NATIONAL RENEWABLE ENERGY LABORATORY

Volume 1 of 4

Renewable Electricity Futures Study

Exploration of High-Penetration Renewable Electricity Futures

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Renewable Electricity Futures Study

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Volume 1: Exploration of High-Penetration Renewable Electricity Futures
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Renewable Electricity Futures Study

Volume 1: Exploration of High-Penetration Renewable Electricity Futures

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Perspective

The Renewable Electricity Futures Study (RE Futures) provides an analysis of the grid integration opportunities, challenges, and implications of high levels of renewable electricity generation for the U.S. electric system. The study is not a market or policy assessment. Rather, RE Futures examines renewable energy resources and many technical issues related to the operability of the U.S. electricity grid, and provides initial answers to important questions about the integration of high penetrations of renewable electricity technologies from a national perspective. RE Futures results indicate that a future U.S. electricity system that is largely powered by renewable sources is possible and that further work is warranted to investigate this clean generation pathway. The central conclusion of the analysis is that renewable electricity generation from technologies that are commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the United States.

The renewable technologies explored in this study are components of a diverse set of clean energy solutions that also includes nuclear, efficient natural gas, clean coal, and energy efficiency. Understanding all of these technology pathways and their potential contributions to the future U.S. electric power system can inform the development of integrated portfolio scenarios. RE Futures focuses on the extent to which U.S. electricity needs can be supplied by renewable energy sources, including biomass, geothermal, hydropower, solar, and wind.

The study explores grid integration issues using models with unprecedented geographic and time resolution for the contiguous United States. The analysis (1) assesses a variety of scenarios with prescribed levels of renewable electricity generation in 2050, from 30% to 90%, with a focus on 80% (with nearly 50% from variable wind and solar photovoltaic generation); (2) identifies the characteristics of a U.S. electricity system that would be needed to accommodate such levels; and (3) describes some of the associated challenges and implications of realizing such a future. In addition to the central conclusion noted above, RE Futures finds that increased electric system flexibility, needed to enable electricity supply-demand balance with high levels of renewable generation, can come from a portfolio of supply- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations. The analysis also finds that the abundance and diversity of U.S. renewable energy resources can support multiple combinations of renewable technologies that result in deep reductions in electric sector greenhouse gas emissions and water use. The study finds that the direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Of the sensitivities examined, improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost. Assumptions reflecting the extent of this improvement are based on incremental or evolutionary improvements to currently commercial technologies and do not reflect U.S. Department of Energy activities to further lower renewable technology costs so that they achieve parity with conventional technologies.

RE Futures is an initial analysis of scenarios for high levels of renewable electricity in the United States; additional research is needed to comprehensively investigate other facets of high renewable or other clean energy futures in the U.S. power system. First, this study focuses on renewable-specific technology pathways and does not explore the full portfolio of clean technologies that could contribute to future electricity supply. Second, the analysis does not attempt a full reliability analysis of the power system that includes addressing sub-hourly, transient, and distribution system requirements. Third, although RE Futures describes the system characteristics needed to accommodate high levels of renewable generation, it does not address the institutional, market, and regulatory changes that may be needed to facilitate such a transformation. Fourth, a full cost-benefit analysis was not conducted to comprehensively evaluate the relative impacts of renewable and non-renewable electricity generation options.

Lastly, as a long-term analysis, uncertainties associated with assumptions and data, along with limitations of the modeling capabilities, contribute to significant uncertainty in the implications reported. Most of the scenario assessment was conducted in 2010 with assumptions concerning technology cost and performance and fossil energy prices generally based on data available in 2009 and early 2010. Significant changes in electricity and related markets have already occurred since the analysis was conducted, and the implications of these changes may not have been fully reflected in the study assumptions and results. For example, both the rapid development of domestic unconventional natural gas resources that has contributed to historically low natural gas prices, and the significant price declines for some renewable technologies (e.g., photovoltaics) since 2010, were not reflected in the study assumptions.

Nonetheless, as the most comprehensive analysis of U.S. high-penetration renewable electricity conducted to date, this study can inform broader discussion of the evolution of the electric system and electricity markets toward clean systems.

The RE Futures team was made up of experts in the fields of renewable technologies, grid integration, and end-use demand. The team included leadership from a core team with members from the National Renewable Energy Laboratory (NREL) and the Massachusetts Institute of Technology (MIT), and subject matter experts from U.S. Department of Energy (DOE) national laboratories, including NREL, Idaho National Laboratory (INL), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), and Sandia National Laboratories (SNL), as well as Black & Veatch and other utility, industry, university, public sector, and non-profit participants. Over the course of the project, an executive steering committee provided input from multiple perspectives to support study balance and objectivity.

RE Futures is documented in four volumes of a single report: This volume—Volume 1—describes the analysis approach and models, along with the key results and insights; Volume 2 describes the renewable generation and storage technologies included in the study; Volume 3 presents end-use demand and energy efficiency assumptions; and Volume 4 discusses operational and institutional challenges of integrating high levels of renewable energy into the electric grid.

Acknowledgments

The Project Leaders for the Renewable Electricity Futures Study gratefully acknowledge the significant contributions from the numerous individuals on the RE Futures team, more than 110 individuals from more than 35 organizations as listed in Appendix D. We appreciate their thorough and thoughtful consideration of the present state and future potential of renewable electricity generation technologies, use of electricity, and electric sector operation. This report is the culmination of their contributions. We are also grateful to the members of the study's executive steering committee, who assisted the RE Futures team in evolving and finalizing the scenarios to include and reviewed and provided comments on the analysis at various stages. We also thank the many outside individuals who reviewed the draft documents.

The ability to represent the technical aspects of future electricity generation portfolios, particularly with high levels of renewable electricity generation, requires sophisticated models operated by experienced analysts. We are grateful to Walter Short for his innovation, vision and leadership at NREL over several decades that led to development of both the Regional Energy Deployment System (ReEDS) and the strong team of analysts who use this model and other tools to provide context and insight around future electricity generation portfolios for this study and many others.

The support and guidance of management at NREL and MIT also was critical to the completion of this study. In particular, we recognize Robin Newmark and Bobi Garrett for their leadership.

We are grateful to the U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy for sponsoring this work. We especially thank Sam Baldwin for his vision and leadership in conceiving, supporting, and contributing to this study from beginning to end. We also thank DOE's Office of Electricity Delivery and Energy Reliability for its input and guidance on specific aspects of the analysis, as well as valuable comments and helpful suggestions to improve the content of the report. NREL's contributions to this report were funded by the DOE Office of Energy Efficiency and Renewable Energy under contract number DE-AC36-08GO28308.

List of Acronyms and Abbreviations

AC	alternating current
AEO	Annual Energy Outlook
AWEA	American Wind Energy Association
BA	balancing area
Btu	British Thermal Unit(s)
CAES	compressed air energy storage
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CO_2e, CO_2eq	carbon dioxide equivalent
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
DOE	U.S. Department of Energy
EEPS	energy efficiency portfolio standard
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EREC	European Renewable Energy Council
FERC	Federal Energy Regulatory Commission
Fossil-HTI	Fossil Energy – Higher Technology Improvement
gal	gallons
GHG	greenhouse gases
GT	gigatonnes
GW	gigawatt(s)
GWEC	Global Wind Energy Council
GWh	gigawatt-hour(s)
hrs	hours
HVDC	high-voltage, direct current
IGCC	integrated gasification combined cycle
INL	Idaho National Laboratory

IPCC	Intergovernmental Panel on Climate Change
IWG	Interagency Working Group
km^2	square kilometers
kV	kilovolt(s)
kW	kilowatt(s)
kW-yr	kilowatt-year
LBNL	Lawrence Berkeley National Laboratory
LCA	life cycle assessment
LMPs	locational marginal prices (LMPs)
m	meter(s)
Mgal	million gallons
MIT	Massachusetts Institute of Technology
MJ	megajoules
MMBtu	million British thermal units
mpg	miles per gallon
MW	megawatt(s)
MWh	megawatt-hour(s)
NCEP	National Centers for Environmental Prediction
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NO_x	oxides of nitrogen
NRC	National Research Council
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
ORNL	Oak Ridge National Laboratory
PEV	plug-in hybrid or electric vehicle
PNNL	Pacific Northwest National Laboratory
PSH	pumped-storage hydropower
ppm	parts per million
PV	photovoltaic
RE	renewable electricity
RE Futures	Renewable Electricity Futures Study
ReEDS	Regional Energy Deployment System

RE-ETI	Renewable Electricity—Evolutionary Technology Improvement
RE-ITI	Renewable Electricity—Incremental Technology Improvement
RE-NTI	Renewable Electricity—No Technology Improvement
RPS	renewable portfolio standard
SEIA	Solar Energy Industries Association
SNL	Sandia National Laboratories
SO_2	sulfur dioxide
SO_x	oxides of sulfur
SolarDS	Solar Deployment System
tCO_2	metric ton carbon dioxide
TW	terawatt(s)
TWh	terawatt-hour(s)
USGS	U.S. Geological Survey
yr	year

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Executive Summary

The Renewable Electricity Futures Study (RE Futures) is an initial investigation of the extent to which renewable energy supply can meet the electricity demands of the contiguous United States[1] over the next several decades. This study includes geographic and electric system operation resolution that is unprecedented for long-term studies of the U.S. electric sector. The analysis examines the implications and challenges of renewable electricity generation levels—from 30% up to 90%, with a focus on 80%, of all U.S. electricity generation from renewable technologies—in 2050. At such high levels of renewable electricity penetration, the unique characteristics of some renewable resources, specifically geographical distribution and variability and uncertainty in output, pose challenges to the operability of the U.S. electric system. The study focuses on some key technical implications of this environment, exploring whether the U.S. power system can supply electricity to meet customer demand with high levels of renewable electricity, including variable wind and solar generation. The study also begins to address the potential economic, environmental, and social implications of deploying and integrating high levels of renewable electricity in the United States.

RE Futures was framed with a few important questions:

- The United States has diverse and abundant renewable energy resources that are available to contribute higher levels of electricity generation over the next decades. Future renewable electricity generation will be driven in part by federal incentives and renewable portfolio standards mandated in many states.[2] Practically, how much can renewable energy technologies, in aggregate, contribute to future U.S. electricity supply?

- In recent years, variable renewable electricity generation capacity in the United States has increased considerably. Wind capacity, for example, has increased from 2.6 GW in 2000 to 40 GW in 2010, while solar capacity has also begun to grow rapidly. Can the U.S. electric power system accommodate higher levels of variable generation from wind or solar photovoltaics (PV)?

- Overall, renewable energy contributed about 10% of total power-sector U.S. electricity supply in 2010 (6.4% from hydropower, 2.4% from wind energy, 0.7% from biopower, 0.4% from geothermal energy, and 0.05% from solar energy).[3] Are there synergies that can be realized through combining these diverse sources, and to what extent can aggregating their output over larger areas help enable their integration into the power system?

[1] Alaska, Hawaii, and the U.S. Territories were not included in this study because they rely on electric grid systems that are not connected to the contiguous United States. However, both states and the territories have abundant renewable resources, and they have efforts are underway to substantially increase renewable electricity generation (see Volume 1, Text Box Introduction-1).

[2] Some states have targets of a 20%–30% share of total electricity generation (see http://www.dsireusa.org/ for information on specific state standards) and are making progress toward meeting these goals.

[3] These data reflect estimates for the electric power sector only, and they exclude the end use sectors (i.e., on-site electric power supply that directly meets customer demands). If the end-use and electric power sectors are considered together, the percentage contribution from biomass would increase from 0.7% to 1.4%, and the contribution from solar would increase from 0.05% to 0.12%.

Multiple international studies[4] have explored the possibility of achieving high levels of renewable electricity penetration, primarily as a greenhouse gas (GHG) mitigation measure. RE Futures presents systematic analysis of a broad range of potential renewable electricity futures for the contiguous United States based on unprecedented consideration of geographic, temporal, and electric system operation aspects.[5]

RE Futures explores a number of scenarios using a range of assumptions for generation technology improvement, electric system operational constraints, and electricity demand to project the mix of renewable technologies—including wind, PV, concentrating solar power (CSP), hydropower, geothermal, and biomass—that meet various prescribed levels of renewable generation, from 30% to 90%. Additional sensitivity cases are focused on an 80%-by-2050 scenario. At this 80% renewable generation level, variable generation from wind and solar technologies accounts for almost 50% of the total generation.

Within the limits of the tools used and scenarios assessed, hourly simulation analysis indicates that estimated U.S. electricity demand in 2050 could be met with 80% of generation from renewable electricity technologies with varying degrees of dispatchability, together with a mix of flexible conventional generation and grid storage, additions of transmission, more responsive loads, and changes in power system operations.[6] Further, these results were consistent for a wide range of assumed conditions that constrained transmission expansion, grid flexibility, and renewable resource availability. The analysis also finds that the abundance and diversity of U.S. renewable energy resources can support multiple combinations of renewable technologies that result in deep reductions in electric sector greenhouse gas emissions and water use. Further, the study finds that the incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Of the sensitivities examined, improvement in the cost and performance of renewable technologies is the most impactful level for reducing this incremental cost.

While this analysis suggests such a high renewable generation future is possible, a transformation of the electricity system would need to occur to make this future a reality. This transformation, involving every element of the grid, from system planning through operation, would need to ensure adequate planning and operating reserves, increased flexibility of the electric system, and expanded multi-state transmission infrastructure, and would likely rely on the development and adoption of technology advances, new operating procedures, evolved business models, and new market rules.

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[4] As examples, recent detailed studies include those prepared for Europe (ECF 2010) and Germany (SRU 2010), as well as a review of 164 global energy scenarios by the Intergovernmental Panel on Climate Change (IPCC 2011). Cochran et al. (2012) also describes several case studies of countries successfully managing high levels of variable renewable energy on their electric grids.

[5] Previous, more conceptual or more-limited analyses of high penetrations of renewable energy in the United States and globally include (but are not limited to) Pacala and Socolow (2004); ACORE (2007); Kutscher (2007); Greenblatt (2009); GWEC/GPI (2008); Fthenakis et al. (2009); Jacobson and Delucchi (2009); Sawin and Moomaw (2009); EREC/GPI (2008); and Lovins (2011).

[6] The study did not conduct a full reliability analysis, which would include sub-hourly, stability, and AC power flow analysis.

Key results of this study include the following:

- Deployment of Renewable Energy Technologies
    - Renewable energy resources, accessed with commercially available generation technologies, could adequately supply 80% of total U.S. electricity generation in 2050 while balancing supply and demand at the hourly level.
    - All regions of the United States could contribute substantial renewable electricity supply in 2050, consistent with their local renewable resource base.
    - Multiple technology pathways exist to achieve a high renewable electricity future. Assumed constraints that limit power transmission infrastructure, grid flexibility, or the use of particular types of resources can be compensated for through the use of other resources, technologies, and approaches.
    - Annual renewable capacity additions that enable high renewable generation are consistent with current global production capacities but are significantly higher than recent U.S. annual capacity additions for the technologies considered. No insurmountable long-term constraints to renewable electricity technology manufacturing capacity, materials supply, or labor availability were identified.
- Grid Operability and Hourly Resource Adequacy
    - Electricity supply and demand can be balanced in every hour of the year in each region with nearly 80% electricity from renewable resources, including nearly 50% from variable renewable generation, according to simulations of 2050 power system operations.
    - Additional challenges to power system planning and operation would arise in a high renewable electricity future, including management of low-demand periods and curtailment of excess electricity generation.
    - Electric sector modeling shows that a more flexible system is needed to accommodate increasing levels of renewable generation. System flexibility can be increased using a broad portfolio of supply- and demand-side options, and will likely require technology advances, new operating procedures, evolved business models, and new market rules.
- Transmission Expansion
    - As renewable electricity generation increases, additional transmission infrastructure is required to deliver generation from cost-effective remote renewable resources to load centers, enable reserve sharing over greater distances, and smooth output profiles of variable resources by enabling greater geospatial diversity.
- Cost and Environmental Implications of High Renewable Electricity Futures
    - High renewable electricity futures can result in deep reductions in electric sector greenhouse gas emissions and water use.
    - The direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Improvement in the cost

and performance of renewable technologies is the most impactful lever for reducing this incremental cost.

- Effects of Demand Growth
    - With higher demand growth, high levels of renewable generation present increased resource and grid integration challenges.

This report presents the analysis of some of the technical challenges and opportunities associated with high levels of renewable generation in the U.S. electric system. However, the analysis presented in this report represents only an initial set of inquiries on a national scale. Additional studies are required to more fully assess the technical, operational, reliability, economic, environmental, social, and institutional implications of high levels of renewable electricity generation, and further explore the nature of the electricity system transformation required to enable such a future.

Study Organization and Report Structure

RE Futures was led by a team from the National Renewable Energy Laboratory (NREL) and the Massachusetts Institute of Technology (MIT). The leadership team coordinated teams of subject matter experts from U.S. Department of Energy (DOE) national laboratories, including Idaho National Laboratory (INL), Lawrence Berkeley National Laboratory (LBNL), NREL, Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), and Sandia National Laboratories (SNL), as well as Black & Veatch and other utility, industry, university, public sector, and non-profit participants. These expert teams explored the prospects for large-scale deployment of specific renewable generation and storage technologies, along with some of the issues and challenges associated with their integration into the electric system.

In total, this report is the culmination of contributions from more than 110 individuals at more than 35 organizations (Appendix D lists the contributors to the study). Over the course of the project, an executive steering committee provided input from multiple perspectives to support study balance and objectivity. Technical reviewers from the renewable technology and electric sector industries, universities, public sector, non-profits, and other entities commented on a preliminary version of this report.

Most of the analysis informing the study, particularly the scenario assessment, was conducted in 2010. As a result, study assumptions concerning technology cost and performance and fossil energy prices were generally based on data available in late 2009 and early 2010. Where possible, more recent published work has been referenced; however, the implications of these publications may not have been fully reflected in the RE Futures study assumptions. For example, both the rapid development of domestic unconventional natural gas resources that has contributed to historically low natural gas prices, and the significant price declines for some renewable technologies (e.g., photovoltaics) since 2010, were not reflected in the study assumptions. Finally, the technology projections presented in RE Futures do not necessarily reflect the current DOE estimates.

RE Futures is documented in four volumes of a single report: This first volume—Volume 1—describes the analysis approach and models, along with the key results and insights. Volume 2 describes the renewable generation and storage technologies included in the study; Volume 3 presents 2050 end-use demand and energy efficiency assumptions; and Volume 4 discusses some operational and institutional challenges of integrating high levels of renewable energy into the electric grid.

This Executive Summary highlights the analysis approach and key results from RE Futures. First, it summarizes the analysis approach, including scenario framework, renewable resources characterization, and modeling tools used to analyze the expansion of the U.S. electricity system and its operational characteristics. The key results from the analysis are then presented, including results associated with renewable technology deployment, grid operations, and economic, environmental and social implications. Finally, additional research opportunities are identified in the conclusions.

Analysis Approach

Scenario Framework

Given the inherent uncertainties involved with analyzing alternative long-term energy futures, and given the variety of pathways that might lead to higher levels of renewable electricity supply, multiple future scenarios were modeled and analyzed. The scenarios examined included the following considerations:

- **Energy Efficiency:** Most of the scenarios assumed adoption of energy efficiency (including electricity) measures in the residential, commercial, and industrial sectors that resulted in flat demand growth over the 40-year study period.[7]
- **Transportation:** Most of the scenarios assumed a shift of some transportation energy away from petroleum and toward electricity in the form of electric and plug-in hybrid electric vehicles, partially offsetting the electricity efficiency advances that were considered.[8]
- **Grid Flexibility:** Most scenarios assumed improvements in electric system operations to enhance flexibility in both electricity generation and end-use demand, helping to enable more efficient integration of variable-output renewable electricity generation.
- **Transmission:** Most scenarios expand the transmission infrastructure and access to existing transmission capacity to support renewable energy deployment. Distribution-level upgrades were not considered.
- **Siting and Permitting:** Most scenarios assumed project siting and permitting regimes that allow renewable electricity development and transmission expansion subject to standard land-use exclusions.

[7] The efficiency gains assumed are described in Volume 3. They do not represent an upper bound of energy efficiency, i.e., they were not as large as estimated by NAS/NAE (2010).
[8] The flat demand (low-demand) projection included this increase in demand from the transportation sector, whereas the business-as-usual demand (high-demand) projection did not. The contribution of biofuels to the transportation sector is not quantified in RE Futures.

In all the scenarios analyzed, only currently commercially available technologies (as of 2010) were considered, together with their incremental or evolutionary improvements despite the long-term (2050) timeframe, because the focus of this study was on grid integration and not on the potential advances of any individual technologies.[9] Technologies such as enhanced geothermal systems; ocean energy technologies (e.g., wave, tidal, current or ocean thermal); floating offshore wind technology; and others that are currently under development and pilot testing—and which show significant promise but are not yet generally commercially available—were not included.

More than two dozen scenarios were modeled and analyzed in this study as outlined in Figure ES-1 and detailed below. The number and diversity of scenarios allowed an assessment of multiple pathways that depended on highly uncertain future technological, institutional, and market choices. The framework included scenarios with specific renewable electricity generation levels to enable exploration of some of the technical issues associated with the operation of the U.S. electricity grid at these levels.[10] This scenario framework does not prescribe a set of policy recommendations for renewable electricity generation in the United States, nor does it present a vision of what the total mix of energy sources should look like in the future. Further, the framework does not intend to imply that one future is more likely than another.

[9] RE Futures did not allow new nuclear plants, fossil technologies with CCS, as well as gasified coal without CCS (integrated gasification combined cycle) to be built in any of the scenarios presented in this report. Existing nuclear (and integrated gasification combined cycle) units, however, were included in the analysis, as were assumptions for the retirement of those units.

[10] The scenarios were not constructed to find the optimal GHG mitigation or clean energy pathway (e.g., to minimize carbons emissions or the cost of mitigating these emissions). In addition, because the scenarios included specific renewable generation levels, they were not designed to explore how renewable technologies might economically deploy under certain technology advancement projections without the generation constraints.

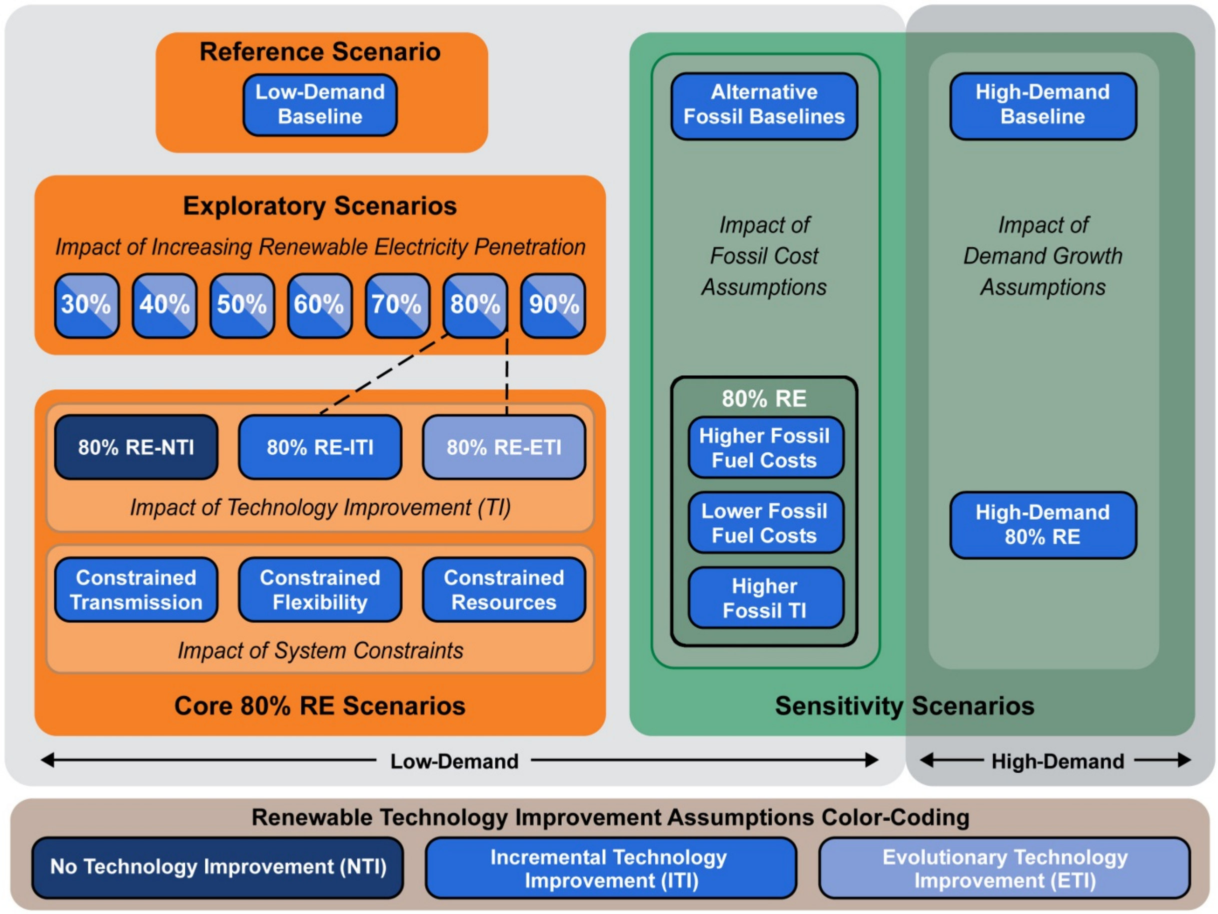

Figure ES-1. Modeling scenario framework for RE Futures

Dotted lines indicate that the 80% RE exploratory scenarios are the same as the 80% RE-ITI and 80% RE-ETI scenarios.

Low-Demand Baseline Scenario

A Low-Demand Baseline scenario was designed to reflect a largely conventional generation system as a point of comparison, or reference, for the high-penetration renewable electricity scenarios. The Low-Demand Baseline scenario assumes that a combination of emerging trends—including policies and legislation dealing with codes and standards, innovation in energy efficiency, and the green building and supply chain movements—drive the adoption of energy efficiency measures in the residential, commercial, and industrial sectors (see Volume 3 for details).[11] Substantial adoption of electric and plug-in hybrid electric vehicles was also assumed. In aggregate, these low-demand assumptions resulted in overall electricity consumption that exhibits little growth from 2010 to 2050. Existing state policies (e.g., renewable portfolio standards) and existing federal policies (e.g., investment tax credits, production tax credits, tax depreciation rules) were assumed to continue only as allowed under existing law, with no

[11] In addition to these trends, the primary historical drivers of electricity demand, population growth, and economic growth, were also considered in the construction of the scenario. While investment costs of these efficiency measures were not considered in the scenario development, findings from other studies generally indicate that such measures can be considered cost-effective or cost-competitive.

extensions. Expiration dates for existing federal policies vary, but generally are 2017 or earlier.[12] In combination with incremental technology improvements, these assumptions result in low levels of renewable electricity generation in the Low-Demand Baseline scenario.

Exploratory Scenarios

A series of "exploratory scenarios," in which the proportion of renewable electricity in 2050 increased in 10% increments from 30% to 90%, was evaluated. The primary purpose of these exploratory scenarios was to assess how increased levels of renewable electricity might impact the generation mix of renewable and non-renewable resources, the extent of transmission expansion in these cases, and the use of various forms of supply- and demand-side flexibility to enable a match between electricity supply and demand. These exploratory scenarios were evaluated under two distinct sets of renewable electricity technology advancement assumptions: Incremental Technology Improvement (ITI) and Evolutionary Technology Improvement (ETI).

Core 80% RE Scenarios

Further analysis was performed on six core 80% RE scenarios, each of which met the same 80%-by-2050 renewable electricity penetration level and each of which was designed to elucidate the possible implications of certain technological, institutional, and market drivers.[13] Three scenarios explored the impacts of future renewable energy technology advancements of currently commercial technologies and the resulting deployment of different combinations of renewable energy technologies[14]:

- The RE – No Technology Improvement (80% RE-NTI) scenario simply assumed that the performance of each renewable technology was maintained at 2010 levels for all years in the study period (2010–2050).
- The RE – Incremental Technology Improvement (80% RE-ITI) scenario reflected only partial achievement of the future technical advancements that may be possible (Black & Veatch 2012).
- The RE – Evolutionary Technology Improvement (80% RE-ETI) scenario reflected a more-complete achievement of possible future technical advancements (Volume 2). The RE-ETI scenario is not designed to be a lower bound and does not span the full range of possible futures; further technical advancements beyond the RE-ETI are possible.[15]

Three additional scenarios explored the impacts of different electricity system constraints based on assumptions that limited the building of new transmission, reduced system flexibility to

[12] Similarly, indirect incentives for conventional energy technologies—sometimes delivered through the tax code without sunset provisions —were assumed to be maintained as allowed under existing law. These same renewable and conventional technology policy assumptions were consistently applied to all the other scenarios as well.

[13] The specific assumptions used for these scenarios are discussed in Chapter 1.

[14] Although the methods used in RE Futures to project the future cost of each renewable electricity technology differ to some degree by technology, the resulting forecasts are largely based on anticipated scientific and engineering advancements rather than on learning-curve-based estimates that are endogenously driven by an assumed learning rate applied to cumulative production or installation. In reality, costs may decline in part due to traditional learning and in part due to other factors, such as research and development investment, economies of scale in manufacturing, component, or plant size, and reductions in material costs.

[15] Indeed, current DOE initiatives are focused on achieving substantially better cost and performance in many cases, with a target of achieving parity with conventional technologies.

manage the variability of wind and solar resources, and decreased renewable resource availability:

- The Constrained Transmission scenario evaluated how limits to building new transmission might impact the location and mix of renewable resources used to meet an 80%-by-2050 future.
- The Constrained Flexibility scenario sought to understand how institutional constraints to and concerns about managing the variability of wind and solar resources, in particular, might impact the resource mix of achieving an 80%-by-2050 future.
- The Constrained Resources scenario posited that environmental or other concerns may reduce the developable potential for many of the renewable technologies in question, and evaluated how such constraints could impact the resource mix of renewable energy supply.

High-Demand Scenarios

The scenarios described above—the Low-Demand Baseline scenario, the exploratory scenarios, and the six core 80% RE scenarios—were based on the low-demand assumptions, with overall electricity consumption that exhibits little growth from 2010 to 2050. To test the impacts of a higher-demand future, a scenario with the 80%-by-2050 renewable electricity generation but a *higher end-use electricity demand* was evaluated, with demand in 2050 30% higher than in the low-demand scenarios.[16] A corresponding reference scenario, the High-Demand Baseline scenario, with the same higher demand was also evaluated.[17]

Alternative Fossil Scenarios

Finally, given uncertainties in the *future cost of fossil energy sources*, the analysis included 80%-by-2050 RE scenarios in which: (1) the price of fossil energy (coal and natural gas) was both higher and lower than otherwise assumed in the other scenarios and (2) fossil energy technologies[18] experienced greater technology improvements over time than assumed in the other scenarios. Corresponding reference scenarios with these alternate fossil energy projections were also evaluated.

Renewable Resources Characterization

The United States has diverse and abundant renewable resources, including biomass, geothermal, hydropower, ocean, solar, and wind resources. Solar and wind are the most abundant of these resources. These renewable resources are geographically constrained but widespread—most are distributed across all or most of the contiguous states (Figure ES-2). Within these broad resource types, a variety of commercially available renewable electricity generation technologies have been deployed in the United States and other countries, including stand-alone biopower, co-fired

[16] The low-demand scenarios assume an annual growth rate of 0.17%; the high-demand scenarios assume an annual growth rate of 0.84%. Details on end-use energy demand assumptions are provided in Volume 3 of this report.
[17] For comparison, all high renewable electricity scenarios require a baseline or reference scenario that uses the same high-level assumptions regarding electricity demand.
[18] Consistent with the study's focus on commercially available renewable generation technologies, emerging fossil and nuclear technologies, such as carbon-capture and sequestration and modular nuclear plants, were not included.

biopower (in coal plants), hydrothermal geothermal, hydropower, distributed PV, utility-scale PV, CSP,[19] onshore wind, and fixed-bottom offshore wind.

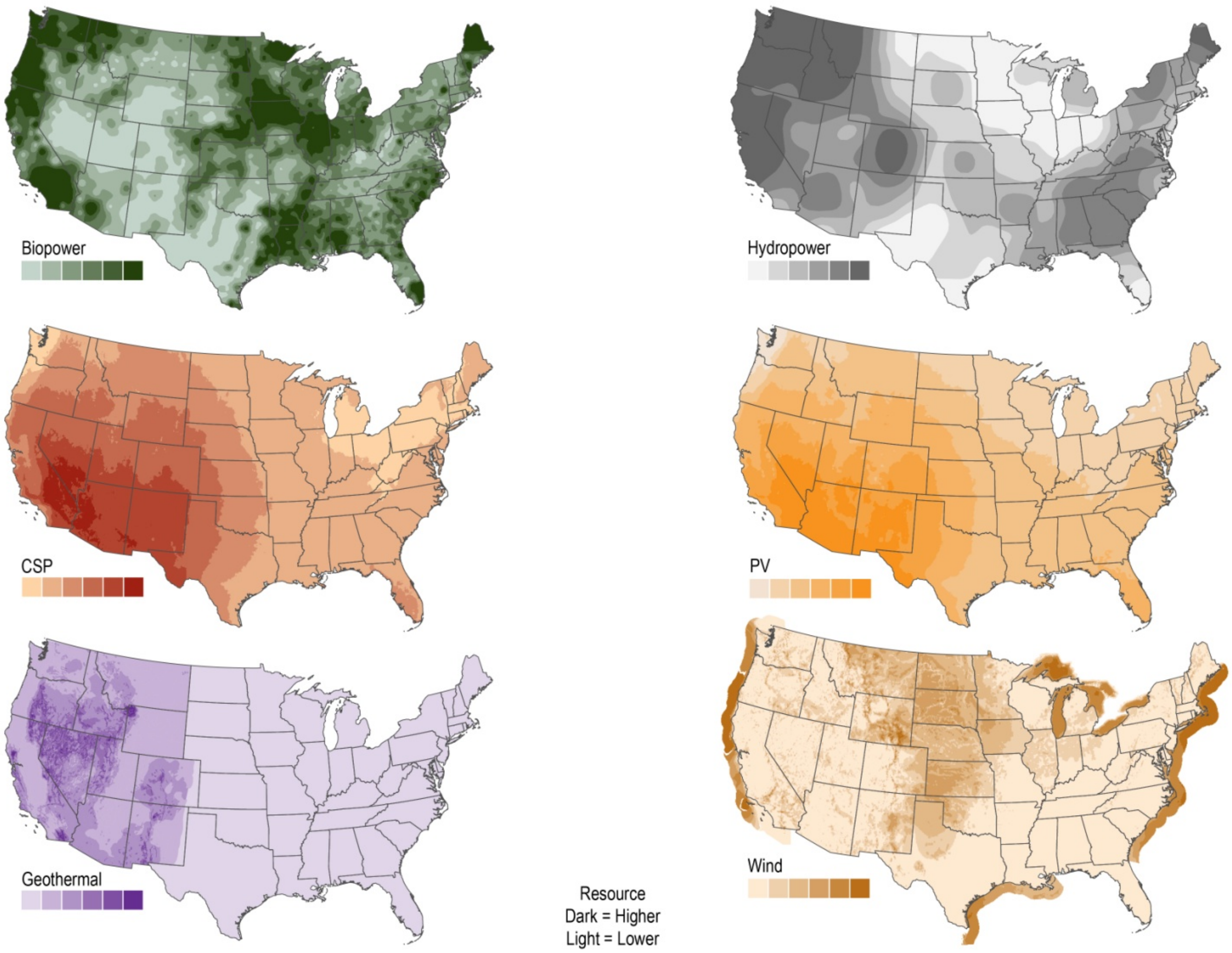

Figure ES-2. Geographic distribution of renewable resources in the contiguous United States

The United States has potential ocean energy and enhanced geothermal resources; however, these technologies were not modeled and therefore the resource potential is not included in this figure.

While only commercially available biomass, geothermal, hydropower, solar PV, CSP, and wind-powered systems were considered in the modeling analysis—only incremental and evolutionary advances in renewable technologies were assumed—the study describes a broad range of commercial and emerging renewable energy technologies in Volume 2, including the following[20]:

[19] In this report, CSP refers to concentrating solar thermal power. Concentrating photovoltaic technologies were not considered in the modeling analysis.

[20] The renewable resource characterizations described below and used in the models are based on historical climatic average resource patterns and have standard land area exclusions applied. After accounting for these standard exclusions, the aggregate renewable generation resource is many times greater than current electricity demand.

- **Biomass power** (Chapter 6, Volume 2) is generated by collecting and combusting plant matter and using the heat to drive a steam turbine. Biomass resources from agricultural and forest residues, although concentrated primarily in the Midwest and Southeast, are available throughout the United States. While biomass supply is currently limited, increased supply is possible in the future from increased production from energy crops and advanced harvesting technologies. DOE (2011) provides an estimate of 696–1,184 million annual dry tonnes of biomass inventory potential (of which 52%–61% represents dedicated biomass crops) in 2030.[21] The estimated biomass feedstocks correspond to roughly 100 GW of dedicated biopower capacity. Biopower can be generated from stand-alone plants, or biomass can be co-fired in traditional pulverized coal plants.
- **Geothermal power** (Chapter 7, Volume 2) is generated by water that is heated by hot underground rocks to drive a steam turbine. Geothermal resources are generally concentrated in the western United States, and they are relatively limited for hydrothermal technologies (36 GW of new technical resource potential), which rely on natural hot water or steam reservoirs with appropriate flow characteristics. Only commercially available hydrothermal technologies were included in the modeling analysis. Although not modeled, emerging technologies, including enhanced geothermal systems, engineered hydrothermal reservoirs, geopressured resources, low temperature resources, or co-production from oil and gas wells, could expand the geothermal resource potential in the United States by more than 500 GW.
- **Hydropower** (Chapter 8, Volume 2) is generated by using water—from a reservoir or run-of-river—to drive a hydropower turbine. Run-of-river technology could produce electricity without creating large inundated areas, and many existing dams could be equipped to generate electricity. The future technical potential of run-of-river hydropower from within the contiguous United States is estimated at 152–228 GW. Only new run-of-river hydropower capacity was considered in RE Futures modeling, and existing hydropower plants were assumed to continue operation. Other hydropower technologies, such as new generation at non-powered dams and constructed waterways, have the potential to contribute to future electricity supply, but they were not modeled in this study.
- **Ocean technologies** (Chapter 9, Volume 2) are not broadly commercially available at this time, and therefore were not modeled in this study, but both U.S. and international research and development programs are working to reduce the cost of the technologies. Ocean current resources are best on the U.S. Gulf and South Atlantic Coasts; wave energy resources are strongest on the West Coast. All resources are uncertain; preliminary estimates indicate that the U.S. wave energy technical potential is on the order of 2,500 TWh/yr. Other ocean technologies, including ocean thermal energy conversion technologies and tidal technologies, may also contribute to future electricity supply.

[21] To be conservative, for each modeled year, the analysis used feedstock estimates from Walsh et al. (2000) and Milbrandt et al. (2005), which are consistent with the low end of the DOE (2011) estimate for 2030, and did not assume any increase in resource over time; on the other hand, the analysis also did not include potential future growth in demand for biomass from the fuel sector. Maximum biopower capacity deployment was assumed to be roughly 100 GW in this study, with 27% from dedicated biomass crops.

- **Solar resources** (Chapter 10, Volume 2) are the most abundant renewable resources. They extend across the entire United States, with the highest quality resources concentrated in the Southwest. The technical potential of utility-scale PV and CSP technologies is estimated to be approximately 80,000 GW and 37,000 GW, respectively, in the United States. Distributed rooftop PV technologies are more limited, with approximately 700 GW available. PV technologies convert sunlight directly to electricity while CSP technologies collect high temperature heat to drive a steam turbine.
- **Wind resources** (Chapter 11, Volume 2) on land are abundant, extending throughout the United States, and offshore resources provide additional options for coastal and Great Lakes regions. Onshore and fixed-bottom offshore technologies are currently commercially available.[22] Floating platform offshore wind technologies that could access high-quality wind resources in deeper waters are less mature and were not considered in the modeling. Wind technical resource estimates exceed 10,000 GW in the contiguous United States.

Renewable resource supply varies by location and, in most cases, by the time of day and season. The electricity output characteristics of some renewable energy technologies also vary substantially, potentially introducing electric system operation challenges. A key performance characteristic of generators in general is their degree of dispatchability, specifically the ability of operators to control power plant output over a range of specified output generation levels. Conventional fossil plants are considered dispatchable, to varying degrees. Several renewable generator types, including biopower, geothermal, and hydropower plants with reservoir storage, are also considered dispatchable technologies in that system operators have some ability to specify generator output, if needed. Concentrating solar power with thermal storage can similarly be considered a dispatchable technology but is limited by the amount of storage. The output from run-of-river hydropower is generally constant over short time periods (minutes to hours) but varies over longer periods (days to seasons). Several emerging ocean technologies, such as ocean-current, may also provide fairly constant output and, in some cases, may be able to offer some level of dispatchability.

Wind and solar PV have little dispatchability—the output from these sources can be reduced, but not increased on demand. An additional challenge is the variability and uncertainty in the output profile of these resources, with wind and solar having limited predictability over various time scales. High levels of deployment of these generation types can therefore introduce new challenges to the task of ensuring reliable grid operation. However, it deserves note that the requirement for balanced supply and demand must be met on an *aggregate* basis—the variability and uncertainty of any individual plant or load entity does not ultimately define the integration challenge associated with high levels of variable renewable generation.

The analysis presented here focuses on electricity generation technology deployment, system operational challenges, and implications associated with specified levels of renewable generation, which represent the total annual renewable electricity generation from commercially available biomass, geothermal, hydropower, solar, and wind electricity generating technologies.

[22] Although there are no offshore wind power plants operating in the United States, a number of projects have been proposed. In addition, offshore wind is widely deployed in Europe.

U.S. Electricity Grid Expansion and Operational Characterization

RE Futures employs two key models to characterize U.S. electricity grid operations with high levels of renewable generation. The NREL Regional Energy Deployment System (ReEDS) model explores the adequacy of the geographically diverse U.S. renewable resources to meet electricity demand over future decades. The ABB model, GridView, explores the hourly operation of the U.S. grid with high levels of variable PV and wind generation.[23] The linked-but-separate use of the two models, ReEDS and GridView, allows for a rich assessment of the technical, geographic, and operational aspects of renewable energy deployment.[24]

ReEDS is the analytical backbone of the study, providing estimates of the type and location of conventional and renewable resource development; the transmission infrastructure expansion requirements of those installations; and the composition and location of generation, storage, and demand-side technologies needed to maintain balance between supply and demand. ReEDS is unique among national, long-term capacity expansion models for its highly discretized regional structure and statistical treatment of the impact of variable wind and solar resources on capacity planning and dispatch. GridView was used to supplement the ReEDS analysis by modeling the hourly operation of the power system in 2050 for a subset of the high renewable scenarios. As one of the commercially available production cost models used by utilities, systems operators, and industry experts, GridView enables a more detailed exploration of the operational implications of a system with high levels of renewable electricity penetration through the use of an hourly time step, a more accurate representation of thermal generation ramp-rate limits, and a more realistic representation of transmission power flows compared with ReEDS.

These models were used to investigate a broad portfolio of supply- and demand-side options available to increase the flexibility of the electric system, including: having dispatchable renewable or conventional generators available to supply needed electricity when there is insufficient electricity generation from variable renewable plants; having the ability to provide reserves or change electricity demand through demand response (interruptible load) or transportation electric loads; deploying storage technologies for added system flexibility; and expanding the electric system transmission infrastructure to move more distant electricity supply to meet the load. Geospatial diversity was also taken into account, since it can assist in the integration of variable renewable generation because wind and solar plants that are located far apart generally have a combined output profile that is less variable than the individual plant profiles. Further, wind and solar resources may be uncorrelated or even anti-correlated

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[23] The NREL Solar Deployment Systems (SolarDS) model was also used in RE Futures to represent rooftop PV deployment.

[24] In assessing high penetrations of variable renewable electricity, RE Futures addressed some aspects of electric system adequacy through statistical treatments of reserve requirements and hourly dispatch analysis; however, the analysis did not include a complete assessment of power system reliability (addressing such issues as stability, contingencies, and AC power flows). Similarly, RE Futures is not a fully detailed renewable energy integration study. Such studies typically seek to understand the impacts of variable and uncertain wind and solar generation on the operations of regional electric power systems and networks, relying on high time-resolution data and using methods that range from statistical analysis and production cost modeling to power flow simulations and steady state and transient grid analysis. RE Futures assessed electric system integration issues on a broader, national level, and the modeling tools used considered the variability and uncertainty of some renewable technologies, but not to the level of detail typical in integration studies.

depending on location; if so, combining their outputs would then further reduce aggregate variability.

Key Results

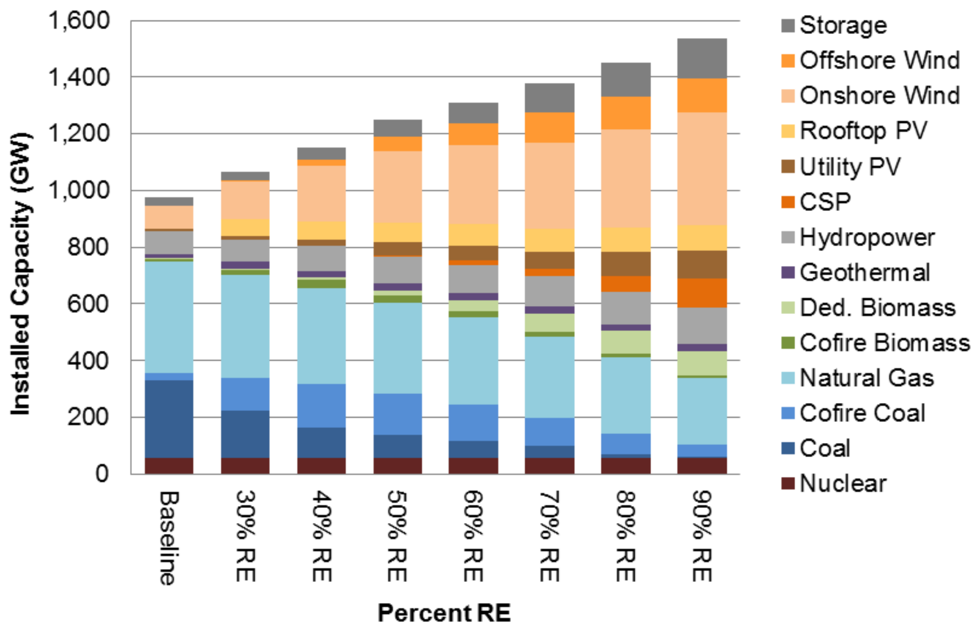
Deployment of Renewable Energy Technologies in High Renewable Electricity Futures

Renewable energy resources, accessed with commercially available renewable generation technologies, could adequately supply 80% of total U.S. electricity generation in 2050 while balancing supply and demand at the hourly level. Figure ES-3 presents estimated 2050 capacity and generation, by technology, for the exploratory scenarios.[25] Generation from wind and PV technologies is variable, with lower capacity factors and relatively limited dispatchability. The growing deployment of this variable generation in these scenarios, increasing with renewable electricity penetration (from 20% in the baseline scenario to as high as 90% at the other end), drives the need for a growing amount of aggregate electric generation capacity in order to meet demand. Specifically, adequate capacity from dispatchable resources is required to ensure delivery of necessary generation year-round.

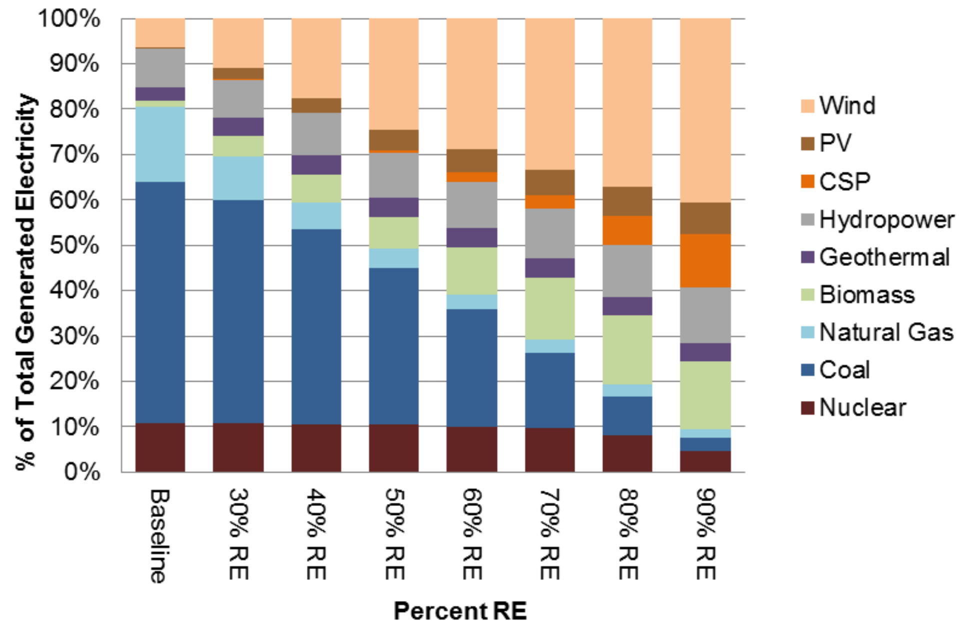
Commercially available renewable technologies were deployed in the modeling to varying degrees in the exploratory scenarios, in part to exploit geographic and temporal diversity in achieving high renewable electricity penetration levels. Onshore wind was found to contribute most significantly in these exploratory scenarios, with offshore wind becoming an increasingly important player as higher renewable electricity levels were achieved. Among the solar technologies, PV (utility-scale and rooftop, combined) was generally found to play a more-sizable role than CSP under the relatively lower renewable penetration scenarios. Electricity supply from CSP was projected to grow more rapidly under the higher renewable penetration scenarios, in part because CSP with thermal storage provides added dispatchability. Both dedicated and co-fired biomass were also found to contribute significantly to the renewable energy mix, with a shift from co-firing to dedicated biomass plants as renewable electricity penetration levels increased. Geothermal and hydropower were found to contribute proportionately less than the other renewable energy sources, especially under the highest renewable electricity scenarios considered, due to assumed resource and cost constraints.[26] However, even for this limited set of geothermal and hydropower resources, capacity expansion was substantial relative to recent trends, and much of the estimated available resource potential was accessed. Enhanced geothermal systems, ocean energy, and floating platform offshore wind energy were not considered, but these technologies may offer large resource potential, additional diversity, and regional advantages if technological advancements enable commercialization.

[25] Deployment results shown in Figure ES-3 used the renewable electricity incremental technology improvement (RE-ITI) assumptions. Results for the RE-ETI scenarios are included in Chapter 2.

[26] The assumptions used in the analysis were particularly constraining on geothermal technologies, for which advanced technologies, such as enhanced geothermal systems that can tap large quantities of energy inside the earth, were not considered in the grid modeling. The modeling analysis focused on currently commercial technologies only.



(a) Capacity mix in 2050 for the exploratory scenarios



(b) Generation mix in 2050 for the exploratory scenarios

Figure ES-3. Installed capacity and generation in 2050 as renewable electricity levels increase (low-demand, RE-ITI technology improvement)

All regions of the United States could contribute substantial renewable electricity supply in 2050, consistent with their local renewable resource base. Figure ES-4 presents the modeled location of renewable electricity generation and capacity by 2050 for one 80%-by-2050 RE scenario (80% RE-ITI). It also compares total regional electricity generated in 2050 to regional electricity demand (based on low-demand assumptions). In the scenario shown, wind energy supply was significant in most regions but was most prominent in the Great Plains, Great Lakes, Central, Northeast, and Mid Atlantic regions (with a large fraction of wind generation coming from offshore resources in the Northeast and Mid Atlantic regions). Solar energy was found to deploy most substantially in the Southwest (dominated by CSP), followed by California and Texas (CSP and PV), and then by the Florida and the Southeast regions (dominated by PV). Biomass supply was most significant in the Great Plains, Great Lakes, Central, and Southeast regions. Hydropower supply was most significant in the Northwest, but hydropower was also a sizable contributor in California, the Northeast, and the Southeast. Geothermal was found to deploy primarily in California and the Southwest.

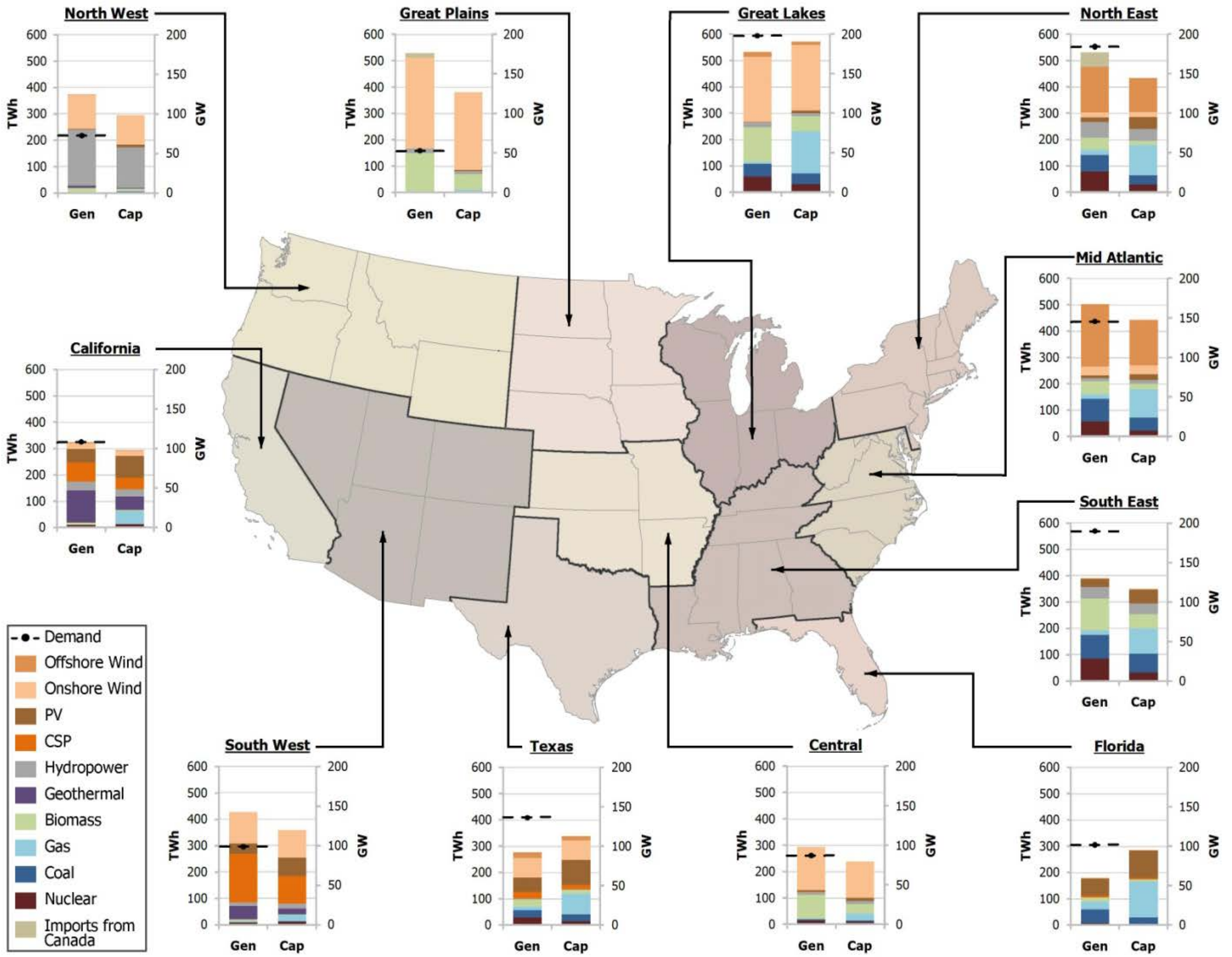


Figure ES-4. Renewable generation and capacity in 2050 by region under 80% RE-ITI scenario (low-demand, RE-ITI technology improvement)

Multiple technology pathways exist to achieve a high renewable electricity future. Assumed constraints, which limit power transmission infrastructure, grid flexibility, or the use of particular types of resources can be compensated for through the use of other resources, technologies, and approaches. The renewable energy resource base of the United States is both abundant and diverse. As a result, a central finding of the analysis is that there are many possible ways to achieve high renewable penetration levels.

For example, the technology improvement scenarios included in the six core 80% RE scenarios (Impact of Technology Improvement scenarios) showed that technologies that are currently at earlier stages of commercialization (e.g., solar) could achieve greater deployment if significant technology improvements were realized in the future. In contrast, if these improvements were not realized, currently more commercially mature technologies (e.g., onshore wind) could deploy to a greater extent. Also, a set of scenarios included in the core 80% RE scenarios explored the impacts of limits on building new transmission, constraints on the flexibility of the electric system to manage the variability of wind and solar resources, and constraints on the developable potential for many renewable technologies (Impact of System Constraints scenarios). The mix of renewable resources deployed and the deployment of flexible supply- and demand-side technologies were significantly impacted in these scenarios. In particular, when new transmission builds were constrained, greater deployment was observed for resources located closer to load centers, including PV, offshore wind, and biomass. A future where the flexibility of the electric system was limited resulted in a shift of renewable electricity supply away from variable wind and PV technologies and toward more dispatchable options, particularly CSP with thermal storage, and to storage technologies. When the assumed availability of renewable energy supply was reduced—due to siting or permitting challenges, for example—the contributions from the most resource-constrained technologies (biopower, geothermal, and hydropower) declined, while more abundant wind and solar resources were used to a greater degree. Figure ES-5 shows the range in 2050 capacity and generation by technology among the six low-demand 80%-by-2050 RE scenarios examined. Although the type and quantity of renewable technologies deployed in these scenarios varied significantly, estimated direct electric sector aggregate cost was relatively insensitive to most of these variations.[27]

Finally, the analysis found that the renewable resource base in the United States was sufficient to support 80% renewable electricity generation by 2050 in a higher demand growth scenario. Figure ES-5 also shows 2050 deployment results for the High-Demand 80%-by-2050 RE scenario, which features a much greater amount of solar capacity compared with the low-demand scenarios.

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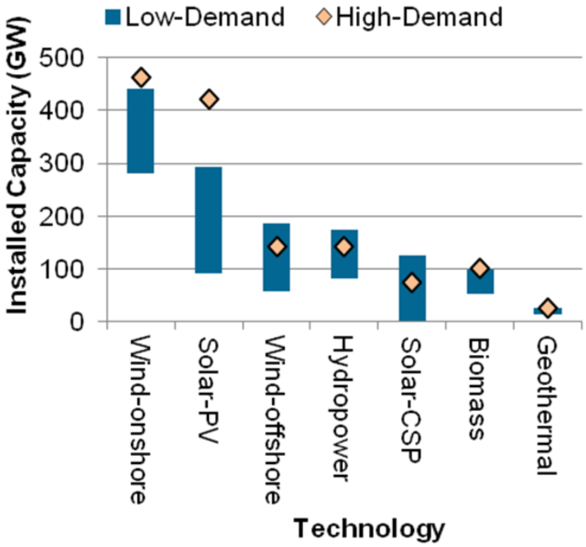
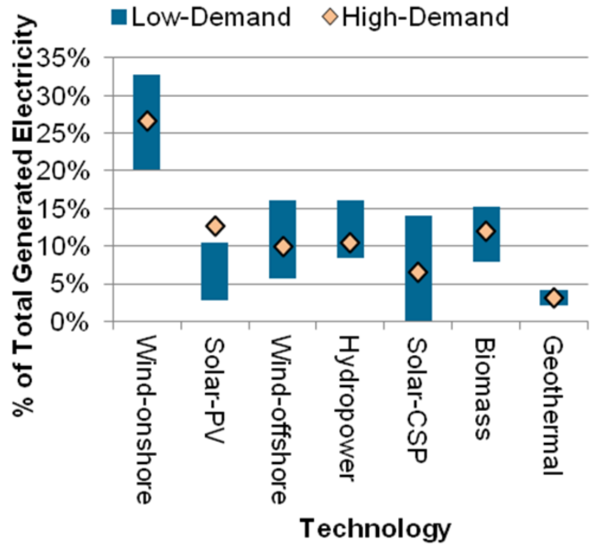
[27] See individual technology chapters in Volume 2 for a discussion of the specific scenarios that lead to high and low estimates for each technology individually; Volume 1 provides more discussion of the operational and cost implications these scenarios.



(a) 2050 installed capacity by technology



(b) 2050 contribution to total generated electricity

Figure ES-5. Range of 2050 installed capacity and annual generated electricity by technology for the low-demand core 80% RE scenarios and the High-Demand 80% RE scenario

Annual renewable capacity additions that enable high renewable electricity are consistent with current global production capacities but are significantly higher than recent U.S. annual capacity additions for the technologies considered. No insurmountable long-term constraints to renewable electricity technology manufacturing capacity, materials supply, or labor availability were identified. The analysis showed that achieving high renewable electricity futures would require a sustained increase in renewable capacity additions. In the core 80% RE scenarios, average annual renewable capacity additions of 19–22 GW/yr from 2011–2020 were estimated, increasing to a maximum rate of 32–46 GW/yr from 2041–2050. Given recent historical experience with U.S. renewable electricity capacity additions (11 GW in 2009 and 7 GW in 2010),[28] achieving these rates of deployment may pose challenges as production ramps up, including those related to materials availability, equipment manufacturing capacity, labor needs, and project development and siting processes. However, no insurmountable long-term technical constraints to renewable technology manufacturing capacity, materials supply, or labor availability were identified; better informed siting practices and regulations can mitigate potential constraints related to project development and siting processes (see Chapter 3 and Volume 2).

Growth in renewable capacity additions in the United States and globally over the last decade has been considerable, and it demonstrates the ability to scale manufacturing and deployment at

[28] The challenges associated with the rates of deployment presented here depend on technology. For example, renewable installations in the United States in recent years were dominated by new wind technologies; therefore, achieving the deployment rates envisioned in the scenarios for wind energy would likely be less challenging from an industry growth perspective compared with other technologies.

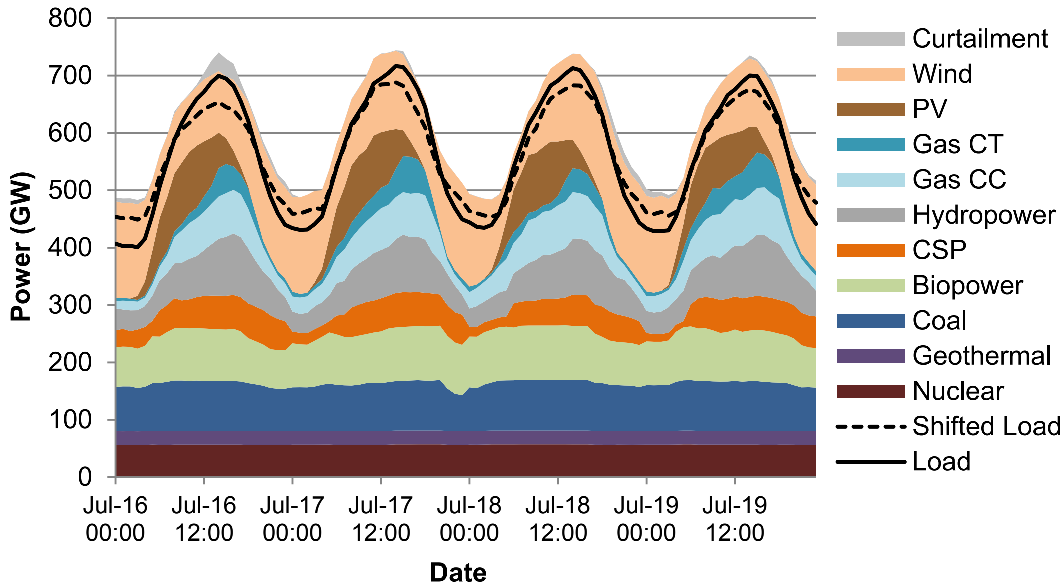
a rapid pace. The wind power additions required in the scenarios, for example, were substantial, but historical growth in manufacturing and installation suggests that manufacturing need not be a major constraint to the continued growth that would be necessary to meet an 80%-by-2050 generation level. The biopower and geothermal additions resulting from the scenario modeling, although greater than recent historical trends, are similarly unlikely to place undue strain on supply chains. The estimated rate of PV deployment is particularly high, but PV manufacturing and deployment are highly scalable, and worldwide PV production capacity has been growing rapidly and is already comparable to the deployment rates projected in high renewable scenarios presented here for the United States. Moreover, many of the renewable technologies are based on common materials that are not supply-constrained. Even for PV, which does use some materials that may be supply-constrained, worldwide production capacity is already sizable and that capacity continues to expand rapidly. In addition, alternate approaches exist to reduce dependence on supply-constrained materials if necessary. While a comprehensive analysis of industry scale-up, including labor demands and access to critical materials, is beyond the study scope, the initial analysis did not identify any insurmountable technical challenges associated with industry scale-up at the technology deployment levels considered.

Grid Operability and Hourly Resource Adequacy in High Renewable Electricity Futures

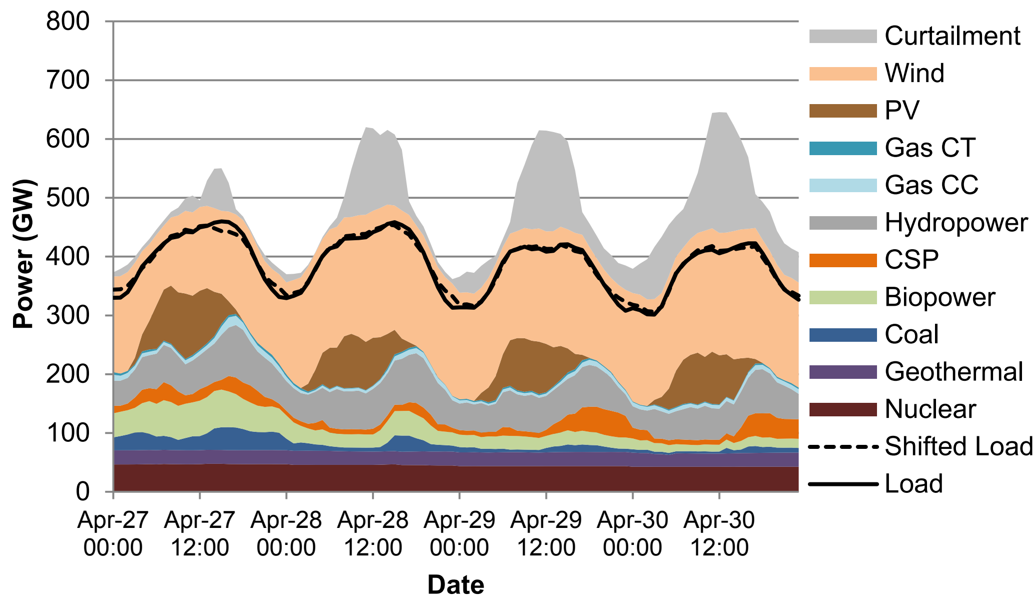
Electricity supply and demand can be balanced in every hour of the year in each region with nearly 80% of electricity from renewable resources, including nearly 50% from variable renewable generation, according to simulations of 2050 power system operations.[29] Although a full reliability assessment is beyond the scope of this analysis, hourly production simulation did consider unit commitment with imperfect forecasts, DC optimal power flow, and thermal generator flexibility limits (e.g., ramp rates and minimum generation levels). Figure ES-6 shows nationwide dispatch by generator type during the annual peak coincident load (Figure ES-6[a]) and during the lowest coincident load of the year (Figure ES-6[b]) in 2050 for a high renewable electricity scenario. The operational simulations did not project any hours of unserved load during the peak load hour, lowest coincident load hour, or any other hour of the year.[30]

[29] Although the capacity expansion modeling (ReEDS) planned for renewable resources to contribute 80% of annual generation in 2050, the hourly operational model (GridView) simulated roughly 75%, in part due to a lack of a renewable generation requirement. GridView model dispatch decisions were based on the variable cost of generation and did not consider the renewable or non-renewable nature of the generation source.

[30] The electric system is a complex system of systems that operates on many time scales ranging from milliseconds to years; ultimately, analyses must be conducted to address all of the potential operating aspects of future electricity generation systems as they evolve. Electric system operations are described in detail in Volume 4.



(a) Summer peak load in 2050



(b) Lowest coincident load in 2050

Figure ES-6. Hourly dispatch stacks for the 80% RE-ITI scenario[a]

[a] The solid black line representing “load” includes charging of electric vehicles. The broken line representing “shifted load” represents “load” minus storage. The Gas CT category includes a small number of oil-fired units. The unit types are ordered (subjectively) from least variable or flexible (at the bottom) to most variable (at the top).

Additional challenges to power system planning and operation would arise in a high renewable electricity future, including management of low-demand periods and curtailment of excess electricity generation. The hourly analysis also found that, in contrast to today's fossil-fuel-dominated electricity system for which the time of peak load (e.g., summer afternoons) is of most concern, operational challenges for high renewable generation scenarios were most acute during low-demand periods (e.g., spring evenings) when the abundance of renewable supply relative to demand would force thermal generators to cycle or ramp down to their minimum generation levels.[31] During low-demand periods in today's system and in the baseline scenario, most of the peaking needs are met with hydropower and combined cycle units; combustion turbines are needed but to a much lesser extent than in the summer. Although the load characteristics in 2050 are similar in the baseline scenario and the high renewable scenarios, during low-demand periods in the latter (e.g., Figure ES-6[b]), there was enough aggregate renewable electricity to fully serve load, causing the net load (load minus variable wind and PV generation) to be much more variable compared to the rest of the year. This increased variability in net load creates challenges associated with greater power plant cycling and ramping.

A primary challenge of variable renewable energy integration at higher levels of penetration is the need at times to curtail excess electricity, particularly during periods with low electricity demands.[32] The hourly dispatch analysis estimated that overall in 2050, 8%–10% of wind, solar, and hydropower generation would need to be curtailed under an 80%-by-2050 RE scenario. Curtailments reduce capacity factors and introduce uncertainty in electricity sales, thereby negatively impacting plant economics. A variety of technical and institutional approaches could be applied to reduce these levels of curtailment. First, additional transmission capacity in congested corridors would help alleviate congestion and reduce curtailment. Second, increasing the size of reserve-sharing groups could help reduce the number of inflexible generators online to provide spinning reserves; curtailment of renewable generation could be reduced if fewer plants operate at minimum levels. Third, the flexibility of the thermal fleet could be improved, or market structures could be implemented to encourage the operation of more flexible generators. Fourth, additional energy storage and controllable loads could be used to improve system flexibility. Finally, new or existing industries could take advantage of the low-cost electricity available during seasons or times when curtailment would have occurred, and the resulting increased demand could then consume electricity that otherwise would have been curtailed.

Electric sector modeling shows that a more flexible system is needed to accommodate increasing levels of renewable generation. System flexibility can be increased using a broad portfolio of supply- and demand-side options and will likely require technology advances, new operating procedures, evolved business models, and new market rules. As renewable electricity generation increased from 20% in the baseline scenario to 90% in the exploratory scenarios, the annual

[31] Peak load still requires management and will be challenging for the same reasons it is today, but in addition, management of low-demand periods and curtailment will be required with high variable renewable electricity.

