. Building load flexibility can complement or substitute for supply-side flexibility as a way to address this challenge (Goldenberg, Dyson, and Masters 2018; Jenkins, Luke, and Thernstrom 2018). Instead of ramping up a flexible generator or storing and shifting solar output through batteries, grid peak demand can be shifted from the evening to the midday by shifting flexible loads. Tapping all existing flexible loads could reduce grid peak demand by as much as 20% (Fernandez et al. 2017; Hledik et al. 2019). Leveraging building load flexibility could be a key measure for integrating solar faster and more cost-effectively.

Building energy technology automation, coordination, and aggregation can significantly enhance the role of solar in building energy decarbonization (O'Shaughnessy et al. 2018; Neukomm, Nubbe, and Fares 2019) (Figure 7 - 3). As of 2020, building automation, coordination, and aggregation capabilities are generally limited to large commercial buildings (Sofos et al. 2020). However, advances in information and communication technologies have led to increasing building automation and coordination capabilities in smaller buildings (Hittinger and Jaramillo 2019). More recently, the emergence of affordable smart thermostats and home assistants (e.g., Amazon Alexa; Google Nest) has improved prospects for residential-scale automation and coordination (Earle and Sparn 2019). Further, demand-side resource aggregation is gaining growing acceptance through the implementation of utility- and developer-led pilot projects (Cook et al. 2018). Future technological advances and the development and refining of new aggregation models present significant opportunities to optimize the roles of distributed solar, flexible loads, and distributed batteries in the decarbonization of the building sector and electric grid more broadly.

Automation	Coordination	Aggregation

Device functions are individually controlled and automated.	Device functions are co-optimized across different devices.	Multiple devices are coordinated as a single unit to provide grid services.
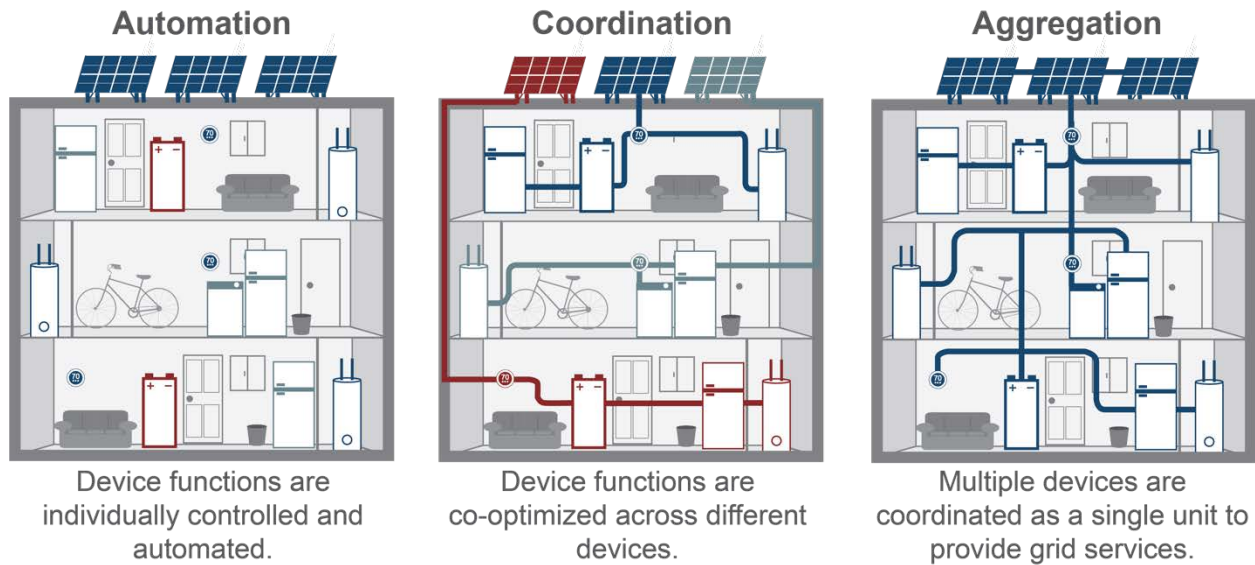
Figure 7 - 3. Building energy system automation, coordination, and aggregation

7.1.6 *Equity*

A central equity issue related to the role of solar in buildings is the inequitable adoption of rooftop solar. We discuss this topic in depth in Chapter 4. Inequitable adoption is not unique to solar and needs to be understood in a broader social and economic context. Regardless, rooftop PV adoption inequity could undermine efforts to implement rate reforms that would incentivize the beneficial adoption of rooftop PV (Welton and Eisen 2019). Future deployment of rooftop solar and other building energy technologies can occur more equitably. Policies—particularly means-tested incentives—and alternative financing models could increase low- and medium-income (LMI) PV adoption rates (O'Shaughnessy et al. 2021). LMI adoption of rooftop or community solar could help reduce LMI energy burdens and directly address historical energy justice issues.

7.1.7 *R&D*

DOE supports various initiatives and programs aimed at enabling high-performing, energy-efficient, and demand-flexible residential and commercial buildings. Projects span technology R&D, demonstration, workforce development, stakeholder engagement, and more. Certain programs are especially relevant to the integration of buildings and DERs, such as work that considers energy efficiency and demand flexibility alongside smart technologies and communications, all of which can help maximize the synergies between PV, buildings, and grid technologies.

Based on our review of the literature and feedback from a technical review panel, we identified the following near-term priorities for R&D focused specifically on optimizing the role of solar in buildings:

- *Soft cost reduction*: Non-hardware or "soft" costs have been and remain a key barrier to distributed solar adoption. Soft costs are increasingly driven by relatively high customer acquisition costs as well as the patchwork of inconsistent local permitting, inspection, and

interconnection requirements for PV installation in the United States. Soft cost reduction remains a central component of the U.S. solar market research agenda.

- *Solar plus*: Co-optimized solar plus storage has gained a foothold in U.S. rooftop PV markets. In contrast, solar plus storage and load flexibility, or simply "solar plus," remains rare, despite a growing body of literature demonstrating the strong synergies between solar, batteries, and load flexibility. Further research is required to identify the barriers to this market and the technology, market, and policy innovations that can unlock solar plus and the associated private and grid benefits.

- *Solar in cities*: Urban environments pose unique challenges to distributed building-sited solar deployment and large-scale electrification. Most of the abundant PV-viable rooftop space in large U.S. cities remains underutilized. The under-deployment of PV in cities represents a host of barriers, many related to split incentives in buildings occupied by lessees rather than owners. Research is required to identify solutions to split incentives and other ways to vitalize urban rooftop PV markets.

- *Building-integrated PV*: Although rooftop-mounted PV is—by far—the dominant form of building-sited solar, other technologies offer attractive alternatives with unique benefits. A variety of building-integrated PV technologies could increase the aesthetic appeal of PV (e.g., solar shingles), use additional building spaces (e.g., walls and windows rather than only rooftops), and increase the technical potential of distributed solar in the United States. However, building-integrated PV remains a small niche market. Further research is required on measures to improve the near- and long-term viability of building-integrated PV and related technologies such as PV paints and glazing.

7.2 Transportation

There are about 290 million vehicles in the United States, including light-duty passenger cars and trucks (about two thirds of vehicles), heavy-duty vehicles, airplanes, ships, boats, and trains (BTS 2021). Transportation energy use is characterized by its nearly complete reliance on direct fuel combustion but good prospects for near-term electrification of light-duty and some medium- and heavy-duty vehicles (Figure 7 - 4). Ongoing vehicle electrification means that solar will play a growing role in decarbonizing transportation in the near term. The long-term role of solar in the transportation sector depends on innovations in solar-based fuels.[79]

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[79] Biofuels could play a substantial role in decarbonizing the transportation and industrial sectors. Consistent with the rest of this report, we focus on fuels with a direct role for solar, meaning primarily hydrogen and synthetic hydrocarbons. These solar-based fuels could be used as feedstocks in the production of biofuels, but this pathway is outside the scope of this section.

ELECTRICITY
About 0.03 PWh/yr today projected to rise to 1.6 PWh/yr in 2050 due partly to large-scale vehicle electrification

| 2020 | ~0% |
| 2050 | 24% |
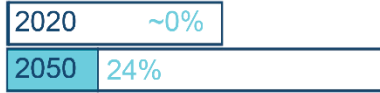
FUELS
About 28 quads/year today projected to fall to 12 quads/year in 2050, mostly for heavy-duty vehicles, air, and maritime travel

| 42% |
| 29% |
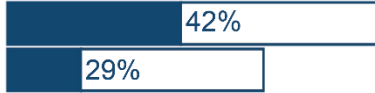
EMISSIONS
About 1.6 billion tons of CO2/year in 2020, declining to 0.8 billion tons in 2050.

| 36% |
| 36% |
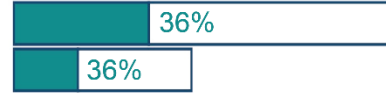
Sector shares of economy-wide electricity and fuel use. Transportation accounts for about 42% of direct fuel use and almost no electricity use today. Large-scale vehicle electrification increases the electricity share of transportation to 24% by 2050 while decreasing the sector's share of direct fuel use to 29%.

Sector share of energy-based emissions

Figure 7 - 4. Key energy and emissions statistics for the transportation sector

Based on the Decarb+E scenario

Text Box 5. Battery electric vehicles versus fuel cell electric vehicles

Most EVs use batteries to generate the electricity that powers the vehicle. Fuel cell electrical vehicles use fuel cells, typically based on hydrogen fuels, to generate electricity that powers the vehicle. The key distinction, for the purposes of this report, is that battery EVs can be charged directly from the grid or a PV system, while fuel cell vehicles require refueling. For this reason, we discuss battery EVs under the sub-section on electricity (Section 7.2.1) and fuel cell vehicles under the sub-section on fuels (Section 7.2.2). Throughout this section, the term EV refers exclusively to battery EVs.

7.2.1 Electricity

Electricity accounted for less than 1% of transportation energy use as of 2020. However, EV markets are growing rapidly in the United States and globally, due to factors including improved battery performance, falling battery costs, policy support, and regulations and standards to reduce fossil fuel consumption (Muratori et al. 2021). In the United States, EV sales increased from around 1,000 vehicles in 2010 to about 300,000 in 2020 (EIA 2021a). In California, EVs already account for 8% of new vehicle sales (Muratori et al. 2021). Projections for vehicle electrification range significantly, from as low as 10% to as high as 100% of light-duty vehicle sales by 2050 (Muratori et al. 2021). In our *Solar Futures* analysis, the electrified share of the transportation sector (in energy terms) increases from 0.2% in 2020 to 1%–11% in 2035 and 1.3%–31% in 2050,[80] representing as much as 76% of vehicle miles traveled by 2050.[81] This uncertainty reflects the dynamic nature of the EV market and many unanswered questions around the deployment of charging infrastructure, consumer acceptance, vehicle performance, and future cost trajectories (Muratori et al. 2021).

Vehicle electrification will occur at different rates for different types of vehicles and for different types of travel. Fortunately, the vehicle classes that are easiest to electrify also account for most of the sector's emissions (Figure 7 - 5). Light-duty vehicles (e.g., passenger cars, light-duty

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[80] Lower bounds are from the Decarb scenario, upper bounds from the Decarb+E scenario.

[81] The shares in energy terms are significantly less than the shares in terms of vehicles and vehicle miles traveled due to differences in the efficiency of EVs.

trucks) that have relatively small power requirements and tend to make frequent, short trips are generally the easiest to electrify. As a result, most light-duty vehicles—which account for about 60% of transportation emissions (EPA 2018b)—could conceivably be electrified in the near term. In the Decarb+E scenario, 88% of light-duty cars and 81% of light-duty trucks are assumed to be electrified by 2050. Medium-duty vehicles that make short, frequent trips are generally the next rung in the vehicle electrification ladder. Examples include city buses and delivery vans, as well as some passenger trains and lightweight aircraft. Under the Decarb+E scenario, 94% of buses and 52% of medium-duty vehicles are electrified by 2050. Heavy-duty vehicles pose more challenges for electrification (Giuliano et al. 2020), but significant shares of heavy-duty transportation could be electrified in the long term (Phadke et al. 2021). Under the Decarb+E scenario, 37% of heavy-duty vehicles are electrified by 2050. For some applications, such as oceangoing tankers and commercial flight, electrification may not be cost-effective even in the long term, though some infrastructure (e.g., maritime ports) can be electrified. Most passenger rail can be cost-effectively electrified, but the higher power requirements of freight rail pose additional challenges for electrification.
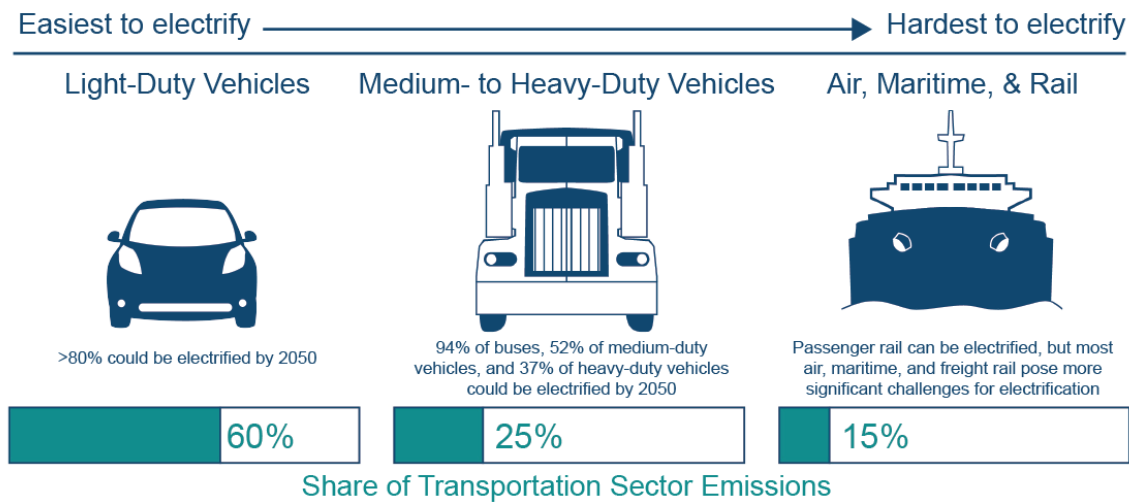
Figure 7 - 5. Electrification projections and shares of transportation sector emissions by vehicle type

The Biden Administration has put forward aggressive goals and initiatives focused on decarbonizing and electrifying the nation's transportation sector.[82] As part of the American Jobs Plan, grant and incentive programs have been proposed to build a national network of 500,000 EV chargers by 2030. In addition, the plan includes replacement of 50,000 diesel transit vehicles and the electrification of 20% of the nation's school bus fleet through a new Clean Buses for Kids Program at the Environmental Protection Agency. Efforts are also underway to electrify the federal fleet, including the United States Postal Service. Several major auto manufacturers have committed to partially or fully electrifying their vehicles over the next few decades.

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[82] Consistent with the rest of this report, here we are referring to decarbonization of the use phase of transportation. Different vehicle types (e.g., internal combustion engine, EVs, fuel cell electric vehicles) entail differences in life-cycle emissions, particularly during resource extraction and manufacturing. The industrial life cycles of vehicles are outside the scope of this report.

7.2.2 Fuels

As of 2020, about 99% of transportation load was powered by direct fuel combustion. Synthetic hydrocarbon fuels, biofuels, and hydrogen fuels are viable transportation fuel alternatives. The future trajectories of these alternative fuels depend on their relative costs, the costs of fossil fuels, and the deployment of fueling infrastructure. Synthetic hydrocarbons and biofuels can largely be deployed using existing infrastructure. In the case of synthetic hydrocarbons, it remains unclear how these fuels could be manufactured and used at scale with net-zero emissions given the challenge of capturing the carbon embedded in these fuels in mobile sources. Biofuels already account for around 10% of transportation fuel inputs.

Hydrogen and hydrogen fuel cells have emerged as a scalable alternative that could be deployed as a zero-carbon transportation fuel source (Ruth et al. 2020). Hydrogen is light, storable, and more energy dense than EV batteries, though still less dense than fossil fuels (IEA 2019). The key barriers to a hydrogen-based transportation system are not technical but economic: hydrogen currently cannot compete with fossil fuels except in small niche applications such as forklifts. However, as hydrogen fuel and fuel cell costs decline and decarbonization efforts ramp up, the economic challenge shifts towards hydrogen's ability to compete with EVs. As of 2021, about 10,000 hydrogen fuel cell vehicles have been sold in the United States (Satyapal 2021), compared to about 300,000 EVs sold every year, and EV fueling infrastructure capacity far exceeds hydrogen fueling capacity (IEA 2019). Hydrogen could complement EVs by fueling transport that is more difficult to electrify, especially light- and medium-duty vehicles with long ranges, heavy-duty vehicles, air travel, rail freight, and maritime travel (IEA 2019).

7.2.3 Solar as a Zero-Carbon Input

Under the Decarb+E scenario, solar constitutes about 42% of annual grid output by 2035 and 45% by 2050. Under the same scenario, transportation energy use is 11% electrified by 2035 and 31% electrified by 2050. Assuming, imperfectly, that transportation consumes proportional shares of solar electricity, we project that solar electricity powers 5% of transportation loads by 2035 and 14% by 2050.

Solar plays a limited near-term role as a zero-carbon source for fuel-based transportation. The long-term role of solar in powering fuel-based transportation depends on innovations and cost reductions in hydrogen fuel production. We did not model the long-term contribution of solar to transportation fuels as part of this study. As a first-order approximation, assuming future fuel use envisioned in the Decarb+E scenario, we estimate that solar-based hydrogen could meet around 9%–20% of transportation fuel use by 2050, accounting for about 6%–14% of all transportation energy use by 2050 (see Section 7.6). Together with solar electricity, these estimates suggest that solar could power around 28% of transportation loads by 2050.

7.2.4 Solar as an Enabling Technology

The unique characteristics of solar could enable broader vehicle electrification and a more prominent role for hydrogen fuels in the transportation sector.

Distributed solar can enable direct EV charging. Solar can be deployed at small scales at EV charging locations, such as on the rooftops of vehicle owners, the parking canopies of commercial fleets, or at public charging stations. PV installed at vehicle chargers provides a source of zero-carbon electricity that can be directly input to the vehicle's battery. Direct PV-to-

vehicle charging could reduce efficiency losses by avoiding the power conversion required when charging direct-current vehicle batteries with AC grid electricity.

Solar can improve the value proposition of vehicle electrification. Higher levels of solar penetration tend to decrease midday wholesale electricity prices. On grids where rate structures reflect wholesale price variation (e.g., time-of-use rates), electricity will generally be cheaper when solar is available. The availability of cheap midday electricity improves the economics of EV adoption. Rooftop PV adoption, in particular, can significantly improve the economics of EV adoption. Households and businesses that have already adopted rooftop PV will, in general, realize quicker paybacks on EVs given their access to zero-marginal-cost electricity. Households with PV may also be primed to adopt EV due to non-economic factors such as peer effects or desires to increase the environmental value of their PV systems (Kaufmann et al. 2021). As a result, rooftop PV adoption could drive EV adoption.

Solar can enable managed EV charging. Managed EV charging refers to measures to purposefully charge EVs at certain times and at certain locations to achieve specific objectives (Szinai et al. 2020). Managed EV charging could be a key solution to mitigating the potential impacts of large-scale vehicle electrification on distribution grids. With unmanaged charging, EV charging will tend to occur in spikes at specific times, such as when commuters return home from work and plug in their vehicles for evening charging. Unmanaged EV charging will significantly increase grid peak demand and force distribution grids to respond to rapid increases and drops in grid electricity demand (Muratori 2018; Abergel et al. 2020). The reliably diurnal and low-cost nature of solar can enable managed EV charging by attracting EV charging away from peak hours. For instance, utilities could implement dynamic rates with lower volumetric ($/kWh) rates during the day, reflecting the availability of low-cost solar in these hours. Dynamic rates would incentivize EV owners to charge vehicles with midday rather than peak electricity. Further, distributed solar could enable managed EV charging over space by incentivizing EV charging at specific locations with direct access to low-cost distributed solar. For instance, businesses could install PV on car parking canopies and feed the output directly into EV charging stations. These workplace charging solutions would incentivize off-peak charging and maximize the use of on-site solar.

Solar can help enable vehicle-to-grid charging. Today, EV batteries are dedicated exclusively to powering vehicles for transportation. However, EV batteries can also be treated as sources of reserve capacity and grid flexibility (Wolinetz et al. 2018). Solar can help enable these "vehicle-to-grid" applications by providing a source of low-cost power to store and shift to meet grid needs. At high levels of EV penetration, leveraging only 5% of EV battery capacity in vehicle-to-grid applications could significantly reduce grid peak demand (Abergel et al. 2020). With vehicle-to-grid capability, vehicles could provide additional storage capacity to temporally shift solar output. Vehicle-to-grid capabilities can also be used to enhance local resiliency by providing backup power.

Abundant low-cost solar can improve the economics of zero-carbon fuels. Even under assumptions for aggressive cost reductions in electrolysis, the economic potential of hydrogen fuels would only power around 19% of future fuel-based transportation loads (Ruth et al. 2020). Fully decarbonizing the transportation sector will require substantial innovations in alternative fuels or much more aggressive cost reductions and innovations in electrolysis. Abundant, low-

cost solar could play a key role in improving the economics of electrolysis (Eichman et al. 2020). We review this enabling role in more depth in Section 7.3.

Vehicle-mounted solar can complement batteries or fuels. PV can be directly deployed onto vehicles, particularly on vehicles with large, exposed surface areas such as delivery trucks and buses. Due to surface space constraints and diurnal solar cycles, it is unlikely that vehicle-mounted PV will ever serve as a primary power source, at least for long-range transportation. Vehicle-mounted PV could, however, complement batteries or engines as power sources in vehicles.

7.2.5 Synergies

Similar to the case of building load flexibility (Section 7.1.5), electrified transportation load flexibility could help integrate larger penetrations of solar. Managed EV charging could simultaneously reduce EV contributions to grid peaks and maximize the use of solar, helping further mitigate the temporal mismatch between solar peaks and grid peak demand (Szinai et al. 2020). Managed EV charging could also reduce solar curtailment, which could drive a more efficient use of solar and significantly reduce grid operating costs (Szinai et al. 2020).

Rooftop solar has a synergistic relationship with EV adoption: rooftop PV adopters are more likely to adopt EVs, and households and businesses that have already adopted EVs are likewise more likely to adopt rooftop PV (Kaufmann et al. 2021). This synergistic relationship could create self-perpetuating cycles of adoption. PV adopters will be driven to adopt EVs, and EV owners will be driven to adopt PV. The strength of this synergy is not yet well understood, but it could have significant implications for the pace of PV and EV deployment.

7.2.6 Equity

LMI households are significantly less likely to adopt EVs than high-income households, primarily owing to the purchase price premiums of EVs and fuel cell vehicles (Borenstein and Davis 2016). As a result, the financial benefits of EV adoption (long-term fuel savings) are likely to be inequitably distributed with respect to income and other demographic factors such as race (Borenstein and Davis 2016). The inequitable adoption of distributed PV may exacerbate the inequitable adoption of EVs: LMI households are less likely to adopt PV, which may make these households even less likely to adopt EVs (Kaufmann et al. 2021). Absent policy intervention, the synergistic relationships between PV and EV adoption could create inequitable cycles of deployment that channel financial benefits away from LMI communities.

EV and fuel cell vehicle deployment can have directly beneficial impacts on local air quality. The potential equity implications of these air-quality impacts are not well understood and require further research. On the one hand, inequitable EV adoption implies an inequitable distribution of these air-quality benefits, with the possibility that high-income neighborhoods will enjoy more air quality improvements than LMI neighborhoods. On the other hand, it is not clear that clustered EV adoption equates to clustered improvements in air quality, and large-scale vehicle electrification could yield broad public air-quality benefits that far outweigh marginal differences in air quality between neighborhoods. Further, the electrification of medium-duty vehicles with short ranges—such as city buses and garbage trucks—present viable near-term opportunities for air-quality improvement in inner-city neighborhoods.

7.2.7 R&D

DOE undertakes research, development, and deployment to advance battery technologies, EVs, charging infrastructure, technology integration, lightweight and propulsion materials, and advanced combustion systems and fuels. For example, one program is supporting battery chemistry and cell technology research to reduce the cost of EV batteries to less than $100/kWh, increase the range of EVs to 300 miles, and decrease charge time to 15 minutes or less. These efforts are important for maximizing the synergies between EVs and PV and for enabling EVs to work in tandem with PV as a grid resource. In addition, DOE R&D efforts are aiming to enable hydrogen use in industrial, energy storage, and transportation applications.

EVs and hydrogen fuel cells are emerging technologies with substantial R&D agendas. A comprehensive review of these agendas is outside the scope of this study, given that many R&D needs do not directly relate to the role of solar (e.g., R&D needs for improved EV charging infrastructure). Based on our review of the literature and feedback from a technical review panel, we identified near-term priorities for R&D focused specifically on optimizing the role of solar in transportation:

- *Technologies to enable large-scale managed EV charging coordinated with solar*: Managed and coordinated EV charging could unlock key synergies between electrified transportation and abundant, low-cost solar. Further research is required on the technological, market, and policy solutions to implement managed EV charging at scale.

- *Batteries that can withstand more charge cycles to enable solar-to-EV-to-grid applications*: Vehicle-to-grid charging could enhance the value of EVs and solar. However, with existing battery technologies, the costs of vehicle-to-grid applications from more rapid battery degradation currently outweigh the benefits. R&D is needed to identify strategies to reduce battery degradation in existing technologies or to identify new technologies that can withstand more frequent charging and discharging in vehicle-to-grid applications.

- *Fast charging technologies coupled with solar and storage*: Faster EV charging could accelerate EV deployment. However, fast charging entails large spikes in power demand. Fast charging could be enabled by coupling fast chargers with solar and storage, which would mitigate the impacts of fast charging on grid demand profiles.

- *Technologies to enable integration of electrolyzers with solar generation*: R&D that reduces the capital cost of electrolysis, improves efficiency, and reduces the cost of renewable energy (such as solar), is essential to cost-competitive production of clean hydrogen.