[32] This situation parallels the use of combustion turbines in conventional systems, which are typically used just a few hundred hours per year to meet summer peak loads and are largely idle much of the rest of the year. As such, both the conventional and the high renewable electricity systems operate with excess capacity most of the time. While the high renewable system generates power with the excess capacity as long as resources are available, the conventional system simply leaves the excess capacity idle.

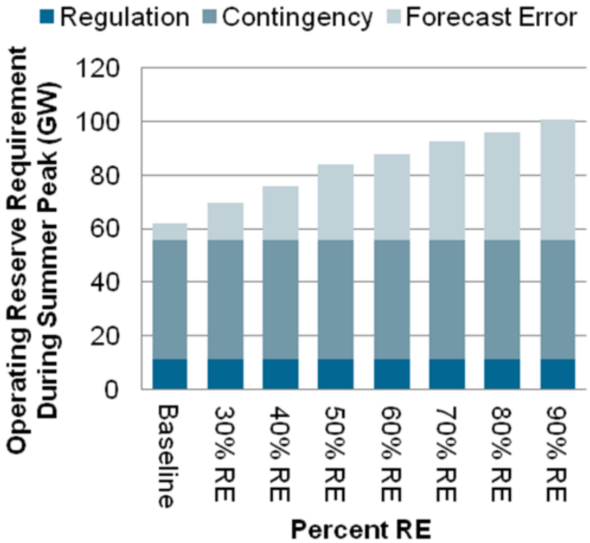
contribution from *variable* generation (wind and solar PV) grew from 7% to 48% in 2050. At this high level of variable generation, ensuring a real-time balance between electricity supply and demand is more challenging The variability and uncertainty associated with these high levels of wind and PV penetration were found to be manageable through the application of adequate flexible generation capacity, the use of grid storage and demand-side technologies, the expansion of transmission infrastructure, and greater conventional plant dispatch flexibility, including significant daily ramping of fossil generators. (Dispatchable renewable technologies, like conventional technologies, do not impose significant additional challenges to system operability, and they are also used to help manage wind and solar PV integration.)

The RE Futures analysis considers reserves necessary for reliable electric system operations, spanning a wide range of timescales (from long-term planning reserves to short-term operating reserves). The same capacity reserve margin requirements were satisfied across all scenarios despite the relatively low capacity values of variable resources and their increasing deployment as renewable penetration increased. Partly to satisfy planning reserve requirements, greater aggregate capacity was needed in high penetration renewable scenarios (see Figure ES-3).

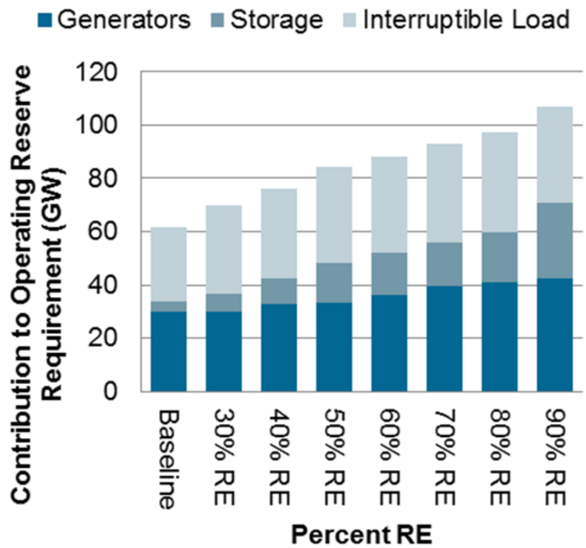
Additional operating reserves were also found to be required in high variable renewable generation systems and were accommodated through the availability of conventional power plants, storage technologies, and demand-side practices. The analysis included multiple components of operating reserves, namely contingency reserves, frequency regulation reserves, and reserves associated with imperfect forecasts of wind and PV generation. Figure ES-7 shows how operating reserve requirements increased as renewable deployment increased and the different options used to meet these requirements in the exploratory scenarios.[33] Although operating reserve *requirements* increase with wind and PV deployment (due to greater forecast errors), because the dispatch of existing conventional power plants declines to accommodate additional wind and PV generation, these existing conventional units were found to be more available to satisfy the necessary operating reserve requirements. In other words, a high renewable electricity future would reduce the energy-providing role of the conventional fleet and increase its reserve-providing role.

The analysis found use of storage to be an attractive option to increase electric system flexibility due to the ability of storage to shift load to better correlate with output from variable generators, reduce curtailments by storing excess generation in times of low demand, and provide firm capacity for a variety of reserve services. In the core 80% RE scenarios, for example, storage deployment was found to increase from approximately 20 GW in 2010 to 100–152 GW in 2050. Demand-side options were also found to play a significant role in meeting the integration challenges of a high renewable electricity future. For example, in the core 80% RE scenarios, 28–48 GW of demand-side interruptible load were deployed in 2050, compared with just 15.6 GW deployed in 2009.

[33] In Figure ES-7, the total contribution to operating reserves exceeds the requirement due to the fact that only one time (summer peak) is shown, while certain reserve-types (e.g., interruptible load) are annual in nature and deployed to serve other times not shown.



(a) 2050 operating reserve requirement during the summer peak by reserve type



(b) 2050 contributions toward total operating reserve requirement by technology type

Figure ES-7. Operating reserve requirements as renewable electricity levels increase

The RE Futures analysis suggests that variable generation levels of up to nearly 50% of annual electricity can be accommodated when a broad portfolio of supply- and demand-side flexibility resources is available at a level substantially higher than in today's electricity system. A broad portfolio of flexible supply- and demand-side resources and options were made available in the scenario modeling, and were relied upon particularly in the high renewable generation scenarios, including:

- Maintaining sufficient capacity on the system for planning reserves
- Relying on demand-side interruptible load, conventional generators (particularly natural gas generators), and storage to manage increased operating reserve requirements
- Mitigating curtailment with storage and controlled charging of electric vehicles
- Operating the system with greater conventional power plant ramping
- Relying on the dispatchability of certain renewable technologies (e.g., biopower, geothermal, CSP with storage and hydropower)
- Leveraging the geospatial diversity of the variable resources to smooth output ramping
- Transmitting greater amounts of power over longer distances to smooth electricity demand profiles and meet load with remote generation

Achieving the system flexibility required to integrate high levels of renewable generation will require some combination of technology advances, new operating procedures, evolved business models, and new market rules. Although the analysis does not examine how these mechanisms could be implemented, it does describe the power system flexibility characteristics needed for the integration of high levels of renewable generation.

Transmission Expansion in High Renewable Electricity Futures

As renewable electricity generation increases, additional transmission infrastructure is required to deliver generation from cost-effective remote renewable resources to load centers, enable reserve sharing over greater distances, and smooth output profiles of variable resources by enabling greater geospatial diversity. Many of the system flexibility resources and options described above can benefit from transmission infrastructure enhancements to enable the transfer of power and sharing of reserves over large areas to accommodate the variability of wind and solar electricity generation in combination with variability in electricity demand. With high penetrations of variable generation, net load (load minus variable generation) in a specific region can show dramatic ramps. Transmission between regions helps reduce ramps in net load because it allows system operators to access a larger pool and more diverse mix of variable generation, with some smoothing of output profiles and demand profiles over larger geographic areas. Figure ES-8 shows projected new transmission capacity deployed over the 40-year study period for the exploratory scenarios. Demands for new transmission capacity are much greater in the higher renewable generation scenarios than in lower renewable generation scenarios, outstripping the effects of the low-demand assumption, reductions in transmission use by conventional fossil generation (freeing up the lines for renewable generation), and deployment of renewable resources that are proximate to load centers (e.g., PV and offshore wind).[34] The increase in transmission needs as renewable electricity supply grows, for all 80%-by-2050 renewable electricity scenarios, result in an average annual projected transmission and interconnection investment that is within the recent historical range for total investor-owned utility transmission expenditures in the United States (i.e., $2 billion/yr to $9 billion/yr from 1995 through 2008) (Pfeifenberger et al. 2009).

[34] The analysis assumed that the existing transmission infrastructure is operational throughout the study period and did not consider maintenance needs for the existing transmission lines or other infrastructure. In addition, the analysis did not consider distribution-level maintenance or upgrades.

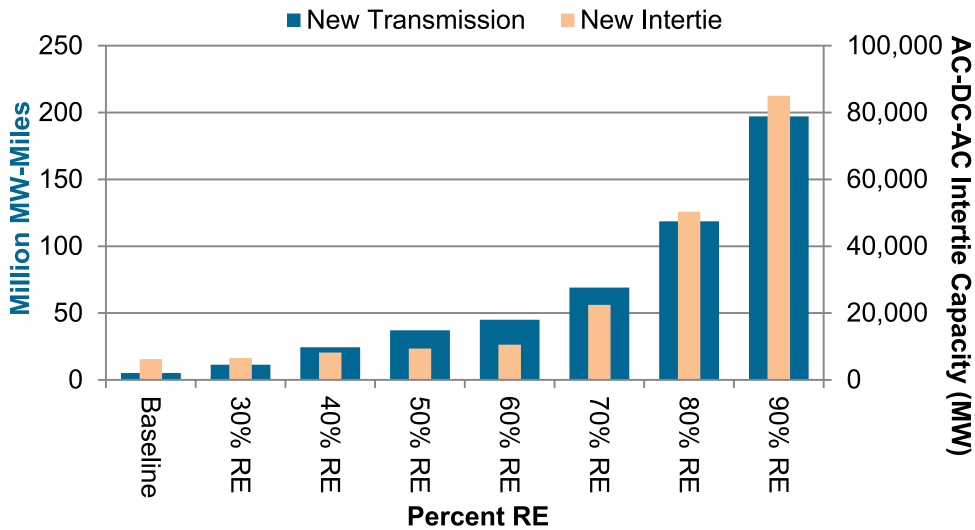


Figure ES-8. New transmission capacity requirements in the baseline and exploratory scenarios

Existing total transmission capacity in the contiguous United States is estimated at 150–200 million MW-miles[35]

New transmission in the high renewable electricity scenarios was found to be concentrated in the middle and southwestern regions of the United States, mainly to access the high-quality wind and solar resources in those regions and to deliver generation from those resources to load centers. For example, Figure ES-9 presents a conceptual map of new transmission infrastructure needed in an 80%-by-2050 scenario. As shown in Figure ES-9 and quantified in Figure ES-8, the current isolation of the three asynchronous interconnections—Western Electricity Coordinating Council (WECC), Electric Reliability Council of Texas (ERCOT), and Eastern Interconnection—was greatly reduced in many of the high renewable electricity scenarios through the expansion of AC-DC-AC interties. This expansion enabled the East to have greater access to the high-quality renewable resources located in the western United States, although the hourly simulations and DC transmission power flow analysis suggests that these east-west transmission linkages were used bi-directionally to manage temporal variations in electricity supply and demand. Expanding interties between the three asynchronous interconnections was found to be desirable in many of the high renewable scenarios; however, results from the Constrained Transmission scenario showed that an 80%-by-2050 RE scenario was achievable even when such expansion was not allowed.

Significant institutional obstacles, including constraints in siting new transmission lines, cost allocation concerns with transmission projects, and coordination between multiple governing entities, currently inhibit transmission expansion. The mechanisms to overcome these obstacles were not explored in the study, but the analysis demonstrates that additional long-distance transmission capacity can be an important characteristic of high renewable electricity futures.

[35] The ReEDS model assumed 150 million MW-miles of existing inter-BA transmission capacity; the 200 million MW-mile estimate is from Homeland Security Infrastructure Database (2008) and other sources.

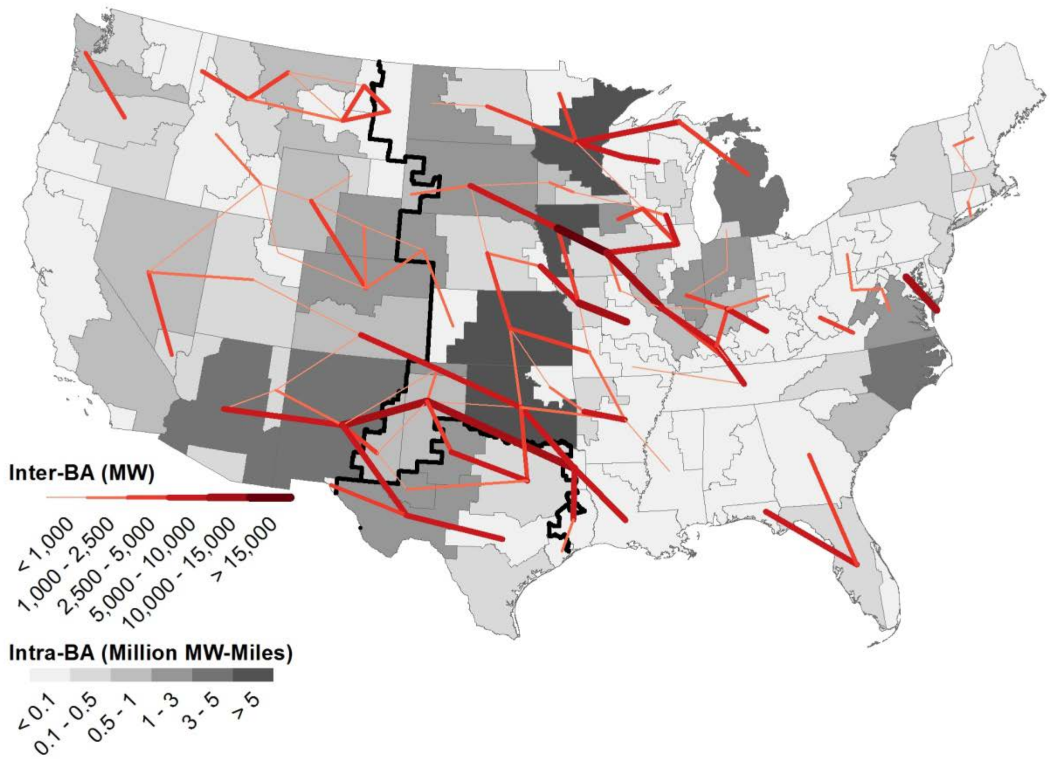


Figure ES-9. New transmission capacity additions and conceptual location in the 80% RE-ITI scenario

Cost and Environmental Implications of High Renewable Electricity Futures

High renewable electricity futures can result in deep reductions in electric sector greenhouse gas emissions and water use. Direct environmental and social implications are associated with the high renewable futures examined, including reduced electric sector air emissions and water use resulting from reduced fossil energy consumption, and increased land use competition and associated issues. At 80% renewable electricity in 2050, annual generation from both coal-fired and natural gas-fired sources was reduced by about 80%, resulting in reductions in annual greenhouse gas emissions of about 80% (on a direct combustion basis and on a full life cycle basis) and in annual power sector water use of roughly 50%. At 80% renewable electricity, gross land-use impacts associated with renewable generation facilities, storage facilities, and transmission expansion totaled less than 3% of the land area of the contiguous United States.[36]

The direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost. The retail electricity price implications estimated for the 80%-by-2050 RE scenarios are comparable to those seen in other studies with similarly transformative electricity futures, as

[36] Net land-use impacts, considering the implications of reduced conventional generation, and land-use impacts based on disrupted lands, are both expected to be smaller. As an example of the latter case, disrupted land would generally be less than 5% of gross land area for wind generation facilities.

shown on Figure ES-10. Low carbon and clean energy scenarios, evaluated by the U.S. Energy Information Administration (EIA) and the U.S. Environmental Protection Agency (EPA), with avoided carbon emissions trajectories similar to the core 80% RE scenarios showed increases in average retail electricity prices (relative to their own reference scenarios) in 2030 of $9–$26/MWh, rising to $41–$53/MWh by 2050. These studies generally considered a portfolio of clean generation technology options, including renewable, nuclear, and low emissions fossil. The estimated incremental price impacts of the core 80% RE scenarios are comparable to these estimates.

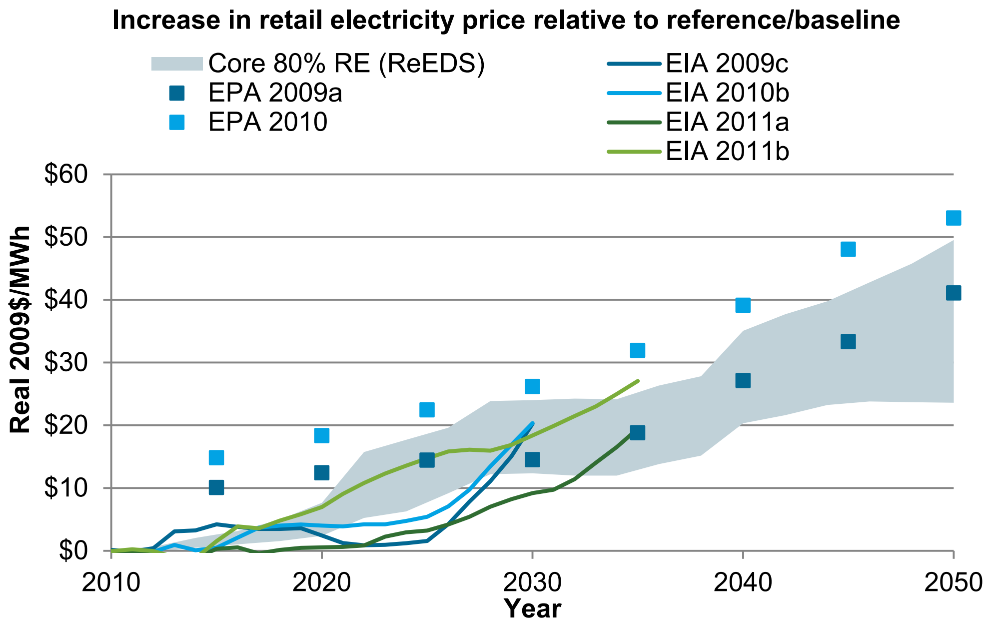


Figure ES-10. Average increase in retail electricity rates relative to study-specific reference/baseline scenarios

EIA 2011a and 2011b document analysis of clean energy scenarios. EIA 2009c, EPA 2009a, EIA 2010b, and EPA 2010 report on analysis of several low carbon emissions scenarios.

As with these other clean generation scenarios that would represent a nearly wholesale transformation of the U.S. electricity system, the high renewable generation scenarios examined show a direct incremental cost relative to the continued evolution of today's conventional generation-dominated system. Higher electricity prices associated with the high renewable scenarios are driven by replacement of existing generation plants with new generators (mostly renewable); additional balancing requirements reflected in expenditures for combustion turbines, storage, and transmission; and the assumed higher relative capital cost of renewable generation, compared to conventional technologies, assumed in the analysis. The increased capital investments associated with these drivers, compared to the baseline scenario, were not fully offset by cost savings associated with lower fossil energy consumption. The incremental cost does not include investments in energy efficiency implied by low electricity demand assumptions, or the savings in avoided generation resulting from these investments. Further, the incremental cost estimate does not consider indirect societal costs associated with the scenarios (e.g., associated with the greenhouse gas emissions described above), or economy-wide impacts.

Advancements in renewable technologies, reflected by technology cost and performance improvement assumptions, had the greatest impact on the incremental cost of the high renewable generation scenarios. For example, the low end of the range of incremental electricity price shown in Figure ES-10 reflects the scenario with the highest assumed renewable technology improvement (RE-ETI), while the high end reflects the lowest technology improvement scenario (RE-NTI).[37] Assumed system constraints had more modest impact on direct incremental costs; scenarios reflecting constraints to transmission expansion, renewable resources, and grid flexibility all had similar costs, which fell well within the bounds identified in Figure ES-10. Finally, incremental costs were largely insensitive to differences in projections for fossil fuel prices and fossil technology improvements.

The lower renewable generation levels examined in the exploratory scenarios showed lower incremental 2050 retail electricity prices. For example, the 30% RE scenario under highest technology improvement assumptions (RE-ETI) showed no price increase in 2050 relative to the baseline scenario (which used RE-ITI assumptions). This result suggests that significant expansion of renewable generation beyond the 2010 level (10% of total generation) could be achieved with little or no incremental cost, assuming evolutionary improvements in renewable technologies.

There are significant inherent uncertainties with respect to future electricity demand, technology improvements, fossil energy prices, social and institutional choices, and regulatory and legislative actions related to the scenarios examined that, in turn, contribute to significant uncertainty in the implications reported above. Further, there are a variety of indirect (or downstream) implications that may result from the direct electric sector cost, environmental, and social implications identified. For example, incremental investment in generation capacity and associated infrastructure will have implications related to economic activity and employment in the energy industry. Reductions in fossil energy consumption will have environmental implications beyond air emissions, including implications related to water quality, terrestrial and marine contamination, and waste disposal, not only associated with electricity generation facilities but also for activities related to fuel extraction and transportation. Further, air emissions reductions will have implications for human health and climate change. Identification, and in some cases quantification, of these indirect implications is an active area of wide-ranging research. This analysis does not attempt to evaluate these indirect impacts of high renewable electricity futures. Further research is critically needed to systematically assess the relative impacts of different forms of energy supply in the context of a robust comprehensive framework that assesses both direct and indirect impacts. Such research could inform national energy policy decisions as well as local siting and permitting processes related to proposed generation facilities and supporting infrastructure.

[37] The RE-ETI assumptions are based on evolutionary improvements to currently commercial technologies and do not reflect DOE activities to further lower renewable technology costs so that they achieve parity with conventional technologies.

Effects of Demand Growth on High Renewable Electricity Futures

With higher electricity demand growth, high levels of renewable generation present increased resource and grid integration challenges. RE Futures did not explicitly evaluate the cost effectiveness of energy efficiency adoption compared with supply-side options. However, the analysis suggests that under a high-demand scenario, greater and more rapid deployment of renewable and other supply- and demand-side technologies would be required. For example, while 32–46 GW/yr of renewable capacity additions were estimated from 2041 to 2050 in the low-demand core 80% RE scenarios, approximately 66 GW/yr would be needed during the same time period under a more-traditional, higher-demand trajectory. The analysis also found that in the 80%-by-2050 renewable electricity high-demand scenario, variable resources (wind and PV) were deployed to a greater extent in absolute and percentage terms than they were in the low-demand scenarios due to the greater resource available for wind and solar generation compared with other forms of renewable generation. As a consequence, additional flexible supply- and demand-side technologies, such as storage facilities, natural gas combustion turbine power plants, and interruptible load, were deployed and greater transmission expansion was needed to connect remotely located renewable resources of all types.

Higher end-use electricity demand increased the environmental impacts from the electric sector, such as greater greenhouse gas emissions, water use for thermoelectric cooling, and land use. In addition, higher demand growth also resulted in a greater increase in electricity prices. For example, in the High-Demand 80% RE scenario, the average annual retail electricity price increased by 1.3% per year (2011–2050, in real dollar terms) compared with 1.1% per year in the (low-demand) 80% RE-ITI scenario.[38] The increase in retail electricity prices driven by higher demand growth is not restricted to the high renewable penetration scenarios; it is evident under the baseline scenario as well. In particular, the average annual retail electricity price increased by 0.6% per year (2011–2050, in real dollar terms) in the High-Demand Baseline scenario compared with 0.3% per year in the Low-Demand Baseline scenario. While these results indicate that higher demand growth would lead to greater electricity price increases, they also demonstrate that the direct *incremental* costs associated with high renewable generation levels actually decreased under higher demand growth.

Conclusions

The RE Futures study assesses the extent to which future U.S. electricity demand could be supplied by commercially available renewable generation technologies—including wind, utility-scale and rooftop PV, CSP, hydropower, geothermal, and biomass—under a range of assumptions for generation technology improvement, electric system operational constraints, and electricity demand. Within the limits of the tools used and scenarios assessed, hourly simulation analysis indicates that estimated U.S. electricity demand in 2050 could be met with 80% of generation from renewable energy technologies with varying degrees of dispatchability together with a mix of flexible conventional generation and grid storage, additions of transmission, more responsive loads, and foreseeable changes in power system operations. While the analysis was

[38] To isolate the effect of demand growth, the High-Demand 80% RE Scenario is compared with the 80% RE-ITI scenario since they both relied on the same technology improvement projection and used the same assumptions related to transmission, system flexibility, and renewable resources.

based on detailed geospatially rich modeling down to the hourly timescale, the study is subject to many limitations both with respect to modeling capabilities and the many assumptions required about inherently uncertain variables, including future technological advances, institutional choices, and market conditions. Nonetheless, the analysis shows that realizing this significant transformation of the electricity sector would require:

- Sustained build-up of many renewable resources in all regions of the United States
- Deployment of an appropriate mix of renewable technologies from the abundant and diverse U.S. renewable resource supply in a way that accommodates institutional or operational constraints to the electricity system, including constraints to transmission expansion, system flexibility, and resource accessibility
- Establishment of mechanisms to ensure adequate contribution to planning and operating reserves from conventional generators, dispatchable renewable generators, storage, and demand-side technologies
- Increasing the flexibility of the electric system through the adoption of some combination of storage technologies, demand-side options, ramping of conventional generation, more flexible dispatch of conventional generators, energy curtailment, and transmission
- Expansion of transmission infrastructure to enable access to diverse and remote resources and greater reserve sharing and balancing over larger geographic areas.

These general requirements indicate that many aspects of the electric system may need to evolve substantially for high levels of renewable electricity to be deployed. Significant further work is needed to improve the understanding of this potential evolution, such as the following:

- A comprehensive cost-benefit analysis to better understand the economic and environmental implications of high renewable electricity futures relative to today's electricity system largely based on conventional technologies and alternative futures in which other sources of clean energy are deployed at scale
- Further investigation of the more complete set of issues around all aspects of power system reliability because RE Futures only partially explores the implications of high penetrations of renewable energy for system reliability
- Improved understanding of the institutional challenges associated with the integration of high levels of renewable electricity, including development of market mechanisms that enable the emergence of flexible technology solutions and mitigate market risks for a range of stakeholders, including project developers
- Analysis of the role and implications of energy research and development activities in accelerating technology advancements and in broadening the portfolio of economically viable future renewable energy supply options and supply- and demand-side flexibility tools.

Introduction

The Renewable Electricity Futures Study (RE Futures) is an initial investigation of the extent to which renewable energy supply can meet the electricity demands of the contiguous United States over the next several decades. It examines the integration of renewables into the grid with geographic, temporal, and electric system operation resolution that is unprecedented for long-term studies of high penetrations of a variety of renewable energy technologies across the entire contiguous U.S. electric sector.

The United States has diverse and abundant renewable resources, and renewable electricity generation capacity in the United States has increased considerably in recent years. Wind power additions in 2010, for example, totaled approximately 5 GW and constituted 25% of all electric capacity additions, with aggregate installed wind power capacity growing from just 2.5 GW at the end of 1999 to 40 GW at the end of 2010.[39] Solar additions have also shown significant growth in recent years, albeit from a smaller base, with 780 MW of grid-connected solar added in 2010, yielding a total installed capacity of 2.6 GW at the end of 2010. Biomass resources in the electric power sector added 267 MW in 2010, yielding a cumulative installed base of 6.7GW.[40] No new geothermal power was added in 2010; cumulative installed capacity therefore held constant at 3.4 GW. Hydropower capacity has been largely unchanged for many years, with just 23 MW added for the electric power sector in 2010. However, with 77 GW of total installed capacity, hydropower still contributes more electricity than all other forms of renewable energy combined.[41] Renewable energy in the electric power sector (excluding onsite generation) contributed 10% of total U.S. electricity supply in 2010 (6.4% from hydropower, 2.4% from wind energy, 0.7% from biopower, 0.4% from geothermal energy, and 0.05% from solar energy).[42]

[39] Wind power additions in 2009 were even greater than in 2010; wind installations totaled approximately 10 GW and constituted 29% of all electric capacity additions in 2009.

[40] If both the electric power and end-use sectors, such as power generation in the industrial sector, are considered together, biomass additions in 2010 totaled 346 MW, with cumulative installations of 13.2 GW. The end-use sector is distinguished from the electric power sector by North American Industry Classification System code. Code 22 is considered the electric power sector. For 2010 additions, however, comprehensive North American Industry Classification System code data do not yet exist. For this reason, to distinguish between the two sectors, the percentage breakdown for 2010 additions was assumed to be the same as that for annual capacity additions in 2009 (as per EIA Form 860 data).

[41] Wind capacity data are from the American Wind Energy Association (2011). Solar capacity data from the Solar Energy Industries Association/Greentech Media (2011) includes both grid-connected PV and CSP, and are expressed in terms of alternating current capacity. All other capacity data are from Ventyx (2010 additions) and from EIA's Form 860 database (cumulative through 2009).

[42] Contributions to U.S. electricity supply in 2010, in both the electric power sector, are primarily from EIA (non-solar) Form 923 data on estimated supply within the electric power sector (some of these data do not provide comprehensive North American Industry Classification System codes, in which case generation in the electric power sector was estimated to be proportional to the capacity in that sector relative to the total capacity in both the electric power and end use sectors); solar electricity generation includes all grid-connected utililty-scale solar installations and was estimated from cumulative capacity and assumed capacity factors for PV and CSP. If both the end-use and electric power sectors were considered, the percentage contribution from biomass would increase from 0.7% to 1.4%, and the contributions from solar would increase from 0.05% to 0.12%.

RE Futures was framed with a few important questions:

- The United States has diverse and abundant renewable energy resources that are expected to contribute higher levels of electricity generation over the next decades. Future renewable electricity generation will be driven in part by federal incentives and renewable portfolio standards mandated in many states.[43] Realistically, how much more can renewable energy technologies, in aggregate, contribute to future U.S. electricity supply?
- In recent years, as noted above, variable renewable electricity generation capacity from wind and solar photovoltaics in the United States has increased considerably. Can the U.S. electric power system accommodate much higher levels of variable renewable generation?
- Overall, renewable energy contributed about 10% of total power-sector U.S. electricity supply in 2010 from the diverse sources noted above. Are there synergies that can be obtained through combining these diverse sources, and to what extent can aggregating their output over larger areas help enable their integration into the power system?

Alaska, Hawaii, and the U.S. Territories were not included in this study because they rely on electric grid systems that are not connected to the contiguous United States. However, all three areas have abundant renewable resources and efforts are underway to substantially increase renewable electricity generation (see Text Box Introduction-1).

[43] Some states have targets of a 20%–30% share of total electricity generation (see http://www.dsireusa.org/ for information on specific state standards) and are making progress toward meeting these goals.

Text Box Introduction-1: Renewable Generation Opportunities in Alaska, Hawaii, and the U.S. Territories

While RE Futures explores high levels of renewable electricity generation in the contiguous United States, other efforts are underway to identify the future role of renewable generation in Alaska, Hawaii, and the U.S. Territories. Unlike the contiguous states, each of these areas has relatively small grid systems, (in many cases very small, isolated systems) and relies heavily on fossil fuel imports (primarily petroleum) for electricity generation. Each area also features large amounts of renewable resource potential of various types and high electricity prices, making renewable generation both a technically viable and cost-effective opportunity for consideration. Finally, each area is making good progress in efforts to substantially increase renewable electricity generation.

Hawaii is the U.S. state most dependent on fossil fuels for its energy supply (over 90%, see The State of Hawaii Data Book 2010) and with the highest average electricity cost. In 2008, the state established a goal to achieve 70% clean energy by 2030 for all energy use, including electricity, as part of a Hawaii Clean Energy Initiative. Ground transportation energy use is also included under the goal with potential pathways that include electric vehicles charged with renewable generation from the grid, vehicle fleet efficiency, reduction of vehicle miles traveled, and use of renewable fuels. A subsequent scenario analysis assessed the potential for high levels of renewable electricity generation across the Hawaiian Islands (Braccio et al. 2012) by evaluating scenarios with high and low levels of deployment of wind, solar, biomass, geothermal, ocean, and energy efficiency technologies, based on then current renewable resource data, electricity load information, economic factors, and potential grid impacts. The study concludes that the clean energy goal is achievable through 30% energy efficiency and 40% renewable generation that utilizes inter-island undersea transmission to access renewable resources available on islands with minimal loads. These efficiency and renewable generation levels were adopted in Hawaii State law as a 30% energy efficiency portfolio standard (EEPS) and a 40% renewable portfolio standard (RPS). Two additional studies, one still ongoing, address technical barriers associated with high levels of variable wind and solar photovoltaic generation, focusing on grid integration (Corbus et al. 2010 and University of Hawaii 2011) and undersea transmission. These studies employ power flow and dynamics modeling to evaluate the variable generation impacts at several seconds to minute time intervals. These studies also make recommendations of strategies for mitigating high levels of variable renewable generation on islanded grids, several of which have already been adopted by the utility company.

Alaska has a central grid system that serves the large portion of the state's population that resides in a relatively concentrated geographic area. However, the state also relies on more than two hundred small, isolated grid systems to serve remote villages, where electricity is sourced almost entirely from diesel generators and the cost of electricity can exceed $1 per kWh ($1000/MWh). Wind-diesel hybrid systems have become a major focus for diesel use reduction. The state is also home to the lowest temperature, electricity-producing geothermal resource in the world, at Chena Hot Springs, as well as the first community-owned hydrokinetic turbine, installed on the Yukon River in Ruby. A 2009 study assessed the broader potential opportunities across the state for renewable generation from biomass, geothermal, wind, and hydropower resource potential and estimated the potential capacity and associated cost of energy for each type of resource at any given location (WHPacific 2009). In addition, a study nearing completion explores how large-scale renewable generation without a grid or load nearby could be utilized in remote locations (Meyer et al. 2012). The development of these renewable resources, referred to as "stranded renewable," would require cost-competitive storage, transport, and/or co-location of energy-intensive industry.

The U.S. Territories generally utilize small, island systems that rely almost entirely on fossil fuel imports for generation, similar to Hawaii, with even higher costs of energy. Rich with renewable potential (e.g., solar, wind, waste-to-energy), these islands are prime opportunities for renewable generation. Scenario analyses to assess renewable resource potential, similar to that described above for Hawaii, have been completed for the U.S. Virgin Islands, Guam, America Samoa, and the Commonwealth of Northern Mariana Islands (Lantz et al. 2011, Davis et al. 2011, Burman et al. 2011, Baring-Gould et al. 2011a, Busche et al. 2011, Baring-Gould et al. 2011b). Detailed technical analyses to identify grid impacts and other potential barriers are required before strategies on high renewable penetration can be contemplated. Additional challenges in these locations include a dearth of locally available technical expertise, older generation systems, and grid systems with minimal upgrade potential.

RE Futures Overview

RE Futures assesses the challenges and implications of renewable electricity generation levels—from 30%–90%, with a focus on 80%, of all U.S. electricity generation from renewable technologies—in 2050. At such high levels of renewable electricity penetration, the unique characteristics of some renewable resources, specifically geographical distribution and variability and uncertainty in output, pose challenges to the operability of the U.S. electric system. The study focuses on some key technical implications of this environment, exploring whether the U.S. power system can supply electricity to meet customer demand with high levels of renewable electricity, including variable wind and solar generation. The study also begins to address the potential economic, environmental, and social implications of deploying and integrating high levels of renewable electricity in the United States.

Within the limits of the tools used and scenarios assessed, hourly simulation analysis indicates that estimated U.S. electricity demand in 2050 could be met with 80% of generation from renewable electricity technologies with varying degrees of dispatchability, together with a mix of flexible conventional generation and grid storage, additions of transmission, more responsive loads, and changes in power system operations.[44] Further, these results are consistent for a wide range of assumed conditions that constrained transmission expansion, grid flexibility, and renewable resource availability. While this analysis suggests such a high renewable generation future is possible, a transformation of the electricity system would need to occur to make this future a reality. This transformation, involving every element of the grid, from system planning through operation, would need to ensure adequate planning and operating reserves, increased flexibility of the electric system, and expanded multi-state transmission infrastructure, and would likely rely on the development and adoption of technology advances, new operating procedures, evolved business models, and new market rules.

Only technologies that are currently commercially available—biomass, geothermal, hydropower, solar photovoltaic (PV), concentrating solar power (CSP), and wind-powered systems—are included in this study. Some of these renewable technologies—such as run-of-river hydropower, onshore wind, hydrothermal geothermal, dedicated and co-fired-with-coal biomass—are relatively mature and well-characterized. Other renewable technologies—such as fixed-bottom offshore wind, solar PV, and solar CSP—are at earlier stages of deployment with greater potential for future technology advancements over the next 40 years. The issues surrounding large-scale deployment of all of these renewable technologies (resource potential, technology development and scale-up, and environmental impacts) are explored in this study.

The NREL ReEDS model was employed to explore the adequacy of the geographically diverse U.S. renewable resources to meet electricity demand over future decades, and the ABB GridView model was employed to explore the hourly operation of the U.S. grid with high levels of variable PV and wind generation. As such, an important subset of the critical electric system operation and expansion challenges and needs—transmission infrastructure expansion, increased

[44] The study did not conduct a full reliability analysis, which would include sub-hourly, stability, and AC power flow analysis.

deployment of energy storage technologies, and end use considerations for providing necessary flexibility and controllability—were explored in this study.

Specific policies—whether carbon cap-and-trade, renewable portfolio standards, or others—are not explored in detail in RE Futures. Rather, RE Futures focuses on exploring the implications of high levels of renewable electricity generation and not necessarily on how to achieve such levels through policy or other measures. This study focuses on technical issues associated with high levels of renewable electricity generation. As such, the scenarios (see Section 1.3) were designed to meet prescribed renewable electricity generation levels to explore technical issues associated with the operation of the U.S. electricity grid at these levels. The scenarios were not constructed to find the optimal greenhouse gas mitigation or clean energy pathway (e.g., to minimize carbon emissions or the cost of mitigating these emissions). In addition, because the scenarios included specific renewable generation levels, they were not designed to explore how renewable technologies might economically deploy under certain technology advancement projections without the generation constraints. However, to provide a cost context for the scenario results, estimated direct electricity sector costs and electricity prices associated with the various scenarios are presented in Appendix A. Several external impacts associated with reductions in fossil energy consumption, including GHG emission reductions and water use reductions are also discussed in Appendix A.

While RE Futures contributes to increased understanding of some of the technical, economic, and institutional challenges and opportunities associated with high levels of renewable energy generation in the U.S. electric sector, the analysis presented in this report is far from complete. Additional research would be required to more fully assess these challenges and opportunities, the market and regulatory changes that may be needed to facilitate such a transformation of the electricity system, as well as the costs and benefits of pursuing high levels of renewable electricity generation relative to non-renewable electricity generation options.

Report Organization

The RE Futures effort is documented in four volumes. This volume, Volume 1, describes the analysis approach and models along with the key results and insights from the analysis. The other volumes document in further detail the renewable generation and storage technologies included in the study (Volume 2), the end-use electricity demand and efficiency assumptions (Volume 3), and the operational and institutional challenges of integrating high levels of renewable energy into the electric grid (Volume 4).

Volume 1 begins with an overview of the analysis approaches and key assumptions used in the study. Specifically, Chapter 1 describes the study approach, the modeling tools, and the scenario framework used in this study; it also describes and compares characteristics of renewable generation technologies and the key challenges of integrating these technologies into the U.S. electric system. A summary of the results of the analysis begins in Chapter 2, which highlights the results of an initial exploratory analysis conducted to understand the impacts of increasing levels of renewable electricity penetration (30%– 90%) on the mix of renewable technologies deployed, transmission infrastructure, and overall electric system operations. Chapter 3 primarily focuses on results from various 80%-by-2050 renewable electricity penetration scenarios. To begin to address the inherent uncertainties in the 40-year span of this study, Chapter 3 focuses on assessing the sensitivity of the results (i.e., the mix of renewable technologies deployed, transmission infrastructure, and overall electric system operations) to input assumptions around end-use demand, renewable electricity technology advancement, renewable resource availability, transmission infrastructure, and system operational flexibility. Chapter 4 details the implications of integrating high levels of variable renewable electricity for the operation of the electric system; the results and discussion focus on challenges and operational options for ensuring that the power system is able to deliver remotely located renewable resources to load centers and to manage the balance between electricity supply and demand at an hourly level. Finally, Chapter 5 addresses some economic, environmental, and social implications of high renewable electricity futures; further details on these impacts are covered in Appendix A.

Chapter 1. Analysis Methods and Assumptions

1.1 Analysis Approach in Context

The Renewable Electricity Futures Study (RE Futures) is not the first study to explore the possibility of achieving high levels of renewable energy penetration. Interest in high-penetration renewable electricity deployment, primarily as a greenhouse gas (GHG) mitigation measure, is evidenced by recent studies of Europe (ECF 2010) and Germany (SRU 2010). These two studies and RE Futures share similarities, although the geographic system of focus differs between the studies. More recently, the Intergovernmental Panel on Climate Change Working Group III conducted a Special Report on Renewable Energy Sources and Climate Change Mitigation that "provides an assessment and thorough analysis of renewable energy technologies and their current and potential role in the mitigation of greenhouse gas emissions" (IPCC 2011). The globally focused Special Report on Renewable Energy Sources and Climate Change Mitigation report analyzes renewable electricity technologies more broadly than RE Futures.[45] While a few studies have been conducted for the United States, none has systematically evaluated a broad range of potential renewable electricity futures for the contiguous United States at the level of geographic, temporal, and electric system operation detail considered in RE Futures.[46]

Some of the key attributes that make RE Futures unique include the following. Specifically, RE Futures:

- has a geographic focus on the contiguous United States;
- evaluates renewable electricity penetrations that exceed 30% and reach 90%;
- explores the possible contributions of a large suite of renewable energy technologies;
- assesses, at a broad level, electric systems integration issues;
- evaluates the implications for new electric transmission;
- identifies where renewable energy might be deployed within the United States;
- estimates some of the environmental impacts of achieving such portfolios; and
- explores these factors across multiple assumptions and "what-if" scenarios.

To provide additional context and further frame this discussion of methods, a summary of what RE Futures is *not*, and what remains for further work follows[47]:

- RE Futures is *not* an estimate, prediction, or forecast of how the electricity sector will develop in the future or how it will respond to any particular set of policy efforts. In the

[45] Cochran et al. (2012) also describes several case studies of countries successfully managing high levels of variable renewable energy on their electric grids.

[46] Previous, more conceptual or more-limited analyses of high penetrations of renewable energy in the United States and globally include (but are not limited to) Pacala and Socolow (2004); ACORE (2007); Kutscher (2007); Greenblatt (2009); GWEC/GPI (2008); Fthenakis et al. (2009); Jacobson and Delucchi (2009); Sawin and Moomaw (2009); EREC/GPI (2008); and Lovins (2011).

[47] Summaries of the global and regional renewable energy scenarios literature can also be found in Hamrin et al. (2007) and Martinot et al. (2007).

United States, for example, the U.S. Energy Information Administration (EIA) regularly releases its Annual Energy Outlook (AEO) that summarizes a reference future, as well as a number of alternative futures (EIA 2010a; 2011c). The EIA, as well as the U.S. Environmental Protection Agency (EPA), are also regularly called upon to evaluate the possible impacts, costs, and benefits of Federal policy proposals, including carbon regulations (EIA 2009c; EPA 2009a; EIA 2010b; EPA 2010), clean energy standards (EIA 2011a; EIA 2011b) and renewable portfolio standards (EIA 2009a). Globally, the International Energy Agency provides a similar outlook (IEA 2011). RE Futures seeks to explore selected aspects of the features of and challenges associated with high-penetration renewable electricity futures without assessing how the energy sector might change in response to any particular policy change.

- RE Futures is *not* a fully detailed renewable energy integration study. Integration studies typically seek to understand the impacts of variable and uncertain wind and solar generation on the planning and operations of electric power systems and networks, relying on high time-resolution data and using methods that range from statistical analysis and production cost modeling to power flow simulations and steady state and transient grid analysis. These studies[48] typically focus on regional electricity systems, and although two recent DOE-funded efforts have explored integration issues across large sections of the Western and Eastern Interconnections (GE 2010; EnerNex 2010), these studies have not, thus far, focused on the United States as a whole. Detailed integration studies have typically evaluated variable renewable energy supply up to approximately 30%. RE Futures assessed electric systems integration issues of up to 50% variable renewables on a broader level and the modeling tools used considered the variability and uncertainty of some renewable technologies, but not to the level of detail as typically done by integration studies. Future work should expand on the assessment provided in RE Futures to include a more complete reliability and integration assessment.
- RE Futures is *not* an integrated modeling assessment of alternative carbon mitigation (or energy supply) pathways. A variety of models is currently used, in the United States and globally, to evaluate alternative pathways to meet energy demand and/or to mitigate GHG emissions and to assess the possible macroeconomic implications of those pathways. These studies can be global or regional in scope, typically cover all forms of energy supply (transport, heating and cooling, and electricity), and sometimes extend well beyond the energy supply sector to cover environmental and macroeconomic linkages.[49] Because of the broad geographic and sectoral scope of these efforts, a detailed technical, geographic, and temporal representation of various renewable supply options is not possible. RE Futures does not seek to evaluate the merits of such renewable electricity futures compared to other low-carbon technologies and pathways. Future work might emphasize these comparisons to a greater degree, including an assessment of integrated pathways that include multiple low-carbon technologies.

[48] Summaries of this literature are available in Gross et al. (2007), Smith et al. (2007), and Holttinen et al. (2009).
[49] For a summary of a recent multi-model comparison of global GHG reduction pathways using these integrated energy-environment-economy models, see Edenhofer et al. (2010); see also IPCC (2007).

- RE Futures is *not* a conceptual "roadmap" of high-penetration renewable energy futures. A variety of recent efforts have depicted roadmaps of the energy sector that involve steep increases in the use of renewable energy and corresponding drops in GHG emissions; many of these studies are largely conceptual in nature, while others conduct analyses of a subset of the technical and economic aspects of achieving such outcomes.[50] Although such assessments are not without merit, these studies sometimes focus on an individual renewable energy technology and typically do not contain the level of analysis required to understand in a detailed fashion the technical, geographic, and operational consequences of achieving such resource portfolios. RE Futures attempts to go beyond many of these efforts in terms of analytic breadth and depth, but unlike some of the studies cited here, maintains a narrow focus on renewable electricity use in the U.S. electricity sector.

1.2 Modeling Tools used in RE Futures

Building on previous efforts by DOE to evaluate technology-specific renewable penetration scenarios for wind (DOE 2008), RE Futures primarily employed two distinct electric-sector models: ReEDS and ABB's GridView. The linked-but-separate use of these two models allowed for a rich assessment of the technical, geographic, and operational aspects of renewable electricity deployment. Each of these modeling platforms is described below, as are their specific advantages and limitations given the needs of RE Futures. Additional details on the design and application of both models are provided in Appendix B and Short et al. (2011), while the limited treatment of electric system reliability in RE Futures is addressed below and in Text Box 1-1. Because the geographic scope of both models is the contiguous United States, RE Futures did not address Alaska or Hawaii.[51] Additional modeling and analysis tools used to supplement ReEDS and GridView are also described.

[50] Examples include Pacala and Socolow (2004); ACORE (2007); Kutscher (2007); Greenblatt (2009); GWEC/GPI (2008); Fthenakis et al. (2009); Jacobson and Delucchi (2009); Sawin and Moomaw (2009); and EREC/GPI (2008).

[51] Imports of electricity between the United States and Canada were considered, as described in Short et al. (2011); however, exchange of power between the United States and Mexico was not.

Text Box 1-1. Electric System Reliability

The North American Electric Reliability Corporation (NERC) defines a reliable bulk power system as one that is "able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity." NERC divides reliability into two categories, adequacy and security, as follows[52]:

- "*Adequacy* means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. *Resources* refers to a combination of electricity generating and transmission facilities, which produce and deliver electricity; and demand-response programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand."
- *Security* is "the ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes … as well as disturbances caused by man-made physical or cyber attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account …these risks to system security."

In assessing high-penetrations of variable renewable electricity, RE Futures addressed some aspects of electric system adequacy. In particular, the NREL ReEDS capacity expansion model handled limited aspects of adequacy, and did so using coarse time slices layered with statistical calculations (Short et al. 2011), but it nonetheless sought to ensure that adequate capacity and operating reserves would be available to match supply and demand. The statistical approach used in ReEDS addresses three major issues associated with the challenges of uncertain and variable resources: capacity value, forecast error, and curtailment. To supplement ReEDS, RE Futures also evaluated high renewable electricity scenarios based on an hourly resolution using the ABB GridView production cost model with security constrained unit commitment and economic dispatch. With GridView simulations, the frequency that load is served (and not served) on an hourly basis can be projected for different ReEDS scenarios, based on a finer time resolution and considering a greater number of constraints to the flexibility of conventional generation units. The RE Futures analysis also evaluated the power flow on the transmission system, again by relying on a coarse treatment from ReEDS and a DC load flow assessment from GridView. Neither model addresses system voltage (real and reactive) or frequency at the level of detail necessary to fully address system adequacy.

RE Futures did not conduct a full reliability assessment. Further analyses along these lines are warranted, although a complete analysis of power system reliability impacts and mitigation measures would require extensive additional efforts, including the following:

System Adequacy: To understand overall system adequacy fully, detailed simulations would be required to measure loss of load probability with the correct probability density functions of various power system variables. Many scenarios would need to be analyzed to understand whether the overall electric system has adequate system capacity to meet load under a variety of operating conditions. With conventional generation units, this type of study typically involves running reliability models using the forced outage rate and mean time to repair of the full suite of conventional units, while also considering possible changes in electricity demand, to estimate the loss of load probability. With high amounts of variable generation, analyses of this type become somewhat more difficult due to the unique behavior of variable generation. As discussed elsewhere, ReEDS addressed system adequacy largely on a statistical basis, whereas GridView was used to analyze a subset of the scenarios to determine whether loss of load would be expected in 2050. Further analysis of system adequacy would require an assessment of a broader array of scenarios, using GridView or alternative tools, as well as more detailed assessment of system voltage and frequency.

[52] NERC's definition of reliability can be found at http://www.nerc.com/page.php?cid=1%7C7%7C114.

High-Resolution Production Modeling: In most electricity systems today, load changes have somewhat regular patterns from one hour to the next, and within each hour, increasing during the morning period, and falling off in the evening. With high penetrations of variable renewable generation, however, net load (i.e., load minus variable generation) may vary irregularly and on shorter time frames than is presently the case. Running simulations at sub-hourly levels or even at sub-minute levels may be needed to understand fully the impacts of these changes in net load and assess the quantity of reserves needed to manage variability and forecast errors that occur within the hour. RE Futures relied on GridView for an hourly production simulation, but sub-hourly concerns were treated statistically, and were not specifically simulated with advanced modeling tools.

Power System Stability Studies: *Stability* is a condition of equilibrium between opposing forces, and maintaining power system stability is essential to ensuring a reliable electricity system. *Rotor angle stability* refers to maintaining synchronism between synchronous machines. *Small-disturbance* (small-signal) rotor angle stability refers to maintaining synchronism following small disturbances, and *large-disturbance* (transient) rotor angle stability refers to maintaining synchronism when subject to severe disturbances. A variety of studies are necessary to address these aspects of power system stability, including analyses of synchronism during transmission system faults as well as other studies that evaluate frequency response during loss-of-supply events. As one example of the issues in question, many variable renewable energy sources cannot currently respond to system-wide frequency deviations with off-the-shelf technology, and analyses are therefore needed to assess (1) future electricity systems in which substantial amounts of generation do not have frequency response capabilities and (2) new technologies that might be used to manage those possible deficiencies. *Voltage stability*, meanwhile, refers to the ability of a power system to maintain steady and acceptable voltages at all buses in the system under both normal conditions and following disturbances; growing shares of renewable energy generation may impact voltage stability. Regardless of the specific aspect of system stability under consideration, stability studies require very high time-resolution analysis, usually at the hundredths-of-second time scale but for only the first few seconds following disturbances. RE Futures did not assess power system stability under high-penetration renewable electricity futures.

AC Analysis: Many power system models use what is called a DC power flow assumption, which approximates how power flows on the system to enable readily solvable optimization programs. In practice, this means the voltage of the system is ignored, reactive power flows on the system are ignored, line losses are approximated, and small angle approximations are used for phase angles. For RE Futures, the ReEDS analysis modeled electricity transmission based on a simple transportation model, while the GridView analysis relied on a DC power flow assumption and, as a result, RE Futures (1) was unable to evaluate voltage issues that may exist in steady state, and (2) approximated actual power flows as well as line losses. A full AC analysis was not conducted with either model but would be needed to more accurately estimate power flows on the system and address these concerns.

Contingency Analysis: Power systems are typically designed for high reliability and therefore need to be secure following severe but credible contingency events. Real power systems are operated with various contingencies in mind, and careful consideration is required to determine which contingencies should be monitored and how the system should operate to maintain a stable system following contingency events. Analysis of such issues usually includes determining those contingencies that are most likely based on historical evidence, as well as those that are most severe based on contingency screening. A system with high levels of variable generation can make these tasks more difficult, and further research is needed to understand fully those implications. Although RE Futures addressed overall reserve requirement in a general fashion by ensuring contingency reserves are held, it did not include detailed analysis of contingency screening or ranking.

Additional information on these types of analyses can be found in Kundur (1994), Taylor (1994), Wood and Wollenberg (1996), NERC (2010), and Vittal et al. (2009). Volume 4 provides additional context on the reliability challenges of high-penetration renewable energy futures.

1.2.1 Regional Energy Deployment System Model (National Renewable Energy Laboratory)

Modeling future renewable energy scenarios requires tools that can accommodate the diversity of the various renewable energy technologies and applications, the location-dependent quality of many of these resources, and the inherent variability and uncertainty of wind and solar generation. Although no modeling tool can meet all needs simultaneously, ReEDS is the analytical backbone of RE Futures. ReEDS is a generation and transmission capacity expansion model of the electricity system of the contiguous United States, developed by NREL. ReEDS is unique among nationwide and long-term capacity expansion models for its highly discretized regional structure and statistical treatment of the impact of variability of wind and solar resources on capacity planning and dispatch.

More specifically, ReEDS is a linear program that minimizes overall electric system cost subject to a large number of constraints. The major constraints include meeting electricity demand within specific regions, regional resource supply limitations, planning and operating reserve requirements, state and federal policy demands, and transmission constraints. In satisfying these constraints, the ReEDS optimization routine chooses from a broad portfolio of conventional generation, renewable generation, storage, and demand-side technologies (see Text Box 1-2). Additionally, because of its detailed regional and temporal representation, ReEDS can estimate the costs of transmission expansion and operational integration.[53] The capacity expansion and dispatch decision-making of ReEDS considers the net present value cost of adding new generation capacity and operating it (considering transmission and operational integration) over an assumed financial lifetime (20 years). This cost minimization routine is applied for each 2-year investment period from 2010 until 2050. As a cost optimization model, ReEDS does not attempt to capture non-economic (e.g., behavioral, social, institutional) considerations in its investment and dispatch decision-making routine. These non-economic factors can be significant, particularly regionally, and further work is necessary to quantify their impacts.

This report focuses on the deployment of renewable and enabling technologies, the operational challenges of integrating high levels of variable and uncertain energy sources, and some of the environmental impacts of high renewable scenarios. As a cost optimization model, ReEDS relies on technology cost and performance projections in order to make its capacity expansion and dispatch decisions. Given the large uncertainty with future technology cost and performance over the long study period, different sets of technology cost and performance data were used in the ReEDS modeling to capture a range, albeit a limited one, of possible deployment scenarios. Section 1.3 qualitatively describes the technology assumptions used in the different modeled scenarios. Detailed technology cost and performance assumptions and the broader economic impacts from the ReEDS scenarios are presented in Appendix A, Volume 2, and Black & Veatch (2012).

[53] However, as described in Text Box 1-1, ReEDS and RE Futures do not explicitly examine many reliability criteria. In addition, ReEDS has limited representation of transmission power flow. These limitations are, in part, addressed by using the GridView model described in Section 1.2.2.

Text Box 1-2. Generation, Storage, and Demand Technologies Considered in RE Futures Modeling for New Builds[a]

Conventional Generation

- Pulverized coal
- Natural gas combined cycle
- Natural gas combustion turbine

Renewable Generation[b]

- Onshore wind
- Offshore wind (fixed bottom)
- CSP with and without thermal storage (only air-cooled)
- Utility-scale PV[c]
- Distributed rooftop PV[d]
- Dedicated biomass
- Co-fired biomass with coal
- Geothermal (hydrothermal) (only air-cooled)
- Hydropower

Storage

- PSH
- CAES
- Batteries

Demand-Side Technologies[e]

- Thermal energy storage in buildings
- Interruptible load
- Utility-controlled PEV charging

Generation Technologies *Not* Considered[f]

- Offshore wind (floating platform)
- Enhanced geothermal systems
- Ocean
- Nuclear
- Carbon Capture and Storage (coal, natural gas, biomass)

[a] ReEDS also represents existing municipal solid waste, landfill gas, and oil steam turbine plants, although "new builds" of these plant types were excluded in the model. Generation from existing municipal solid waste and landfill gas facilities was assumed to count toward the renewable energy levels evaluated in RE Futures and was counted in the dedicated biomass category.
[b] Only currently commercial renewable generation technologies were considered in RE Futures modeling.
[c] The utility-scale PV category in ReEDS encompasses all non-rooftop systems, including smaller (up to tens of megawatts) systems that are within the distribution network and larger systems. Short et al. 2011 describes the different model treatments for these systems.
[d] Rooftop PV deployment was estimated using the SolarDS model and was exogenously input into ReEDS.
[e] RE Futures does not include a comprehensive analysis of all demand-side technologies. The representative demand-side technologies and practices included in RE Futures are described in Volume 3 and the model implementation is described in Short et al. (2011).
[f] Although ReEDS has the technical capability to consider new nuclear plant builds, fossil technologies with CCS as well as gasified coal without CCS (integrated gasification combined cycle), RE Futures did not allow new plants of these types to be built in any of the analyses presented in this report because this report was focused solely on the potential role of renewable electricity technologies, and not on other low carbon or clean energy options. Existing nuclear (and integrated gasification combined cycle) units, however, were included in ReEDS, as were assumptions for the retirement of those units (see Appendix A).

ReEDS represents the contiguous United States[54] using 356 wind and solar (CSP) resource regions, 134 balancing areas (BAs), and 21 reserve sharing groups. This level of geographic detail enables the model to account for geospatial differences in resource quality, transmission needs, electrical (grid-related) boundaries, political and jurisdictional boundaries, and demographic distributions.[55] ReEDS dispatches generation within 17 different time slices (four time slices for each season representing morning, afternoon, evening, and nighttime, with an additional summer-peak time slice). This level of temporal detail—though not as sophisticated as that of an hourly chronological dispatch model, which is addressed in RE Futures using GridView and is described in Section 1.2.2—enables ReEDS to consider seasonal and diurnal changes in demand and resource availability. Moreover, because significant demand and resource variations can occur within each time slice, ReEDS uses statistical calculations to estimate the capacity value, forecast error reserves, and curtailment of wind and solar resources; these calculations also consider the correlations of output profiles between projects of the same type in different locations, between projects that rely on different resource types, and between different regional demand profiles.

The statistical calculations in ReEDS are used in multiple reserve and load balancing constraints in the model. At the longest timescales, ReEDS enforces a planning reserve requirement that ensures that there is sufficient generating capacity to exceed the annual forecasted peak demand hour by the requisite reserve margin.[56] At shorter hourly to sub-hourly timescales relevant to daily electric system operations, ReEDS requires sufficient supply- and demand-side technologies to satisfy operating reserve requirements. The operating reserves considered in ReEDS include wind and solar forecast error reserves, contingency reserves, and frequency regulation. Because contingency reserves and frequency regulation requirements are assumed to be established as a fraction of demand (6% for contingency and 1.5% for frequency regulation), they are independent of the amount of variable generation. In contrast, forecast error reserve requirements are estimated based on hourly persistence forecasts for wind and solar PV, and therefore increase as variable generation increases. ReEDS does not directly capture the wear-and-tear costs associated with operating the conventional thermal power plant fleet in a more flexible fashion: additional research on these costs and their implications for renewable energy integration are warranted.

In ReEDS, planning and operating reserves were assumed to be maintained independently in 21 reserve sharing groups for all years of the study period, representing greater cooperation over

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[54] ReEDS also represents net electricity imports from Canada into the contiguous United States based on projections by province from 2010 to 2020 (National Energy Board 2009). For the purpose of RE Futures, net imports from Canada were assumed to remain constant from 2020 to 2050, and to make up approximately 2% of U.S. electricity demand in 2050 under the low-demand assumption (see Section 1.4.1). The entirety of these net imports were assumed to be hydropower in RE Futures, but not to be dispatchable; seasonal and diurnal profiles were estimated based on EnerNex (2010). ReEDS does not represent energy transfers between the United States and Mexico.

[55] In ReEDS, BAs are the regional areas within which demand requirements must be satisfied. Although existing BA authority boundaries were considered in the design of the BAs, the BA boundaries are often not aligned with the boundaries of real BA authorities in order to accommodate other aforementioned boundaries (e.g., political boundaries).

[56] Regionally varying reserve margins ranging from approximately 12.5% to 17.2% were applied to planning reserve requirements.

larger areas than exist in the current grid. Existing regional transmission organizations and independent system operators[57] were used in the construction of some of the reserve sharing groups; where there was no existing regional transmission organization or independent system operator, a future reserve-sharing region was assumed. Some of these reserve-sharing groups were larger than those that currently operate under the assumption that additional market integration and transmission expansion over the next 40 years would expand current reserve-sharing regions.

For transmission, existing transmission infrastructure was assumed to continue to be operable throughout the study period, and existing line capacity was assumed to be usable by both conventional and renewable generation sources. For input to the ReEDS model, the existing transmission grid capacity and line location were estimated based on an analysis of interface transfer limits using GridView. The regional resolution of the ReEDS model allows it to roughly estimate new transmission expansion needs[58] and their associated investment requirements. The ReEDS model's deployment decision-making algorithm is therefore able to compare the total costs, including costs of additional required transmission infrastructure, of distant but higher-quality renewable resources with more local but lower-quality resources, based on generation and transmission cost considerations. In addition to the expansion of long-distance transmission lines, interconnection costs for new generation and storage technologies are considered in ReEDS. For wind and CSP technologies, additional interconnection supply curves are applied to account for the strong location-dependence of those resources, yielding total interconnection costs for these technologies that are generally greater than for other technologies. Short et al. (2011) provides a detailed description of these supply curves and of the transmission treatment in ReEDS. Implicit in the ReEDS treatment of transmission is that new transmission can be built within and between regions to enable access to renewable resources and leverage geospatial, temporal, and technological diversity between resources.

These measures were used to help ensure that ReEDS' RE Futures results are as detailed geographically and temporally as computational constraints allow, while also being consistent with an electricity system that is able to maintain an overall balance between supply and demand. In sum, ReEDS provides a means of estimating the type and location of conventional and renewable resource development; the transmission infrastructure expansion requirements of those installations; and the composition and location of generation, storage, and demand-side technologies needed to maintain balance between supply and demand. Additional detail on ReEDS can be found in Short et al. (2011).

Because ReEDS is not designed to account for distributed generation, the penetration of distributed (residential and commercial) rooftop PV capacity was exogenously input into ReEDS from NREL's Solar Deployment Systems (SolarDS) model. SolarDS is a market penetration

[57] Examples of existing regional transmission organizations and independent system operators include Midwest Independent Transmission System Operator; Independent System Operator New England; PJM Interconnection; Southwest Power Pool; and California Independent System Operator.

[58] ReEDS represents transmission using a transportation or pipeline model where electrical power is only limited by the carrying capacity of the lines and not by actual power flow limitations. The GridView model simulates transmission transfers using DC power flow modeling.

model for commercial and residential rooftop PV, which takes as input rooftop PV technology costs, regional retail electricity rates,[59] regional solar resource quality, and rooftop availability (Denholm et al. 2009a). Given the large uncertainty for many of these input parameters, including PV technology costs, the rooftop PV deployment scenarios presented in this report should not be interpreted as forecasts or predictions. PV is the only type of distributed generation represented by the models used in RE Futures.

1.2.2 GridView (ABB)

GridView is a commercial security constrained unit commitment and hourly security constrained economic dispatch model (designed and marketed by ABB) that simulates the financial operation of the electric power system with a constrained transmission grid based on a DC power flow assumption.[60] GridView commits and dispatches electric generating units in order to minimize the production cost of the system as a whole while meeting electricity demand and reliability reserve requirements. GridView models the same generation technologies as those represented in ReEDS, including thermal generators[61]; hydroelectric generators; and pumped storage, variable generators such as wind and PV, CSP with thermal storage, and compressed air energy storage. GridView also represents the same demand-side technologies as ReEDS, including interruptible load and utility-controlled plug-in hybrid or electric vehicle (PEV) charging.

In RE Futures, GridView was used to supplement the ReEDS analysis by modeling the hourly operation of the power system in 2050 under a sample of the high renewable scenarios and the baseline scenario. GridView results help to further demonstrate the operational feasibility of a system with high levels of renewable electricity penetration by using an hourly time step, a more accurate representation of thermal generation ramp-rate limits, and a more realistic representation of transmission power flows as compared to ReEDS.[62] In addition, GridView can simulate forecast error events for wind and solar PV based on day-ahead forecasts, which enables it to estimate how often reserves are relied on (at the hourly timescale), including interruptible load. As a result of these capabilities, GridView can analyze how the system responds to sharp and uncertain ramps in the output of variable generation, and provides a more complete understanding of the need for curtailment in times when generation supply exceeds demand; even with these capabilities, however, a full reliability assessment was not possible.

The GridView analysis used a subset of ReEDS scenario results for 2050 as inputs to the GridView modeling. The database of existing (2006) electric system infrastructure comes from three separate sources, one for each interconnect.[63] Transmission capacity and generator fleet

[59] AEO 2010 Reference Case (EIA 2010a) electricity prices (extrapolated to 2050) were used in SolarDS. Since RE Futures did not attempt to estimate highly uncertain *regional* electricity prices, retail prices from the ReEDS scenarios were not used in the SolarDS projections. Sensitivities using SolarDS with different electricity price assumptions were explored and showed only minor differences in rooftop PV deployment.

[60] For more information, see the GridView User's Manual, Version 6.0 (ABB 2008).

[61] The thermal generators modeled in GridView include generators that use conventional fuels (e.g., natural gas and coal) and renewable fuels (e.g., biomass and geothermal).

[62] For simulating transmission, GridView simulates DC power flow, whereas ReEDS has a simpler transportation or pipeline model for representing electric power transmission.

[63] The three sources are (1) the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee, (2) the Electric Reliability Council of Texas, and (3) the North American Electric Reliability Council

expansion projections from ReEDS were also input into GridView as individual new units and lines, subject to the assumptions detailed in Appendix B. The electric power systems represented in these various data sets were merged into a single database[64] and centrally dispatched to minimize production cost on a national basis. Nationwide dispatch is an inherent feature of the modeling framework and can be interpreted as either a single system operator that manages the entirety of the U.S. electric system or alternatively, frictionless markets between separate system operators. Nationwide dispatch results in the lowest-cost energy supply solution for the United States as a whole, given the assumptions used. Although economic dispatch was assumed at the national level in both GridView and ReEDS, planning and operating reserves were still assumed to be maintained regionally (at the same 21 reserve-sharing group level as in ReEDS). Although the transmission system in GridView is capable of operating in a detailed nodal format (where every major substation and transmission line is modeled individually), computational constraints and the spatial resolution of the ReEDS output limited the GridView analysis conducted in RE Futures to a more-coarse zonal format (where transmission constraints were modeled only across the interfaces between the 134 assumed BAs, as defined in ReEDS). Additional assumptions specific to the GridView modeling are detailed in Appendix B; details are also available on the GridView model (Feng et al. 2002) and previous studies (Liu et al. 2009).

1.3 Scenario Framework

1.3.1 Overall Scenario Framing

The scenarios postulated in RE Futures, while not intended to be policy proscriptive, are set in the context of a world in which carbon emissions reductions and a diversification away from fossil energy is sought. For purposes of this study, this implies the following:

- **Energy Efficiency:** Most of the scenarios assumed significant adoption of energy efficiency (including electricity) measures in the residential, commercial, and industrial sectors that resulted in flat demand growth over the 40-year study period.[65]
- **Transportation:** Most of the scenarios assumed a shift of some transportation energy requirements away from petroleum and toward electricity in the form of electric and plug-in hybrid electric vehicles, partially offsetting the electricity efficiency advances that were considered.[66]
- **Grid Flexibility:** Most scenarios assumed improvements in electric system operations to enhance flexibility in both electricity generation and end-use demand, helping to enable more efficient integration of variable-output renewable electricity generation.

Multiregional Modeling Working Group, with proprietary updates from ABB. Location information is from the Transmission Atlas by Energy Visuals, Inc. (http://www.energyvisuals.com/products/ta.html)

[64] The three interconnections are currently connected with high-voltage DC transmission lines, and the extent to which these connections are increased are represented by the ReEDS and GridView models.

[65] The efficiency gains assumed are described in Volume 3. They do not represent an upper bound of energy efficiency; i.e., they not as large as estimated by NAS/NAE (2010).

[66] The contribution of biofuels to the transportation sector is not quantified in RE Futures. The flat demand (low-demand) projection included this increase in demand from the transportation sector, whereas the business as usual demand (high-demand) projection did not.

- **Transmission:** Most scenarios expand the transmission infrastructure and access to existing transmission capacity to support renewable energy deployment. Distribution-level upgrades were not considered.
- **Siting and Permitting:** Most scenarios assumed project siting and permitting regimes that allow renewable electricity development and transmission expansion with standard land-use exclusions.

In all of the scenarios included in this analysis, only currently (as of 2010) commercially available renewable energy technologies were considered, including wind (onshore and fixed-bottom offshore); solar (utility PV, rooftop PV, CSP); geothermal (hydrothermal); biomass (dedicated and co-fired with coal); and hydropower. Further, only incremental or evolutionary improvements in the technologies were considered despite the long-term (2050) timeframe. RE Futures Volume 2 also discusses the potential importance of renewable energy technologies that are currently under development and pilot testing—and which show significant promise but are not yet generally commercially available at scale, including, but not limited to, various types of ocean energy, enhanced geothermal systems, and floating-platform offshore wind, that may become available with enhanced and successful research and development investments. Although RE Futures did not evaluate these currently non-commercial technologies in its modeling scenarios, that choice does not imply that these technologies will not play important roles in the future U.S. energy sector and does not imply that research and development in these technologies is not warranted. In fact, some or all of these technologies may become commercially available during the timeframe of the RE Futures analysis (2010–2050), and in that instance would be expected to further diversify the renewable energy resource mix relative to what is estimated in this report.

Deployment of renewable energy is accomplished in ReEDS by imposing specific annual renewable electricity generation requirements by 2050, ranging from 30% to 90% of annual electrical demand (see Section 1.3.2). No requirement is imposed on renewable capacity. Curtailed renewable electricity, transmission losses associated with renewables, and storage inefficiencies were not counted toward the renewable electricity penetration level.[67] Requirements for intervening years were established based on an assumed linear increase in renewable generation from 12% by the end of 2010[68] to the prescribed fractions by 2050.[69] The ReEDS model then optimized the mix and location of renewable electricity technologies while satisfying the simple operational and reliability criteria and still achieving the prescribed

[67] Specifically, the annual percentage of renewable electricity (e.g., 80%) is defined by the following equation: $\%RE = (Generation_{RE} - Curtailment - TransLoss_{RE} - StorLoss_{RE})/Demand_{BB}$, where $Generation_{RE}$ is the total potential (non-curtailed) generation from renewable resources; Curtailment is the amount of energy potentially available from non-dispatchable energy sources (e.g., wind and solar PV) but not generated due to a lack of demand; $TransLoss_{RE}$ is the transmission losses estimated to be associated with renewable energy; $StorLoss_{RE}$ is the storage losses estimated to be associated with renewable energy; and $Demand_{BB}$ is the annual bus-bar demand (i.e., the amount of energy that needs to be delivered to the bus-bar in order to accommodate distribution losses and meet annual end-use customer load).

[68] The 12% renewable generation by the end of 2010 includes imports from Canada, which are assumed to be renewable. Excluding the imports from Canada, renewable generation comprised approximately 10% to total electricity supply in the contiguous United States in 2010.

[69] Alternative intermediate targets were not evaluated, and would lead to differing results.

renewable generation levels. The balance of necessary generation was similarly met by ReEDS' selection of the mix of modeled conventional technologies (based on the assumed input costs, characteristics, and policy and market conditions), while still ensuring an overall supply-demand balance and that reserve requirements are met.

Rather than postulating the explicit extension of existing or enactment of new state or federal policies, the analysis instead largely assumed that existing state renewable portfolio standard programs and federal tax credits (e.g., investment tax credit, production tax credit) would continue only as allowed under existing law[70]; possible extensions of or additions to those policies were not considered.[71] Tax depreciation rules designed to benefit certain renewable energy technologies were assumed to follow current law. Indirect incentives for conventional energy technologies—sometimes delivered through the tax code—were assumed to be maintained. Carbon policies were assumed to not be enacted or in force, and air pollution regulations were assumed to remain as they currently stand despite ongoing efforts to enact more-stringent environmental standards.

This approach allowed for a relatively straightforward comparison among modeled scenarios based on electric system characteristics without discriminating among technologies based on policies that may or may not be extended or that may or may not come into existence over the study period (2010–2050). The above assumptions were made simply to enable this comparison, and in no way represent policy recommendations; the use of these assumptions in the analysis is not intended to suggest that existing or new renewable energy, climate, or air pollution policies are valuable or warranted, or not, or that the energy technologies are on a level playing field with respect to direct and indirect subsidies. Moreover, because future state and federal policies and regulations will assuredly differ from those assumed here, some caution is warranted in interpreting the results presented in this report. As an example, the future role of fossil energy power plants, and the relative contribution of generation sourced from coal and natural gas, will be influenced by a number of considerations, including future regulatory and policy decisions, fuel prices, and power plant operational practices. The uncertainty associated with each of these considerations is discussed in Text Box 1-3.

[70] Federal and state incentives for the distributed market are represented in the SolarDS model for rooftop PV.

[71] Current statute specifies the expiration of the production tax credit by 2012 or 2013 (depending on the technology, 2012 for wind energy, 2013 for other technologies), while the investment tax credit for solar and geothermal drops to 10% (in 2016 for solar, and earlier for geothermal). The 10% investment tax credit for solar and geothermal has no legislatively established expiration, but to avoid modeling outcomes that are impacted by such preferential long-term policy decisions, the analysis assumed the expiration of the 10% investment tax credit in 2030. This modeling choice was not intended to represent any policy recommendation, nor to discount the potential role of such mechanisms to impact market development for new technologies.

Text Box 1-3. Uncertainties on the Future Role of Fossil Energy Power Plants

Real-world decisions to dispatch existing power plants, retire old plants, or install new capacity are based on numerous, interlinking factors. These decisions are generally based on power plant economics, as impacted by technical as well as legislative and regulatory constraints. Uncertainties in future economic and regulatory environments, as well as technical needs and capabilities, also lead to uncertainties on the future use of various types of power plants. Although RE Futures forecasts a specific role for fossil energy power plants in various baseline and high-penetration renewable electricity scenarios, those forecasts are constrained by input assumptions. In reality, the future role of fossil energy power plants is highly uncertain due to factors including, but not limited to, the following:

1. **Environmental regulations** can and do vary over time. Some of the regulations currently being considered and developed by the EPA include: The Cross States Air Pollution Rule (formerly known as the Clean Air Transport Rule or Clean Air Interstate Rule) to reduce long-range transport of low-level ozone and particulate matter; the National Emission Standards for Hazardous Air Pollutants (also referred to as the Mercury Air Toxics Standard or Maximum Achievable Control Technology standard) to reduce mercury and toxic emissions; Section 316(b) on Cooling Water Intake Structures of the Clean Water Act to minimize the impact of cooling water withdrawal on aquatic life; Coal Combustion Residuals to minimize risk associated with coal ash disposal; and National Ambient Air Quality Standard updates. Congress or the Supreme Court mandates these rulings, although there are some efforts in Congress to restrict the EPA's authority to implement the new rules. Implementation of several rules has been significantly delayed (the Cross States Air Pollution Rule, Mercury Air Toxics Standard, and National Ambient Air Quality Standard). Although most rules are still under draft development, they are expected to be implemented in some form between 2012 and 2018.

   There is significant uncertainty over the projected impacts of these new rules, especially because important details remain to be finalized. However, older, existing coal-fired generators, in particular, are likely to be the most affected because they would face decisions over whether to install new environmental compliance equipment or to retire the units. Significant retirements have been predicted in some studies (e.g., ICF 2010; Wynne et al. 2010; M.J. Bradley and Analysis Group 2010; PIRA 2010; NERC 2010). Moreover, it is possible that environmental regulations will become increasingly stringent even after these new rules are put into place, further encouraging plant retrofits or retirements. *(For a subset of the older coal-fired generators, uncertainty in retirement decisions would likely be present even without new environmental regulations, particularly given the long time frame of this study.)*

2. In recent years, the U.S. Congress has considered *carbon policies* (e.g., American Clean Energy and Security Act of 2009 and American Power Act of 2010) and, although no federal carbon legislation has been enacted into law, carbon policies could be re-visited in the coming years and decades. In addition, the EPA is in the process of developing regulatory measures associated with GHG emissions, including the New Source Review, the Title V Greenhouse Gas Tailoring Rule, and additional phased GHG mitigation efforts. There have also been state and regional efforts to curb carbon and other GHG emissions (e.g., Regional Greenhouse Gas Initiative), which, depending in part on the fate of federal carbon legislation, may become more or less prevalent over time.

   The significance of carbon policies on electric sector investments and operations depends strongly on the specific design of potential legislation or regulations. However, analyses of recently considered federal carbon and clean energy policies indicate that these policies could cause a dramatic shift in electric power generation away from conventional coal-based generation, and toward lower carbon-emitting generation sources (EPA 2009a, 2010; EIA 2009c, 2010b, 2011a, 2011b). Moreover, even in the absence of legal requirements to limit carbon emissions, the perceived risk of possible future implementation of carbon regulation may reduce the level of investment in new coal-based generation capacity.

3. **Fossil energy prices** are uncertain and can alter dispatch and investment decisions among different fossil plants. The historical variability and uncertainty in natural gas prices, in particular, has caused substantial changes in the dispatch and investment in natural gas plants over time. Moreover, forecasts of future natural gas prices have been decidedly poor and, because future fossil generation mixes are strongly dependent on these forecasts, those mixes are also highly uncertain. In addition, new discoveries or sources of fossil energy can significantly alter future fossil energy price expectations. For example, new discoveries and recovery practices for shale gas may help stabilize and lower natural gas prices below what has been observed historically, thus increasing the share that natural gas power plants contribute to electric generation (MIT 2010; EIA 2010b), although countervailing environmental concerns may limit those impacts.

4. **New power plant operational needs and practices** are likely to become more common with higher levels of variable and uncertain generation supply from wind and solar, in particular. Specifically, greater operational flexibility in fossil energy power plants, including more frequent and greater cycling and ramping, may be required to accommodate the additional variability in renewable energy supply. Some recent studies have shown that operation and maintenance (O&M) costs, emissions, and heat rates may be negatively affected by this increased need for operational flexibility (Göransson and Johnsson 2009; Troy et al. 2010; Agan et al. 2008). These impacts are expected to influence the future role of coal and natural gas power plants, particularly when high levels of renewable electricity sources are deployed, but remain uncertain and may be mitigated by new technical solutions for new generating units and retrofitting existing units (Tilley and McCalla 2004) to enable greater operational flexibility with a lower cost penalty. However, some new power plants, particularly natural gas combustion turbine and combined cycle plants, are designed for flexible operation without these penalties. Further work is needed to more accurately understand and quantify these impacts.

The uncertainties in these factors, and their numerous potential combinations, prevent their full consideration in RE Futures. The models and analyses included in RE Futures partially address these issues by including the following: (1) a SO_2 cap based on the Clean Air Interstate Rule requirements issued by the EPA in March 2005; (2) additional carbon policy regulatory risk for new coal generators based on the methodology used in EIA (2010a); and (3) additional operational costs for fossil unit ramping and cycling (see Short et al. 2011 for details). Nonetheless, the uncertainties described above may lead to future fossil energy generation decisions that differ markedly from those reflected in RE Futures. These differences would appear in the baseline scenarios, but also in the residual fossil energy generation mix for the higher renewable scenarios. For example, some combination of new environmental regulations, a federal carbon policy, increased accessibility of shale gas, and the need for greater fossil plant operational flexibility might be expected to lead to greater amounts of natural gas generation compared with what is presented in RE Futures. In addition, because of the coarse temporal resolution of the "timeslices" used in ReEDS, electric generation for ancillary services is not estimated in ReEDS, and electricity generation from natural gas generation is therefore likely underestimated. While the results presented in RE Futures reflect only a narrow range of possible future pathways for fossil energy generation given the narrow range of input assumptions, different outcomes even for this narrow range are possible.

1.3.2 Modeled Scenarios

Given the inherent uncertainties involved with analyzing alternative long-term energy futures, and given the multiple pathways that might be taken to achieve higher levels of renewable electricity supply, more than two dozen future scenarios were analyzed. Specifically analyzed were a broad array of different scenarios that should help characterize and loosely bound the possible challenges and implications of achieving renewable energy deployment of up to and exceeding 80% renewable electricity by 2050, while also exploring the impact of certain institutional, technical, and market drivers on the implications of such scenarios. The framework included scenarios with specific renewable electricity generation levels to enable exploration of some of the technical issues associated with the operation of the U.S. electricity grid at these levels.[72] Figure 1-1 shows the scenarios modeled in RE Futures and a description of the scenarios follow.

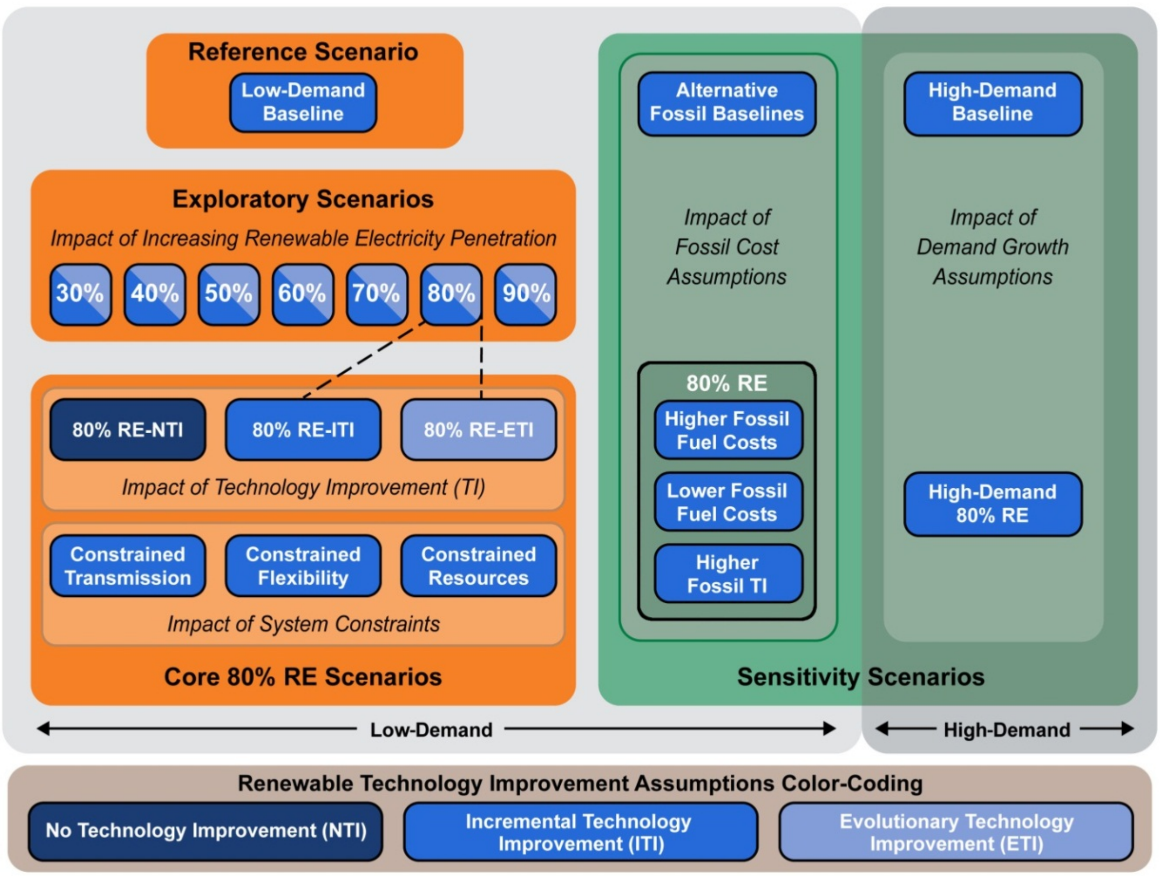

Figure 1-1. Modeling scenario framework for RE Futures

Dotted lines indicate that the 80% RE exploratory scenarios are the same as the 80% RE-ITI and 80% RE-ETI scenarios.

[72] The scenarios were not constructed to find the optimal GHG mitigation or clean energy pathway (e.g., to minimize the carbon emissions or the cost of mitigating these emissions). In addition, because the scenarios included specific renewable generation levels, they were not designed to explore how renewable technologies might economically deploy under certain technology advancement projections without the generation constraints.

1.3.2.1 Reference Scenarios

The RE Futures analysis began with the construction of a "reference" scenario (Low-Demand Baseline scenario), to which the other (low-demand[73]) renewable energy scenarios were compared. Projected electricity demand growth under the Low-Demand Baseline scenario, and all other scenarios except otherwise noted, was assumed to be lower than historical trends would otherwise suggest, as described in Section 1.4.1. The adoption of energy efficiency measures and technologies as projected in the lower demand scenario restricts growth of all supply technologies, in both the baseline scenarios as well as the higher renewable scenarios. *The Low-Demand Baseline scenario was not intended to predict the future of electricity supply in the United States but was instead designed to reflect a largely conventional generation system as a point of comparison.* In particular, the Low-Demand Baseline scenario assumed that renewable energy deployment would expand, as it is economic to do so, considering the assumed improvements in technology cost and performance and any influence by existing state and federal policies. Existing renewable energy policies at the state and federal level were (largely) assumed to continue only as dictated by current law; extensions of or additions to those policies were not considered.[74] For example, current federal production tax credits for wind end in 2013, and investment tax credits for solar drop from 30% to 10% in 2017, and then continue at the 10% rate. To ensure level treatment of renewables in the longer-term modeling, even this 10% solar investment tax credit was assumed to end in 2030, despite current statutory authority that it continue. Similarly, no carbon policies were assumed to be enacted or in force, and air pollution regulations[75] were largely assumed to remain as they currently stand despite ongoing efforts to enact more-stringent environmental standards (see Text Box 1-3). On net, these assumptions allowed the construction of a baseline scenario that served as a useful (albeit limited) reference for the high-penetration renewable electricity futures that were the focus of RE Futures. However, because state and federal policies will assuredly differ from those assumed here, some caution is warranted in interpreting the deployment in this no-new-policy Low-Demand Baseline scenario. Finally, to be clear, these assumptions were not intended to suggest that extensions of or new renewable energy, climate, or air pollution policies are not valuable or are not warranted because the RE Futures analysis did not evaluate the costs and benefits of such policies.

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[73] Assumed electricity demand projections, including low-demand and high-demand, are described in Section 1.4.1. In short, *low-demand* refers to a projection in which future total electricity demand does not differ greatly from today, whereas *high-demand* refers to a demand growth projection that follows historical demand growth trends and is largely based on the demand growth trends from the reference case of EIA's 2010 AEO (EIA 2010a). RE Futures Volume 3 describes the assumptions that went into the low-demand and high-demand projections, and includes a comparison of potential efficiency gains reflected in these projections relative to other independent demand projections.

[74] Specifically, existing state renewable energy policies (e.g., renewable portfolio standards) and existing federal renewable energy policies (e.g., investment tax credit, production tax credit, tax depreciation) were assumed to continue only as allowed under existing law, with no extensions. Indirect incentives for conventional energy technologies—sometimes delivered through the tax code—were assumed to be maintained. In addition, to facilitate later comparisons with other cases, the baseline scenarios excluded distributed PV technologies. Distributed rooftop PV deployment was determined exogenously from the core model used in this analysis (ReEDS); as such, it was inappropriate to include distributed rooftop PV in a baseline scenario that was intended only as a comparison scenario in which little renewables are deployed. The assumption of no rooftop PV deployment was a simplifying assumption and does not reflect the current deployment levels and possible growth in the rooftop PV market.

[75] A SO_2 cap based on EPA's Clean Air Interstate Rule from 2005 is applied in ReEDS for all scenarios; however, as described in Text Box 1-3, these rules are currently under revision.

To account for the range of future demand possibilities, a second reference scenario, the High-Demand Baseline scenario, was developed to represent, to some degree, "business-as-usual" trends in energy consumption as described in Section 1.4.1.

1.3.2.2 Exploratory Scenarios

A series of "exploratory scenarios" was then evaluated in which the proportion of renewable electricity in 2050 increased, in 10% increments, from 30% to 90%. The primary purpose of these exploratory scenarios was to assess how increased levels of renewable energy deployment might impact the generation mix of renewable and non-renewable resources, the extent of transmission expansion in these cases, and the use of various forms of supply- and demand-side flexibility to enable a match between supply and demand. In particular, these exploratory scenarios were evaluated to identify whether or not technical obstacles were observable as renewable deployment levels increased. The lower demand assumptions were used for all of these scenarios. These exploratory scenarios were evaluated under two distinct sets of renewable electricity technology advancement assumptions: Incremental Technology Improvement (RE-ITI) and Evolutionary Technology Improvement (RE-ETI), described in the next section.

From this set of exploratory scenarios, a renewable electricity penetration level of 80%-by-2050 was selected for further analysis in the remainder of the report. Although the selection of 80% renewable electricity was, to a degree, arbitrary, it allowed for a robust assessment of some of the implications of achieving high-penetration RE Futures. This assessment included an analysis of six core 80% RE scenarios, each of which met the same 80%-by-2050 renewable electricity penetration level and each of which was designed to elucidate the possible impact of certain institutional, technical, and market conditions. All six of these core 80% RE scenarios described below relied on the lower demand assumptions.

1.3.2.3 Core 80% RE—Technology Improvement Scenarios

Given uncertainty in future renewable energy costs, the core 80% RE scenarios included three scenarios that explored the impacts of future renewable electricity technology advancements of currently commercial technologies and the resulting deployment of different combinations of renewable energy technologies[76]:

- The No RE Technology Improvement (80% RE-NTI) scenario simply assumed that the performance of each renewable technology was maintained at 2010 levels for all years in the study period (2010–2050).
- The Incremental RE Technology Improvement (80% RE-ITI) scenario reflected only partial achievement of the future technical advancements that may be possible (Black & Veatch 2012).

[76] Although the methods used in RE Futures to project the future cost of each renewable electricity technology differ to some degree by technology, the resulting forecasts are largely based on anticipated scientific and engineering advancements rather than on learning-curve-based estimates that are endogenously driven by an assumed learning rate applied to cumulative production or installation. In reality, costs may decline in part due to traditional learning and in part due to other factors, such as research and development investment, economies of scale in manufacturing, component, or plant size, and reductions in material costs. Performance estimates for conventional (fossil and nuclear) and storage technologies were not varied among these modeled scenarios.

- The Evolutionary RE Technology Improvement (80% RE-ETI) scenario reflected a more complete achievement of possible future technical advancements based on the engineering improvements described in Volume 2. The RE-ETI scenario is not designed to be a lower bound and does not span the full range of possible futures; further technical advancements beyond the RE-ETI are possible.[77]

The 80%-by-2050 renewable electricity scenarios under these different technology improvement assumptions are referred to as 80% RE-NTI, 80% RE-ITI, and 80% RE-ETI, respectively. The RE-ITI and RE-ETI projections assumed greater future advancements for those technologies that are at earlier stages of technological development (e.g., solar) than those technologies that are more commercially mature (e.g., onshore wind, hydropower, geothermal). In particular, the projections assumed greater improvements in performance for concentrating solar and PV technologies compared with the other technologies evaluated. *These renewable energy improvement projections were not intended to encompass the full range of possible futures. Greater performance improvements are possible; therefore, different deployment scenarios may result from these greater improvements. Specifically, the technology improvement estimates used in RE Futures modeling do not reflect improvements that may be realized by DOE technology program activities or related research, development, or demonstration initiatives for any of the renewable technologies.*[78] (For analytic simplicity, only the RE-ITI projections were used for the Low-Demand Baseline scenario.)

1.3.2.4 Core 80% RE—Constraint Scenarios

Also included in the six core 80% RE scenarios were a set of three scenarios that explored the impacts of different electricity system constraints based on assumptions that limited the building of new transmission, reduced system flexibility to manage the variability of wind and solar resources, and decreased renewable resource availability as follows:

- The Constrained Transmission scenario evaluated how limits to building new transmission might impact the location and mix of renewable resources used to meet an 80%-by-2050 future.
- The Constrained Flexibility scenario sought to understand how institutional constraints to and concerns about managing the variability of wind and solar resources, in particular, might impact the resource mix of achieving an 80%-by-2050 future.
- The Constrained Resources scenario posited that environmental or other concerns may reduce the developable potential for many of the renewable technologies in question, and evaluated how such constraints could impact the resource mix of renewable energy supply.

The deployment of renewable technologies to achieve 80% renewable electricity by 2050 is sensitive to certain technological, institutional, and market drivers. This subset of the core 80% RE scenarios were designed to explore the sensitivities to these drivers by varying one set of

[77] Indeed, current DOE initiatives such as the SunShot Initiative (DOE 2012) are focused on achieving substantially better cost and performance in many cases.

[78] In particular, none of the technology improvement estimates for the solar technologies represent improvements sought by the SunShot initiative; discussion of the SunShot initiative can be found in Chapter 10 (Volume 2).

assumptions at a time. For analytic simplicity and ease of comparison, these constrained scenarios used the incremental renewable technology improvement estimates (RE-ITI).

1.3.2.5 High-Demand Scenario

In addition to the six core 80% RE scenarios, all of which applied the lower electricity demand assumptions, a High-Demand 80% RE scenario was evaluated using a set of higher demand growth assumptions. Again, for the purpose of analytic simplicity, the High-Demand 80% RE scenario used the incremental renewable technology improvement estimates. The designs of the two demand scenarios analyzed in RE Futures are described in more detail in Section 1.4.1.

1.3.2.6 Fossil Cost Scenarios

Uncertainty exists about the cost of conventional energy technologies, and varying the cost of these technologies will alter the predicted impact of meeting an 80% renewable electricity future in comparison to the baseline scenarios. Therefore, RE Futures also evaluated 80%-by-2050 renewable electricity future scenarios (and related baseline scenarios) in which (1) the cost of fossil fuel (coal and natural gas) was both higher and lower than otherwise assumed in the other scenarios (80% RE-Higher Fossil Fuel Costs and 80% RE-Lower Fossil Fuel Costs scenarios), and (2) the cost of fossil energy technologies was lower than the assumptions used in the other scenarios (80% RE-Higher Fossil Technology Improvement [Fossil-HTI] scenario). The primary purpose of this set of fossil energy cost and technology improvement sensitivity scenarios is to evaluate how future fossil fuel and technology behavior might impact the *implications* of high renewable electricity scenarios; the results of these scenarios are presented in Appendix A only. Again, for the purpose of analytic simplicity, the fossil sensitivity scenarios used the incremental renewable technology improvement estimates (RE-ITI).

1.4 Summary of Key Assumptions

The results of the analysis presented in this report are driven by key assumptions, and the time horizon of the analysis (until 2050) ensures a large degree of uncertainty in those assumptions. Critical assumptions around demand, conventional generation, renewable resource potential, and grid operations are highlighted below. Deviations from these assumptions in the model scenarios are described in the following sections. In general, these assumptions were developed based on a review of the published literature and in consultation with external subject matter experts. Appendix A, Appendix B, Volume 2, Volume 3, and Short et al. (2011) provide detailed descriptions of the many assumptions that underlie RE Futures.

1.4.1 Electricity Demand

In 2008, end-use electricity demand in the United States totaled approximately 3,700 TWh. The buildings sector comprised the bulk of electricity consumption, with residential buildings making up 37% of demand, and commercial buildings representing another 36%. Within the buildings sector, the primary end uses for electricity are air conditioning and lighting, although electronics, computers, and office equipment represent a growing share. Electricity use in industry accounted for approximately 26% of total demand, with more than 50% of that electricity used to power electric motors. The transportation sector represented just 0.2% of electricity demand in 2008 (EIA 2010a).

Historically, increases in electricity consumption have primarily been driven by population growth and economic growth. In general, the demand for goods and services, and the associated energy required to meet those demands, has scaled with population. Similarly, economic growth increases disposable income and has historically increased demand for technologies and services, also resulting in rising electricity demands. In RE Futures, assumptions of future electricity demands took both of these demand drivers into account. Going forward, a diversification away from fossil energy and a reduction in carbon emissions may become important and could impact the way in which and the amount of energy consumed. These emerging trends may oppose the historically observed effects of population and economic growth on overall energy consumption, and may impact the development of new electricity-using devices.

To account for the range of future demand possibilities, two electricity demand projections were used in RE Futures: a low-demand projection and a high-demand projection. Both demand projections relied on the same assumptions for population growth and economic growth. The low-demand projection was used in most of the analysis, and assumed that a combination of innovation, societal attitudes, and policy drives the adoption of energy efficiency measures. Within the buildings sector under the low-demand projection, an increased emphasis on integrated design, retrofits that improve the performance of the building shell, building codes and appliance standards that are more stringent, and the availability of more efficient equipment led to reductions in overall electricity intensity of 60% from today's levels in new buildings and 30%–40% in existing buildings by 2050.[79] Within the industrial sector, increases in the efficiency of motors and other processes combined with a slower growth rate of the more energy-intensive manufacturing industries reduce consumption. Finally, under this particular future, 40% of the personal vehicle stock was comprised of PEVs by 2050. In aggregate, these trends were estimated to result in overall electricity consumption of 3,920 TWh in 2050 (comprised of 35% residential, 37% commercial, 18% industrial, 1% non-PEV transportation, and 9% PEV), as shown in Figure 1-2.[80] In summary, as a consequence of these various efficiency improvements (changes in demand, increased use of PEVs, and other assumptions), the low-demand projection includes very low-demand growth over the 40-year study period, with an average rate of demand growth of only 0.17% per year. Because RE Futures focused on representing high-penetration renewable electricity scenarios, *neither the costs nor the direct benefits associated with the energy efficiency measures included in this projection were explicitly calculated*. Instead, the resulting demand level was taken as a given in the Low-Demand Baseline and high-penetration renewable electricity scenarios. The majority of the analysis described below was based on the low-demand trajectory.

The high-demand projection represents, to some degree, "business-as-usual" trends in energy consumption within the residential, commercial, and industrial sectors. It was largely based on demand projections from the reference scenario from EIA's AEO 2010 (EIA 2010a), and generally assumed no radical changes in available technologies or consumer behavior, although

[79] Energy intensity is defined as electricity use per square foot of floor space for commercial buildings, electricity use per household for residential buildings, and electricity use per dollar of shipments for industry. Volume 3 includes details on energy intensity assumptions for existing and new buildings of different types.

[80] PEV deployment assumptions and impacts on electricity demand are consistent with other studies (e.g., EPRI 2007), as described in Volume 3.

current technologies were assumed to evolve in terms of cost and efficiency. Additionally, no new regulations or laws impacting electricity end-use were envisioned, and reliance on the electrification of the vehicle stock was assumed to be negligible. In aggregate, as shown in Figure 1-2, this combination of assumptions results in annual demand of 5,100 TWh by 2050 (comprised of 37% residential, 44% commercial, 18% industrial, 1% non-PEV transportation, and approximately 0% PEV), approximately 30% greater than in the low-demand projection. The average rate of demand growth under this projection was 0.84% per year over the 40-year study period. *The annual demand growth rate in the High-Demand Baseline scenario is significantly lower than the historical annual growth rate of approximately 2.4% from 1970 to 2010*. Additional details on the demand assumptions used in RE Futures can be found in Volume 3.

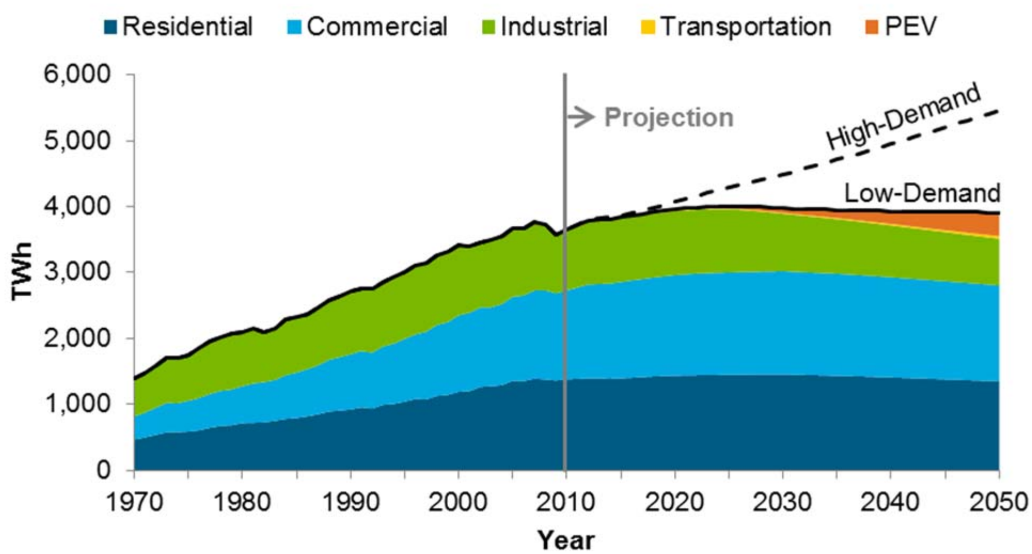

Figure 1-2. Historical and projected electricity demand assumptions in low-demand and high-demand scenarios

1.4.2 Conventional Generation Technologies

While RE Futures focused primarily on scenarios with high renewable electricity penetrations, assumptions for conventional generation technologies are important because they affected the capacity and generation mix of the baseline scenarios as well as the residual mix in the high renewable scenarios. For the ReEDS capacity expansion modeling, assumptions related to the treatment of new capacity builds, fossil energy prices, and power plant retirements are particularly important factors that can have considerable implications for modeling results. Simplified assumptions were necessary given uncertainties in future recoverable fuel supply, regulations, and power plant economics over the 40-year analysis period (see Text Box 1-3).[81]

First, although ReEDS has the technical capability to consider new nuclear plant builds, fossil technologies with carbon capture and storage (CCS), and gasified coal without CCS, RE Futures

[81] A more detailed treatment of conventional generation technologies in ReEDS and GridView modeling can be found in Appendix A, Appendix B and Short et al. (2011).

chose not to allow new builds of other possible low-carbon generation technologies, including these technologies, because the focus of this study was on technical issues associated with high levels of renewables and because no carbon or related policies were considered. The future cost of nuclear power plants as well as power plants using CCS is particularly uncertain. In addition, deployment of these technologies will be highly dependent on policy decisions and institutional and social factors, which are beyond the scope of RE Futures. Instead, RE Futures focused on scenarios with high penetrations of renewable energy, and therefore chose to not allow new builds of other possible low-carbon generation technologies. Because RE Futures did not postulate a future specific carbon policy, the exclusion of these other low-carbon technologies from the analysis had little impact on modeling results.

Second, natural gas and coal fuel prices were assumed to vary over time, among regions, and among scenarios, as described in Short et al. (2011). Fossil fuel prices assumed in the modeling analysis were based on AEO 2010 (EIA 2010a) reference case fuel prices. More recent projections of natural gas prices, such as projections in AEO 2011 (EIA 2011c) are lower.

Third, retirement of conventional capacity influences modeling outcomes. The treatment of plant retirements in the ReEDS model is based on assumed service lifetimes for all generation types with the exception of coal-powered generators, in which only usage-based retirements were assumed. Consequently, retirements of existing coal capacity are likely underestimated under the baseline and lower renewable electricity scenarios. Fossil energy plant retirement assumptions are described in Appendix A. The cost and performance estimates for the modeled conventional generation technologies are presented in Appendix A and Black & Veatch (2012).

1.4.3 Renewable Generation Technologies

1.4.3.1 Renewable Resource Potential

The United States has diverse and abundant renewable resources, including biomass, geothermal, hydropower, ocean, solar, and wind resources. Solar and wind resources are the most abundant of these resources. These renewable resources are geographically constrained but widespread—most are distributed across all or most of the contiguous states (see Figure 1-3).

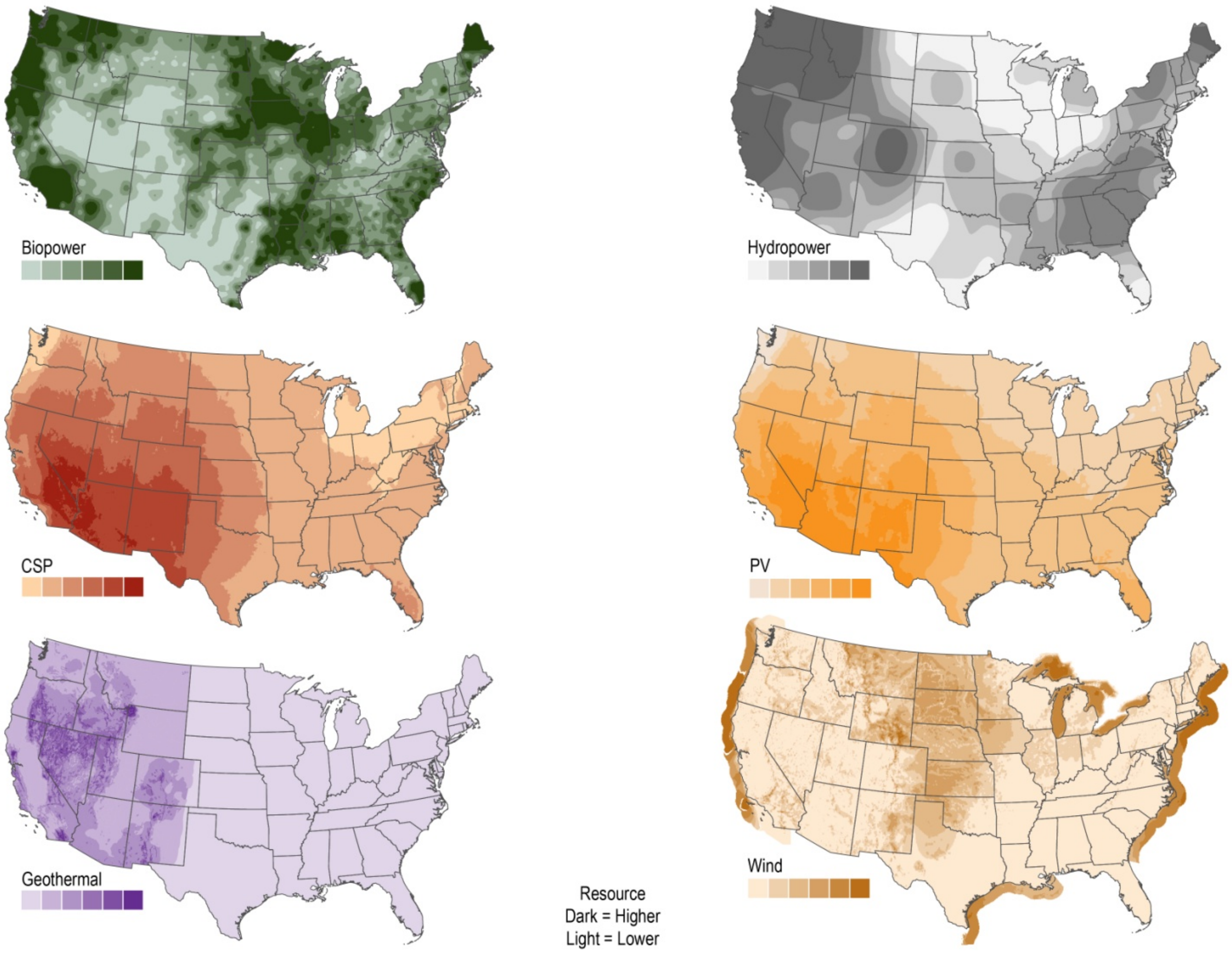

Figure 1-3. Geographic distribution of commercial renewable resources in the contiguous United States

The data used in RE Futures modeling may differ from the underlying data for these maps. See Short et al. (2011) for a detailed description of the data sources used in the ReEDS modeling. Sources for the underlying data used in Figure 1–3 include Chapter 8 (Volume 2) for hydropower; Milbrandt (2005) for biopower; NREL (2007) for solar (CSP and PV); the standard wind resource database (April 2009 update) for onshore wind energy; Schwartz et al. (2010) for offshore wind energy; and Augustine et al. (2010) for hydrothermal geothermal.

Within these broad resource categories, a variety of commercially available renewable electricity generation technologies have been deployed in the United States and other countries, including stand-alone biopower, co-fired biopower, hydrothermal geothermal, hydropower, distributed PV, utility-scale PV, CSP,[82] onshore wind, and fixed-bottom offshore wind. Only incremental or evolutionary improvements in the renewable technologies were considered despite the long-term (2050) timeframe of the analysis. A number of emerging technologies, including marine-hydrokinetic devices that use wave, tidal, open-ocean and river currents, and ocean thermal

[82] In this report, CSP refers to concentrating solar thermal power. Concentrating photovoltaic technologies were not considered in the modeling analysis.

resources; enhanced geothermal systems; and floating-platform offshore wind technology, are under development. These technologies were not modeled in this study, but they could provide greater diversity to the U.S. renewable electricity generation mix and lower system costs if research and development investment in these technologies can significantly lower their cost over the next decades. The resource potential for each of the renewable electricity technologies considered in RE Futures is summarized as follows,[83] and details are provided in Appendix A and Volume 2:

- Biomass power is generated by collecting and combusting plant matter and using the heat to drive a steam turbine. Biomass resources from agricultural and forest residues, although concentrated primarily in the Midwest and Southeast, are available throughout the United States. While biomass supply is currently limited, increased supply is possible in the future from increased production from energy crops and advanced harvesting technologies. Biopower can be generated from stand-alone plants, or biomass can be co-fired in traditional pulverized coal plants.

  Wide-ranging estimates of current and future biomass resources exist. Some of these resource estimates are summarized in Chapter 6 (Volume 2), including the DOE (2011) estimate of 696–1184 million annual dry tonnes of potential inventory of biomass (of which 52%–61% represents dedicated biomass crops) in 2030. Estimates for biomass feedstock in RE Futures modeling were based on estimates from Walsh et al. (2000) and Milbrandt et al. (2005), which are consistent with the low end of the DOE (2011) estimate for 2030. In fact, no increases in biomass resource supplies were assumed in the ReEDS model. However, the modeled scenarios also did not explicitly assume any competition for biomass resources, including from transportation demand for biofuels. As a result, maximum biopower capacity deployment was assumed to be roughly 100 GW (with 27% from dedicated biomass crops).[84] Details on biopower can be found in RE Futures Chapter 6 (Volume 2).

- Geothermal power is generated by circulating water that is heated by hot underground rocks to drive a steam turbine. Geothermal resources are generally concentrated in the western United States, and they are relatively limited for hydrothermal technologies (36 GW of new resource potential), which rely on natural hot water or steam reservoirs with appropriate flow characteristics. New enhanced geothermal systems, engineered hydrothermal reservoirs, geopressured resources, or co-production from oil and gas wells could dramatically expand resource potential by more than 500 GW if research and development in these technologies are successful (Williams et al. 2008); these currently

[83] The renewable resource potentials presented here are drawn from recent literature. They are based on historical climatic average resource patterns and have standard land are exclusions applied. After accounting for these standard exclusions, the aggregate renewable generation resource is many times greater than current electricity demand. The resource potentials shown in Figure 1-3 and described in this section may differ somewhat from those used in the ReEDS model; see Short et al. (2011) for a description of the renewable resource potential assumed in ReEDS.

[84] Estimates for the available biopower *capacity*, given a fixed amount of feedstock, depend on a variety of factors including biomass heat content, biopower heat rates, and plant capacity factors. To be conservative, for each modeled year, the analysis used feedstock estimates from Walsh et al. (2000) and Milbrandt et al. (2005), which are consistent with the DOE (2011) estimate for 2030, and did not assume any increase in resource over time; on the other hand, the analysis did not include potential future growth in demand for biomass from the fuel sector.

non-commercial technologies were not included in the RE Futures grid system modeling.[85] Details on geothermal power are presented in RE Futures Chapter 7 (Volume 2).

- Hydropower is generated by using water—from a reservoir or run-of-river—to drive a hydropower turbine. Hydroelectric plants are sited in all U.S. states except Mississippi, with the greatest total installed capacities in Washington and California. Opportunities for hydropower expansion exist. For example, run-of-river technology could produce electricity without creating large inundated areas, and many existing dams could be equipped to generate electricity.

  The future potential of conventional hydropower from run-of-river facilities within the contiguous United States is estimated at 152–228 GW, depending on the regional capacity factor assumed (see Chapter 8 [Volume 2]). Only new run-of-river hydropower capacity was considered in RE Futures modeling, and existing hydropower plants were assumed to continue operation. Other hydropower technologies, such as new generation at non-powered dams and constructed waterways, have the potential to contribute to future electricity supply, but they were not modeled in this study. Details on hydropower are provided in RE Futures Chapter 8 (Volume 2).

- Ocean technologies are not broadly commercially available at this time (and were not modeled in this study), but both U.S. and international research and development programs are working to reduce the cost of these technologies. Ocean current resources are best on the U.S. Gulf and South Atlantic coasts; wave energy resources are strongest on the West Coast. All resources are uncertain; preliminary estimates indicate that the U.S. wave energy potential is on the order of 2,500 TWh/yr. Other ocean technologies, including ocean thermal energy conversion technologies and tidal technologies, can also contribute to future electricity supply. Details on ocean technologies are provided in RE Futures Chapter 9 (Volume 2).

- Solar resources are abundant and extend across the entire United States, with the highest quality resources concentrated in the Southwest. PV technologies generate electricity directly, while CSP technologies collect high temperature heat to drive a turbine. Only conventional PV and CSP systems were included in the grid modeling.

  Solar energy technologies have a larger energy resource than any other renewable energy technology. U.S. electricity use is approximately 4,000 TWh/yr, which is approximately the same amount of energy that the contiguous U.S. land surface receives from the sun in a few hours of daylight. This amount of solar energy could support tens of thousands of gigawatts of both utility-scale PV (~80,000 GW) and CSP capacity (~37,000 GW). Distributed rooftop PV capacity is more limited (~700 GW) due to constraints on available rooftop area. Details on solar power are provided in RE Futures Chapter 10 (Volume 2).

[85] RE Futures considers only hydrothermal resources, and it does not consider low-temperature, coproduced, "geopressured," or alternative sedimentary resources due to their early stage of commercialization or insufficient resource assessment data. Inclusion of these resources could expand geothermal electricity generation potential.

- Wind resources on land are abundant, extending throughout the United States, and offshore resources provide options for coastal and Great Lakes regions. Onshore and fixed-bottom offshore technologies are currently commercially available.[86] Floating platform offshore wind technologies that could access high-quality wind resources in deeper waters in the future are less mature and were not considered in the grid modeling.

  Recent studies estimate that the 80-m wind resource of the contiguous 48 states could support more than 10,000 GW of wind capacity with a capacity factor of 30% or greater.[87] Although this amount of wind capacity is not expected to be built, this capacity estimate theoretically translates to approximately 37,000 TWh of energy generation (Elliot et al. 2010). The offshore wind resource has not been characterized as well as the onshore resource. Preliminary work estimates the offshore wind resource at 90 m above the surface extending to 50 nautical miles from the shore of the contiguous United States at 3,500 GW (Schwartz et al. 2010). Details on wind power are provided in RE Futures Chapter 11 (Volume 2).

Further details on the renewable energy cost, performance, and resource assumptions used in the modeling for RE Futures can be found in Appendix A, Volume 2, and Black & Veatch (2012).

1.4.3.2 Renewable Technologies Dispatchability

Renewable resource supply varies by location and, in most cases, by the time of day and season. The electricity output characteristics of some renewable energy technologies also vary, and several of these characteristics are summarized in Table 1-1. A key performance characteristic of generators in general is their degree of dispatchability, specifically the ability of operators to control power plant output over a range of specified output generation levels. Conventional fossil plants are considered depatchable, to varying degrees. RE Futures explores a variety of renewable energy resources. The resources modeled to power 2050 demand may include a significant fraction of renewable electricity technologies that are at least somewhat similar to conventional technologies in their operation (geothermal, biopower, hydropower); these renewable generator types are considered dispatchable resources in a manner similar to conventional generators. Geothermal and biopower plants (whether co-firing with fossil energy or in dedicated plants) are also considered dispatchable technologies in that system operators have some ability to specify generator output, if needed. Hydropower plants with reservoir storage are also dispatchable resources, and are often among the most flexible plants available to utilities to respond to variations in electricity demand. The output from run-of-river hydropower is constant over short time periods (minutes to hours) but varies over longer time periods (days to seasons). Other renewable energy resources may be considered “partially dispatchable.” CSP with thermal storage, for example, can be considered a dispatchable technology but is limited by the amount of storage.

The remaining renewable generation sources are listed in Table 1-1 as having “low partial dispatchability.” This essentially means that the output from these sources can be reduced, but

[86] Although there are no offshore wind power plants operating in the United States, a number of projects have been proposed. In addition, offshore wind is widely deployed in Europe.
[87] The maximum estimated capacity factor is slightly greater than 50%.

not increased on demand (unless they were being operated at less than their potential at the time.) These generators have also been labeled as "intermittent," although "variable" or "variable and uncertain" may be more technically accurate terms. Solar PV, wind, and several ocean technologies fall into this category, with varying levels of variability and limited predictability over various time scales. High levels of these generation types can therefore introduce new challenges to the task of ensuring reliable grid operation. However, it deserves note that the requirement for balanced supply and demand must be met on an *aggregate* basis—the variability and uncertainty of any individual plant or load entity does not define the integration challenges faced by high levels of variable renewable penetration. Integrating high levels of solar PV and wind generation can require a number of enabling techniques and technologies, including: having other generators available to supply the needed electricity when there is insufficient electricity generation from variable renewables; the ability to change electricity demand through operational flexibility; and the expansion of the electric system transmission infrastructure to move more distant electricity supply to meet the load. Complementary renewable sources can assist in the integration of variable renewables. This includes the use of dispatchable renewables, or mixes of different renewables whose outputs are not highly correlated, such as solar and wind.

In addition to dispatchability, variability, and uncertainty, there are several other factors listed in Table 1-1. This includes capacity value, or the ability of renewable generators to reliably meet demand. Capacity value is based in part on generator dispatchability, but also the coincidence of generator output with normal load patterns. As a result, PV at low levels of deployment may have a high-capacity value despite its lack of dispatchability because the sun is typically shining during periods of high demand for much of the United States. Wind tends to have a lower capacity value at low levels of deployment because its output is typically lower during hot afternoons when demand peaks. Additional discussion of grid services provided by different renewable generators is provided in RE Futures Volume 4.

Table 1-1. Summary of Integration Characteristics for a Selection of Renewable Electricity Technologies[a]

Technology		Variability (Time Scale of Variability)	Dispatachability[b]	Geographic Diversity Potential[c]	Predictability[d]	Capacity Value Range (%)[e]
Bioenergy		Seasons	+++	+	++	Similar to thermal
PV		Minutes to Years	+	++	+	<25–75
CSP (with thermal storage)[f]		Hours to years	++	+	++	90
Geothermal		Years	+++	NA	++	Similar to thermal
Hydropower	Run-of-River	Hours to Years	++	+	++	0–90
	Reservoir	Days to years	+++	+	++	Similar to thermal
Ocean Energy	Tidal	Hours to days	+	+	++	<20
	Wave	Minutes to years	+	++	+	16
Wind		Minutes to years	+	++	+	5–40

[a] Adapted from IPCC 2011, Ch. 8., p. 23
[b] *Dispatchability:* degree of plant dispatchability: + low partial dispatchability, ++ partial dispatchability, +++ dispatchable.
[c] *Geographical diversity potential:* degree to which siting of the technology may mitigate variability and improve predictability, without substantial need for additional network: +moderate potential, ++ high diversity potential.
[d] *Predictability:* Accuracy to which plant output power can be predicted at relevant time scales to assist power system operation: + moderate prediction accuracy (typical <10% Root Mean Square error of rated power day ahead), ++ high prediction accuracy.
[e] *Capacity value* (also referred to as capacity credit): Probability that a particular type of generation will reliably contribute to meeting demand, which generally means that it will be available to generate electricity during the peak demand hours. The capacity value ranges shown here reflect the ranges from IPCC 2011, Ch. 8., p. 23 and do not necessarily equal the capacity values estimated in RE Futures modeling.
[f] Assuming a CSP system with six hours of thermal storage and direct-normal irradiance >2,000 kWh/m^2/yr (7,200 MJ/m^2/yr). Thermal storage enables high capacity value and greater predictability than CSP systems without storage.

1.4.4 Flexible Technologies

The key to addressing the variability and uncertainty of variable renewable electricity integration is increasing the overall flexibility in the power system. Previous studies have examined the flexibility required to integrate up to 30%–35% variable generation,[88] while RE Futures explores higher levels of variable generation. This amount of penetration will likely require additional flexibility derived from a variety of sources, including energy storage, demand-side technologies and practices (flexible load), flexible dispatch of conventional and renewable generation, and resource sharing. This section focuses on the major modeling assumptions associated with energy storage and flexible load in RE Futures, while details can be found in Chapter 12 (Volume 2) and Volume 4, respectively. Flexible conventional generation and resource sharing are described briefly below, and detailed observations can be found in the chapters describing the study results (Chapters 2–4).

Energy storage can provide a variety of flexibility services, including provision of operating reserves and shifting energy over time to better match generation and load. Three utility-scale storage technologies were represented in RE Futures: pumped-storage hydropower (PSH), compressed air energy storage (CAES), and batteries. PSH is widely used globally, with approximately 20 GW of existing capacity in the United States. New PSH installations were conservatively restricted in capacity and location to include only currently planned PSH projects as indicated by the Federal Energy Regulatory Commission (FERC) in its licensing procedure (see Chapter 12 [Volume 2]). For CAES, a resource assessment identified possible locations and available capacity for potential new CAES developments based on local geology (see Chapter 12 [Volume 2]). Batteries were not restricted in location. Because ReEDS is not a chronological model, simplifications were required to assess the economic competitiveness of storage technologies. The size (number of hours of storage) for each device was fixed (8 hours of storage for PSH and batteries, and 15 hours of storage for CAES), and storage was assumed to be able to provide firm capacity to contribute to planning reserves for the system. Storage was also assumed to be able to shift energy across various time periods in the ReEDS model to capture some of the value of daily load shifting. ReEDS also captures some of the ability of storage to reduce renewable curtailment during periods of high renewable output or low load.

In addition, although the ReEDS model allows storage to provide some operating reserve services, its reliance on coarse time slices prevents ReEDS from accurately evaluating all of the short-term (e.g., subhourly) services that can be provided by some storage and flexible technologies. Thus, the deployment of these technologies is likely underestimated in RE Futures. Further, no attempt was made to model the competitiveness of short-term storage devices such as flywheels. A more accurate evaluation of actual storage operation was captured in GridView, which performs hourly simulations.

Flexible load involves using technologies to provide a variety of services to help manage variability and uncertainty. Examples of these technologies and practices include incentives (e.g., price signals) to motivate a better match between demand and supply, contracts that enable the

[88] Western Wind and Solar Integration Study (GE 2010) and Eastern Wind Integration and Transmission Study (EnerNex 2010)

system operator to control loads during times of system stress, and existing and new technologies (e.g., smart appliances and controlled or timed electric vehicle charging). Demand response can be in response to a price signal, initiated by the consumer manually, or controlled by the operator in a semi-automatic or fully automatic fashion. Existing examples in the residential sector are storage water heating and the controlled cycling of air conditioning. New "smart grid" infrastructure would potentially greatly expand flexibility by including more categories of load.

While a large number of demand-response technologies are possible, RE Futures considered a fairly limited set of options. Interruptible load (for provision of operating reserves) was considered using regional supply curves based in large measure on FERC (2009) (Volume 3). Annual interruptible load resource availability was based on a percentage of peak demand within a region, and was assumed to grow from a range of 1%–8% in 2010 to 11%–17% in 2030, and to 16%–24% in 2050; the ranges indicate regional variations in assumed interruptible load availability. ReEDS did not estimate or constrain the frequency with which interruptible load could be accessed because it does not have the chronological detail necessary to do so. As a chronological hourly model, GridView estimates the use of interruptible load but only for situations in which the interruptible load is called for at least 1 hour.[89]

New controllable loads could absorb otherwise unusable variable generation output. One example is dynamically scheduling charging of electric vehicles, so that electricity consumption at the recharge station would increase or decrease according to the net supply of renewable resources. RE Futures assumed that a substantial fraction (~40%) of the passenger transportation fleet transitions to electric and PEVs by 2050 in the low-demand projection. Of the assumed 356 TWh of electric vehicle load in 2050, 165 TWh were assumed to be operated under utility-controlled charging. The remaining electric vehicle load not under utility control was assumed to have a daily charging profile that peaked during evening hours, as described in RE Futures Volume 3. (The PEV demand only applied to the Low-Demand Baseline scenario and was not included in the high-demand projection.)

Demand-side thermal energy storage in commercial buildings was also considered. In particular, chilled water and ice storage cooling capable of shifting air conditioning loads were represented. Regional capital cost supply curves for thermal storage were developed that considered building space availability, building air conditioning turnover rates, and cooling technologies. The use of these demand-side storage devices was restricted by regional commercial cooling loads.

In addition to new deployment of storage technologies and the possibility of increased emergence of flexible load, RE Futures modeling assumed that the existing and future conventional fleet could be used to provide increased system flexibility. Conventional fossil power plants currently provide system flexibility and reserves by rapidly ramping in response to changes in system demand and operating at part load to provide reserves. This inherent flexibility can also be used to address the added variability in high renewable scenarios. The

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[89] Interruptible load could be called to provide energy due to forecast error or generator forced outages. Although the transmission transfer capacity between regions is secure to N-1 contingencies, transmission contingency events were not explicitly modeled, so the interruptible load considered in RE Future was not modeled as being available to provide energy during transmission contingencies in GridView.

flexibility of each generator is limited in terms of its minimum operating point and how fast it can be ramped up and down or restarted after being completely shut down. Newer generators have the capability to have faster ramp rates, larger ramp ranges, and minimal part-load heat-rate degradation, which enhances the ability of such unit to follow load. In some cases, existing equipment can be modified to enhance the unit's flexibility. Natural gas-fueled assets are normally more flexible resources, and taking full advantage of their flexibility may involve new operational practices, including additional gas storage.

Finally, inherent in the ReEDS capacity expansion modeling is the consideration of resource sharing to use spatial, temporal, and technological diversity. Resource sharing includes renewable and conventional generators, operating reserves, and net loads through power pools, markets, or other mechanisms that effectively increase the area over which supply and demand is balanced. Statistically, load variation is more manageable over a larger geographical area; not all customer load changes occur at the same time, and greater diversity smoothes load variations. On the supply side, sharing conventional generation across a larger pool reduces the likelihood that the failure of a single large generator will lead to system-wide failure. Similarly, sharing variable resources distributed over a wide geographic region smoothes the variability and reduces forecasting error. Maximizing the benefits of resource sharing is contingent on two factors: market conditions that allow resources to be shared over large areas, and adequate transmission.

1.4.5 Transmission

1.4.5.1 Costs of Transmission

Pre-existing transmission infrastructure was assumed to continue to be operable throughout the study period, and existing line capacity was assumed to be usable by both conventional and renewable generation sources. For input to the ReEDS model, the existing transmission grid capacity and line location were estimated based on an interface transfer limit analysis using GridView.

The regional resolution of the ReEDS model allows it to crudely estimate new transmission expansion options[90] and the associated costs of those investments. ReEDS was therefore able to compare the total costs, including costs of additional required transmission infrastructure, of distant but higher-quality renewable resources with more local but lower-quality resources, based on generation and transmission cost considerations.

The major cost assumptions associated with transmission and interconnection used in this study are provided in Appendix A and Short et al. (2011).

[90] ReEDS represents transmission using a transportation or pipeline model in which electrical power is only limited by the carrying capacity of the lines and not by actual power flow limitations. The GridView model simulates transmission transfers using DC power flow modeling.

Chapter 2. Exploring Alternative Renewable Electricity Penetration Levels

In order to explore electric system characteristics associated with high renewable electricity scenarios, the RE Futures analysis began with a comparison of a reference scenario (the Low-Demand Baseline scenario) that reflects current technology options with a series of scenarios in which the proportion of renewable electricity increases, in 10% increments, from 30% to 90%. For this analysis, the ReEDS model was used to evaluate how increased levels of renewable energy deployment might impact the mix of renewable and non-renewable resources, the degree of transmission expansion, and the use of various forms of supply- and demand-side flexibility to ensure a match between supply and demand.

2.1 With No New Policy Measures, Renewable Energy Deployment is Relatively Modest, Reaching 20% of Total Electricity Supply by 2050

With limited demand growth and under the assumptions specified for the reference scenario (Low-Demand Baseline scenario), the ReEDS model forecast renewable electricity deployment to be relatively modest (see Figure 2-1). As a proportion of total electricity supply, renewable electricity increased from 12.0% in 2010 to 19.5% in 2050.[91] Total onshore wind power capacity grew from approximately 38 GW at the end of 2010 to 80 GW in 2050 (2.6% to 6.1% of electricity supply during the study period), whereas geothermal capacity expanded from 2.4 GW to 16 GW (0.5% to 2.8%). Utility-scale PV deployed primarily in the early half of the study period due to support from the investment tax credit and state renewable portfolio standard requirements, but only reached 8.4 GW by 2050 (0% to 0.4%). Virtually no growth came from dedicated biomass (flat at approximately 5 GW, or 1%), although some coal capacity was retrofitted to co-fire biomass (4.5 GW, 0.6%).[92] Little growth was observed for CSP (less than 0.5 GW throughout the study period, or 0.0%); offshore wind (2.7 GW, 0.3%); and hydropower[93] (78 GW to 79 GW, or 8.1% to 8.4%).[94]

Absent new or extended policy efforts to counter these trends, the assumptions behind the Low-Demand Baseline scenario resulted in the United States electricity *supply* mix would remain largely in stasis. As a low-demand scenario, demand grew modestly (7% in total during the study period), therefore requiring limited new capacity and supply additions. However, nuclear retirements (declining from 100 GW to 57 GW of U.S. capacity, and 20% to 11% of total

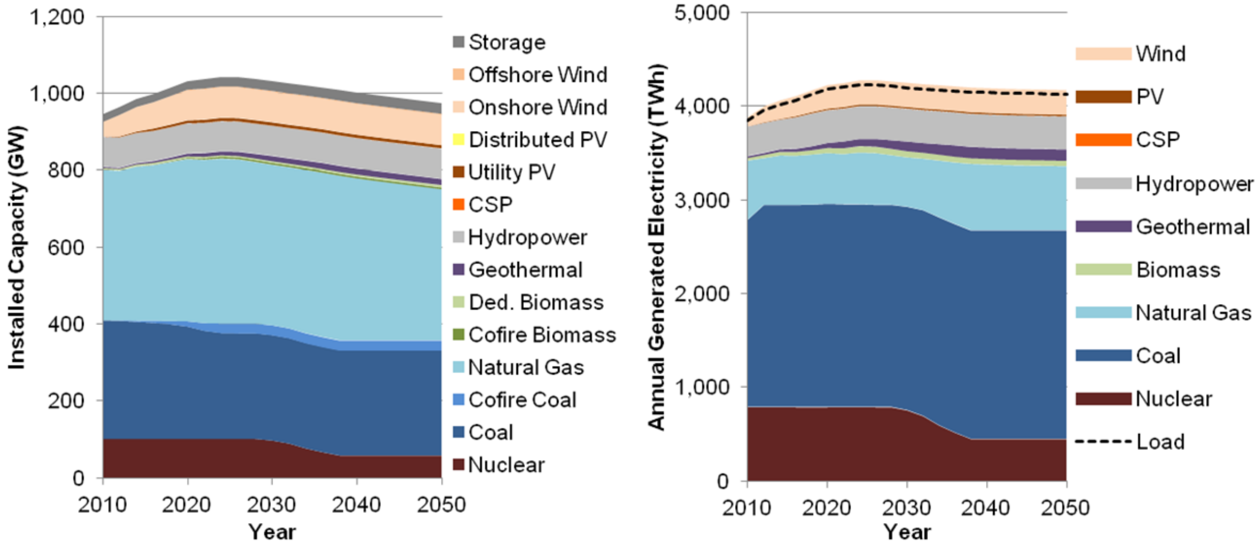
[91] Renewable generation fractions shown here and in the remainder of this volume include imports from Canada, which are assumed to be renewable. Excluding the imports from Canada, renewable generation comprised approximately 10% of total electricity supply in the contiguous United States in 2010.

[92] Dedicated biomass capacity and generation shown here and in the remainder of this volume include existing landfill gas and municipal solid waste facilities.

[93] The hydropower generation or percent generation values quoted in this chapter include all electricity imported from Canada (see Short et al. 2011). In contrast, the quoted capacity figures only include those plants that are located within the contiguous United States.

[94] The 2010 capacity and percent generation numbers reported here are based on ReEDS model results and slightly differ from those reported earlier. The differences are primarily a result of the fact that the ReEDS model start year is 2006 and not 2010, but are largely insignificant to the overall results and key findings of the analysis.

generation)[95] lead to increased reliance on renewable electricity, as described previously, and a slight increase in natural gas generation, while coal generation increased somewhat but remained at approximately 53% of total supply throughout the entire period.[96]



(a) Capacity expansion from 2010–2050 (b) Generation expansion from 2010–2050

Figure 2-1. Capacity and generation expansion in Low-Demand Baseline scenario

For conciseness, the Natural Gas category in all figures and tables includes natural gas-fired and oil-fired power plants. By 2050, a considerable amount of the existing oil-powered generation fleet was assumed to be retired across all scenarios, so the bulk of the generation and capacity in the Natural Gas category is, in fact, natural gas. The ReEDS model distinguishes between natural gas combustion turbine technologies, natural gas combined cycle technologies, and natural gas and oil steam technologies

To summarize, the Low-Demand Baseline scenario resulted in a future U.S. electric system that largely resembles today's fossil-dominated one. The lack of change over time found in this modeled scenario is a direct result of the currently scheduled phaseout of many of the supporting incentives for renewables, and the lack of carbon or other new emissions reduction or clean energy policies or regulations. In addition, the low-demand growth assumption and the extended coal plant lifetimes assumed in the Low-Demand Baseline scenario contributed to this lack of change by requiring only limited new capacity installations. *The Low-Demand Baseline scenario was evaluated for comparison purposes only, and it does not represent a forecasted or recommended outcome*.

[95] For all scenarios, nuclear power plant retirement assumptions were simply based on the age of the power plants: nuclear power plants installed before 1980 were assumed to have a 60-year lifetime, whereas plants installed on or after 1980 were assumed to have an 80-year lifetime.
[96] An assumed regulatory risk of coal, represented by an additional 3% to the cost of equity and debt for new coal plants (see Short et al. [2011]), contributed to the deployment of natural gas over coal in the Low-Demand Baseline scenario, although no new carbon policies were explicitly assumed to impact the generation mix.

2.2 As Renewable Electricity Levels Increase, an Expanded Mix of Renewable Energy Technologies are Deployed

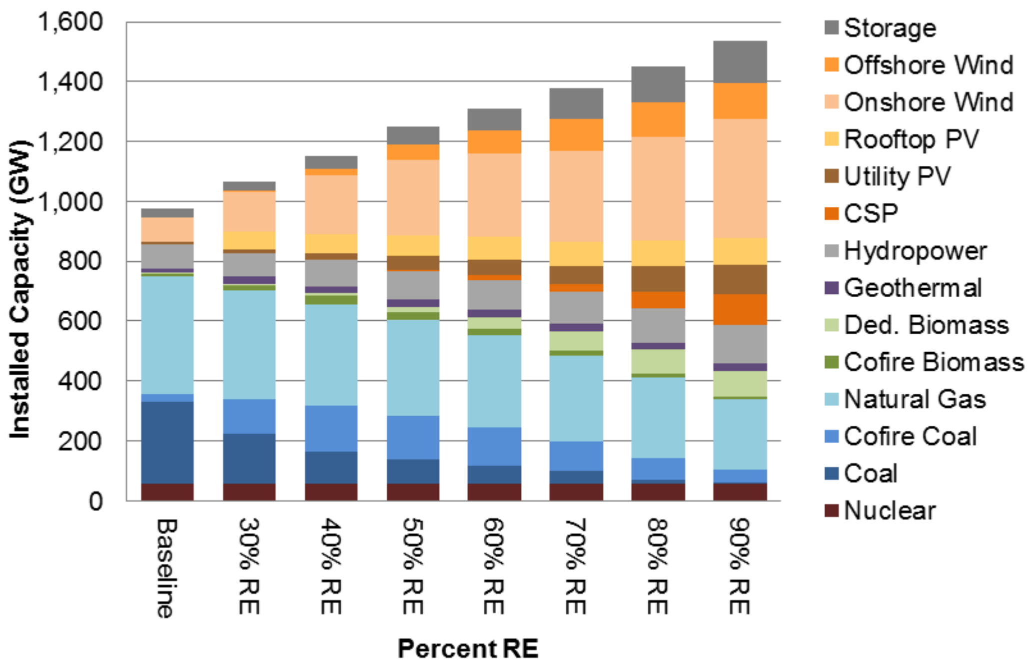
A series of scenarios in which the required proportion of renewable electricity increased, in 10% increments, from 30% to 90%, was evaluated and compared with the Low-Demand Baseline scenario. Within the generation levels required for renewables, the different renewable technologies competed for their share, taking into account technology costs, resources, transmission needs, loads, operational requirements, and other considerations, as discussed in Short et al., 2011. Figure 2-2 presents estimated 2050 capacity and generation, by technology, in these exploratory scenarios under the RE-ITI assumptions. Because of the relatively limited dispatchability, variability, and lower capacity factors of wind and PV technologies and their growing deployment in these scenarios, increasing renewable electricity (from 20% in the Low-Demand Baseline scenario to as high as 90% at the other end) drives the need for a growing amount of aggregate electric generation capacity in order to meet demand, even with low-demand growth. Under the Low-Demand Baseline scenario, 950 GW of total capacity was required by 2050; under the 90% RE scenario, on the other hand, 1,390 GW was required to meet the same level of aggregate electricity demand.[97] Wind and PV capacity does not contribute fully to planning reserves, thus capacity is required from other sources, including dispatchable renewable and storage technologies, resulting in overall greater system capacity. Reserves needs are discussed more fully in Section 2.5.

As described in Chapter 1 (Section 1.3.2), these exploratory scenarios were evaluated using two distinct renewable technology improvement projections, RE-ITI and RE-ETI. For analytic simplicity, however, the results presented in this chapter are predominantly focused on only one of the projections (RE-ITI). The trends demonstrated in this chapter, particularly with respect to the degree of transmission expansion and the use of various forms of supply- and demand-side flexibility, are generally applicable to both sets of exploratory scenarios. Primary differences between the two sets primarily relate to the types of renewable technologies deployed. These differences arise from the underlying assumptions about future renewable technology improvements, with the RE-ETI set assuming greater improvements than the RE-ITI set for technologies that are at an earlier stage of commercialization (e.g., solar). Appendix A Volume 2 discuss these and other differences between the two technology improvement projections in detail.

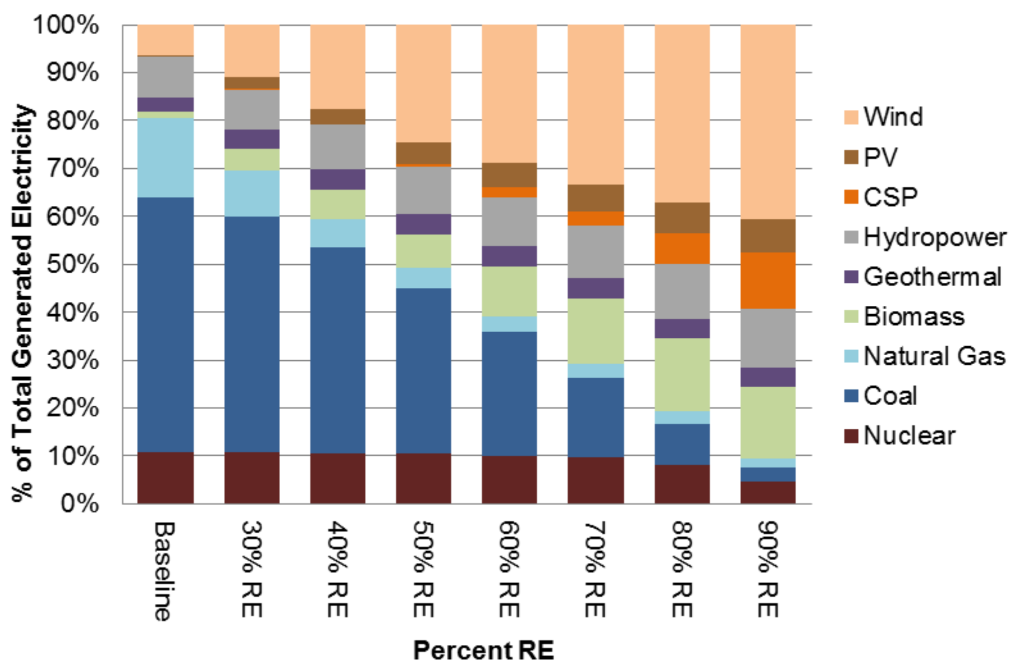
Figure 2-3 presents estimated 2050 capacity and generation, by technology, in the exploratory scenarios under the RE-ETI assumptions. A comparison of Figure 2-3 with Figure 2-2, which presents deployment results under the RE-ITI assumptions, reveals that the primary differences are the greater solar deployment and reduced wind deployment under RE-ETI. For example, for the 90% RE scenario under RE-ETI, the 2050 installed CSP capacity was 178 GW compared with 102 GW for the 90% RE scenario under RE-ITI. For the same two scenarios, total (onshore and offshore) wind installed capacity in 2050 was 413 GW and 517 GW, respectively. Because of this greater reliance on CSP with thermal storage compared to wind, the higher capacity factor of CSP, and the higher level of dispatchability for CSP, 2050 aggregate installed generation

[97] The capacity from storage and demand-side (interruptible load) technologies are excluded from these reported values.

capacity was lower for the RE-ETI scenarios than for the RE-ITI scenarios. For example, in 2050, under the 90% RE (RE-ETI) scenario, 1,300 GW was required, whereas under the 90% RE (RE-ITI) scenario, 1390 GW was required. Other important differences between the two sets of exploratory scenarios relate to the implications of high renewable futures; these are explored in Appendix A. The remainder of this chapter presents results for the exploratory scenarios under RE-ITI assumptions only except where explicitly noted otherwise.