- *Technologies to enable solar-to-FCEV-to-grid applications:* Fuel cell electric vehicles (FCEVs) can also act as flexible generators and provide electricity back to the grid. However, fuel cell system improvements—such as using advanced membrane materials, decreasing platinum group metal catalyst loading to reduce costs while maintaining good performance, improving corrosion-resistant bipolar plate materials, and improving system control strategies to reduce fuel cell degradation—are needed to attain durability sufficient to meet vehicle lifetime requirements and provide additional grid services.

7.3 Industry

Industry comprises all energy uses involved in producing goods and services. While industry includes hundreds of different activities, most industrial emissions stem from a few specific activities. Fuel refining, chemicals manufacturing, and iron and steel manufacturing together account for around 45% of current industrial emissions. Major industrial end uses include combined heat and power generation, conventional boiler use, and process heating (McMillan et al. 2016). Industrial energy use is characterized by a relatively large share of direct fuel combustion and limited prospects for further electrification even in the long term (Figure 7 - 6). Solar can play immediate roles in decarbonizing the roughly 14% of industrial loads that are already electrified. The long-term role of solar in decarbonizing the industrial sector will largely hinge on innovations and cost reductions in solar thermal technologies, electrochemical manufacturing, and the production of solar-based fuels.

ELECTRICITY

About 1 PWh/yr today projected to rise to 1.5 PWh/yr in 2050.

27%	2020
22%	2050

FUELS

About 22 quads/year today projected to increase to 23 quads/year in 2050 due to limited prospects for electrification

36%	
55%	

EMISSIONS

About 1.3 billion tons of CO$_2$/year in 2020, declining to 1.1 billion tons in 2050.

29%	
49%	

Sector shares of economy-wide electricity and fuel use. Industry accounts for about 27% and 36% of electricity and direct fuel use today. Given the sector's limited prospects for further electrification, industry's share of direct fuel use increases to 55% by 2050.

Sector share of energy-based emissions

Figure 7 - 6. Key energy and emissions statistics for the industrial sector

Based on the Decarb+E scenario.

7.3.1 Electricity

Electricity plays a relatively limited long-term role in industry owing to the unique power and heat requirements of industrial processes. While most industrial processes can technically be electrified, the prospects for cost-effective electrification of many processes are limited even in the long term (Deason et al. 2018). However, some industrial processes lend themselves better to electrification than others. As a general rule, industrial activities that do not require high-temperature (>400°C) process heat are more suitable for electrification (Deason et al. 2018). Examples include paperboard mills, wet corn mills, breweries, and electrochemical manufacturing (i.e., producing chemical outputs via the application of electric current to chemical inputs). Many industrial processes can at least be supplemented with electricity, such as process cooling and powering electric machines. Electrified technologies such as industrial heat pumps, electric boilers, resistance heaters, microwave heaters, and electric arc furnaces could substitute for fuel-based technologies in some industrial applications. Electrolysis (mediating chemical reactions using electricity) can theoretically substitute for fuel combustion in processes such as steel production from iron ore and extractive metallurgy, but significant R&D is required to scale these applications (Bataille et al. 2018).

Advances in electrochemical manufacturing could play a critical role in the decarbonization of the industrial sector and the energy system more broadly (De Luna et al. 2019). Most chemical

manufacturing today relies on fossil fuels for energy and chemical inputs, resulting in emissions both from the burning of fuels for energy and from the release of carbon during chemical reactions. Electrochemical manufacturing, in contrast, derives chemical outputs through the application of electricity to chemical inputs, mostly hydrogen, carbon, and nitrogen. Electrochemical manufacturing can decarbonize chemical energy feedstocks by using zero-carbon electricity sources such as solar rather than carbon-emitting fossil fuels. Further, electrochemical manufacturing can decarbonize chemical reactions, either by using hydrogen rather than carbon or by using recycled carbon from other processes (e.g., carbon captured from fossil fuel combustion). Solar-based electrochemical manufacturing could therefore play a critical role in decarbonizing chemical products such as alcohols, plastics, and fertilizers (De Luna et al. 2019).

Crucially, electrochemical manufacturing can also develop hydrogen fuels and synthetic hydrocarbon fuels. These hydrogen and synthetic hydrocarbon fuels can, in turn, be used as energy inputs to power industrial processes and as inputs into the broader U.S. energy system. Electrochemical manufacturing plays a central role in deep decarbonization by providing the most viable pathway for decarbonizing major end uses that pose long-term challenges to electrification (Larson et al. 2020). While the potential of electrified fuels for deep decarbonization should not be understated, nor should the challenges of achieving that potential. As of 2019, electrochemical processes accounted for around 4% of hydrogen manufacturing and negligible shares of synthetic fuels production (De Luna et al. 2019). Electrochemical manufacturing will ramp up as the technology improves and renewable electricity costs decline, but ramping up the industry poses real near-term challenges (De Luna et al. 2019; IEA 2019).

7.3.2 Fuels

Direct fuel combustion is the most cost-effective energy input for many energy-intensive industrial applications, particularly for process heat, cogeneration processing, and conventional boilers (McMillan et al. 2016). Natural gas accounts for around 40% of direct fuel combustion for industrial processes, with most of the remainder coming from other petroleum fuels, and around 4% from coal combustion. Even under the Decarb+E scenario, we project that around 80% of industrial loads will still rely on fuel combustion by 2050.

Hydrogen and synthetic hydrocarbon fuels are the primary alternatives to carbon-emitting fossil fuels as inputs to industrial processes. Several industries already use pure hydrogen and hydrogen fuels, especially oil refining, ammonia production, methanol production, steel production, and the direct reduction of iron ore. Other industrial processes could be converted to hydrogen or synthetic hydrocarbon fuels rather than carbon-emitting fossil fuels (IEA 2019).

7.3.3 Solar as a Zero-Carbon Input

Under the Decarb+E scenario, solar constitutes about 42% of annual grid output by 2035 and 45% by 2050. Under the same scenario, industrial loads are 15% electrified by 2035 and 18% electrified by 2050 (in energy terms). Assuming, imperfectly, that industry consumes proportional shares of solar electricity, we project that solar electricity powers 7% of industrial loads by 2035 and 8% by 2050.

Solar plays a limited near-term role as a zero-carbon source for fuel-based industrial applications. The long-term role of solar in powering these applications depends on innovations

and cost reductions in synthetic fuel production such as hydrogen. We did not model the long-term contribution of solar to fuel-based industrial loads as part of this study. One possibility is that fuel-based industrial loads are completely electrified by 2050, as envisioned in the Energy Decarbonization scenario. However, assuming most industrial load continues to rely on direct fuel use as envisioned in the Decarb+E scenario, we estimate that solar-based hydrogen could meet around 6% of industrial fuel use by 2050, accounting for about 5% of all industrial energy use by 2050, as a first-order approximation (see Section 7.6).[83] Together with electricity, these estimates suggest that solar could power around 13% of industrial loads by 2050.

Solar thermal energy can also be used as a direct input to certain industrial processes (McMillan et al. 2016). Heat generated at CSP facilities can be delivered directly to industrial facilities and used in high-temperature applications such as process heat, thus obviating the need for fuel combustion. Solar thermal heat can theoretically serve as a direct input to most high-heat industrial processes. In an analysis of energy-intensive industries, McMillan et al. (2016) find that solar thermal heat could provide around 25% of industrial heat demand. The key constraining factors for the role of solar thermal heat and CSP more generally are resource potential and the need for new investments to integrate solar thermal heat with industrial loads. See Chapter 6 for more information on solar thermal heat generation.

7.3.4 Solar as an Enabling Technology

The unique characteristics of solar could enable more industrial electrification, scaling of electrochemical manufacturing, and industrial load flexibility, among other factors in the industrial sector. In particular, the low-cost nature of solar could make it an attractive substitute for natural gas and other industrial fuels. Using solar as an industrial power source therefore relies on ways on directly connecting industrial processes to solar (e.g., co-location) or rate structures that pass low solar costs through to industrial customers.

Abundant low-cost solar could drive electrification of industrial processes. As solar electricity prices decline, solar electricity will increasingly compete with natural gas as a fuel input to industrial processes such as generating process heat (Victoria et al. 2021). In the near term, solar could accelerate the electrification of industrial processes that are more immediately suitable for electrification, such as process cooling and powering machines. In the long term, abundant, low-cost solar could incentivize innovations to electrify industrial processes that are more difficult to electrify, particularly processes requiring high-temperature (>400°C) process heat.

Abundant low-cost solar could improve the economics of electrochemical manufacturing. The economics of electrochemical manufacturing depend primarily on electricity prices (De Luna et al. 2019). Abundant, low-cost solar could significantly increase the economic viability of electrochemical manufacturing and accelerate the production of zero-carbon fuels. Indeed, achieving deep decarbonization largely depends on a central role of solar in electrochemical manufacturing. Even under assumptions for aggressive cost reductions in electrolysis, the economic potential of hydrogen fuels would power less than 20% of future fuel-based sectors (Ruth et al. 2020). Fully decarbonizing transportation and industry will require substantial

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[83] Note that direct combustion of hydrogen fuels emits nitrogen oxides, an ozone precursor, and is thus not emissions free, though it is carbon free.

innovations in zero-carbon fuels or much more aggressive cost reductions and innovations in electrochemical manufacturing. Abundant, low-cost solar could play a key role in improving the economics of hydrogen or synthetic hydrocarbon fuels as substitutes for carbon-emitting fossil fuels.

Solar could help reduce process emissions. A unique characteristic of the industrial sector is the significant contribution of non-energy processes to the sector's emissions. Certain industrial processes—such as steel and chemicals manufacturing—require chemical reactions that release carbon dioxide, adding to the industrial sector's emissions. These process emissions are not directly related to energy use, similar to other non-energy emissions such as methane from livestock and carbon dioxide releases from deforestation. Nonetheless, solar can help reduce these process emissions in at least two ways. First, low-cost solar could be used to power systems to capture process emissions. The captured carbon could then be used as inputs to other industrial process, such as the production of synthetic hydrocarbon fuels, or permanently sequestered. Second, solar could provide an energy input to alternative chemical inputs. For instance, hydrogen can replace carbon as the key chemical input for iron ore reduction in steel manufacturing, resulting in chemical reactions that emit water vapor rather than carbon dioxide. By serving as the power source for hydrogen electrolysis, solar could therefore produce zero-carbon hydrogen as an input for zero-carbon steel.

Solar could enable distributed industry. Industrial facilities tend to cluster in specific regions, particularly those with access to low-cost energy and other inputs. Industrial agglomeration leads to a similar concentration of jobs and industrial economic activity. Further, industrial agglomeration exposes industries and local economies to the risks of market volatility. An alternative is modular or "distributed" industry with relatively small facilities sited more sparsely. Distributed industry reduces the financial risks of individual plants (Baldea et al. 2017). Distributed industry is particularly well suited for emerging, innovative products that may not be able to bear the risks associated with upfront investments in large facilities (Baldea et al. 2017). Solar could enable distributed energy by providing a broadly distributed source of low-cost power. Distributed industrial facilities could also co-locate with distributed solar projects.

7.3.5 Synergies

Similar to the other two end-use sectors, industrial load flexibility can be leveraged to optimize the value of solar. Certain industrial loads are inherently flexible. For instance, electrified machine operations can be shifted to maximize use of on-site solar output. In some industrial applications there is also potential for spatial load flexibility: shifting loads across space to take advantage of grid conditions, such as the availability of low-cost solar at one point on the grid. Some data centers have already begun experimenting with ways to shift data-processing loads between centers based on the availability of variable renewable energy. Firms with reserve manufacturing capacity could conceivably take a similar approach.

Growing demand for zero-carbon fuels could be a game-changing development for the role of solar in decarbonizing not only the industrial sector, but also the energy system more broadly. The constant energy needs of electrochemical facilities would incentivize these facilities to site on grids with low-cost electricity or co-locate with solar power plants. By siting on grids with abundant, low-cost solar, electrochemical loads could reduce future solar curtailment, resulting

in more efficient utilization of existing solar systems and driving long-term demand for further solar deployment.

7.3.6 Equity

Industrial facilities generate on-site point emissions that pose direct health risks to surrounding communities. Owing to the historically inequitable siting patterns of industrial facilities, these health risks are disproportionately borne by LMI communities and communities of color (Ash et al. 2009). Replacing fossil fuel inputs with distributed solar electricity or solar-based hydrogen fuels could improve air quality in such communities. However, many air toxics stem not from fossil fuel combustion but from various chemical refining processes. The decarbonization of industrial processes is an incomplete solution to these historical environmental justice issues, and the role of solar in alleviating these issues should not be overstated.

The U.S. industrial sector directly employs around 15 million people and underpins local economic activity in thousands of U.S. communities.[84] Deep decarbonization will require significant industrial restructuring that could affect the quantity and quality of industrial-sector jobs. The long-term impacts of deep decarbonization on industry remain unclear, but it is clear that deep decarbonization will drive gains in certain sectors (e.g., PV installation, EV manufacturing, electrochemical manufacturing) while driving losses in other sectors (e.g., fossil fuel refining, coal mining, internal combustion engine manufacturing). The quest for a just transition is the topic of growing academic and policymaker interest (Carley and Konisky 2020; M. S. Henry, Bazilian, and Markuson 2020).

7.3.7 R&D Needs

DOE leads several initiatives and programs focused on supporting the manufacturing of clean energy technologies, and it is investing in advanced, energy-related manufacturing technologies including combined heat and power and distributed energy systems for industry. In addition, DOE is leading RD&D for hydrogen and fuel cell technologies across 10 different program areas including, but not limited to, hydrogen production, hydrogen delivery, hydrogen storage, fuel cells, technology validation, and market transformation.

Based on our review of the literature, we identify two specific R&D priorities for maximizing the role of solar in industry:

- *Advances in electro- and thermochemical production of zero-carbon fuels.* These advances are critical to the deep decarbonization pathways envisioned in most major decarbonization studies, including the *Solar Futures Study*. R&D is required to identify near-term opportunities for cost reductions in electrochemical manufacturing to accelerate the transition to zero-carbon fuels. Further research is also required to understand tradeoffs between alternative fuels such as hydrogen, ammonia, and synthetic hydrocarbons, and the respective near- and long-term roles of these alternatives.

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[84] Jobs estimates depend on how the industrial sector is defined. According to the U.S. Bureau of Labor Statistics, in 2020 about 14.6 million people worked in manufacturing and another 700,000 worked in mining.

- *Further research on tradeoffs between different approaches to industrial decarbonization*. There are three primary pathways to industrial-sector decarbonization: (1) electrification, (2) conversion to solar-based fuels, and (3) use of zero-carbon thermal energy. Solar can play roles in all three pathways as an electricity input (1), energy input to solar-based fuels (2), and through CSP as a source of thermal energy (3). The tradeoffs and relative technical and economic potential of each pathway are not well understood (McMillan et al. 2016). Further research is required to analyze these pathways and identify priority applications of each pathway to specific industrial subsectors.

7.4 Barriers and Opportunities

Despite differences in energy use across the end-use sectors, the barriers and opportunities for a large-scale role of solar in decarbonizing these end uses are similar across the sectors. The primary barrier, particularly in the near term, is the limited economic potential of solar-based fuel production and the limited prospects for near-term electrification. Zero-carbon fuels are unlikely to compete at scale by 2035 (IEA 2019; Eichman et al. 2020; Ruth et al. 2020). As a result, solar will most likely have a limited near-term role in decarbonizing fuel-based end uses in all three sectors. This near-term barrier presents a long-term opportunity. As the technology evolves and costs decline, solar could become a critical input to the production of zero-carbon fuels (Eichman et al. 2020).

A second key class of barriers and opportunities, common across the sectors, includes barriers that undercut the synergies between solar and the end uses. Solar can enable specific end-use technologies (e.g., load flexibility, managed EV charging), and vice-versa. The realization of these synergies depends largely on regulatory structures, incentives, and business models. Potential barriers exist in each of these categories, but there are also clear opportunities to address these barriers:

- *Regulatory barriers and opportunities*: Existing energy regulatory structures designed around a centralized energy system can pose barriers to the use of demand-side resources. Opportunities to address these barriers include utility business model reforms, utility resource procurement reforms, and wholesale energy market reforms that eliminate inefficient barriers to the provision of demand-side services.

- *Incentive barriers and opportunities*: Electricity rate structures are key drivers of the economics of energy technology adoption decisions. Typical rate structures provide little or no incentive to invest in synergistic technologies, such as flexible building and industrial load technologies and managed EV charging software. Rate reform opportunities to address these barriers include time-of-use rates, real-time pricing, value of solar tariffs, or any other rate that provides price signals to incentivize load shifting. Any rate reform must consider tradeoffs in efficiency and equity, and how rate design could affect LMI ratepayers.

- *Business model barriers and opportunities*: New business models will be required to aggregate, automate, and optimize the use of distributed building energy technologies, vehicles, and flexible industrial loads. Emerging business models include distributed energy resource aggregation (a utility or third party aggregates and manages demand-side resources), virtual power plants (a third party aggregates demand-side resources and bids

those services to utilities or wholesale markets), microgrids (a cluster of solar and demand-side resources is managed as a system capable of islanding from the main grid), and community energy models (solar and demand-side resources are controlled on behalf of a community such as a neighborhood).

Technology lock-in is a third key class of barriers and opportunities for the role of solar in these end uses. All three end-use sectors include technologies that, once adopted, have useful lifetimes of more than 10 years. Particularly in the buildings and industrial sectors, large capital investments made today will result in infrastructure that will still be usable in 2050. As a result, decisions made today could pose long-term barriers to the role of solar and deep decarbonization more broadly. Technology lock-in illustrates the importance of immediate action to invest in solar-compatible infrastructure such as electric alternatives and hydrogen fuel systems. Technology lock-in also presents opportunities. Actions taken today could have long-term ripple effects by driving systemic changes that force systems to lock into zero-carbon pathways. For instance, investments in EV charging infrastructure could accelerate EV adoption, setting off more self-perpetuating cycles of PV and EV adoption. Ignoring these long-term ripple effects could result in an inefficient undervaluation of actions taken today that could help the system lock into zero-carbon pathways. Conversely, accounting for beneficial lock-in in infrastructure planning, grid integrated resource planning, and other planning and policymaking could accelerate the role of solar in decarbonizing the end uses.

Behavioral factors pose a fourth class of barriers and opportunities. The energy system exists to power human activities. These activities are influenced by numerous tangible and intangible behavioral factors. Lack of understanding of human behavior can, at times, pose direct barriers to the role of solar in decarbonizing end uses. A simple example is compliance: people do not always comply with protocols to optimize technologies. Partial compliance reduces the value proposition of many solar applications to end uses. For instance, EV owners are unlikely to strictly comply with managed charging protocols owing to the reality that people cannot always connect vehicles to chargers at specified times. As a result, theoretical values from solar-optimized EV charging are likely to overstate realized values. The field of behavioral economics provides numerous potential solutions, such as designing policy "nudges" that prompt beneficial behavior through non-intrusive interventions. Behavioral barriers to solar and the potential opportunities to address these barriers are not yet well understood, and they pose a promising area for further research.

7.5 Summary

Solar plays key roles in decarbonizing end uses in buildings, transportation, and industry. Solar plays the most immediate role in the buildings sector, which is characterized by a relatively large share of electrified loads, good prospects for near-term electrification, and the potential for near-universal electrification by 2050. Solar plays more limited near-term roles in transportation and industry because of the reliance of these sectors on direct fuel combustion. Large-scale vehicle electrification, reaching more than 80% of vehicles, creates a growing role for electricity in transportation over time. The long-term prospects for industrial electrification are relatively limited. In the long term, solar also plays a role in decarbonizing fuel-based sectors that are more difficult to electrify, particularly in transportation and industry. By 2050, using the assumptions of the Decarb+E scenario, we estimate that solar electricity powers around 37% of building energy, 28% of transportation energy, and 13% of industrial energy (Figure 7 - 7).
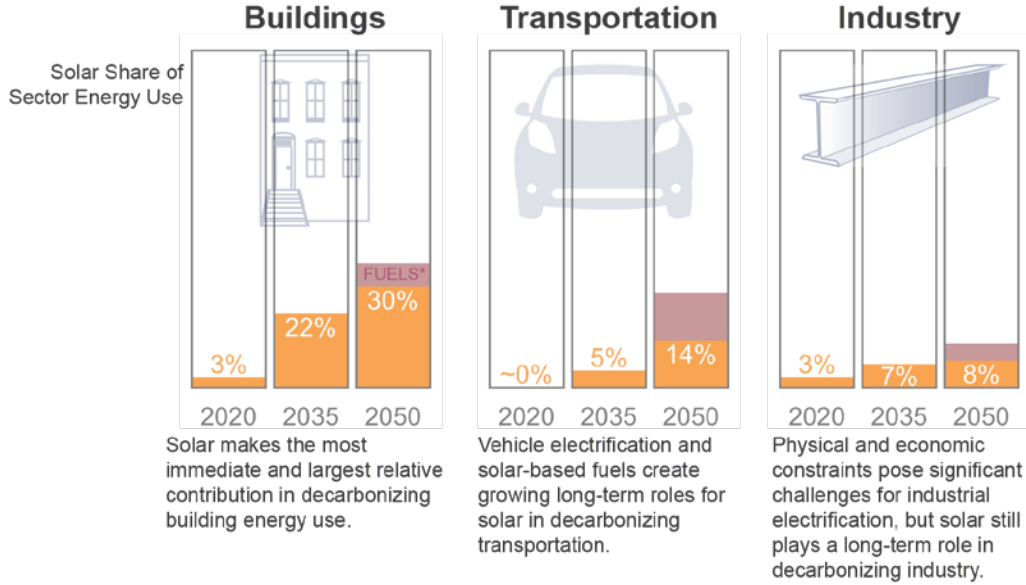
Figure 7 - 7. The role of solar by end use

* We did not model zero-carbon fuels as part of this study, displayed here are the rough approximations for hydrogen fuels described in Section 7.6

Solar also enables technologies and innovations in all three sectors. As a modular power source, solar can be co-located with end uses. Co-location can improve the value proposition of load flexibility and EV adoption. As a predictable power source, solar enables practices and technologies that optimize end-use demand through load shifting. Building and industrial loads can be shifted to midday, and EV charging can be managed to maximize the use of solar. As a low-cost power source, solar could enable key technological and market developments that will be critical for deep decarbonization. Low-cost solar could accelerate electrification by making electricity outcompete fuel alternatives such as natural gas in building heating and gasoline in transportation. Low-cost solar could also play a central role in improving the economics of electrochemical manufacturing and accelerating the transition to zero-carbon fuels.

7.6 Notes on Approximations for Zero-Carbon Fuels

We did not model the future contribution of solar to hydrogen-based fuels in this study. We estimate first-order approximations of this role by sector using 2050 fuel-use assumptions under the Decarb+E scenario. In all cases, we assume the hydrogen is manufactured using the same grid mix projected under the Decarb+E scenario. For buildings, the lower bound is given by the projected demand for hydrogen fuels in building heating by 2030 of about 1 quad, as estimated by the International Energy Agency (IEA 2019).[85] For the upper bound, we assume demand triples from 2030 to 2050, to 3 quads. For transportation, the lower bound is given by an estimated economic potential of about 2.3 quads of electro-manufactured hydrogen for transportation fuels (Ruth et al. 2020). The upper bound is the 5.4 quads of hydrogen fuels[86] for transportation assumed under the Energy Decarbonization scenario. For industry, we assume an

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[85] Throughout this section, these conversions assume an energy content of 0.14 exajoules per Mt of hydrogen. This particular estimate is based on IEA's upper-bound projection of 7.7 Mt of hydrogen demand for building heating in 2030.

[86] This includes both direct use of hydrogen and indirect use as fuel input for other synthetic fuels.

economic potential of 3.2 quads of electro-manufactured hydrogen for industry (Ruth et al. 2020).

8

Key Considerations for the Solar Supply Chain, Environment, Circular Economy, and Workforce

8 Key Considerations for the Solar Supply Chain, Environment, Circular Economy, and Workforce

The solar deployment envisioned in the *Solar Futures* scenarios could be associated with major economic, social, and environmental challenges and opportunities beyond the targeted reductions in carbon-emitting fossil fuel use, greenhouse gas (GHG) emissions, and air pollution reported in Chapter 2. Solar technologies would be manufactured in large quantities, requiring large amounts of materials, and ultimately resulting in substantial volumes of end-of-life (EOL) materials. Installing these technologies would result in job creation, as would manufacturing (if the domestic solar supply chain were to increase) and EOL management. Land would be needed to host solar energy installations. Considerable financial investments would need to be made. The United States would need to compete for resources and market share in a global clean energy economy. These potential challenges and opportunities should be considered in advance to ensure benefits are maximized and drawbacks minimized. The types and magnitudes of potential impacts depend in part on choices made by governments, businesses, and individuals.