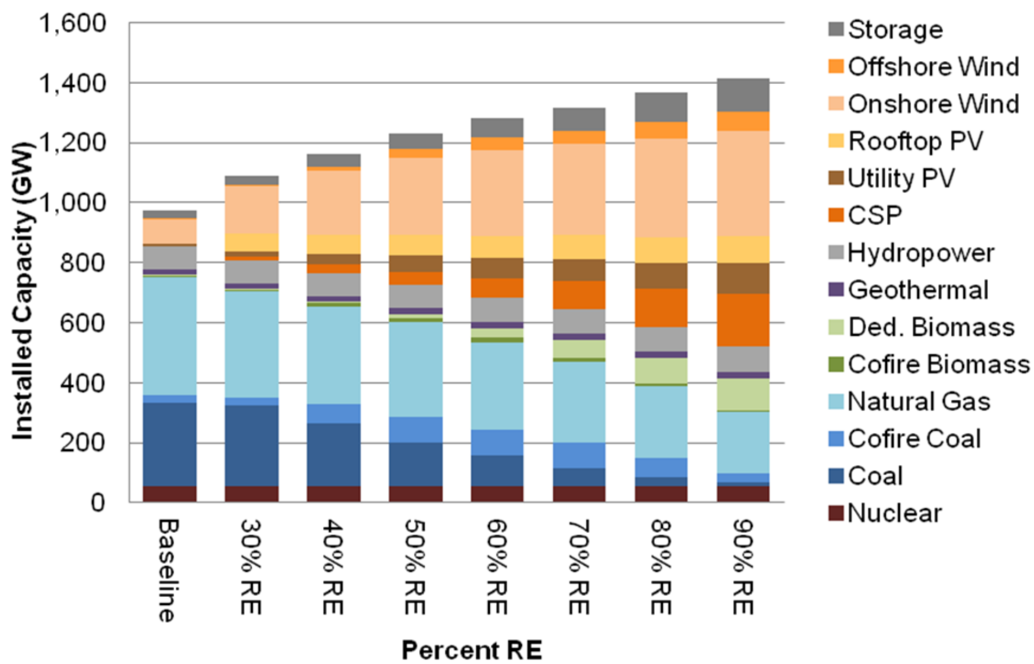


(a) Capacity mix in 2050

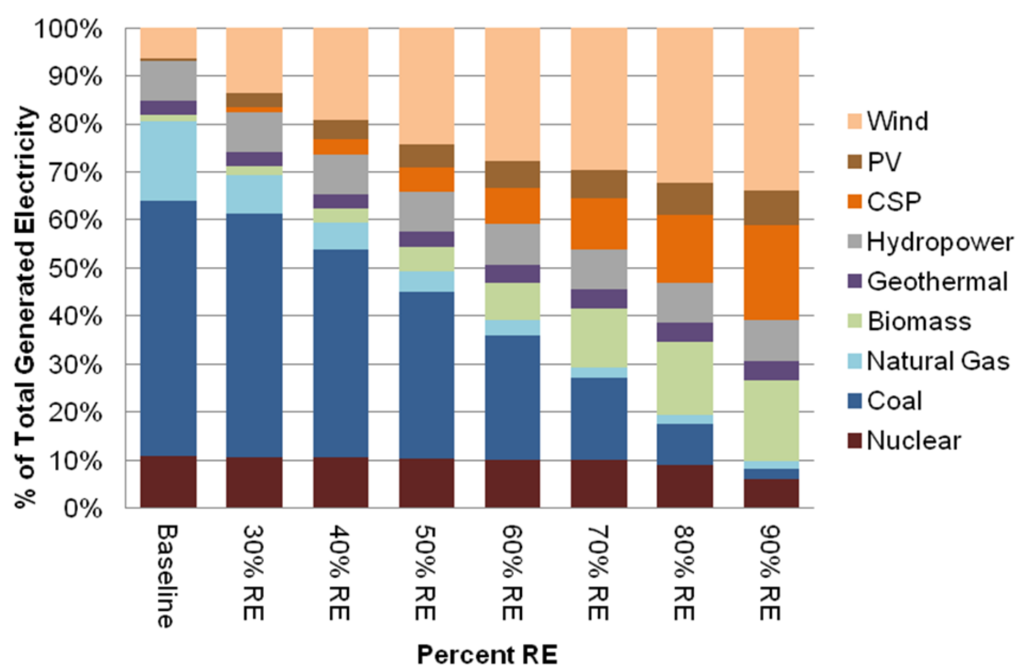


(b) Generation mix in 2050

Figure 2-2. Installed capacity and generation in 2050 as renewable electricity increases under RE-ITI assumptions



(a) Capacity mix in 2050



(b) Generation mix in 2050

Figure 2-3. Installed capacity and generation in 2050 as renewable electricity increases under RE-ETI assumptions

Commercially available renewable energy technologies were deployed to varying degrees in the exploratory scenarios, in part to leverage geographic and temporal diversity in achieving high renewable electricity penetration levels. Onshore wind was found to contribute most significantly in these exploratory scenarios, with offshore wind becoming an increasingly important player as higher renewable electricity levels were achieved. Among the solar technologies, PV (utility-scale and rooftop, combined[98]) was generally found to play a more-sizable role than CSP under the relatively lower renewable penetration scenarios, but electricity supply from CSP was projected to grow more rapidly under the higher renewable penetration scenarios, in part because CSP with thermal storage provides dispatchable capabilities. Both dedicated and co-fired biomass were also found to contribute significantly to the renewable energy mix, with a shift from co-firing to dedicated biomass plants as the renewable electricity penetration levels increase. This shift occurs partly because of the retirement of greater numbers of coal plants at higher renewable levels, and also because only up to 15% of the electricity from co-fired coal units was assumed to be derived from biomass. New hydropower and, especially, geothermal energy were found to contribute proportionately less than the other renewable energy sources, especially under the highest renewable electricity scenarios considered, due to assumed resource and cost constraints. For example, similar levels of geothermal deployment (24 GW) were observed for all scenarios ranging from 40% to 90% renewable electricity, and although some limited additional hydrothermal resources were assumed to be available beyond 24 GW, those resources were found to not be economically viable under these scenarios.[99] However, even for this limited set of geothermal and hydropower resources, capacity expansion was substantial relative to recent trends, and much of the estimated available resource potential was accessed. Again, only currently commercial renewable energy technologies were included in these scenarios: enhanced geothermal systems, ocean energy, and floating platform offshore wind energy, and other non-commercial technologies were not considered, but may offer large resource potential, additional diversity, and regional advantages if technological advancements enable commercialization.

As renewable energy supply increased, the overall balance between generation and demand was maintained through a reduction in conventional fossil and nuclear generation.[100] Although substantial natural gas capacity remained even at the highest renewable energy levels, the supply of electricity from those plants was found to decline rapidly with renewable energy penetration. Even under the relatively more-modest 30%–50% renewable electricity scenarios, the percentage

[98] Based on the output of SolarDS, 2050 rooftop PV deployment was simply assumed to increase linearly from 58.4 GW to 90.3 GW for the 30% RE scenario to the 90% RE scenario; the 80% RE scenario included 85 GW of rooftop PV by 2050. These deployment scenarios from SolarDS should not be interpreted as forecasts of rooftop PV deployment. Due to the great deal of uncertainty in factors that determine consumer adoption, including PV technology costs, subsidies and supporting policies, and trends in consumer preferences, these rooftop PV deployment scenarios from SolarDS were largely arbitrarily chosen for RE Futures.

[99] The assumptions used in the analysis were particularly constraining to geothermal technologies, for which advanced technologies, such as enhanced geothermal systems that can tap huge quantities of energy inside the earth, were not considered in the grid modeling. The modeling analysis focused on currently commercial technologies only.

[100] A full reliability analysis, including sub-hourly, stability, and AC power flow analysis, was beyond the scope of RE Futures (see Text Box 1), although aspects of electricity reliability were evaluated by ReEDS and GridView, as discussed in more detail in Section 2.5.

of generation from natural gas in 2050 dropped substantially with increasing renewables (from 16% in the Low-Demand Baseline scenario to about 4% in the 50% RE scenario). Dedicated coal capacity dropped sharply as well, although the low cost of coal fuel supply and the ability to co-fire biomass resulted in the maintenance of some coal capacity, even in the highest renewable electricity scenarios. Different assumptions about the relative costs of coal and natural gas fuels would change the relative shares of each. Nuclear capacity remained constant across all scenarios, representing only already-built plants and the retirement of those plants (new nuclear builds were not allowed in the analysis), although electricity supply from those nuclear plants began to drop noticeably once renewable electricity reached approximately 70%. From an electricity supply perspective, coal, nuclear, and natural gas were found to play differing roles in the future energy mix, with existing nuclear plants offering base-load generation, coal being increasingly ramped on a seasonal and diurnal basis, and natural gas being used less-frequently and only to accommodate acute periods of electric system need[101]; storage also became increasingly important as the renewable energy levels increased (see Section 2.5).

The more-rapid initial drop in natural gas generation compared with the slower decline in coal generation under progressively higher renewable energy levels may be non-intuitive. Numerous studies, for example, have found that significant displacement of coal with natural gas is feasible and may be an important route toward lower carbon dioxide (CO_2) emissions (e.g., MIT 2010; EIA 2010b). New environmental regulations are also anticipated to impact coal plant operations, retirements, and development, and natural gas plants may be technically able to manage the variability of wind and solar to a greater extent than coal plants do. Uncertain fuel prices will also impact the future generation mix.[102]

As described more fully in Text Box 1-3, the slower initial decline in coal usage relative to natural gas with increasing renewable energy penetration levels reflects the assumptions that underlie the modeling. For example, RE Futures did not explicitly include a carbon tax or cap, nor did it include consideration of new environmental regulations. Without such policies included, the carbon mitigation and environmental benefits of natural gas relative to conventional coal were not fully considered, and coal's lower assumed fuel costs led to its slower phase-out as renewable energy penetration increased. In addition, ReEDS is not an hourly model and is therefore unable to precisely address the operational limits of coal units. GridView results, presented in Chapter 4, suggest a somewhat greater reliance on natural gas.

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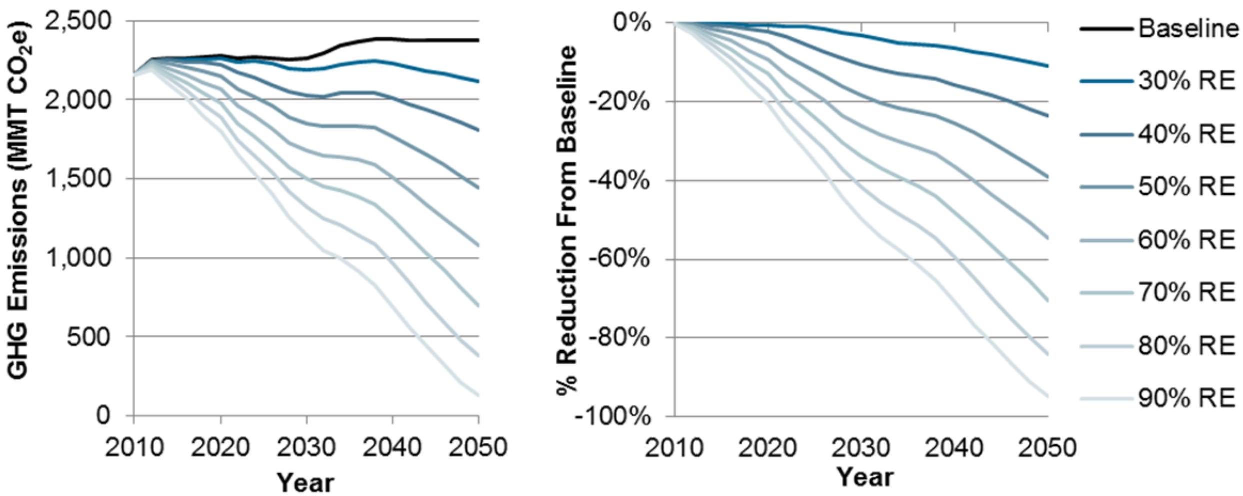
[101] Nuclear and fossil power plant operation is subject to a large number of variables, including technical plant limitations, system operator decisions, economic considerations, and electric sector policies and regulations. For RE Futures, the flexibility of nuclear and fossil plants was generally assumed to be based on traditional plant operation that may not be fully reflective of actual physical capabilities or future technological designs. For example, nuclear plants were assumed to have very limited flexibility with no ability to ramp within a season, although variations in nuclear plant output between seasons were allowed. Power plant designs and retrofits, system operator practices, and altered policies and regulations may alter how nuclear and fossil power plants are operated in the future compared with the model results and assumptions used in RE Futures modeling.

[102] Recent projections of future natural gas prices tend to be lower than those made earlier, primarily due to trends in shale gas production. In RE Futures, assumptions for future fossil energy prices were based on AEO 2010 (EIA 2010a), which projects somewhat higher natural gas prices than more recent projections from AEO 2011 (EIA 2011c).

2.3 Electric Sector Emissions Decline with Increasing Renewable Electricity Penetration

Increased renewable electricity supply reduced direct carbon emissions in the electricity sector. Specifically, Figure 2-4 shows the decline in annual carbon emissions for the exploratory scenarios described above; relative to the Low-Demand Baseline, 2050 annual direct combustion CO_2 emissions declined by approximately 10% in the 30% RE scenario, 55% in the 60% RE scenario, and 95% in the 90% RE scenario.

Appendix A includes a more thorough discussion of the implications of the renewable electricity scenarios presented here, including a discussion on GHG emission reductions. It also discusses life cycle GHG emissions and compares the GHG emission reductions (and associated costs) found in the high renewable electricity scenarios with other carbon policy studies. Other environmental, social, and economic implications of high renewable electricity penetration scenarios can also be found in Appendix A.



(a) CO_2 emissions (b) CO_2 emissions as proportion of baseline

Figure 2-4. Annual combustion-only carbon dioxide emissions decrease as renewable electricity levels increase

2.4 The Need for New Transmission Infrastructure Grows with Increased Renewable Energy Deployment

Because regions with cost-effective renewable resources are often located at a distance from load centers, the need for and associated investments in new transmission increases with higher levels of renewable energy supply. These needs are somewhat mitigated as existing transmission lines become available as conventional generation is displaced, but this freed transmission was found to be insufficient to fully accommodate the needs of increased renewable energy deployment.

Although ReEDS does not simulate detailed transmission planning processes, the model is able to estimate as a first-order approximation the quantity and cost of the transmission expansion needed to accommodate increasing levels of renewable energy. More detailed transmission issues were examined using the GridView model; these are discussed in Chapter 4. Figure 2-5(a) depicts the resulting amount of new transmission capacity found by ReEDS to be needed in the Low-Demand Baseline scenario as well as in the increasing renewable electricity scenarios. The following information is included in Figure 2-5(a):

- Estimated new transmission miles built during the study period, including "long-distance" transmission between the 134 BAs in ReEDS and transmission built within each of the BAs to connect wind and CSP plants to the grid (grid-interconnection related transmission miles for other generation types are not included).
- New intertie capacity between the three major interconnections in the contiguous United States (Western Electricity Coordinating Council, Electric Reliability Council of Texas, and Eastern Interconnection).[103]

The Low-Demand Baseline scenario was found to require 5.1 million MW-miles of new transmission. This occurs in part because the Low-Demand Baseline scenario assumed little growth in electricity demand, in part because grid-interconnection related transmission miles were excluded from these calculations for all generation technologies other than wind and solar, and in part because ReEDS is unable to capture the transmission requirements associated with large new power plants that serve load in multiple areas.[104] The three interconnections are currently electrically isolated with the exception of approximately 3,000 MW of existing AC-DC-AC intertie capacity; this isolation was found to remain in the Low-Demand Baseline scenario, with only approximately 6,000 MW of additional intertie capacity added by 2050.

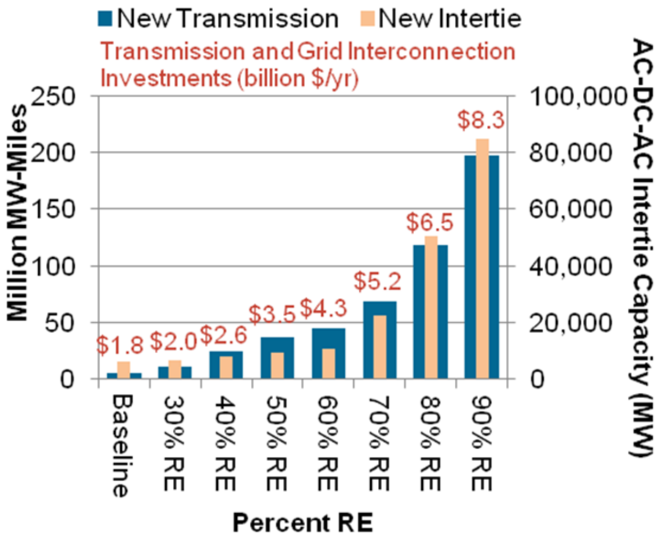
Despite also assuming virtually no growth in electricity demand, the progressively higher renewable energy deployment scenarios yielded approximately 11 million MW-miles of transmission in the 30% RE scenario, 45 million MW-miles in the 60% RE scenario, and 197 million MW-miles in the 90% RE scenario.[105] Similarly, significant amounts of new transmission interties between the three interconnections were deployed as the renewable electricity levels grew: 6,500 MW in the 30% RE scenario; 10,500 MW in the 60% RE scenario; and 85,000 MW in the 90% RE scenario. These results indicate that high renewable scenarios

[103] The Western Electricity Coordinating Council, the Electric Reliability Council of Texas, and the Eastern Interconnection are operated as separate, asynchronous systems. This was assumed to remain unchanged in RE Futures for all scenarios. However, AC-DC-AC intertie capacity connecting the separate interconnections was allowed to increase, except under the Constrained Transmission scenario, discussed in Chapter 3.

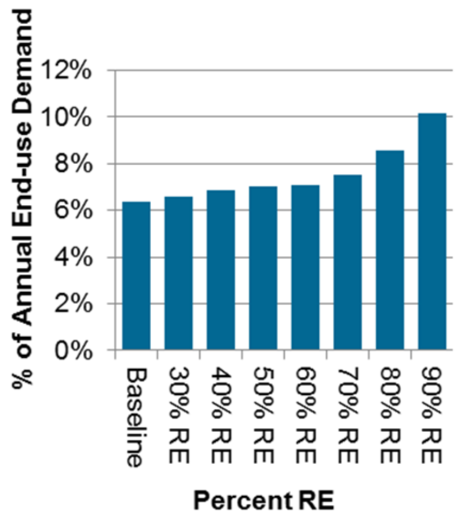
[104] As a linear program, ReEDS cannot capture economies of scale and therefore builds power plants at whatever size is needed in each local region. This obviates the need for transmission lines to multiple load centers from individual new large power plants.

[105] As a linear program, ReEDS builds transmission lines at whatever size (capacity) needed; therefore, estimates for new transmission capacity are quoted in units of megawatt-miles, instead of more standard metrics (e.g., miles). In addition, the total transmission needs represent long-distance, high-voltage transmission lines with high carrying capacities and transmission lines to connect wind and CSP plants to the grid (which are likely to have lower-voltage ratings and smaller carrying capacities per line); the transmission lines represented in a linear program, such as ReEDS, would necessarily have carrying capacities that range widely. As such, to translate the megawatt-miles of transmission from above to estimate miles of transmission lines, one would likely divide by a range of different carrying capacities. For example, the 197 million MW-miles in the 90% RE scenario is roughly equivalent to a range of 49,000 miles (using an average 4,000-MW carrying capacity) to 197,000 miles (using an average 1,000-MW carrying capacity).

use abundant and diverse resources in the West to supplement those in the East, while the GridView analysis reported in Chapter 4 shows that power transfer along these interties is often bi-directional throughout the year. For comparison, the existing total transmission capacity in the contiguous United States is estimated at 150–200 million MW-miles.[106]



(a) New transmission capacity[a] by 2050, and average annual investments from 2010–2050



(b) Transmission and distribution losses as a percentage of electricity demand in 2050

Figure 2-5. New transmission capacity, investment, and losses as renewable electricity levels increase

[a] See Short et al. (2011) for a description of how transmission capacity is defined in ReEDS and the factors that are included in investment estimates. The existing total transmission capacity in the contiguous United States is estimated at 150–200 million MW-miles. The new transmission capacity (megawatt-miles) shown in the figure includes transmission interconnection capacity needed for wind and CSP, whereas the investments associated with the interconnection for all generator types were included in the investment figures.

As a result of these new lines, as well as other generation interconnection costs for all plants, average annual (undiscounted) transmission and interconnection investments during the study period were estimated to increase from $1.8 billion/yr in the Low-Demand Baseline scenario to $2 billion/yr in the 30% RE scenario, $4.2 billion/yr in the 60% RE scenario, and $8.3 billion/yr in the 90% RE scenario.[107] Despite the low load growth assumed in these scenarios, these figures generally fall within the recent historical range for total investor-owned utility transmission

[106] The ReEDS model assumed 150 million MW-miles of existing inter-BA transmission capacity; the 200 million MW-mile figure is estimated from Homeland Security Infrastructure Database (2008) and other sources.
[107] In Figure 2-5(a), the transmission capacity (in megawatt-miles) shown accounts for new intra-BA capacity estimated for wind and CSP and new inter-BA line capacity only, whereas the transmission investments reported here include costs related to new transmission lines, substations, AC-DC-AC interties, and other grid interconnection infrastructure for all new generation capacity. Because the investment values include more types of infrastructure, the differences in transmission investments between scenarios are smaller than the differences in transmission capacity shown in Figure 2-5(a).

expenditures in the United States of between $2 billion/yr and $9 billion/yr from 1995 through 2008 (Pfeifenberger et al. 2009). Moreover, ReEDS-estimated new transmission miles and investments do not include replacement in kind of existing transmission lines, substations, or other infrastructure, and therefore understate the total amount of and associated investment in transmission infrastructure likely to be built over the study period.

Increased transmission infrastructure provides a variety of services to the electricity system as a whole. In addition to delivering power from remote renewable resources to load centers, a robust transmission network enables increased geospatial smoothing of power from variable wind and PV generators, enables access to potentially lower cost power resources (both renewable and conventional) to reduce generation costs, and helps support a more reliable and efficient electricity system by allowing the ability to share reserves across larger areas. The full benefits of transmission expansion were not examined in RE Futures, and further work on the impacts of transmission infrastructure in high renewable futures is necessary.

Finally, in addition to the growth of the necessary transmission infrastructure, the increase in transmission within and across interconnections led to an increase in transmission and distribution losses, as seen in Figure 2-5(b): from 6.3% of total electricity demand in the Low-Demand Baseline scenario to 10.1% in the 90% RE scenario.[108]

2.5 Systems Integration Challenges are Managed by a More Flexible Power System

A critical challenge in meeting a high-penetration renewable electricity future is to ensure a real-time balance between electricity supply and demand. Ensuring such a balance is more complicated with high proportions of variable generation technologies, such as wind and solar PV. Among the scenarios highlighted here, wind and PV contributed a progressively increasing percentage of the overall electricity supply mix as the overall level of renewable electricity penetration rose. In the 30% RE scenario, for example, wind and PV constituted 13% of overall electricity supply, and this proportion increased to 34% in the 60% RE scenario, and to 48% in the 90% RE scenario. Text Box 2-1 describes qualitatively some of the technologies and mechanisms that can be used to manage the inherent variability and uncertainty of wind, solar PV, and load. These technologies and mechanisms are relied upon to varying degrees today to ensure a reliable electric system, and they would be called upon to an even greater extent in a high-penetration renewable electricity future, as suggested by the ReEDS analysis results that are described below.

[108] Distribution-level losses were assumed constant across all scenarios in ReEDS. In addition, transmission loss factors were assumed constant for all years of the study period (i.e., no improvements in transmission technologies were assumed).

Text Box 2-1. Managing Variability and Uncertainty in the Power System

The electric system is unlike other commodity delivery systems due to two fundamental physical principles: limited flow control and limited electrical storage. Consequently, aggregate generation and consumption of electricity must occur simultaneously under power flow constraints that are dictated by physical laws. The job of an electric system operator is to ensure the reliable delivery of electricity to consumers in real time. Traditionally, the challenges associated with performing this task have been driven by the variability of demand over a range of timescales, along with power plant and transmission line outages. A high-penetration renewable electricity future that includes a large amount of wind and solar PV would place greater demands on electric system operation due to the increased variability and uncertainty associated with the output of those plants. Isolating and quantifying the specific impact of this variability and uncertainty in renewable generation system operations is challenging because the system is operated as a whole and because of the large number of technologies and practices (with a wide range of characteristics) that are available to help manage these challenges. Technologies and practices used to accommodate variability and uncertainty include but are not limited to the following:

- **Flexible conventional generation:** Fossil and nuclear power plants can provide reserve generation for times of high load and low variable renewable generation. These generators can be held in reserve until needed, either by operating at part load and turned up (or down) depending on system needs (e.g., coal or natural gas plants) or by remaining idle and quickly started (or stopped) when needed (e.g., natural gas combustion turbine plants).
- **Flexible renewable generation (including curtailment):** Dispatchable renewable generation sources (e.g., hydropower, geothermal, biopower, CSP with thermal storage) can also provide the same reserve for variable resources in a similar manner as fossil and nuclear plants. (Variable renewable resources can also provide some ancillary services, such as wind plants that can provide frequency regulation services (Miller et al. 2010) depending on specific equipment.) In addition, curtailment of variable generation is an option to ensure a balance of supply and demand in times of low electricity demand and/or high variable generation.
- **Flexible load (including new load):** Demand-side technologies and practices can also provide a variety of services to help manage variability and uncertainty. Examples of these technologies and practices include incentives (e.g., price signals) to motivate a better match between demand and supply, contracts that enable the system operator to control loads during times of system stress, and existing and new technologies (e.g., smart appliances and controlled or timed electric vehicle charging).
- **Energy storage:** The ability of storage to store electricity during times when it is not needed (e.g., during times when wind and PV generation exceeds demand), and deliver it when called upon, allows the system operator to better match generation and load without wasting or curtailing electricity. Storage can also provide reserve services.
- **Resource sharing and spatial diversity:** Resource sharing includes a variety of mechanisms that effectively increase the area over which supply and demand is balanced, making load variation more manageable, reducing the likelihood that the failure of a single large generator will lead to a system-wide failure, and smoothing the variability and reducing forecasting errors associated with variable renewable technologies.

A variety of other mechanisms can also be used to help manage variability and uncertainty (see RE Futures Volume 4). In general, a combination of these options is currently used or will likely be implemented to manage variability and uncertainty at all relevant timescales necessary to ensure a reliable electric system. The ReEDS and GridView analyses included many of the options listed here, weighing the service benefit and associated cost of these options in deployment and dispatch decisions.

To help ensure a balance between supply and demand, ReEDS requires sufficient generating capacity with appropriate flexibility characteristics to be able to handle the inherent variability of wind and PV (as well as the variability of electricity demand) over a range of timescales. At the longest timescale, a planning reserve requirement is applied in ReEDS to ensure that adequate aggregate generating capacity is available to meet times of extreme demand.[109] At shorter timescales relevant to daily electric system operations, ReEDS requires sufficient flexible supply- and demand-side technologies to satisfy operating reserve requirements. The operating reserves considered in ReEDS include wind and solar forecast error reserves, contingency reserves, and frequency regulation. Although these reserve requirements are primarily focused on ensuring a supply-demand balance when unforeseen or uncontrollable events lead to a reduction in electricity generation (or increase in load), the opposite scenario of over-generation is also important, especially from an economic point of view. Because wind and PV, in particular, are not fully dispatchable sources of power, electricity generation from these plants may need to be curtailed in over-generation conditions, and ReEDS estimates the level of that curtailment.[110] Because ReEDS is not a unit commitment and hourly dispatch, its treatment of these resource adequacy considerations requires approximations. As such, although ReEDS results are presented here, the grid integration and operability impacts of high penetrations of renewable electricity are further examined with the GridView model in Chapter 4. Even with the GridView results, however, a complete analysis of the integration challenges associated with high levels of variable generation is beyond the scope of the present study. Text Box 1-1 and RE Futures Volume 4 identify other issues and challenges associated with variable generation that may be confronted as renewable energy penetration increases but that are not addressed fully in RE Futures.

2.5.1 Planning Reserves and Capacity Value

The capacity value of non-variable/dispatchable generation technologies represents the proportion of nameplate capacity that can be (statistically) counted toward planning reserves and is approximated in ReEDS as the nameplate capacity of the generator. In contrast, because variable generation technologies (wind and PV) cannot as reliably deliver their nameplate capacity at times of system stress, the capacity value of these technologies is typically well below nameplate capacity. In addition, as variable generation increases, the capacity value of these resources will tend to decrease due to correlations between the output of nearby wind or solar plants,[111] and because the peak "net load" of the system (i.e., load minus variable

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[109] Specifically, planning reserves are required to exceed the highest forecasted demand by approximately 12.5%–17.2%, depending on the region (Short et al. 2011).

[110] Conventional power plants also regularly "curtail" power when the plant operator decreases power output below nameplate capacity. These reductions in output, and the dispatch of conventional power plants more generally, are necessary to maintain a balance between supply and demand, and are not strictly defined as "curtailment" in RE Futures. Curtailing wind and PV does not represent a fundamentally different principal, but because the variable operating cost of wind and PV are lower than fossil units, the economic consequences of curtailing wind and PV are more severe, making such curtailment the last action likely to be pursued by an electric system operator. When making investment decisions, ReEDS considers the lower capacity factor of a potential plant (either renewable or conventional) as a result of dispatch or curtailment.

[111] Wind and solar output are determined by the immediate weather conditions (e.g., wind speed or solar insolation) so the output profiles of proximately located wind (or PV) plants are generally correlated with each other. Having positive correlations within a group of wind (or PV) power plants increases the likelihood that all members of the

generation) tends to shift to times when variable generation is more limited. ReEDS accounts for these nuances through the simplified methods described in Short et al. (2011). In general, the average capacity value of wind and PV is found to drop as renewable electricity penetration increases. When high solar deployment is observed, for example, the capacity value of PV drops significantly as the peak net load shifts toward the evening hours when PV output is limited or zero. The capacity value of wind can also change with a shift in peak net load.

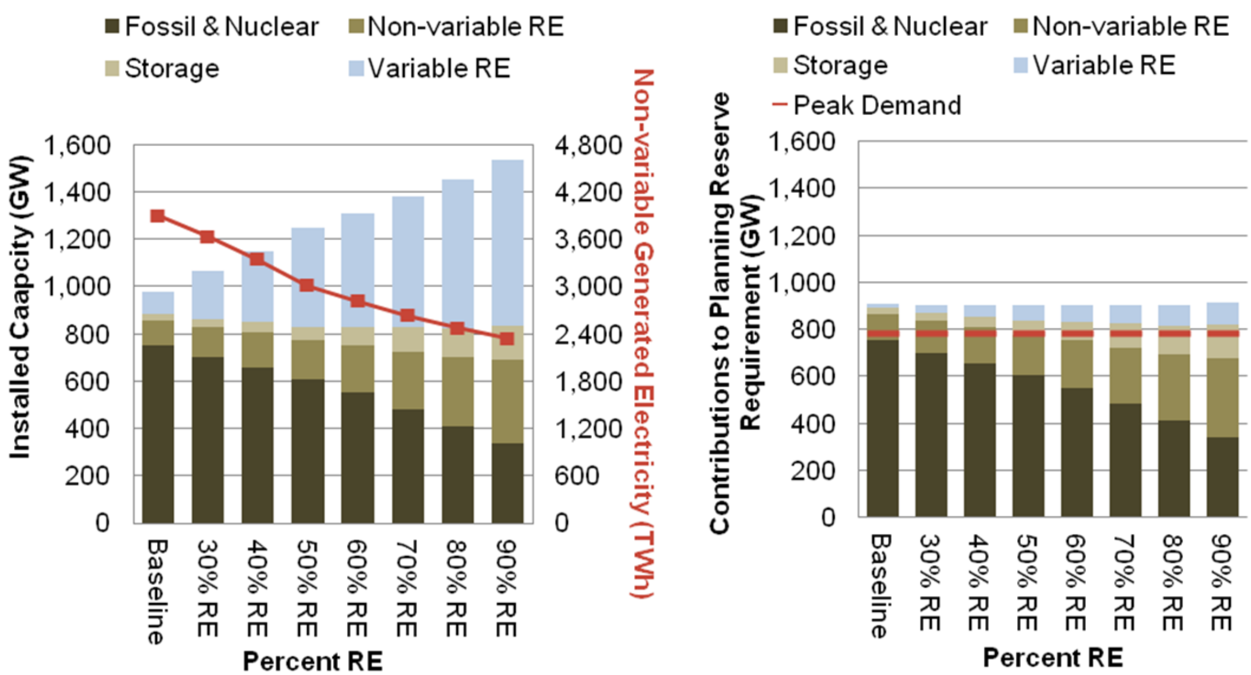
All of the ReEDS scenarios presented in this report have the same reserve margin, and thus, planning reserve requirement. In other words, the reserve margin, which partially helps to ensure resource adequacy, is independent of the level of (variable) renewable penetration in the system. *Wind and solar PV do not impose additional planning reserve requirements.* The ReEDS analysis, however, does not address the market structures necessary to provide adequate incentives to ensure that planning reserves are maintained, particularly with the increasing levels of variable generation. Furthermore, adequate transmission within each reserve-sharing group is needed, and the ReEDS modeling in RE Futures does not examine these transmission requirements within each of its 21 reserve sharing groups. Pursuing these analyses and topics of research is necessary to improve the understanding of the implications of high renewable scenarios.

Despite these limitations, the ReEDS model accounts for the lower capacity value of wind and solar PV in the high renewable penetration scenarios. Specifically, to ensure that planning reserve requirements are satisfied despite the reduced capacity value of variable generation technologies, large amounts of non-variable (renewable and conventional generation, and storage) capacity are found to remain available even if that capacity rarely operates. Figure 2-6(a), for example, shows that non-variable electric generation and storage capacity in 2050 under the progressively higher renewable electricity scenarios was only modestly lower than in the Low-Demand Baseline scenario, despite the very high penetrations of wind and solar PV in these instances; the overall electricity production from these non-variable energy sources, however, declined more dramatically. Specifically, non-variable generation and storage installed capacity by 2050 was found to drop by only 6% (880 GW to 830 GW) from the Low-Demand Baseline scenario to the 90% RE scenario, whereas electricity generation from these plants dropped by nearly 40% (from 3,890 TWh/yr to 2,340 TWh/yr). As described earlier, the ReEDS model enforces a planning reserve (resource adequacy) requirement that was set to a level that exceeds the forecasted peak demand by a reserve margin. Non-variable generation and storage technologies are assumed to contribute their full *installed* capacity toward this resource adequacy requirement, whereas variable generation technologies contribute less than the installed nameplate capacity (i.e., the capacity value of variable generation technologies is less than 1). Figure 2-6(b) shows the contribution of each technology type to the planning reserve requirement for the Low-Demand Baseline scenario and exploratory scenarios.[112] In comparing

group will have diminished power outputs simultaneously, thereby decreasing the capacity value of the group. On the other hand, negative correlations, such as frequently exist between nearby wind and PV plants, can increase the capacity value of the group as a whole.

[112] Figure 2-6(b) shows peak demand and resource adequacy contributions during the summer afternoon "time slice" in ReEDS, which is typically the time slice of highest demand for most regions. In actuality, the ReEDS model applies a separate planning reserve requirement for *each* time slice to account for reserve sharing groups that have

Figure 2-6(b) with Figure 2-6(a), it is clear that only a small fraction of the installed variable renewable capacity contributed to the resource adequacy requirement, especially at the higher levels of renewable energy penetration (e.g., in the 90% RE scenario, although there was more than 700 GW of installed wind and PV capacity, its contribution to the planning reserve requirement is less than 100 GW). Finally, Figure 2-6(b) also shows that the forecasted bus-bar peak demand in 2050 (about 780 GW), the overall contribution to planning reserves (about 900 GW), and the national average reserve margin (about 15%) are the *same across all of the scenarios*, independent of renewable penetration. In other words, the planning reserve requirement and capacity value calculations used in the ReEDS model attempt to ensure that the deployment in every year and every scenario has a comparable degree of "reliability" from a resource adequacy perspective—however, as described in Text Box 1-1, a full reliability assessment is beyond the scope of RE Futures.



(a) Installed capacity and non-variable generation in 2050

(b) 2050 Contribution to planning reserve requirement by technology

Figure 2-6. Installed capacity and planning reserve contributions in 2050 as renewable electricity levels increase

The trends shown in Figure 2-6 did not yield *increases* in the amount of conventional fossil capacity on the system as renewable energy penetrations increase; even renewable sources with variable generation profiles have some capacity value, particularly over large areas, and therefore offset the need for conventional capacity. Variable generation does not impose additional

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winter peaking demands or in circumstances where the effective or net peak load shifts from the afternoon to the evening. In other words, the planning reserve requirement may be "binding" in different time slices for different regions, and can shift from one year to the next. For simplicity, Figure 2-6(b) shows the resource adequacy contributions during the summer afternoon time slice only, and for the United States as a whole.

planning reserve requirements. Instead, the result of these trends is that high penetrations of variable renewable generation tend to depress the generation of conventional energy plants to a greater extent than their capacity, yielding a conventional generation mix that is found to operate at lower average capacity factors than otherwise would be the case.[113]

Trends in natural gas exemplified this result. For example, in the Low-Demand Baseline scenario, 16% (690 TWh) of total U.S. electricity generation came from the 390 GW (42% of all generation capacity) of natural gas capacity that was forecast to be online by 2050. Natural gas capacity in 2050 remained significant at 360 GW (35% of all generation capacity) in the 30% RE scenario; 310 GW (25% of all generation capacity) in the 60% RE scenario; and 230 GW (17% of all generation capacity) in the 90% RE scenario, but electricity generation from these plants dropped to 10% (400 TWh), 3% (140 TWh), and 2% (80 TWh), respectively.[114] Due to the relatively low capital cost of natural gas plants, particularly combustion turbine technologies, ReEDS found natural gas plants to be among the most cost-effective for satisfying planning reserve requirements, but those plants were generally also found to operate only to meet acute periods of electric system need. This follows standard practice today where natural gas combustion turbines are typically used to meet peak load and other critical needs for power only.

2.5.2 Operating Reserves

ReEDS seeks to balance supply and demand not only by ensuring adequate overall capacity on the system but also by ensuring adequate operating reserves (delivered by both supply- and demand-side technologies) to manage variability and uncertainty in load and generation at short timescales—seconds to minutes. These operating requirements can be viewed as another form of "reserve" capacity that is needed by the electricity system as a whole, and these needs increase with higher penetrations of variable renewable generation. *Of most interest here is that imperfect forecasts of the output of wind and PV require additional operating reserve capacity*; as the capacity of these variable sources increases, forecast errors are assumed to become larger in absolute terms, driving operating reserve capacity requirements higher.

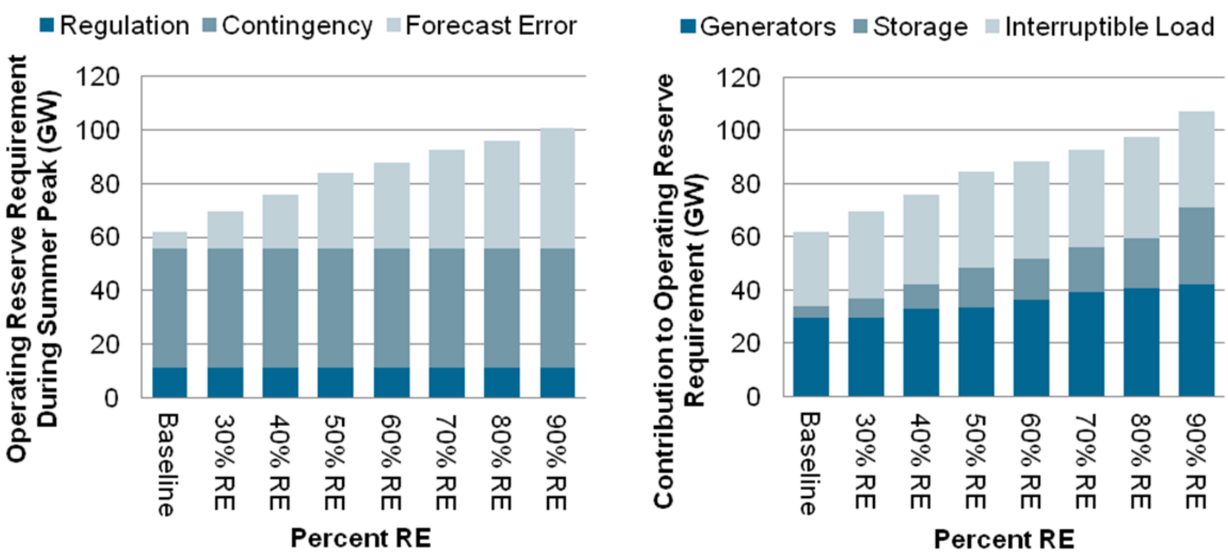
Using the simplified algorithms described in Short et al. (2011), Figure 2-7(a) shows the increasing operating reserve requirements estimated by ReEDS as renewable energy deployment increases.[115] However, while operating reserve *requirements* increase with wind and PV

[113] Although ReEDS captures the full—capital, fuel, and (fixed and variable) O&M—set of costs, it does not address the issue of cost allocation for different services, including reserve services. Further work is needed to understand how cost allocation and recovery are achieved under high renewable scenarios.

[114] Because of the coarse time slices in ReEDS, electricity generation for ancillary services (e.g., contingency events or intra-time slice load following) is not counted in the model. Therefore, the electricity generation from natural gas is likely underestimated in the RE Futures analysis. As discussed in Chapter 4, estimates of the contribution to electricity supply from natural gas based on the hourly GridView model were higher than are those from ReEDS, but the qualitative trends described here still apply.

[115] Differences in operating reserve requirements among these scenarios are entirely associated with differences in forecast error reserves, as the other operating reserves considered in ReEDS were assumed to be identical for all low-demand scenarios; specifically, contingency reserve and frequency regulation requirements were assumed to equal 6% and 1.5% of demand, respectively, regardless of the scenario. The assumption of uniform frequency regulation reserves for all renewable target scenarios is inaccurate, and further work is necessary to quantify the incremental need for regulation as variable generation increases, and to incorporate appropriate algorithms into ReEDS. Estimations of forecast error reserve and contingency reserve requirements, on the other hand, were likely

deployment (due to greater forecast errors), because the dispatch of existing conventional units declines to accommodate the additional wind and PV generation, these existing conventional units were found to be more available (unless retired) to satisfy the necessary operating reserve requirements.[116] In other words, an increasing fraction of the existing conventional fossil fleet may evolve from an energy-providing role to a reserve-providing role as renewable energy supply increases, thereby reducing the need to install new generation capacity solely to meet operating reserve requirements. Figure 2-7(b) shows the different technology types used to satisfy the operating reserve requirements for the different renewable electricity penetration scenarios.[117] The figure shows how the contribution from electricity generators (primarily natural gas and hydropower) grows with renewable deployment. For example, the contribution from generators grows from less than 30 GW in the Low-Demand Baseline scenario to more than 42 GW in the 90% RE scenario.



(a) 2050 operating reserve requirement during the summer peak by reserve type

(b) 2050 contributions toward total operating reserve requirement by technology type

Figure 2-7. Operating reserve requirements as renewable energy levels increase

conservative. For the former, ReEDS relies on 1-hour-ahead persistence forecasts, which are unlikely to be as accurate as those forecasts used in practice or that will be used in the future. Moreover, with the retirement of large coal and nuclear units under the higher penetration renewable energy scenarios, contingency reserve requirements might be expected to decline; the contingency reserve requirement is commonly based on the single largest plant or transmission line serving a reserve-sharing group—therefore, the amount of reserves needed to maintain the same reliability in the absence of a large generator may be reduced.

[116] This finding is consistent with more-detailed integration studies such as GE (2010).

[117] In Figure 2-7(b), the total contribution to operating reserves exceeds the requirement due to the fact that only one time (summer peak) is shown, while certain reserve-types (e.g., interruptible load) are annual in nature and deployed to serve other times not shown. In addition, Figure 2-7(b) shows the amount of generation and storage capacity dedicated for operating reserves during the summer peak timeslice and not the total installed capacity.

Dispatchable generation and storage technologies were assumed in ReEDS to contribute to operating reserves in varying degrees based on the nature of the reserves and the physical limitations of the technology. For example, coal-powered plants were assumed to be capable of offering spinning reserves for contingency events when operating below nameplate capacity, but they were assumed to be unable to contribute toward quick start (non-spinning) reserves if they were offline due to their inability to start up in the 10-minute timescale needed to support contingency events.[118] In addition to supply-side contributions, demand-side contributions to operating reserves were found to play an important role as renewable energy levels increased. Based on the assumptions for interruptible load detailed in RE Futures Volume 3, Figure 2-7(b) shows the forecasted adoption of interruptible load in 2050 with growing penetrations of renewable energy: 28 GW of interruptible load in the Low-Demand Baseline scenario, 33 GW in the 30% RE scenario, 36 GW in the 60% RE scenario, and 36 GW in the 90% RE scenario. FERC estimated the amount of interruptible load used in the United States in 2009 to be 15.6 GW (FERC 2009). As a fraction of total operating reserves, however, the contributions of interruptible load declined as renewable energy deployment rose; this is due to (1) the assumed increase in cost of interruptible load at higher levels of deployment and (2) the increasing availability of idle conventional plants to offer operating reserve services as renewable energy increasingly displaces generation from conventional fossil plants. Regardless, interruptible load was found to play a sizable role in helping to manage system operations under the high-penetration renewable electricity futures presented here. Similarly, as shown in Figure 2-7(b) for operating reserves, and as discussed further below, storage was also found to play an increasing role as renewable energy penetration increased.

2.5.3 Curtailment and Storage

The integration challenges considered in RE Futures are not limited to potential shortfalls in meeting demand but also include the curtailment of wind and solar energy in instances in which aggregate generation supply exceeds available demand and storage capacity. Figure 2-8(a) shows how the estimated annual amount of curtailed energy from variable resources (wind and PV) increased with increasing renewable electricity (the amount of curtailed energy also increased over time within each scenario as growing quantities of wind and PV were deployed). ReEDS estimated that by 2050, 2% of all variable wind and PV generation would be curtailed in the 30% RE scenario, 4% in the 60% RE scenario, and 7% in the 90% RE scenario.[119] Although conventional power plants also regularly curtail their output at below nameplate capacity as they respond to dispatch instructions,[120] curtailment has a larger impact on the relative economics of

[118] In contrast, natural gas combustion turbines were assumed capable of contributing to contingency reserves even if they were not operating.

[119] As will be shown in Chapter 4, in comparison to GridView, ReEDS underestimated curtailment by approximately a factor of 2 because it did not adequately capture transmission congestion at the hourly level.

[120] Conventional power plants also regularly "curtail" power when the plant operator decreases power output below nameplate capacity. These reductions in output, and the dispatch of conventional power plants more generally, are necessary to maintain a balance between supply and demand, and are not strictly defined as "curtailment" in RE Futures. Curtailing wind and PV does not represent a fundamentally different principal, but because the variable operating cost of wind and PV are lower than fossil units, the economic consequences of curtailing wind and PV are more severe, making such curtailment the last action likely to be pursued by an electric system operator. When making investment decisions, ReEDS considers the lower capacity factor of a potential plant (either renewable or conventional) as a result of dispatch or curtailment.

more capital-intensive and lower-operating-cost technologies, such as wind and PV, compared to conventional power plants.

Increased storage capacity not only provides valuable services to the electricity system as a whole and contributes toward planning (Figure 2-6) and operating (Figure 2-7) reserve requirements, but can also help reduce the need to curtail variable generation technologies by storing excess generation in times of low demand. Figure 2-8(b) shows the ReEDS-estimated increase in total storage capacity[121] as renewable electricity penetration increases, and shows that this increase tracks the overall increase in variable generation as a proportion of total electricity supply. It is noted that utility-controlled charging of electric vehicles also reduced curtailment to some degree by focusing charging times during periods of high variable generation, low demand, or both.[122]

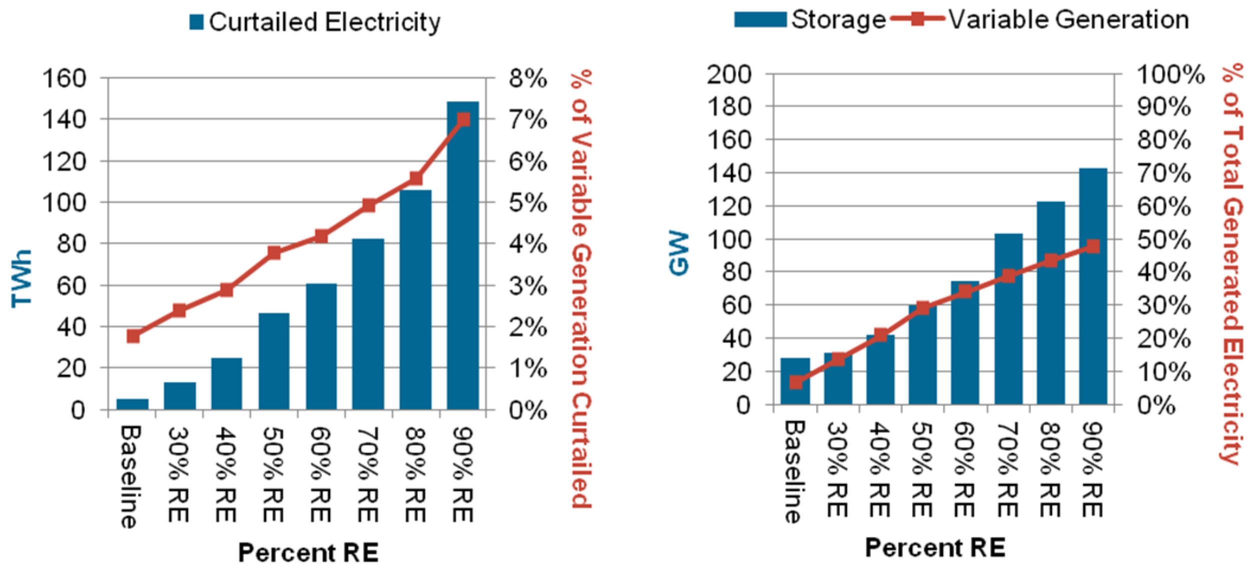
By 2050, storage capacity was estimated at 28 GW in the Low-Demand Baseline scenario, 31 GW in the 30% RE scenario, 74 GW in the 60% RE scenario, and 142 GW in the 90% RE scenario. Based on the assumed resource, cost, and performance assumptions presented in Black & Veatch (2012), ReEDS projected that new storage installations would be predominantly CAES plants, although small amounts of new PSH and utility-scale batteries were also present in the highest renewable energy penetration scenarios. Further deployment of storage technologies was limited by the relatively high-assumed costs (particularly for utility-scale batteries), location dependence (based on geology for CAES and water resources for PSH), and efficiency losses.[123] *RE Futures did not attempt to fully evaluate, nor did it comprehensively compete, different storage technologies*. In particular, although ReEDS does capture the increased need for operating reserves as greater levels of variable generation are deployed (which storage can provide), it does not disaggregate various market opportunities for different storage technologies. For example, ReEDS does not fully differentiate between ancillary service markets, nor does it fully capture the different roles that different storage technologies may play in providing such services. As a result, no attempt was made to model several short-term storage devices such as flywheels and batteries currently being deployed to provide frequency regulation and other high-value grid services. In addition, explicit modeling of the distribution system is not included in RE Futures; therefore, the analysis is unable to identify the potential value and opportunities of storage sited in the distribution system. Additionally, the resource for PSH used in the ReEDS

[121] Because ReEDS is not a chronological model, the number of hours of storage was not well captured. Moreover, only daily (less than 24 hours) storage was assumed, with seasonal storage not considered. GridView is a chronological hourly model and assumed 8 hours of storage for PSH plants and 15 hours of storage for CAES plants.

[122] In all results presented here, transportation electricity load was assumed to be 356 TWh in 2050, of which 165 TWh were assumed to be utility-controlled. The 165 TWh under utility control were found by ReEDS (and GridView) to be charged in large part during periods in which curtailment occurred.

[123] Thermal storage in commercial buildings was also considered in the modeling, but the assumed costs and limitations of thermal storage prevented significant penetrations of this technology in ReEDS. Specifically, thermal storage is represented in ReEDS by ice and chilled water devices, and is therefore restricted to temporally shifting cooling demands. Because curtailment is most prevalent in the winter and spring, thermal storage does little to reduce energy curtailment. In addition, thermal storage devices were disallowed from contributing to operating reserves, in contrast to supply-side storage options, and therefore were disadvantaged in the ReEDS modeling. Furthermore, ReEDS did not capture the very significant distributed benefits of thermal storage. Under different cost or capability assumptions, thermal storage in commercial buildings may play a larger role in high renewable futures.

model was conservatively limited to the existing FERC queue only, and further work is needed to expand this resource assessment. As a result of these factors, ReEDS will undervalue many opportunities for storage and likely understate its adoption into the marketplace. RE Futures Chapter 12 (Volume 2) discusses other opportunities for storage technologies that are not considered in the modeling analysis.



(a) Curtailed electricity in 2050 (b) Storage capacity in 2050

Figure 2-8. Curtailment and storage capacity as renewable energy levels increase

The future storage deployment results from ReEDS present the general amount of storage that might be helpful to support high renewable electricity futures. However, there are large uncertainties associated with the future mix of storage types and ReEDS does not capture many of these uncertainties (see RE Futures Chapter 12 [Volume 2] for a discussion of some of the major considerations for future storage deployment). As a result of the modeling assumptions, most of the new storage is CAES; however, the tradeoff between CAES and PSH is largely due to the data limitations in the ReEDS model, where the vast majority of potential PSH in much of the United States was not evaluated. In addition, the relative risk associated with CAES versus PSH was not considered. PSH is a proven technology, while CAES has yet to be deployed in either bedded salt or in porous rock formations, which represents a large fraction of assumed deployments. The limited deployment of batteries estimated by ReEDS is due to their high cost and assumed minimal projected cost reduction over time as well as to a lack of full valuation of their benefits to bulk power and distribution systems. Overall, ReEDS results demonstrate an obvious discrepancy with relative historical and proposed deployment of these technologies, where PSH dominates. The analysis of energy storage technologies for RE Futures demonstrates the need for more comprehensive estimates of the cost and resource availability for both CAES and PSH, as well as a more complete assessment of the various benefits of energy storage as renewable energy penetrations increase.

2.5.4 Flexible Generation

High levels of renewable energy deployment would also have substantial consequences for the operations of fossil and nuclear plants. Figure 2-9 shows national dispatch stacks for 2050 within each of the ReEDS 17 time slices, ordered by season and time of day, for the Low-Demand Baseline, 60% RE, and 90% RE scenarios. Plant operation and dispatch in the Low-Demand Baseline scenario was as follows: nuclear and coal plants operate largely in base-load mode; hydropower operates in an intermediate mode with some variation across time periods[124]; and natural gas plants operate as intermediate and peaking units with greater variation in use across different time periods.[125] Under the 60% RE scenario, much of the coal fleet was retrofitted to co-fire biomass, and those units continued to operate in largely a base-load fashion throughout the year in order to maintain their ability to deliver biomass electricity generation. The remaining (non-co-firing) coal capacity, however, operated with significant daily ramping in the non-summer months and with significant seasonal variations in output. Natural gas plants continued to serve intermediate and peaking needs, and power output from the nuclear fleet remained constant throughout the year. In the 90% RE scenario, greater changes to conventional plant operations were apparent. Seasonal variations and diurnal ramping of co-fired coal units were observed, with units ramping daily from their minimum load levels to their nameplate capacity during non-summer months. Significant seasonal variations in nuclear energy output also became common, and natural gas plants were used solely as summer "peakers." CSP plants were found to leverage their thermal storage capability to generate power in the evening and night times. The impact of such operational changes on power plant wear-and-tear and maintenance costs were not assessed fully in either ReEDS or in RE Futures as a whole, although the GridView results presented in Chapter 4 provide stronger documentation of the operational feasibility of such dispatch schedules.

The dispatch stacks in Figure 2-9 also show the time slices in which generation exceeded demand, indicating the times when there were high levels of curtailment. Excess generation was most prevalent during the non-summer seasons, and especially during spring, due to the lower electricity demand and higher wind output during those periods. Because high levels of transmission losses and curtailment occurred throughout the non-summer seasons and in multiple time slices during those seasons, there was a limit to the ability of diurnal storage technologies (e.g., CAES, PSH) to minimize curtailment. The development of seasonal storage technologies and/or a flattening of the demand profile across seasons through various demand-side management approaches could have more significant impacts on curtailment levels.

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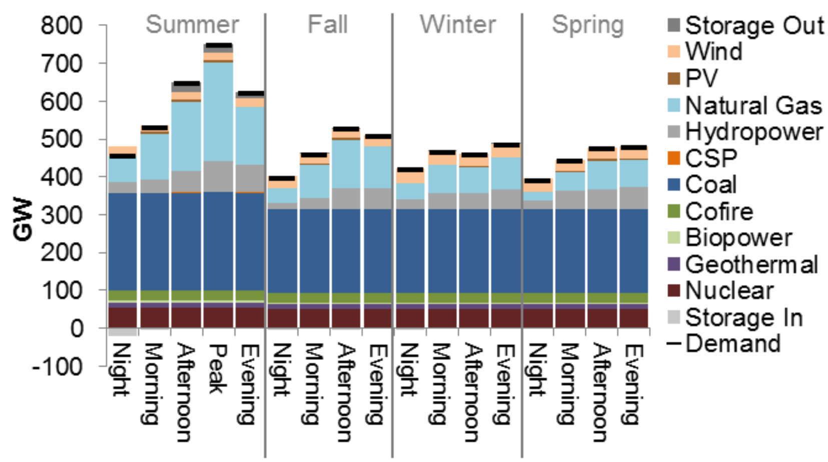
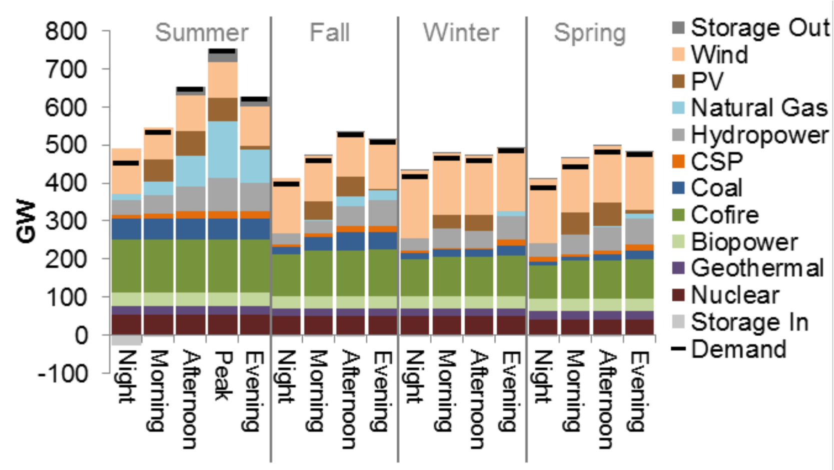
[124] Existing hydropower plants were treated as dispatchable generators with seasonally varying limits. However, new hydropower plants represent "run-of-river" plants and were limited in the modeling to have flat profiles within each season.

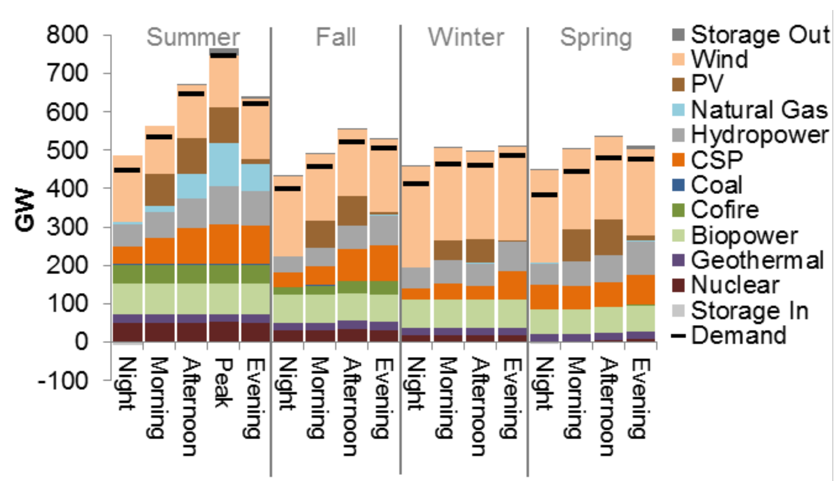
[125] In today's U.S. electricity system, plants are generally and loosely categorized into three types based on their dispatch characteristics: base-load, intermediate, and peaking. *Base-load* units refer to plants that are largely operating at high and constant output for many hours of the year due to their low operating and fuel costs (e.g., large coal and nuclear power plants). *Peaking* units have higher variable costs (e.g., natural gas combustion turbines) and therefore are only used relatively sparingly, often during times of high demand, such as during summer afternoons when air conditioning use is high. The dispatch of *intermediate* units lies somewhere in between the base-load and peaking units (e.g., natural gas combined cycle); the dispatch of intermediate units is variable throughout the year, including days and seasons when constant output is required, other times of year when the units are cycled and ramped daily, and some seasons when the intermediate units are sparingly used. ReEDS represents natural gas combustion turbine and combined cycle capacities independently.



(a) Low-Demand Baseline scenario – 2050 dispatch by time slice



(b) 60% RE scenario – 2050 dispatch by time slice



(c) 90% RE scenario – 2050 dispatch by time slice

Figure 2-9. Dispatch stacks for Low-Demand Baseline, 60% RE, and 90% RE scenarios

Overall, these results show that high-penetration renewable electricity futures will require substantial changes in how the electricity system is planned and operated. Moreover, the dispatch stacks in Figure 2-9 suggest that the operational challenges associated with integrating high penetrations of renewable electricity may be particularly acute in months with lower electricity load because greater ramping is needed from conventional generators and greater curtailment from renewable generators.[126] At the same time, the electric sector modeling presented here suggests that variable generation levels of up to nearly 50% of annual electricity can be accommodated when a broad portfolio of supply- and demand-side flexibility resources and options were made available in the scenario modeling, and were relied upon particularly in the high renewable generation scenarios. These flexibility options include:

- Maintaining sufficient capacity on the system for planning reserves
- Relying on demand-side interruptible load, conventional generators (particularly natural gas generators), and storage to manage increased operating reserve requirements
- Mitigating curtailment with storage and controlled charging of electric vehicles
- Operating the system with greater conventional power plant ramping
- Relying on the dispatchability of certain renewable technologies (e.g., biopower, geothermal, CSP with storage and hydropower)
- Leveraging the geospatial diversity of the variable resources to smooth output ramping
- Transmitting greater amounts of power over longer distances to smooth electricity demand profiles and meet load with remote generation

Achieving the system flexibility required to integrate high levels of renewable generation will require some combination of technology advances, new operating procedures, evolved business models, and new market rules. Although the analysis does not examine how these mechanisms could be implemented, it does describe the power system flexibility characteristics needed for the integration of high levels of renewable generation.

[126] A fundamental shift in end-use demand profile could significantly alter the dispatch stacks presented here. For example, new industrial loads might take advantage of the potentially low-cost electricity in the off-peak months, thereby using the curtailed electricity identified in the ReEDS modeling. Further work is needed to evaluate the economic consequences of such new and altered practices by electricity end-use entities, beyond the simple interruptible load programs considered in RE Futures.

2.6 Summary

In summary, the results presented in this chapter suggest that achieving high levels of renewable electricity penetration in the United States would be demanding but achievable. At the same time, there are at least two major limitations to the work presented to this point. First, the analysis has focused on progressively increasing levels of renewable electricity penetration, but under a single set of fundamental input assumptions relating to transmission, electric system operation, renewable supply, demand, fossil energy prices, and fossil technologies. Second, the economic modeling framework used in this section is not a detailed time-series model, and is not able to address a number of the operational impacts or to assess fully the grid feasibility of a high-penetration renewable electricity future. The next two chapters address these limitations. Specifically, as described in Chapter 3, ReEDS was employed to evaluate a range of alternative scenarios, each of which was designed to elucidate the possible impact of varied system conditions. As described in Chapter 4, GridView was used to perform a more detailed (but still partial) technical assessment of the operational feasibility of meeting a high-penetration renewable electricity future. For the purpose of these further analyses, emphasis was placed on the 80% RE scenario. The 80%-by-2050 renewable electricity penetration level was selected because the analysis presented in this chapter suggested that such a penetration level was aggressive but potentially viable. Moreover, due to an abundance and diversity of both supply- and demand-side technologies, electricity supply and demand was found to balance in the ReEDS analysis even in an 80% renewable electricity future. Finally, the carbon emissions from the 80% RE scenario, as described in Section 2.3, were reasonably consistent with other low-carbon or clean-energy scenario analyses (see Appendix A).

Chapter 3. Envisioning a Future with 80% Renewable Electricity

The analysis presented to this point suggests that an 80%-by-2050 renewable electricity future may be viable, but Chapter 2 largely focused on one of many possible 80% renewable electricity futures. In this chapter, the ReEDS model is used to compare this scenario, referred to as the 80% RE-ITI scenario, to several alternative RE Futures scenarios, each of which meets the same 80%-by-2050 renewable electricity penetration level. As described in Section 1.3.2, these alternative scenarios focus on alternative assumptions around technology advancement, system constraints, and future electricity demand.

The three different renewable technology improvement scenarios (80% RE-ETI, 80% RE-ITI, and 80% RE-NTI scenarios) and the three constrained scenarios (Constrained Transmission, Constrained Flexibility, and Constrained Resources scenarios)[127] make up the six core 80% RE scenarios evaluated in Sections 3.1–3.5. In addition to reporting the results of these core 80% RE scenarios, which assume a low-demand trajectory, this chapter reports the results of more-traditional high-demand scenarios, using the "business-as-usual" forecast highlighted in Section 1.4.1. Details on the specific design and implementation of these 80%-by-2050 RE scenarios are described in Figure 3-1. (Results from the fossil fuel cost and technology improvement sensitivity scenarios can be found in Appendix A.)

In combination, comparisons among these different scenarios are intended to help characterize and bound the possible challenges and implications of achieving an 80% renewable electricity future, while also informing key energy system decisions that may affect the feasibility and implications of reaching high levels of renewable electricity penetration. None of these scenarios is posited to be more likely than any other; the realization of the results from, or assumptions that went into, any of the scenarios will depend on the decisions made over the next 40 years.

[127] For analytic simplicity and ease of comparison, these constrained scenarios used the incremental renewable technology improvement estimates.

80% RE-ITI

- Set the cost and performance of all renewable technologies to be those projected in incremental technology improvement estimates, reflecting only partial achievement of possible future technical advancements

80% RE-ETI

- Set the cost and performance of all renewable technologies to be those projected in evolutionary technology improvement estimates, reflecting a more complete achievement of possible future technical advancements

80% RE-NTI

- Set the cost and performance of all renewable technologies to their 2010 values through 2050
- 2010 cost and performance values are based on RE-ITI estimates

Constrained Transmission

- Triple costs of transmission lines
- Only allow new transmission lines along existing coridoors between BAs
- Disallow new intertie capacity
- Double the deployment of rooftop PV (most other scenarios assumed 85 GW by 2050)
- Double transmission loss factors
- Limit transmission of variable generation to 1,000 miles (all other scenarios assumed a 2,000-mile limit)

Constrained Flexibility

- Halve the capacity value of wind and PV
- Double the reserves required for wind and solar forecast errors
- Set the required minimum load of coal and biomass plants to 70% (all other scenarios assumed 40%)
- Cap availability of interruptible load to 2010 levels in all years

Constrained Resources

- Halve the available resource base for all renewable energy technologies (except utility-scale and distributed PV)
- For biopower, this meant halving the available biomass feedstock

High-Demand 80% RE

- "Business-as-usual" higher growth in electricity demand
- 50% greater deployment of rooftop PV

Figure 3-1. Variations in model assumptions for (low-demand) core 80% RE and High-Demand 80% RE scenarios

3.1 Meeting 80%-by-2050 Renewable Electricity Penetration Would Require Renewable Energy Capacity Additions of 20–45 GW Per Year

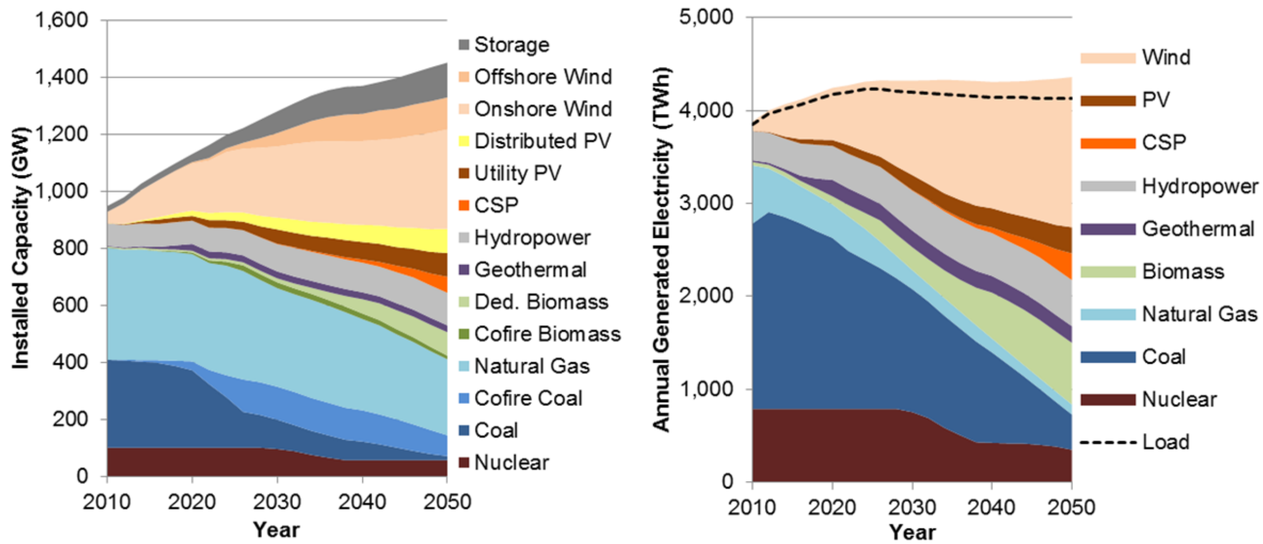
Meeting an 80%-by-2050 renewable electricity future would require a significant increase in renewable capacity and energy supply. Because the selection of renewable technology type, quantity, timing, and location depend on a large number of unknown and uncertain factors, an accurate projection of renewable technology deployment is not possible. Growth in capacity and supply of each renewable technology considered in the analysis was found to occur in all 80%-by-2050 RE scenarios. General trends observed across the scenarios, are discussed in the following sections using the 80% RE-ITI scenario as an example.

Focusing on the 80% RE-ITI scenario, Figure 3-2 presents estimated cumulative installed capacity and energy supply during the study period. Figure 3-3 depicts annual additions for the renewable energy technologies alone. A diverse mix of renewable energy technologies was projected to be employed in the 80% RE-ITI scenario. Wind energy deployed rapidly beginning in 2010, initially dominated by onshore wind technology but with a growing proportion of offshore wind over time. The growth in solar energy was slower in early years, but PV and then CSP began to deploy rapidly in the later years of the forecast horizon. Both dedicated and co-fired biomass were found to contribute significantly to the renewable energy mix, with growth continuing throughout the forecast period, initially focused on co-fired plants and then on dedicated biomass facilities. New hydropower and geothermal[128] were found to contribute proportionately less than the other renewable energy technologies; even within these two technologies, however, capacity expansion was substantial, especially in the early (geothermal) to middle (hydropower) portion of the 2010–2050 time period.

In aggregate, approximately 20 GW of renewable energy capacity would need to be added each year during the first half of the study period and up to 45 GW per year thereafter to reach an 80% renewable electricity future by 2050, compared to approximately 7 GW added in 2010, and 11 GW added in 2009. These annual additions (Figure 3-3) include new renewable generation capacity and the replacement of retired capacity.[129] Total renewable energy capacity would expand from 130 GW at the end of 2010 to 540 GW by 2030 and 920 GW by 2050. This expansion and required growth rate could pose challenges to the renewable energy industries, as highlighted in Section 3.7.

[128] The available hydrothermal resource used in the ReEDS model was limited to approximately 30 GW, and most of this capacity deployed in nearly every 80%-by-2050 RE scenario. Discovery of new resources or widespread application of enhanced geothermal technology could increase the contribution of geothermal resources.

[129] In ReEDS, renewable capacity is automatically replaced at the end of the assumed physical lifetimes (see Appendix A). The annual additions shown in Figure 3-3 include the replacement capacity (repowering). For this reason, annual builds for certain technologies (e.g., geothermal) show a repeating pattern.



(a) Capacity expansion, 2010–2050 (b) Generation expansion, 2010–2050

Figure 3-2. Capacity and generation expansion in the 80% RE-ITI scenario, 2010–2050

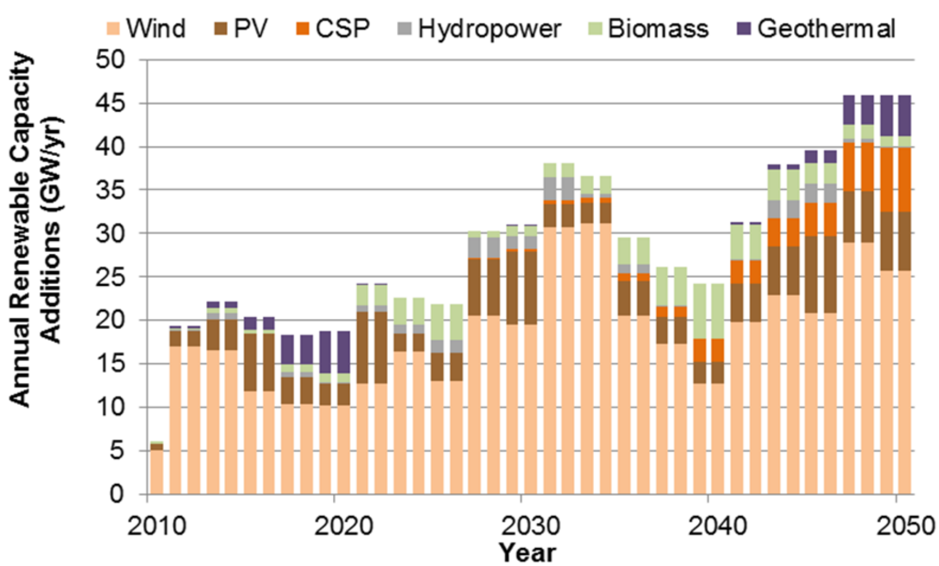


Figure 3-3. Renewable capacity expansion in 80% RE-ITI scenario

This figure includes new installations and the replacement of renewable power plants at the end of their assumed physical lifetimes.

As renewable energy supply increases during the study period, conventional fossil and nuclear generation decreases through plant retirements and reductions in capacity factors. Dedicated coal plant capacity and supply, in particular, drop rapidly, although coal generation from co-fired plants continued throughout the period. Natural gas capacity, meanwhile, remains largely constant in order to meet overall reliability needs, as discussed in Section 2.5.1, but the generation of electricity from those plants declines steadily and significantly with time as renewable electricity generation increases.

3.2 Substantial Renewable Resource Penetrations Would be Required in Every Region

Focusing again on the 80% RE-ITI scenario, Figure 3-4 presents the generated electricity and installed capacity in 2050 by region and technology, and compares total regional generation in 2050 to regional electricity demand in the same year.[130]

As shown in Figure 3-4, several regions are forecast to be net exporters of electricity by 2050, with total electricity supply exceeding regional electricity demand. Most prominently, these include the Great Plains, Northwest, and Southwest regions. Several other regions are found to be net importers of electricity generation, including the Southeast, Florida, and Texas. As described in Section 3.4, new transmission would be required to support these inter-regional electricity transfers.

In the 80% RE-ITI scenario, wind energy supply was significant in most regions, but was most prominent in the Great Plains, Great Lakes, Central, Northwest, and Mid-Atlantic regions (with a large fraction of wind generation coming from offshore resources in the Northeast and Mid-Atlantic regions). Solar energy was found to deploy most substantially in the Southwest (dominated by CSP), followed by California and Texas (CSP and PV), and then by Florida and the Southeast regions (dominated by PV). Biomass supply was most significant in the Great Plains, Great Lakes, Central, and Southeast regions. The significant biomass supply required a large quantity of feedstock from diverse sources, including 14% from urban waste, 18% from mill waste, 11% from forest residue, 30% from agricultural residue, and 27% from dedicated crops. Additional information on biomass feedstock availability and use can be found in RE Futures Chapter 6 (Volume 2). Hydropower supply was most significant in the Northwest, but hydropower was also a sizable contributor in California, the Northeast, and the Southeast. Geothermal was found to deploy primarily in California and the Southwest.

Similar to Figure 3-4, in which the regional breakdown is based on the 11specified regions, Figure 3-5 shows the 2050 regional deployment of generation technologies for the 80% RE-ITI scenario, except the regions shown are generally based on NERC regional boundaries.[131]

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[130] The 11 regions shown in Figure 3-4 were designed arbitrarily and not based on transmission or other electric-grid boundaries.

[131] The regions depicted in Figure 3-5 are based on NERC regions in the Eastern Interconnection and NERC subregions in the Western Electricity Coordinating Council (see http://www.nerc.com/ for a description of NERC regions and subregions).

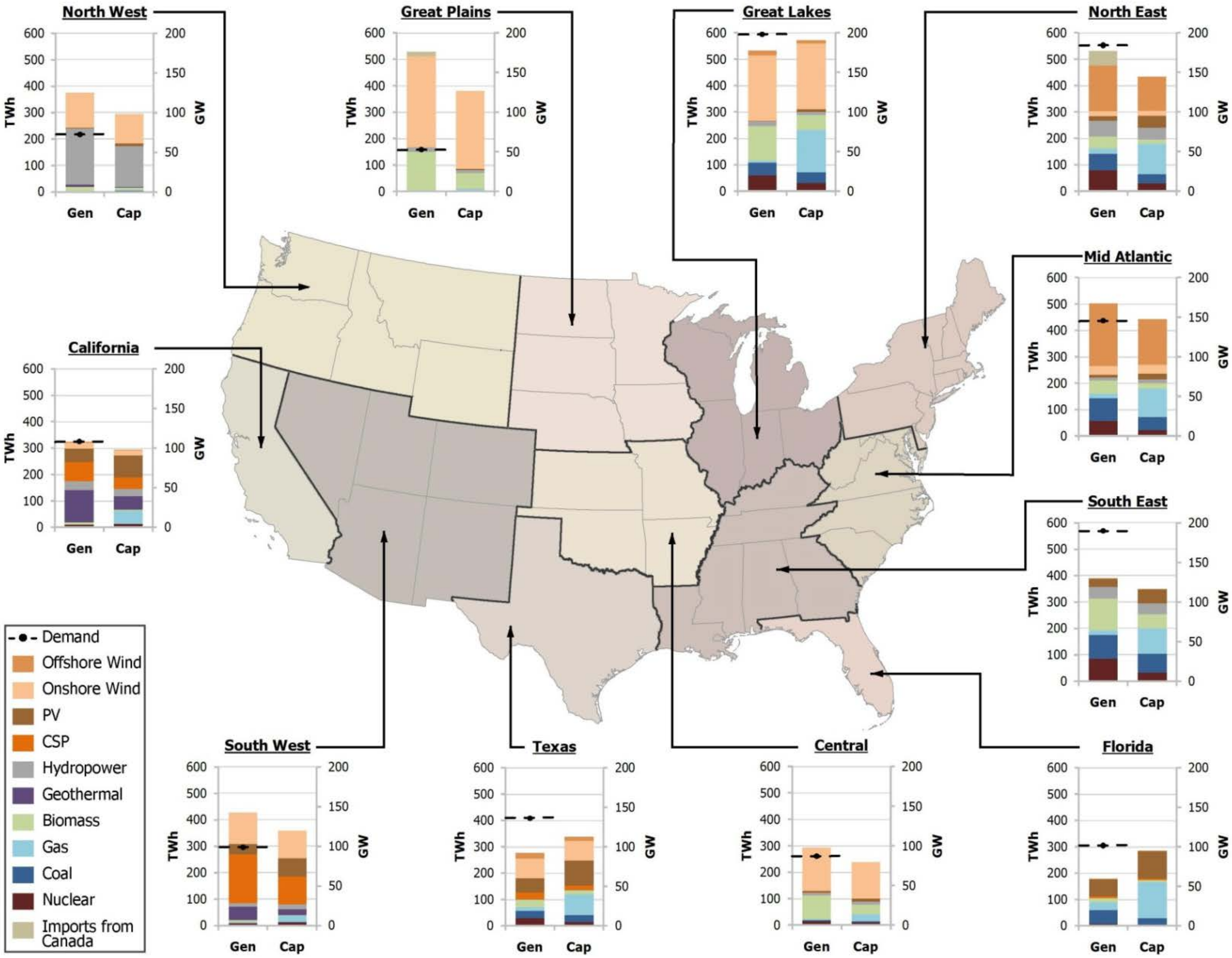


Figure 3-4. Renewable generation and capacity in 2050 in 80% RE-ITI scenario, by region

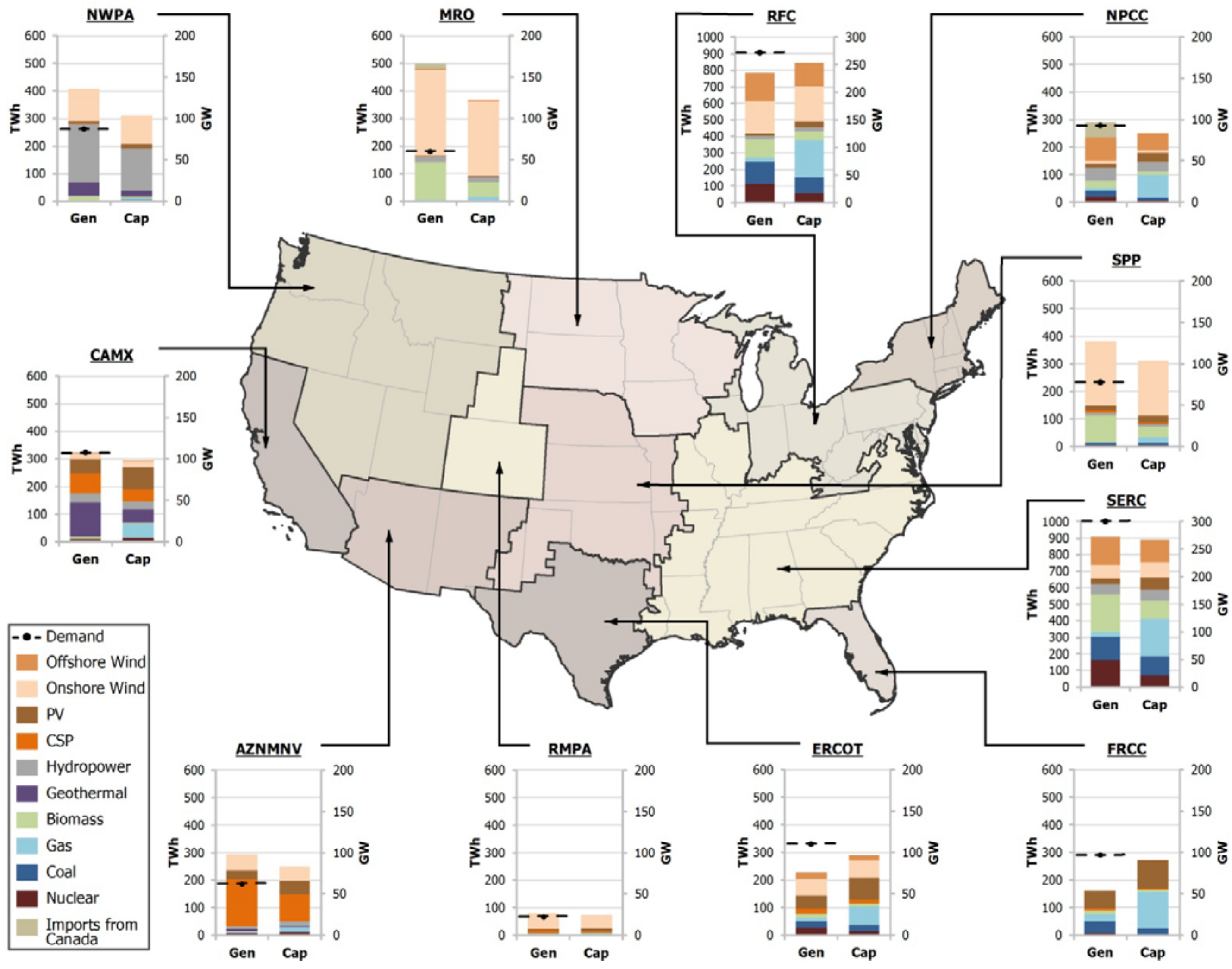


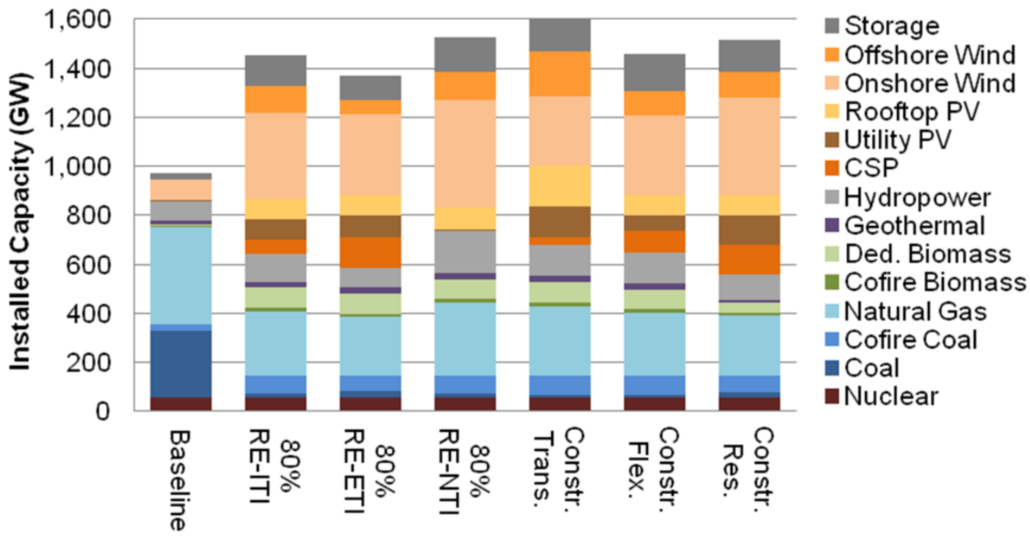
Figure 3-5. Renewable generation and capacity in 2050 in 80% RE-ITI scenario, by North American Electric Reliability Corporation region

AZNMNV = New Mexico Nevada
CAMX = California Mexico
ERCOT = Electric Reliability Council of Texas
FRCC = Florida Reliability Coordinating Council
MRO = Midwest Reliability Organization
NPCC = Northeast Power Coordinating Council
NWPA = Northwest Power Area
RFC = Reliability First Corporation
RMPA = Rocky Mountain Power Area
SERC = SERC Reliability Corporation
SPP = Southwest Power Pool

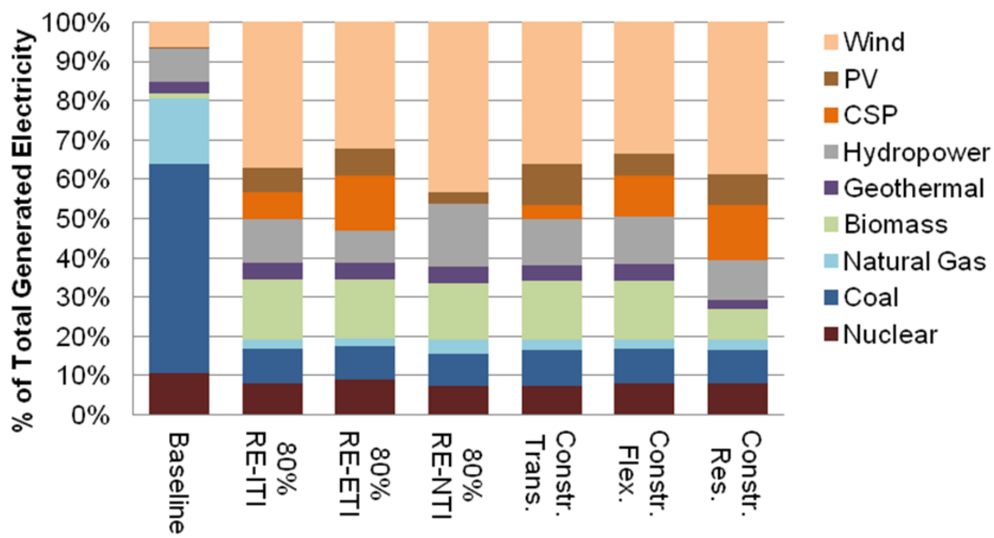
3.3 The Mix of Renewable Generation Technologies Changes to Accommodate Differences in System Conditions and Estimated Technology Improvements

While growth in capacity and supply of each renewable technology considered in the analysis was found to occur in all 80%-by-2050 renewable electricity scenarios, the specific mix of those technologies varied among the six core 80% RE scenarios. Because of the relatively low capacity factor and capacity value of some renewable energy technologies, the 80%-by-2050 renewable electricity scenarios required approximately 1,300 GW–1,500 GW of total electric generation capacity by 2050, compared to 950 GW in the Low-Demand Baseline scenario. Approximately 70% of total generation capacity was found to come from renewable technologies across all of the 80%-by-2050 renewable electricity scenarios, with the relative contribution of different renewable technologies varying by scenario (see Figure 3-6, Figure 3-7, and Table 3-1).

Wind energy was found to contribute 32%–43% of overall electricity generation by 2050 (of which offshore wind contributed 6%–16%), depending on the scenario. Solar energy contributed 3%–22%, depending on the scenario. The growth of CSP was found to be particularly sensitive to scenario design. The sensitivity in the contribution of solar energy was driven by the specific characteristics of solar; for example, CSP is transmission-dependent, PV is variable, and both technologies have high but uncertain cost reduction potential and extensive resource potential. Biomass was found to supply 8%–15% of total electricity generation by 2050, while hydropower's contribution was 8%–16%. Geothermal energy's contribution was 2%–4% because only commercial hydrothermal technologies were considered; geothermal supply could increase if advances in enhanced geothermal systems or other geothermal technologies are realized.



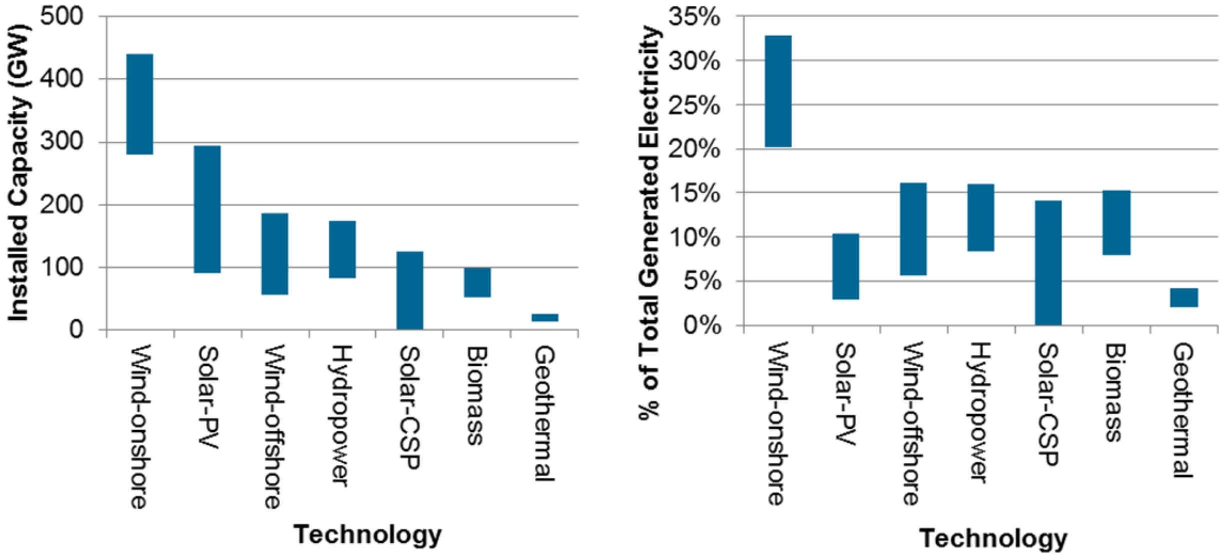
(a) Capacity mix in 2050



(b) Generation mix in 2050

Figure 3-6. Capacity and generation in 2050 in the Low-Demand Baseline and core 80% RE scenarios

Figure 3-7 and Table 3-1 show the range in 2050 capacity and generation by technology among the six low-demand core 80% RE scenarios. Although all of the scenarios meet the same 80% renewable electricity by 2050 penetration level, *the fraction of variable generation (wind and PV) ranges from 39% to 47%*. In Table 3-1, the "low" and "high" columns refer to the lowest and highest deployment levels observed across all low-demand core 80% RE scenarios, and thereby summarize the overall deployment range for each technology across the scenarios presented in this section.



(a) 2050 installed capacity by technology (b) 2050 contribution to total generated electricity

Figure 3-7. Range of 2050 installed capacity and annual generation by technology for the core 80% RE scenarios

Table 3-1. Summary of Cumulative Installed Renewable Capacity and Electricity Contributions in Core 80% RE scenarios[a]

Technology	Installed Capacity (GW) 2010	Installed Capacity in 2050 (GW) Low	High	Percentage of Generation Mix in 2050[b] Low	High
Wind Energy	40	390	560	32%	43%
Onshore	40	280	440	20%	33%
Offshore	0	56	180	5.6%	16%
Solar Energy[c]	2.6	91	330	2.9%	22%
Utility PV	0.3	5	120	0.3%	5.2%
Rooftop PV	1.8	85	170	2.6%	5.2%
CSP	0.5	1	130	0.1%	14%
Hydropower	77	81	170	8.3%	16%
Geothermal	3.4	12	25	2.1%	4.2%
Biomass Energy	6.7	52	98	7.9%	15%
Co-fired[d]	0	11	14	1.1%	1.5%
Dedicated	6.7	40	84	6.7%	14%
Total Renewable	130	880	1040	81%	81%

[a] The Total Renewable row in the Low and High columns is not the sum of the rows above because Low and High refer to the lowest and highest deployment levels observed across all of the low-demand 80%-by-2050 renewable electricity scenarios, and therefore represent different scenarios for each technology.
[b] The percentage of generation mix is associated with generation at the source, and does not consider transmission losses or curtailment due to an inability to associate those quantities with particular technologies. For the same reason, the total percentage of renewable generation presented in Table 3-1 exceeds 80%, even though the delivered renewable energy at the bus-bar is consistently 80% for all scenarios.
[c] 2010 Rooftop PV installed capacity represents all systems that are within distribution networks, including roof-mounted PV systems and non-roof-mounted, but “behind-the-meter” systems. Utility PV installed capacity in 2010 represents all other PV systems. In contrast, for the 2050 model results, Rooftop PV represents roof-mounted systems only. Distinctions in the model treatment of PV systems are described in Short et al. (2011).
[d] Co-fired biomass capacity increased for a number of years, and then decreased with coal retirement. As such, the installed capacity presented in the table for 2050 understates the maximum amount of co-fired biomass capacity build prior to 2050.

Key results from the six core 80% RE scenarios are as follows:

- Deployment results for the 80% RE-ITI scenario are presented in Sections 3.1–3.2. Deployment of each renewable technology for this scenario generally falls near the midpoint of the deployment ranges shown in Figure 3-7 and Table 3-1.
- The 80% RE-ETI scenario generally favored those technologies that are currently at an earlier stage of commercialization and could achieve greater deployment if significant technology improvements were realized in the future. Although all renewable technologies were estimated to achieve some level of technological improvement relative to that used in the other 80% RE scenarios, solar technologies, particularly CSP, were estimated to experience the greatest level of improvement. As such, the 80% RE-ETI scenario yielded the highest level of CSP capacity deployment (130 GW) and generation (14% of total generated electricity) among the core 80% RE scenarios. While the 80% RE-ETI scenario realized a great deal of deployment in solar technologies, lower levels of deployment were witnessed for today's mature technologies, particularly hydropower (81 GW) and wind (390 GW).
- The 80% RE-NTI scenario favored more mature technologies and showed very low levels of deployment from those technologies that, in 2010, were at an earlier stage of commercialization. In particular, this scenario yielded the highest level of wind (560 GW) and hydropower (170 GW) deployment among the low-demand core 80% RE scenarios. In generation terms, wind and hydropower made up 43% and 16%, respectively, of the total generated electricity in 2050. On the other hand, solar technologies experienced little deployment, with only about 1 GW of CSP capacity and 5 GW of utility-scale PV capacity (rooftop PV capacity was exogenously set to be 85 GW) installed by 2050. Among the currently commercial renewable technologies, the contributions of solar energy to a high-penetration renewable electricity future depended most critically on continued technology advancements and cost reduction.
- The Constrained Transmission scenario tended to favor resources that are less dependent on transmission. In addition to the exogenous increase in rooftop PV (170 GW compared with 85 GW for all other core 80% RE scenarios), the Constrained Transmission scenario realized the greatest levels of deployment for offshore wind (180 GW), utility-scale PV (120 GW), and biomass (98 GW) among the low-demand core 80% RE scenarios. This relatively large capacity deployment corresponded to very large contributions to electricity supply with 16%, 15%, and 10% deriving from offshore wind, biomass, and PV, respectively. The contributions of CSP (33 GW) and onshore wind (280 GW) were correspondingly lower due to increased challenges in accessing the highest quality (and often remote) CSP and onshore wind resources.
- The Constrained Flexibility scenario resulted in a shift of renewable energy supply from variable wind and PV technologies to other non-variable options. Among the low-demand core 80% RE scenarios, utility-scale PV and wind witnessed relatively modest deployment levels (64 GW of PV and 420 GW of all wind) in this scenario. CSP with thermal storage was deployed at high levels (89 GW) to accommodate the constrained

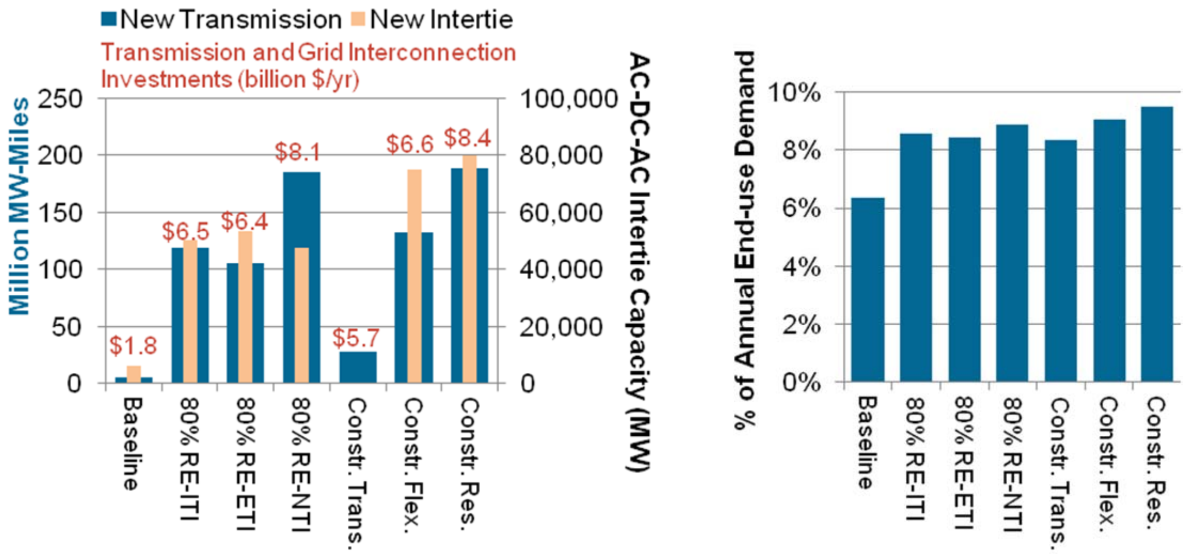
system flexibility. The Constrained Flexibility scenario also realized greater deployment of storage technologies as described in Section 3.5.

- In the Constrained Resources scenario, the contributions from the most resource-constrained technologies—biopower, geothermal, and hydropower—were at or near the lowest levels among the core 80% RE scenarios. Only 52 GW of biomass capacity, 12 GW of geothermal, and 104 GW of hydropower were deployed in this scenario, corresponding to 8%, 2%, and 10% of total generated electricity, respectively. In contrast, the more abundant resources, particularly CSP and onshore wind, were used to a greater degree; by 2050, CSP deployment reached 120 GW and onshore wind deployment was nearly 400 GW.

3.4 New Transmission Needs are Substantial, but Estimated Transmission Investments are in Line with Recent Historical Trends

Achieving 80% renewable electricity would require considerable transmission investment relative to the Low-Demand Baseline scenario. In particular, ReEDS estimated that the core 80% RE scenarios, excluding the Constrained Transmission scenario, would require 110–190 million MW-miles of new transmission and 47,500–80,000 MW of new intertie capacity across the three interconnections. The average annual investment required for this new transmission infrastructure, along with interconnections for all plants, ranged from $6.4 billion/yr to $8.4 billion/yr from 2011 through 2050 (see Figure 3-8[a]). Transmission and intertie amounts and expenditures tended to increase in the Constrained Resources, Constrained Flexibility, and 80% RE-NTI scenarios because there was a tendency in each of those scenarios toward greater quantities of onshore wind and/or CSP (see Section 3.3), both of which generally require more transmission than other available renewable technologies. The Constrained Transmission scenario yielded the opposite result as limits on new transmission pushed resource supply toward those technologies and locations that required smaller amounts of new transmission infrastructure (although the investments that were made are more expensive per megawatt-mile, by the design of the scenario itself).

Although differences in the nature and magnitude of the new transmission needs exist among the 80%-by-2050 RE scenarios, it appears that the transmission challenges of achieving an 80% renewable electricity future may be more institutional than cost-based. The estimated average annual transmission and interconnection expenditure across all of the low-demand core 80% RE scenarios presented here ranged from $5.7 billion/yr to $8.4 billion/yr, which is within the recent historical range for total investor-owned utility transmission expenditures in the United States of $2 billion/yr to $9 billion/yr from 1995 through 2008 (Pfeifenberger et al. 2009). New transmission capacity needs were somewhat reduced in many of the high renewable generation scenarios due to the low-demand assumption, reductions in transmission use by conventional fossil generation (freeing up lines for renewable generation), and deployment of renewable resources that are proximate to load centers (e.g., PV and offshore wind). Additionally, these ReEDS-estimated annual investments do not account for replacement in kind of existing transmission infrastructure, and therefore understate the absolute quantity of new transmission need.[132] RE Futures Volume 4 provides a discussion of some of the issues and challenges associated with transmission planning and expansion.



(a) New transmission capacity by 2050, and average annual investments from 2010–2050

(b) Transmission and distribution losses as a percentage of electricity demand in 2050

Figure 3-8. New transmission capacity, investment, and losses in the Low-Demand Baseline and core 80% RE scenarios

[a] See Short et al. (2011) for a description of how transmission capacity is defined in ReEDS and the factors that are included in investment estimates. The existing total transmission capacity in the contiguous United States is estimated at 150–200 million MW-miles. The new transmission capacity (in megawatt-miles) shown in the figure includes transmission interconnection capacity needed for wind and CSP, whereas the investments associated with the interconnection for all generator types were included in the investment figures.

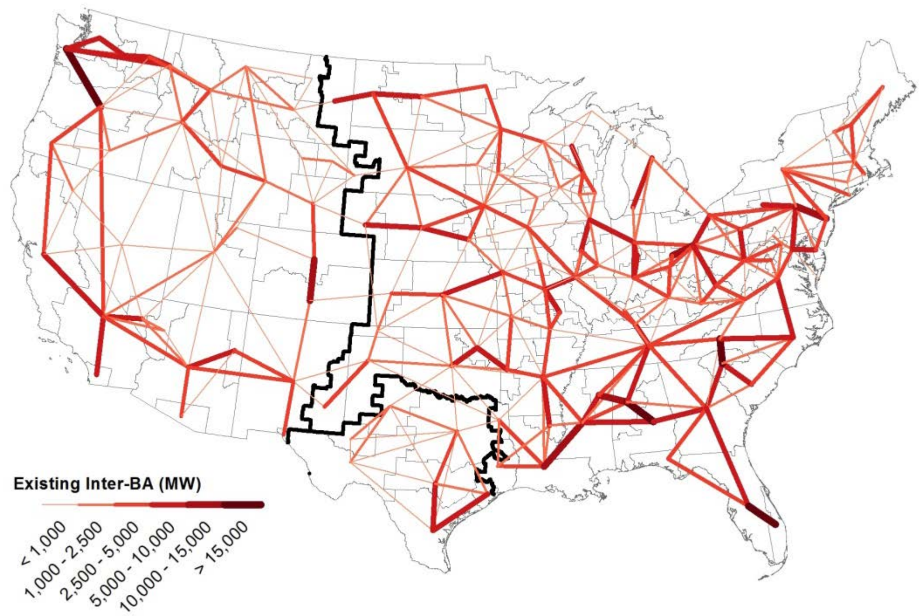
In addition to new transmission infrastructure, achieving 80% renewable electricity resulted in an increase in transmission and distribution losses. Transmission and distribution losses ranged from 8.4% to 9.5% of annual electricity demand (see Figure 3-8[b]) in 2050 for the core 80% RE scenarios, compared with 6.4% in the Low-Demand Baseline scenario.

[132] The cost for transmission presented here also does not include costs associated with the distribution network.

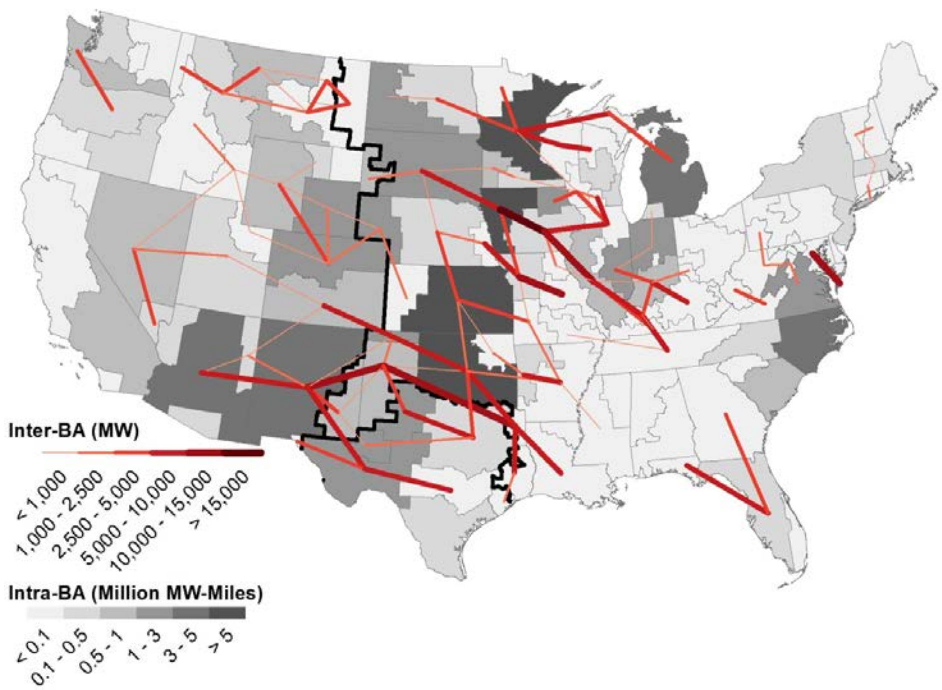
ReEDS provided a very general estimation of the location and design of the necessary transmission infrastructure, and Figure 3-9 presents a conceptual map of both the existing transmission system in the United States (as represented in ReEDS) and the additions to that system that ReEDS anticipated might be needed to achieve the 80% RE-ITI scenario. Due to the relatively low-demand growth assumed for this scenario and the displacement of conventional generation, increased renewable energy supply is found to rely to a significant extent on the existing transmission system (Figure 3-9[a]). In addition, Figure 3-9(b) shows the new long-distance (inter-BA) transmission lines added to the system during the study period in order to accommodate the renewable additions in the 80% RE-ITI scenario. Transmission interconnection lines are also required to connect new renewable facilities, specifically wind and CSP, to the existing transmission grid. The shading in Figure 3-9(b) shows the regional intensity of these new (intra-BA) lines. As shown, for the 80% RE-ITI scenario, new transmission infrastructure was found to be concentrated in the middle and southwestern regions of the contiguous United States, mainly to access the high-quality wind and solar resources in those regions and to deliver those resources to load centers. At a high level, most of the other core 80% RE scenarios resulted in similar locations and amounts for the new transmission infrastructure, although regional differences do exist. For example, greater offshore wind deployment estimated for the Constrained Transmission scenario resulted in more transmission in the Mid-Atlantic states. Similarly, greater deployment of CSP technologies in the 80% RE-ETI scenario resulted in more transmission lines originating from states in the Southwest to serve load centers in the East.

The current isolation of the three asynchronous interconnections (Western Electricity Coordinating Council, Electric Reliability Council of Texas, and the Eastern Interconnection) was greatly reduced in many of the high renewable electricity scenarios through the expansion of AC-DC-AC interties. For example, Figure 3-9(b) shows the expansion of AC-DC-AC interties by 2050 for the 80% RE-ITI scenario, primarily located near the boundaries between New Mexico and Texas and between Colorado and Oklahoma, but also along the northern boundary between the Western and Eastern Interconnections. Figure 3-8(a) includes the level of AC-DC-AC intertie expansion across all of the core 80% RE scenarios. With the exception of the Constrained Transmission scenario, in which new intertie capacity was restricted by design, AC-DC-AC interties expanded by more than 40,000 MW in all other core 80% RE scenarios.

Significant institutional obstacles, including constraints in siting new transmission lines, cost allocation concerns with transmission projects, and coordination between multiple governing entities currently inhibit transmission expansion. The mechanisms to overcome these obstacles were not explored in this study, but the analysis indicates that additional long-distance transmission capacity can be an important characteristic of high renewable electricity futures.



(a) Existing transmission grid representation in ReEDS



(b) New transmission estimated to be required by ReEDS by 2050 in the 80% RE-ITI scenario

Figure 3-9. Existing and new transmission required in the 80% RE-ITI scenario

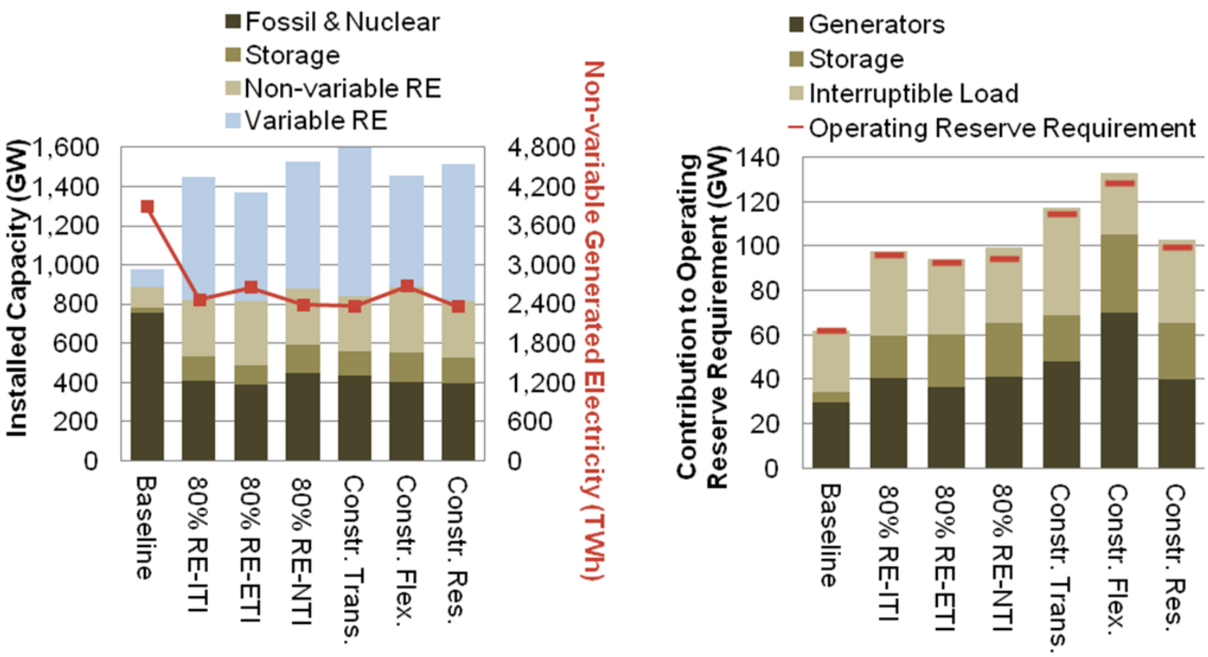
3.5 Integration of 80% Renewable Electricity Requires Changes in Electric System Design and Operations under All Scenarios

Many renewable resources, including hydropower, geothermal, biomass, and CSP with thermal storage, do not introduce significant integration challenges for electric system operations. Wind and PV, on the other hand, are both variable and uncertain, and both of these resources are found to be sizable contributors to an 80% renewable electricity future. In the six core 80% RE scenarios, for example, 39%–47% of total electricity generation in 2050 was found to come from wind and PV, compared to 3% today and 7% in 2050 in the Low-Demand Baseline scenario. Variable generation was most prevalent (47%) in the Constrained Transmission and Constrained Resources scenarios, whereas wind and PV generation was lower in the Constrained Flexibility and 80% RE-ETI scenarios.

As discussed in Section 1.2.1, the ReEDS modeling framework sought to ensure a balance between overall supply and demand by applying planning and operating reserve requirements and by using supply- and demand- side technologies to mitigate curtailments and ensure resource adequacy. The results of ReEDS modeling suggest that, while managing the electric system at 80% renewable electricity penetration poses substantial new challenges, a variety of technical and institutional solutions exist to help proactively meet these challenges. The results of that analysis are presented here for the six core 80% RE scenarios. Chapter 4 evaluates a subset of these scenarios with the more-detailed hourly dispatch and unit commitment capability in GridView. Text Box 1-1 and RE Futures Volume 4 identify other reliability issues and challenges associated with variable generation that may be confronted under high-penetration scenarios that are not addressed in RE Futures.

Adequate generation capacity is required to serve load at times of forecasted peak demand. A planning reserve (or resource adequacy) requirement in ReEDS thereby seeks to ensure that substantial amounts of dispatchable (conventional, renewable, and storage) capacity remains available at all times to meet anticipated peak demands, while variable generation generally do not provide firm capacity toward planning reserves (i.e., variable resources have lower capacity values than dispatchable resources). Figure 3-10(a) shows a decrease in non-variable generation from almost 3,900 TWh in 2050 in the Low-Demand Baseline scenario to 2,400–2,700 TWh in 2050 for the core 80% RE scenarios. The reduction in non-variable generation capacity was much more modest, however, from 860 GW in the Low-Demand Baseline scenario to 680–740 GW in the core 80% RE scenarios. When storage is included, the reduction in dispatchable capacity is non-existent for some scenarios, from 880 GW in the Low-Demand Baseline scenario to 810–890 GW in the core 80% RE scenarios.[133] This is a direct result of ReEDS ensuring that adequate generation capacity was available at times of system stress and that the same measure of resource adequacy was maintained for all scenarios. In other words, the planning reserve requirements were identical across all scenarios.

[133] The high end of the range represents the significant non-variable capacity online in 2050 under the Constrained Flexibility scenario due, in part, to the halving of the capacity value of wind and PV in this scenario.



(a) Non-variable electric capacity and electricity generation in 2050

(b) 2050 contributions toward total operating reserves by technology type

Figure 3-10. Non-variable capacity and reserve provision in the Low-Demand Baseline and core 80% RE scenarios

A future with high levels of variable generation will also require increases in operating reserve requirements. Figure 3-10(b) shows the ReEDS-estimated operating reserve requirements, which include contingency reserves, frequency regulation reserves, and forecast error reserves, during the summer afternoon peak in 2050 for the Low-Demand Baseline scenario and the core 80% RE scenarios.[134] The contingency and frequency regulation reserve requirements were respectively based on 6% and 1.5% of demand, and therefore were largely the same (approximately 56 GW) across these low-demand scenarios, and thus, the differences in operating reserve requirements shown in Figure 3-10(b) are almost entirely due to differences in forecast error reserve requirements. The forecast error reserve requirement in the Low-Demand Baseline scenario was only 6 GW and comprised a minor portion of overall operating reserves. In contrast, the forecast error reserve requirement exceeded 36 GW for all of the core 80% RE scenarios to accommodate variable generation. In the Constrained Transmission scenario, forecast error reserves increased to 58 GW to manage the increase in variable PV and concomitant reduction in CSP with storage. Meanwhile, in the Constrained Flexibility scenario, where the forecast error reserve requirements were conservative by design, 72 GW were found to be required.

Figure 3-10(b) also shows the contribution to the operating reserves from generators, storage technologies, and interruptible load. Adoption of demand-side interruptible load was found to be substantial in most of the 80% RE scenarios, with 34–48 GW installed in most of the core 80% RE scenarios. (The Constrained Flexibility scenario resulted in 28 GW of interruptible load

[134] The calculation of forecast error requirements for wind and solar PV are described in Short et al. (2011).

because the availability of interruptible load was restricted by design.[135]) For comparison, 28 GW of interruptible load was deployed in the Low-Demand Baseline scenario by 2050, and 15.6 GW of interruptible load was deployed in the United States in 2009 (FERC 2009). Investments in interruptible load were greater when operating reserve requirements increased, so trends in interruptible load capacity tended to follow forecast error reserve requirements.[136] As noted previously, an exception existed for the Constrained Flexibility scenario. In addition to interruptible load, a number of supply-side options are available to meet operating reserve requirements. These supply-side options include hydropower plants, natural gas combustion turbines, part-loaded coal and natural gas combined cycle plants, and storage technologies. Because the availability of interruptible load was limited in the Constrained Flexibility scenario, alternative supply-side options were used to a greater degree in that instance, including non-variable (mainly conventional) generation capacity and electrical storage. As shown in Figure 3-11, a large amount of storage was built in the Constrained Flexibility scenario, despite the fact that this scenario had the lowest percentage of variable generation.

In addition to meeting reserve requirements and providing other services to the electric system, storage also enables a reduction of curtailed energy from variable resources. Figure 3-11 shows the curtailed variable generation in 2050 for the Low-Demand Baseline scenario and the core 80% RE scenarios, and the storage capacity installed in part to mitigate that curtailment. Because there was sufficient flexibility in the Low-Demand Baseline scenario to handle the relatively low levels of variable generation (and only 5 TWh of curtailed variable generation from this generation), little new storage capacity was installed in that scenario, resulting in a cumulative storage capacity of 28 GW in 2050; most of this storage capacity (20 GW) consists of existing PSH installations. In contrast, higher curtailment was estimated in the core 80% RE scenarios (91–177 TWh or 5%–9% of variable generation),[137] and storage capacity was estimated to reach 100–152 GW by 2050. Given the assumptions used, the majority of the new storage capacity was expected to come from CAES installations.[138] The Constrained Transmission and 80% RE-NTI scenarios witnessed the highest estimated curtailment levels in 2050 with 177 TWh and 161 TWh, respectively, or 9% and 8% of variable generation. In the former scenario, the decreased ability to leverage geospatial diversity to decrease output correlations between sites with variable generation increases the expected level of curtailment. In the 80% RE-NTI scenario, the increase in curtailed energy was a direct result of high levels of variable generation (particularly, onshore wind) in that scenario.

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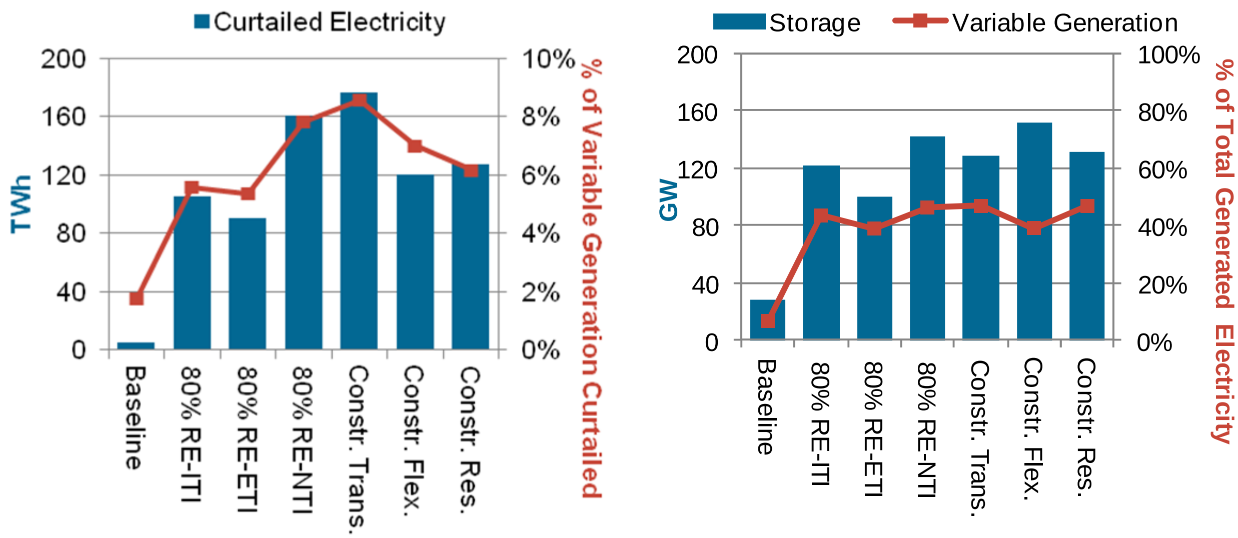
[135] The interruptible load supply curve was not exhausted even in the Constrained Flexibility scenario, but greater amounts of interruptible load did not appear to be cost effective in that scenario given the assumption applied.
[136] Interruptible load could be used for contingency reserves as well as forecast error reserves.
[137] As shown in Chapter 4 with GridView results, ReEDS underestimates curtailment by a factor of approximately 2 because it does not adequately capture transmission congestion at the hourly level.
[138] Although it does not vary across cases, electric and PEV electrical load by 2050 was assumed to be 356 TWh, of which 165 TWh was operated under utility-controlled charging. The availability of partially dispatchable load of this nature also reduced curtailment.



(a) Curtailed electricity in 2050

(b) Storage capacity in 2050

Figure 3-11. Curtailment and storage capacity in Low-Demand Baseline and core 80% RE scenarios

Achieving an 80% renewable electricity future would also have substantial impacts on the operation of existing and new fossil and nuclear plants. Figure 3-12 shows the national dispatch stack for the 80% RE-ITI scenario. Natural gas plants were found to be used almost entirely as peaking units, while co-fired coal units experienced both seasonal and diurnal ramping. Even the remaining aggregate nuclear generation was predicted to experience seasonal output variations under the assumptions used in ReEDS, while the thermal storage of CSP plants was relied on heavily to extend CSP output to evening and nighttime hours. Curtailment and transmission losses (depicted in Figure 3-12 when the generation bars exceed the demand line) tended to be most prevalent in the spring, when relatively high levels of wind (and solar) generation and relatively low levels of load result in higher levels of overall curtailment.

The national dispatch stacks for the other core 80% RE scenarios were qualitatively similar to the one shown in Figure 3-12 for the 80% RE-ITI scenario, particularly with regard to the ramping and operational demands of nuclear and fossil energy-powered plants.[139] However, there were subtle differences between the 80%-by-2050 scenarios that are worth noting; these were primarily driven by differences in generation mix. In particular, there was greater daily ramping of coal and co-fired units in the Constrained Transmission scenario relative to the 80% RE-ITI scenario during non-summer seasons. This increased ramping was due to the increase in variable PV and the decrease in CSP with its associated thermal storage. The daily ramping of coal and co-fired units was limited in the Constrained Flexibility scenario by design, thereby also reducing reliance on variable renewable generation—storage and CSP deployment increased significantly to accommodate the assumed operational inflexibility of coal-powered units. The

[139] As noted previously, by 2050, many of today's existing coal units were found to either be retired or retrofitted to cofire biomass in the core 80% RE scenarios. The operational impacts of renewable electricity on coal-powered plants are therefore largely highlighted in the Cofire category of Figure 3-12.

high solar deployment in the Constrained Resources and 80% RE-ETI scenarios caused net load to reach its minimum during the morning time slices during winter and spring. The effect of this shift was a corresponding shift in minimum output time for coal-powered units, which increased required ramp rates as demand increased in the afternoon. In contrast, the substantial reduction in solar and the corresponding increase in wind in the 80% RE-NTI scenario reduced the morning-to-afternoon ramping of coal. The reduction in PV in this scenario also required greater use of natural gas peaking units, particularly during the summer.

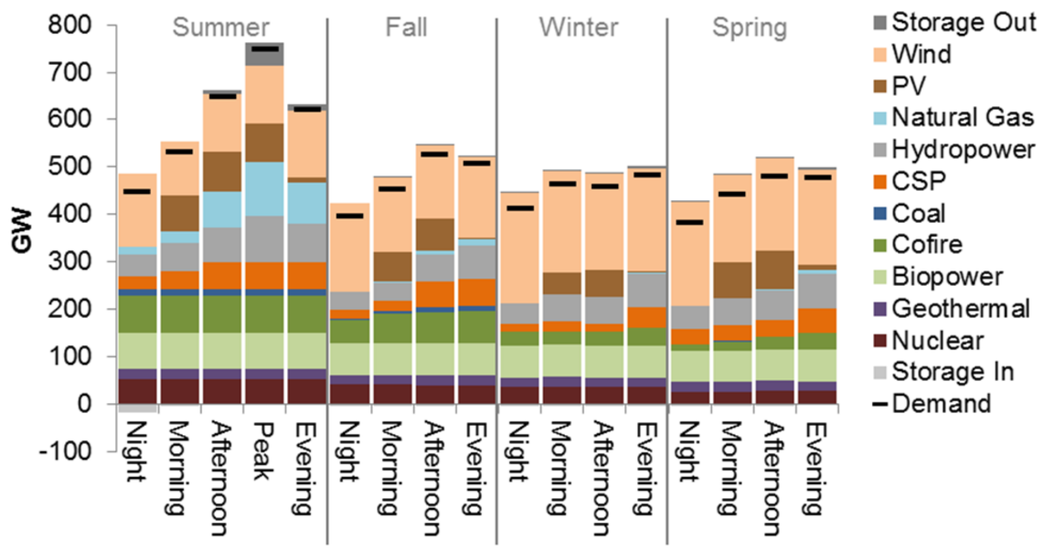


Figure 3-12. Dispatch stack for the 80% RE-ITI scenario

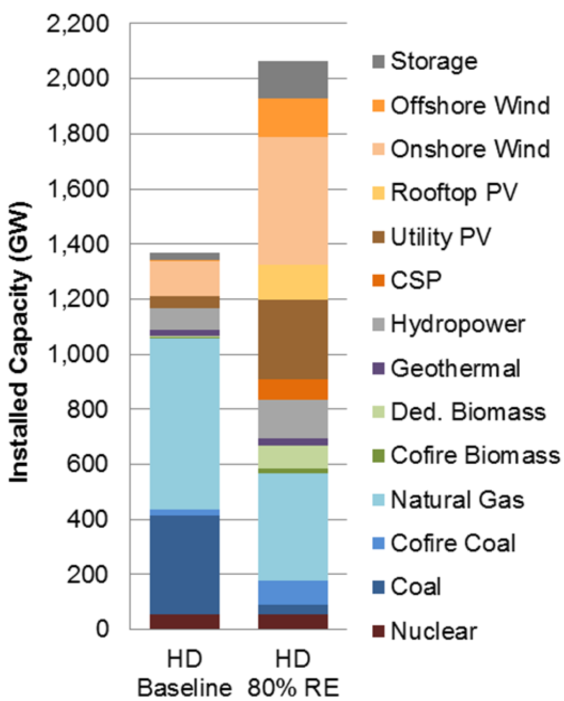
These ReEDS results suggest that the integration challenges of meeting an 80% renewable electricity future are significant, but that integrating high levels of variable generation is not an insurmountable task even under relatively conservative assumptions for transmission and institutional flexibility. Although further research is needed, some of which is identified in Chapter 4, the results presented here suggest that a sufficiently broad portfolio of supply- and demand-side flexibility resources could be available to meet those challenges and, if one or more of those options prove unavailable in the quantities or at the costs assumed here, other available options exist to compensate.

Estimated electricity supply costs and average retail electricity prices for the core 80% RE scenarios are summarized in Appendix A.

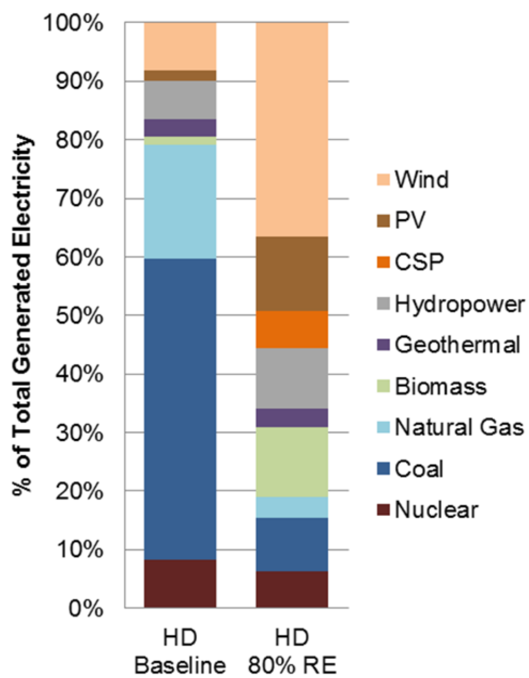
3.6 Achieving an 80% Renewable Electricity Future in the Face of Higher Demand Growth is More Challenging

To this point, all 80%-by-2050 RE scenarios have been based on an assumed low-demand scenario in which energy efficiency investments depress demand growth to modest levels over the 2010–2050 timeframe. To assess the implications of a more traditional, higher-demand growth scenario on the feasibility of meeting 80%-by-2050 renewable electricity penetration levels, a High-Demand 80% RE scenario was evaluated using a forecast in which electricity demand in 2050 is approximately 30% greater than it was in the low-demand scenarios presented earlier. A High-Demand Baseline scenario was also developed for comparison purposes. The high-demand scenarios were evaluated using the RE-ITI renewable technology cost and performance estimates only.

Because of the much higher level of electricity demand, total generation capacity was substantially greater in the high-demand scenarios (compare Figure 3-13, below, with Figure 3-6, earlier). The High-Demand Baseline scenario resulted in 1,340 GW of generation capacity by 2050, compared to 950 GW in the Low-Demand Baseline scenario, whereas the High-Demand 80% RE scenario yielded 1,930 GW of capacity, compared to 1,270–1,470 GW in the (low-demand) core 80% RE scenarios.



(a) Capacity mix in 2050



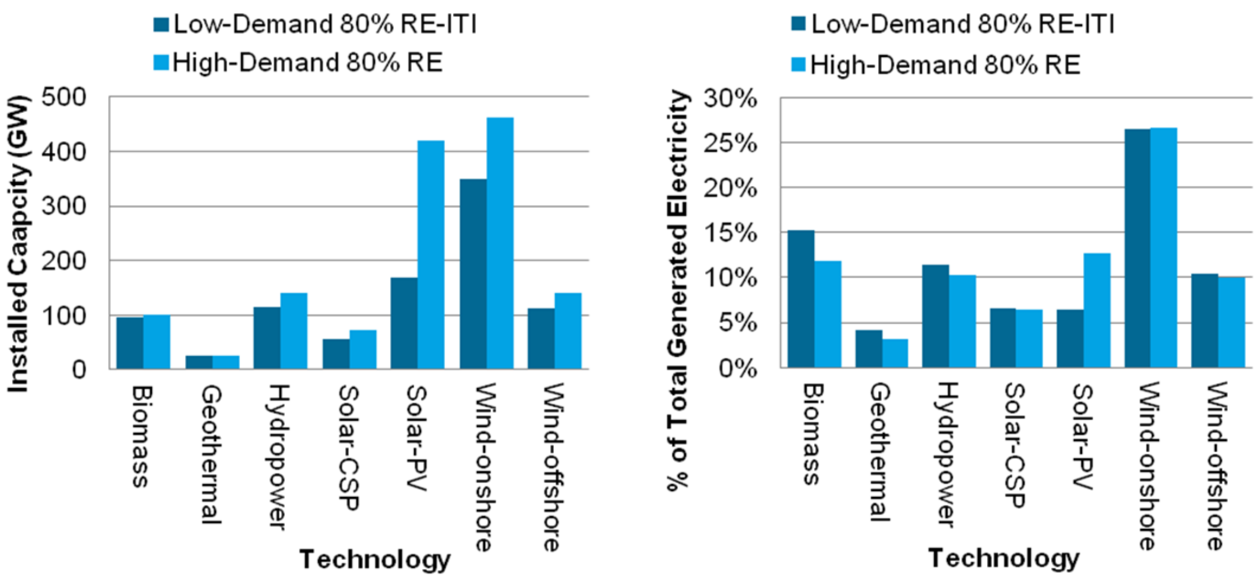
(b) Generation mix in 2050

Figure 3-13. Capacity and generation in 2050 in High-Demand Baseline and High-Demand 80% RE scenarios

The renewable resource base in the United States was found to be sufficient to meet these increased demands. For example, Figure 3-14 compares the 2050 installed renewable capacity and contribution to electricity supply for the High-Demand 80% RE scenario and the (low-demand) 80% RE-ITI scenario.[140] The high-demand scenario realized greater capacity

[140] To isolate the effects of increased end-use demand only, Figure 3-14 compares the High-Demand 80% RE scenario to the 80% RE-ITI scenario only and does not show results from the other low-demand 80% RE scenarios. In contrast, Table 3-2 compares the High-Demand 80% RE scenario with the full range of (low-demand) core 80% RE scenarios presented in the preceding sections. More generally, for conciseness, the analysis did not explore multiple sensitivities with the high-demand scenarios; high-demand 80% renewable electricity scenarios were not,

deployment for all renewable technologies. However, because of resource limits, the *percentage* contributions (generation by technology divided by generation from all sources) of hydropower, biomass, and geothermal noticeably declined under the High-Demand 80% RE scenario compared with the (low-demand) 80% RE-ITI scenario (aggregate generation and capacity from these resources increased but not enough to keep up with the higher demand growth). As shown in Figure 3-15(b), CSP and wind technologies contributed approximately the same share to the generation mix in the high-demand scenario compared to the low-demand 80% RE-ITI scenario, demonstrating that there are sufficient resources to keep up with the greater demand. The significant solar PV resource potential allowed the PV contribution to electricity supply to increase to 13% in the High-Demand 80% RE scenario from 6.4% in the low-demand 80% RE-ITI scenario.



(a) Installed renewable capacity in 2050 (b) Percent of total generated electricity in 2050

Figure 3-14. Renewable supply in 2050 in High-Demand 80% RE scenario and the (low-demand) 80% RE-ITI scenario

Although this analysis suggests there are sufficient renewable resources to reach 80%-by-2050 renewable electricity even in a more-traditional higher demand growth scenario, there may be institutional challenges to deploying renewable energy at the rate required in that instance. In particular, approximately 20 GW–30 GW of renewable capacity is expected to be added each year through 2030 in order to achieve an 80% renewable electricity future under business-as-usual demand growth, compared to approximately 7 GW installed in 2010 and 11 GW installed in 2009, increasing to approximately 70 GW each year for the last decade of the period (Figure 3-15).[141] Such a growth path would bring total renewable energy capacity from 130 GW at the

for example, evaluated under different technology cost assumptions or different system constraints. Although multiple high-demand 80% renewable electricity sensitivity model runs were not evaluated, similar trends to those presented earlier would be expected.

[141] The fact that these annual renewable capacity additions increase over time is partly a reflection of load growth, but also a result of nuclear retirements, replacement of renewable plants after their physical lifetime, and the relatively low capacity factors for PV, which deployed in greater quantities later in the time frame.

end of 2010 to 630 GW by 2030 and then to 1,360 GW by 2050. Some of the possible challenges of achieving this rate of annual capacity growth are highlighted in Section 3.7.

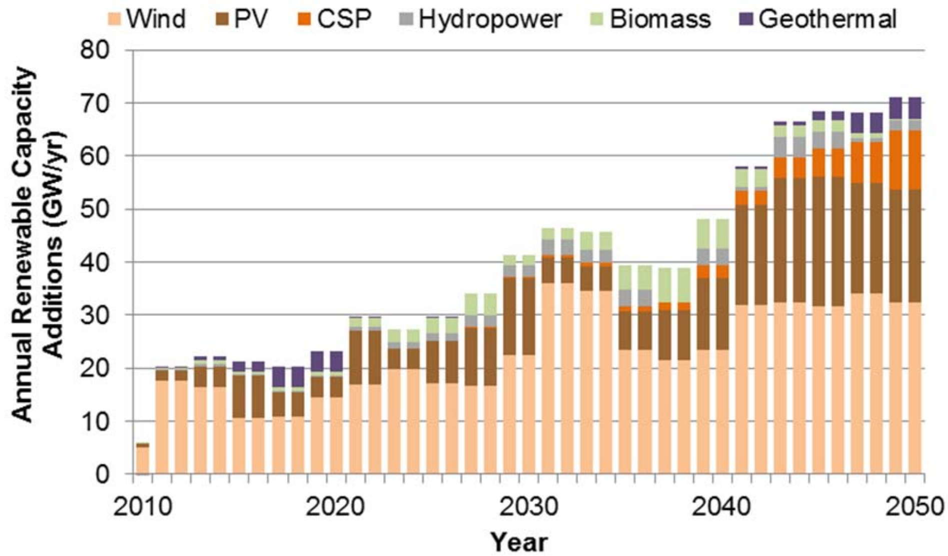


Figure 3-15. Renewable capacity expansion in the High-Demand 80% RE scenario

A high-demand scenario was found to increase the supply of wind and solar PV, both variable generation technologies; variable generation comprised 49% of total generation in the High-Demand 80% RE scenario compared with 39%–47% in the core 80% RE scenarios. The resulting shift in resource supply and the underlying higher demand level that must be met with matching supply have implications for transmission and integration. Specifically, the need for new transmission and new intertie capacity in the High-Demand 80% RE scenario was on the high end of the range of new transmission needs for the low-demand core 80% RE scenarios (Table 3-2). As a result, average incremental annual transmission and interconnection investments were higher in the High-Demand 80% RE scenario than for the low-demand core 80% RE scenarios.[142] To accommodate the increased end-use demand and to manage the variability and uncertainty inherent in increased wind and PV output, greater amounts of natural gas generation capacity were estimated to be needed, reserve requirements were increased, greater quantities of interruptible load were deployed, storage capacity was on the high end of the low-demand range, and a somewhat greater amount of renewable generation was curtailed. Table 3-2 summarizes the transmission and operational integration differences between the six (low-demand) core 80% RE scenarios and the High-Demand 80% RE scenario. The impacts of higher demand on the estimated electricity supply costs and average retail electricity prices are summarized in Appendix A

.

[142] The new transmission capacity shown in Table 3-2 includes long-distance (inter-BA) transmission as well as intra-BA transmission for connecting new wind and CSP plants to the grid (i.e., interconnections for other plants were excluded). In contrast, the average annual transmission and interconnection investments presented in Table 3-2 include interconnection costs for all technologies.

3.7 Supply Chain Challenges to Scaling up Renewable Deployment are Significant but Appear Surmountable

A sustained increase in renewable capacity additions would be required to achieve an 80%-by-2050 renewable electricity future. As shown in Figure 3-16, the six low-demand core 80% RE scenarios were estimated to require average annual renewable capacity additions of 19–22 GW/yr from 2011–2020, compared to 2010 renewable capacity additions of approximately 7 GW and 2009 renewable capacity additions of approximately 11 GW. Average annual renewable capacity additions increased further in later decades, to a maximum of 32–46 GW/yr, equivalent to a multiple of 4.6–6.6 times 2010 capacity additions. Under a more traditional "business-as-usual" demand projection, realizing 80%-by-2050 renewable electricity was found to require considerably greater growth in renewable capacity additions; in the High-Demand 80% RE scenario, growth in renewable capacity additions started at approximately 21 GW/yr in the 2011–2020 time period, and reached an annual average of 66 GW/yr from 2041 to 2050. In that final decade of the RE Futures forecast horizon, average annual renewable capacity additions were equivalent to a multiple of approximately 9 times 2010 additions and approximately 6 times 2009 additions.

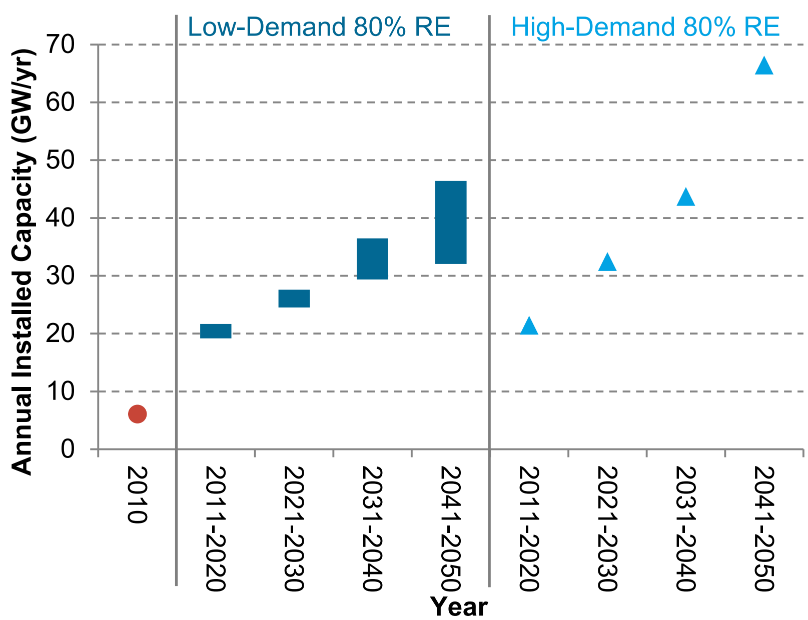


Figure 3-16. Renewable energy deployment scaling to achieve an 80% renewable electricity future in the (low-demand) core 80% RE scenarios and High-Demand 80% RE scenario

Achieving this rate of annual capacity and the associated investment growth—and maintaining it for 40 years—may pose challenges to the renewable energy industries, especially in the High-Demand 80% RE scenario, in which annual average growth rates are significant relative to historical experience and the low-demand core 80% RE scenarios. Those challenges could extend to many aspects of the industries' supply chain, including materials availability, equipment manufacturing, project development and siting, and labor needs.