This chapter aims to inform choices that would increase economic, social, and environmental benefits. It examines the impacts and options associated with the full solar project life cycle, including technology manufacturing, operation, and EOL treatment. Circular economy (CE) strategies—such as recycling, repair, and reuse—are highlighted throughout, as are approaches to addressing historical environmental justice and equity concerns. The framework in Figure 8 - 1 comprehensively depicts various strategies that can be implemented across the three main life cycle stages to enable the transition to a CE for photovoltaics (PV). The chapter also identifies key R&D needs related to improving the impacts from solar manufacturing, operation, and EOL treatment. The chapter does not address other technologies deployed in the *Solar Futures* scenarios, such as wind turbines and batteries, although the magnitude of their envisioned deployment justifies future study of their impacts. For details on the CE and environment aspects of this chapter, see (Heath et al. Forthcoming).
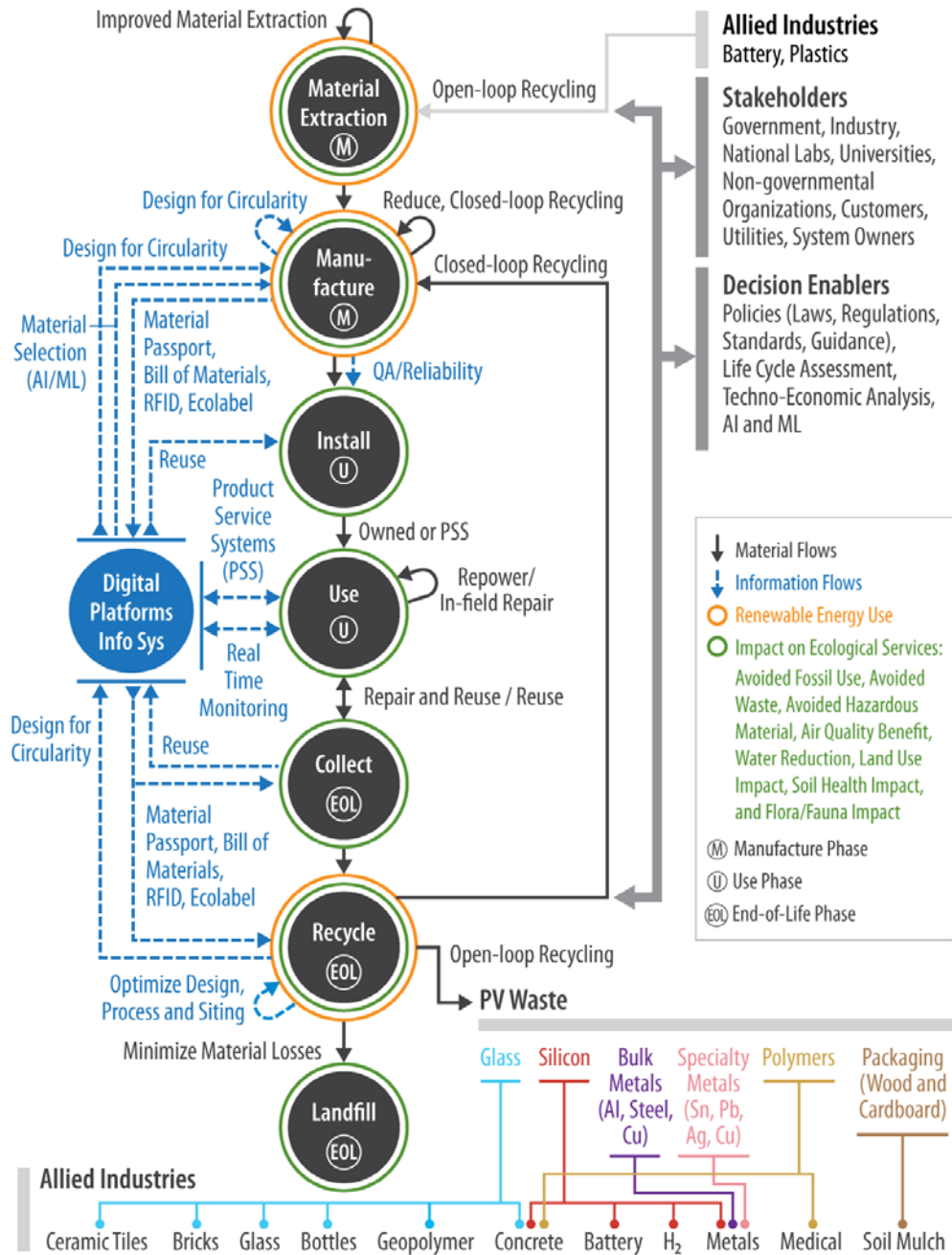
Figure 8 - 1. Systems framework to assess the current state-of-the-art and identify opportunities to advance the CE for PV

Material flows are in solid black arrows and information flows in dashed blue arrows, both of which flow through different stages within the three main life cycle phases denoted "M", "U," and "EOL" in circles representing the PV manufacturing, use, and EOL stages, respectively. Renewable energy can be used to lower the CO_2 footprint of the life cycle stages within orange circles. The life cycle stages within the green circles have an impact on ecological services. The framework includes stakeholders and decision enablers which impact the transition to a CE for PV. Allied industries are the downstream non-PV CE pathways to reuse materials recovered from a PV system and non-PV sources for secondary materials which can be reused in the manufacture of PV systems. Product service system (PSS) is the consumption of PV electricity without ownership of the PV system (e.g., leasing a residential PV system).

8.1 Manufacturing

The globalized, rapidly changing nature of the PV industry poses challenges to achieving the *Solar Futures* scenarios in the United States, but it also presents opportunities to re-envision the U.S. role in the global PV economy and maximize domestic benefits. Boosting U.S. PV manufacturing, resource extraction, and CE strategies could help mitigate material and component supply risks while creating domestic jobs. These benefits, however, must be weighed against cost efficiencies that may be attainable through global trade. The scale of envisioned PV growth also means that supply chain choices have important consequences for local and global social and environmental issues.

8.1.1 Material Demands

The *Solar Futures* scenarios would demand significantly higher amounts of materials used to manufacture PV and concentrating solar power (CSP) systems, compared with demands in 2021. In the context of simultaneously expanding global solar deployment, material requirements rise dramatically, and many materials used in solar technologies are used in other globally traded products, presenting resource competition challenges. However, analysis of potential U.S. and global demands suggests that material supplies likely will not limit solar deployment growth, especially if EOL materials are recovered and used in solar products. Breakthroughs in technologies and participation in what is currently a voluntary recycling and CE landscape in the United States will be required to maximize use of recoverable materials—yielding benefits in energy and materials security, social and environmental impacts, and the domestic workforce and manufacturing sectors. Section 8.3 discusses EOL materials and the challenging preconditions associated with substituting them for virgin materials in new module manufacturing.

PV

Material demands for a significantly expanded solar generation sector have been raised as a concern, most recently by the International Energy Agency (IEA 2021b). The IEA found that materials intensity for clean energy technologies, including PV, is multiple times higher than for the fossil energy sources it replaces. While the IEA found that electric vehicle (EV), electricity networks, and batteries are of significantly greater concern for issues surrounding materials requirements, PV's growth does require attention to materials demands.

We use the PV in Circular Economy tool (PV ICE) (Ayala, Mirletz, and Silverman 2020) to calculate virgin material demands for c-Si PV module manufacturing during 2010–2050 based on deployment in the *Solar Futures* scenarios.[87] PV ICE is a stock-vintage model, capturing c-Si PV manufacturing and technology evolutions in back- and forecasted annual cohorts, including improvements to cells, quality/reliability, and module lifetime as well as considering the market share of different module designs such as bifacial (glass-glass) modules and frameless modules. PV ICE extends its analysis through to module EOL by probabilistically modeling both performance degradation and failures, thereby providing more accurate and temporally refined

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[87] We focus on module-related material demands because of the unique importance of these materials to the PV industry and their unique circular-economy considerations. Our analysis does not address materials for other components of PV systems, such as aluminum racking and steel racking and tracking structures. See (B. Smith and Margolis 2019) for a broader discussion of PV material demands and supplies. Further research is needed on potential future issues for all PV-related materials at Solar Futures scales.

estimates of installed capacity, and of when cohorts of modules would be decommissioned as compared to the decommissioning estimates provided by the Regional Energy Deployment System (ReEDS) model (which assumes a constant 30-year lifetime). The evolution of efficiency is based on projections of the latest International Technology Roadmap for Photovoltaics (ITRPV 2021) and the PV Roadmap projections in (Wilson et al. 2020), which are roughly consistent with the assumptions underlying the PV cost projections used in ReEDS.[88] EOL is defined as a product failure, a degradation resulting in modules that produce 80% of their initial power rating, or the end of the expected project lifetime, which varies by year of installation (based on (Wiser, Bolinger, and Seel 2020)). Installed capacity in a given year equals the new year's installations plus all the previous generations deployed, minus degradation of operating modules and minus capacity from modules that have reached EOL through the three outlined pathways.

Material demands account for two factors reflecting material use efficiency: mining/refining efficiency and PV manufacturing efficiency. These account for material lost as part of the extraction and refining processes and capture manufacturing materials efficiency improvements over time.

The results presented here are preliminary estimates that could over- or underestimate true material demands in a few ways. First, we assume no recycled content in module manufacturing, nor any repaired or reused modules or components, i.e., a completely linear economy. To the extent some manufacturers use secondary (recycled) materials, virgin material demands are overestimated, though we hypothesize secondary materials utilization is low given demanding quality specifications of PV manufacturing. Similarly, if the nascent module secondary market grows, that will also reduce virgin material demands. In addition, PV ICE currently only models c-Si modules here. To account for the domestic market share of other PV module technologies, only a fraction of the ReEDS PV deployment projections are input to PV ICE. Based on analysis of prior-year deployment data, we assume 85% of the domestic PV market is c-Si. Future market shares are unknown; to the extent c-Si market share is higher, our material demand projections are underestimated, and to the extent market share is lower for c-Si, they are overestimated. Further details on the data assumptions and inputs can be found in (Heath et al. Forthcoming).

Figure 8 - 2 compares cumulative virgin material demands for c-Si PV for 2020–2050 by scenario. Glass accounts for most of the mass in each scenario. Though high in value, silver is barely visible within the scale of the chart; the amount of high embodied energy and carbon solar silicon is also very small compared to glass. The Decarb+E scenario has the greatest cumulative material demand through 2050. See (Heath et al. Forthcoming) for tabulated data.

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[88] While both ReEDS and PV ICE achieve the same maximal efficiency of 25%, they do so following different paths, leading to slight differences in market-average efficiency for any given year. The International Technology Roadmap for Photovoltaics (ITRPV) is also the source of PV ICE forecasts of cell thickness, kerf losses, silver and copper use, glass thickness, module size, and market shares of mono- vs. multi-crystalline silicon and bifacial and frameless modules.
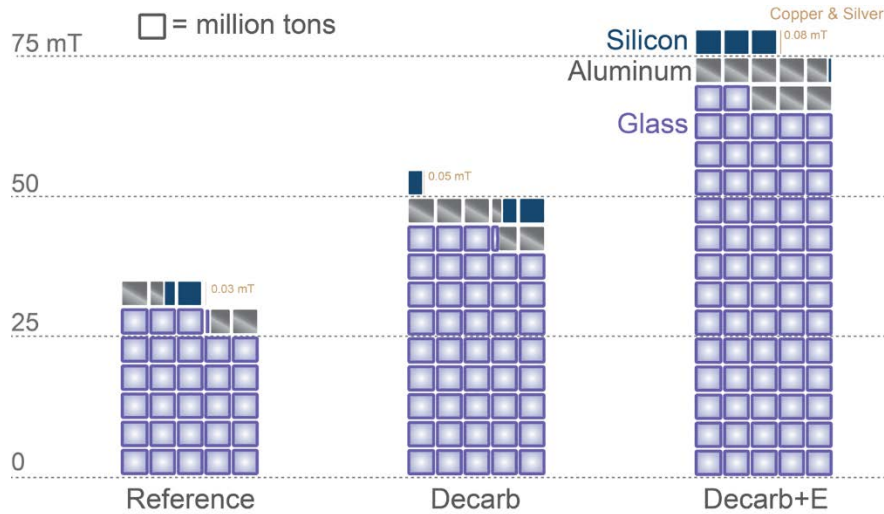
Figure 8 - 2. Comparison of virgin material demands for each silicon-based PV material cumulatively (2020–2050) across the three scenarios

Figure 8 - 3 puts average annual c-Si module material demands in context of the 2020 global production of each material. No increase in mining is assumed, and, for this comparison, material demands are not assumed to be met with either material stockpiles or recycled content. This analysis provides linear-economy (non-circular) "worst case" material demands and waste. Global PV deployment is estimated from analyst projections (IRENA 2019) to average approximately 300 GW$_{DC}$/year, while a global decarbonization study estimated roughly 1 TW$_{DC}$/year (Bogdanov et al. 2019). Global PV is assumed to be composed of 99% c-Si modules based on extrapolation of historical trends (Feldman, Wu, and Margolis 2021). Silver is the material demanded at the highest fraction of global supply. While still under 5% for the U.S. Decarb+E scenario, silver demand from PV could reach almost 40% of 2020 global production in a global decarbonization scenario. Concerns regarding the supply and expense of silver contacts have spurred research into copper substitutes. In addition, the mining industry has a history of adjusting capacity to meet demand, and neither national stockpiles nor secondary recovered materials are assumed in our analysis. Silver represents a major opportunity for CE strategies to alleviate future supply constraints by reducing material demands through dematerialized designs and by recovering materials from EOL solar technologies (see Section 8.3). In contrast to the silver projections, demand for copper within modules[89] barely registers against 2020 global production, and the IEA (2021b) found that global copper demands for the energy transition (including transmission and distribution infrastructure investments, as well as EVs) double compared to historical levels.

While c-Si PV is the focus of this analysis, there is potential for thin-film PV to gain market share and reduce some of the material demanded from c-Si PV. This could involve further growth of cadmium telluride (CdTe) PV or the emergence of perovskite PV technologies.

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[89] Copper within junction boxes, external connector wiring and field wiring are not considered within PV ICE.
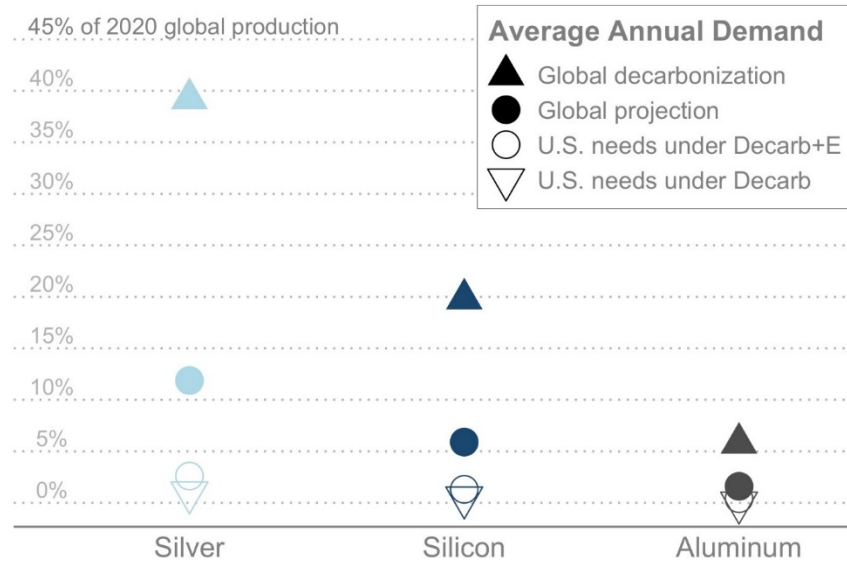
Figure 8 - 3. Percentage of 2020 global production of various materials needed to supply annual average virgin materials demand for c-Si PV

The material needs in the global projection scenario are based on projected global PV deployment in (IRENA 2019). The material needs in the global decarbonization scenario are based on projected global PV deployment in (Bogdanov et al. 2019). 2020 mining production (metric tons): silver 22,260 (The Silver Institute 2020), silicon 8,000,000 (U.S. Geologic Survey 2021), aluminum 65,267,000 (International Aluminium 2021), copper 20,000,000 (S. Hernandez, Yusheng, and Labo 2017).

CSP

CSP material requirements are quantified for manufacturing and construction of power tower CSP systems, including site improvement, the collector system, the receiver system, the thermal energy storage system, the steam generation system, and the electricity generation system. The material requirement for the power tower CSP system is from a published study (Whitaker et al. 2013) and is detailed in (Heath et al. Forthcoming). Although most CSP systems use parabolic trough technology as of 2021, power tower systems with TES are increasing in prevalence (NREL 2021a).

Concrete, aggregate, carbon steel, sodium nitrate and solar glass are the most consumed materials in the manufacturing and construction of power tower CSP systems. Supply scarcity is unlikely to impact the raw material requirements for CSP installation (Pihl et al. 2012). All 27 materials required for the construction and manufacturing of power tower CSP plants are detailed in (Heath et al. Forthcoming).

8.1.2 Domestic PV Supply Chain Development

Developing the U.S. PV supply chain would mitigate several challenges to achieving the *Solar Futures* scenarios. PV-related industries can experience production disruptions, especially those that require large-scale facilities for cost-effective production. For example, nearly 15% of global polysilicon capacity went offline owing to incidents in China over a 6-month period in 2020, which resulted in temporary increases in spot prices. Disruptions due to the COVID-19 pandemic provide another recent example. One study found that COVID-related balance-of-system (BOS)

supply shortages alone could result in 300–700 MW$_{dc}$ of utility-scale project delays in the United States in 2020 (X. Sun, Smith, and Manghani 2020).

Competing demand from other industries or countries presents another challenge. The polysilicon price spike in 2006–2009 resulted from PV demands exceeding the polysilicon available to the PV industry from the electronics industry (Sandor et al. 2018). In 2018, China restricted additions of glass capacity owing to an oversupply in the buildings and construction industries, which resulted in PV glass shortages and price spikes in 2020 (Daly 2018; Stoker 2020). As the PV supply chain has scaled up, some of these issues have been mitigated, but PV still relies on global commodities such as steel, aluminum, and microchips.

Global politics can also disrupt the PV supply chain. For example, when the United States placed anti-dumping and countervailing duties on cells and modules manufactured in China, China imposed tariffs on U.S. polysilicon (Sandor et al. 2018). These measures led the United States to import cells and modules from other Asian countries, and they reduced demand for U.S. polysilicon exports. Such situations have prompted the United States to develop a list of minerals critical to national security and economic prosperity (U.S. Department of the Interior 2018). The listed materials most relevant to PV include aluminum (used in module frames and racking), cesium (perovskites), and tellurium (CdTe modules). Additional minerals should be identified based on use in inverters, other electronics, and storage. High-purity polysilicon could also be considered as critical for PV because of its scarcity. Recent restrictions on importing metallurgical-grade silicon from China, because of human rights abuses tied to China's production of this material, illustrate the importance of having multiple sources of supply (U.S. Department of Labor 2021).

Overall, a resilient supply chain would be diversified and not over reliant on any single supply avenue. However, the benefits of a domestic supply chain must be weighed against the potential costs of foregoing cheaper imports, because cost-competitive PV is also vital to achieving the *Solar Futures* scenarios. This section provides a holistic look at the economic implications and related impacts of increased U.S. PV installations and manufacturing.

Current U.S. and Global PV Supply Chains

In 2020, roughly 140 GW of PV modules—mostly using c-Si technology—were shipped globally, 4.4 GW (3%) of which were produced in the United States (Figure 8 - 4, Figure 8 - 5) (SEIA/Wood Mackenzie 2021). In the same year, the United States installed 19.2 GW of PV (SEIA/Wood Mackenzie 2021). The vast majority of c-Si PV capacity—including polysilicon production and c-Si ingot, wafer, cell, and module manufacturing—is located in China and Asia more broadly.
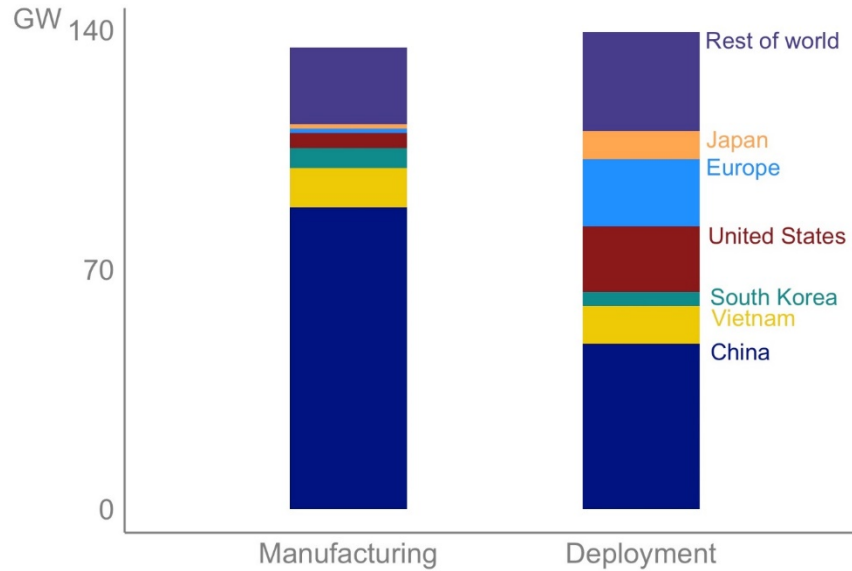
Figure 8 - 4. PV manufacturing and deployment by location, 2020

Sources: (Mints 2021; IEA 2021a; SEIA/Wood Mackenzie 2021). U.S. manufacturing includes c-Si module assembly and thin-film module production.

Figure 8 - 5. PV shipments by technology, 2020

Sources: (Mints 2021)

As of 2020, the United States no longer manufactured c-Si PV ingots, wafers, or cells. Thin-film technologies accounted for 33% of U.S. PV manufacturing in 2020 (SEIA/Wood Mackenzie 2021), a significantly larger share than their global market share of 4% (Mints 2021). Domestic polysilicon production facilities, which still have 60,000 MT of manufacturing capacity, have been operating at reduced capacity due to unfavorable market conditions.

Global module, cell, and wafer capacity is expected to increase 40%–60% (to around 300–350 GW) between 2020 and 2022, with the increase driven almost entirely by Chinese companies across Asia (Goldman Sachs 2021). Analysts project cumulative installed PV capacity could grow up to 14-fold by 2050, to more than 8 TW, requiring an average installation rate of 200–300 GW/year, which is very similar to the global PV manufacturing capacity projected within the next few years. Thus, even if U.S. deployment reaches the levels envisioned in the Decarb+E scenario, a significant scaleup of the global PV supply chain may not be required. However, if global PV demand accelerates at the same rates as the U.S. Decarb+E scenario, global manufacturing capacity would need to grow by 4–6x, i.e., to roughly 400–600 GW/year.

Cost-Competitiveness

The cost-competitiveness of a U.S. PV supply chain must be measured against global producers, particularly China. For example, higher labor costs and material import costs (including 2020 tariffs and shipping) are the primary drivers of higher U.S. costs across the PERC c-Si PV supply chain. Based on a detailed bottom-up cost analysis, as of April 2021, we find the following delta between U.S. and China costs (without considering tariffs): $0.02/W_{DC}$ higher in U.S. for polysilicon, $0.02/W_{DC}$ higher in U.S. for monocrystalline wafers, $0.02/W_{DC}$ higher for cell conversion, and $0.04/W_{DC}$ higher for module assembly. As a result, a c-Si module with all supply chain elements manufactured in the United States would cost $0.10/W_{DC}$ more than a c-Si module with all supply chain elements manufactured in China (Feldman and Margolis 2021).[90] The U.S. PV manufacturing industry may be able to improve its competitive position by increasing use of automation and exploiting the inherent advantages of domestically manufacturing particular components; for example, the expense of shipping heavy, fragile PV glass over long distances increases the economic favorability of local glass production.

China produces most of the equipment used in the primary c-Si supply chain. The cost structure of producing such equipment domestically is unavailable owing to the dearth of U.S. firms and associated data.

Regional differences in the cost structure of the module bill of materials (BoM)—such as coverglass, aluminum frames, and backsheets—are not known in detail. However, U.S. module producers have reported that prices from domestic BoM suppliers are significantly higher than imports from Asia (B. Smith et al. 2021). Similarly, regional cost differences for racking, inverters, and other BOS components are not known in detail. In any case, the amount of upstream domestic content in these supply chains is not guaranteed: racking is often extruded from imported metal, and inverter production can entail domestic assembly of imported components.

The characteristics of some components result in cost advantages for local production. For example, racking is heavy and expensive to ship, as is glass (which is also fragile). Thus, most regions may benefit from a local module assembly industry and local production of coverglass and racking. Conversely, products that require advanced technology or automation, such as advanced cell architectures or monitoring electronics, may be candidates for U.S. exports.

Regional cost data for extracting most PV raw materials are readily available for only a few materials. Global average all-in sustaining primary silver production costs were $9.85/oz in 2018 and $11.47/oz in 2019. Higher North American costs—$10.61/oz in 2018 and $12.18/oz in 2019—resulted primarily from lower-grade ores, higher treatment charges, and lower prices for base metals (The Silver Institute 2020). U.S. aluminum extraction costs are higher than in other regions due to the aging fleet of energy-inefficient aluminum smelters and higher labor costs

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[90] To illustrate the impact of tariffs, the module that costs $0.10/W_{DC}$ more to manufacture in the United States compared with manufacturing in China yields a final price to consumers that is $0.02/W_{DC}$ lower than the consumer price of the imported Chinese-manufactured module.

(Platzer 2018). As such, the U.S. produces significantly more secondary aluminum than primary aluminum.

Capital Expenditures

Capital expenditures (CapEx) for building manufacturing facilities are expected to decrease per GW of capacity as higher power conversion efficiencies are achieved, throughputs are increased, and other manufacturing improvements are made. For the U.S. to develop a domestic PV module manufacturing supply-chain at the scale of 50 GW/year by 2030 (assuming 85% c-Si) would require $9 billion–$21 billion of CapEx by 2030. At this level of production, the U.S. would be roughly self-sufficient in the Decarb scenario. To be roughly self-sufficient in the Decarb+E scenario, the U.S. would need to reach 70 GW/year of capacity by 2040, which would require an additional $2 billion–$5 billion of CapEx by 2040, for a total investment of $11 billion–$26 billion by 2040. Further CapEx investments would be necessary to keep equipment updated through 2050. What is clear is that because of the rapid declines in CapEx during the past decade and continued expected declines, the required investments are relatively modest. What will drive the viability of these types of investments is broader issues around competitiveness and stability of domestic markets.

Information about CapEx for industries outside of PV module production is limited. The CapEx necessary to establish 50–70 GW of PV glass production is likely around $2 billion–$5 billion,[91] depending on the fraction of glass-glass modules produced. Increasing domestic production of primary aluminum likely would require CapEx to update or replace existing aluminum smelters. A new smelting facility requires an investment of about $4.5 billion (Platzer 2018), while a typical U.S. smelter has a capacity of 200,000–300,000 MT/year (B. Smith and Margolis 2019)—about half the aluminum demand from PV at 50 GW/year deployment.

Strategies for Promoting Domestic PV Manufacturing

The United States has enacted policies intended to support domestic manufacturing (Feldman et al. 2020). At the federal level, this has included manufacturing tax credits, loan guarantees, and tariffs. The use of past manufacturing tax credits is unknown, because tax filings are private, while most previous loan guarantees for PV companies were not drawn upon (Oremus 2012). However, a new set of manufacturing tax credits has recently been introduced in the U.S. Senate (Ossoff 2021).

Investing in R&D has also been a core U.S. strategy for supporting domestic manufacturing. At this stage of PV industry maturity, R&D most relevant to supporting domestic PV manufacturing would address labor intensity (increased automation), Ecodesign (in concert with embodied carbon regulations), reduced manufacturing CapEx, increased manufacturing throughput, and the design and operation of manufacturing clusters. Several U.S. PV companies reported that supply contracts with utilities or roofing companies helped motivate establishment of U.S. facilities (B. Smith et al. 2021). This fact, in addition to evidence that manufacturing clusters abroad result in reduced costs and risk may emphasize the benefits of coordinated manufacturing clusters (Ball et al. 2017; Goodrich et al. 2013).

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[91] Based on float glass CapEx, which may be greater than for rolled glass equipment and facilities.

At the state and municipal levels, policies intended to support domestic PV manufacturing have included grants, tax exemptions, land provision, and consumer incentives for purchasing domestic PV products (Feldman et al. 2020). Many U.S. PV manufacturers have reported that local grants and tax exemptions were helpful in establishing their facilities, and that such incentives are commonly available (B. Smith et al. 2021). However, consumer incentives for locally made or domestic PV products have been consistently ruled as violations of international trade law (Trachtman 2019). In contrast, federal government procurement of preferentially domestic PV is a strategy that could be pursued within international trade law (with some restrictions) (World Trade Organization 1994).

Trade agreements such as the United States–Mexico–Canada Agreement (USMCA) could be structured to create a regionally resilient supply chain that operates based on each country's respective resources and strengths. Policies should be designed with a holistic perspective to avoid promoting unintended outcomes, such as incentivizing the export of U.S. cells to be assembled into modules overseas to avoid module import tariffs, which took place in 2019 (B. Smith et al. 2021).

Given the low levels of PV manufacturing currently existing in the United States, it may be inferred that previous U.S. policies intended to support domestic PV manufacturing were insufficient to some extent. Other countries have successfully implemented policies to build domestic PV supply chains. Most notably, China has used national five-year-plans that set PV development goals, subsidies from central and local government organizations, credit to PV manufacturers from the China Development Bank, easy access to debt from Chinese banks at government direction, requirements to qualify for government financial benefits (e.g., a 200-MW minimum cell factory size, 3% of revenue for R&D), and funding from joint ventures or subsidiaries that have direct relationships with the government (Feldman et al. 2020). France and South Korea have implemented regulations regarding the carbon emissions associated with PV module manufacturing. South Korea requires carbon footprints to determine which modules qualify for government subsidies (Stoker 2020), while France uses carbon footprints as a cutoff for bids to qualify for public tenders (Bellini 2019).

8.1.3 Creating Equitable Supply Chains

Section 4.4 discusses measures to ensure equity in the solar workforce. Similar measures could help ensure equitable supply chains; for example, the solar industry could encourage the broader supply chain to embrace high-road labor practices. The solar industry could also encourage equitable practices in complementary supply chains, especially related to energy storage. Many key resources for batteries (e.g., lithium, cobalt) are sourced from regions with documented human rights abuses associated with materials extraction (Lèbre et al. 2020). The solar industry—as a large buyer of these resources—could potentially use its buying power to promote supply chain equity in all aspects of the clean energy transition. Measures to ensure equity in the solar supply chain are an area for further research.

8.1.4 Circular Economy in PV Manufacturing

A range of CE methods can be incorporated in the PV manufacturing stage, improving the economic and environmental performance of PV systems while mitigating supply constraints and improving equity.

Reduced Material Intensity and Closed-Loop Recycling

To reduce the silicon intensity of c-Si PV manufacturing, R&D has focused on reducing kerf losses by shifting to less wasteful sawing methods (Kumar and Melkote 2018; Schwinde, Berg, and Kunert 2015) and kerf-free wafering (Henley et al. 2011), the recovery and reuse of silicon from the kerf loss (Li et al. 2021; Wang et al. 2008), and recycling and reusing silicon from ingot cuts in manufacturing PV cells. Developing and refining manufacturing processes, standards, and guidelines to reuse secondary silicon from PV manufacturing waste can further accelerate CE practices. Section 6.1.3 describes additional methods for reducing module material intensity.

Impurities that can degrade PV cell performance are a concern when reusing silicon recovered from kerf losses and ingot cuts (Davis et al. 1980). Further research is required to characterize the level and type of impurities from ingot and kerf losses and benchmark the purity and properties of recovered silicon with those of virgin silicon (SEMI 2021). R&D is needed to optimize the recovery process to minimize impurities (Li et al. 2021; Drouiche et al. 2014) and to evaluate tradeoffs in cell performance (Wang et al. 2008), economic costs, and environmental impact from replacing virgin solar grade silicon with secondary silicon (Ravikumar et al. 2017) across a broad range of silicon manufacturing conditions. In addition, the supply of kerf loss as feedstock in alternate applications (e.g., hydrogen production (Kao, Huang, and Tuan 2016), lithium-ion batteries (Kim et al. 2019)) may be economically and environmentally preferable to landfilling.

In closed-loop recycling, materials recovered from a PV module at EOL are reused in PV manufacturing. Beyond the reuse of silicon, bulk (e.g., glass) and other specialty (e.g., silver) materials can be recovered and potentially reused in the PV module. Studies should explore how CE pathways can affect material demand. For example, for a given scenario, some percentage of virgin material demand could be offset by recycling the annual EOL PV materials in a closed loop back into PV material feedstock. Using this pathway for c-Si PV would require research into reverse logistics and high-quality PV recycling. Alternatively, increasing module longevity (via reduced degradation, repair, etc.) would reduce required annual deployments, because fewer panels would be needed to attain and maintain capacity and generation levels—reducing virgin material demands and eventual EOL materials. This pathway requires continued research into module and system reliability, degradation modes, repairs, and optimized system design. The PV industry is also moving towards modules with higher energy yield per unit area, which will also affect material demands.

Open-Loop Recycling to Reuse Materials from Allied, Non-PV Industries

Open-loop recycling offers opportunities to reuse materials recovered from non-PV systems in PV manufacturing, which can be economically and environmentally preferable for sourcing raw materials. For example, post-consumer plastic waste can be reused to produce PV encapsulants (DuPont Teijin Films 2020). Future R&D is required to robustly quantify the tradeoffs in the technical (e.g., module reliability, durability, panel efficiency), economic, and environmental performance of a PV system when various secondary materials obtained from open-loop pathways replace virgin materials in PV manufacturing. This will help identify and scale only those open-loop recycling pathways that ensure an improvement in technical, economic, and environmental performance of the PV system.

GHG Reduction Via Renewable Electricity and Manufacturing Improvements

Energy used to extract and purify silicon accounts for up to 40% of the energetic footprint and climate impact of a c-Si PV module (Fthenakis and Leccisi 2021). CO_2 emitted from energy use early in the PV life cycle can significantly increase PV's climate footprint (Ravikumar et al. 2017; 2014). A switch from CO_2 intensive fossil electricity to renewable electricity to manufacture PV modules can significantly decrease the climate footprint (Ravikumar et al. 2017). Studies show that GHG payback times could be reduced by up to 40% by locating PV manufacturing in less CO_2-intensive geographies (Yue, You, and Darling 2014; Grant and Hicks 2019). In addition, the net CO_2 benefit of PV can be improved by decreasing the consumption and waste of CO_2 intensive raw materials in PV manufacturing operations (Weckend, Wade, and Heath 2016). The PV industry is currently incorporating CE strategies in the supply chain and manufacturing to decrease PV's embodied carbon (Ultra Low Carbon Solar Alliance 2020). Climate footprint should be used as a metric to understand the benefits of different CE strategies, with advances to consider the time-value of emissions to capture the temperature-mitigation benefits of locking in lower carbon emissions during manufacturing.

Design for Circularity

Design for circularity (DfC) can help address emerging sustainability challenges. Machine learning (ML) and artificial intelligence (AI) methods can inform selection of non-hazardous and environmentally benign materials during PV module design (Rajan et al. 2020) and improve the stability and longevity of the PV module (Q. Tao et al. 2021). Use of recyclable materials in modules can enhance recyclability at EOL and decrease landfilling (DSM 2021). Substituting abundant materials for constrained materials, e.g., copper metallization replacing silver metallization (Karas et al. 2020) can decrease the cost of manufacturing PV systems (ITRPV 2020).

Replacing hazardous materials in PV modules can decrease environmental and human health risks during the use and EOL stages. Substituting fluorinated backsheets with fluorine-free polymers or a double glass design can decrease human health risks during EOL and allow for high temperature recycling processes for faster and more efficient recycling of the spent PV module (Aryan, Font-Brucart, and Maga 2018; Fraunhofer UMSICHT 2017). Eliminating lead solders can prevent potential release of lead during thermal recycling (Goris et al. 2015) or after disposal. The industry currently manufacturers lead- and fluorine-free modules (Dziedzic and Graczyk 2003; Mitsubishi Electric Solar 2021), and projections show that lead and fluorine content is expected to decrease in future (ITRPV 2020; Norgren, Carpenter, and Heath 2020). Suppliers of modules with low or no lead and fluorine are incentivized by the potential to obtain higher sustainability scores in emerging standards (NSF/ANSI 2019; The Silicon Valley Toxics Coalition 2017). Frameless modules help reduce aluminum content, decrease transportation burdens, eliminate the need for deframing during recycling and, thereby, simplify the recycling process and decrease the climate and energy footprint of the module (Norgren, Carpenter, and Heath 2020). A laminate-free design (Einhaus et al. 2018) or replacing ethylene-vinyl acetate (EVA) with edge sealants decreases the time and energy required for recycling by avoiding the need for thermal, chemical, or mechanical processes required to eliminate EVA (Goris et al. 2015).

DfC strategies may entail tradeoffs in other PV life cycle stages. Replacing silver metallization with copper metallization can degrade cell performance and module durability (Phua et al. 2020).

A laminate free design impacts the electricity generation profile and module durability, which impacts the economic and environmental performance of PV systems (Couderc et al. 2017). Lead free alternatives can increase costs and raise temperatures for soldering, which can cause thermomechanical stress and wafer breakage during manufacture (Song et al. 2019). Field studies have shown that durability of modules with fluorine free backsheets is lower than the durability of those with fluorinated backsheets (DuPont 2020).

A holistic assessment of tradeoffs that material and design choices impose on module performance (e.g., electricity generation) and economic and environmental impact (Ravikumar et al. 2018; Ravikumar 2016) will help select the most sustainable DfC alternative. This will help prioritize DfC methods that generate the highest net economic and environmental benefit over the PV life cycle.

Government and Industry Initiatives

Concerns about supply chain vulnerabilities and PV waste have led to government and industry discussions, policies, and initiatives that could impact domestic resource recovery and U.S. PV manufacturing. For example, Washington State implemented a product stewardship regulation that requires PV module manufacturers, beginning July 1, 2023, to finance the takeback and reuse or recycling of modules sold within or into the state, after July 1, 2017, at no cost to the owners (Washington State Legislature, n.d.). Washington is the only U.S. jurisdiction to implement takeback requirements, but New York, Minnesota, and Maryland have considered similar stewardship policies (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021).

Other state policies could indirectly impact U.S. PV manufacturing. California and Washington recently enacted policies reducing the regulatory burden associated with module recycling. California allows modules to be managed as universal waste, a subset of hazardous waste, which has less stringent handling, transport, and storage requirements (California Legislative Information 2018; DTSC 2020a; 2020b; 2020c). Washington allows modules that are being recycled to be regulated under less stringent requirements than those modules destined for disposal (Washington State Legislature 2020; Washington State Department of Ecology 2007). Managing modules under an alternative regulatory scheme for those being recycled compared to those being disposed of, such as the policy in Washington, could reduce the costs and liability associated with regulatory compliance, which could support increased rates of resource recovery and increase domestic material supplies, e.g., of glass, silicon, tellurium (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021). States including Arizona, Hawaii, Illinois, New Jersey, and North Carolina are considering mandating or incentivizing PV module and BoS equipment recycling, which could enable investment in new and expanded domestic recycling (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021).

Industry-led/voluntary initiatives, such as the NSF/ANSI 457 Sustainability Leadership Standard for PV Modules and Inverters and the Silicon Valley Toxics Coalition (SVTC) Solar Scorecard, could also affect U.S. PV manufacturing. NSF/ANSI 457 sets sustainable performance objectives related to module design, manufacturing, and EOL management (Curtis, Buchanan, Smith, and

Garvin 2021; Curtis, Buchanan, Heath, et al. 2021).[92] The Solar Energy Industries Association's (SEIA's) National PV Recycling Program provides EOL material management best practices for asset owners and recycling resources to encourage module and BOS equipment recycling among its membership (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021). PV manufacturers may find that compliance with such voluntary industry standards can enhance their corporate responsibility image and increase consumer trust and overall competitiveness (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021). Overall, CE initiatives necessitate inputs from and collaboration with multiple stakeholders and allied industries as well as use of decision-enabling tools. For this reason, investments in R&D and analysis for partnerships or consortiums involving multiple actors in the value chain, including allied industries, would be valuable. For example, studying the performance of modules that utilize secondary materials recovered from recycling, as well as the environmental and economic impacts, could assess the benefits or tradeoffs of closing the loop on recycling. R&D for recycling technology could also consider how new technology designs may be regulated. In the United States, regulations are often specific to the recycling processes used and the materials being recycled; as a result, certain recycling processes are regulated more stringently than others. For this reason, regulatory analysis can inform R&D and the true cost-effectiveness of a particular technology (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021).

These recent government- and industry-led policies and initiatives may signal a shift towards increased domestic resource recovery and sustainable PV manufacturing. They may also present opportunities for growth in upstream U.S. manufacturing sectors, such as the flat glass industry (B. Smith and Margolis 2019).

Equity Benefits
CE strategies in PV manufacturing could improve environmental justice outcomes and increase social benefits. The use of renewable electricity helps decrease the reliance on carbon-emitting fossil fuels and thereby minimize climate change and the health effects, including deaths, attributable to fossil fuel combustion, which disproportionately impacts minority and low-income communities and the developing world, and exacerbates socio-economic inequities (Vohra et al. 2021; Diffenbaugh and Burke 2019). By following closed-loop recycling and increasing emphasis on substituting hazardous materials with environmentally benign materials in the supply chain, CE strategies in PV manufacturing can significantly decrease the likelihood of environmental and health hazards, which have previously impacted communities in the vicinity of PV manufacturing facilities (Cha 2008). The ratings provided by scorecards (The Silicon Valley Toxics Coalition 2017) to preferentially rank socially responsible PV suppliers help incentivize transparency in the supply chain to avoid the sourcing of conflict minerals and prevent the violation of worker rights (Politico 2021) and health and safety requirements. NSF/ANSI 457 has more stringent worker rights and supply chain requirements as well as third-party verification through its adoption in the EPEAT registry of green electronics. Further, the emergence of industry alliances, which prioritize CE strategies in the PV supply chain, can increase PV manufacturing competitiveness and, thereby, increase employment potential in the

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[92] NSF/ANSI 457 has been implemented in the PV module and inverter category of the EPEAT registry of green electronics (https://epeat.net/search-pvmi).

U.S. PV sector (U.S. Bureau of Labor Statistics 2021). Finally, all CE strategies that reduce material demands consequently reduce burdens experienced in frontline communities neighboring the extraction industries. Promising quantitative approaches for analyzing environmental justice outcomes include near-source air-quality modeling, complex system science methods such as agent-based or systems dynamics modeling, and social life cycle analysis (LCA).

8.2 Operation

Operation of solar technologies—which includes the construction/installation phase—affects land and water use as well as the economics and social equity of solar energy. Operation of solar also displaces the operation of other generation technologies, which can prevent emission of air pollutants resulting from operation of combustion sources. This latter aspect is addressed in Chapter 2.

8.2.1 Land Use

More than enough land is available to accommodate solar development in the *Solar Futures* scenarios. At the highest deployment level in 2050, ground-based solar technologies require a land area equivalent to 0.5% of the contiguous U.S. surface area, and this requirement could be met using less than 10% of potentially suitable disturbed lands, thus avoiding conflicts with high-value lands in current use. However, solar installations will affect local communities, ecosystems, and agricultural areas. Various approaches are available to mitigate such impacts or even enhance the value of the land that hosts solar systems.

Note that this analysis considers land used for projected solar installations only. Other technologies that generate electricity in the *Solar Futures* scenarios also entail land-use impacts, as does electric transmission infrastructure, which is projected to expand substantially in our scenarios. Thus, the land requirements described below represent only the solar portion of the overall impacts that would be associated with the envisioned energy systems. In addition, although almost 200 GW of rooftop PV are deployed in our decarbonization scenarios by 2050 (see Appendix 2-A), the potential for rooftop PV is much larger. Gagnon et al. (2016) estimate the total U.S. technical potential of rooftop PV at 1,100 GW of installed capacity, representing an upper bound on potential deployment as calculated at the time; improving module efficiencies increase potential rooftop PV capacity. Assuming a constant total amount of PV deployment, increasing the ratio of rooftop PV to ground-based PV would reduce the amount of land used for solar installations.

Solar Land Requirements in the Solar Futures Scenarios

Solar land requirements in the *Solar Futures* scenarios are evaluated with respect to the amount of available, potentially suitable land (especially disturbed and contaminated lands) by region in the contiguous United States. Land-use requirements are estimated using recent, empirically derived estimates of land used by existing solar facilities per unit of installed capacity (MW) (Ong et al. 2013; Hartmann et al. 2016; Walston et al. 2021; Bolinger 2021). Utility-scale PV (UPV) and distributed utility-scale PV (DUPV) are assumed to require approximately 7.5 ac (3.0 ha) per installed MW; CSP solar facilities are assumed to require approximately 10 ac (4.0 ha)

per installed MW.[93] Multiplying these land-use intensities by estimated capacities yields estimates of the total land area required for ground-based solar.

The land-availability analysis is based on a stepwise geographic information system (GIS) framework. First, the footprint of potentially available land for each technology type is identified based on exclusion criteria including slope (slopes greater than 5% excluded), land cover type, land ownership and status, and amount of urban development (Ho et al. 2021). Next, additional geospatial filters are applied to identify previously disturbed, non-protected areas that might be used for solar development. Examples of disturbed lands include developed areas (ground areas only in this analysis, not rooftops), invasive species-impacted lands, and other types of non-vegetated lands such as quarries or gravel pits. Another category of previously disturbed lands considered here includes lands identified as contaminated by improper handling or disposal of toxic and hazardous materials and wastes but remediated for some forms of reuse. Such lands include Resource Conservation and Recovery Act (RCRA) and Superfund sites as well as landfills, abandoned mine lands, brownfields, and non-federally-owned RCRA and Superfund sites. The potential suitability of these contaminated sites for solar development is evaluated using data provided by EPA's Re-Powering America's Land screening tool (EPA 2020). For this assessment, contaminated lands are filtered to locations with less than 5% slope (Hartmann et al. 2016). In addition, a minimum size of 7.5 ac (3.0 ha) is assumed for PV projects on contaminated lands. CSP projects are assumed to be at least 50 MW in capacity and therefore require at least 500 ac (202 ha) with an additional restriction that insolation levels in CSP locations must be at least 6 kWh/m^2/day (Mehos et al. 2016).

Previously disturbed lands are often in rural areas or marginal regions of urban areas, which may need economic revitalization. Siting a financially attractive project in an area without other productive land use opportunities could improve temporary and permanent local economic conditions. When carefully implemented, using formerly contaminated lands for solar deployment can minimize stress on intact, undeveloped lands while improving soil stability and decreasing health risks in some areas. Previously developed or contaminated lands may also have existing onsite infrastructure (e.g., roads, water service), potentially lower transaction costs, greater public support for development, and streamlined permitting and zoning processes, and they are often already located close to roads, rail, and transmission lines (EPA 2020).

Although the areas identified as potentially suitable disturbed and contaminated lands in this study passed a screening-level review for valuable resources, actual solar siting requires location-specific and jurisdictional reviews and input from various stakeholders. Thus, although

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[93] The PV estimate is based primarily on analysis in (Walston et al. 2021), which uses GIS techniques to measure the total footprint of 192 utility-scale PV installations in the Midwest in 2018. The relationship between total footprint and nameplate capacity yields a total land-use requirement of about 7.5 ac (3.0 ha) per MW$_{AC}$. This estimate is supported by analysis in (Bolinger 2021), which also uses GIS techniques but measures the land directly occupied by arrays for 736 utility-scale PV installations across the United States in 2019. A median direct land-use requirement of 4.2 ac (1.7 ha) per MW$_{DC}$ is calculated for systems with one-axis tracking, which equates to 5.5 ac (2.2 ha) per MW$_{AC}$ at a median ILR of 1.30. Accounting for non-array space used within the fenced PV system area (disturbed ground, operational facilities, etc.) would increase the area per MW$_{AC}$. A ratio of direct to total area of 0.73, which broadly aligns with some anecdotal observations, would result in the same total footprint of 7.5 ac (3.0 ha) per MW$_{AC}$ found in (Walston et al. 2021). The CSP estimate of 10 ac (4.0 ha) per MW$_{AC}$ is based on analysis in (Ong et al. 2013) and (Hartmann et al. 2016).

this study identifies these lands as potentially suitable for solar development, actual determination of suitability will require project-specific analysis.

This study calculates land requirements on a regional basis (within ReEDS model balancing areas) and then aggregates to each state. Figure 8 - 6 shows the national land-use projections for the three core scenarios from 2010 to 2050. The total U.S. solar development area is about 10.3 million acres (41,683 km^2) by 2050 in the Decarb+E (highest land-use) scenario. An adequate amount of potentially suitable disturbed land is available to meet this requirement; approximately 6% of potentially suitable disturbed lands are needed for solar development (Table 8 - 1). Most of the 48 contiguous states contain enough potentially suitable disturbed lands, but potentially suitable contaminated lands are more limited. In a larger context, total maximum land requirements across all technology types for ground-based solar in 2030, 2040, and 2050 are approximately 0.2%, 0.3%, and 0.5%, respectively, of the total surface area of the contiguous United States. Figure 8 - 7 compares the largest land requirement (0.5%) with solar-suitable disturbed and contaminated land areas and examples of other areas in the United States. Ground-based solar energy is not expected to exceed 5% of any state's land area, with the exception of Rhode Island (6.5%).

These results entail several uncertainties. Increased efficiency of solar technologies would reduce land requirements, as would use of non-land-based technologies such as floating systems (Hooper, Armstrong, and Vlaswinkel 2020) or solar cells incorporated into the sides of buildings (Hughes, Smith, and Borca-Tasciuc 2020); our land-use estimates do not account for such advancements. In addition, the life cycle land-use impacts of solar development are not well understood, including, for example, the impacts of mining minerals used in solar technologies.
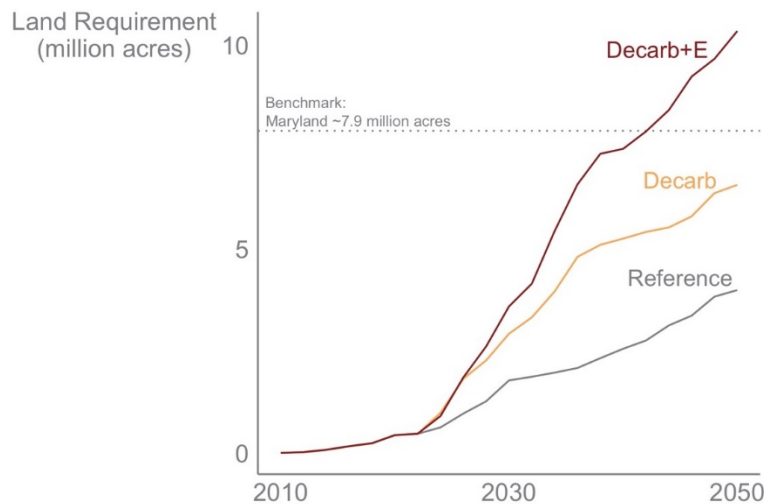
Figure 8 - 6. National solar deployment land-use projections for the three core scenarios, 2010–2050

Table 8 - 1. Solar Development Land Needs in 2030, 2040, and 2050 Across the Contiguous U.S.

Solar Energy Deployment[1]	Maximum Land Requirement (acres)[2]	Percent of Total Disturbed Lands	Percent of Total Contaminated Lands
2030			
PV	3,577,622	2.2%	39.9%
CSP	18,879	< 0.01%	0.3%
2040			
PV	7,437,108	4.5%	83.0%
CSP	22,017	0.1%	1.4%
2050			
PV	10,291,802	6.2%	114.9%
CSP	53,280	0.2%	3.4%

[1] PV development includes DUPV and UPV technologies.

[2] Maximum cumulative land requirement. Note that the maximum land requirement is per state; it mostly follows the Decarb+E scenario, but in a few cases a different scenario projects higher deployment and thus land use.
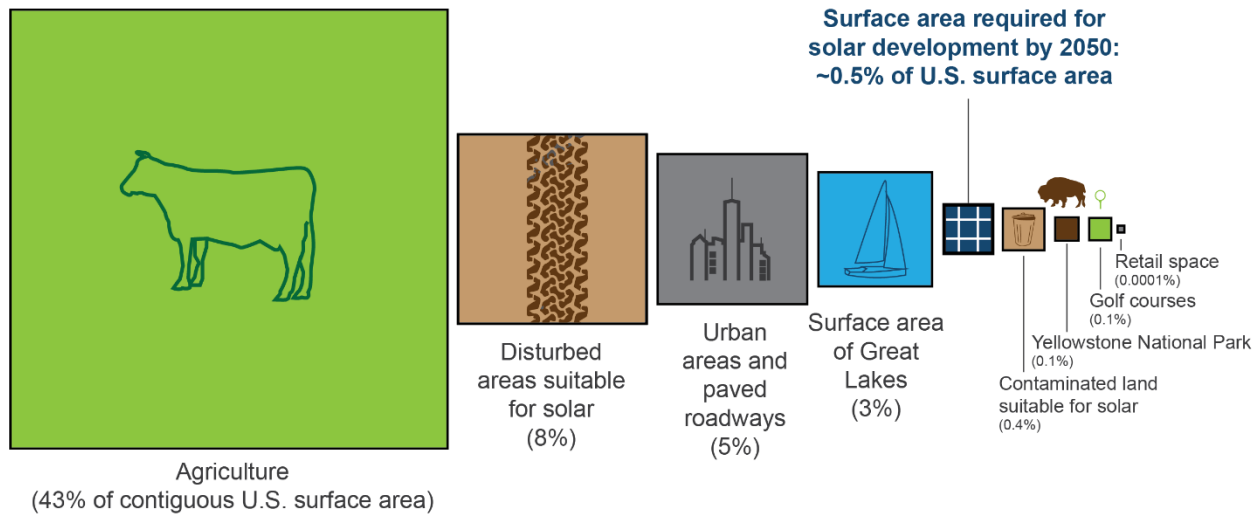
Figure 8 - 7. Maximum land use required for solar in 2050 in the *Solar Futures* scenarios compared with solar-suitable disturbed and contaminated areas and examples of other U.S. areas

Amounts of disturbed and contaminated lands depicted here represent the amounts suitable for solar energy development calculated in the *Solar Futures Study*. Sources: (EPA 2020; USDA 2014; LANDFIRE, n.d.).