Table 3-2. Summary of Transmission and Integration Implications of the High-Demand 80% RE and (Low-Demand) Core 80% RE Scenarios

Transmission	**Low-Demand Core 80% RE**	**High-Demand 80% RE**
New Transmission Capacity, 2011–2050 (million MW-miles)	28–188	182
New Intertie Capacity Between Interconnections, 2011–2050 (MW)	0–80,050	66,560
Average Annual Transmission and Interconnection Investment, 2011–2050 (billion 2009$/yr)[a]	$5.7–$8.4	$9.0
Transmission and Distribution Losses as a Percentage of Electricity Demand, 2050 (%)	8.3%–9.5%	8.9%
Operational Integration	**Low-Demand Core 80% RE**	**High-Demand 80% RE**
Natural Gas Generation Capacity, 2050 (GW)	240–301	390
Operating Reserve Requirements During Summer Peak, 2050 (GW)	93–128	143
Interruptible Load Capacity, 2050 (GW)	28–48	64
Curtailed Electricity, 2050 (TWh)	91–177	202
Curtailment as Percentage of Variable Generation, 2050 (%)	5.4%–8.6%	7.1%
Storage Capacity, 2050 (GW)	100–152	136

[a]The average annual transmission and interconnection investment figures shown include investments to interconnect all (conventional and renewable) new generation capacity. Because of this, the investment figure for the High-Demand 80% RE scenario exceeds the range shown for the (low-demand) core 80% RE scenarios despite the fact that the new transmission capacity for the High-Demand 80% RE scenario is less than the high end of the range shown for the core 80% RE scenarios.

RE Futures does not identify any insurmountable long-term constraints to manufacturing capacity, materials supply, or labor availability for any of the renewable technologies considered in this study (see RE Futures Volume 2). Growth in renewable capacity additions globally and in the United States has been considerable over the last decade, demonstrating the ability to scale manufacturing and deployment at a rapid pace. The wind power additions required by the scenarios presented in this chapter, for example, are substantial, but historical growth in manufacturing and installation suggests that manufacturing need not be a major constraint to the continued growth that would be needed to meet an 80%-by-2050 renewable energy future. The necessary biomass and geothermal additions, although greater than recent historical trends, are similarly unlikely to place undue strain on manufacturing capabilities. The estimated annual capacity of PV deployment is high, especially in later years, but PV manufacturing and deployment are scalable. Worldwide PV production capacity has been growing rapidly and is already comparable to the deployment levels projected for the latter years in many of the 80%-by-2050 RE scenarios. Moreover, many of the renewable technologies are based on common materials that are not supply-constrained. Even for PV, which uses some materials that may be supply-constrained, worldwide production capacity is already sizable, and that capacity continues to scale rapidly. Even considering the High-Demand 80% RE scenario, and worldwide demand for PV, given the variety of PV feedstocks used today and the possibility of newer ones being developed in the future, reaching the required levels of installed capacity need not be limited by the availability of raw materials.

Although materials supply and manufacturing capacity do not appear likely to impose insurmountable constraints and the renewable energy resource base is found to be large enough to meet even the most aggressive renewable energy targets, the process of developing and siting the needed renewable energy facilities and associated transmission infrastructure would likely face substantial social, environmental, and institutional constraints that would need to be overcome. Some of these issues are addressed in Appendix A and in Volume 2 and Volume 4.

Achieving an 80%-by-2050 renewable electricity future would also have implications for the U.S. workforce, although the precise nature and magnitude of those influences are not specifically evaluated in RE Futures. In general, however, such a scenario would support new jobs in the renewable energy sectors while reducing employment in the natural gas, coal, and nuclear energy sectors. There would also be changes in the domestic manufacturing and logistics support industries, with an increase in equipment production for renewable power plants and the management of transport and installation of that equipment. The degree of increase in domestic manufacturing of renewable energy equipment would be determined in part by the competitiveness of U.S. manufacturing compared to other countries, as impacted by any policy measures enacted to directly or indirectly support localized production in the United States or abroad. At the same time, domestic production of equipment and logistics for fossil power generation would presumably decrease.

Whether or not these various employment and industrial transitions would lead to net job, Gross National Product, and balance-of-trade gains or losses is not addressed in RE Futures. Some research has found that renewable electricity is more job-intensive than fossil generation. For example, one study that sought to synthesize some of the available literature reports that, "all renewable energy and low-carbon sources generate more jobs than the fossil energy sector per unit of energy delivered . . ." (Wei et al. 2010). However, after considering net employment impacts across the entire economy, as impacted by energy prices and other outcomes, and after accounting for jobs losses in the fossil sectors, and export opportunities, studies have come to conflicting findings about whether or not net gains or losses in employment might be anticipated (e.g., Hillebrand et al. 2006; Lehr et al. 2008). At a minimum, net employment, Gross National Product, and balance of trade impacts are clearly sensitive to many assumptions, including future energy prices and renewable energy cost reductions, the capacity to export new technology, and whether or not GHG emissions reductions are presumed mandatory.

Regardless of the net impacts, these transitions may benefit from workforce training (for the renewable energy sectors) and some level of retraining (for the fossil energy and other sectors that experience economic losses). The domestic energy workforce is already diverse, consisting of natural resource extraction, manufacturing, construction, power plant operations, and grid integration, among other jobs, but some argue that the renewable energy sector has already faced challenges in building a sufficiently skilled work force (Kratzat and Lehr 2007; Saha 2010). Moving from the current U.S. energy portfolio to one with 80% renewable electricity may require new vocational, academic, and other training programs to meet the expanding needs of the renewable energy industries, spanning the spectrum from short-term instruction courses to post-graduate academic degrees.

3.8 Summary of Results from the 80%-by-2050 Renewable Electricity Scenarios

The ReEDS electric sector modeling presented in this chapter highlights some of the characteristics and challenges associated with achieving an 80% renewable electricity future. Deploying renewable energy to achieve an 80% renewable electricity future is found to require a sizable and sustained increase in renewable supply additions over a 40-year period. Transmission expansion would be a necessary element of such a future, and managing operational integration concerns would require additional electric system capacity, greater ramping of conventional generation sources, increased storage capacity, increased use of demand response technologies, and a growing amount of curtailment.

A central finding of the ReEDS analysis, however, is that constraints to one resource type or set of resource characteristics can often be compensated through other. Likewise, the analysis shows that an 80%-by-2050 renewable electricity future can be achieved, even given uncertainties around future end-use demand and fossil energy costs (see Appendix A for details). As a result, there are multiple pathways to achieving an 80% renewable electricity future. Assumed constraints that limit power transmission infrastructure, grid flexibility, or the use of particular types of resources can be compensated for through the use of other resources, technologies, and approaches.

Chapter 4. Operating the Electricity System with 80% Renewable Electricity

ABB's GridView model was used to supplement the ReEDS analysis and provide further insights into the operational feasibility of reaching an 80%-by-2050 renewable electricity future. GridView is an hourly, chronological production cost model with optimal DC power flow and security constrained unit commitment and security constrained economic dispatch requirements (see Section 1.2.2 for more detail). Its hourly time resolution facilitates an improved understanding of how variable generation, thermal unit flexibility constraints, and transmission congestion impact the ability of the system to serve load and limit curtailment. In RE Futures, the generation fleet and transmission network in 2050 under the Low-Demand Baseline, 80% RE-ITI, 80% RE-ETI, and Constrained Transmission scenarios, as estimated by ReEDS, were used as inputs to GridView. Although the full suite of reliability considerations listed in Text Box 1-1 were not addressed, the GridView analysis helped validate the operational feasibility of the ReEDS results, taking into account a more detailed representation of variable generation, flexibility constraints, and transmission flow. Because production and integration costs depend strongly on a large number of uncertain and unpredictable factors, including future power plant flexibility and system flexibility, these costs were not evaluated in the GridView analysis. The analysis suggests that more research in these topic areas is warranted. The key findings from this assessment are presented in Sections 4.1–4.5.

4.1 Adequate Resources are Available to Serve All Hourly Load in the High-Penetration Renewable Electricity Futures that were Modeled

GridView does not project any unserved load in the Low-Demand Baseline scenario or any of the 80% RE scenarios that were modeled (80% RE-ITI, 80% RE-ETI, and Constrained Transmission). Specifically, the GridView modeling showed that, in 2050, there were sufficient supply- and demand-side resources *in each hour of the year* in each region to meet anticipated demand.[143] In addition, in conducting this analysis, GridView was required to commit spinning and non-spinning reserves to ensure that enough reserves were online or ready to come online to deal with sub-hourly variability in load, wind generation, and solar generation. These algorithms, following methods summarized by Ela et al. (2010), were intended to ensure that sufficient reserves were in place to account for ramping events, forecast errors, and generator outages.[144]

This result does not imply that the electric power system would never have outages in the scenarios, nor that other reliability considerations can be ignored; sub-hourly and local impacts were not assessed here (see Text Box 1-1). The GridView results did show, however, that the supply- and demand-mix, planning and operating reserves, and transmission system predicted by ReEDS under the scenarios analyzed were sufficient to meet load on an hourly basis, and that hourly mismatches between supply and demand on a regional basis were therefore not anticipated. The dispatch of the three 80% RE scenarios was similar (the main difference was

[143] The electric system is a complex system of systems that operates on many timescales ranging from milliseconds to years; ultimately, analyses must be conducted to address all of the potential operating aspects of future electricity generation systems as they evolve. Electric system operations are described in detail in RE Futures Volume 4.
[144] The methods described in Ela et al. (2010) were developed for the Eastern Wind Integration and Transmission Study (EnerNex 2010).

different renewable electricity technologies in different locations). For the rest of the section, the 80% RE-ITI scenario is studied in detail as an example 80% RE scenario with important differences noted for the other 80%-by-2050 renewable electricity scenarios.

4.2 A Variety of Supply- and Demand-Side Technologies Helps the System Meet the Operational Challenges of High Variable Renewable Electricity Penetrations

GridView seeks to serve load at minimum production cost, subject to transmission and generation constraints. When net load (i.e., load minus variable generation) in a specific region shows dramatic ramps, as becomes common with high penetrations of variable generation, several approaches can be employed to accommodate these ramps. First, transmission between regions can help reduce ramps in net load because it allows system operators to access a more diverse mix of variable generation, with some smoothing of output profiles and of demand profiles over larger geographic areas. Second, thermal conventional and renewable generation units can provide varying degrees of ramping capability, from base-load units that provide relatively little flexibility to natural gas combustion turbines that have low minimum generation constraints and are less expensive and faster to start. Some of the constraints that limit the flexibility of generating units as evaluated in GridView include minimum generation levels, maximum ramp rates, minimum on and off times, and startup costs (details on the specification of some of these parameters are provided in Appendix B). Third, dispatchable, but non-combustion renewable generation units, including CSP with storage and hydropower, can be dispatched to accommodate changes in net load. Fourth, energy storage technologies, including PSH and CAES, are available to provide flexibility. Finally, curtailment of renewable generation is also an option in GridView. The relative use and ordering of the aforementioned options is determined in GridView's production cost minimization routine.[145]

On the demand side, GridView considers interruptible load and optimal charging of electric vehicles. Interruptible load is primarily used (along with storage and thermal units) to provide spinning reserves to handle contingencies and short-term forecast errors. In the case of day-ahead forecast errors, interruptible load can also be used to shed load to ensure that the balance of energy supply and demand is kept in equilibrium; in the present GridView results, however, this latter situation arose for only 1 hour in the 80% RE-ITI scenario (interruptible load was never required to handle day-ahead forecast errors in the Low-Demand Baseline scenario). This means that interruptible load is primarily called upon by GridView to curtail load for brief periods of time during contingencies while the system operator brings other units online; the frequency with which the interruptible load would be called upon to provide these services is not known, however, because GridView (as an *hourly* model) only estimates the use of interruptible load in situations where it is called for at least 1 hour. In addition, system operators were assumed to be

[145] Curtailment of renewable generation is considered economically in GridView. For example, if it is cheaper to curtail renewable energy than to cycle a thermal unit to meet changes in net load, curtailment will be selected. Curtailment would likely be somewhat lower than presented in this chapter if there were an explicit renewable energy requirement or an additional economic incentive to use renewable energy (e.g., a production tax credit) implemented in GridView. As it is, this analysis simply includes the resource mix based on the ReEDS results, so there was no inherent *additional* economic incentive to minimize curtailment in GridView as there was in ReEDS, which required the renewable target to be achieved.

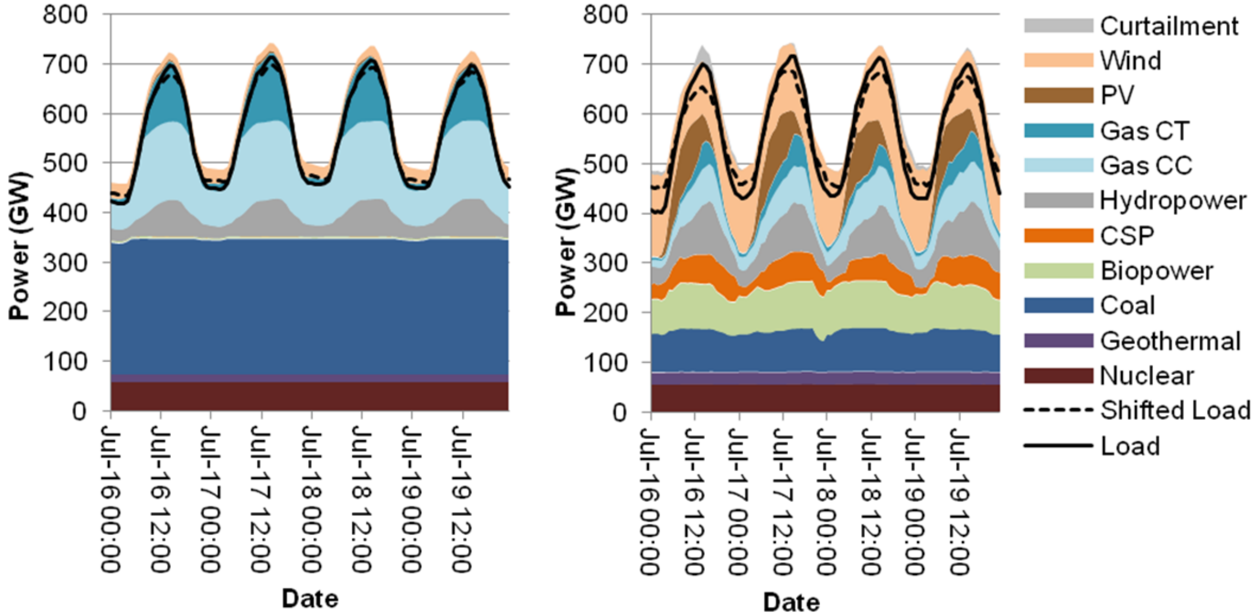
able to control the charging cycles of nearly one half of the assumed electric and PEV load. This allowed electric vehicle scheduling to be done day-ahead (during unit commitment) and adjusted in real-time (during dispatch) to smooth net load.[146]

Figure 4-1 shows the resulting nationwide dispatch by generator type for a 4-day period in July 2050, a period that includes the annual peak coincident load (July 17), under both the Low-Demand Baseline scenario and the 80% RE-ITI scenario.[147] In the Low-Demand Baseline scenario, the nuclear units did not ramp, diurnal coal[148] ramps were very limited, combined cycle units ramped more than coal did, and hydropower and natural gas combustion turbines were used to meet most peaking needs. The dispatch characteristics of the different plant types are similar to today's system. In the 80% RE-ITI scenario, the peak of net load (approximately equal to the top of the Gas CT [combustion turbine] category) occurred a few hours later each day than it did in the Low-Demand Baseline scenario due primarily to the daytime solar PV output. Although most of the peaking needs of the overall system were still found to be provided by combustion turbines and hydropower, combined cycle and coal units ramped to a greater extent than they did in the Low-Demand Baseline scenario. Small amounts of curtailment occurred periodically during the daytime, and somewhat more regularly (although still in small quantities) during the nighttime hours.

[146] GridView found that charging the 165 TWh of PEV load that was under utility control during periods in which curtailment occurs was optimal.

[147] Projected hourly load data is from modeling described in RE Futures Volume 3. It was disaggregated for the GridView modeling from the NERC region level to balancing authorities based on hourly 2006 data. The meteorological profiles are consistent with 2006 meteorology.

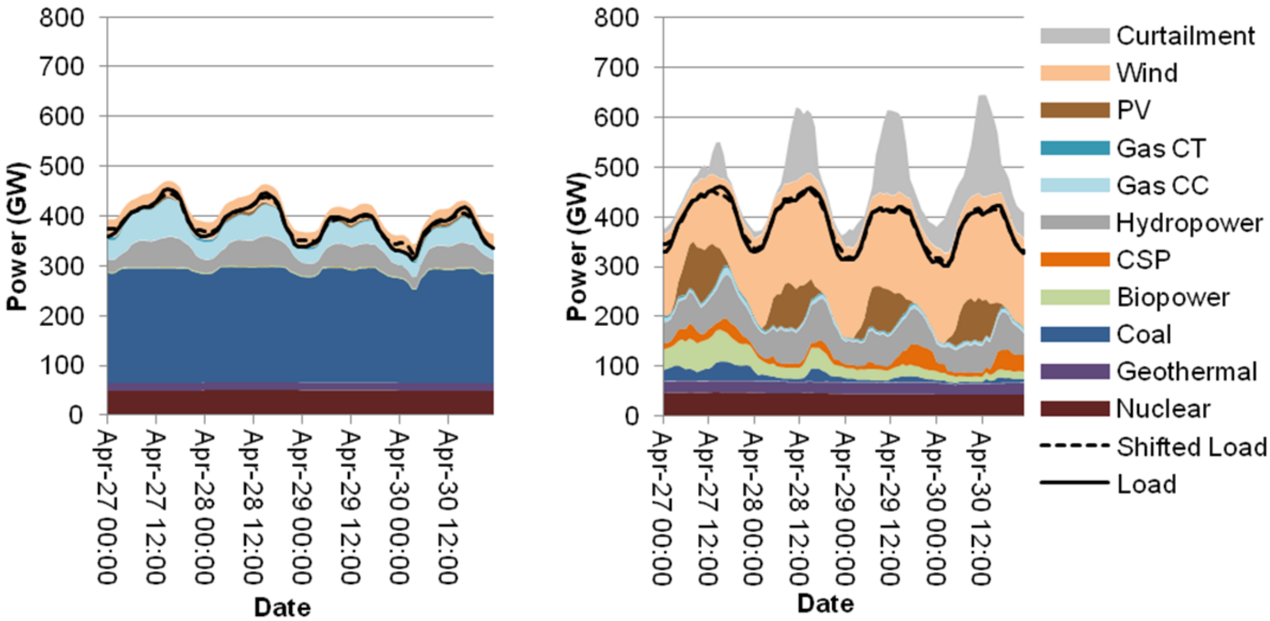
[148] GridView does not treat coal and cofired coal/biomass plants separately. Because ReEDS projects that nearly all coal plants are retrofitted to cofire biomass by 2050 in the 80% RE-ITI scenario, the ramping and other operational characteristics of coal in the GridView results should be compared with the cofire category from ReEDS.



(a) Low-Demand Baseline scenario (b) 80% RE-ITI scenario

Figure 4-1. Dispatch stack during summer peak in 2050

The solid black line representing "load" includes charging of electric vehicles. The broken line representing "shifted load" represents "load" minus storage. "Gas CT" refers to natural gas combustion turbine and "Gas CC" refers to natural gas combined cycle. The Gas CT category includes a small number of oil-fired units. The unit types are ordered (subjectively) from least variable or flexible (at the bottom) to most variable (at the top).



(a) Low-Demand Baseline scenario (b) 80% RE-ITI scenario

Figure 4-2. Dispatch stack during spring off peak in 2050

The solid black line representing “load” includes charging of electric vehicles. The broken line representing “shifted load” represents “load” minus storage. "Gas CT" refers to natural gas combustion turbine and "Gas CC" refers to natural gas combined cycle. The load is different between the Low-Demand Baseline scenario and the 80% RE-ITI scenario due to the different “optimal” charging of PEV in these two scenarios.

Figure 4-2 shows similar nationwide dispatch results during the spring of 2050, including the lowest coincident load of the year (the night between April 29 and 30). In comparison to the summer peak period, Figure 4-2 suggests that the operational challenges associated with maintaining reliability under a high-penetration renewable electricity future may be particularly acute in months with lower electricity load. This is in contrast to today’s fossil-fuel-dominated electricity system for which the time of peak load (e.g., summer afternoons) is of most concern; operational challenges for high renewable generation scenarios were most acute during low-demand periods (e.g., spring evenings) when the abundance of renewable supply relative to demand would force thermal generators to cycle or ramp down to their minimum generation levels.[149] During spring, system operation in the Low-Demand Baseline scenario is relatively simple compared with the summer because the daily peak load is low in absolute terms (450 GW vs. more than 700 GW during the summer) and relative terms (daily peak load is only100 GW higher than off-peak load vs. 300 GW higher during the summer). As a result, in the Low-Demand Baseline scenario, most of the peaking needs were met with hydropower and combined cycle units; more-expensive combustion turbines were needed but to a much lesser extent than in the summer. Although the load characteristics are similar in the 80% RE-ITI scenario, on many days during the spring there was enough aggregate renewable electricity to fully serve load

[149] Peak load still requires management and will be challenging for the same reasons it is today, but in addition, management of low-demand periods and curtailment will be required with high variable generation electricity.

causing the net load (i.e., load minus variable renewable generation) to be much more variable compared to the rest of the year. As a result, there was slightly less nuclear generation and much less coal and natural gas generation. Coal, biopower, and geothermal units were called to provide greater dispatch (including cycling and ramping) flexibility compared to the spring for the Low-Demand Baseline scenario and also compared to the summer months for the 80% RE-ITI scenario.[150] Energy storage, meanwhile, was called upon to shift the load earlier to coincide with greater PV generation, while CSP thermal storage was used to shift production to later into the evening hours. Due to the transmission constraints, reserve requirements, and minimum generation constraints considered by GridView, some nuclear, coal, and natural gas units remained in operation that would not be required were these constraints ignored.[151] In part, as a result, curtailment was needed in large quantities to ensure a balance between supply and demand, especially during the daytime hours when both wind and solar generation was high. Which particular technologies would bear this curtailment will depend on many factors, including the technical and economic characteristics of the various technologies, market structure, transmission congestion, and reliability rules. GridView primarily curtails CSP because its stored, dispatchable energy is more valuable than variable renewable electricity that cannot be stored or dispatched. Hence, CSP appears to generate very little during the spring (see Figure 4-2[b]) due to the model preference to curtail CSP generation.[152]

4.3 Transmission System use Increases, but the Transmission System Appears Sufficient to Deliver Most Renewable Energy to Load

In addition to the increased construction of transmission infrastructure estimated by ReEDS, the average utilization factor (i.e., transmission usage divided by transmission capacity) of long-distance transmission connections (specifically, those between ReEDS' BAs) in 2050 was found by GridView to increase from 32% in the Low-Demand Baseline scenario to 40% in the 80% RE-ITI scenario. Correspondingly, transmission and distribution losses were estimated by GridView to be higher in the 80% RE-ITI scenario than in the Low-Demand Baseline scenario (7.7% of load vs. 6.3%).

GridView results found the transmission system to be more congested[153] in the 80% RE-ITI scenario than in the Low-Demand Baseline scenario: the congestion cost, number of lines congested, and number of hours of congestion were all higher. Figure 4-3, for example, shows

[150] Some of the constraints that limit the flexibility of conventional units in the GridView model include minimum generation levels, maximum ramp rates, minimum on and off times, and startup costs; these factors tend to increase curtailment. Typical parameters for different unit types are included in Appendix B. Actual ramp rates tend to be non-binding with the hourly resolution of GridView, however, because most units can ramp from minimum generation to maximum capacity within 1 hour.

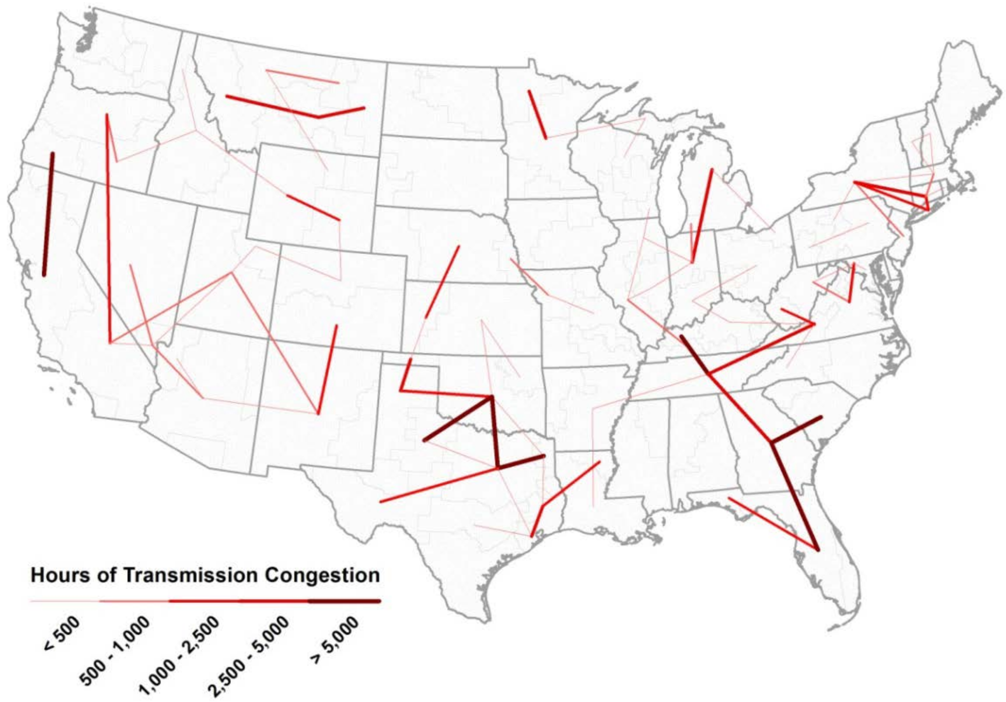
[151] This situation parallels the use of combustion turbines in conventional systems, which are typically used just a few hundred hours per year to meet summer peak loads and are largely idle much of the rest of the year. As such, both the conventional and the high renewable electricity systems operate with excess capacity most of the time. While the high renewable system generates power with the excess capacity as long as resources are available, the conventional system simply leaves the excess capacity idle.

[152] See Appendix B for further explanation on curtailment choices in GridView.

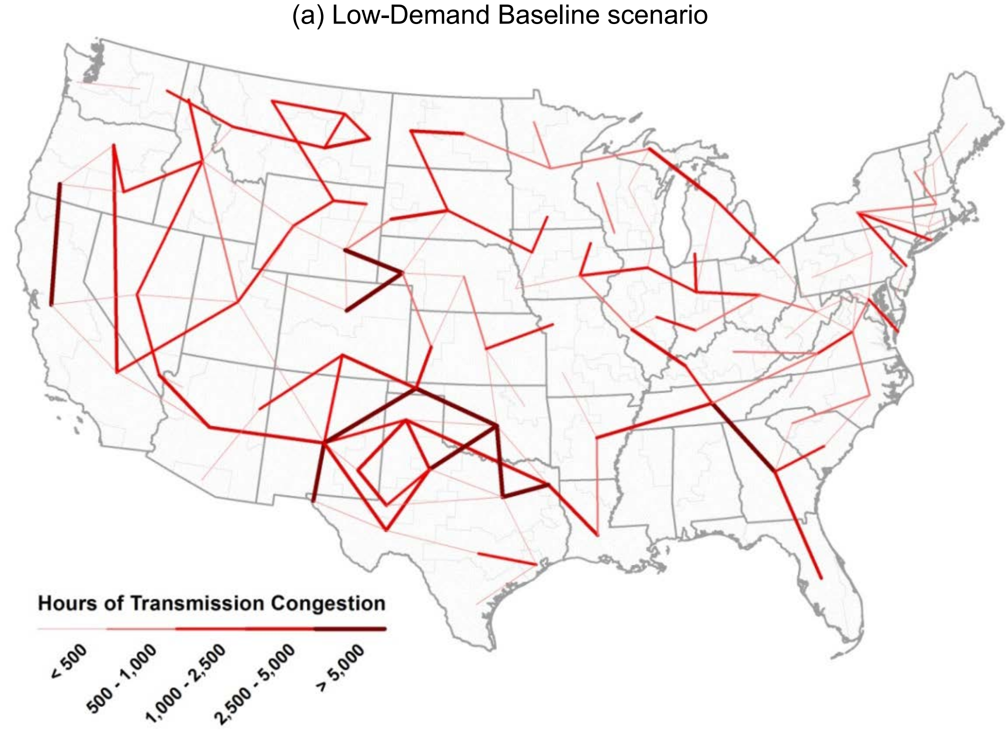
[153] Transmission congestion between two areas occurs when the transmission line connecting the areas has reached its flow capacity. Congestion leads to sub-optimal dispatch and a higher marginal price of electricity in one or more of the congested regions.

the number of hours of congestion on each transmission pathway in 2050 in the Low-Demand Baseline and 80% RE-ITI scenarios. Congestion in the 80% RE-ITI scenario was clearly found to be more widespread across the contiguous United States than in the Low-Demand Baseline scenario. This will lead to additional sub-optimal dispatch, which can, in turn, lead to curtailment of renewables and the operation of more expensive generators in order to serve load and maintain reliability.

In the 80% RE scenarios modeled, transmission capacity was not exclusively used as a means to ship power from lower-cost areas with many renewable resources (e.g., Western Electricity Coordinating Council) to areas with generators that have higher marginal costs, particularly from non-renewable sources. Each transmission interface (a group of lines connecting two areas) is also used to diversify both supply and demand and minimize the cost of integrating the variable generation technologies. Figure 4-4 shows duration curves and diurnal profiles across two example interfaces from Western Electricity Coordinating Council to the Eastern Interconnection. The Montana to North Dakota interface is used primarily to export power from the northwestern United States to the Eastern Interconnection, with the interface congested (from west to east) about half of the year. It is optimal to send power into Montana from North Dakota for only a few hours per year (Figure 4-4[a]) with little variation in usage between hours in the day (Figure 4-4[b]). The Colorado to Kansas interface, on the other hand, is regularly used to provide flexibility to the system by transferring power at different levels and in different directions. This interface is congested less than half of the year, and power flows are approximately evenly split between eastward and westward flows. The diurnal profile shows that power is more likely to flow west to east during the day and the opposite is true at night. Both these interfaces have annual utilization factors (ignoring direction) of 0.71, where the utilization factor is the ratio of the average amount of power transmitted across an interface throughout the year to the physical capacity of the transmission line. However, the average directional usage for any hour never exceeds 0.25 of capacity in either direction in the Colorado to Kansas interface, demonstrating that the direction of flow is not always consistent between days.

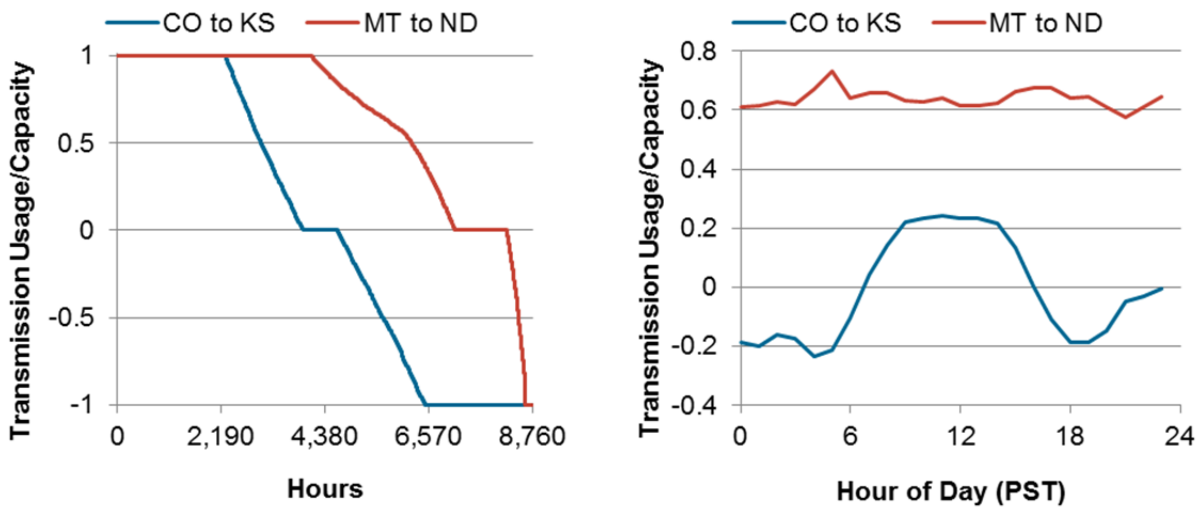


(a) Low-Demand Baseline scenario



(b) 80% RE-ITI scenario

Figure 4-3. Numbers of hours of congestion along transmission interfaces in 2050



(a) Transmission Duration Curve (b) Diurnal Profile

Figure 4-4. Transmission across example Western Electricity Coordinating Council to Eastern Interconnection interfaces

Negative numbers indicate flow in the reverse direction (e.g., from Kansas to Colorado).

4.4 An Estimated 8%–10% of Wind, Solar, and Hydropower Generation will be Curtailed in an 80%-by-2050 Renewable Electricity Future

GridView predicted 214 TWh of curtailment in the 80% RE-ITI scenario in 2050, representing 5.5% of annual electricity demand and 8.1% of wind, solar, and hydropower generation. GridView projected curtailment to equal 8.6% and 9.9% of those same generators in the 80% RE-ETI and Constrained Transmission scenarios, respectively.

Figure 4-5 presents GridView-estimated monthly curtailment by interconnect in 2050 for the 80% RE-ITI scenario. Fifty-seven percent of annual curtailment in 2050 was predicted to occur in the Eastern Interconnection, while 42% occurs in the Western Electricity Coordinating Council, and just 1% in the Electric Reliability Council of Texas. Curtailment as a fraction of wind, solar (CSP and PV), and hydropower generation was projected to be higher in the Western Electricity Coordinating Council (10.5%) than in the Eastern Interconnection (7.4%) or the Electric Reliability Council of Texas (1.8%). Similar seasonal patterns of curtailment were apparent in each of the three interconnections. Specifically, curtailment peaks in the spring (40% of all curtailment occurs between March and May); during this period, electricity demand is relatively low but variable renewable generation (including wind and solar) is relatively high. Winter and autumn also have significant curtailment (26% and 22% of annual curtailment, respectively) despite lower production from wind, solar, or both sources. The lowest fraction of curtailment occurs during the summer months (12% of curtailment occurs from June to August) due to the higher overall demand and generally lower wind generation. In the Western Electricity Coordinating Council, curtailment peaks in spring (due to the extensive solar resources), while in the Eastern Interconnection, curtailment is consistently high from fall through spring.

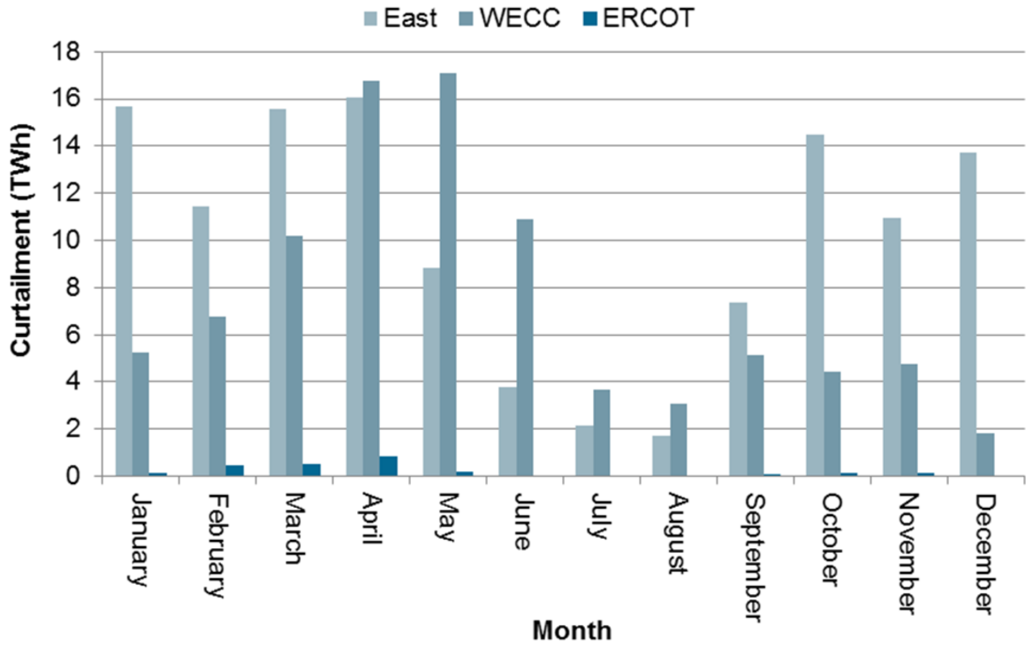


Figure 4-5. Monthly curtailment by interconnection in the 80% RE-ITI scenario

A variety of technical and institutional approaches might be used to reduce curtailment, some of which are discussed in RE Futures Volume 4. First, additional transmission capacity in congested corridors would help alleviate congestion and reduce curtailment. This would work best for areas that would see curtailment during many hours of the year. Second, increasing the size of reserve-sharing groups[154] could help reduce the aggregate amount of operating thermal capacity needed to provide spinning reserves, thereby reducing the need to curtail renewable generation when the flexibility characteristics of the fossil units are exhausted.[155] Third, the flexibility of the thermal fleet could be improved or market structures could be used to encourage the operation of more flexible generators. Fourth, additional energy storage and controllable loads could be used to improve system flexibility. This would work best for areas where curtailment occurs occasionally (not regularly for many consecutive hours). Finally, new or existing industries could take advantage of the low-cost electricity available during seasons or times where curtailment would have occurred.

One implication of transmission congestion, curtailment, and increased reliance on renewable resources with low operating costs (e.g., wind and solar) was a growing prevalence of low or

[154] Reserve-sharing groups assumed in RE Futures modeling (both ReEDS and GridView) exceed today's reserve-sharing groups for many regions of the United States. Expanding these reserve-sharing groups further would likely reduce curtailments.

[155] When BAs cooperate, the variability of the generators within the footprint is relatively lower because of the geographic diversity of the resource. This requires less spinning reserves for the cooperating reserve sharing group. Higher spinning reserve requirements require that more generators are online to provide the energy and reserves. More online generators will lead to higher minimum generation levels from the online fossil-fuel units in a system. Higher minimum generation levels could lead to curtailment during periods of high renewable generation and/or low load.

zero wholesale locational marginal prices (LMPs). Specifically, regions with enough generating units with low or zero marginal costs at a given time will tend toward locational marginal prices of approximately zero, especially when transmission capacity is inadequate to export “excess” renewable generation to other regions and when storage is inadequate to absorb fully that excess generation. The prevalence of near-zero locational marginal prices implies that markets for multiple services in addition to the energy market would likely be needed to reduce revenue risk and to provide financial incentive to generators for producing renewable energy and ensuring reliability. These markets might include capacity markets, renewable generation credit markets, and ancillary service markets for spinning reserves, frequency regulation, and load following. None of these was explicitly modeled as separate markets in this analysis, although modeling constraints required that sufficient operating reserves were online at every hour, based on the amount of forecasted load and variable generation. Although widespread low and zero locational marginal prices in the energy markets could pose challenges, changes in market design and policies can potentially help create the financial incentives needed to encourage generators to provide resource adequacy within the system. Low locational marginal prices are not, alone, a technical operational challenge to the electric power system.

The broader implications of widespread low and zero locational marginal prices on wholesale market design and new plant investments within the context renewable deployment are discussed in recent literature, such as Smith et al. (2010), Fink et al. (2009), and Nicolosi (2010).

4.5 Electricity Supply by Generation Type is Similar Between GridView and ReEDS

Although GridView relies on the same generator types and capacities (and, generally, fuel prices[156]) as estimated by ReEDS, its hourly dispatch differs from the dispatch estimated by ReEDS. Despite those differences, Figure 4-6 shows that the estimated generation mix from GridView was very similar to that estimated by ReEDS in the Low-Demand Baseline scenario and the 80% RE-ITI scenario. Some subtle differences, however, do exist. In the Low-Demand Baseline scenario, for example, GridView dispatched natural gas units somewhat more, and coal units somewhat less, than did ReEDS. In the 80% RE-ITI scenario, GridView again relied more heavily on its natural gas generators. This could be due to its more realistic depiction of the flexibility constraints of coal and nuclear units that use current technology, or to its ability to better model congestion. Nuclear units, meanwhile, were found to run more heavily in GridView, in part due to the lack of an explicit renewable electricity requirement in GridView as it cannot enforce annual constraints; GridView does not have an incentive to reduce curtailment beyond minimizing production cost, so GridView favored curtailment over reduced nuclear output. Finally, transmission constraints limit the amount of power that can be shipped from one region to another. In particular, GridView shows greater transmission flow limits coming from the Midwest, which has excellent wind and biomass resources, compared to ReEDS. Because GridView projects more congestion than ReEDS does, less power can be transmitted out of the

[156] Because the production cost modeling in GridView does not and cannot consider a strict annual renewable requirement as a modeling constraint, biomass feedstock prices were set at an arbitrarily low level to encourage the operation of biomass plants in the production cost modeling (see Appendix B).

Midwest, and the capacity factor of the biomass units in the Midwest was therefore lower when compared to ReEDS projections.

Due to the additional curtailment and reduced average capacity factor of biopower units, the GridView model projects that the renewable capacity estimated by ReEDS in 2050 would deliver 75% of total generation in the 80% RE-ITI scenario, compared to 80% in ReEDS. GridView projects 75% and 76% of generation would come from renewable sources in the 80% RE-ETI and Constrained Transmission scenarios. The Constrained Transmission scenario resulted in the highest renewable generation percentage because GridView and ReEDS project transmission congestion to be more similar in a system without much transmission "buildout" from today. Therefore, GridView and ReEDS curtailment numbers are closest in this scenario.

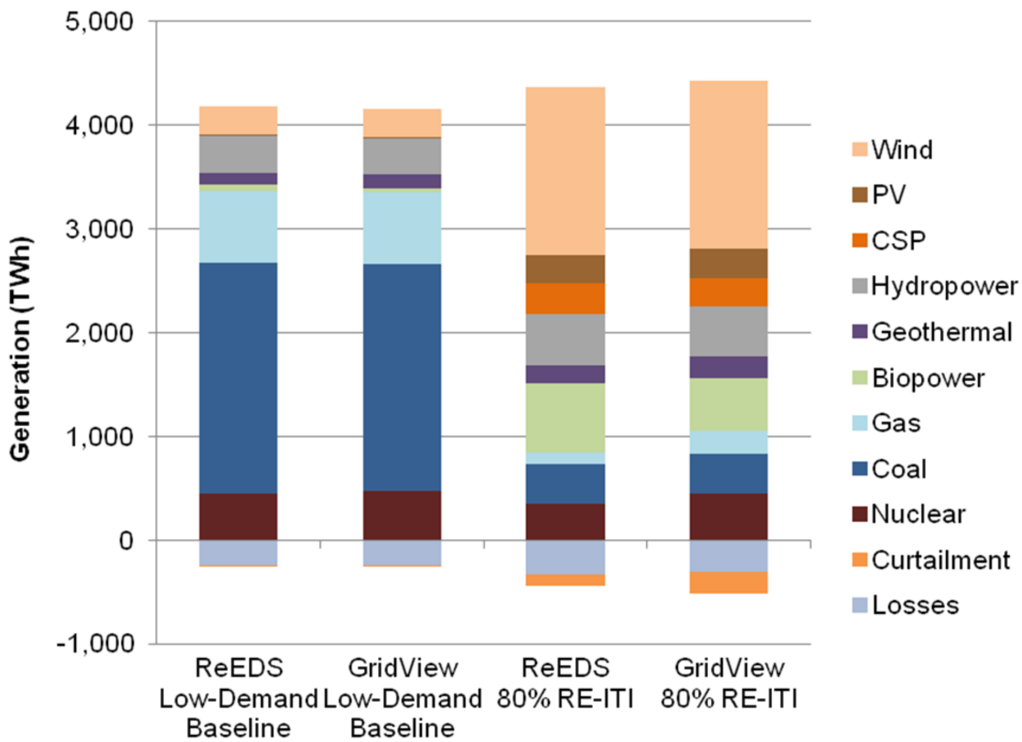


Figure 4-6. Generation in 2050 in ReEDS and GridView in the Low-Demand Baseline and 80% RE-ITI scenarios[157]

[157] Comparisons of ReEDS and GridView results for the other 80%-by-2050 renewable electricity scenarios modeled, including the 80% RE-ETI and Constrained Transmission scenarios, were qualitatively similar to the results shown here for the 80% RE-ITI scenario. Generally, GridView showed greater levels of nuclear and natural gas generation, greater levels of curtailment, and lower levels of biopower generation compared with ReEDS. Among the three 80%-by-2050 scenarios where GridView and ReEDS results were compared, the Constrained Transmission scenario showed the highest degree of similarities between the models.

4.6 Summary of Results from Hourly Modeling of High Renewable Scenarios

The GridView modeling presented in this chapter supplements the ReEDS analysis summarized earlier, and provides further insights into the challenges of reaching high-penetration renewable electricity futures. Although detailed sub-hourly impacts were not analyzed, the GridView analysis suggests that serving load on an hourly timescale is feasible in a high-penetration renewable energy scenario. System-wide operational challenges were met with a variety of supply- and demand-side technologies, including flexible generators, utility controlled charging of electric vehicles, storage, interruptible load, curtailment, and increased transmission capacity, the latter of which enables dispatch decisions to take advantage of the geospatial diversity of wind and solar. Operational challenges were found to be most significant during off-peak times, both seasonally (spring) and diurnally (night).

Significant curtailment was estimated to occur, driven by excess renewable generation, minimum generation levels for thermal power plants, and transmission congestion. Curtailment was found to peak during the spring due to high renewable generation and low load. Transmission use and congestion was higher in the 80% RE-ITI scenario than in the Low-Demand Baseline scenario, and the combination of transmission congestion and substantial deployment of low or zero marginal cost generators was found to lead to many hours with near-zero locational marginal prices and curtailment. GridView modeling, however, demonstrated that, despite the challenges of curtailment and transmission congestion, hourly system operation was achievable, and hourly demand could be served in a high-renewable scenario. Actual achievement of this result would require overcoming numerous institutional challenges, however, as discussed in Volume 4, as well as addressing issues associated with electricity reliability not addressed in RE Futures (see Text Box 1-1).

Chapter 5. Economic, Environmental, and Social Implications of High Renewable Scenarios

The RE Futures study focuses on key technical implications of high renewable deployment, exploring whether the U.S. power system can supply electricity to meet customer demand on an hourly basis with high levels of renewable electricity, including variable wind and solar generation. With this focus, the analysis results presented in Chapters 2–4 were primarily related to renewable deployment and power systems operations under high renewable electricity scenarios. These modeled scenarios represent a transformative change to the U.S. electric sector and such a change would likely have far-reaching environmental, social, and economic implications. These long-term implications are inherently highly uncertain and difficult to quantify. Appendix A presents an initial attempt at understanding some of the implications of the RE Futures modeled scenarios. More specifically, the scenario implications discussed in Appendix A include direct electric sector costs, greenhouse gas emissions, electric sector water use, and land use. The implications presented in the appendix do not represent a comprehensive list. The results from the analysis in Appendix A are summarized as follows:

High renewable electricity futures can result in deep reductions in electric sector greenhouse gas emissions and water use. Direct environmental and social implications are associated with the high renewable futures examined, including reduced electric sector air emissions and water use resulting from reduced fossil energy consumption, and increased land use competition and associated issues. At 80% renewable electricity in 2050, annual generation from both coal-fired and natural gas-fired sources was reduced by about 80%, resulting in reductions in annual greenhouse gas emissions of about 80% (on a direct combustion basis and on a full life cycle basis) and in annual power sector water use of roughly 50%. At 80% renewable electricity, gross land-use impacts associated with renewable generation facilities, storage facilities, and transmission expansion totaled less than 3% of the land area of the contiguous United States.[158]

The direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost. The retail electricity price implications estimated for the 80%-by-2050 RE scenarios are comparable to those seen in other studies with similarly transformative electricity futures, as shown on Figure ES-10. Low carbon and clean energy scenarios, evaluated by the U.S. Energy Information Administration (EIA) and the U.S. Environmental Protection Agency (EPA), with avoided carbon emissions trajectories similar to the core 80% RE scenarios showed increases in average retail electricity prices (relative to their own reference scenarios) in 2030 of $9–$26/MWh, rising to $41–$53/MWh by 2050. These studies generally considered a portfolio of clean generation technology options, including renewable, nuclear, and low emissions fossil. The estimated incremental price impacts of the core 80% RE scenarios are comparable to these estimates.

[158] Net land-use impacts, considering the implications of reduced conventional generation, and land-use impacts based on disrupted lands, are both expected to be smaller. As an example of the latter case, disrupted land would generally be less than 5% of gross land area for wind generation facilities.

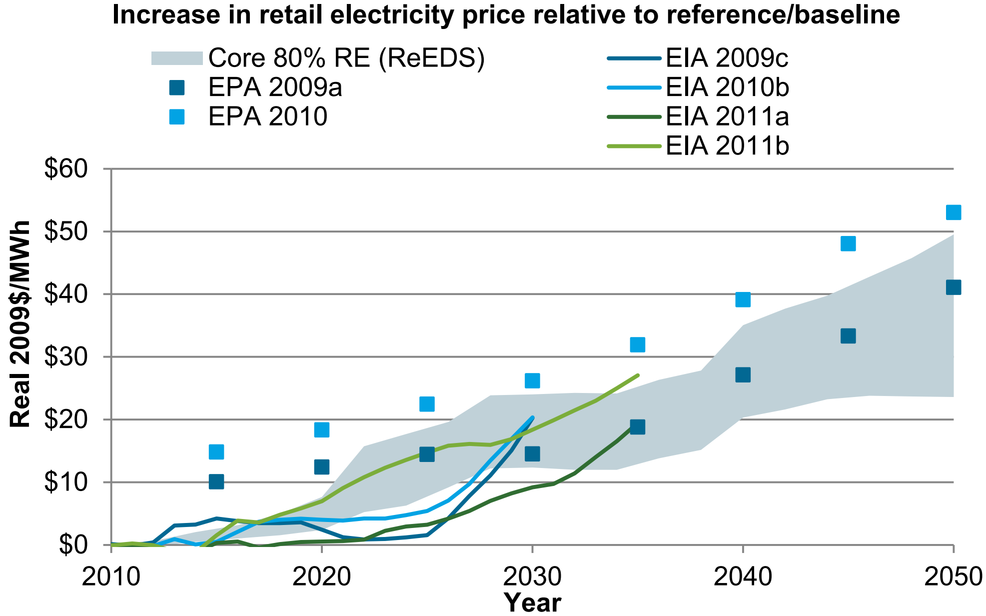


Figure 5-1. Average increase in retail electricity rates relative to study-specific reference/baseline scenarios

EIA 2011a and 2011b document analysis of clean energy scenarios. EIA 2009c, EPA 2009a, EIA 2010b, and EPA 2010 report on analysis of several low carbon emissions scenarios.

As with these other clean generation scenarios that would represent a nearly wholesale transformation of the U.S. electricity system, the high renewable generation scenarios examined show a direct incremental cost relative to the continued evolution of today's conventional generation-dominated system. Higher electricity prices associated with the high renewable scenarios are driven by replacement of existing generation plants with new generators (mostly renewable); additional balancing requirements reflected in expenditures for combustion turbines, storage, and transmission; and the assumed higher relative capital cost of renewable generation, compared to conventional technologies, assumed in the analysis. The increased capital investments associated with these drivers, compared to the baseline scenario, were not fully offset by cost savings associated with lower fossil energy consumption. The incremental cost does not include investments in energy efficiency implied by low electricity demand assumptions, or the savings in avoided generation resulting from these investments. Further, the incremental cost estimate does not consider indirect societal costs associated with the scenarios (e.g., associated with the greenhouse gas emissions described above), or economy-wide impacts.

Advancements in renewable technologies, reflected by technology cost and performance improvement assumptions, had the greatest impact on the incremental cost of the high renewable generation scenarios. For example, the low end of the range of incremental electricity price shown in Figure ES-10 reflects the scenario with the highest assumed renewable technology improvement (RE-ETI), while the high end reflects the lowest technology improvement scenario

(RE-NTI).[159] Assumed system constraints had more modest impact on direct incremental costs; scenarios reflecting constraints to transmission expansion, renewable resources, and grid flexibility all had similar costs, which fell well within the bounds identified in Figure ES-10. Finally, incremental costs were largely insensitive to differences in projections for fossil fuel prices and fossil technology improvements.

The lower renewable generation levels examined in the exploratory scenarios showed lower incremental 2050 retail electricity prices. For example, the 30% RE scenario under highest technology improvement assumptions (RE-ETI) showed no price increase in 2050 relative to the baseline scenario (which used RE-ITI assumptions). This result suggests that significant expansion of renewable generation beyond the 2010 level (10% of total generation) could be achieved with little or no incremental cost, assuming evolutionary improvements in renewable technologies.

There are significant inherent uncertainties with respect to future electricity demand, technology improvements, fossil energy prices, social and institutional choices, and regulatory and legislative actions related to the scenarios examined that, in turn, contribute to significant uncertainty in the implications reported above. Further, there are a variety of indirect (or downstream) implications that may result from the direct electric sector cost, environmental, and social implications identified, including economic development in the energy industry, water quality, land and marine contamination, waste disposal, human health, and climate change. Identification, and in some cases quantification, of these indirect implications is an active area of wide-ranging research. This analysis does not attempt to evaluate these indirect impacts of high renewable electricity futures. Further research is critically needed to systematically assess the relative impacts of different forms of energy supply in the context of a robust comprehensive framework that assesses both direct and indirect impacts. Such research could inform national energy policy decisions as well as local siting and permitting processes related to proposed generation facilities and supporting infrastructure.

[159] The RE-ETI assumptions are based on evolutionary improvements to currently commercial technologies and do not reflect DOE activities to further lower renewable technology costs so that they achieve parity with conventional technologies.

Conclusions

The RE Futures study assesses the extent to which future U.S. electricity demand could be supplied by commercially available renewable generation technologies—including wind, utility-scale and rooftop PV, CSP, hydropower, geothermal, and biomass—under a range of assumptions for generation technology improvement, electric system operational constraints, and electricity demand. Within the limits of the tools used and scenarios assessed, hourly simulation analysis indicates that estimated U.S. electricity demand in 2050 could be met with 80% of generation from renewable energy technologies with varying degrees of dispatchability together with a mix of flexible conventional generation and grid storage, additions of transmission, more responsive loads, and foreseeable changes in power system operations. Further, these results were consistent for a wide range of assumed conditions, including constrained transmission expansion, grid flexibility, and renewable resource availability. Overall, RE Futures contributes substantially to increased understanding of some of the technical, economic, and institutional challenges and opportunities associated with high-levels of renewable energy generation in the U.S. electric sector. Key study findings are restated here.

Deployment of Renewable Energy Technologies in High Renewable Electricity Futures

Renewable energy resources, accessed with commercially available generation technologies, could adequately supply 80% of total U.S. electricity generation in 2050 while balancing supply and demand at the hourly level.

All regions of the United States could contribute substantial renewable electricity supply in 2050, consistent with their local renewable resource base.

Multiple technology pathways exist to achieve a high renewable electricity future. Assumed constraints, which limit power transmission infrastructure, grid flexibility, or the use of particular types of resources can be compensated for the through use of other resources, technologies, and approaches.

Annual renewable capacity additions that enable high renewable generation are consistent with current global production capacities but are significantly higher than recent U.S. annual capacity additions for the technologies considered. No insurmountable long-term constraints to renewable electricity technology manufacturing capacity, materials supply, or labor availability were identified.

Grid Operability and Hourly Resource Adequacy in High Renewable Electricity Futures

Electricity supply and demand can be balanced in every hour of the year in each region with nearly 80% electricity from renewable resources, including nearly 50% from variable renewable generation, according to simulations of 2050 power system operations.

Additional challenges to power system planning and operation would arise in a high renewable electricity future, including management of low-demand periods and curtailment of excess electricity generation.

Electric sector modeling shows that a more flexible system is needed to accommodate increasing levels of renewable generation. System flexibility can be increased using a broad portfolio of supply- and demand-side options, and will likely require technology advances, new operating procedures, evolved business models, and new market rules.

Transmission Expansion in High Renewable Electricity Futures

As renewable electricity generation increases, additional transmission infrastructure is required to deliver generation from cost-effective remote renewable resources to load centers, enable reserve sharing over greater distances, and smooth output profiles of variable resources by enabling greater geospatial diversity.

Cost and Environmental Implications of High Renewable Electricity Futures

High renewable electricity futures can result in deep reductions in electric sector greenhouse gas emissions and water use.

The direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost.

Effects of Higher Demand Growth on High Renewable Electricity Futures

With higher demand growth, high levels of renewable generation present increased resource and grid integration challenges.

Caveats and Implications

While the analysis was based on detailed geospatially rich modeling down to the hourly timescale, the study is subject to many limitations both with respect to modeling capabilities and the many assumptions required about inherently uncertain variables, including future technological advances, institutional choices, and market conditions. Nonetheless, the analysis shows that realizing this significant transformation of the electricity sector would require:

- Sustained build-up of many renewable resources in all regions of the United States
- Deployment of an appropriate mix of renewable technologies from the abundant and diverse U.S. renewable resource supply in a way that accommodates institutional or operational constraints to the electricity system, including constraints to transmission expansion, system flexibility, and resource accessibility
- Establishment of mechanisms to ensure adequate contribution to planning and operating reserves from conventional generators, dispatchable renewable generators, storage, and demand-side technologies
- Increased flexibility of the electric system through the adoption of some combination of storage technologies, demand-side options, ramping of conventional generation, more flexible dispatch of conventional generators, energy curtailment, and transmission

- Expansion of transmission infrastructure to enable access to diverse and remote resources and greater reserve sharing and balancing over larger geographic areas.

Further Work

This study is an initial exploration of renewable energy-based clean electricity futures. Considerable further analysis is needed to improve the understanding of the potential evolution described above, and to examine in detail, at varying geographic scales and time resolutions, implications for electric system operations, reliability, costs, and benefits. This work includes the following:

- A comprehensive cost-benefit analysis to better understand the economic and environmental implications of high renewable electricity futures relative to today's electricity system largely based on conventional technologies and alternative futures in which other sources of clean energy are deployed at scale
- Further investigation of the more complete set of issues around all aspects of power system reliability because RE Futures only partially explores the implications of high penetrations of renewable energy for system reliability
- Improved understanding of the institutional challenges associated with the integration of high levels of renewable electricity, including development of market mechanisms that enable the emergence of flexible technology solutions and mitigate market risks for a range of stakeholders, including project developers
- Analysis of the role and implications of energy research and development activities in accelerating technology advancements and in broadening the portfolio of economically viable future renewable energy supply options and supply- and demand-side flexibility tools.

The results of this study can stimulate dialogue that will create additional insights and inform the design of more detailed follow-on analyses, and can contribute to broader discussion of the evolution of the electric system and electricity markets toward clean systems.

Appendix A: Cost, Environmental, and Social Implications of High-Penetration Renewable Electricity Futures

1. Introduction

1.1 Overview of the Appendix

This appendix supplements the analysis approach, scenario outcomes, and key results presented in Volume 1 by further analyzing the implications of high renewable electricity futures. The analysis in Volume 1 focuses on the deployment and operational results from the modeled scenarios, including exploring implications related to operating the grid with high levels of renewables. As described, hourly simulation of the contiguous U.S. grid found that high levels of renewables were feasible across a wide range of scenarios. This appendix summarizes the major assumptions, particularly those relating to technology cost and performance, used in the modeling, and discusses some of the economic, environmental, and social implications of the scenarios described in Chapters 2–4. More specifically, the scenario implications discussed here include direct electric sector costs, fossil energy consumption, GHG emissions, electric sector water use, land use, and other related environmental and social impacts. The implications presented do not represent a comprehensive treatment, particularly with respect to more indirect (downstream) impacts, and the analysis includes many uncertainties and limitations, which are identified in the relevant sections.

This appendix is organized as follows. The present section re-summarizes the models and scenarios used in RE Futures. Section 2 lists the major assumptions used in the modeling, focusing on technical potential, cost, and performance parameters not discussed in Chapter 2. Direct electric sector implications, including present value of electric system costs and electricity prices, are assessed in Section 3. Section 4 presents the environmental and social implications noted above. Finally, the results of this analysis are summarized in the conclusion section, Section 5.

1.2 Electric Sector Models in RE Futures

RE Futures primarily employed two distinct electric-sector models: NREL's ReEDS and ABB's GridView. ReEDS is a least-cost optimization capacity expansion model, and GridView is an hourly chronological production cost model. The linked-but-separate use of these two models allowed for a rich assessment of the technical, geographic, and operational aspects of renewable energy deployment in the contiguous United States. The major cost assumptions described in Section 2 below are primarily used in the ReEDS capacity expansion model. Similarly, the economic, environmental, and social implications detailed in this appendix are also primarily based on results from ReEDS. Additional details on the design and application of both models, along with other modeling and analysis tools used to supplement ReEDS and GridView, are provided in Chapter 1, Appendix B, and Short et al. (2011).

1.3 Modeled Scenarios

Given the inherent uncertainties involved with analyzing alternative long-term energy futures, and given the multiple pathways that might be taken to achieve higher levels of renewable electricity supply, multiple future scenarios were modeled and analyzed. Figure A-1 shows the scenarios modeled and the relationship between the scenarios. A detailed description of the scenarios is provided in Chapters 1–4. The scenarios rely on three renewable technology cost and performance projections: (1) No Technology Improvement (RE-NTI), (2) Incremental Technology Improvement (RE-ITI), and (3) Evolutionary Technology Improvement (RE-ETI). Section 2 of this appendix summarizes these projections; RE Futures' analysis of renewable energy technologies (Volume 2) and Black & Veatch (2012) contain more detailed descriptions of the assumptions underlying these projections.

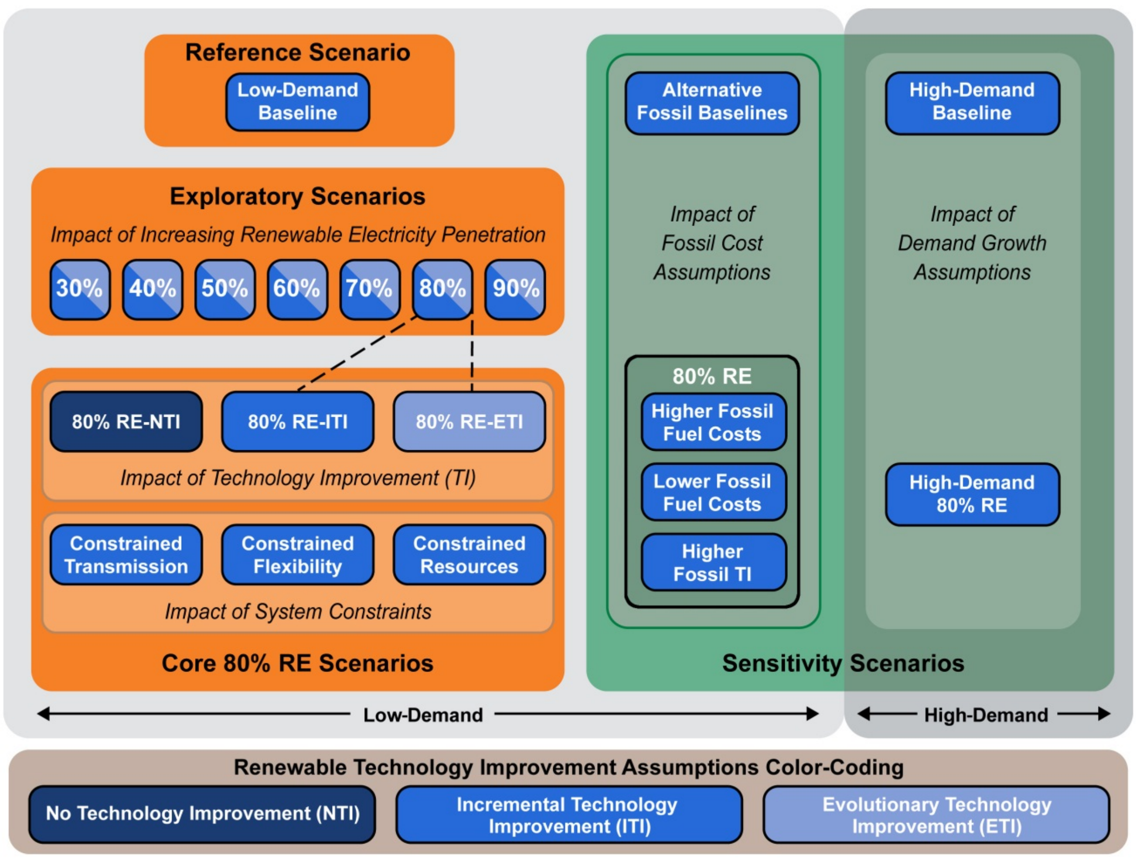


Figure A-1. Modeling scenario framework for RE Futures

Dotted lines indicate that the 80% RE exploratory scenarios are the same as the 80% RE-ITI and 80% RE-ETI scenarios.

Section 3 of this appendix presents direct electric sector cost estimates of the scenarios, including the present value of total system cost and retail electricity prices. The present value of system cost includes discounted costs of new generation capacity additions; transmission and storage capacity additions; and operating, fuel, and other costs through 2050. The order in which direct electric sector cost estimates are presented in Section 3 follows the presentation of the scenario results in Chapters 1–3. This order is summarized below.

First, a Low-Demand Baseline scenario was constructed as a point of comparison for the high-penetration renewable electricity scenarios (see Figure A-1). To be consistent with a future with no additional policy support for renewable energy, the lower renewable technology improvement (RE-ITI) projections were used for this baseline scenario. Next, a series of "exploratory" scenarios, in which the proportion of renewable electricity in 2050 increased in 10% increments from 30% to 90%, was evaluated. Given uncertainties associated with future renewable technology cost and performance, the series of exploratory scenarios were evaluated under two separate renewable technology cost and performance projections, RE-ITI and RE-ETI.

Further analysis was then performed on six core 80% RE scenarios, each of which met the same 80%-by-2050 renewable electricity penetration level. Three scenarios explored the impacts of future renewable energy technology advancements; these scenarios included the no technology improvement (80% RE-NTI), lower technology improvement (80% RE-ITI), and higher technology improvement (80% RE-ETI) scenarios. Three other scenarios explored the impacts of different possible electricity system constraints, including limits to building new transmission (Constrained Transmission), constraints on how the system can manage the variability of wind and solar resources (Constrained Flexibility), and constraints on resource availability (Constrained Resource).

To test the impacts of a higher-demand future, a scenario—referred to as the High-Demand 80% RE scenario, with an 80%-by-2050 RE generation level but a higher end-use electricity demand—was evaluated. A corresponding reference scenario with the same higher demand was also evaluated. The lower renewable technology improvement (RE-ITI) projections were used for the high-demand scenarios.

Finally, given uncertainties in the future cost of fossil energy sources, the analysis included 80%-by-2050 renewable electricity scenarios in which (1) the cost of fossil energy (coal and natural gas) was both higher and lower than otherwise assumed in the other scenarios, and (2) fossil energy technologies experienced greater improvements over time than assumed in the other scenarios. These scenarios are referred to as Higher and Lower Fossil Fuel Costs, and Higher Fossil Technology Improvement (Fossil-HTI) scenarios, respectively. Corresponding reference scenarios with these alternate fossil energy projections were also evaluated. These fossil sensitivities were evaluated using the RE-ITI technology projections and the low-demand assumption.

The scenarios were not constructed to find the optimal GHG mitigation or clean energy pathway (e.g., to minimize carbons emissions or the cost of mitigating these emissions)—

rather, the scenarios were designed with specific renewable electricity generation levels to explore technical issues associated with the operation of the U.S. electricity grid at these levels. In addition, because the scenarios included specific renewable generation levels, they were not designed to explore how renewable technologies might economically deploy under certain technology advancement projections without the generation constraints.

2. Summary of Generation, Storage, and Transmission Cost and Performance Assumptions

This section summarizes the cost and performance assumptions for renewable technologies (Section 2.1), conventional technologies (Section 2.2), storage and demand-side flexibility technologies (Section 2.3), transmission (Section 2.4), and financial parameters (Section 2.5) used in the modeling analysis. The descriptions and tables in Section 2 provide a concise summary of these major modeling assumptions. A more complete description of these assumptions, the context in which they are applied within the scenario framework used in RE Futures, and their limitations are described in Chapter 1, Volume 2, and Black & Veatch (2012).

2.1 Renewable Technologies

2.1.1 Overview of Projections Used in RE Futures

The current and projected future cost and performance of commercially available electricity generation technologies were major drivers of the scenario model results, and inherent uncertainties exist for cost projections over the 40-year analysis time frame. For simplicity and transparency, multiple future technology cost and performance estimates were explicitly assumed throughout the study period (2010–2050). Scenario modeling was then conducted using each of these cost and performance estimates rather than imposing an endogenous learning rate (see Text Box A-1), which would rely on the cumulative installed capacity of a given technology to determine future cost trajectories. More specifically, the majority of the model scenarios assumed one of two renewable technology cost and performance projections, RE-ITI and RE-ETI, representing lower and higher future renewable technology improvements, respectively,[160] and correspondingly higher and lower renewable costs. These projections are for technologies commercially available in 2010 and their incremental or evolutionary improvements only.

[160] None of the technology cost projections presented in RE Futures necessarily reflects the best estimates of DOE. In particular, the solar technology RE-ITI and RE-ETI projections assume substantially higher technology costs than those projected under DOE's SunShot Initiative (see Volume 2, Chapter 10).

Text Box A-1. Technology Cost Estimates and Learning Curves

Although the methods used in RE Futures to project the future cost of each renewable electricity technology differ to some degree by technology, the resulting forecasts are largely based on anticipated scientific and engineering advancements rather than on learning-curve-based estimates that are endogenously driven by an assumed learning rate applied to cumulative production or installation.

Learning curves have been used extensively to understand past cost trends and to forecast future cost reductions for a variety of energy technologies, including renewable energy (e.g., McDonald and Schrattenholzer 2001; Kahouli-Brahmi 2009; Junginger et al. 2010). Learning curves begin with the premise that an increase in the cumulative production or installation of a given technology leads to a reduction in its costs. The rate at which costs decline with each doubling of cumulative production or installation is referred to as the *learning rate*. A wide range of historical learning rates has been estimated for individual renewable energy technologies, variation that can be characterized, in part, by differences in learning model specifications (single-factor learning or multiple-factor learning that also incorporates research and development advancements); variable selection (e.g., whether installed cost, component cost, or levelized energy costs are considered); assumed system boundaries (e.g., whether global or country-level cumulative installations are used); data quality; and the time period over which data are available. Regardless of the differences, learning rates are often usefully applied in energy-sector modeling to simulate the endogenous influence of technology deployment on the underlying cost of the technologies.

However, in addition to learning model specification errors, there are a number of limitations to the use of generic historical learning rates to forecast future costs. Perhaps most importantly, learning curves typically model how costs have decreased with increased production or installations in the past, and do not seek to comprehensively explain the reasons for those decreases (Mukora et al. 2009). In reality, costs may decline in part due to traditional learning and in part due to other factors, such as R&D investment, economies of scale in manufacturing, component, or plant size, and reductions in material costs (e.g., Nemet 2006). Learning rate estimates that do not account for such factors may suffer from omitted variable bias, and may therefore be inaccurate. Moreover, if learning curves are used to forecast future cost trends, not only should the other factors that may influence costs be considered, but one must also assume that learning rates derived from historical data can be appropriately used to estimate future trends. As technologies mature, however, diminishing returns in cost reduction might be expected, and the drivers that have impacted cost reductions in the past may not continue into the future (e.g., Arrow 1962; Ferioli et al. 2009). The application of learning rates to model future cost evolution in U.S.-based energy futures is also complicated by the question of system boundaries. Renewable energy markets are international in scope, and if learning does take place, it will in large part be driven by global cumulative installations. Endogenously defined future cost reductions based on learning would therefore need to be based on estimates of global renewable energy installations that are outside of the scope of RE Futures. As a result of these factors, and despite the countervailing benefits to the use of learning rates in modeling energy futures, endogenous learning was not modeled in RE Futures.

Incremental renewable technology improvement estimates (RE-ITI) were primarily developed by the engineering company Black & Veatch (2012). Black & Veatch has substantial experience with power plant design and construction of both renewable and conventional power plants, which enables it to provide an electric-sector-wide perspective on the relative cost and performance of the full range of (conventional and renewable) generation technologies. In addition to relying on that experience, Black & Veatch also considered the existing bottom-up engineering cost literature on renewable generation technologies as provided by the technology experts included in RE Futures. Black & Veatch (2012) describes the factors that went into the RE-ITI technology projection estimates.

In contrast to the electric-sector-wide perspective used to develop the RE-ITI estimates, the RE-ETI estimates relied on the perspective of each renewable generation technology independently. The RE-ETI estimates represent the technical advances currently envisioned through evolutionary improvements associated with continued research and development for each technology, and depending on external market conditions, policy incentives and R&D investments; these anticipated technical advances could be accelerated or achieve greater magnitude than what is assumed here. Volume 2 includes details on the bottom-up engineering analysis used to develop the RE-ETI data for each individual technology. In addition, Volume 2 provides comparisons of the RE-ETI estimates with the RE-ITI estimates, technology projections from other sources (if available), and historical trends for each currently commercially available renewable technology.

The dual use of the RE-ITI and RE-ETI data in the model scenarios enables RE Futures to reflect the inherent uncertainties in future technology cost and performance trajectories.[161] *These two renewable energy cost projections were not intended, however, to encompass the full range of possible future renewable technology costs; greater cost and/or performance improvements are possible.* Volume 2 describes the engineering improvements for renewable technologies envisioned under RE-ETI. In addition, the cost and performance assumptions used in RE Futures are not related to DOE program targets.[162] Some technologies, such as PV technologies, have recently shown significant

[161] The RE-ITI and RE-ETI data do share some common characteristics and assumptions. In particular, while generation technology capital costs increased during the mid- to late-2000s, in part associated with increasing commodity and labor costs, neither the RE-ITI nor the RE-ETI data assumed any future increase or decrease in commodity or labor costs that would tend to impact all generation technologies similarly. In addition, in both RE technology projections, the magnitude and timing of future cost and performance improvement reflect today's relative commercial maturity of the technologies. For example, solar technologies achieve greater cost improvement than other, more commercially mature renewable electricity technologies.

[162] The direct electric sector cost implications presented in Section 3 could differ if greater renewable technology improvements, such as those envisioned by DOE, were assumed in the modeling analysis. In particular, the Low-Demand Baseline scenario would likely include greater renewable deployment, and the difference in direct electric sector costs between the Low-Demand Baseline scenario and the higher renewable penetration scenarios (e.g., 80%-by-2050 RE scenarios) would likely be reduced from the differences presented in Section 3.

cost declines closely in line with DOE program targets but beyond what was assumed in the analysis. These examples demonstrate the difficulty in predicting future technology progress, particularly with the long projection window of the analysis.

Sections 2.1.2–2.1.3 summarize the technology improvements estimated in the RE-ITI and RE-ETI data for each of the renewable technologies considered in RE Futures, with greater detail provided in Volume 2 and Black & Veatch (2012).

In addition to the two renewable technology cost and performance projections described above, a scenario assuming no future renewable technology improvements was modeled. The 80% RE-NTI scenario assumed higher technology costs in 2050 than those of either the RE-ITI scenario or the RE-ETI scenario data by simply maintaining the recent cost and performance of each renewable technology with no future cost reduction or performance improvement. For the 80% RE-NTI scenario, the 2010 renewable technology cost and performance estimates from the RE-ITI data were assumed for all future years.

2.1.2 Renewable Technology Projections

The trends in assumed future renewable technology cost and performance as estimated under RE-ITI and RE-ETI are summarized below.[163] Tables summarizing these assumptions are provided in the next section with additional detail included in Volume 2 and Black & Veatch (2012).

Biopower plants were estimated in RE-ITI and RE-ETI to have little or no capital cost reductions during the 2010–2050 study period, although heat rate improvements were estimated for dedicated biopower facilities (14% and 33% reductions in heat rate over the study period for RE-ITI and RE-ETI, respectively) and operation and maintenance (O&M) cost reductions were also assumed under the RE-ETI estimates. Coal plants were allowed to be retrofitted to co-fire biomass, with a hard ceiling of 15% of electricity generation deriving from biomass fuel. The same retrofit costs were estimated in both RE-ITI and RE-ETI. The O&M costs and heat rates of co-fired plants were assumed to be the same as the pre-existing coal plant. Although no generation capacity limitations to dedicated biopower or biomass co-fired power plants were applied, regional feedstock supply curves[164] comprised of a combination of urban and mill waste, forest and agriculture residues, and dedicated crops were used to appropriately constrain feedstock availability (Walsh et al. 2000 and Milbrandt 2005). These resource supply assumptions are described further in Chapter 6 (Volume 2), and the model implementation is explained in Short et al. (2011). In real dollar terms, biomass feedstock prices vary by "resource class" (a proxy for variations in biomass feedstock sources), but were assumed to remain constant over time for each class in the supply curve. Biomass plants with carbon capture and storage were

[163] The modeled scenarios focused solely on currently commercial renewable technologies; therefore, ocean, enhanced geothermal, and floating offshore wind technologies were not included. As such, cost and performance projections for these technologies are not included here.
[164] ReEDS does not allow the transport of feedstock between BAs. In other words, a power plant in a BA can only access feedstock available within the same BA, although electricity generated from the plant can be transmitted to different BAs.

not considered in RE Futures because they are not yet commercially available technologies.[165]

Geothermal (hydrothermal) technologies were estimated in RE-ITI to not experience further cost or performance improvements. Due to the strong site-dependence of geothermal resources, however, regional capital cost supply curves with a wide range in overnight capital costs starting at $2,990/kW were used in the capacity expansion modeling. RE-ETI relied on the same current-year regional capital cost supply curves; however, a 17% reduction in capital costs was estimated for each supply step over the study period. Due to the focus on currently commercial technologies only, the modeling analysis only considered hydrothermal technologies and did not consider enhanced geothermal systems and other advanced geothermal technologies (see Chapter 7 [Volume 2], for a discussion of the potential contribution from other geothermal technologies). The cost estimates used in RE Futures assumed dry-cooled geothermal plants only.

Hydropower technologies were estimated to not experience further capital cost or performance improvements in both RE-ITI and RE-ETI over the study period. RE-ETI estimates included slightly lower O&M costs than the RE-ITI estimates. As with geothermal technologies, regional capital cost supply curves were used in the capacity expansion modeling, with capital costs ranging from $3,500/kW to $5,500/kW. Large regional differences in capacity factors were driven primarily by water resource availability and were estimated from the historical (1990–2007) generation of existing hydroelectric plants. All new hydroelectric power plants were assumed to be run-of-river facilities, of varying designs, and modeled to have no seasonal or diurnal dispatchability in the ReEDS model. The costs for new projects were estimated to include new civil works in all instances, although in many cases these facilities might rely on pre-existing civil works (e.g., existing dams). Federal and environmental exclusions were assumed to reduce the available sites for potential development, as detailed in Chapter 8 (Volume 2). All existing hydropower plants were assumed to remain operational for the entire study period.

Photovoltaic (PV) technologies were projected in both RE-ITI and RE-ETI projections to experience significant technological gains over the study period due to the currently earlier state of commercialization of these technologies relative to other renewable technologies and in line with the recent gains in solar technologies (Mints 2011). These advancements were reflected in large reductions in the estimated capital cost of utility-scale PV, residential rooftop PV, and commercial rooftop PV—between 2010 and 2050, overnight

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[165] Biomass with CCS was not considered in RE Futures because biomass with CCS is not yet a commercial technology due to limited operational experience and because RE Futures does not postulate a specific future carbon policy. As a technology that may have a net positive carbon impact, however, analyses of global carbon mitigation scenarios have sometimes identified a sizable potential role for biomass CCS, especially in cases with low GHG stabilization targets (e.g., van Vuuren et al. 2010). The exclusion of biomass with CCS from RE Futures is not meant to imply that this technology will not play a role in the future energy supply mix.

capital costs were estimated to decline by 50%, 51%, and 45%, respectively, in RE-ITI, and by 58%, 69%, and 65%, respectively, in RE-ETI. These cost reductions are less than the DOE SunShot goals; for example, RE-ETI projected overnight capital costs of about \$1690/kW in 2050 for utility PV systems; in comparison, the DOE SunShot goal is to achieve \$1000/kW in 2020 (DOE 2012). Cost improvements were also implicit in the 2010 capital costs, which reflect the lower module pricing that became apparent in 2009.[166] O&M costs were also assumed to drop over the study period under both estimates, though to varying degrees. Project-level capacity factors, however, were assumed to remain constant over time. Regional capacity factors (by time slice) were estimated using the National Solar Radiation Database and National Renewable Energy Laboratory's System Advisor Model.[167] Residential and commercial PV deployment was estimated based on NREL's SolarDS model (Denholm et al. 2009a).

Concentrating Solar Power (CSP) with thermal energy storage was estimated in RE-ITI to realize cost reductions during the study period, with overnight capital costs decreasing by 33%. RE-ITI also assumed CSP systems built between 2010 and 2025 to have cost and performance characteristics consistent with trough systems, and systems built between 2025 and 2050 to have characteristics of tower systems.[168] In contrast, RE-ETI assumed a transition from troughs to towers occurring earlier (2015) and estimated a much greater capital cost reduction of 64% over the 40-year period. Regional capacity factors (by time slice) for both trough and tower systems were estimated from direct normal solar radiation from the National Solar Radiation Database and using the System Advisor Model. Only resource regions with greater than 5 kWh/m^2/day of direct normal solar insolation were considered in ReEDS, with other land area exclusions detailed in Chapter 10 (Volume 2). The ReEDS model also considers CSP systems without storage, details of which can be found in Short et al. (2011). To reflect concerns about water use associated with wet-cooled systems, the cost and performance estimates used in RE Futures assumed higher-cost dry-cooled CSP.

Onshore Wind energy technology cost and performance were estimated to remain mostly static over time in RE-ITI and to achieve modest improvements in RE-ETI. In RE-ITI, capital costs for onshore wind were estimated to be constant, while annual capacity factors were estimated to improve slightly during the study period, but only for lower quality (class 3–5) wind resource areas. The RE-ETI estimates include a 10% reduction in capital costs from 2010 to 2050 and higher (and increasing) annual capacity factors for all classes over the same time period compared with the RE-ITI estimates. The quality of the local wind resource (in average wind power density) was derived from the wind resource maps

[166] The RE-ITI and RE-ETI estimates were made in 2010 and do not capture the recent trends in PV costs, which have declined at an even greater rate than those estimated in either RE-ITI or RE-ETI. These rapid changes in technology costs are difficult to predict and no attempt was made to project these changes in either RE-ITI or RE-ETI.

[167] https://www.nrel.gov/analysis/sam/

[168] Although trough and tower systems were used as benchmarks in defining reasonable future cost and performance characteristics, the model does not distinguish between different CSP technologies that have the same cost and performance characteristics.

of individual states, while seasonal and diurnal output variations were derived from AWS Truewind and NCEP/NCAR ReAnalysis data (DOE 2008). Environmental and land use exclusions for onshore and offshore wind, as well as exclusions for sloped terrain, are detailed in Chapter 11 (Volume 2).

Offshore Wind energy technology was estimated to experience cost improvements in both RE-ITI and RE-ETI, with capital cost reductions of 18% and 26%, respectively, by 2050, for the two projections. Similar to onshore wind, RE-ITI estimated only slight performance improvements for lower quality wind resource areas, whereas RE-ETI estimated moderate capacity factor increases for all resource classes. The representation of offshore wind resources was similar to that of onshore wind described above. Because the model analysis in RE Futures only included currently commercial technologies, only fixed-bottom offshore wind technologies were modeled; floating-platform offshore wind was excluded from the modeling analysis[169] because this technology is not yet commercial.

2.1.3 Tables of Renewable Technology Projections

As noted earlier, and as summarized in Table A-1 and Table A-2, the RE-ITI and RE-ETI projections represent two distinct perspectives on future renewable technology cost and performance: RE-ETI estimates include lower costs and/or greater performance improvements than the RE-ITI estimates across all renewable technologies. Other differences between the RE-ITI and RE-ETI estimates are described in Volume 2. One key observation is that, for both RE-ITI and RE-ETI, the solar technologies were estimated to experience the greatest cost reductions over the study period when compared with the other, more commercially mature, renewable technologies. These significant cost reductions, however, are at a rate less than or comparable to what has been observed in recent years (Mints 2011). Additionally, it deserves reiteration that these two renewable energy cost and performance projections were not intended to encompass the full range of possible future renewable technology costs; greater cost and/or performance improvements are possible, but were not modeled in RE Futures. Further details on and the underlying assumptions for the RE-ITI and RE-ETI projections can be found in Black & Veatch (2012) and Volume 2, respectively.

[169] Fixed-bottom offshore resources were restricted to regions where ocean depths were less than 30 m.

Table A-1. Cost and Performance Estimates for Renewable Energy (RE-ITI Data) [a]

	Year	Capital Costs[b] ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Annual Capacity Factor[c] (%)	Heat Rate (MMBtu/ MWh)
Biopower, Dedicated[d]	2010	3830	94	15	Up to 84%	14.5
	2030	3830	94	15	Up to 84%	13.5
	2050	3830	94	15	Up to 84%	12.5
Biopower, Co-fire Retrofit[d,e]	all years	990				
Geothermal (Hydrothermal)	all years	2990+	229	0	Up to 85%	—
Hydropower	all years	3500–5500	15	6	13%–75%	—
PV, Utility-Scale (1-axis)[f]	2010	4000	50	0	17%–28%	—
	2030	2310	41	0	17%–28%	—
	2050	2030	33	0	17%–28%	—
PV, Residential (Rooftop)	2010	5950	50	0	10%–18%	—
	2030	3290	41	0	10%–18%	—
	2050	2930	33	0	10%–18%	—
PV, Commercial (Rooftop)	2010	4790	50	0	10%–18%	—
	2030	2960	41	0	10%–18%	—
	2050	2620	33	0	10%–18%	—
CSP (6 hrs storage)[g]	2010	7060	50	0	29%–46%	—
	2030	5310	50	0	37%–56%	—
	2050	4700	50	0	37%–56%	—
Wind, Onshore	2010	1980	59	0	32%–46%	—
	2030	1980	59	0	35%–46%	—
	2050	1980	59	0	35%–46%	—
Wind, Offshore (Fixed-Bottom)	2010	3640	99	0	36%–50%	—
	2030	2990	99	0	38%–50%	—
	2050	2990	99	0	38%–50%	—

[a] Unless otherwise noted, all dollar values quoted are in real 2009 dollars.
[b] The capital costs listed do not include interest incurred during construction or grid interconnection costs, the latter of which are described in Section 2.4 of this appendix. Though not listed here, ReEDS considers both of these cost elements in its optimization routine.
[c] Capacity factors used throughout the report account for unit availability.
[d] Biomass feedstock prices range from $1.64/MMBtu to $4.09/MMBtu. Regional biomass feedstock supply curves used in the modeling are shown in Short et al. (2011).
[e] The cost to retrofit coal plants to co-fire biomass shown here is applied to the capacity associated with the biomass portion only (e.g., retrofitting a 100-MW coal plant to co-fire up to 15%

biomass has a cost of 100 MW x 15% x $990,000/MW = $14,850,000). Retrofitted coal plants to co-fire biomass are assumed to have the same heat rate and O&M costs as the pre-existing plant.
[f] Photovoltaic capacity factors are associated with DC module ratings.
[g] ReEDS allows the different components of a CSP plant (field, turbine, and storage) to be optimized independently. The cost and performance assumptions, shown here, are for plants with 6 hours of storage and a solar multiple of 2. Cost and performance assumptions assume dry-cooled systems to minimize water use.

Table A-2. Cost and Performance Estimates for Renewable Energy (RE-ETI Data)[a]

	Year	Capital Costs[b] ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Annual Capacity Factor[c] (%)	Heat Rate (MMBtu/ MWh)
Biopower, Dedicated[d]	2010	3,870	103	5	Up to 84%	12.5
	2030	3,840	89	5	Up to 84%	11.1
	2050	3,800	63	7	Up to 84%	8.36
Biopower, Co-fire Retrofit[d,e]	all years	990				
Geothermal (Hydrothermal)	2010	2,990+	229	0	Up to 85%	—
	2030	2,770+	229	0	Up to 85%	—
	2050	2,480+	229	0	Up to 85%	—
Hydropower	all years	3,500–5,500	15	3	13%–75%	—
PV, Utility-Scale (1-axis)[f]	2010	4,000	21	0	17%–28%	—
	2030	1,880	15	0	17%–28%	—
	2050	1,690	9	0	17%–28%	—
PV, Residential (Rooftop)	2010	6,440	33	0	10%–18%	—
	2030	2,230	15	0	10%–18%	—
	2050	2,010	10	0	10%–18%	—
PV, Commercial (Rooftop)	2010	5,100	23	0	10%–18%	—
	2030	1,980	13	0	10%–18%	—
	2050	1,780	7	0	10%–18%	—
CSP (6 hrs storage)[g]	2010	8,090	80	3	29%–46%	—
	2030	2,940	50	3	37%–57%	—
	2050	2,940	45	3	37%–57%	—
Wind, Onshore	2010	1,980	12	7	35%–50%	—
	2030	1,840	12	5	38%–53%	—
	2050	1,780	12	5	38%–53%	—
Wind, Offshore (Fixed-bottom)	2010	3,640	16	22	37%–52%	—
	2030	2,870	16	14	40%–55%	—
	2050	2,700	16	12	40%–55%	—

[a] Unless otherwise noted, all dollar values quoted are in real 2009 dollars.
[b] The capital costs listed do not include interest incurred during construction or grid

interconnection costs, the latter of which are described in Section 2.4 of this appendix. Though not listed here, ReEDS considers both of these cost elements in its optimization routine.
[c] Capacity factors used throughout the report account for unit availability.
[d] Biomass feedstock prices range from $1.64/MMBtu to $4.09/MMBtu. Regional biomass feedstock supply curves used in the modeling are shown in Short et al. (2011).
[e] The cost to retrofit coal plants to co-fire biomass shown here is applied to the capacity associated with the biomass portion only (e.g., retrofitting a 100-MW coal plant to co-fire up to 15% biomass has a cost of 100 MW x 15% x $990,000/MW = $14,850,000). Retrofitted coal plants to co-fire biomass are assumed to have the same heat rate and O&M costs as the pre-existing plant.
[f] Photovoltaic capacity factors are associated with DC module ratings.
[g] ReEDS allows the different components of a CSP plant (field, turbine, and storage) to be optimized independently. The cost and performance assumptions, shown here, are for plants with 6 hours of storage and a solar multiple of 2. Cost and performance assumptions assume dry-cooled systems to minimize water use.

2.1.4 Renewable Technology Resource and Levelized Costs

In addition to the cost and performance estimates presented in Table A-1 and Table A-2, the size and quality of the available resource must also be considered. Figure A-2 and Figure A-3 depict the resource potential of each renewable energy technology at a given levelized cost of energy (LCOE),[170] based on the cost and performance estimates provided by RE-ETI and RE-ITI data (shown in Table A-1 and Table A-2) and the resource potential estimates described in Volume 2. Specifically, Figure A-2 and Figure A-3 show the LCOEs calculated from the 2010[171] cost and performance estimates (RE-NTI) and from the 2050 estimates from RE-ITI and RE-ETI data, based on the financial assumptions described in Section 2.5 of this appendix, and identify the available resource for that LCOE. The estimates provided in the figures do not include currently available federal investment and production tax credits.

Wind and solar[172] technologies were shown to have the greatest resource potential in the contiguous United States, whereas hydropower, biopower,[173] and geothermal

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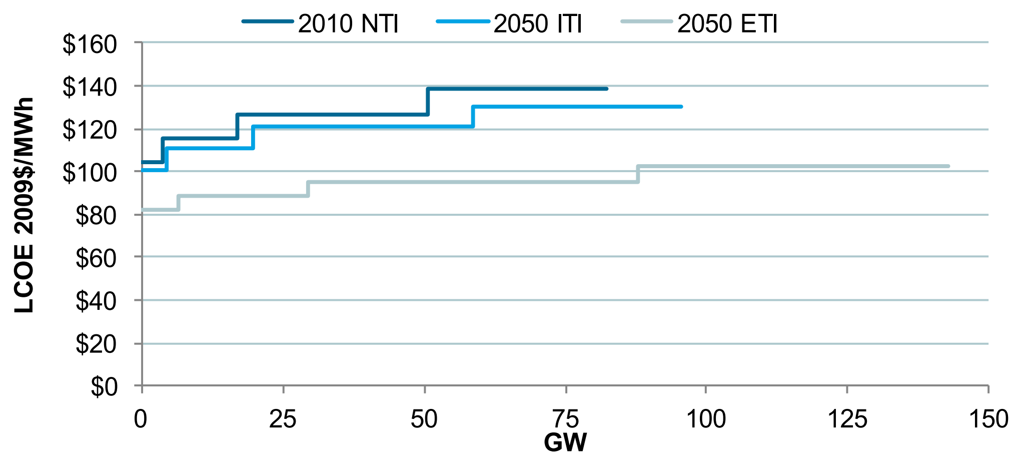
[170] The LCOEs shown in Figure A-2 and Figure A-3 are based on 20-year economic lifetimes and financing as described in Section 2.5. Actual plant lifetimes were assumed in many cases to exceed 20 years (see Section 2.2.3 for a discussion of plant retirements). In addition, because ReEDS does not directly rely on LCOEs in its capacity expansion decision-making, the LCOEs shown in Figure A-2 and Figure A-3 are illustrative only.
[171] The RE-NTI estimates are based on the 2010 cost and performance estimates of the RE-ITI data.
[172] Because nearly 80,000 GW of solar PV resource were available, PV resource limitations were not represented in ReEDS, in contrast to all other renewable technologies. Including explicit PV resource limitations in the model would not change the model's results by a measurable amount given the scale of the available resource.
[173] The available capacity for dedicated biopower was estimated based on available feedstock supply, and it was assumed in Figure A-2(a) that all plants operate at their maximum annual capacity factor. If plants operate at part load, the available nameplate capacity could increase. These estimates did not account for feedstocks that might otherwise be used by cofired power plants, and the resource availability shown here assumed that all of the feedstocks available nationally are fully available for electric power generation (i.e., biofuels for transportation were not *explicitly* considered, although the Constrained Resources scenario is in part motivated by competition between sectors, as described in Chapter 3). To be conservative, for each modeled year, the analysis used feedstock estimates from Walsh et al. (2000) and Milbrandt et al. (2005), which are considerably less than other estimates (see Volume 2, Chapter 6 for a comparison of biomass

(hydrothermal) were more limited in resource quantity. Figure A-2 and Figure A-3 only represent the resources considered in RE Futures modeling; the inclusion of currently non-commercial or not considered resources and technologies (i.e., enhanced geothermal systems, future energy crops, other forms of hydropower, floating-platform offshore wind, and ocean technologies) would significantly increase the potential supply of biopower, hydropower, and especially geothermal.

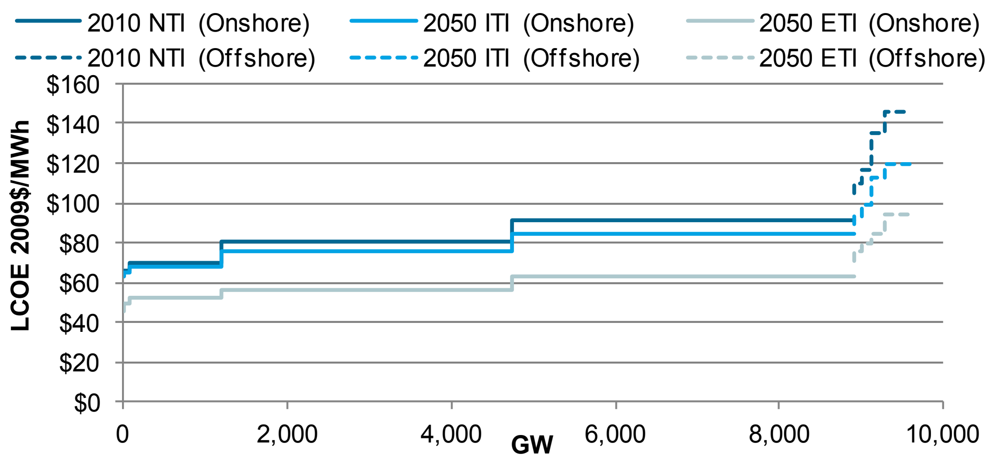
In comparing the 2010 (RE-NTI) and 2050 LCOEs under RE-ITI estimates as shown in Figure A-2 and Figure A-3, solar technologies are estimated to experience significant improvements, whereas improvements in other technologies are estimated to be relatively modest or non-existent. Figure A-2 and Figure A-3 also show the relatively higher LCOEs from the RE-ITI estimates compared with the RE-ETI cost and performance projections across all technologies, and particularly for CSP. The ranges in LCOEs represent variations in wind speed (wind), solar insolation (PV and CSP), site-specific features (hydropower and geothermal),[174] and feedstock costs (biopower). The levelized costs shown, however, do not include grid interconnection costs; reductions to actual electricity output from full availability (e.g., the LCOE calculations assume dispatchable renewable generators operate at full availability, and curtailed wind and PV are not considered); and other system impacts (e.g., increased required reserves and transmission). As such, Figure A-2 and Figure A-3 show simplified levelized costs to show the general trends in technology cost, performance, and resource among the technologies and different projections used in the modeling. *The deployment decision-making in ReEDS depends on a large number of other considerations, and not simply the lowest levelized cost.* These other considerations—grid interconnection costs, variability, reserves, transmission, available federal tax incentives, and others—are captured in the ReEDS and GridView modeling, but are not included in the following illustrative figures.

resource estimates), and did not assume any increase in resources over time; on the other hand, the analysis also did not include potential future growth in demand for biomass from the fuel sector. Differences in estimated potential generating capacity shown in Figure A-2 for biopower result solely from differences in projected heat rates and do not result from any differences in biomass feedstock estimates.

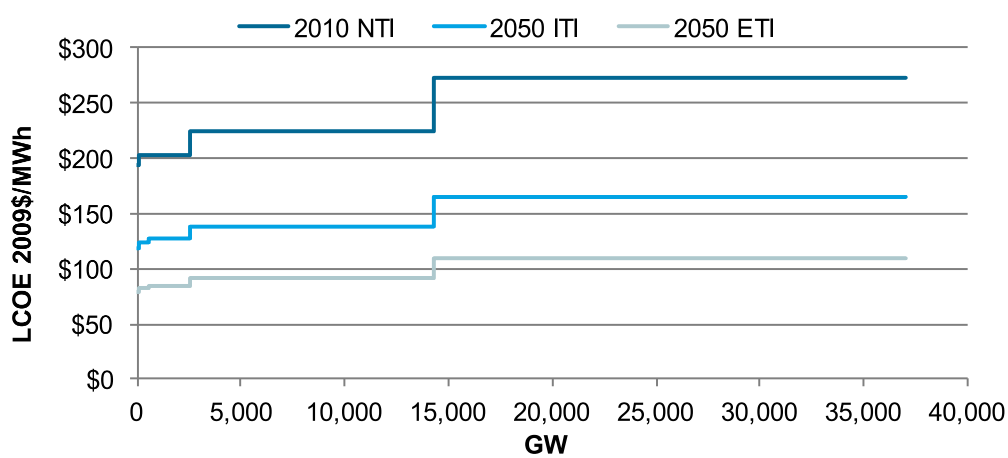
[174] For the hydropower and geothermal supply curves, the 2010 NTI trace is equivalent to the 2050 ITI trace. In other words, the ITI projections assumed no improvements over time from 2010 to 2050 for these two technologies.



(a) Dedicated Biopower

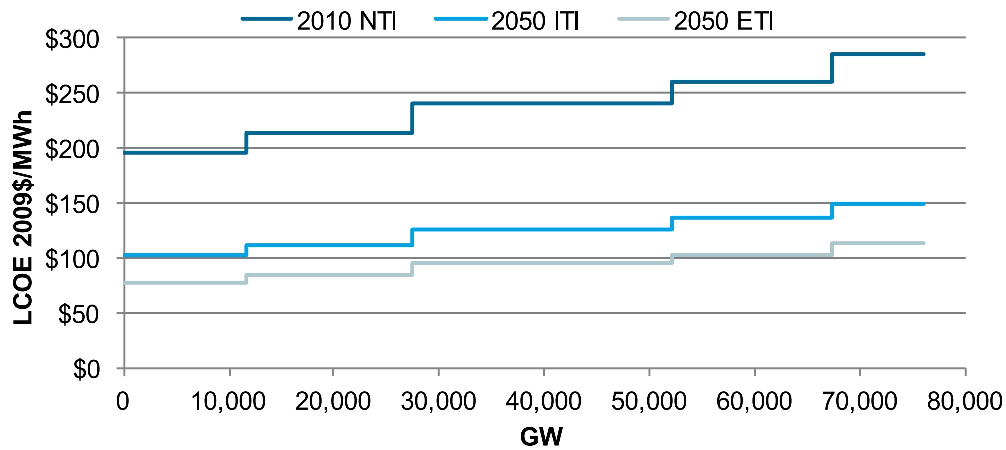


(b) Onshore Wind and Offshore Wind (fixed-bottom)

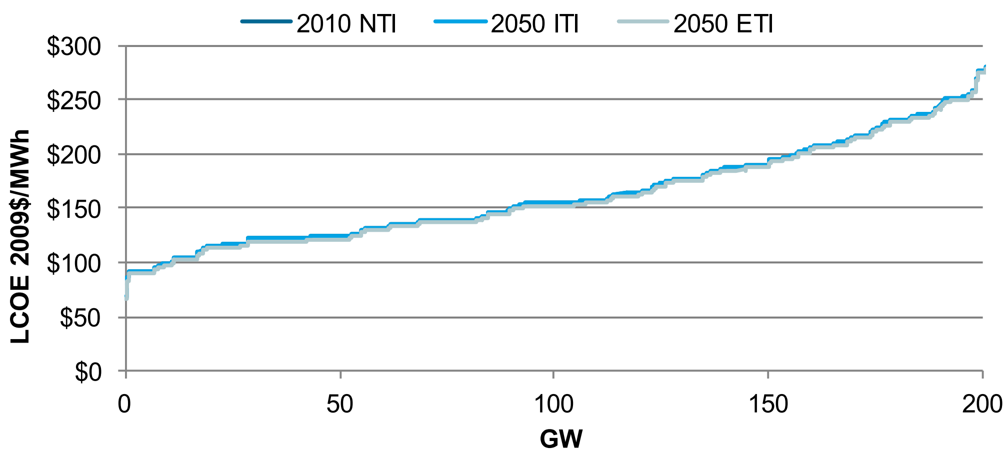


(c) Concentrating Solar Power (6 hours of storage, dry-cooled)

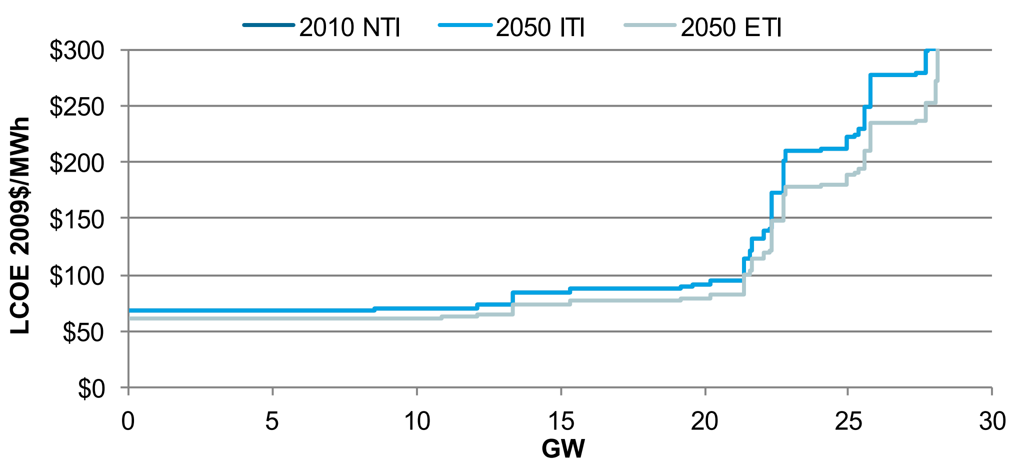
Figure A-2. Supply curves for dedicated biopower, wind energy, and concentrating solar power technologies



(a) Utility-Scale Solar PV



(b) Hydropower (run-of-river)



(c) Geothermal (hydrothermal, dry-cooled)

Figure A-3. Supply curves for utility-scale solar photovoltaic, hydropower, and geothermal energy technologies

2.2 Conventional Generation Technologies

2.2.1 Fossil Energy Technology Projections

Although RE Futures focuses primarily on scenarios with high renewable electricity penetrations, cost and performance estimates for conventional generation technologies are important because they affect the capacity and generation mix of the baseline scenarios as well as the residual mix in the high renewable electricity scenarios. Additionally, the cost, performance, and availability assumptions for renewable and conventional generation technologies directly affect the national electric system cost and electricity price estimates for all scenarios.

The cost and performance estimates used for the modeled conventional generation technologies, developed by Black & Veatch and including coal-powered and natural gas-powered plants, are shown in Table A-3. These cost and performance parameters were estimated to remain mostly constant over the study period, with only slight improvements in the cost and heat rate of pulverized coal units. The relatively limited rate of assumed technology improvement for these mature technologies mirror similar estimates made for mature, non-solar renewable technologies in the RE-ITI data, as discussed earlier. A more complete description of these estimated fossil energy plant characteristics can be found in Black & Veatch (2012). To explore the potential impact of lower fossil energy technology costs, a Fossil-HTI scenario was also developed. In this scenario, the current and future cost and performance for conventional coal- and gas-fired plants were set to equal the estimates of the Energy Information Administration's (EIA's) 2010 Annual Energy Outlook (AEO) Reference Case forecast.[175] These alternative cost and performance estimates are summarized in Table A-4. As shown, the Fossil-HTI scenario estimates have substantially lower capital costs and generally lower heat rates for conventional fossil technologies than the Black & Veatch (2012) estimates. Fossil-HTI O&M costs are not consistently lower than the Black & Veatch (2012) estimates, but they are also based on AEO 2010 Reference Case estimates.

Although ReEDS has the technical capability to consider new nuclear plant builds, fossil technologies with CCS, and gasified coal with and without CCS, RE Futures excluded these plants from the analysis to focus on commercially available technologies. The future cost of nuclear power plants as well as power plants using CCS is particularly uncertain. In addition, deployment of these technologies will be highly dependent on policy decisions and institutional and social factors, which are not the focus of RE Futures. Instead, the study focuses on scenarios with high penetrations of renewable energy, and therefore largely precludes new builds of other possible low-carbon generation technologies. Because RE Futures does not postulate a future, specific carbon policy, the exclusion of these other low-carbon technologies from the analysis has little impact on modeling results.

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[175] Cost and performance for conventional coal- and gas-fired plants from 2035 to 2050 are assumed to be equal to the projections for 2035. The EIA has developed cost and performance parameters for use in the AEO 2011 Reference Case (EIA 2011c) that differ from and are sometimes considerably higher than those used in the AEO 2010 Reference Case (EIA 2010a); these new estimates are not considered in RE Futures.

Table A-3. Cost and Performance Estimates for Fossil Energy (Black & Veatch 2012)[a]

	Year	Capital Costs[b] ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (MMBtu/ MWh)
Pulverized Coal	2010	2,890	23	4	9.37
	2030	2,890	23	4	9.00
	2050	2,890	23	4	9.00
Natural Gas Combined Cycle	2010	1,230	6	4	6.71
	2030	1,230	6	4	6.71
	2050	1,230	6	4	6.71
Natural Gas Combustion Turbine	2010	650	5	30	10.39
	2030	650	5	30	10.39
	2050	650	5	30	10.39

[a] The fossil technology cost and performance estimates presented here are used in all scenarios except for the Fossil-HTI scenarios. These fossil technology projections were developed with similar considerations as the RE-ITI estimates (Black & Veatch 2012).
[b] The capital costs listed here do not include interest incurred during construction or grid interconnection costs, the latter of which is described in Section 2.4 of this appendix.

Table A-4. Cost and Performance Estimates for Fossil Energy, Fossil-HTI Scenario (EIA 2010a)

	Year	Capital Costs[a] ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (MMBtu/ MWh)
Pulverized Coal	2010	2,220	28	5	9.32
	2030	1,870	28	5	8.74
	2050	1,680	28	5	8.74
Natural Gas Combined Cycle	2010	960	12	2	6.82
	2030	780	12	2	6.33
	2050	700	12	2	6.33
Natural Gas Combustion Turbine	2010	650	11	3	9.34
	2030	510	11	3	8.55
	2050	450	11	3	8.55

[a] The capital costs listed here do not include interest incurred during construction or grid interconnection costs, the latter of which is described in Section 2.4 of this appendix.

2.2.2 Fossil Fuel Price Projections

Natural gas and coal fuel prices were assumed to vary over time, among regions, and between scenarios. The ReEDS model includes endogenous fuel price elasticities in which fuel prices depend on electric sector fuel usage; final fuel prices therefore varied among the scenarios modeled, depending on fuel demand. Section 4.4 presents electric sector fossil fuel prices and demand for the Low-Demand Baseline scenario and the core 80% RE scenarios. For the majority of the scenarios, base fuel prices were derived from the AEO 2010 Reference Case,[176] and deviations from those prices based on assumed elasticities[177] do not reflect the fundamental uncertainties that exist in projecting future natural gas and coal prices. To partially account for those more fundamental uncertainties, RE Futures evaluated two alternative scenarios, Higher Fossil Fuel Costs and Lower Fossil Fuel Costs, within which future base natural gas and coal prices were simply assumed to be approximately 30% higher or 30% lower, respectively, than the base fuel prices otherwise assumed in all other scenarios.[178]

[176] More recent EIA AEO projections have shown lower future natural gas prices than the AEO 2010 estimates used in RE Futures; these new estimates are not considered in RE Futures and would, all else being equal, increase the estimated incremental cost of high renewable generation futures. Fossil energy price sensitivities were, however, evaluated in RE Futures.

[177] The elasticity of the fuel price to fuel demand is based on AEO's high and low economic growth scenarios as well as the AEO 2010 Reference Case; see Short et al. (2011) for more details.

[178] Scenarios in which fuel prices vary by more than 30% are possible, but 30% was selected as a reasonable figure with which to test the sensitivity of outcomes to underlying fuel prices.

2.2.3 Power Plant Retirement Assumptions

Assumptions about physical plant lifetimes and the retirement of conventional and renewable generating units can have considerable cost implications. Considerations that go into the decision-making process regarding whether an individual plant should be retired involve a number of factors, including the economics of plant O&M. Projecting these detailed considerations into the future given the uncertainties involved (particularly with high renewable electricity deployment) was beyond the scope of RE Futures. Retirements are therefore simply assumed to occur as follows:

- **Coal-powered** generators, including those co-firing coal with biomass, were assumed to retire based on proxies for economic considerations, not based on technical lifetimes. In particular, any capacity that was estimated to remain unused for energy generation or operating reserves for four consecutive years was then assumed to be retired.[179] Coal capacity was also retired by requiring a minimum annual capacity factor of 50%—after every 2-year investment period, if the coal capacity in a BA had a capacity factor of less than 50% during the previous 2-year period, an amount of capacity was retired such that the capacity factor increased to the 50% threshold level.
- **Natural gas** generation technologies were assumed to retire based on a service lifetime. The retirement assumptions for natural gas account for the large increase in new natural gas capacity during the 1990s and 2000s. More specifically, for all model years preceding 2030, existing natural gas capacity that was installed prior to 2000 was reduced by 8.3% during each 2-year investment period, while natural gas capacity that was installed on or after 2000 was not retired. From 2030 to 2050, natural gas capacity in each BA was simply reduced by 6.67% (1/30th for each year, which corresponds to a 30-year service lifetime) during each 2-year period.
- **Nuclear** power plants were retired simply based on the age of the plants; older nuclear plants (online before 1980) were assumed to retire after 60 years; newer plants (online on or after 1980) were assumed to retire after 80 years.
- **Renewable generation** technologies were assumed to retire based on technology-specific lifetimes.[180] After retirement, the capacity was assumed to be automatically "re-built" with the appropriate capital costs incurred at that time.[181] Grid interconnection costs were not applied, as the previous interconnection was assumed to suffice.

[179] The same metric of four consecutive years of unused capacity was applied to oil and gas steam turbine power plants. These plants were also retired based on an assumed 65-year service life.
[180] In particular, wind plants were assumed to have service lifetimes of 20 years, while solar and geothermal plants were assumed to have a service lifetime of 30 years.
[181] The retirement and replacement assumption for renewable generation technologies likely results in an overestimation of the direct electric sector cost of the scenarios (see Section 3) because it is unlikely that an entire plant would need to be re-built from scratch upon reaching the end of its technical lifetime, and because technological advance might dictate that older plants be retired and replaced by a different renewable energy technology altogether.

In summary, the treatment of plant retirements in the ReEDS model is based on assumed service lifetimes for all generation types with the exception of coal-powered generators, in which only usage-based retirements were assumed. The effect of this retirement treatment is that retirements of existing coal capacity are likely to be underestimated under the baseline and lower RE scenarios from a plant-lifetime perspective. Because much of the existing coal capacity remains online throughout the study period under these scenarios, many of the coal plants will have ages that approach or exceed 100 years by 2050. As a consequence, a lower amount of new capacity, and the associated investments in that new capacity, is required under these scenarios. In addition, the ReEDS model does not account for retrofit costs due to deterioration, new compliance standards, or any other considerations beyond standard O&M costs. For these reasons, the ReEDS results likely underestimate the direct electric sector costs, particularly and to a greater degree for the baseline and lower renewable electricity penetration scenarios.

2.3 Storage and Flexible Demand-Side Technologies

Because futures with high levels of renewable electricity could benefit from flexible supply- and demand-side technologies, a suite of utility-scale storage technologies were represented in ReEDS and GridView, as was thermal storage in buildings. Table A-5 summarizes the cost and performance estimates for these technologies, with additional details provided in Chapter 12 (Volume 2) (utility-scale storage) and Volume 3 (thermal energy storage in buildings). The model treatment of these technologies is described in Short et al. (2011) (ReEDS) and Appendix B (GridView).

Three utility-scale storage technologies were represented: PSH, CAES, and batteries. The cost and performance of PSH and CAES were assumed to remain unchanged over time, while batteries were assumed to witness a 22% reduction in capital cost over the study period. Although the cost of batteries was assumed to be significantly higher than were the costs of the other storage options, there were no location limitations for battery installations, in contrast to PSH and CAES. New PSH installations were conservatively restricted in capacity and location to include only currently planned PSH projects as indicated by the Federal Energy Regulatory Commission in its licensing procedure.[182] For CAES, a resource assessment identified possible locations and available capacity for potential new CAES developments based on local geology (see Chapter 12 [Volume 2]). Because ReEDS is not a chronological model, simplifications were required to assess the economic competitiveness of storage technologies. One implication is that the number of hours of continuous discharge for each storage technology was not explicitly used in ReEDS, although the size (i.e., capacity) of storage devices did affect the assumed cost of the storage facility. As a chronological model, GridView is able to explicitly constrain energy storage capacity and assumed 8 hours of storage for PSH and batteries, and 15 hours of storage for CAES. In addition, although the ReEDS model takes into account some of the operational needs and characteristics of the grid, its reliance on coarse time

[182] As of November 2010, FERC has issued preliminary permits for 40 plants, representing approximately 32 GW of capacity. The capacity of proposed plants, including those with issued and pending preliminary permits, exceeds 40 GW.

slices prevents it from accurately assessing all of the short-term (e.g., sub-hourly) services that can be provided by some storage and flexible technologies (e.g., batteries and flywheels). Thus, the deployment of these technologies is likely underestimated in RE Futures.

Demand-side thermal energy storage in commercial buildings was also considered. In particular, chilled water and ice storage cooling capable of shifting air conditioning loads were represented. Regional capital cost supply curves for thermal storage were developed (see Volume 3) and considered building space availability, building air conditioning turnover rates, and cooling technologies. Capital cost reductions of 16% between 2012 and 2050 were assumed for thermal storage technologies. The use of these demand-side storage devices was restricted by regional commercial cooling loads.

Table A-5. Cost and Performance Estimates for Energy Storage Technologies

	Year	Capital Costs ($/kW)[a]	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Round Trip Efficiency[b]	Heat Rate (MMBtu/ MWh)
PSH	all years	1,500–2,000	31	0	0.80	—
Batteries	2010	3,990	25	59	0.75	—
	2030	3,590	25	59	0.75	—
	2050	3,200	25	59	0.75	—
CAES	all years	900–1,200	12	2	1.25	4.91
Thermal Storage In Buildings[c]	2012	2,200–3,060	17	0	1.00	—
	2030	1,900–2,920	17	0	1.00	—
	2050	1,590–2,450	16	0	1.00	—

[a] ReEDS uses costs per unit of power capacity ($/kW), but energy storage units are often framed in terms of cost per unit of energy storage ($/kWh). Details on the cost of energy storage systems can be found in Chapter 12 (Volume 2), while ReEDS' treatment of energy storage can be found in Short et al. (2011).
[b] Round-trip efficiencies are defined as the electricity output of the storage device divided by the electricity input into the same device. For CAES, the round trip efficiency is greater than 1 because CAES uses natural gas (in a more efficient compressed air environment) to generate electricity. This use of natural gas was included in the generation mix, reported later, for all modeled scenarios. The cited round trip efficiency for thermal storage devices is typically well above 0.9, and sometimes higher than 1.0, because a cold-storage based cooling system can use less electricity than its conventional alternative. Thermal storage stores energy with low losses and can operate refrigeration equipment at nighttime when the system efficiency is higher due to cooler ambient conditions. The net effect is the potential to decrease total energy consumption associated with cooling, in addition to the load-shifting and capacity benefits.
[c] The costs represent thermal storage systems for commercial buildings only. In RE Futures, thermal storage deployment was assumed to start in 2012 at the earliest. Additional details on thermal storage can be found in Volume 3 and Gansler et al. 2001.

Interruptible load was also considered using regional supply curves based in large measure on a study by the Federal Energy Regulatory Commission (2009) (see Volume 3). Annual interruptible load resource availability was based on a percentage of peak demand within a region, and grew from 1%–8% in 2010 to 11%–17% in 2030, and to 16%–24% in 2050, with all of the ranges encompassing regional variation. For all years, the assumed annual costs of interruptible load programs ranged from $3.36/kW to $37.1/kW, and the analysis assumed that interruptible load could only be used for operating reserves. ReEDS did not estimate or constrain the frequency with which interruptible load could be accessed because it does not have the chronological detail necessary to do so. As a chronological *hourly* model, GridView estimates the use of interruptible load but only in situations for which the interruptible load is called for at least one hour.[183]

Finally, a substantial fraction (approximately 50%) of the passenger transportation fleet was assumed to transition toward electric and plug-in hybrid electric vehicles in all but the high-demand scenarios. Of the assumed 356 TWh of resulting electric vehicle load in 2050, 165 TWh was assumed to be operated under utility-controlled charging. The remaining electric vehicle load was assumed to not be utility-controlled and to have a daily charging profile that peaked during evening hours, as described in Volume 3.

2.4 Transmission

Existing transmission infrastructure was assumed to continue to be operable throughout the study period, and existing line capacity was assumed to be usable by both conventional and renewable generation sources. For input to the ReEDS model, the existing transmission grid capacity and line location were estimated based on an analysis of interface transfer limits using GridView.

Table A-6 includes the major assumptions used in ReEDS associated with new transmission and interconnection built in the scenario modeling, with additional details provided in Short et al. (2011). The long-distance "inter-BA" transmission line costs were consistent with high-voltage infrastructure, with ratings that differed by region, but ranged from 500 kV to 765 kV[184]; line costs shown in Table A-6 include a 25% contingency factor that covers the cost of redundancies in the transmission lines, thus representing self-contingent lines.[185] In addition to line costs, substation costs were also applied to the endpoints of every new transmission line segment. The GridView database was used to

[183] Interruptible load could be called to provide energy due to forecast error or generator forced outages. Although the transmission transfer capacity between regions is secure to N-1 contingencies, transmission contingency events were not explicitly modeled, so the interruptible load considered in RE Futures was not modeled as being available to provide energy during transmission contingencies in GridView.

[184] Transmission line costs were assumed to vary regionally (e.g., a multiplier of more than 3.5 was applied to the cost of transmission lines in California, New York, and New England). This regional variation, consistent with EnerNex (2010), is described in Short et al. (2011).

[185] A set of transmission lines is considered "self-contingent" when it is under-loaded in normal operation to accommodate events when extra capacity may be required. For example, each line of a set of lines is loaded below its physical carrying capacity limit and in the event that one of the lines becomes inoperable, the other lines can increase their loads so that the set as a whole continues to support the same power transfer capacity.

estimate regional substation availability and costs based on voltage ratings for the substation and the assumed voltages of transmission lines. Intertie[186] costs apply when grid expansion spans two of the three U.S. interconnections.

In addition to the expansion of long-distance "inter-BA" transmission lines, interconnection costs for new generation and utility-scale storage technologies were considered. A base interconnection cost of $110,000/MW was applied to new natural gas, biopower, wind, CSP, and utility-scale PV[187] installations. This interconnection cost was assumed doubled for coal, hydropower, geothermal, CAES, and PSH due to the greater siting restrictions for these plant types. Separate interconnection costs were not applied to rooftop PV, utility-scale batteries, or thermal storage systems in buildings. For wind and CSP technologies, additional interconnection supply curves were applied to account for the strong location-dependence of those resources, yielding total interconnection costs that ranged from $110,000/MW at the low end to more than $1,000,000/MW in the more extreme situations. These interconnection supply curves account for the distance from remotely located wind and CSP sites to the existing transmission system or load centers, and rely on even finer-resolution data than the 356 wind and CSP regions in ReEDS. Wind and CSP interconnections include lower voltage "intra-BA" transmission lines with costs shown in Table A-6.

Table A-6. Assumptions for Transmission and Interconnection[a]

Category	Range
Inter-BA line costs ($/MW-mile)	$1,200–$5,340
Substation costs ($/MW)	$10,700–$24,000
Intertie (AC-DC-AC) costs ($/MW)	$230,000
Base grid interconnection costs ($/MW)[b]	$110,000
Intra-BA line costs ($/MW-mile)	$2,400–$10,680
Transmission losses	1% per 100 miles

[a] Transmission and interconnection costs and other parameters are primarily from Hein (personal communication) with regional multipliers based on Enerex (2010). See Short et al. (2011) for details.
[b] Assumed interconnection costs in ReEDS vary by technology (Short et al. 2011). For wind and CSP, in particular, interconnection costs can be significantly greater than the base interconnection cost shown here due to addition transmission lines needed to access resources that are currently remotely located from existing transmission infrastructure.

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[186] Throughout this report, *intertie* corresponds to AC-DC-AC interconnections that allow transmission of power between two asynchronous systems. For RE Futures, the ReEDS model assumes that the three interconnections in the contiguous United States remain asynchronous throughout the study period.
[187] As described in Short et al. (2011), ReEDS differentiates between distributed, but non-rooftop, wholesale PV (systems that are tens of megawatts or smaller) and utility-scale PV (systems that are approximately 100 MW). Interconnection costs are exempted for the former due to their location within distribution networks. Interconnection costs for utility-scale PV plants were assumed to be similar to natural-gas fired technologies and are generally lower than the interconnection costs for coal, wind, and CSP plants. These lower assumed interconnection costs represent the combination of abundant resource potential for PV and the lower variation in resource quality between nearby sites. For example, while CSP relies on direct normal radiation, PV can generate electricity from a greater range of solar irradiance.

2.5 Financial Assumptions

The cost and performance assumptions described above were input to the ReEDS model, which sought (during each 2-year investment period) to minimize overall national electric sector costs based on net present value cost estimates over a 20-year evaluation period (model details are described in Short et al. [2011]). Estimates of the net present value costs of installing and operating different technologies rely on assumptions about how projects are financed. The key assumptions underlying these calculations were developed by the study team based on expert opinion and published data, and are shown in Table A-7. In particular, a weighted average cost of capital discount rate of 8.9% nominal (5.7% real) was used as the discount rate for calculating the net present value costs used in the ReEDS decision-making algorithm.[188] To represent carbon-based regulatory risk for fossil energy technologies, financing of conventional coal-based technologies was assumed to be more costly than for other technologies, with an additional 3% added to the required rate of return on equity and to the debt interest rate; this approach is similar to that used in EIA (2010a) to represent carbon policy risk in the absence of such a policy. Although a common 20-year financial evaluation period was used across all technologies, actual physical plant lifetimes were assumed to vary by technology, as described earlier in Section 2.2.3.

Table A-7. Financial Assumptions Used for Capacity Expansion Modeling

Assumption	Value
Annual Inflation Rate	3%
Evaluation Period	20 years
Rate of Return on Equity (nominal)	13%
Debt Interest Rate (nominal)	8%
Interest Rate During Construction (nominal)	8%
Debt Fraction	50%
Weighted Average Cost of Capital Discount Rate (nominal)	8.9%
Weighted Average Cost of Capital Discount Rate (real)	5.7%
Corporate Tax Rate (combined federal and state)	40%
MACRS Depreciation (non-hydropower renewables)	5 years
MACRS Depreciation (fossil technologies and hydropower)	15 years

[188] The discount rate used in the investment decision-making process in ReEDS (8.9% nominal or 5.7% real) differed from the discount rate used in later sections to describe the present value of overall system cost for the study period (3% real). The former was intended to reflect a discount rate that approximates the expected market rate of return of investors, and was used in order to properly account for private-sector investment decisions in the electric sector. The latter and lower "social" discount rate was only used to present the resulting cost implications of each modeled scenario, and was chosen so that costs in the latter years of the study period were more strongly emphasized than if a higher discount rate were used. The 3% real social discount rate used for this purpose is consistent with the rate used by the DOE in its budgetary submissions to Congress, and is reasonably consistent with discount rates sometimes used by the EIA, IEA, and IPCC when evaluating alternative energy futures. A 3% discount rate is also consistent with Office of Management and Budget guidance when conducting "cost-effectiveness" analysis that spans a 30+ year time horizon.

3. Direct Electric Sector Cost Implications of RE Futures Scenarios

Chapters 2–4 identify the deployment and operational implications of high renewable electricity futures by using a range of scenarios summarized in Section 1.3. This and the following section discuss economic and environmental implications of these scenarios: direct electric sector cost implications of the modeled scenarios are presented in Section 3, and environmental and social implications associated with reduced fossil energy consumption are presented in Section 4. In general, these implications are highly uncertain and often difficult to quantify; therefore, the methodologies, uncertainties, and caveats that underlie the analysis are also presented. Section 3.1 defines the simple cost metrics used in the ReEDS model to evaluate the direct electric sector costs. Sections 3.2 and 3.3 present the direct electric sector cost results across the various modeled scenarios. The scenario results are presented in the same order as in Chapters 2–3; the direct electric sector costs of the baseline and exploratory scenarios are first presented in Section 3.2, and the direct electric sector cost implications of the various 80%-by-2050 RE scenarios are presented in Section 3.3.

3.1 Direct Electric Sector Cost Metrics Used in RE Futures

Two electric sector cost metrics are calculated in ReEDS for each scenario: (1) present value of electric system costs and (2) national average retail electricity prices. The former represents the discounted costs of all electric sector investments considered by the ReEDS model during the study period. These investments correspond to investments for new generation, storage, interruptible load, and transmission capacity installations; replacement capacity in the case of renewable technologies (see Section 2.2.3); O&M for all generators; and fuel for all generators. These investments occurring during 2011 to 2050 are discounted using a real discount rate of 3% (see Footnote 188). To account for the fact that capital investments made during the latter half of the study period (2031–2050) are likely to provide services beyond the 2050 timeframe, discounting of these investments is adjusted; see Short et al. (2011) for details. In addition, although tax credits are considered in the ReEDS optimization routine in an attempt to mimic investor decision-making, the present value of electric system costs calculated by ReEDS excludes the effects of tax credits.[189] In summary, the present value of system cost is an estimate of the total discounted cost to build and operate the electricity system realized for each of the scenarios through 2050.

ReEDS also calculates a national average retail electricity price. In contrast to the present value electric system cost metric, the electricity price is a time series estimate of the impact to electricity consumers for each year rather than on a discounted basis for costs incurred over the entire study period. The electricity price in ReEDS assumes a regulated market structure with a 30-year rate base or amortization of all capital payments to 30

[189] In other words, transfer payments (tax credits) are not considered in the present value of total electric system cost, but are considered in the ReEDS least-cost optimization routine.

equal annual payments.[190] The calculated wholesale cost of power includes the rate base payment, interest for these payments, and generation costs incurred during the year (including O&M and fuel costs); the cost of generation, storage, interruptible load, and transmission are all included. In addition to this wholesale cost of power, the retail price of electricity must also cover distribution and other costs. These additional costs are not estimated directly in ReEDS. Instead, the markup from wholesale to retail prices is estimated based on a calibration with historical (2006) prices. This markup is assumed constant for all years. Short et al. (2011) provides additional details on how ReEDS calculates the national average retail electricity price.

The two cost metrics described above are calculated for each scenario in RE Futures and are primarily used to compare the relative direct electric sector costs between the scenarios from both a discounted total cost perspective and an electricity price consumer perspective. Although these metrics provide some insight into the cost impacts of the various scenarios, they have severe limitations, and when using them to compare scenarios, the following considerations must be acknowledged: First, the system cost and electricity price estimates are uncertain, following the many uncertainties associated with the underlying assumptions that went into the model. The large uncertainties in future technology improvements, power plant retirements, fuel costs, and future policies limit the accuracy of these metrics (or any metric on the cost of a long-term future). Second, the present value of electric system cost and the retail electric prices calculated in this report are relatively simple metrics applied to the entire U.S. system and do not attempt to capture all of the nuances of separate markets. For example, the electricity price calculation in ReEDS ignores the different market structures of different regions of the United States including regulated versus de-regulated markets and the robustness of ancillary service markets. It is unclear if including these regional variations or market structures would increase or decrease the estimated electricity prices. Furthermore, as described previously, the calculated retail electricity prices simply assume a constant markup from wholesale prices—whereas, in reality, the relationship between wholesale and retail prices is more complex and can depend on different regulations, distribution-side effects, and other factors that were not considered. Finally, *the system cost and electricity price metrics described above consider only the direct investments related to the scenarios. They do not consider any external costs related to other environmental implications of the scenarios, e.g., air emissions*. Some of these external factors are discussed separately in Section 4 of this appendix.

[190] The 30-year rate base assumed to estimate electricity prices differs from the 20-year present value costs used in the objective function of the ReEDS model cost optimization routine and differs from the various technology lifetimes presented in Section 2.2.3.

3.2 Direct Electric Sector Costs of the Baseline Scenario and Exploratory Scenarios

The Low-Demand Baseline scenario serves as a point of reference to compare with the higher renewable scenarios and evaluate the impacts of higher renewable penetration. It does not represent a prediction or a desired outcome. The deployment results from the Baseline scenario are presented in Chapter 2. To summarize those results: with no new policies, little retirement of the existing coal fleet, incremental renewable technology improvements, and low-demand growth, the Baseline scenario results in a predominantly fossil-fuel-powered electricity system in 2050 that largely resembles today's system. In addition, the average retail electricity rates were found to increase only slightly in real dollar terms, from \$99/MWh in 2010 to \$111/MWh in 2050.[191] This increase corresponds to an annual rate of increase (in real dollar terms) of 0.3% per year. Total electricity expenditures from 2011 to 2050, discounted to the present at a 3% real discount rate, were estimated to be \$3,990 billion in 2009 dollars.

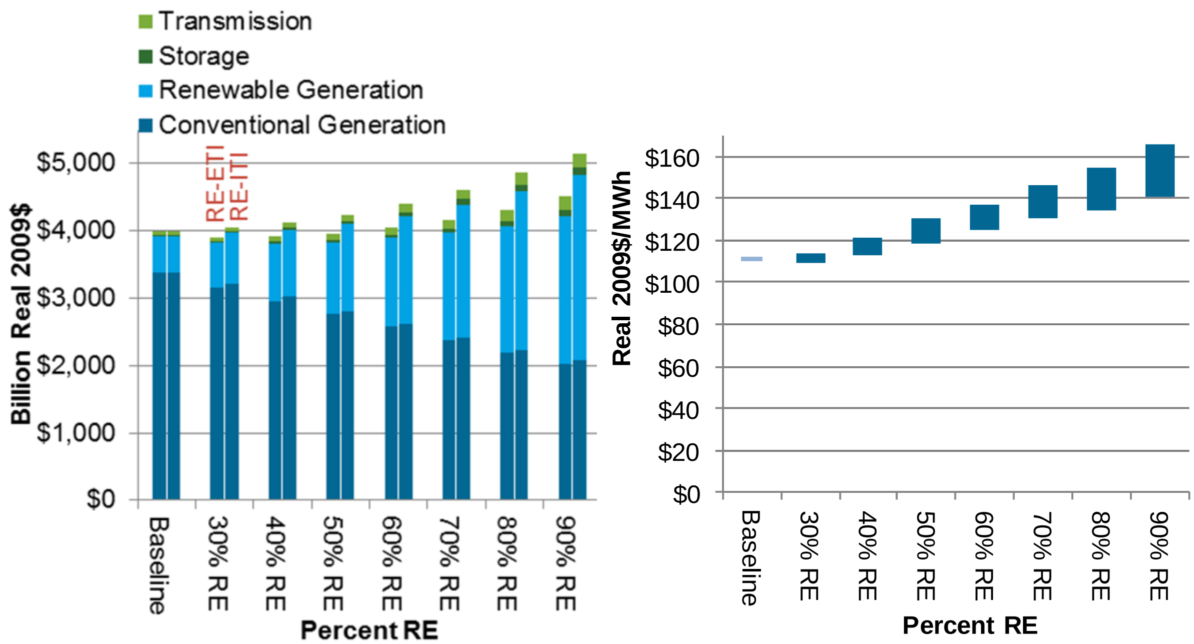
At the levels of renewable electricity penetration envisioned under the exploratory scenarios (30%–90% RE by 2050), and under the assumptions presented earlier, increased renewable electricity levels generally led to higher electricity system costs and average retail electricity prices (see Figure A-4). Figure A-4 shows ranges of present value electric system costs and 2050 national average retail rates for all of the exploratory scenarios, where the lower level of each range represents scenarios using the RE-ETI data and the upper level represents scenarios using the RE-ITI data. Specifically, the present value of total electricity system cost (2011–2050), when discounted at a 3% real discount rate (see Footnote 188), was found to be \$3,990 billion in the Low-Demand Baseline scenario. The difference from this value ranged from -\$80 billion to \$60 billion in the 30% RE scenario (a decrease of 3% to an increase of 2%), from \$60 billion to \$400 billion in the 60% RE scenario (an increase of 2%–10%), and from \$530 billion to \$1,160 billion in the 90% RE scenario (an increase of 13%–29%).[192]

The average retail electricity price in 2050, meanwhile, was estimated to be \$111/MWh in 2009 real dollar terms in the Baseline scenario, and ranged from \$109/MWh to \$113/MWh in the 30% RE scenario (a decrease of 1% to an increase of 2% from the Baseline scenario); \$125/MWh to \$137/MWh in the 60% RE scenario (an increase of 12%–24%); and \$140/MWh to \$165/MWh in the 90% RE scenario (an increase of 26%–49%). The average annual increase in retail electricity prices over the 2011–2050 period also increased with renewable penetration. In real dollar terms, the average annual retail price growth rate was found to equal 0.3% per year in the Low-Demand Baseline scenario,

[191] The increase is much more dramatic if presented in nominal terms: from \$100/MWh to \$366/MWh, assuming a 3% annual inflation rate from 2010 to 2050 and a 1% inflation rate from 2009 to 2010.

[192] To test the sensitivity of the results to the assumed social discount rate, a 6% real discount rate was also applied for the purpose of calculating the present value of electricity system costs. In that instance, the present value of total electricity system costs was \$2,710 billion in the baseline scenario, increasing by -\$20 to +\$60 billion in the 30% RE scenario (a decrease of 1% to an increase of 2%); \$120–\$310 billion in the 60% RE scenario (an increase of 4%–11%); and \$450–\$800 billion in the 90% RE scenario (an increase of 17%–30%).

approximately 0.3% per year for the 30% RE scenario, ranged from 0.6% per year to 0.8% per year for the 60% RE scenario, and increased to a range of 0.9% per year to 1.3% per year under the 90% RE scenario. The smaller percentage increase in present value costs compared with electricity prices is due to the fact that the former is an estimate of the aggregate cost over the entire study period, including early years with less-stringent renewable energy levels, and a stronger discounting of future years in which higher targets apply. The retail electricity price impact is presented as an annual value in 2050, the year with the highest renewable electricity penetration.



(a) Present Value of System Costs (2011–2050, 3% discount rate)

(b) Range of Average Retail Electricity Price in 2050[a]

Figure A-4. Electric system costs and 2050 retail electricity prices as renewable electricity levels increase

[a] Wholesale electricity prices were estimated within ReEDS based on a simplified assumption of a regulated structure for all markets, using a 30-year rate base calculation (see Section 3.1). The mark-up from wholesale prices to retail prices, including utility maintenance fees, administrative fees, distribution costs, and existing transmission costs, were based on calibrations with historical (2006) data.

These increased costs and prices, especially at high levels of renewable energy deployment, reflect a nearly wholesale transformation of the U.S. electricity system: the higher electricity prices in the high renewable scenarios are driven by replacement of existing generation plants with new generators (mostly renewable); additional balancing requirements reflected in expenditures for combustion turbines, storage, and transmission; and the higher relative cost of renewable generation, compared to conventional technologies, assumed in the analysis. The increased capital investments associated with these drivers, compared to the Baseline scenario,[193] were not fully offset by savings associated with lower fossil energy consumption.[194] *These results reflect the underlying assumptions described earlier for technology cost and performance assumptions, lack of new policy interventions, and a Baseline scenario in which new policies supporting renewable energy were not considered, and in which certain direct and indirect subsidies for fossil-fuel and nuclear generation were assumed to be maintained*: under alternate assumptions, the cost and price impacts shown here could be substantially different.

For the lower renewable penetration levels, the range of calculated system costs and electricity rates were only slightly higher than, and in some cases even less than, the system cost and 2050 electricity rate found for the Baseline scenario.[195] Specifically, under the RE-ETI technology improvement projections, all scenarios with up to 50% renewable electricity by 2050 were estimated to have a present value of system cost that is less than that of the Baseline scenario. In addition, the 30% RE scenario (under RE-ETI projections) resulted in a 2050 retail electricity price that is slightly less than that of the Baseline scenario. These results demonstrate that significant expansion of renewable penetration beyond 2010 levels (10%) can be achieved with little or no incremental cost with only evolutionary improvements in renewable technologies. In addition, other direct implications, including environmental and fuel use implications, were not considered in the direct cost estimates presented here; these are discussed below.

3.3 Direct Electric Sector Costs of the 80%-by-2050 RE Scenarios

Consistent with the deployment and operational implications discussed in Chapter 3, a set of 80%-by-2050 RE scenarios was examined in more detail. These 80%-by-2050 RE scenarios included a set of low-demand core 80% renewable electricity scenarios, a High-Demand 80% RE scenario, and a set of alternative fossil scenarios. Section 3.3.1 focuses on the direct electric sector cost implications of the subset of the core 80% RE scenarios in which a range of future renewable technology improvement projections was considered. Section 3.3.2 discusses the remaining subset in which the impacts of system constraints are explored. The cost implications of higher demand growth are discussed in Section 3.3.3. Finally, Section 3.3.4 describes how alternative fossil energy and fossil technology cost projections might affect the direct electric sector costs associated with 80% renewable electricity generation in 2050.

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193 As described previously, the Low-Demand Baseline scenario included little new capital investments (e.g., no new coal capacity was installed in this scenario). As a result, the direct electric sector cost of the Baseline scenario is primarily comprised only of fuel and O&M costs. In addition, the Low-Demand Baseline scenario included limited retirement of coal capacity, thereby obviating need for much new capacity to be added. In comparison, the direct electric sector costs of the high renewable scenarios include new capital investments with lesser reliance on the existing capital stock.

194 Section 3.3.4 describes the impact that high renewable penetration has on fossil energy consumption and prices.

195 The Low-Demand Baseline scenario was evaluated using the incremental renewable technology improvement (RE-ITI) projections only.