Mitigating the Impacts of Solar Land Use

Regardless of the land required for solar installations under the *Solar Futures* scenarios and the use of previously disturbed lands, these installations will affect local communities, ecosystems, and agricultural areas. This section describes approaches to mitigating the impacts of solar land use, or even enhancing land value through purposeful solar system design and installation.

Vegetation Management to Provide Ecosystem Services

Establishing a diverse plant community at solar facilities has been investigated as a means to mitigate land use impacts (Macknick, Beatty, and Hill 2013; Armstrong, Ostle, and Whitaker 2016; Beatty et al. 2017; Walston et al. 2021). Conventional solar site preparation generally has involved grading and removing all vegetation and then introducing gravel or turf grass ground cover (Macknick, Beatty, and Hill 2013). Establishing a varied deep-rooted plant community has many potential ecological benefits. Such habitat has been termed "solar-pollinator" habitat (Walston et al. 2018), although its benefit can extend beyond pollinators. A study of ecosystem services provided by solar-pollinator habitat in the midwestern U.S. indicated a potential threefold increase in pollinator supply, 65% increase in carbon storage potential, 95% increase in soil/sediment retention, and 19% increase in water retention (Walston et al. 2021). However, these potential ecosystem services will vary by geographic region. Other potential benefits include pest control, easier permitting, increased solar facility aesthetic quality, and greater community acceptance (Wratten et al. 2012; R. R. Hernandez et al. 2019), as well as potentially increased pollination services and crop yields at nearby agricultural lands (Walston et al. 2018).

The costs of installing solar-pollinator habitat remain understudied, though one analysis suggests an approximate 6% increase in value of energy produced per acre from solar facilities with pollinator habitat established throughout versus turf grass (Siegner et al. 2019). This value derives from efficiency gains due to a cooler microclimate under solar panels. Lifetime costs largely depend on the cost of seed mixes used, extent of solar-pollinator habitat established, and site-specific changes in mowing frequency and vegetation management over the facility lifetime. Horowitz, Ramasamy, et al. (2020) found that site preparation is a primary source of higher installed costs for solar-pollinator applications.

Siegner et al. (2019) also estimated social and environmental benefits from pollinator habitat at solar facilities including avoided carbon emissions, reduced soil erosion, additional groundwater recharge, and increased crop yields at nearby farms. They estimated a 13% cost benefit (considering private and social costs) due to facilities with solar-pollinator habitat near pollinator-dependent soy crops. Walston et al. (2018) also estimated substantial potential benefits for pollinator-dependent crops near solar facilities due to increased yields. Some assumptions (e.g., amount of crop yield increase) used in these studies lack empirical supporting data, although other studies of pollination benefit for soy crops support the increased yield assumptions (Cunningham-Minnick, Peters, and Crist 2019). The U.S. Department of Energy's Solar Energy Technologies Office is supporting research on the economic, ecological, and performance impacts of co-located pollinator plantings (DOE 2021c) that may answer some questions regarding costs and benefits of various vegetation management practices at solar facilities.

Co-location of Agriculture and Solar Energy

Solar development increasingly will be located in rural areas on marginal or previously disturbed lands; about 90% of projected *Solar Futures* PV deployment by 2050 is expected to be generated from UPV projects in rural settings. Such development could benefit rural communities (Brummer 2018; Poggi, Firmino, and Amado 2018). Many rural development plans aim to invest in renewable energy to boost economic development (Poggi, Firmino, and Amado 2018). PV can benefit rural areas by increasing land use, providing tax benefits to communities, providing local workers with jobs, creating new markets for local contractors, diversifying landowner income,

and increasing available local resources (Brummer 2018; SEIA 2020; Siegner, Brehm, and Dyson 2021).

The U.S. Department of Agriculture supports the use of "integrated agricultural systems" (IAS) to improve agricultural sustainability (Liebig et al. 2017). Co-located solar energy and agriculture, or "agrivoltaic," systems can be considered a form of IAS that improves the value of dual-use sites from energy and food production (Ravi et al. 2016; Dinesh and Pearce 2016; Hoffacker, Allen, and Hernandez 2017; Malu, Sharma, and Pearce 2017; Barron-Gafford et al. 2019). Although in some locations agrivoltaic systems can reduce yields because of crop shading, the microclimate created by solar panels can increase yields for some crops (Barron-Gafford et al. 2019). Novel agrivoltaic systems are being demonstrated to increase crop yields even for shade-intolerant crops (Sekiyama and Nagashima 2019). In addition, a recent study showed increased PV panel efficiency when vegetation is present under the panels (Barron-Gafford et al. 2019), though this effect requires further investigation. Overall, combined energy and crop production from agrivoltaic systems can increase land productivity by 70% (Weselek et al. 2019)

Because rural development guidelines often recommend avoiding prime farmland (e.g., (Birkholz et al. 2020)) and focusing on areas of marginally productive or disturbed soils, solar development locations may not be the most suitable sites for crop production. However, methods are being developed to maximize efficiency of these solar fields for collocated agricultural production (Ravi et al. 2016). For example, water used for cleaning panels can be conserved for irrigation. In semi-arid pastures with wet winters, agrivoltaic systems increase water use efficiency where water is stored in shaded areas (Adeh, Selker, and Higgins 2018). Another potential benefit of agrivoltaic systems is providing off-grid power to rural communities, increasing their resilience while adding the economic value of the crops produced (Weselek et al. 2019).

Grazing is also proving compatible with PV facilities (Andrew 2020; Maia et al. 2020; ASGA 2021). Solar panels in grazing areas have a positive impact on soil moisture and biomass (Adeh, Selker, and Higgins 2018). Solar grazing can benefit livestock because the PV facilities provide food and shade while decreasing water needs (Maia et al. 2020; R. R. Hernandez, Hoffacker, and Field 2014). Grazing can decrease solar O&M costs by decreasing the need for mowing. Honey production may also be a natural agricultural pairing for solar facilities.

Floating Photovoltaic Systems
Floating PV (FPV), or floatovoltaic, systems may produce energy more efficiently than land-based systems owing to lower operating temperatures (Spencer et al. 2019; Golroodbari and Sark 2020; Hooper, Armstrong, and Vlaswinkel 2020). They also reduce shading loss and panel dusting, reduce algal blooms, and decrease evaporation rates (Spencer et al. 2019; Golroodbari and Sark 2020; Hooper, Armstrong, and Vlaswinkel 2020). Challenges associated with FPV systems include susceptibility to fouling organisms, corrosion, and high maintenance costs (Spencer et al. 2019; Hooper, Armstrong, and Vlaswinkel 2020). Further study is needed to understand interactions with birds, marine mammals, and fish; effects on water quality and biodiversity; and whether leaching of toxic elements is a concern (see, e.g., (Armstrong et al. 2020)).

To date most FPV systems have been installed in enclosed freshwater reservoirs and small lakes. The cumulative global installed capacity of FPV reached 1.1 GW in mid-2018; Asia had the highest installed capacity, followed by Europe (Oliveira-Pinto and Stokkermans 2020). Spencer et al. (2019) estimated that FPV systems on suitable human-made U.S. water bodies could produce almost 10% of current national electricity generation. Another study estimated potential use of the 6,350-km California canal network for generating electricity using PV panels mounted over the canals (McKuin et al. 2021). The authors estimated that the net present value of this system would exceed the value of conventional over-ground solar by 20%–50%, and that the system would reduce annual evaporation by an average of 39,000 m^3 per km of canal.

8.2.2   Water Use

Fossil fuel and nuclear electricity generation use large amounts of water (Macknick et al. 2012). In 2015, the power sector accounted for 41% of total U.S. water withdrawals (Dieter et al. 2018). In contrast, PV and wind—the dominant generators in all *Solar Futures* scenarios—use minimal water (Macknick et al. 2012). CSP can use substantial water, but CSP deployment is low in the core scenarios, and cost and performance parameters in the scenarios assume dry cooling, which minimizes water use. As a result, water withdrawals decline substantially in all core scenarios. In the Decarb+E scenario, power-sector withdrawals decrease from 48,500 billion gal/yr in 2010 to 6,040 billion gal/yr in 2050. Even in the two southwestern states where CSP grows to account for almost all power-sector water withdrawals, water withdrawals are still below current power-sector withdrawals associated with fossil fuel power plants.

8.2.3   Circular Economy During PV Use

Figure 8 - 1 shows CE strategies for the PV use phase. The PSS strategy delinks PV ownership from PV services (Schmidt-Costa, Uriona-Maldonado, and Possamai 2019), which lowers cost barriers to PV (Rai and Sigrin 2013), could widen access to PV electricity, transfers the burdens of purchase and maintenance from individual customers to third-party owners (Rai, Reeves, and Margolis 2016), and could potentially reduce the cost of PV electricity via enhanced economies of scale and learning rates. Needs for PSS development include reducing information barriers that prevent financiers from evaluating PV PSS investments (Svatikova et al. 2015), designing policy incentives to accelerate PSS for PV systems (Lam and Yu 2016; O'Shaughnessy et al. 2021), increasing funding for PSS PV projects (Svatikova et al. 2015), and assessing the environmental and social efficacy of PV PSS projects at a national scale.

Repowering refers to replacing aging PV system components with newer components to improve performance and durability, address maintenance issues, extend project lifetimes, and prevent outages due to increased frequency of faults in older components (Longi Solar 2018b; 2018a; Jean, Woodhouse, and Bulović 2019; REC Solar 2019). Repowering should be combined with proper management of decommissioned components (e.g., recycling or reuse). Yet there is no empirical data on the prevalence of repowering in the United States, nor are there tools or methods to support repowering decisions, especially tools that holistically consider multiple private and societal economic, employment, circularity, environmental, and other benefits and tradeoffs (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021).

Finally, in-field repair may be necessary to address manufacturing defects, faulty installations, extreme weather events, and so forth. For example, poor manufacturing practices alone have led to global deployment of more than 10 GW of PV modules with faulty backsheets (Osborne 2019;

Pickerel 2020, 20; Oreski 2020). Growing concerns about backsheet failures and overall system efficiencies have led to industry discussions and initiatives around in-field module repair. Needs related to repair options relate to the module inspection process and the safety and reliability of the repair product, regulatory requirements, and legal liability associated with repair technologies and installation (Curtis, Buchanan, Smith, and Garvin 2021; Curtis, Buchanan, Heath, et al. 2021).

8.3 End of Life

This section projects the mass of EOL materials from c-Si PV modules and CSP systems under the three *Solar Futures* core scenarios. CE and equity considerations are also addressed.

8.3.1 Photovoltaic End of Life Materials Projection

Management of EOL PV systems requires extensive infrastructure, which in turn requires significant capital and long lead times. Governments (federal, state and local), industry, and associated stakeholders must begin preparing now for the EOL solar volumes that will be generated in the near future, for instance: identifying technical solutions for EOL management, reducing recycling costs, addressing transport costs, maximizing value from recovered materials, matching recovered materials with markets, minimizing use of landfill capacity, partially offsetting material demands for solar manufacturing via recovered materials, and protecting the reputation of solar as a "clean" technology.

Figure 8 - 8 shows annual c-Si PV module EOL material mass by scenario through 2050, calculated using PV ICE.[94] Cumulatively (2020–2050), the Reference scenario results in 5.8 Mt of EOL materials, and the Decarb and Decarb+E scenarios each result in 7.1 Mt. Because glass is such a large fraction of the weight of PV modules, it makes up an equally large fraction of the total EOL materials in the *Solar Futures* scenarios. We assume modules will generally last through their 30-year warrantied lifetime, so most modules deployed within the scenario period will not have reached EOL by 2050; there is less of a difference between scenarios in EOL material mass than material demands (see Figure 8 - 2).

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[94] PV ICE EOL material calculations were validated by reproducing the mass of PV in service and cumulative PV EOL materials from a 2016 report from the IEA and the International Renewable Energy Agency (Weckend, Wade, and Heath 2016). The material demand results are also compared to a recent EOL material projection from the CSA Group. A comparison of predictions is presented in Heath et al. (Forthcoming).
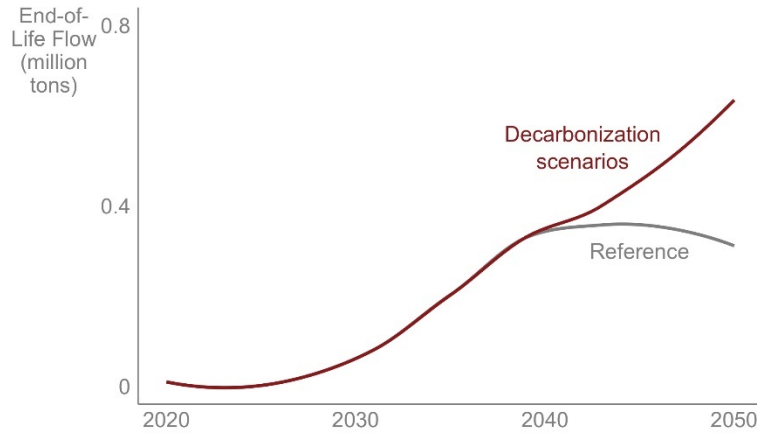
Figure 8 - 8. Annual PV module EOL material mass for the Reference and decarbonization (Decarb and Decarb+E) scenarios through 2050

If several challenging preconditions were met, then it is conceivable for materials embodied in EOL modules to be recovered and used as virgin material replacements for new module manufacturing. These preconditions will require technological advances to drive down recycling costs and develop integrated, high-value PV recycling technologies,[95] the ability to purify recycled material sufficiently in a cost-effective manner, and alteration of existing or development of new manufacturing processes that can use recovered materials as virgin feedstock replacement (for instance, in optimizing the value of recovered silicon within the virgin silicon supply chain). The preconditions could be accelerated by policy that encourages or requires use of CE strategies like recycling.[96]

Because of fluctuations in material demand and EOL material supply, the fraction of c-Si virgin material demand that could be met with EOL materials varies significantly. Yet, c-Si EOL materials could provide a significant proportion of virgin material demand in some scenarios and timeframes. This is especially true for silver, where the higher material intensity (material mass used per module) of earlier generations of PV modules can help meet the significant growth in silver demand for new c-Si PV modules. This is a technical potential analysis; many technological and market realities will reduce the recovery of silver (or other materials) from the theoretical maximum. This reinforces the need for R&D investment in approaches to achieve as much of this potential as possible, not only to secure domestic supply chains, but also to realize the sustainability potential of c-Si PV. It also emphasizes that, with only 9 years before the more significant volumes of EOL modules become available, R&D investment should start soon, given known timelines from the lab to the market.

EOL material volumes can also be broken down by region; see (Heath et al. Forthcoming). Such an analysis enables stakeholders to plan for EOL materials on a regional basis, which can

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[95] "High-value PV recycling" refers to technologies that can recover all materials constituent within a PV module in one integrated process and at recovered material quality and form that secondary markets will find highly valuable as primary material replacements. See (Heath et al. 2020) for further discussion.

[96] Policy at the federal level would be ideal to ensure markets are coordinated and industry has clear and consistent goals. This could lead to minimized costs of EOL management and a more efficient market. State policies can also help and even innovate beyond a federal floor.

facilitate an equitable CE and prevent perpetuation of environmental injustices such as racial disparities in locating polluting industries. For example, tighter circular loops, such as repair and reuse, could keep PV modules in the field longer (offsetting virgin material demands and waste generation) and create regional, higher-skilled jobs in the sustainability sector. Longer circular loops, such as recycling, could enable industries (e.g., glass manufacturing) to use a local supply of EOL materials from PV modules. Further analysis of PV module lifetime extensions, recycling, and the social, environmental (e.g., decarbonization potential), and economic impacts of each can clarify pathways toward circular, cross-sector economic opportunities to address challenges communities will face in coming decades.

Currently, no data exist on the reasons for and total flow of PV modules reaching EOL. Partnering across the PV value chain (from owners to installers/servicers, insurers, and financiers) on regular surveying of modules reaching EOL could provide the data necessary to reduce investment risk in the nascent EOL management industry. As satellite imagery continues to increase resolution, it might be conceivable in the future to track module removal and replacement at the facility or even per-module level.

8.3.2 Concentrating Solar Power End of Life Materials Projection

With no publicly available data on the rate of material recovery from decommissioned CSP systems, this analysis assumes that the material recovered per unit of decommissioned capacity is the same as material required per unit of installed capacity. The results show that the total cumulative CSP waste across the United States from 2020 to 2050 is estimated to be 4.5 Mt. The CSP is spread across Utah, Nevada, New Mexico, Colorado, California, and Arizona, with California and Arizona contributing around 90% of the overall waste. Four of the CSP EOL materials—concrete (2.4 Mt), aggregate (1.2 Mt), carbon steel (0.6 Mt), and solar glass (0.1 Mt)—are bulk materials and can leverage existing recycling infrastructure. The likelihood of recycling the concrete and aggregate waste as aggregates can be increased by supplying them to the construction and demolition waste market (EPA 2018a; Construction & Demolition Recycling Association 2021a). While carbon steel and solar glass represent significant volumes in the waste, they can be recycled through the existing network of glass and steel recyclers. Given the geographical spread of the projected CSP waste volumes, the recovered materials can leverage the existing network of glass and metal recyclers in the southwestern United States (Construction & Demolition Recycling Association 2021b; Glass Recycling Coalition 2021; American Iron and Steel Association 2021). There are no publicly available data on the recycling of sodium nitrate and the associated economic and environmental impacts. However, recycling can offset the production of sodium nitrate from mines or the more environmentally intensive synthetic route. In addition, nitrate salt can be recycled as a nitrogen-rich fertilizer (EPRI 2014). If other CSP heat-transfer media achieve significant market share, they may require different EOL management.

8.3.3 Circular Economy at Photovoltaic End of Life

This section addresses the EOL CE strategies from Figure 8 - 1.

Recycling

Recycling is the most widely applied and analyzed PV CE strategy, and recycling R&D should continue—including clarifying the relative benefits and costs of different policy designs and connecting the full value chain of recyclers, raw material manufacturers, and their customers to

identify viable uses of recovered materials. Overall, to ensure solar is sustainable throughout its life cycle, including EOL, technical and policy solutions better than landfilling should be identified, studied, piloted, demonstrated, and deployed throughout the country.

In open-loop recycling pathways, materials recovered from PV modules are used in non-PV applications. The materials recovered from c-Si PV modules have been investigated or demonstrated for use in lithium-ion batteries (Eshraghi et al. 2020), cement and concrete (Fernández et al. 2011; Chao et al. 2015; Stehlík, Knapová, and Kostka 2019), paper production (Palitzsch and Loser 2011), ceramic tiles (K.-L. Lin, Lee, and Hwang 2014), geopolymers (Hao et al. 2015), clay bricks (K.-L. Lin et al. 2013), medical applications (Qin et al. 2020), and fiberglass (Wambach, Heath, and Libby 2017). Conversely, materials recovered from non-PV products could be reused in PV systems. Three recent studies (Heath et al. 2020; Deng et al. 2019; M. Tao et al. 2020) have identified key trends and challenges for c-Si PV recycling, which are highlighted below.

One vital area is determining how the impurity profile of recovered silicon might necessitate changes to silicon manufacturing processes, cost structures, and product characteristics. Developing high-value products and markets for products from the largest constituent of PV modules—glass—also deserves significant research attention.

R&D has focused less on recovery of trace module materials (tin, lead, copper, and silver), possibly because of mass-based recovery targets in PV recycling regulations (Ardente, Latunussa, and Blengini 2019). For example, the European Union's Waste Electrical and Electronic Equipment Directive mandates that 85%/80% of PV module mass is recovered/recycled (Tsanakas et al. 2020), which makes bulk materials attractive for recycling because they contribute around 90% of the module weight (Farrell et al. 2020). However, exponential growth in PV waste may motivate regulations to include recovery of both bulk and specialty materials. One study focuses on recovery of bulk and trace materials from c-Si modules, but this study recovers the trace materials as a part of larger aggregates containing other bulk materials, which is not well suited for direct reuse and requires further downstream processing (Akimoto, Iizuka, and Shibata 2018). Furthermore, only 33.2% of the mass of silver in the module was recovered, leading to a potential revenue loss. Another study used sequential electrowinning to recover trace metals from a simulated solution of metals, which falls short of demonstrating an integrated process that can recover trace metals from the leachate obtained during module recycling (W.-H. Huang et al. 2017). In addition, using platinum electrodes in the electrowinning process may increase recycling costs. These shortcomings show there is need for a low-cost, integrated, high-value recycling process that can recover bulk and trace materials at high efficiencies from c-Si modules (Heath et al. 2020). Applying anticipatory analytical methods (Wender et al. 2014), such as LCA and techno-economic analysis, in the early stages of technology development can help prospectively quantify and compare the economic and environmental effectiveness of novel recycling technologies as well as other CE strategies. Many more studies using these methods are needed to show the economic and environmental impacts of technology design (solar technology, recycling technology, a repair method, etc.) or policy design.

Another key challenge is delamination to eliminate EVA and separate the glass and silicon wafer (Komoto et al. 2018). Using organic solvents to dissolve EVA is time intensive and increases

health risks (Doi et al. 2001; Ravikumar et al. 2020), mechanical processes increase energy use (Ravikumar 2016), and high-temperature processes can have hazardous emissions (Fraunhofer UMSICHT 2017). Commercial processes combine mechanical, thermal, and optical processes, but delamination could be facilitated through DfC approaches such as laminate-free design (Einhaus et al. 2018; Mittag, Eitner, and Neff 2017).

Robust and publicly available assessments of the economic viability of PV recycling at commercial scale are needed to help design better policies and incentives to transition to a PV CE. Despite existing commercial operations (Veolia 2018; Vorrath 2021), there is significant variability in recycling costs based on the recycling technology—for example, from generating $3.40 per module in additional revenue to costing $96 per module (Deng et al. 2019)—and recyclers charge recycling fees because revenue from recovered materials alone typically cannot economically sustain PV recycling (Deng et al. 2019; M. Tao et al. 2020).

The variability in designs and evolution of manufacturing trends across legacy and current generations of PV modules may hinder the commercialization and economic viability of recycling technologies. Declining silver and silicon content (ITRPV 2020) decreases potential revenue from reselling the recovered materials. Use of high-temperature recycling processes, although well suited for glass-glass and fluorine-free PV modules, may release hazardous fluorinated emissions when Tedlar is used as a backsheet (Aryan, Font-Brucart, and Maga 2018). Clarifying the costs of treatment and corrosive effects on recycling equipment of fluorine-containing modules would inform decisions on the use of fluorine-containing backsheets. The variability in design and material content of modules, even among products of the same model and from the same manufacturer, can introduce variability in the results for toxicity compliance (e.g., toxicity characteristic leaching procedure [TCLP] tests). Additional variability may result based on the method used to obtain samples from the module (TamizhMani et al. 2019; forthcoming).

Lead is the primary concern for regulatory characterization of module toxicity; if the module lead content is minimized or eliminated, modules could avoid some issues around hazardous material classification at EOL. Working with industry on recognizable standards to ensure module lead content is below the TCLP conformance limit could, if validated and accepted by regulatory agencies, relieve final owners of the costs of testing and burdens of potential hazardous waste treatment. California's decision to allow EOL modules to be managed as universal waste simplifies waste characterization and encourage recycling over landfilling.

To address challenges due to the variability in module design and material content, there is need for a repository of different module designs and material contents, which stakeholders can access and continually update. The repository could facilitate collaboration and information sharing among PV manufacturers and recyclers, address concerns about data confidentiality, increase transparency around the design and material content of past and present modules, ensure repeatability of results and compliance with toxicity tests (e.g., TCLP (ASTM International 2021)), and help customize recycling strategies. Manufacturers can share information with recyclers through bills of materials, material passports, RFIDs, or ecolabels (Arup 2020, 2020; Chowdhury and Chowdhury 2007).

Global growth in PV capacity additions will require collection and transport of waste modules from geographically dispersed installation sites to centralized recycling facilities. Recycling modules at installation sites in small-scale decentralized plants can avoid CO_2 emitted from transporting the modules. However, smaller-scale recycling plants forgo economies of scale realized by centralized plants. There is an opportunity to optimally locate recycling facilities to minimize the economic and environmental cost of PV recycling (Ravikumar et al. 2020; Choi and Fthenakis 2010; 2014; Goe, Gaustad, and Tomaszewski 2015; Guo and Guo 2019).

Because PV and CSP are undergoing rapid change, the capital-intensive recycling industry should carefully consider how their infrastructure can be designed to be as adaptive as possible to handling anticipated amount of EOL materials as well as changes to form factor, materials content, assembly, and so forth.

EOL Repair and Reuse

EOL repair is an emerging CE alternative to recycling. Repair can address defects in parts such as the junction box, backsheet, bypass diodes, encapsulant, glass, and connectors (Tsanakas et al. 2020; Rinovasol 2020; Haque et al. 2019; Ahmad et al. 2019). Repair avoids economic and environmental burdens associated with the destructive processes of disassembly, separation, and recycling of individual material constituents and extends the module lifetimes (PV Europe 2017). The PV repair and maintenance market is expected to be worth $9 billion by 2025 (Wood Mackenzie 2020). In addition, repaired modules on the secondhand market cost less than new PV modules and decrease the cost barrier for purchasing PV systems in price-sensitive markets (Solar Power World 2021).

Module defects can be detected through real-time monitoring, infrared thermographic imaging (Tsanakas et al. 2015; Tsanakas, Ha, and Buerhop 2016), electroluminescence imaging (Djordjevic, Parlevliet, and Jennings 2014), and leveraging ML and AI-based diagnostic approaches (Haque et al. 2019). The emergence of information system/digital service providers has helped link suppliers with potential buyers and expand the markets internationally for repaired and reusable PV systems (SecondSol 2020; Hirshman 2016).

There is need to increase publicly available data on reliability, failure mechanisms, and standards to ensure quality and performance of repaired and reused modules, to provide an objective pricing mechanism and improve market confidence in these modules. Such an assessment could help decrease the variability (Tsanakas et al. 2020; Enbar, Weng, and Klise 2016) in the costs of repairing PV systems and clarify how costs vary based on module conditions (e.g., type of defect, age of module, reason for decommissioning) and diagnostic approach used for repair as well as market conditions (e.g., cost of repaired module versus revenue from recycling the module) (Wade et al. 2017; Rajagopalan et al. 2021). There is need to compare the economic and environmental tradeoffs between module repair/reuse and alternative CE strategies (e.g., recycling) (Wade et al. 2017). Developing standards around reuse and repair is also important for the safety and reliability of secondary products.

Employment and Equity Benefits

PV recycling and repair/maintenance could increase employment opportunities in the sustainability sector, which job seekers could find an attractive alternative to linear economy waste management employment. Further research is required to quantify the tradeoffs among

employment opportunities in repair, recycling, and landfilling, because, for example, repairing modules may diminish PV waste volumes going to recyclers and landfills. In addition, there is need to enhance planning and collaboration among various stakeholders (e.g., researchers, policymakers, PV and waste management industry) to identify relevant skill sets and develop training programs to ensure creation of a workforce to staff U.S. PV repair, repowering, and recycling jobs without the need to export the PV waste.

By managing hazardous materials (e.g., lead) in an environmentally responsible manner, the potential negative impacts on human health are minimized, and environmental justice outcomes are improved. Minority and low-income communities have disproportionally borne the negative health impacts from waste management operations (Kramar et al. 2018; Mohai and Saha 2015; Burwell-Naney et al. 2013; Maranville, Ting, and Zhang 2009; Martuzzi, Mitis, and Forastiere 2010).

To design policies towards maximizing social benefits and improving environmental justice outcomes, tools are needed to explore the behavioral responses of stakeholders to incentives (e.g., recycling versus landfilling PV waste), account for policy incentives (e.g., tax rebates), include market signals (e.g., price of secondary materials), and determine social outcomes (e.g., decreased energy poverty) of CE strategies. Frameworks such as social life cycle assessment (van Haaster et al. 2016), agent-based modeling (Walzberg, Carpenter Petri, and Heath 2020; Tong et al. 2018), and discrete event simulation (Walzberg et al. 2021; Charnley et al. 2019), and tools such ML and AI are promising candidates to determine the social outcomes of CE at PV EOL (Ghoreishi and Happonen 2020).

8.4 Workforce

The Solar Foundation (2021) reported that there were approximately 230,000 U.S. solar industry jobs in 2020 (Figure 8 - 9). Installation and project development represented the largest subsector, accounting for around 150,000 jobs in 2020. An additional 31,000 jobs were attributed to manufacturing, which in the United States related to racking, c-Si module assembly, CdTe modules, monitoring systems, water thermal collectors, and inverters. About 30,000 people were employed in solar sales and distribution. Another 10,000 jobs were associated with operations and maintenance (O&M) of existing PV installations, which depend on total U.S. PV installations (approximately 100 GW_{DC} in 2020). The solar industry is among the fastest-growing industries in the United States, employs more people than any other electricity-generation sector (Figure 8 - 10), and ranks third in terms of total employment among all energy industries, behind only petroleum and natural gas (Gilliland 2020).

Solar Industry Jobs
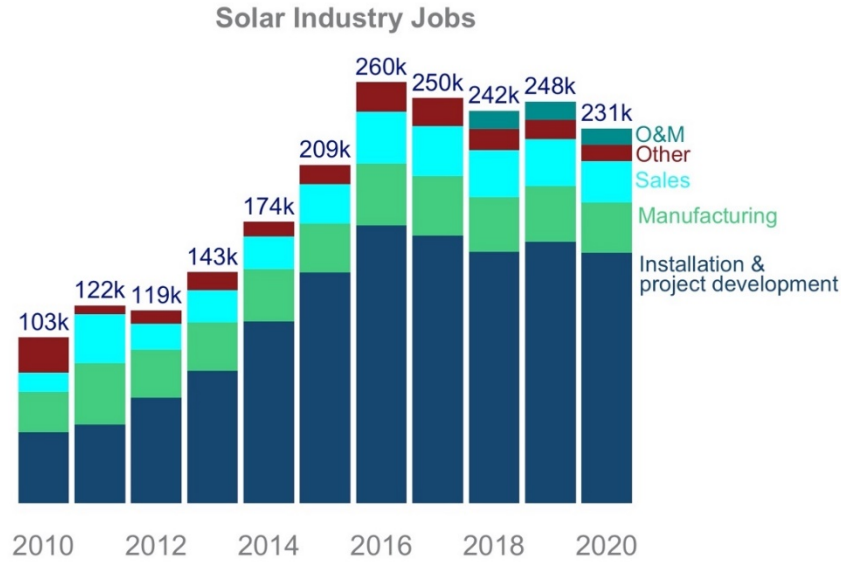
Figure 8 - 9. Solar jobs by type, 2010–2020

Based on data from (The Solar Foundation 2021)
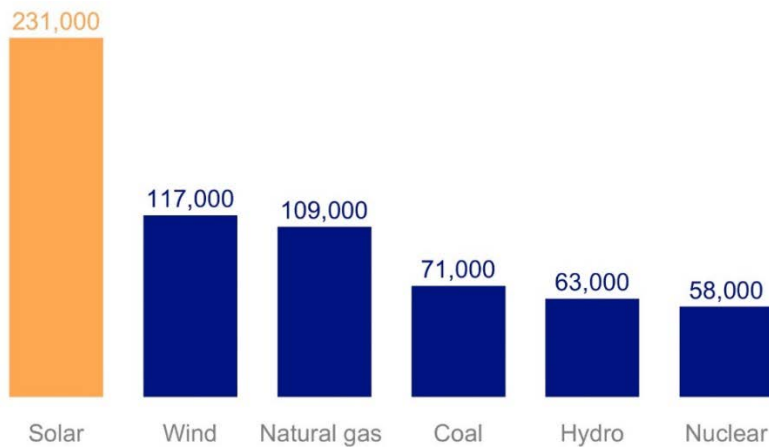
Figure 8 - 10. Estimated electricity jobs in key sectors in 2020

The solar jobs estimate is from The Solar Foundation (2021). Estimates for the other sectors are from DOE (2021d).

8.4.1 Workforce Development

The grid transformation envisioned in this study presents substantial workforce development opportunities. Pollin and Callaci (2019) estimate that each $1 million in clean energy investment generates 17 jobs across a range of occupations, including people directly employed by clean energy companies as well as electricians, roofers, steel workers, engineers, and lawyers. Muro et al. (2019) estimate that the clean energy transition will drive job growth in more than 100 occupations to support clean energy generation, including electricians, roofers, and manufacturers. The rise of rooftop solar markets has resulted in hundreds of new companies as well as increased business for contractors in related trades such as electricians and roofers (O'Shaughnessy and Margolis 2020). Rooftop solar, in particular, can drive significant job growth given that distributed energy projects support more jobs than large-scale, centralized projects (Clack et al. 2020). Available research suggests that new jobs in clean energy industries

pay above-average wages (Muro et al. 2019). Clean energy industries also tend to be relatively equitable in that low-wage workers within the industry earn significantly more than low-wage earners in other industries (Muro et al. 2019). In some cases, skills developed in fossil fuel industries may be applicable to clean energy jobs, thus contributing to a just clean energy transition (see Section 4.4). For example, skills related to CSP power plant operation are similar to skills related to operation of thermal power plants fueled by coal and natural gas.

Most solar companies find it at least somewhat difficult to fill workforce vacancies (Gilliland 2020). The most common reasons cited for hiring difficulties are lack of experience, training, or technical knowledge in the application pool (Gilliland 2020). Solar hiring difficulties represent both a challenge and an opportunity for workforce development. The Solar Foundation identified several workforce development opportunities (The Solar Foundation 2018):

- Engage with public workforce development systems that build talent and connect applicants with industry (e.g., local workforce development boards, American Job Centers).

- Leverage workforce training funds to train unemployed individuals to develop the skills necessary to obtain jobs in the solar industry.

- Offer formal on-the-job training programs to attract more applicants.

- Develop formal career pathways that clearly define opportunities for career growth within the solar industry.

- Reduce prerequisites for hiring and develop prerequisite skills on the job. For instance, many companies require hires to already be certified by the North American Board of Certified Energy Professionals. Instead, solar companies can hire uncertified applicants and help them get certified on the job.

The rapidly emerging solar industry is working to increase diversity and representation in its workforce. According to data compiled by Van Leuven and Gilliland (2019):

- Women only account for about 26% of the solar industry workforce.

- Black and Hispanic groups account for about 25% of the solar industry workforce, comparable to the racial diversity of the U.S. workforce.

- 37% of men in the industry work in managerial, directorial, or presidential positions, compared to 28% of women.

- Men earn 26% more than women, on average.

See Section 4.4 for a discussion of potential measures to increase diversity and equity in the solar workforce.

8.4.2 Workforce Projections

Solar industry job projections vary significantly depending on assumptions about technology and process advances that affect labor productivity, assumptions about how the U.S. solar supply chain evolves, and the assumed decarbonization trajectory. Recent estimates assuming the electricity grid is decarbonized by 2035 have varied from 500,000–1,500,000 total solar industry

jobs by 2035 (Larson et al. 2020, 20; Phadke et al. 2020; The Solar Foundation 2021).[97] Here we discuss how various factors might impact solar jobs projections. For simplicity, we explore these impacts in three categories: installation and development jobs (including sales), manufacturing jobs, and O&M. This discussion is broad and does not explore issues such as the characteristics of different job types and indirect job creation, which could be important considerations in a more detailed analysis.

Installation and development jobs might be expected to be increase roughly in proportion to increasing annual installations, with distributed projects supporting more jobs than large-scale, centralized projects (Clack et al. 2020). However, gains in module efficiency and efforts to streamline installation procedures would increase labor productivity and thus could result in significantly smaller job gains. On the other hand, such efficiency gains may be offset by other industry or technology trends: increased inverter loading ratios, combining solar with storage, and blurring the line between solar, roofing, and new home construction could all affect the labor intensity associated with solar installations. How these types of solar-associated jobs are accounted for helps explain the wide variation in job projections. The fact that the lines between solar and associated industries may be blurring indicates opportunities to realize broad employment benefits as the solar industry grows. Overall, gains in installation and development jobs are likely to be in the multiple hundreds of thousands of jobs, with installation and development continuing to account for most solar jobs.

In the manufacturing sector, the 2020 jobs numbers only account for manufacturing a fraction of the PV hardware installed in the United States. For example, less than a quarter of PV modules installed in the United States in 2020 were assembled or manufactured domestically. In the case of c-Si modules, most of the materials—including cells, glass, and frames—were largely imported, with only final assembly occurring in the United States. Expanding the U.S. manufacturing supply chain to produce a larger share of the equipment in domestic installations and to include domestic production of a broader set of materials across the solar supply chain (polysilicon, wafers, cells, PV glass, encapsulant sheets, etc.) could increase domestic PV manufacturing employment significantly. On the other hand, increased module efficiency and process automation would put downward pressure on these potential job gains. Overall, gains in manufacturing jobs are likely to be in the multiple tens of thousands of jobs.

In contrast to installation, development, and manufacturing jobs, O&M jobs are driven by cumulative installations. In the *Solar Futures* scenarios, cumulative PV deployment is projected to grow to 1,000–1,200 GW_{DC} by 2035 and 1,400–2,100 GW_{DC} by 2050 in the Decarb and Decarb+E scenarios, respectively. This corresponds to roughly 10–20 times above 2020 installations. The corresponding increase in O&M jobs will likely be smaller owing to technological advancements and changes in O&M practices. For example, developments that could improve O&M labor productivity include longer inverter lifespans, improved monitoring systems, anti-soiling coatings, and general process improvements. Overall, gains in O&M jobs

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[97] Larson et al. (2020) include cases for decarbonizing the entire energy system by 2050, with a total of 2.5 million solar jobs by 2050 in their most aggressive case.

are likely to be in the multiple tens of thousands of jobs, perhaps reaching a total of 100,000–150,000 jobs.

Data on solar EOL-related jobs (landfilling, recycling, or other CE options) do not yet exist, but such jobs will likely remain domestic because the modules are already local and cost-prohibitive to ship.

A

Appendices

Appendix: Chapter 2

2-A: Distributed Photovoltaic Modeling

ReEDS models the bulk power system and does not represent the distribution system or DERs. However, we include rooftop PV projections from the Distributed Generation (dGen) model (Sigrin et al. 2016), an agent-based consumer adoption model. Specifically, dGen rooftop PV adoption projections for 2020 to 2050 serve as exogenous inputs for ReEDS. dGen models other distributed resources—including distributed wind, storage, and geothermal heat pumps—but these technologies are not directly considered in our scenarios.

Our scenarios rely on two rooftop PV adoption forecasts that differ by assumed PV technology cost trajectory: Moderate and Advanced technology projections from the ATB 2020 (NREL 2020). These projections rely on the default dGen assumptions and are used in the NREL 2020 Standard Scenarios (Cole, Corcoran, et al. 2020). A Breakthrough price scenario is also modeled (see Chapter 2 and Appendix 2-B). Figure 2-A-1 presents the three DPV projections used across the scenarios and sensitivities with the choice of DPV trajectory used corresponding to the cost assumptions (Moderate, Advanced, or Breakthrough) used for utility PV (see scenario specifications in Section 2.1). Other interactions with distributed generation deployment—such as from changes to electricity prices, policies, or electricity demand—are not considered directly in the scenarios. A recent study examines additional DPV and battery adoption scenarios driven by a wider range of drivers, including PV and battery costs, value of backup power, and compensation policies (Prasanna et al. 2021).
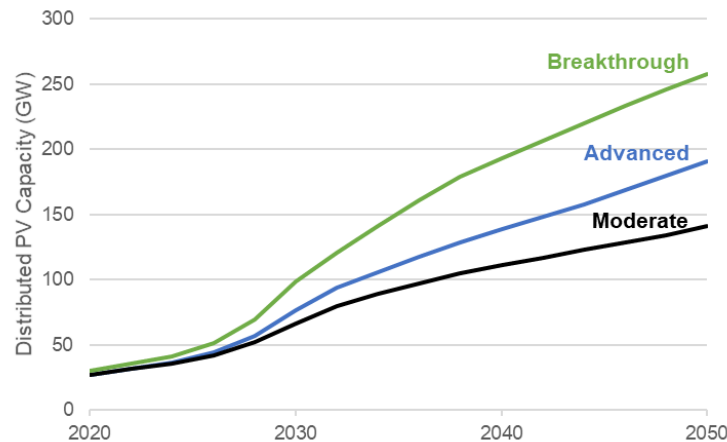
Figure 2-A-1. DPV projections

Prior research using the ReEDS and dGen models shows that total (utility-scale and distributed) solar generation is largely independent of the exogenously specified DPV projection (Cole et al. 2016). For this reason, we consider a limited number of DPV projections in the *Solar Futures* scenarios, and we aggregate all DPV and UPV into a single category. Additional research is needed to assess cost, equity, land use, and other implications of different mixes of distributed and utility-scale solar adoption.

2-B: Sensitivity Scenarios

Here we show sensitivity analyses related to decarbonization trajectory, breakthrough cost reductions for PV and battery technologies, costs for RE-CTs and zero-carbon fuels, and changes to the portfolio mix. Unless otherwise noted, the sensitivity scenarios use assumptions from the core Decarbonization (Decarb) scenario. These scenarios do not cover all possibilities, but they are designed to examine key uncertainties, particularly for their impacts on power system costs.

2.B.1 Decarbonization Trajectory

Here we vary the CO_2 emissions trajectory used in the Decarb scenario. The Decarb100 scenario fully eliminates power-sector emissions by 2035, and the Decarb90 scenario achieves 90% emissions reductions by 2035. In the Decarb90 scenario, emissions reductions continue after 2035 at the same rate as in the core Decarb scenario, reaching 95% below 2005 levels by 2050.

The Decarb100 scenario slightly increases solar capacity in 2035 compared to the core Decarb scenario, whereas solar capacity is slightly lower in the Decarb90 scenario (Figure 2-B-1). The solar capacity ranges are relatively narrow across all three scenarios in 2035 (702–759 GW) and 2050 (1,047 GW–1,123 GW). The Decarb100 scenario results in earlier deployment of CSP, with 27 GW by 2035, driven in large part by the need to replace the carbon-emitting fossil fuel capacity with new resources—particularly those that can provide firm capacity. In fact, the largest difference between the scenarios is the timing and magnitude of storage and RE-CT deployment. By 2035, 392 GW of storage is deployed in the Decarb100 case, whereas storage capacity is 285 GW and 232 GW under the Decarb and Decarb90 cases, respectively. Similarly, 376 GW of RE-CT capacity are required by 2035 under the Decarb100 case, whereas RE-CTs are not deployed until after 2035 in the other cases. By 2050, RE-CT and storage capacity are similar in the two cases that reach zero-carbon electricity (Decarb and Decarb100). In contrast, RE-CTs are not needed in the Decarb90 case, because the small (120 Mt) amount of CO_2 allowed in 2050 enables existing fossil capacity to support resource adequacy.

The differences in solar, storage, and other clean technology deployment rates—along with the degree of fossil fleet replacement—affect system costs. The present-value power-system costs for the Decarb100 case are $288 billion (12%) greater than for the core Decarb scenario. Conversely, system costs are $171 billion (6.9%) lower under the Decarb90 scenario. Of course, these cost differences come with differences in emissions. For example, cumulative (2021–2050, undiscounted) CO_2 emissions are 1,800 Mt lower under the Decarb100 case and 2,700 Mt higher under the Decarb90 case, relative to the core Decarb scenario.
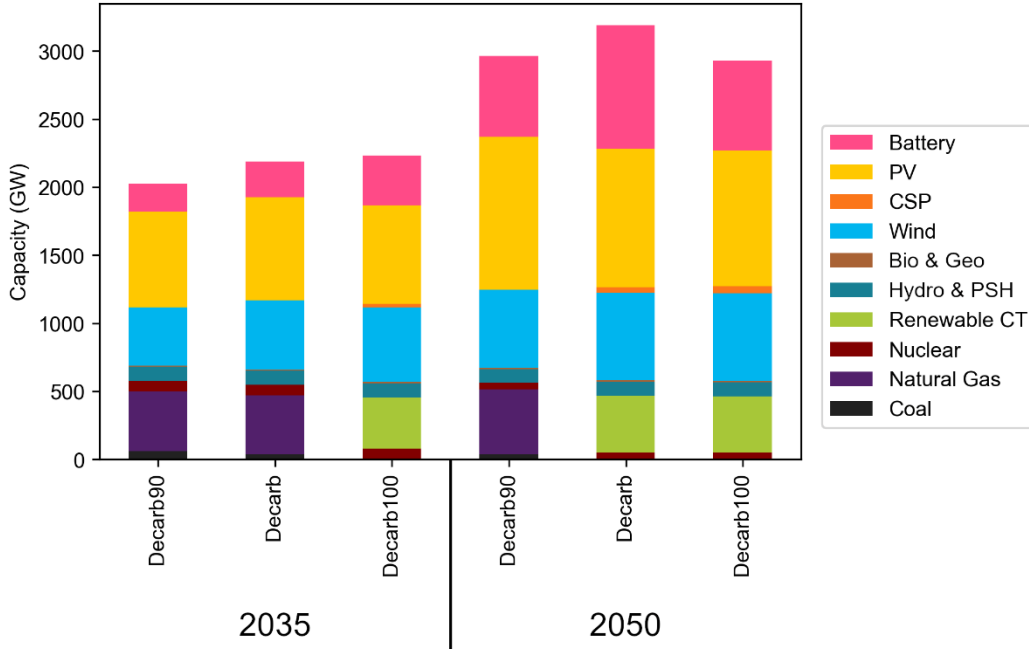
Figure 2-B-1. Capacity mix in 2035 and 2050 for the decarbonization trajectory scenarios

2.B.2 Electricity Technology Costs

The core Decarb scenario uses the ATB Advanced technology projections. In contrast, the core Reference scenario uses the ATB Moderate projections, so incremental costs reflect the combined impact of the decarbonization target and additional technology advancements. To isolate these impacts, we model the Moderate technology assumptions with the 95%-by-2035 emissions-reduction target. These analyses use the Moderate assumptions for non-solar RE technologies as well. Scenarios with technological progress beyond the Advanced case for UPV and battery storage technologies are also examined[98]; these Breakthrough cost projections are described in Appendix 2-E.

The Breakthrough PV and battery assumptions are modeled under a reference (current policies) scenario and a 95%-by-2035 grid-decarbonization scenario. Figure 2-B-2 shows solar and storage capacities over time in the Moderate, Advanced, and Breakthrough scenarios. Unsurprisingly, Breakthrough assumptions yield greater deployment of solar and storage capacity; over 1,300 GW of solar capacity are deployed by 2050 in the Reference.Break and Decarb.Break scenarios. Storage capacity totals 1,210 GW and 1,670 GW for the same two scenarios, respectively. As a result of this deployment, solar generation constitutes 42% of total 2050 generation under current policies and 45% of generation with a fully decarbonized grid.

Lower PV and battery costs also reduce electricity prices and system costs. For example, 2035 marginal system cost of electricity under the Decarb.Break scenario is $9.50/MWh lower than under the Decarb.Mod scenario. Impacts on power-system costs are presented in Section 2.B.5.

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[98] Under these scenarios, the Advanced projections are used for CSP and other non-PV renewable electricity technologies.
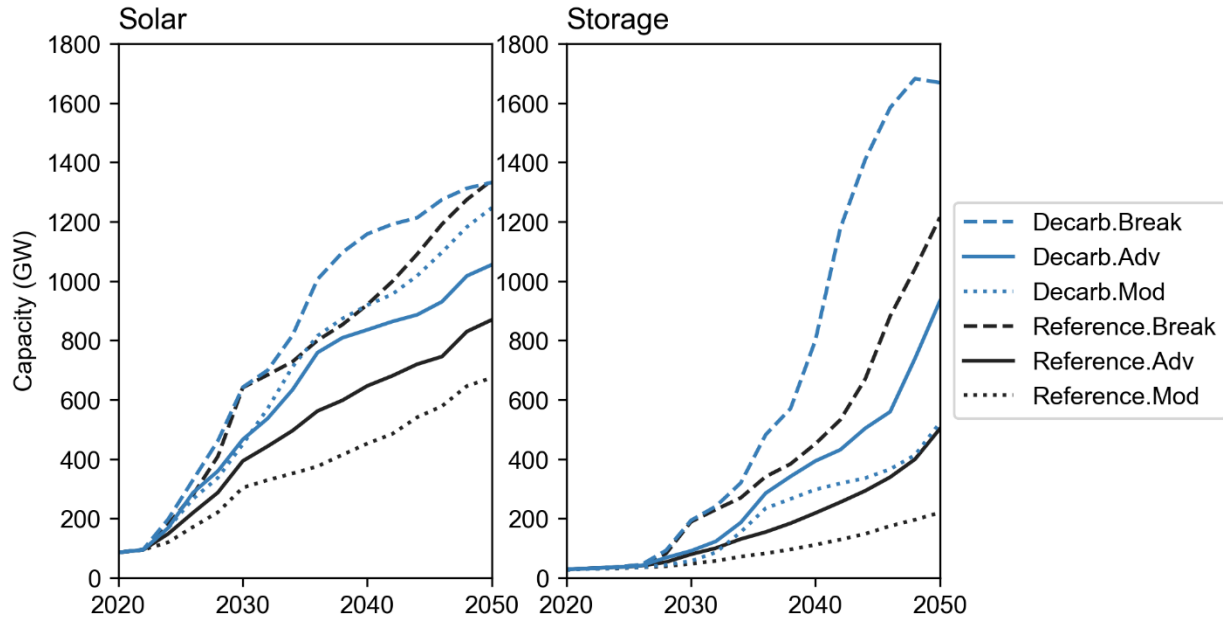
Figure 2-B-2. Solar (left) and storage (right) capacity under a range of cost assumptions

"Mod" and "Adv" refer to the ATB Moderate and Advanced assumptions for all renewable and storage technologies. Reference.Mod is the same as the core Reference scenario, and Decarb.Adv is the same as the core Decarb scenario. "Break" refers to the Breakthrough assumptions for PV and batteries but uses the ATB Advanced assumptions for all other RE technologies. Appendix 2-E summarizes the three cost and performance projections for solar and battery technologies.

2.B.3 Renewable Energy Combustion Turbine Assumptions

The future cost of RE-CTs is highly uncertain given the early stage of commercial zero-carbon fuels and the wide-ranging fuel pathways. Our sensitivity analysis includes a RE-CT Low-Cost scenario that assumes a zero-carbon fuel cost of $10/MMBtu, compared to the $20/MMBtu used in the core scenarios. In addition, upgrades of existing NG plants incur lower costs (3% versus 20%).[99] An RE-CT High-Cost scenario assumes higher ($30/MMBtu) fuel costs and disallows NG plant upgrades. Both scenarios use the same emissions trajectory (95% emissions reductions by 2035) and other technology assumptions (e.g., Advanced RE technology costs) from the core Decarb scenario.

Figure 2-B-3 shows the difference in installed capacity from 2030 to 2050, relative to the Decarb scenario, for the RE CT Low-Cost and High-Cost scenarios. These results primarily highlight the economic competition between batteries and RE-CTs to provide firm capacity as the grid becomes fully emissions free. Variations up to 100 GW of RE-CT capacity and up to 300–500 GW of storage capacity are observed across the scenarios. There are variations in other technologies as well. For example, the cost of RE-CTs has an impact on CSP capacity. More expensive RE-CTs result in 77 GW of CSP by 2050 (compared to 39 GW under the core Decarb

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[99] The cost adders are relative to the cost of new NG-CT capacity. See Appendix 2-C.

case). Conversely, low-cost RE-CTs are more competitive, resulting in only 2.3 GW of CSP by 2050.

The cost of RE-CTs and zero-carbon fuels can impact total system costs. Present-value power-system costs for the RE-CT Low-Cost scenario are $62 billion (2.5%) lower than for the core Decarb scenario, whereas system costs are $84 billion (3.4%) higher for the RE-CT High-Cost scenario. The system cost measure may understate the sensitivity to zero-carbon fuels, because it is a present-value measure that more heavily discounts expenditures during the last decade of the analysis when RE-CTs are primarily deployed. Another measure that reveals the cost sensitivity of RE-CT assumptions without these discounting impacts is the marginal system cost of electricity. Under the RE-CT Low-Cost scenario, these electricity prices are nearly $10/MWh lower in 2050, relative to the core Decarb scenario, whereas 2050 electricity prices are $8/MWh higher under the RE-CT High-Cost scenario.
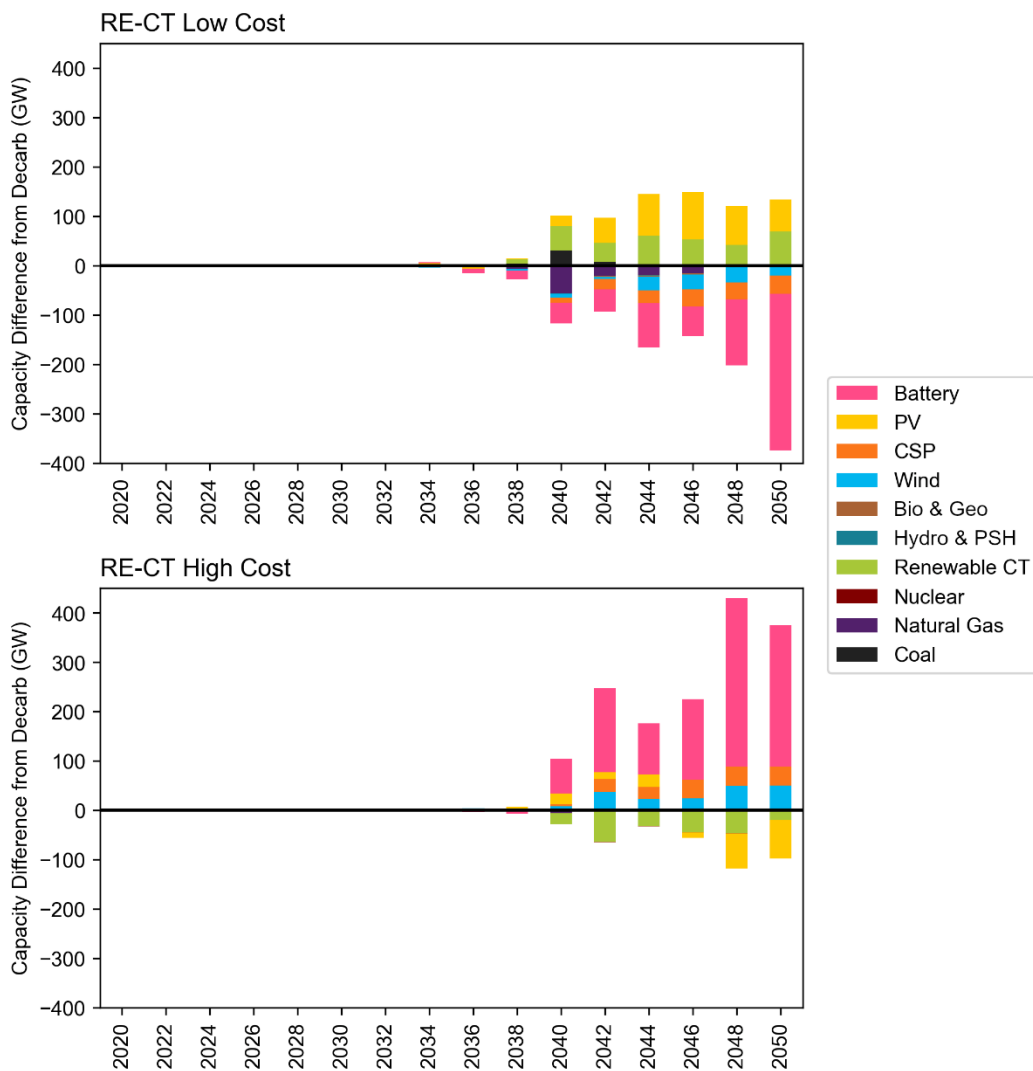
Figure 2-B-3. Difference in installed capacity from the core Decarb scenario for the RE-CT Low-Cost (top) and High-Cost (bottom) scenarios

2.B.4 Technology Carveouts

These sensitivity scenarios examine the cost impacts of small changes to the core Decarb scenario. ReEDS identifies the least-cost solution given a set of assumptions, but it is unclear how non-optimal other solutions may be; in other words, the shallowness of the optimization space is not revealed solely by examining the optimal solution. To test this, our "carveout" scenarios prescribe an additional generation requirement for select technologies. We require annual generation shares from CSP starting in 2030 and ramping up to 10% by 2050, on top of the emissions cap and all other constraints modeled in the core Decarb scenario. Two additional sensitivity scenarios apply the same generation requirement for geothermal and offshore wind, separately. A similar scenario prescribes 20% of 2050 generation from nuclear. The last carveout scenario prescribes 80 GW of *capacity* from PSH by 2050.

Figure 2-B-4 compares the 2050 generation shares under the carveout scenarios and the core Decarb scenario. In the core Decarb scenario, three technologies (PV, onshore wind, and RE-CTs) make up 81% of 2050 generation, with the remaining 19% from the technologies shown in the figure. The increased generation from the designated technology, along with the associated 2050 capacity, is shown for each carveout scenario. For example, in the CSP scenario, 98 GW of CSP are needed to provide 10% of total 2050 generation. The capacity needed to reach the carveout generation targets varies by technology depending on capacity factors, deployment location, and other system dependencies (e.g., curtailment). The additional prescribed generation comes at the expense of other clean energy technologies, including PV, onshore wind, and RE-CTs. The PSH carveout scenario has a modest impact on the generation mix but impacts deployment of batteries and RE-CTs. In this scenario, the increase in PSH displaces about 47 GW of batteries.

The carveout scenarios show multiple technology pathways to the decarbonization targets. Importantly, these distinct pathways all result in similar system costs. All the carveout scenarios shown in Figure 2-B-4 have power-system costs within 3% of that from the core Decarb scenario. Given uncertainties with future technological progress and local deployment preferences, R&D investments for a broad suite of options may be valuable to hedge against future risks to any individual option.
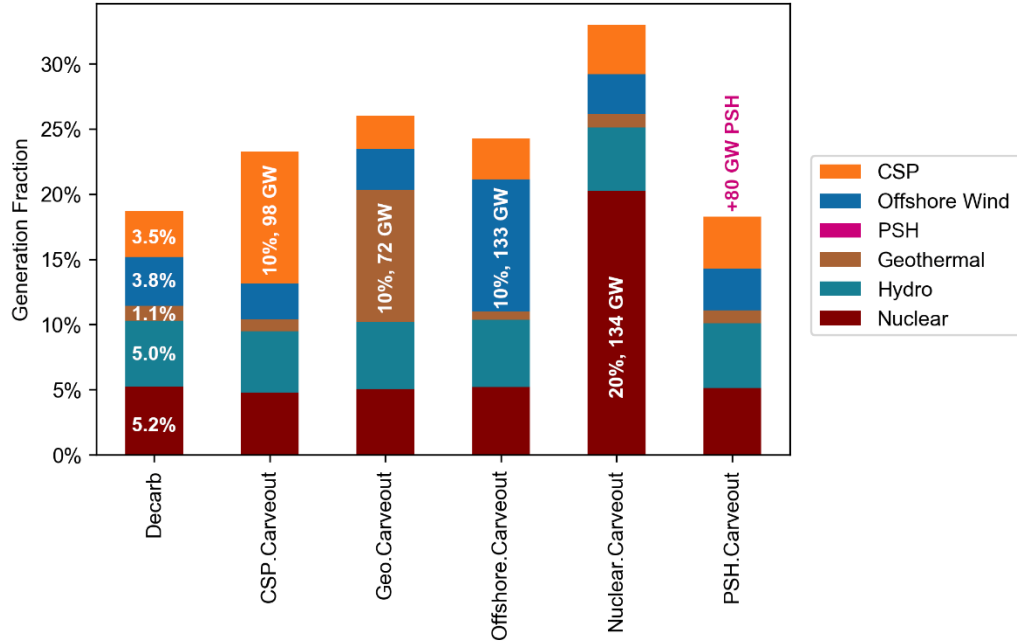
Figure 2-B-4. Generation shares from select technologies under the core Decarb and carveout scenarios, 2050

2.B.5 Summary Cost Uncertainties

Figure 2-B-5 shows the incremental system cost, relative to the core Reference scenario, across a collection of scenarios. The incremental system cost for the core Decarb scenario ($225 billion, 9.9% higher than the Reference scenario cost) is shown in blue for comparison. Incremental power-system costs are most sensitive to the rate and extent of decarbonization (top bar); the Decarb90 scenario results in system costs only 2.4% ($54 billion) higher, whereas the Decarb100 scenario has an incremental cost of 23% ($513 billion). Costs are also highly sensitive to future solar and other clean energy technology assumptions, highlighting the importance of R&D. Under the Decarbonization scenario using Breakthrough PV and battery assumptions, incremental system costs are only 3.5% ($87 billion) higher than the Reference scenario, whereas Moderate technology assumptions result in much higher costs ($503 billion, +22%). Incremental system costs range from 7.2% to 14% for the RE-CT assumptions. Finally, incremental costs are least sensitive to the carveout scenarios.
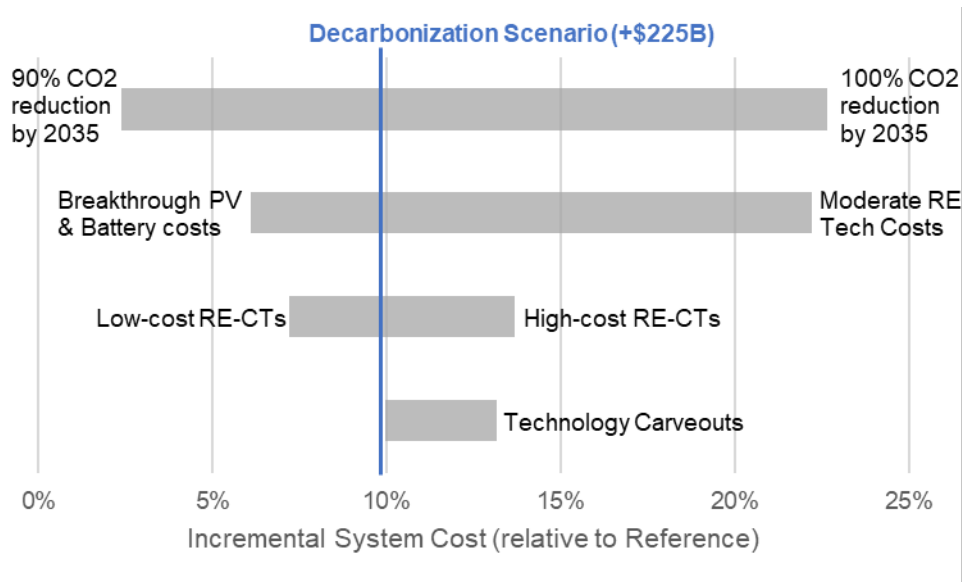
Figure 2-B-5. Uncertainties in incremental power-system costs relative to the Reference scenario across key drivers

2-C: Renewable Energy Combustion Turbines

Combustion turbines or gas turbines in the United States currently combust NG to provide peaking generation needs and support system resource adequacy. RE-CTs are a technology option in ReEDS that relies on the same underlying generation technology as NG-CTs, but RE-CTs use a renewable or zero-carbon fuel such as biofuels, hydrogen, synthetic methane, and other options. The multiple types of zero-carbon fuels that could be used by RE-CTs enable significant flexibility, given uncertainties with fuel production, demand, costs, and cross-sectoral interactions in the future.

The RE-CT model representation in ReEDS and default assumptions are from Cole et al. (2021). Capital costs for greenfield RE-CTs are assumed to be 103% of the capital costs for new NG-CTs, but retrofits of existing NG-CT and NG combined-cycle (CC) power plants to use zero-carbon fuels are also modeled. NG-CT retrofits incur a 20% (of new NG-CT capacity) cost. NG-CC capacity can also be retrofit to RE-CT with an assumed cost of 63% of the capital cost for new NG-CT capacity. The slightly higher costs for new plants and the cost for retrofits include costs for clutches to enable RE-CTs to operate as synchronous condensers and provide inertial response even when not generating electricity (see Chapter 3). O&M costs and heat rates are assumed to be the same as for NG-CTs. The upstream fuel supply—including pipeline, storage, or other infrastructure—for RE-CTs is not explicitly modeled, and no specific renewable fuel is assumed. Instead, a delivered fuel price of $20/MMBtu for all years is simply assumed. These delivered prices include the cost for fuel storage and transport. Sensitivity analyses using alternative cost assumptions are included in Appendix 2-B.

Numerous technologies can provide similar services as RE-CTs, and ReEDS considers the capabilities and costs for a wide suite of technologies. However, ReEDS does not comprehensively model all possible future technologies; long-duration storage, hydrogen fuel cells, biomass with CCS, negative-emissions technologies, and small modular nuclear are not represented. If included and if cost-competitive, these technologies could displace some of the

market share estimated for RE-CTs, batteries, and other technologies deployed in the scenarios. Further research and improved modeling are necessary to assess the tradeoffs across a wide range of technologies and fuels.

2-D: Assumptions for the Energy Decarbonization Scenario

The Energy Decarb scenario is designed to approximate possible incremental solar demand if decarbonization efforts—particularly in end-use sectors—extend beyond those from the core scenarios. The Energy Decarb scenario starts from the residual fossil energy consumption estimated for the Decarb+E scenario, in which 40.6 quads of final fossil energy consumption remain in 2050. This consumption is spread across the industrial (22.6 quads), transportation (12 quads), commercial buildings (2.9 quads), and residential buildings (3.1 quads) sectors. A fully decarbonized energy system would need to replace this consumption of carbon-emitting fossil fuels with zero-carbon alternatives, some of which would increase electricity demand and associated demand for solar energy and capacity.

To estimate possible incremental solar demand, we apply a simple accounting method consisting of five steps:

1) Assume a market share for the avoided fossil fuel consumption.

2) Estimate final energy from zero-emission replacement (electricity, hydrogen, biofuel, synthetic hydrocarbon, ammonia, methanol, and solar thermal) using relative efficiencies of different end-use equipment.

3) Adjust electricity and hydrogen energy demand based on required inputs for relevant zero-emission replacements.

4) Calculate electricity demand based on direct demand for electricity and electricity demand for electrolytic hydrogen production.

5) Estimate solar demand from the incremental electricity demand and generation and capacity shares from the core *Solar Futures* scenarios.

Each subsector is considered separately for steps (1) and (2). Only national total estimates for 2050 are calculated. Significant uncertainties are associated with each step, which could drive a different amount of solar demand (see Section 2.3.2). The following subsections describe the key assumptions used for each of these five steps.

2.D.1 Market Share for Avoided Fossil Fuel Consumption

Several low-emission replacement options are considered, including energy efficiency, electrification, hydrogen, biofuels, synthetic hydrocarbons, ammonia, methanol, solar thermal, and CCS. The market share assumptions are based loosely on other studies where available, although—consistent with the overall Energy Decarb scenario development process—simple assumptions are applied throughout.

For the buildings sectors, a combination of energy efficiency and increased electrification is considered. Energy efficiency constitutes 16% to 38% of the residual market share across buildings subsectors based on annual efficiency improvement estimates from (Laitner et al.

2012; Steinberg et al. 2017a).[100] The greatest efficiency improvements are assumed for space heating. These efficiency estimates fall within a broad range of estimates (Hostick et al. 2014; Nadel and Ungar 2019; Larson et al. 2020; Langevin, Harris, and Reyna 2019; Sofos et al. 2020; Dean et al. 2018; DOE 2015; Neukomm, Nubbe, and Fares 2019; Roth and Reyna 2019). The remaining fossil fuel consumption is replaced with electric technologies, consistent with (Steinberg et al. 2017a) and, to a slightly lesser extent, (Larson et al. 2020).

We assume electrification is widespread in industry based on (Madeddu et al. 2020). Notable exceptions include biofuel use in agriculture (replacing 3% of the residual fossil energy consumption) (E. Brown and Elliott 2005) and construction (8.7%), synthetic hydrocarbons in the glass industry (30%), solar thermal for 5% of industrial boiler loads (McMillan et al. 2021), and continued petroleum use for part of construction (e.g., asphalt) and with CCUS for the cement industry.

A broad mix of fuels and technologies is assumed for the transportation sector given the varied applications and subsectors. Low-carbon fuels considered include electricity, hydrogen, and a variety of drop-in fuels (biofuels, synthetic hydrocarbons, ammonia, and methanol). Table 2-D-1 (Ardani et al. 2021) summarizes the market share assumptions across subsectors along with references that informed those market shares.[101]

Table 2-D-1. Summary of Estimated Low- and Zero-Carbon Fuel Market Shares, Fuel Economy Ratios, and References for the Transportation Sector

Subsector	Low-Carbon Fuel	Subsector Market Share	Fuel Economy Ratio	Market Share Reference	Fuel Economy Reference
LDV	Electric	1	2.6	Approximated based on (Brooker et al. 2021)	(Brooker et al. 2021)
MDV	Electric	0.5	2.8		(Brooker et al. 2021)
MDV	Hydrogen	0.5	1.9		(Brooker et al. 2021)
Buses	Electric	0.25	2.7		(Brooker et al. 2021)
Buses	Hydrogen	0.50	1.8		(Brooker et al. 2021)
Buses	Biofuels	0.25	1		Drop-in fuel
HDV	Electric	0.25	2.2		(Brooker et al. 2021)

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[100] The average rate between the two studies is used and extrapolated over 30 years to get the total amount of efficiency to replace the residual amount of fossil energy consumption.

[101] Ardani et al. (2021) is a technical report associated with Chapter 7 of the *Solar Futures Study*.

Subsector	Low-Carbon Fuel	Subsector Market Share	Fuel Economy Ratio	Market Share Reference	Fuel Economy Reference
HDV	Hydrogen	0.50	1.4		(Brooker et al. 2021)
HDV	Biofuels	0.25	1		Drop-in fuel
Rail	Biofuels	0.4	1	50% of remaining market-share	Drop-in fuel
Rail	Synthetic hydrocarbons	0.4	1	50% of remaining market-share	Drop-in fuel
Rail	Hydrogen	0.2	1.15	(McKinsey & Company 2017)	(Ahluwalia, Papadias, and Wang 2020)
Maritime	Ammonia	0.82	1	(McKinsey & Company 2021; Concawe 2017)[102]	Drop-in fuel
Maritime	Methanol	0.18	1	(McKinsey & Company 2021; Concawe 2017)[103]	Drop-in fuel
Air	Electric	0.15	1.25	(Schäfer et al. 2019)	(Schäfer et al. 2019)[104]
Air	Hydrogen	0.25	1	(McKinsey & Company 2021)	Assume hydrogen turbines used
Air	Synthetic hydrocarbons	0.6	1	(McKinsey & Company 2021)	Drop-in fuel
Lubricants	Synthetic hydrocarbons	1	1	Assumption	Drop-in fuel
Military	Biofuels	0.5	1	Assumption	Drop-in fuel
Military	Synthetic hydrocarbons	0.5	1	Assumption	Drop-in fuel

HDV = heavy-duty vehicle, LDV = light-duty vehicle, MDV = medium-duty vehicle.

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[102] The ammonia share is estimated based on ships with long routes, less frequent stops, no passengers, and lower potential total cost of ownership

[103] Methanol share estimated based on ships with shorter routes, more frequent stops, potential for passengers, and lower potential total cost of ownership

[104] Electric aircraft currently have about two times higher propulsion efficiency but are 1.5-2 times heavier due to battery weight. We assume a 1.25 fuel economy ratio representing the middle of this range.

2.D.2 Final Energy of Low-Carbon Alternatives Considering Efficiency Differences

End-use equipment that relies on different fuels requires different amounts of fuel input to provide the same service. These differences in fuel economy are accounted for to estimate the final energy consumption of the low-carbon alternative compared to the fossil fuel that is replaced.[105] In other words, combining the market shares from step (1) with these efficiency ratios leads to the final energy consumption by fuel type estimates.

For the buildings sector, electric technologies are assumed to be as efficient or more efficient than their fossil fuel counterparts. Heat pumps for space and water heating are assumed to be three times more efficient, and electric cooktops are assumed to be twice as efficient. These estimates are based on (Jadun et al. 2017) and (Miller and Higgins 2021). For all other uses, we simply assume the same efficiency between an electric and non-electricity technology.

Most industrial electrotechnologies are assumed to be twice as efficient as their fossil counterparts. Technologies that rely on biofuels and syngas are assumed to have the same efficiency. Low-carbon electric and solar thermal boilers are assumed to be 30% more efficient than natural gas and other fossil fuel-fired boilers (McMillan et al. 2021).

Table 2-D-1 shows the assumed fuel economy ratio between the low-carbon and fossil-fuel-based options in transportation.

2.D.3 Adjusted Electricity and Hydrogen Demand Based on Fuel Input Requirements

Production of the drop-in fuels considered—including biofuels, synthetic hydrocarbons, ammonia, and methanol—requires electricity and hydrogen input based on the assumed pathways. Although this electricity and hydrogen are not consumed at the point of final consumption, they could increase solar electricity demand and therefore are considered in our calculations. Table 2-D-2 shows the amount of electricity and hydrogen fuel input (in quads) needed per quad of low-carbon fuel. These estimates are based on the following conversion factors.[106]

- Biofuels are produced using biomass and hydrogen: 490 g exogenous hydrogen/gal biofuel (Ruth et al. 2020) and 65.5 gal biofuel/dry ton biomass using endogenous hydrogen (Dutta et al. 2020).

- Synthetic hydrocarbons are produced using methanol (production assumptions below) and electricity: 2.48 lb methanol/gal gasoline equivalent synthetic hydrocarbon and 0.07 kWh-e/gal gasoline equivalent (Tan et al. 2015).

- Ammonia is produced using hydrogen and electricity: 10 kWh-e/kg ammonia electricity requirement (producing the hydrogen, purifying nitrogen, and producing ammonia from nitrogen and hydrogen) (C. Smith, Hill, and Torrente-Murciano 2020) with 9.25 kWh-

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[105] On one extreme, energy efficiency would fully avoid energy consumption.

[106] All conversion factors are on a high heating value (HHV) basis.

e/kg ammonia as electricity demand for hydrogen production and the remainder for purifying nitrogen and producing ammonia.

- Methanol is produced using hydrogen and electricity: 1.27 kWh-e are required to capture each kg of CO_2, and 1.46 kg CO_2 are needed per kg of methanol (Dieterich et al. 2020), resulting in an electricity demand for CO_2 capture of 1.86 kWh-e/kg methanol. An additional 0.12 kWh-e/kg methanol is required for other electricity loads in methanol production (Knighton et al. 2020). Based on those values and a total electricity demand of 12.14 kWh-e/kg methanol, the hydrogen demand is estimated at 0.2 kg H_2/kg methanol (Dieterich et al. 2020).

Table 2-D-2. Electricity and Hydrogen Fuel Input Required (Quads) Per Quad of Low-Carbon Fuel Consumed

	Biofuels[a]	**Synthetic Hydrocarbons**	**Ammonia**	**Methanol**
Electricity	0	0.38	0.12	0.31
Hydrogen	0.53	1.49	1.16	1.25

[a] 1.74 quads of biomass are also required per quad of biofuel.

For the Energy Decarb scenario, we also assume hydrogen is used in the RE-CTs from the Decarb+E scenario. Based on the heat rates and estimated generation from RE-CTs, this totals 1.8 quads of hydrogen.

2.D.4 Electricity Demand

In this step, we convert quads of hydrogen to quads of electricity. We assume all hydrogen is produced through electricity and use a conversion factor of 1.28 (quads of electricity per quad of hydrogen), which is equivalent to 50.5 kWh/kg H_2 (Badgett, Xi, and Ruth 2021).[107] Based on the assumptions described above, electricity demand for hydrogen production totals 7.2 quads.

The quads of electricity are then converted to TWh of electricity using a simple conversion factor of 293 TWh per quad (or 3,412 Btu per kWh). This conversion yields an *incremental* annual electricity demand of 6,900 TWh of electricity needed to avoid the *residual* fossil energy consumption from the Decarb+E scenario. Of this 6,900 TWh, 3,800 TWh are needed for direct electrification, 400 TWh are for production of synthetic hydrocarbons, ammonia, and methanol, and 2,700 TWh are estimated for electrolytic hydrogen production. When added to the 6,700 TWh of electricity demand in 2050 under the Decarb+E scenario, 2050 annual electricity demand under the Energy Decarb scenario totals nearly 13,600 TWh or roughly double that of the Decarb+E scenario.

2.D.5 Solar Demand

To estimate the amount of solar generation and capacity under the Energy Decarb scenario, we simply use the portfolio mix in 2050 from the Decarb+E scenario. Note that the electricity demand estimates described above are at the point of end-use consumption. We effectively

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[107] Solar Futures E2M technical report.

assume the same loss rates (for transmission, distribution, and storage) and curtailment rates in our method. With these assumptions, 2050 solar generation and capacity are estimated to be nearly 7,000 TWh and over 3,000 GW, respectively, under the Energy Decarb scenario.

2-E: Solar and Battery Technology Cost Assumptions

Technology cost and performance assumptions are primarily based on the NREL ATB 2020 (NREL 2020). These tables summarize those assumptions for solar and battery technologies, and include projections used for the Breakthrough PV and battery case.

Table 2-E-1. Overnight Capital Costs ($/kW)

		2020	2030	2040	2050
ATB Moderate	Utility PV	1325	819	746	673
	Commercial PV	1701	1013	895	777
	Residential PV	2644	1125	991	858
	Battery – 4 hrs	1455	817	715	613
	CSP – TES 10 hrs	7027	4878	4125	3903
	CSP – TES 14 hrs	7887	5514	4636	4363
ATB Advanced	Utility PV	1312	673	590	507
	Commercial PV	1679	777	675	572
	Residential PV	2620	858	730	602
	Battery – 4 hrs	1203	567	456	345
	CSP – TES 10 hrs	7027	3551	2965	2640
	CSP – TES 14 hrs	7887	3950	3295	2944
Breakthrough	Utility PV	1296	507	447	387
	Commercial PV	1672	654	577	499
	Residential PV	2597	602	541	479
	Battery – 4 hrs	1224	400	300	200

Table 2-E-2. Fixed O&M ($/kW-year)

		2020	2030	2040	2050
ATB Moderate	Utility PV	15.85	9.80	8.93	8.05
	Commercial PV	12.49	7.44	6.57	5.71
	Residential PV	19.83	8.43	7.43	6.43
	Battery – 4 hrs	36.37	20.43	17.88	15.32
	CSP – TES[a]	67.61	54.13	52.45	52.45
ATB Advanced	Utility PV	15.69	8.05	7.06	6.06
	Commercial PV	12.33	5.71	4.96	4.20
	Residential PV	19.65	6.43	5.48	4.52
	Battery – 4 hrs	30.06	14.19	11.41	8.63
	CSP – TES[a]	67.61	43.94	40.98	40.98
Break-through	Utility PV	15.51	6.06	5.35	4.63
	Commercial PV	12.20	4.20	3.75	3.30
	Residential PV	19.48	4.52	4.06	3.59
	Battery – 4 hrs	30.61	10.00	7.50	5.00

[a] CSP thermal electric storage variable O&M costs in ATB 2020 are identical between ATB future cost projections. Variable O&M starts at $4.2/MWh and changes to a constant $3.6/MWh starting in 2022.

Table 2-E-3. Solar Capacity Factors (ranges reflect differences across regions)

		2020	2030	2040	2050
ATB Moderate	Utility PV	22-35%	24-37%	25-38%	26-39%
	Commercial PV	13-20%	13-21%	14-22%	15-23%
	Residential PV	13-21%	14-21%	14-21%	14-22%
	Battery – 4 hrs[a]	n/a	n/a	n/a	n/a
	CSP – TES	50-64%	50-64%	50-64%	50-64%
ATB Advanced	Utility PV	22-36%	26-39%	27-41%	29-43%
	Commercial PV	13-20%	15-23%	15-24%	16-25%
	Residential PV	13-21%	14-22%	14-22%	14-22%
	Battery – 4 hrs[a]	n/a	n/a	n/a	n/a
	CSP – TES	50-64%	50-64%	50-64%	50-64%
Break-through	Utility PV	22-36%	26-39%	27-41%	29-43%
	Commercial PV	13-20%	15-23%	15-24%	16-25%
	Residential PV	13-21%	14-22%	14-22%	14-22%
	Battery – 4 hrs[a]	n/a	n/a	n/a	n/a

[a] Batteries are assumed to have a roundtrip efficiency of 85% in all years and scenarios.

2-F: Cost Metrics

Metric	Definition and Notes
Marginal system cost of electricity ($/MWh) Sections 1 and 2.2.5	Definition: The marginal system cost of electricity is based on the cost of providing the next unit of electricity while meeting all major grid services and complying with policies modeled. Marginal costs provide a useful metric because they are similar to electricity prices from restructured power markets. Grid services considered include load balancing, firm capacity requirements, and operating reserves. These services and state energy policies are reflected as constraints in the ReEDS model. The marginal system cost of electricity is calculated from the sum of the products of the shadow prices of these constraints and the requirements, divided by the delivered electricity. Reported costs reflect national averages. Notes: The metric is similar to electricity prices from restructured power markets but encompasses multiple grid service "products" in a single measure and considers both long-run capital expenditures and variable operating costs. It does not include administrative and distribution system costs and, therefore, should not be compared with retail electricity prices. It is a *marginal* measure and is typically higher than the *average* cost of electricity.
Marginal CO$_2$ abatement cost ($/tCO$_2$) Section 2.2.5	Definition: The marginal CO$_2$ abatement cost is the incremental cost to avoid the next metric ton of CO$_2$ from the power sector. It is based directly on the shadow price of the national emissions constraint modeled in ReEDS. Notes: This is a *marginal* measure and is typically higher than *average* abatement costs.
Bulk power system cost (billion $) Sections 1 and 2.2.6	Definition: The bulk power system cost for a scenario is the present value of total capital, O&M, and fuel expenditures for electricity generation, storage, and transmission capacity from 2020 to 2050. We use a 5% real discount rate. Notes: Reported costs are on a relative basis, with the Reference scenario serving as the baseline. The measure is a total cumulative measure rather than a marginal measure.

Metric	Definition and Notes
Demand-side electrification cost (billion $) Sections 1 and 2.2.6	Definition: The demand-side electrification cost is the difference in the present value of total capital, O&M, and fuel non-power-system expenditures between the Decarb+E and Reference scenarios from 2020 to 2050. Examples of such expenditures include differences in upfront costs between electric and internal combustion vehicles, costs for electric vehicle charging infrastructure, and avoided gasoline purchases. These costs exclude electricity system expenditures, because those costs are reflected in bulk power system costs. We use a 5% real discount rate. Notes: Reported costs are on a relative basis, with the Reference scenario serving as the baseline. The measure is a total cumulative measure rather than a marginal measure. Annual expenditures are based directly on the Electrification Futures Study (Murphy et al. 2021), including multiple technology assumption scenarios; the central estimate is from the "Moderate" technology advancement case.
Total system costs (billion $) Sections 1 and 2.2.6	Definition: The total system cost is the sum of the bulk power system cost and the demand-side electrification cost. Notes: Reported costs are on a relative basis, with the Reference scenario serving as the baseline. The measure is a total cumulative measure rather than a marginal measure.
Avoided climate damages (billion $) Sections 1 and 2.2.6	Definition: Avoided climate damages refer to the present value of the product of the SCC and the difference in emissions from the Reference scenario from 2020 to 2050. For the Decarb+E scenario, differences in total energy system emissions are used. We use a 5% real discount rate. Notes: These avoided damages are also referred to as climate benefits. Reported benefits are on a relative basis, with the Reference scenario serving as the baseline. The measure is a total cumulative measure rather than a marginal measure. SCC estimates are from IWG (2021). Uncertainty ranges reflect the four SCC trajectories from the IWG, with the central estimate representing the 2.5% discount rate SCC estimate.

Metric	Definition and Notes
Air-quality benefits (billion $) Sections 1 and 2.2.6 (Text Box 3)	Definition: Air-quality benefits are the present value of monetized avoided health damages from reduced non-greenhouse gas emissions (e.g., particulate matter, ozone precursors) from 2020 to 2050. We use a 5% real discount rate. Notes: Reported benefits are on a relative basis, with the Reference scenario serving as the baseline. The measure is a total cumulative measure rather than a marginal measure.

2-G: Historical and Modeled Capacities and Generation Shares

Installed Capacity (GWAC)	2020	2035/2036			2049/2050		
	(EIA 2021a)	Reference	Decarb	Decarb +E	Reference	Decarb	Decarb+ E
Coal	219	163	36	31	93	-	-
Oil-gas-steam	89	40	38	39	11	-	-
Natural gas-CT	131	126	117	112	109	-	-
Natural gas-CC	268	325	279	289	466	-	-
Nuclear	97	79	79	79	47	47	47
RE-CT	-	-	-	-		419	305
Hydropower	76	79	79	79	79	80	80
Pumped-storage hydropower	23	23	23	23	23	23	26
Biopower	7	6	6	6	3	3	3
Geothermal	3	4	4	5	8	8	12
Onshore wind	121	152	482	547	257	593	897
Offshore wind	0	25	25	25	35	52	80
CSP	1	2	2	2	-	39	5
PV	76	373	757	994	674	1,016	1,563
Battery-2 hrs	2	12	25	71	34	37	117
Battery-4 hrs	1	42	159	187	111	292	393
Battery-6 hrs	-	5	70	99	50	251	618
Battery-8 hrs	-	-	8	17	1	111	212
Battery-10 hrs	-	-	0	0	0	219	336

Annual Generation Share (%)	2020	2035/2036			2049/2050		
	(EIA 2021b)	Reference	Decarb	Decarb+ E	Reference	Decarb	Decarb+ E
Coal	19.8%	17.2%	0.4%	0.3%	6.6%	0.0%	0.0%
Oil-gas-steam	39.3%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
Natural gas-CT		1.5%	1.3%	1.1%	1.1%	0.0%	0.0%
Natural gas-CC		29.0%	3.8%	3.5%	29.0%	0.0%	0.0%
Nuclear	20.3%	13.9%	13.2%	10.8%	7.2%	5.2%	3.5%
RE-CT	-	0.0%	0.0%	0.0%	0.0%	4.1%	2.2%
Hydropower	7.5%	6.3%	5.9%	5.0%	5.4%	5.0%	3.5%
Biopower	1.1%	0.3%	0.3%	0.3%	0.1%	0.1%	0.1%
Geothermal		0.6%	0.6%	0.6%	1.1%	1.1%	1.2%
Onshore wind	8.7%	11.4%	35.3%	34.4%	19.7%	37.0%	40.0%
Offshore wind		2.1%	2.0%	1.6%	2.6%	3.8%	4.3%
CSP	3.4%	0.1%	0.1%	0.1%	0.0%	3.5%	0.5%
PV		17.6%	36.9%	42.2%	27.3%	40.1%	44.8%

Appendix: Chapter 5

5-A: Notes on Energy Storage in Scenarios

This section describes storage technologies modeled in the *Solar Futures* scenarios, storage cost and performance, and storage benefits and values.

The *Solar Futures* scenarios use cost projections from the NREL Annual Technology Baseline (ATB) as inputs for developing the core scenarios (NREL 2020). These include cost projections for PSH and batteries with 2, 4, 6, 8, and 10 hours of storage duration. While the battery technology is non-specific, it is based largely on cost projections for Li-ion batteries, which have a large and increasing manufacturing base, driven largely by EVs. Two other forms of storage and grid flexibility are included in the scenarios: CSP with thermal energy storage is discussed in Chapter 6, and demand flexibility from buildings and vehicles is discussed in Chapter 7. Finally, although seasonal storage is not directly modeled in the scenarios, renewable energy combustion turbine (RE-CT) technologies serve as a proxy for seasonal storage and are discussed in Section 5.1.5.

Despite basing storage cost and performance on only two specific technologies, this study is agnostic as to which technologies will be deployed over time. Many types of storage technologies are available or under development as of 2021. The cost and performance values used in the scenarios should be viewed as benchmarks for what other technologies must achieve to be competitive. Increasing need for storage likely will open opportunities for new technologies. Section 5.3.1 discusses alternative technology pathways for diurnal storage.

The cost-effectiveness of batteries may be enhanced when deployed in a photovoltaic (PV) plus battery hybrid system, driven in part (at least in the near term) by eligibility of the battery for some fraction of the 30% federal investment tax credit (Denholm, Margolis, and Eichman 2017). Hybrids also offer cost-reduction benefits including shared components and shared engineering and permitting. As a result, a growing fraction of proposed storage facilities are associated with PV plants (Bolinger et al. 2021). The version of the Regional Energy Deployment System (ReEDS) used to model the *Solar Futures* scenarios does not explicitly consider several benefits of PV-plus-storage hybrids, including reduced costs and the ability of direct current (DC) coupled systems to avoid clipping that can result from higher DC to AC ratios. However, ReEDS does capture the inherent synergies between PV and storage, including changes in net load shape (see Section 5.1.2). ReEDS updates to consider hybrids, completed in early 2021, will be included in future analyses.

ReEDS considers multiple cost elements including initial fixed capital costs, ongoing fixed costs, and variable costs. It also considers the roundtrip efficiency, defined as the AC-AC efficiency, including parasitic losses.

ReEDS assumes PSH plants with 12 hours of storage and a supply curve (NREL 2020). These assumptions do not vary over time or as a function of duration. New and existing plants are assumed to have a roundtrip efficiency of 80%. Lack of data prevents creation of a detailed PSH cost curve as a function of duration. PSH costs are typically site specific and can leverage

economies of scale for power- and energy-related costs. Ongoing DOE-sponsored work will better quantify new PSH potential and cost-reduction opportunities.

Battery cost and performance assumptions are detailed in the ATB as discussed in Chapter 5. ReEDS considers batteries with five discrete sizes, from 2–10 hours, and assumes a roundtrip efficiency of 85%.[108] This does not include short-duration batteries for providing operating reserves. The *Solar Futures* scenarios do not explicitly model storage with durations beyond 12 hours.

Costs increase as a function of duration, and the relationships between duration and capital costs strongly influence the economic performance of storage technologies used for different applications. Therefore, understanding the impact of duration on overall storage value is critical. By modeling different durations and the associated costs and benefits, ReEDS optimizes both power and energy (duration) based on grid needs.

In addition to capital costs, the total life-cycle cost of storage technologies includes several other important components that vary by technology. Technologies with shorter calendar lives or higher cycling-induced degradation require more frequent replacement or refurbishment of key components. Variable operations and maintenance costs also vary by technology, while roundtrip efficiency impacts the cost of electricity needed to provide different services. These factors can be considered when evaluating total economic performance. However, the considerable uncertainty around many technologies requires the *Solar Futures* scenarios to use a simplified set of assumptions for these other cost components. Additional discussion of technology evolution is provided in Section 5.3.

Much of the storage deployed to date, and expected to be deployed in the near future, has resulted from difficult-to-model factors such as very local and site-specific grid requirements, small complex markets such as frequency regulation, or various state, local, and federal policies that can distort "pure" economic deployments of assets. As a result, ReEDS relies heavily on project queues to project near-term (2020–2024) deployments. In the longer term, modeling for the *Solar Futures* scenarios optimizes deployment in a least-cost manner, using fundamental power-system costs and values while still considering longer-term or permanent policies at the federal and state levels. In this framework, new storage is deployed based on its potential ability to provide a cost-effective alternative or supplement to the various technologies that currently provide the services needed to maintain a reliable grid. Assessing the economic performance of a new storage plant involves estimating the cost and benefits (or revenues) over the project life and comparing the associated economic performance with that of alternative resources or investment options.

It can be difficult to compare storage to alternative resources in any modeling framework. The simplest economic performance metric commonly applied to generation technologies is the levelized cost of energy (LCOE). LCOE measures the delivered cost of energy including fixed and variable costs, and it includes the impact of financing, expected life, and expected annual energy production. A similar metric, levelized cost of storage (LCOS), includes all fixed and

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[108] Duration represents usable energy, after accounting for state-of-charge limitations, conversion to AC, and other factors.

variable cost components over the storage plant's life, including charging energy and the impact of roundtrip efficiency. The limitations of LCOE and LCOS as standalone performance metrics are widely documented; most obviously, neither metric indicates the value of the energy or other services potentially provided (Bistline et al. 2020). This is particularly problematic when comparing technologies that operate differently, such as when comparing traditional peaking generation to storage that also provides time shifting of energy during non-peak periods. To properly evaluate the economic performance of storage, metrics that consider costs and benefits must be used.

ReEDS performs a least-cost optimization, similar to how vertically integrated utilities and other regulated entities typically use a least-cost planning approach, which is sometimes referred to as integrated resource planning (IRP) (Mills and Wiser 2013). This approach compares various resources over a multidecade period to derive a least-cost mix while considering reliability and various policy constraints. Although the final performance metric is expressed in terms of cost (for example, a net present cost or LCOE of the entire system), the value of services provided by the entire system are embedded in this cost. For example, storage acting as a peaking plant can reduce operating costs across the generation fleet, and this benefit is reflected in a reduced system cost. Because of this approach, there is no simple, single metric used by ReEDS (or other IRP-type approaches) that captures the cost-competitiveness of storage. However, the components of costs and benefits can be explored to show how and why storage can provide a cost-effective alternative to traditional generation resources, and to show the synergies between solar and storge deployment.

ReEDS calculates power system cost in four major classes, which translate into equivalent services that storage can provide (Ho et al. 2021). These four general classes (Table 5-A-1) historically capture over 95% of the costs of operating the bulk power system.[109]

Table 5-A-1. Four Major Categories of Bulk Power System Storage Services

Service	Description
Capacity	Firm capacity
Energy	Energy shifting, dispatch efficiency, avoided curtailment
Transmission	Avoided capacity, congestion relief
Ancillary services	Operating reserves including spinning, regulation, and flexibility

Table 5-A-1 does not explicitly list renewable energy (RE) specific applications, such as "renewable firming" or "renewable time shifting." Many of these applications are specific cases of the more general applications listed and are therefore already captured in the table.[110]

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[109] The bulk power system comprises the high-voltage transmission system and generators, but not the distribution network. The 95% value is based on (PJM 2017) and (ISO-NE 2018).

[110] For example, curtailed energy (typically resulting from energy production that cannot be used in a given hour and therefore has zero value) can be captured by storage and shifted to another period, the same way low-value off-peak grid energy can be

Likewise, Table 5-A-1 captures some applications that can be provided by behind-the-meter storage. For example, firm capacity and energy shifting value can be reflected in tariffs including demand charges and time-of-use rates. However, the table does not include several additional values that can be provided by distribution- or customer-sited storage, including avoided upgrades and local reliability and resilience. ReEDS evaluates only utility-scale storage; thus, we likely undervalue the potential benefits of distributed storage. The potential opportunities for distributed and behind-the-meter storage are being evaluated as part of the *Storage Futures Study* (NREL 2021b).

ReEDS considers the ability of storage to provide multiple services,[111] including provision of physical capacity (capacity credit), energy time shifting, and operating reserves during certain periods. Storage can provide capacity and energy-shifting services simultaneously, because the periods of highest prices (when the battery will discharge to maximize revenue or minimize system costs) are very highly correlated to periods of highest demand when the system needs reliable capacity (Sioshansi, Madaeni, and Denholm 2014). Periods of low prices (when the battery will charge) are also periods of low demand and thus when large amounts of spare capacity are available and the risk of an outage is low. Therefore, these two services (capacity and energy time shifting) do not double count either the energy or power capacity of the battery and can be "stacked" (Albertus, Manser, and Litzelman 2020; Denholm et al. 2013).

Duration has a significant impact on storage costs and value. A major component of storage value is its ability to replace traditional peaking capacity such as gas turbines.[112] The actual value of batteries for replacing traditional capacity depends on their capacity credit, which is the fraction of installed capacity that could reliably be used to meet peak demand (or offset conventional capacity) (Munoz and Mills 2015).[113] More simply stated, capacity credit determines the duration of storage required for the device to provide the same level of reliability as a traditional resource. Figure 5-A-1 illustrates the concept of peak demand, using the hourly load shape from California in 2012 on the day of peak demand.[114] Most of the United States is summer peaking, and meeting this peak demand with storage requires ensuring the aggregated energy capacity (duration) of the installed storage is sufficient for the number of hours of the peak demand period.

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shifted in time. However, some applications, such as avoided clipping from PV systems with oversized PV arrays, are not captured.

[111] The concept of combining multiple services, or "value stacking," is not unique to storage. Many generation resources provide multiple services and thus inherently value stack, although this term seldom appears when talking about traditional generation capacity.

[112] ReEDS considers the value of energy storage providing all four services in Table 5-A-1. . Although operating reserves can provide significant value, the amount required is relatively small—only about 30 GW of frequency response, regulating reserves, and contingency reserves are required in the entire U.S. power system, compared to hundreds of GW of peaking capacity.

[113] Following Mills and Wiser (Mills and Wiser 2012), here "capacity credit" represents physical capacity, and "capacity value" represents the monetary value of this capacity.

[114] More recent data are available. However, we use 2012 data to illustrate the load prior to significant adoption of behind-the-meter solar. Load reported by utilities and system operators typically includes behind-the-meter generation.
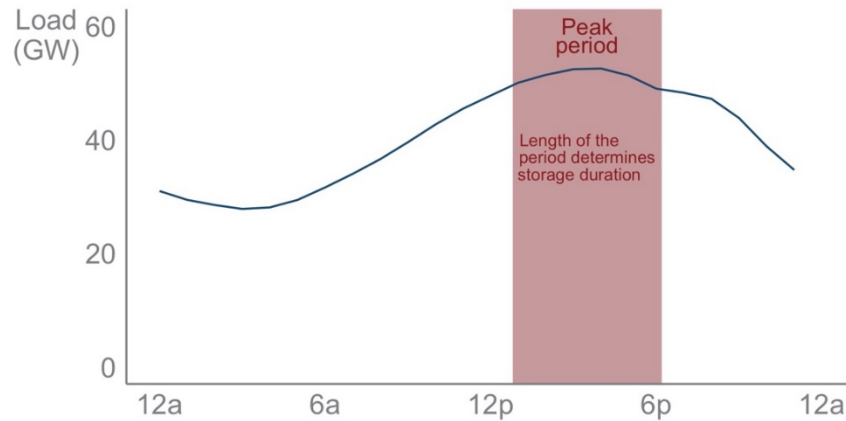
Figure 5-A-1. Concept of peak demand and capacity credit applied to energy storage

In most U.S. regions, the need for new capacity and the capacity credit applied to new resources are established by some combination of state regulators and the local market operator. In 2018, the Federal Energy Regulatory Commission issued Order 841, which requires all independent system operators and regional transmission organizations under the commission's jurisdiction to establish duration requirements for a device to receive full capacity or resource adequacy credit (Frazier et al. 2020). Many regions—including CAISO, MISO, NYISO, and SPP—established 4 hours as the minimum duration for full capacity credit, with shorter durations requiring a derate (St. John 2019).[115]

ReEDS does not use the duration requirements established by independent system operators, because the actual capacity credit of storage changes based on the impacts of PV and storage itself. Instead, ReEDS performs a dynamic calculation that reflects how the storage capacity credit can change as the grid evolves. ReEDS calculates the credit for durations of 2–12 hours (Frazier et al. 2020). This credit is then used to compare the value of storage against the value of a more conventional peaking resource such as a combustion turbine (CT).[116] Figure 5-A-2 illustrates the importance of duration to value. This simplified case shows the total and marginal value of capacity, assuming a 4-hour duration requirement, and an annualized capacity value of $70/kW-yr.[117]

ReEDS allows derating of storage if the duration is less than the minimum requirement (as is allowed in U.S. electricity markets). So, if the requirement for full capacity credit is 4 hours, a device with 2 hours is derated to half its nameplate power capacity. Any duration more than the minimum duration requirement for 100% capacity credit (meaning it can provide the same contribution to resource adequacy as a CT) provides no incremental capacity value.

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[115] CAISO = California Independent System Operator, MISO = Midcontinent Independent System Operator, NYISO = New York Independent System Operator, SPP = Southwest Power Pool.

[116] This assumes the CT has a reliable source of fuel.

[117] This is roughly equal to the assumed annualized cost of a CT in 2020 for the *Solar Futures Study*, derived from the NREL ATB (NREL 2020). This comparison is simplified, because it assumes the two resources have identical outage rates.
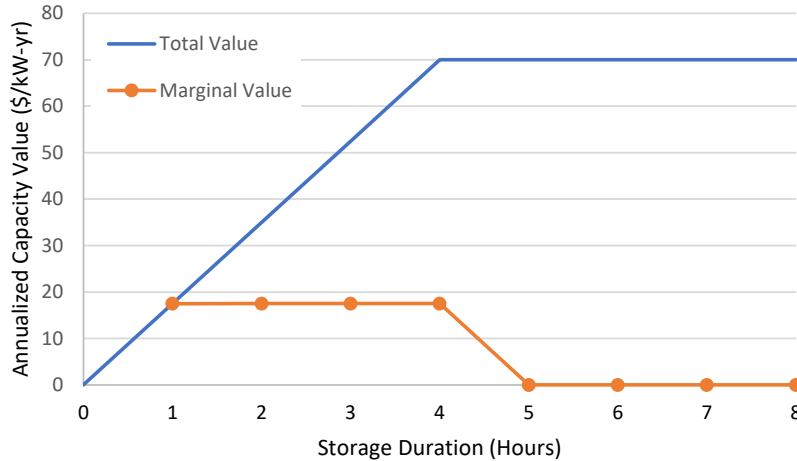
Figure 5-A-2. Value of storage providing capacity, assuming a 4-hour duration requirement and a $70/kW-yr capacity value

The figure also represents a system in which new capacity is needed. In locations with sufficient capacity, the value of batteries will be driven by other factors such as energy time shifting. As a result, battery storage or other sources of peaking capacity will not necessarily be cost-competitive until there is increased demand or sufficient retirement of existing capacity resulting in a need for new capacity.

ReEDS estimates the value of energy time shifting based on storage's ability to charge from off-peak resources and displace the variable costs of more expensive generators (Frazier et al. 2021). Charging can occur from available resources including coal, natural gas, nuclear, or otherwise-curtailed wind or solar. This stored energy then displaces the highest-variable-cost resource that would have otherwise been operated. Although the absolute value varies considerably depending on location and factors such as transmission constraints, the general trend in value as a function of duration is similar. The first hour of storage has the highest value, because it is arbitraging the largest spread in prices. This incremental value declines rapidly as diurnal price spreads decrease, approaching—but not reaching—zero beyond about 10 hours of capacity as the diurnal variability in prices is completely arbitraged.

The ReEDS optimization compares the storage cost and value components to the cost and value components of all other resources, including conventional peaking capacity and renewable resources. ReEDS also considers the various storage durations available to choose the duration that produces the lowest life-cycle cost. This formulation applies to the least-cost approach used by ReEDS and resembling vertically integrated markets. The simplified example shown in this section is consistent with the literature, which generally finds a higher value associated with capacity than with energy time shifting. However, in regions with wholesale markets, determining long-term capacity and energy prices (which are needed for an appropriate comparison of storage to alternatives) is very complicated given the evolving generation mix, need for new capacity, and market rules limiting scarcity prices that may occur during periods of peak demand (Cole, Greer, et al. 2020; Bistline et al. 2021).

Appendix: Acknowledgements

Overview

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The final version of the *Solar Futures Study* is the sole responsibility of DOE. The participation of authors and external reviewers does not imply that they, or their respective organizations, either agree or disagree with the findings of this report.

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The following individuals were responsible for the overall leadership of the *Solar Futures Study*, as well as leading the drafting, review, and editing processes. The study was carried out in support of, and in collaboration with, staff from the DOE Solar Energy Technologies Office (SETO).

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In March 2020, a TRP was formed for the *Solar Futures Study* to provide strategic guidance and feedback throughout the development of the study. Two meetings that included all TRP members were convened on 1) October 5–6, 2020, and 2) March 15–16, 2020. In addition, multiple sub-group meetings were held between March and December 2020. The following list includes TRP members by sub-group:

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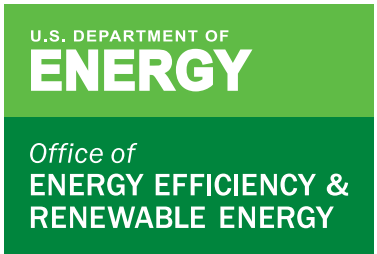———. 2021. "National Solar Jobs Census 2020." https://www.thesolarfoundation.org/national/.

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