3.3.1 Direct Electric Sector Costs of the Core 80% RE Scenarios: Impacts of Renewable Technology Improvements

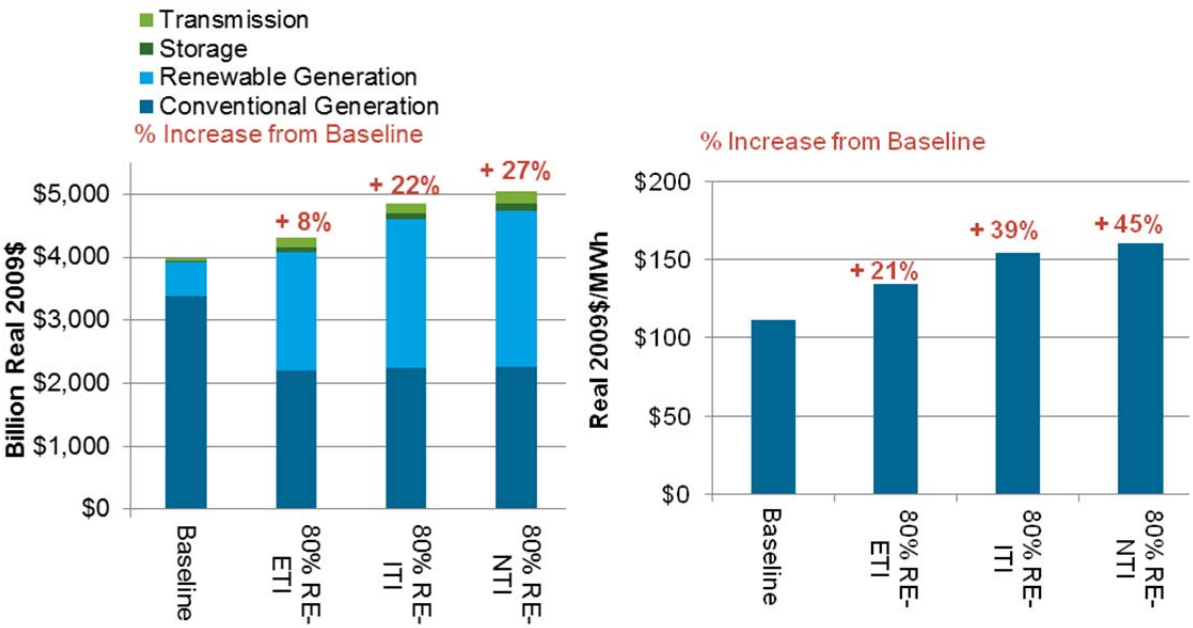
For the core 80% RE scenarios, variation in the estimated future cost and performance of renewable energy technologies was found to be a primary driver for the direct cost of achieving 80% renewable electricity by 2050. Consequently, the 80% RE-NTI, 80% RE-ITI, and 80% RE-ETI scenarios showed a wide range in electric sector costs and retail electricity prices. Under the 80% RE-NTI scenario, the present value of total electricity system costs (2011–2050) increased by 27% compared to the Low-Demand Baseline scenario (an increase of +$1,060 billion, from $3,990 billion to $5,050 billion), while average retail electricity prices in 2050 increased by 45% (an increase of +$50/MWh, from $111/MWh to $161/MWh). The 2050 retail electricity price for the 80% RE-NTI scenario reflects an average annual growth rate of 1.2% per year (2011–2050, in real dollar terms) compared with 0.3% per year for the Low-Demand Baseline scenario. The assumption in the 80% RE-NTI scenario of no technological improvements beyond 2010 levels over the next 40 years is not realistic and serves only as a frozen technology benchmark. In fact, there have been substantial improvements in technology cost and performance during the past 2 years, such as in solar PV.

With incremental improvements in renewable technology cost and performance as used in the 80% RE-ITI scenario, the percent increase in present value of system costs relative to the Baseline scenario declined to 22% (+$870 billion), while the increase in 2050 average retail electricity price declined to 39% (+$43/MWh). Under the 80% RE-ETI scenario, in which greater, but only evolutionary, technology improvements were assumed, the present value of electric system costs increased by a much lower 8% (+$320 billion) relative to the baseline scenario, while average retail electricity prices increased by 21% (+$24/MWh).[196] The annual retail electricity price increases were found to be 1.1% per year, and 0.8% per year (2011–2050, in real dollar terms) for the 80% RE-ITI and 80% RE-ETI scenarios, respectively. Figure A-5 summarizes these results.

From these results, it is evident that the cost of achieving 80% renewable electricity generation can be substantially reduced if the future cost and performance of commercially available renewable technologies envisioned in Volume 2 are achieved. This suggests that public and private research and development can have considerable potential value in reducing the expected cost of a high-penetration renewable electricity future.[197] *Renewable technology improvements beyond those projected under RE-ETI are also possible, and if these improvements are achieved, the direct electric sector cost differences between the 80%-by-2050 RE scenarios and the Baseline scenario would be further reduced.*

[196] As described previously, the present value of system cost was calculated using a 3% real discount rate. Using a 6% real discount rate, the present value costs for the Low-Demand Baseline, 80% RE-ETI, 80% RE-ITI, and 80% RE-NTI scenarios were $2,710, $3,010, $3,320, and $3,430 billion, respectively.

[197] This result is consistent with Showalter et al. (2010), which found that meeting carbon reduction targets in the United States would be substantially less costly were the DOE goals for the future cost and performance of renewable energy technologies achieved.



(a) Present value of system costs (2011–2050, 3% discount rate)

(b) National average retail electricity price in 2050

Figure A-5. Electric system costs and retail electricity prices in the Low-Demand Baseline, 80% RE-ETI, 80% RE-ITI, and 80% RE-NTI scenarios

3.3.2 Direct Electric Sector Costs of the Core 80% RE Scenarios: Impacts of System Constraints

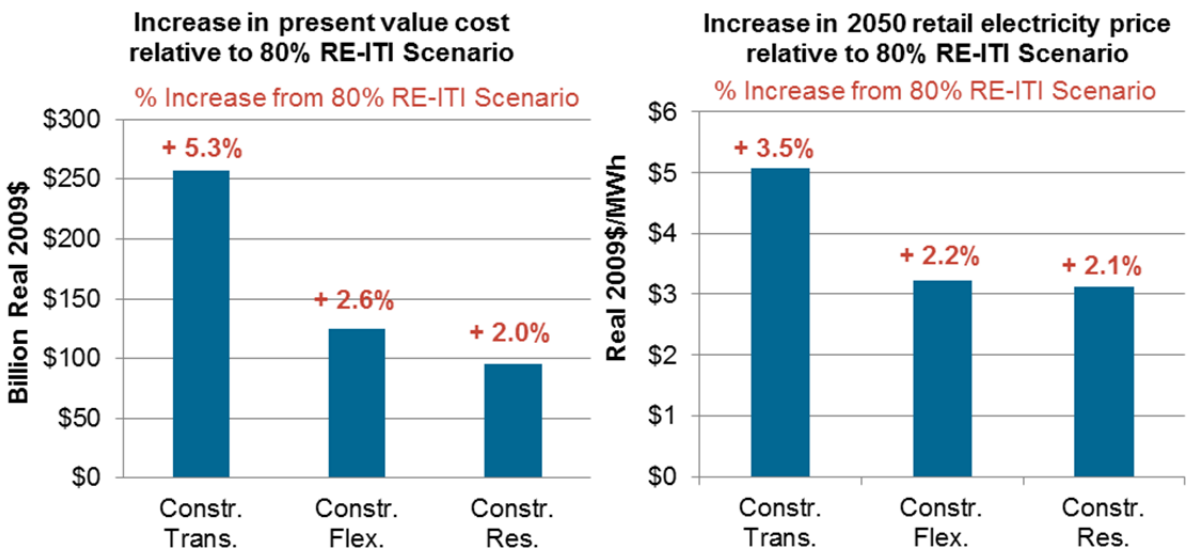
In contrast to the wide range in system cost and electricity price results for the different renewable technology cost improvement scenarios, the direct electric sector cost implications of achieving an 80% renewable electricity future were found to be relatively insensitive to key input parameters and constraints that do not involve renewable technology improvements. Figure A-6 shows the increased present value of total electricity system costs and 2050 average retail electricity prices *relative to the 80% RE-ITI scenario*[198] for the Constrained Transmission, Constrained Flexibility, and Constrained Resources scenarios. Among the constrained scenarios, constraining transmission resulted in the largest cost increases. Under the Constrained Transmission scenario, the present

[198] A comparison with the 80% RE-ITI scenario was made because all of the constrained scenarios relied on the same RE-ITI technology cost estimates used in the 80% RE-ITI scenario. Constrained scenarios were also evaluated using the RE-ETI technology cost estimates and compared with the 80% RE-ETI scenario. As expected, lower renewable technology costs resulted in lower present value of system costs and retail electricity prices, but the cost implications of the constraints (transmission, flexibility, and resources) themselves were similar. For example, constraining transmission under the RE-ETI estimates resulted in an increase relative to the 80% RE-ETI scenario of about 5% to the present value of total electric system costs and an increase of about 3% to the 2050 average retail electricity price. Because these percentage increases are almost identical to the increases for the Constrained Transmission scenario relative to the 80% RE-ITI scenario, only the comparison to the 80% RE-ITI scenario is shown in Figure A-6.

value of total electricity system costs increased by slightly more than 5.3% (+$260 billion) compared to the 80% RE-ITI scenario, while retail electricity prices in 2050 increased by about 3.5% (+$5/MWh). The retail electricity price for the Constrained Transmission scenario grew by 1.2% per year (2011–2050, in real dollar terms) compared with 1.1% per year for the 80% RE-ITI scenario. Cost impacts for the Constrained Flexibility and Constrained Resource scenarios were found to be even lower. These cost results for the constrained scenarios are relatively robust in large measure because of the diversity and abundance of renewable energy technologies that are available for use in the United States. The impacts of assumed system constraints on direct costs are summarized by the following:

- Although system cost and electricity prices increase if one applies severe constraints to new transmission, the level of that increase was found to be modest because lower-quality renewable resources that are located closer to load centers can be used to avoid significant transmission expenditure, and at relatively limited incremental cost.
- Similarly, institutional constraints to and concerns about managing the variability of wind and PV resources were found to raise the cost of energy supply, but not significantly as other renewable resources and technical measures (e.g., storage, increased transmission) could be deployed to manage integration concerns.
- Even eliminating half the potential renewable supply from consideration due to presumed siting challenges (or, for biomass, competing fuel uses) did not lead to dramatic system cost or electricity price increases because the resource potential of solar and onshore wind was found to be large enough to compensate for those technologies that were more-severely resource constrained.

These results indicate that there are multiple technology pathways to achieving high renewable electricity penetration levels *with similar direct electric sector costs*. The abundance and diversity of renewable resources in the United States and the assumed availability of many demand- and supply-side flexibility options enable these multiple pathways.



(a) Increase in present value of system costs (2011–2050, 3% discount rate)

(b) Increase in national average retail electricity price in 2050

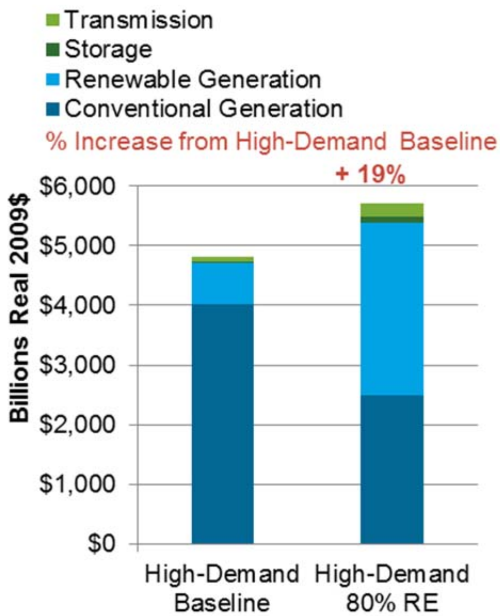
Figure A-6. Increases in electric system costs and retail electricity prices in the constrained scenarios relative to the 80% RE-ITI scenario

3.3.3 Impact of Demand Growth on Direct Electric Sector Costs

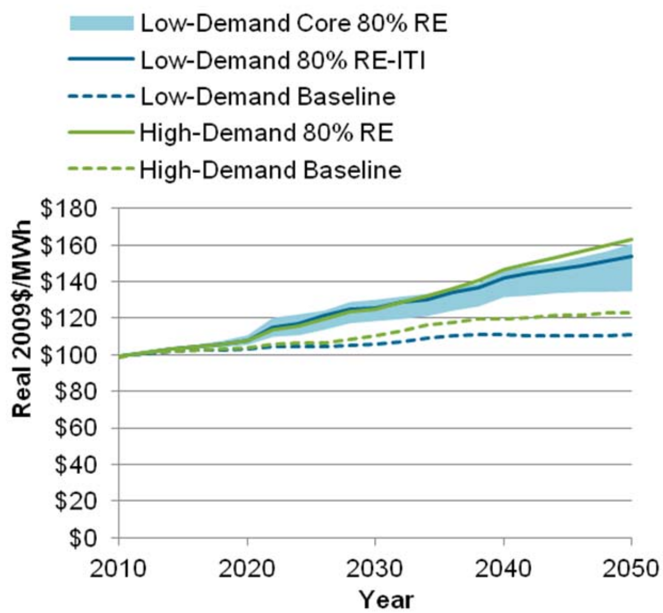
The impacts of electricity demand growth on the electric system cost and retail electricity prices of an 80%-by-2050 RE scenario were also found to be relatively modest. The High-Demand Baseline scenario yielded higher costs and prices than the Low-Demand Baseline scenario; the present value of system costs was $4,810 billion in the High-Demand Baseline scenario and $3,990 billion in the Low-Demand Baseline scenario. Annual retail electricity price increases for the High-Demand Baseline and Low-Demand Baseline scenarios were 0.6% per year and 0.3% per year (2011–2050, in real dollar terms), respectively, which resulted in national average electricity prices in 2050 equaling $123/MWh and $111/MWh, respectively. These higher costs and prices, even in the baseline scenarios, are caused by the need for additional new electricity generation and transmission investments and higher fossil fuel prices driven by greater demand for fossil energy under more-traditional demand growth.

Higher demand growth also generally yielded higher costs and prices in the 80%-by-2050 renewable electricity scenarios; however, the increases were somewhat lower than in the baseline scenarios. As a result, the *incremental* costs and prices that result from achieving 80% renewable electricity generation is *less* with higher electricity demand growth. For example, while the difference in 2050 average retail electricity price between the (low-demand) 80% RE-ITI and Low-Demand Baseline scenarios was found to be $43/MWh (+39%), this difference reduces to $40/MWh (+32%) between the High-Demand 80% RE and High-Demand Baseline scenarios. The incremental cost of the (low-demand) 80%

RE-ITI scenario should be most directly compared with cost of the High-Demand 80% RE to isolate the effect of demand growth because these two scenarios share the same technology cost and system constraint assumptions (Figure A-7).[199] However, Figure A-7(b) and Table A-8 also show that the incremental costs of the High-Demand 80% RE scenario is nearly within range of the incremental costs of the full suite of (low-demand) core 80% RE scenarios The reason for these results is that, while the cost of marginal renewable energy supply is higher in the High-Demand 80% RE scenario, so too is the value of that generation in reducing the capital and operating cost of fossil generation that is otherwise required in the High-Demand Baseline scenario.[200]



(a) Present value of system costs (3% discount rate)



(b) National average retail electricity price

Figure A-7. Electric system costs and retail electricity prices in the High-Demand Baseline and High-Demand 80% RE scenarios

[199] The High-Demand 80% RE scenario relied on the RE-ITI data and did not include additional constraints to transmission, system flexibility, or renewable resource accessibility that the Constrained Transmission, Constrained Flexibility, and Constrained Resources scenarios assumed, respectively.

[200] The 2050 installed capacity of coal- and natural-gas-powered plants totaled 356 GW and 622 GW, respectively, in the High-Demand Baseline scenario compared with 275 GW and 394 GW, respectively, in the Low-Demand Baseline Scenario. These greater amounts of fossil capacity resulted in greater electric sector consumption of fossil energy, thereby driving up fossil energy prices; 2050 coal and natural gas prices were $2.29/MMBtu and $8.09/MMBtu, respectively, in the High-Demand Baseline scenario, compared with $2.09/MMBtu and $7.13/MMBtu, respectively, in the Low-Demand Baseline scenario. Price elasticities with fuel demand are described in Section 3.3.4.

Table A-8. Summary of Cost, Transmission, and Integration Implications of High-Demand 80% and (Low-Demand) Core 80% RE Scenarios

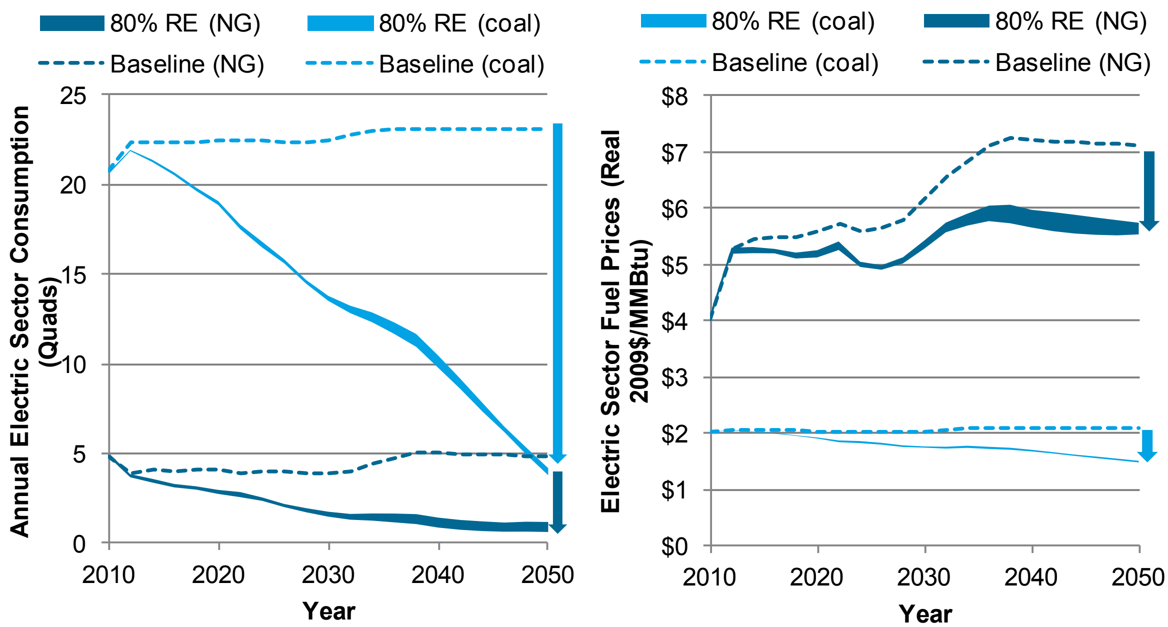
Cost and Prices	Low-Demand Core 80% RE	High-Demand 80% RE
Present Value of System Costs 2011–2050 (Billion 2009$)	$4,320–$5,150	$5,700
Average Retail Electricity Price, 2050 (2009$/MWh)	$135–$161	$163
Annual Increase in Retail Electricity Price, 2011–2050 (% per year)	0.8% per year–1.2% per year	1.3% per year
Incremental Present Value of System Costs Compared to Baseline (Billion 2009$)	$325–$1,160	$895
Incremental Average Retail Electricity Price Compared to Baseline, 2050 (2009$/MWh)	$24–$50	$40

3.3.4 Alternative Fossil Energy Cost and Technology Improvement Scenarios

All of the scenarios presented to this point used the same base fuel prices for coal and natural gas, and they used fossil technology cost and performance estimates described in Section 2. As such, these scenarios only reveal a limited range of possible fossil futures and their impacts on achieving high levels renewable electricity. Figure A-8 demonstrates this limited range and compares fossil fuel consumption and prices between the core 80% RE and the Low-Demand Baseline scenarios.[201] Among the six low-demand core 80% RE scenarios, coal-based electricity generation was found to decline by 80%–82% by 2050, relative to 2010 levels. Natural gas-fired generation was estimated to decline by 76%–86% by 2050, relative to 2010 levels.[202]

[201] Estimated electric sector fossil energy consumption shown in Figure A-8 is restricted to electricity producers only (i.e., fossil energy consumption from combined heat and power generators is excluded). Estimated fossil energy prices presented in Figure A-8 reflect prices to the power sector and do not reflect wellhead prices or prices seen by other sectors.

[202] Under the High-Demand 80% RE scenario, coal generation declined by 74% and natural gas generation by 68%.



(a) Natural gas and coal demand

(b) Natural gas and coal prices

Figure A-8. Natural gas and coal demand and prices in the electricity sector in the Low-Demand Baseline scenario and the low-demand core 80% RE scenarios

Reduced power sector fossil fuel consumption is projected to apply downward pressure on fossil fuel prices. The magnitude of the estimated price reduction will depend on the shape of the natural gas and coal supply curves, and the degree of demand reduction. Based on natural gas and coal supply curve assumptions embedded within the EIA's National Energy Modeling System as used in the 2010 Annual Energy Outlook (reflected in ReEDS), and the gas and coal demand reductions projected to occur, reductions in natural gas and coal prices across the six low-demand core 80% RE scenarios, relative to the baseline scenario, were estimated at 19%–22% (natural gas) and 28%–30% (coal) in 2050 (see Figure A-8).[203] The electric sector savings of these lower fuel prices for the coal and natural gas electricity generation in all renewable electricity scenarios were accounted for in the electricity system cost and retail electricity price results presented previously; savings in other sectors, such as reduced natural gas costs for heating are not included here and are discussed below.[204] Details on fuel price elasticities in ReEDS can be found in Short et al. (2011).

Lower or higher fossil fuel prices than those presented in Figure A-8 for the Baseline and core 80% RE scenarios are certainly possible. For example, while natural gas prices in

[203] In comparison, relative to the High-Demand Baseline scenario, the High-Demand 80% RE scenario yielded natural gas and coal price reductions in 2050 of 27% and 33%, respectively.
[204] The possible spillover consumer benefits of these price reductions in other (non-electric) segments of the energy economy are discussed in Section 4.5.3.

2012–2020 were projected to exceed $5/MMBtu for all scenarios shown in Figure A-8, trends from August 2011 to January 2012 indicate that natural gas electric power prices can dip below $5/MMBtu or even $4/MMBtu (EIA 2012b). In addition, the 2011 and 2012 editions of the AEO forecast natural gas prices in the coming years that are lower than forecasted gas prices from AEO 2010 (EIA 2010a, EIA 2011c, EIA 2012b). Projected low natural gas prices are driven by a number of factors, including growth in unconventional gas supplies and demand for natural gas both within the electricity sector and by other end-use sectors (e.g. residential, commercial, industrial, transportation). Gas prices may react to difficult-to-predict changes in underlying market drivers,[205] leading to substantial historical price volatility and to price forecasts for gas that have been decidedly poor (see Figure A-9).

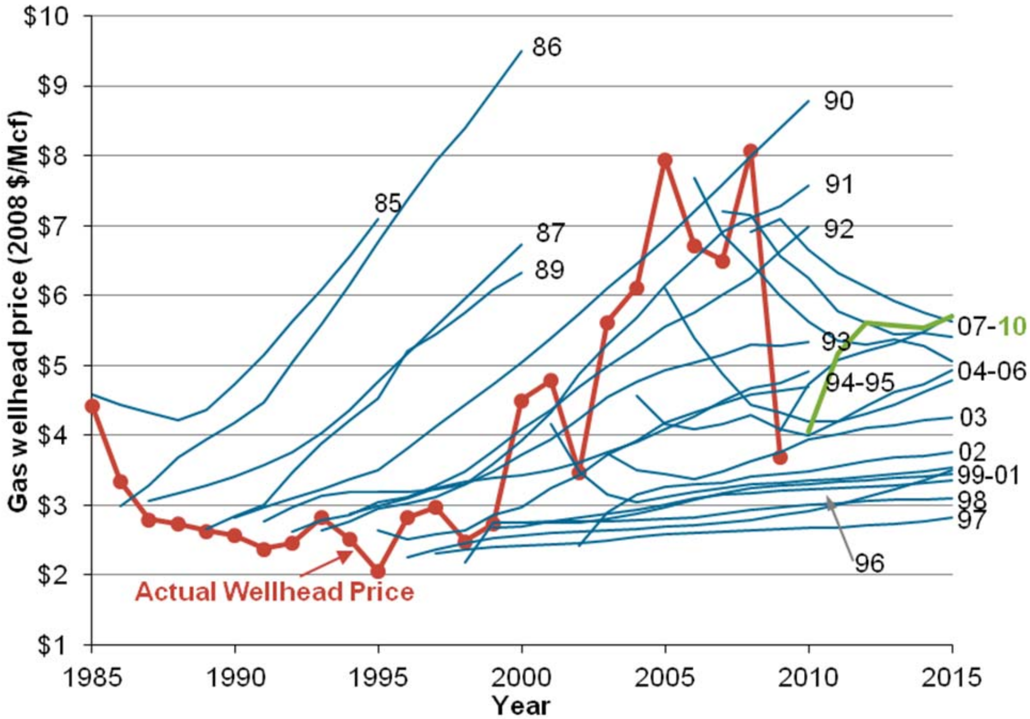


Figure A-9. Historical wellhead natural gas prices vs. price forecasts of EIA Annual Energy Outlook

Each blue line represents *forecasted* wellhead natural gas prices from the AEO of the corresponding labeled year (1985–2010). The bold red line shows *actual* historical wellhead prices.

[205] For example, EIA (2012a) estimates that potential growth in natural gas exports may apply upward pressure on future prices.

Given such uncertainties in the future cost of fossil energy sources, baseline and 80% RE scenarios were also analyzed under higher and lower assumed fossil fuel prices. In particular, an 80% RE under Higher Fossil Fuel Costs scenario and an 80% RE under Lower Fossil Fuel Costs scenario were evaluated; these scenarios used the same assumptions as the 80% RE-ITI scenario, except that the base natural gas and coal prices were simply assumed to be 30% higher and 30% lower, respectively, for all years between 2012 and 2050.[206] For comparison purposes, two new baseline scenarios were also evaluated (Baseline under Higher Fossil Fuel Costs and Baseline under Lower Fossil Fuel Costs), with the only difference between these scenarios and the Low-Demand Baseline scenario presented earlier again being the 30% changes in base fossil fuel prices.[207]

In addition to assessing the implications of altered fossil fuel prices to achieving an 80%-by-2050 renewable electricity future, RE Futures also sought to assess the potential implications of greater fossil technology improvements. To this end, an 80% RE under Fossil-HTI scenario was developed, using conventional fossil technology cost and performance as projected from EIA's AEO 2010 Reference Case, as summarized Section 2.2.[208] For comparison purposes, a new baseline scenario (Baseline under Higher Fossil Technology Improvement scenario) was also evaluated. Figure A-10 summarizes the resulting set of scenarios presented in this section.

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[206] Scenarios in which fuel prices vary by more than 30% are possible, but 30% was selected as a reasonable figure with which to test the sensitivity of outcomes to underlying fuel prices. In addition, to isolate the effect of fossil fuel and technology costs, fossil fuel and technology cost sensitivity scenarios were not evaluated under different renewable technology improvement assumptions.

[207] As described in Section 2.2.2 and Short et al. (2011), ReEDS endogenously considers fuel price elasticities, and fossil fuel prices therefore differ between scenarios even when the starting, or base, fossil fuel prices are identical. As a result, although the scenarios presented here revised base fuel prices by +/-30% relative to the 80% RE-ITI and Low-Demand Baseline scenarios, final natural gas and coal prices are estimated in ReEDS and differ from these figures. For the new baseline scenarios, for example, final natural gas prices in 2050 differed relative to the Low-Demand Baseline scenario by +18% and -19%, whereas coal prices differed by +17% and -17%. For the new 80%-by-2050 RE scenarios, natural gas prices in 2050 differed relative to the 80% RE-ITI scenario by +27% and -26%, whereas coal prices differed by +26% and -25%.

[208] As described in Section 2.2, conventional technologies considered in RE Futures included pulverized coal, natural gas combined cycle, and natural gas combustion turbine technologies. RE Futures did not evaluate the impacts of more advanced conventional power plants, including nuclear, gasified coal, and carbon capture and storage technologies, although the existing nuclear fleet (and coal IGCC) is represented in ReEDS. In addition, the fossil technology cost and performance from AEO 2010 are not meant to represent the lower bound on future technology costs, as greater technological advances are possible.

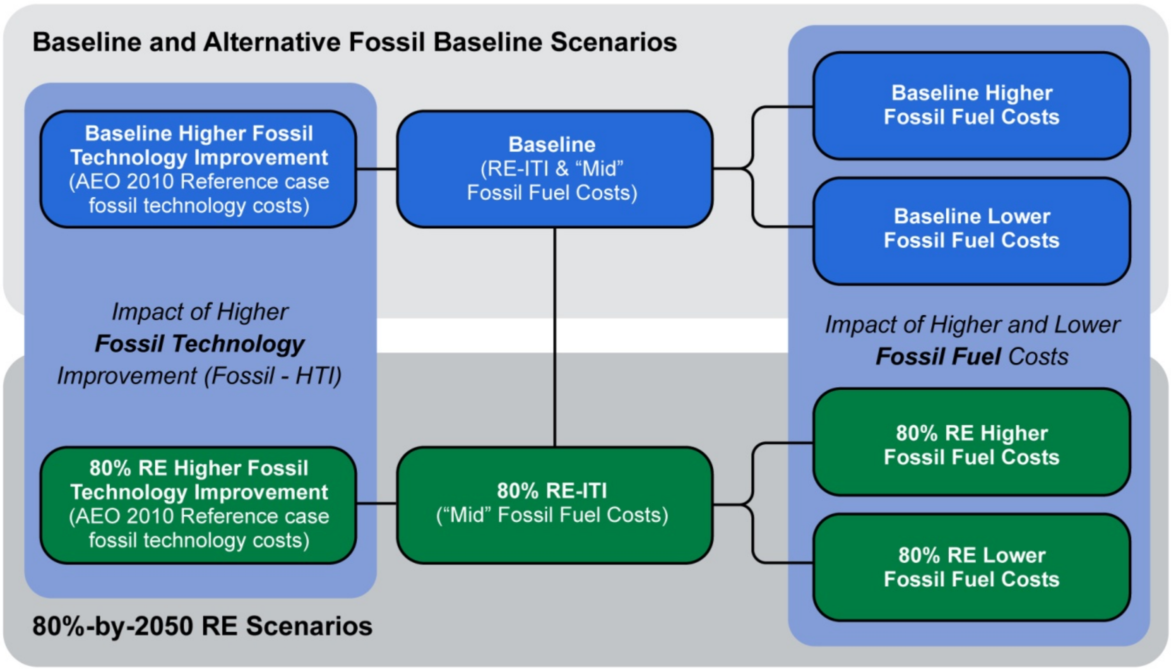


Figure A-10. Illustration of fossil scenario framework

Fossil fuel price and technology cost assumptions affect the future capacity and generation mix of the baseline scenarios as well as the residual mix in the 80%-by-2050 RE scenarios. Additionally, fossil fuel and technology costs directly affect total electric sector costs and estimated retail electricity prices, especially in the baseline scenarios. Due to the lower capacity and use of fossil technologies in the 80% RE scenarios, fossil fuel prices and fossil technology cost assumptions have a relatively smaller impact on those scenarios.[209]

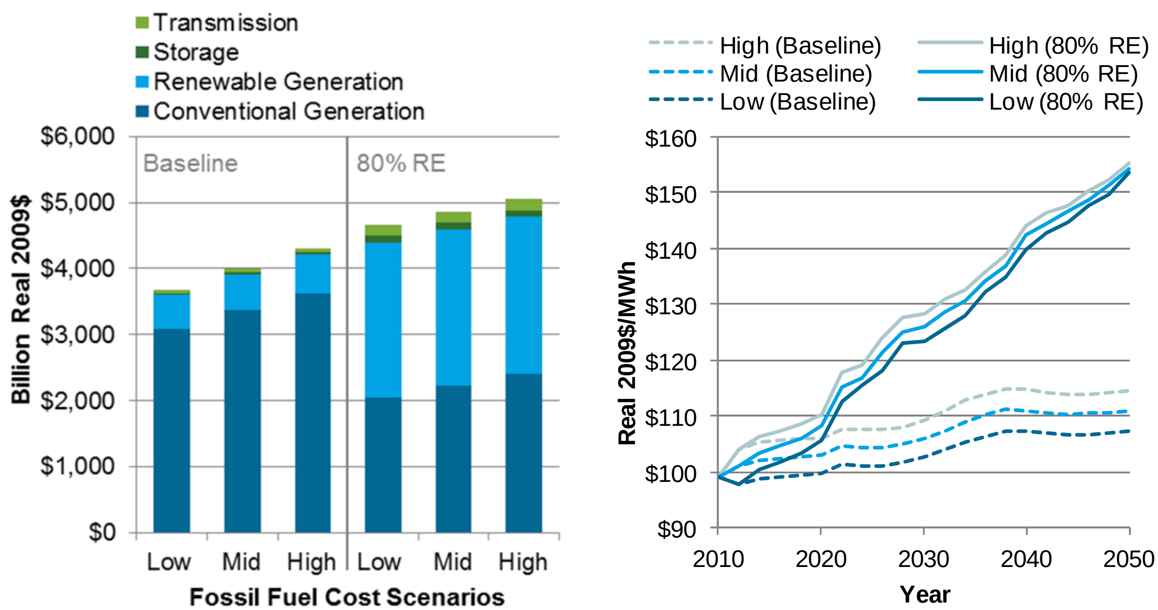
3.3.4.1 Alternative Fossil Energy Cost Scenarios

Figure A-11 shows the present value of electric system costs and average retail electricity prices over the 2011–2050 period for the "mid" 80% RE-ITI scenario (and its corresponding "mid" baseline), in comparison to the scenarios in which base fossil fuel prices were altered by +/-30%. In the baseline scenarios, the altered fuel cost assumptions resulted in changes in the present value of system costs of +7.8% (+$310 billion) higher and -7.9% (-$320 billion) lower for the higher and lower fuel cost assumptions, respectively. Because the 80%-by-2050 RE scenarios rely less heavily on fossil energy, present value cost differences are less affected by fossil fuel cost assumptions—altered fuel cost assumptions resulted in changes in the present value of system costs of +4.0% (+$190 billion) and -4.0% (-$190 billion), respectively, compared to the "mid" 80% RE-

[209] In the Low-Demand Baseline scenario, for example, the present value cost attributed to conventional fuels (which include coal, natural gas, and uranium) accounted for 48% of total discounted (using a 3% discount rate) electric system costs over the 2011–2050 analysis period. Under the 80% RE-ITI scenario, the cost of conventional fuels constituted a smaller (but still substantial) fraction of 23%.

ITI scenario. These trends indicate that the *incremental* cost of achieving 80% renewable electricity penetration by 2050 is inversely related to fossil energy cost—as fossil costs fall, the incremental cost of achieving an 80% renewable electricity future grows. Specifically, the *difference* in present value of system cost between the 80% RE scenario and its corresponding baseline scenario was +$750 billion (+17%) when "high" fuel costs were assumed, +$870 billion (+22%) when "mid" fuel costs were assumed (the 80% RE-ITI scenario), and +$990 billion (+27%) when "low" fuel costs were assumed.

Electricity prices followed the same basic trend, with prices in the 80% RE scenarios much less sensitive to fossil energy cost assumptions than prices in the baseline scenarios. Specifically, 2050 retail electricity prices in the baseline scenarios changed by +3.1% and -3.3% under the altered fuel cost assumptions, whereas the range was considerably narrower in the 80% RE scenarios: -0.3% to +0.8%.[210] The 2050 retail rate increase associated with the 80% RE-ITI scenario in 2050 (relative to the Low-Demand Baseline scenario), as presented earlier, was $43.1/MWh (+38.8%). Higher and lower fossil fuel costs changed these figures to $40.9/MWh (+35.7%) and $46.4/MWh (+43.2%), respectively, again demonstrating that as fossil fuel costs decrease, the estimated incremental rate impact of achieving an 80% renewable electricity future increases to some degree.[211]



Present value of system costs (3% discount rate)

(b) National average retail electricity price

Figure A-11. Electric system costs and average retail electricity prices for alternative fossil energy cost scenarios

[210] Section 4.5.3 discusses the implication of this reduced sensitivity as a hedge against fuel price volatility.

[211] The baseline scenarios under higher and lower fossil fuel cost assumptions resulted in annual retail electricity price increases of 0.4% per year and 0.2% per year (2011–2050, in real dollar terms), respectively. The annual growth rate remained at approximately 1.1% per year for all of the 80% RE scenarios discussed in this section.

In addition to the cost implications described above, fossil fuel cost assumptions also affect capacity expansion and dispatch decisions. Specifically, under the baseline scenarios, fossil fuel cost changes impacted the relative contributions of natural gas and renewable generation, as depicted in Figure A-12. Higher fossil fuel costs resulted in a slight reduction in the use of natural gas and a corresponding increase in renewable generation; the opposite was true with lower fossil fuel costs. Electricity supply from coal and nuclear, meanwhile, remained mostly constant among these scenarios. Under the 80% RE scenarios, on the other hand, natural gas continued to be used only to meet peak net load regardless of the fuel price assumptions, and altered fossil fuel cost assumptions were instead found to impact the relative dispatch of coal and nuclear generation somewhat. Under the higher fossil fuel cost scenario, for example, existing nuclear plants are relied upon to a greater degree. Moreover, with the somewhat greater amount of (assumed less flexible) nuclear generation in this instance, a greater amount of solar capacity was deployed (and less wind power) in order to leverage the greater correlation between solar output and electricity demand and the thermal storage capabilities of CSP. These differences in renewable deployment are, however, relatively minor on a national basis.

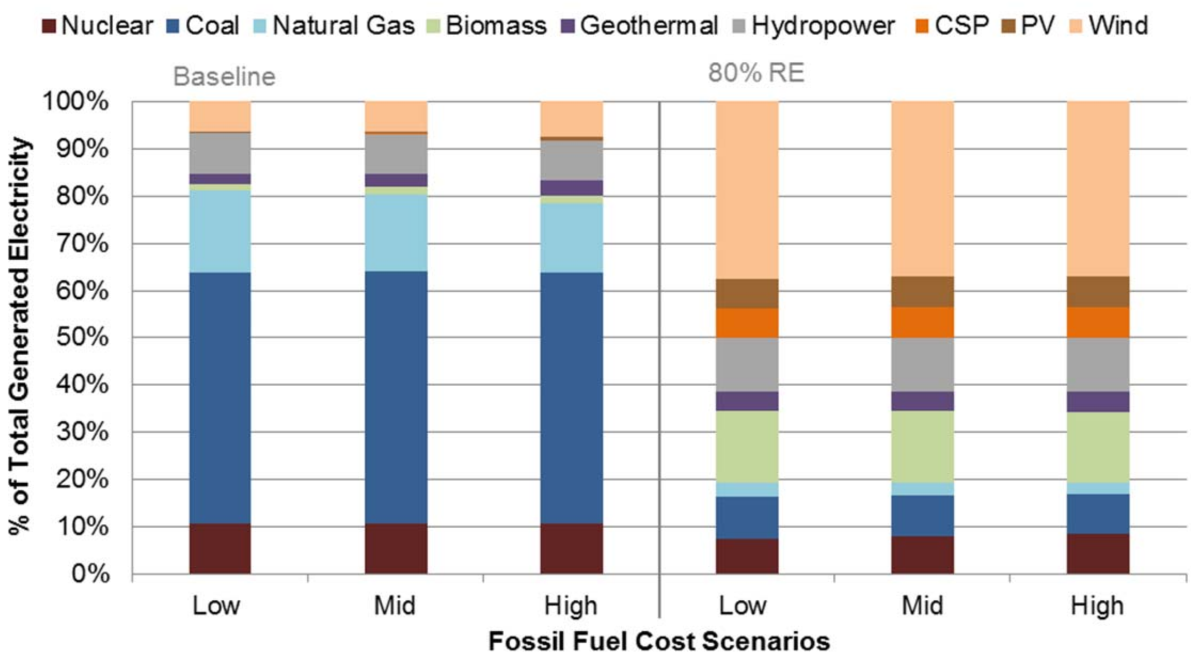


Figure A-12. Generation mix of fossil fuel scenarios in 2050

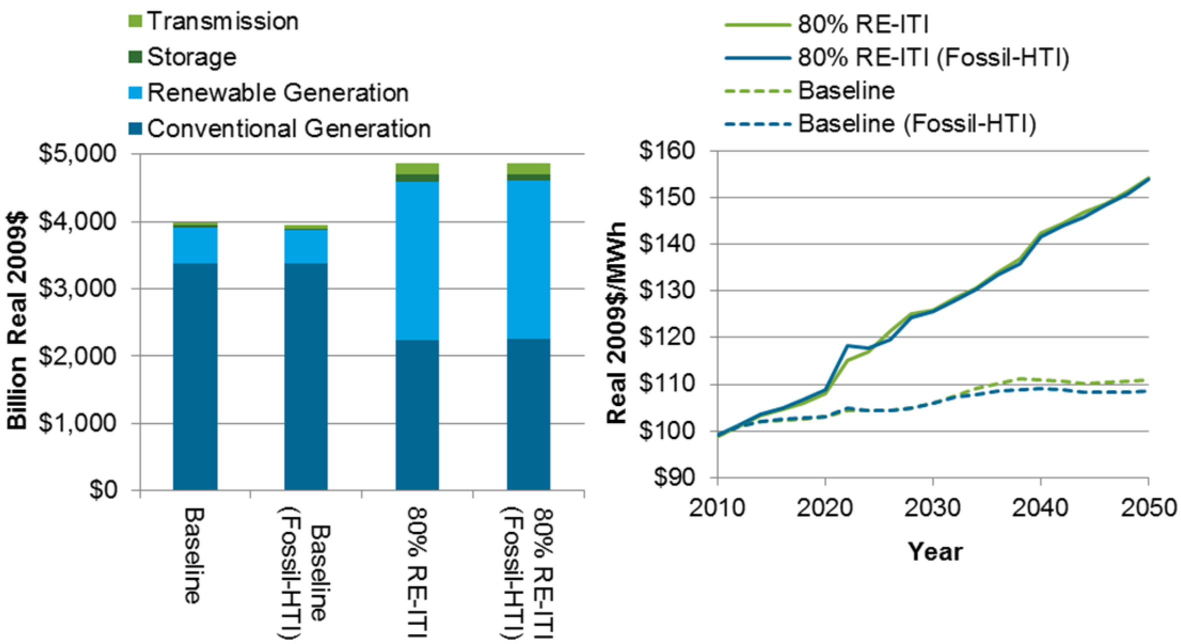
3.3.4.2 Higher Fossil Technology Improvement Scenario

A separate scenario was evaluated in which the fossil technology cost and performance assumptions provided by Black & Veatch were replaced with assumptions from EIA's AEO 2010, referred to as the Fossil-HTI scenario.[212]

Figure A-13 shows the present value of electric system costs and average retail electricity prices over the study period for the AEO-derived fossil technology cost scenarios in comparison to the 80% RE-ITI and Low-Demand Baseline scenarios. As shown, the present value of electric system costs were almost indistinguishable (within about 1%) when fossil technology costs were altered, while the *incremental* cost of achieving an 80% renewable electricity future was found to be only slightly greater (+$920 billion difference between the 80% RE [Fossil-HTI] and the baseline [Fossil-HTI] scenarios compared with the +$870 billion difference between the 80% RE-ITI and Low-Demand Baseline scenarios) under lower assumed fossil technology costs. Changes in electricity prices associated with lower fossil technology costs were more pronounced in the baseline scenarios than in the 80%-by-2050 renewable electricity scenarios, but differences were again modest. The incremental retail rate increase associated with the 80% RE-ITI scenario in 2050 (relative to its baseline) was $43.1/MWh (+38.8%); with the AEO-derived fossil technology costs, this rate impact increased modestly to $45.3/MWh (41.7%).[213]

These results suggest that the cost of achieving high levels of renewable electricity penetration is largely insensitive to reasonable assumptions about the cost and performance of fossil technologies (as shown earlier, direct electric sector costs are more sensitive to fossil fuel price assumptions[214]). The reason for this lack of sensitivity of scenario costs to fossil technology costs is two-fold. First, for the 80%-by-2050 RE scenarios, only a small amount of natural gas and no new coal facilities are added; high renewable energy penetrations drive existing plants to retire, and those existing plants that remain (along with the new renewable plants) are largely adequate to meet load. Second, even in the baseline scenarios, the assumed low-demand growth and limited amount of coal plant retirements obviate the need for significant new fossil additions. Because little new fossil generation capacity is required in either instance, altered fossil technology costs have little impact on overall system costs or retail electricity rates.[215]

[212] RE-ITI estimates were used for renewable technologies; therefore, the Fossil-HTI scenarios are compared with the 80% RE-ITI scenario. Similar trends are expected under RE-ETI renewable technology cost estimates.
[213] The baseline (Fossil-HTI) and 80% RE (Fossil-HTI) scenarios resulted in annual retail electricity price increase of 0.2% per year and 1.1% per year (2011–2050, in real dollar terms), respectively.
[214] More analysis is needed to conclusively compare the relative sensitivity of the scenarios to fossil *energy* prices versus fossil *technology* costs. The analysis presented only included two alternative fossil energy cost scenarios and one alternative fossil technology cost scenario.
[215] Under a more traditional high-demand projection, the effect of fossil technology costs was found to be more pronounced. Specifically, when the AEO-derived fossil technology costs were applied under the high-demand assumptions, the incremental cost of achieving an 80% renewable electricity future was calculated



(a) Present value of system costs (3% discount rate)

(b) National average retail electricity price

Figure A-13. Electric system costs and average retail electricity prices for Fossil-HTI scenarios

3.4 Summary of Direct Electric Sector Cost Implications of RE Futures Scenarios

Using simplified cost metrics that account for only direct electric sector costs, the analysis found that achieving higher levels of renewable electricity penetration generally requires increased direct electric sector investments compared with baseline scenarios that represent a continued evolution of today's conventional generation system. The increased costs and prices reflect the fact that the higher capital expenditures associated with most renewable generation technologies were not found to be fully offset by savings in fossil energy purchases. The cost and price increases also reflect the higher transmission and system balancing needs associated with renewable energy. Under alternate assumptions, the present value electric system cost and electricity price impacts shown here could be substantially different.

In some cases, moderately higher levels of renewable energy penetration were found to have limited impacts on electric sector costs and prices. For example, when the greater evolutionary, renewable technology improvements were assumed, scenarios with moderate to significant levels (up to approximately 30%) of renewable penetration in 2050

to increase by +$170 billion (+$1065 billion vs. +$895 billion), compared to an increase of just +$50 billion (+$920 billion vs. +$870 billion) for the low-demand sensitivities presented here.

were found to have no increase in electricity price compared with the Low-Demand Baseline scenario that relied upon incremental technology advancement assumptions.

The analysis found that the incremental cost of the 80% RE-by-2050 scenarios relative to the Low-Demand Baseline scenario ranged from 8% to 28% for present value of total electricity sector costs and from 21% to 45% for 2050 national average retail electricity prices, depending on the scenario.[216] Further improvements in renewable technologies, beyond those assumed in the ETI projections, would reduce these incremental costs. Higher demand growth led to greater electric sector investments for baseline and high renewable deployments. In addition, the analysis found that the incremental cost associated with high renewable generation scenarios is inversely related to future fossil technology costs and fossil fuel prices; thus, high renewable generation scenarios were significantly insulated from fossil energy price increases and volatility.

The analysis found that among all drivers examined, future renewable technology improvements have the greatest influence on the direct electric sector cost associated with high levels of renewable generation, whereas assumed non-generation system constraints have more modest impacts on direct costs (Figure A-14). In contrast, electricity prices in high renewable scenarios are largely insensitive to projections for fossil fuel prices and fossil technology improvements. Electricity prices of baseline scenarios are more sensitive to demand growth, fossil energy prices, and fossil technology improvements compared with the 80%-by-2050 RE scenarios.

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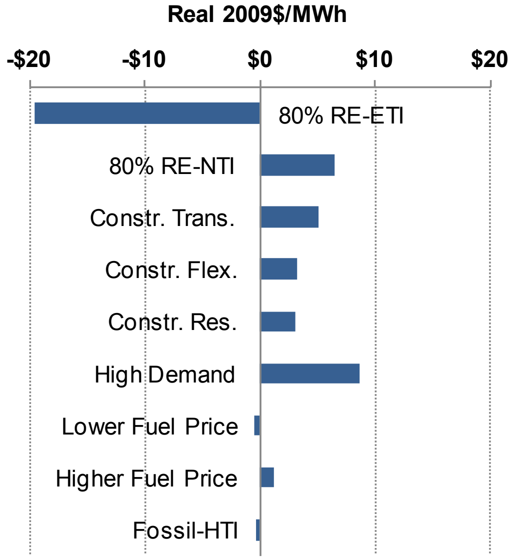
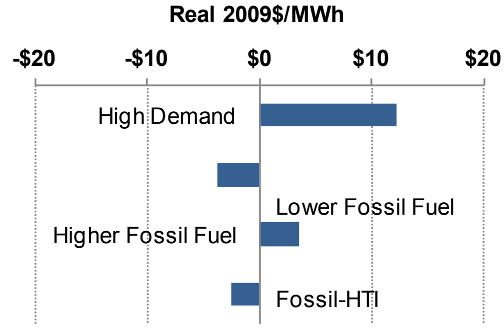
[216] On an annualized basis (i.e., percent increase from the previous year), the annual increase in retail electricity prices (in real dollar terms) from 2010 to 2050 under the core 80% RE scenarios ranged from 0.8% per year to 1.2% per year, depending on the scenario, compared to 0.3% for the Low-Demand Baseline scenario.



(a) Difference in 2050 Electricity Price of Varied 80% RE Scenarios Relative to 80% RE-ITI Scenario



(b) Difference in 2050 Electricity Price of Varied Baseline Scenarios Relative to Baseline (low-demand, ITI) Scenario

Figure A-14. Impact on 2050 national average electricity price from various model drivers to the (a) 80% RE-ITI scenario and the (b) Low-Demand Baseline scenario

Finally, there are significant inherent uncertainties with respect to future electricity demand, technology improvements, fossil energy prices, social and institutional choices, and regulatory and legislative actions related to the scenarios examined that in turn contribute to significant uncertainty in the implications reported above.

4. Environmental and Social Implications of Renewable Electricity Futures Scenarios

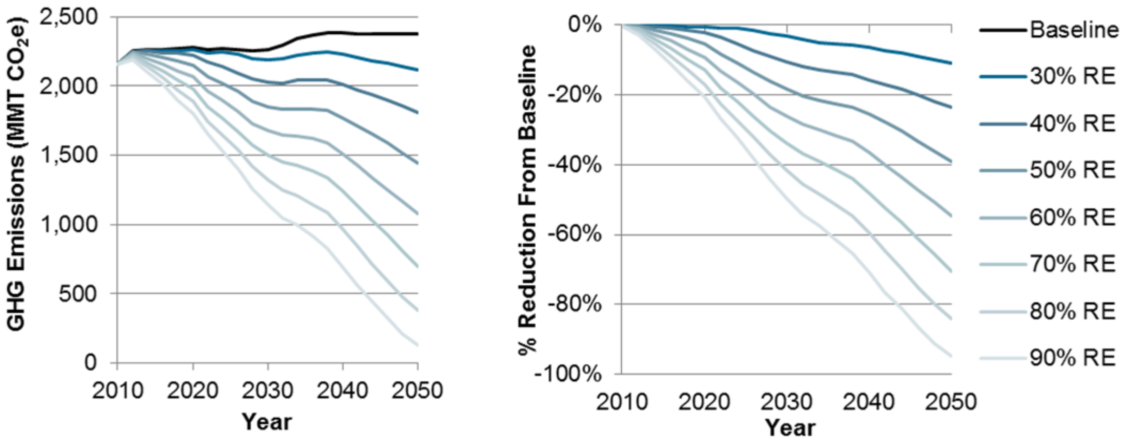
The analysis provided in this volume suggests that achieving a high-penetration renewable electricity future, while feasible at the hourly level based on the modeling conducted for RE Futures, would require attention to transmission needs, operational integration challenges, and system cost and retail electricity rate impacts. There are also direct environmental and social implications associated with the high levels of renewable generation studied in RE Futures. This section offers quantitative and qualitative assessments of the following direct environmental and social implications also associated with the high renewable generation futures examined: electric sector air emissions, water use, and land use and associated issues. Where appropriate, the range of impacts across all six of the low-demand core 80% RE scenarios are summarized here. Because they have different baselines, the alternative fossil fuel and technology cost scenarios and the High-Demand 80% RE scenario are selectively reported in this section, where important differences in results are apparent. To avoid an unnecessarily large number of comparisons, the analyses presented here in many cases focus specifically on the 80% RE-ITI scenario relative to the Low-Demand Baseline scenario; where significant differences among other scenarios exist, these are noted. The implications presented here do not represent a comprehensive list and the analysis includes many uncertainties and limitations, which are identified in the relevant sections. For example, among the many limitations of the present analysis is an incomplete assessment of the impacts of biomass energy crops.

Many of the environmental and social implications of high renewable electricity futures described here relate to reduced electric sector fossil energy consumption. In particular, among the six low-demand core 80% RE scenarios, natural gas-fired and coal-based electricity generation was found to decline by approximately 80% by 2050, relative to 2010 levels. These reductions were described in detail in Section 3.3.4. The direct impact that these reductions have on GHG emissions, water use, and other environmental implications are estimated in Sections 4.1-4.4. Section 4.5 discusses some of the indirect implications of high renewable penetration scenarios.

4.1 Renewable Electricity Reduces Greenhouse Gas Emissions

4.1.1 Annual Electric-Sector Carbon Emissions Decline by Roughly 80% with 80% Renewable Electricity

The reduced fossil energy consumption described above and in Section 3.3.4 leads to reduced direct fossil-fuel-based carbon emissions in the electricity sector. Specifically, Figure A-15 shows the decline in annual carbon emissions for the exploratory scenarios; relative to the Low-Demand Baseline scenario, 2050 annual direct combustion carbon dioxide (CO_2) emissions declined by approximately 10% in the 30% RE scenario, 55% in the 60% RE scenario, and 95% in the 90% RE scenario. (Unless otherwise noted, all reported values related to carbon dioxide or GHG emissions are in units of metric tonne of CO_2 or CO_2-equivalent.)

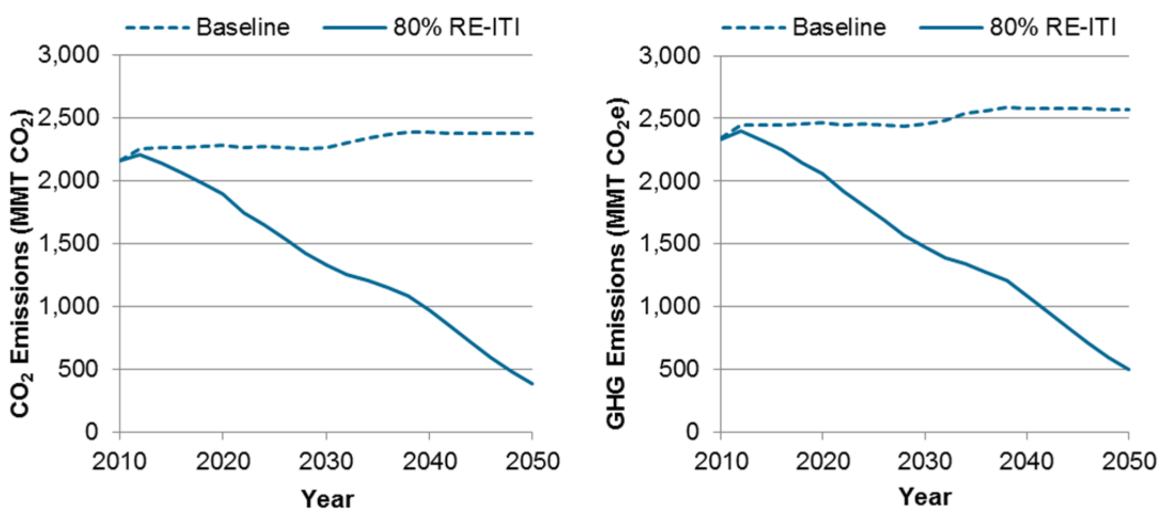


(a) Annual direct-combustion CO_2 emissions

(b) CO_2 emissions as a proportion of the Low-Demand Baseline scenario

Figure A-15. Annual combustion-only carbon dioxide emissions as renewable electricity levels increase

Focusing exclusively on the 80% RE-ITI scenario, Figure A-16(a) shows that direct combustion-related, electric-sector fossil-fuel-based CO_2 emissions in 2050 were estimated to decline, relative to the Low-Demand Baseline scenario, by roughly 84%. On a cumulative basis (2011–2050), combustion-only electric sector fossil-fuel-based CO_2 emissions were found to be 42.5% (39.3 GT) lower under the 80% RE-ITI scenario than under the Low-Demand Baseline scenario. Across all six of the core low-demand 80% RE scenarios, CO_2 emissions reductions by 2050 were found to range from 83% to 85% in comparison to the Low-Demand Baseline scenario. In comparison to its baseline, the High-Demand 80% RE scenario was found to result in direct combustion-related CO_2 emissions reductions in 2050 of 81%.



(a) Direct, combustion-only CO_2 emissions

(b) Life cycle GHG emissions

Figure A-16. Greenhouse gas emissions in Low-Demand Baseline and 80% RE-ITI scenarios

These estimates, however, do not consider several effects. First, only CO_2 emissions were considered while other GHG were ignored; this may be particularly important for methane released in coal mining, oil production, and natural gas production and transport, as well as any GHG impacts of other air pollutants released through combustion processes. Second, only emissions from the combustion of fossil energy were counted, while emissions from upstream fuel extraction and processing were disregarded. Finally, a focus on combustion-only emissions means that the GHG emissions implications of equipment manufacturing and construction, O&M activities, and plant decommissioning were not considered. As a result, although most renewable electricity technologies have no or limited direct GHG emissions (with the exception of biopower[217]), a more-comprehensive evaluation of the impact of an 80%-by-2050 renewable electricity future requires that GHG emissions across the full life cycle of each technology be evaluated with life cycle assessment (LCA) procedures.

An extensive review and analysis of previously published LCAs on electricity generation technologies was conducted (see Appendix C). The LCA considers upstream emissions, ongoing combustion and non-combustion emissions, and downstream emissions. Upstream and downstream emissions include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, on-site construction, project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site material. Figure A-17 summarizes the results of this review for a wide range of renewable and non-renewable electricity generation technologies,[218] including the full range of estimates of life cycle emissions

[217] Combustion of biomass produces GHG emissions. However, because the carbon that is emitted during combustion is absorbed during photosynthesis in feedstock production, these emissions cancel when summed over the life cycle. The combustion-only CO_2 emissions impacts reported in this chapter assume no net emissions from biopower facilities. Nevertheless, there are non-cancelling GHG emissions from biopower systems outside of the biomass production and combustion processes associated with component manufacturing and construction; O&M; and, often, feedstock production. All of these so-called direct GHG emissions were accounted for here in the life-cycle estimates. Unaccounted for in RE Futures altogether, however, are potential GHG emissions associated with changes in land use directly or indirectly induced by the cultivation of a biomass feedstock. There is considerable scientific debate regarding the magnitude of land use change-related GHG emissions and even whether the land-use change effects would result in net positive or net negative GHG emissions (depending on context-specific factors). This is an important limitation of the RE Futures calculation, and further work is recommended to understand the GHG implications of the direct and indirect land use impacts associated with biomass feedstocks.

[218] New nuclear- and coal-IGCC plant additions were not considered in RE Futures; however, the non-combustion emissions for these technologies include emissions associated with retirements and O&M activities, and are therefore relevant for existing plants. For co-firing (coal and biomass) technologies, the emission factors are assumed to be based on a weighted average of dedicated biomass and coal as determined by the amount of input energy of biomass used (up to 15%). For Figure A-17, the concentrating solar power data represent trough systems only.

factors for each technology based on the literature survey (see Appendix C), though not considering land-use related impacts from bioenergy crops.[219]

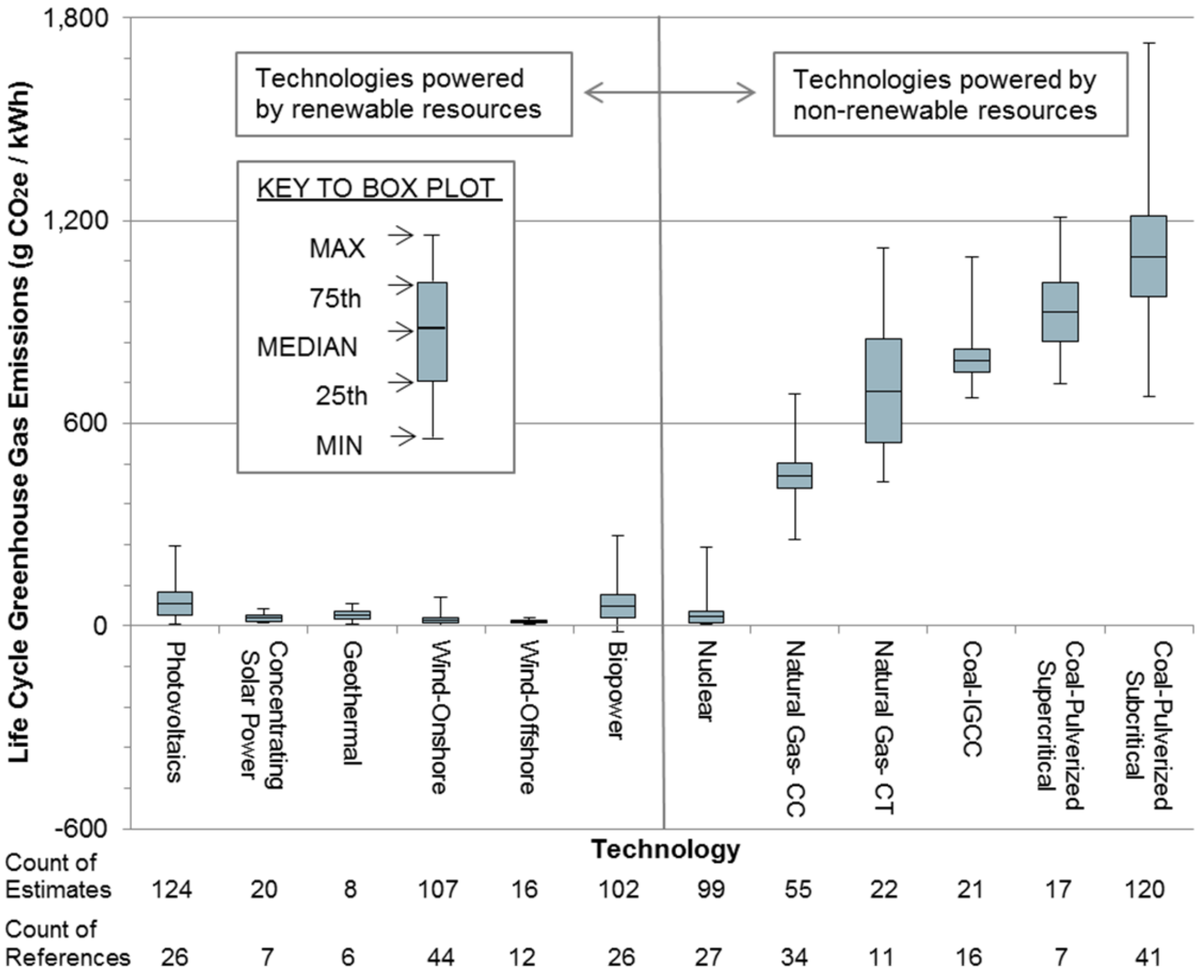


Figure A-17. Full life cycle greenhouse gas emission factors by technology based on life cycle assessment literature survey

Based on this literature survey and assessment, the median life cycle, non-combustion GHG emission values for each electricity generation technology from the pool of selected estimates was used to estimate non-combustion related GHG emissions. While the combustion-only CO_2 emissions shown in Figure A-16(a) are based on ReEDS-

[219] As Appendix C elaborates, GHG emissions were estimated by considering each life cycle stage separately. ReEDS-calculated CO_2 emissions were used in the place of LCA literature estimates for combustion-related GHG emissions, and therefore the results reported in Figure A-17 do not perfectly align with the actual estimates used in the calculations.

calculations,[220] Figure A-16(b) shows a similar comparison based on the full life cycle GHG emissions of the Low-Demand Baseline scenario and the 80% RE-ITI scenario.

As seen by comparing Figure A-16(a) to Figure A-63(b), GHG emissions in both the Low-Demand Baseline scenario and the 80% RE-ITI scenario were higher when the full life cycle impacts were considered than when only combustion-related CO_2 was considered. However, emissions resulting from non-combustion activities are higher in the Low-Demand Baseline scenario compared with the 80% RE-ITI scenario; therefore, absolute avoided emissions in the 80% RE-ITI scenario was found to be greater when full life cycle impacts were considered. This result arises because GHG emissions per kilowatt-hour from fossil energy extraction and processing activities are slightly higher than those from the upstream and downstream activities associated with renewable electricity generation technologies. As a result, the cumulative (2011–2050) life cycle GHG emissions from the 80% RE-ITI scenario were 41% (41.3 GT) lower than those of the Low-Demand Baseline scenario, representing slightly greater absolute GHG emissions reductions than when considering direct combustion-related CO_2 emissions alone. In 2050 alone, LCA-based GHG emissions in the 80% RE-ITI scenario were found to be 81% (2 GT/yr) below the Low-Demand Baseline (see Appendix C for a full discussion of these results and the assumptions that underlie them). These figures suggest that an estimate of relative GHG benefits (i.e., the percent GHG emissions reductions comparing a high renewable penetration scenario to the Low-Demand Baseline scenario) based on combustion-only emissions alone is a reasonable approximation of the relative benefits of the 80%-by-2050 RE scenarios when considering GHG emissions across the full life cycle of each technology (at least when not considering the GHG emissions associated with land use changes).

The GHG emissions impact of variable renewable generation may, however, be offset in part by the increased flexibility, ramping, and part-loading required of conventional fossil generation to ensure a supply-demand balance; part-loading fossil generators, for example, decreases the efficiency of the plants and therefore creates a fuel efficiency and GHG emissions penalty relative to a fully loaded plant. The annual GHG emissions shown in Figure A-16 do not consider these effects. However, Figure A-16(b) demonstrates that for the 80% RE-ITI scenario (with almost 50% variable generation), much of the aggregate generation from fossil plants could be substituted with renewable electricity generation such that annual GHG emissions in 2050 would be roughly 500 $MMTCO_2e$ compared with approximately 2500 $MMTCO_2e$ in the Low-Demand Baseline Scenario. Part-loading and ramping effects on GHG emissions would likely be much less than this difference in GHG emissions between the scenarios.

Gross et al. (2006), for example, performed a literature review of the costs and impacts of variable renewable generation, including analyses of the fuel savings and GHG emissions impacts of wind energy. The efficiency penalty due to the variability of wind power output (and its impact on the operations of the conventional generation fleet) in four studies that

[220] Assumed combustion and non-combustion emission factors for each technology can be found in Appendix C.

explicitly addressed the issue ranged from near 0% to as much as 7%, for up to 20% wind electricity penetration. Pehnt et al. (2008) calculated an emission penalty of 3%–8% for a wind electricity penetration of 12%, with the range reflecting varying types of conventional power plants built in future years.[221] Fripp (2011) finds that, in larger regions (more than 500 km) where geospatial smoothing can be significant, the operating reserves required for wind generation will undo less than 6% of the GHG emissions savings that would otherwise be expected. As summarized by Gross and Heptonstall (2008), at least for moderate levels of wind electricity penetration, "there is no evidence available to date to suggest that in aggregate efficiency reductions due to load following amount to more than a few percentage points."[222] Nonetheless, it is clear that efficiency penalties associated with part-loading and ramping fossil generation may modestly impact the carbon emissions savings of high-penetration renewable electricity futures, although storage, interruptible load, and any flexibility offered by renewable energy supply (e.g., CSP with storage) would mitigate those penalties to some degree. Additional research is needed to assess the degree of the degradation of the remaining fossil generation plants under the 80%-by-2050 RE scenarios considered in RE Futures, as those impacts are not quantified in this report.

Notwithstanding some of the above caveats, the estimated electric-sector combustion-only carbon emissions reductions associated with the 80% RE scenarios presented here are reasonably consistent with electric-sector emission reductions found in recently examined low carbon or clean energy scenarios by the Energy Information Administration (EIA 2009c, EIA 2010b, EIA 2011a, EIA 2011b) and the Environmental Protection Agency (EPA 2009a, EPA 2010). Among the six low-demand core 80% RE scenarios, for example, combustion-related CO_2 emissions in the electric sector were reduced by 41%–42% in 2030 and 83%–85% in 2050, relative to the Low-Demand Baseline scenario. These reductions are similar to and within the range of CO_2 emission reductions found in the low carbon and clean energy scenarios analyzed by EIA and EPA; relative to the study-specific baseline or reference scenarios, the EIA and EPA low carbon and clean energy scenarios resulted in CO_2 emission reductions of 34%–59% in 2030 and 77%–88% in 2050.[223] Table A-9 summarizes these comparisons.

[221] Accounting for only the start-up and minimum load requirements of conventional generators (but not including the part-load efficiency penalty), Göransson and Johnsson (2009) estimate an emission penalty of 5%.

[222] Katzenstein and Apt (2009) concluded that the efficiency penalty could be as high as 20%, but appear to have assumed that every wind power plant requires spinning reserves equivalent to the nameplate capacity of the wind plant. This assumption does not conform to actual spinning reserve practices (Mills et al. 2009, EnerNex 2010).

[223] Results presented here for each of the EIA and EPA analyses relate to the primary low carbon or clean energy scenario of each analysis only and do not include any alternative scenarios or sensitivities evaluated by the EIA and EPA.

Table A-9. Reduction in Electric-Sector Combustion-Only Carbon Dioxide Emissions Relative to Study-Specific Baseline

	2030	2050
Core 80% RE scenarios[a]	41%–42%	83%–85%
EIA 2009c	59%	—
EPA 2009a	52%	77%
EIA 2010b	34%	—
EPA 2010	47%	88%
EIA 2011a	34%	—
EIA 2011b	46%	—

[a] The High-Demand 80% RE scenario was found to result in CO_2 emissions reductions of 38% by 2030 and 81% by 2050 relative to the High-Demand Baseline scenario.

In summary, the analysis shows that 80% renewable electricity generation in 2050 can have a substantial impact on U.S. power sector GHG emissions.[224]

4.1.2 Comparing Cost Implications Between RE Futures and Published Carbon Reduction Scenarios

One benchmark for the cost of the 80% renewable electricity scenarios are other recent analyses of the cost of GHG reductions in the electric power sector. As shown in Figure A-18, average retail electricity prices in the six low-demand core 80% RE scenarios were $12–24/MWh (12%–23%) and $24–50/MWh (21%–45%) higher than they were in the Low-Demand Baseline scenario in 2030 and 2050, respectively. By comparison, the low carbon and clean energy scenario analyses conducted by the EIA (2009c, 2010b, 2011a, 2011b) and the EPA (2009a, 2010), which, as noted above, have avoided carbon emissions trajectories similar to the core low-demand RE scenario, estimated increased average retail electricity prices (relative to their own reference scenarios) in 2030 of $9–$26/MWh, rising to $41–$53/MWh by 2050.[225] The estimated incremental price impacts of the low-demand core 80% RE scenarios are comparable to these estimates; the same is true for the High-Demand 80% RE scenario and the 80% RE under alternative fossil scenarios.[226] It

[224] There are several potential implications of reduced GHG emissions. Section 4.5.1 briefly summarizes literature on the cost of GHG emission mitigation and global damages associated with these emissions.

[225] In addition, Paltsev et al. (2009) examined a similar low carbon scenario to the EIA (2009c) and EPA (2009a) scenarios and found that retail electricity prices would increase by 15% and 47% above a reference scenario in 2030 and 2050, respectively.

[226] Figure A-18 emphasizes comparisons between the Low-Demand Baseline and the six low-demand core 80% RE scenarios. In the more-traditional high-demand cases, average retail electricity prices in the High-Demand 80% RE Scenario were $14/MWh and $40/MWh higher than the relevant High-Demand Baseline, in 2030 and 2050, respectively. Under the alternative fossil fuel cost and technology improvement scenarios, the incremental price impacts of achieving an 80% renewable electricity future in 2050 (relative to the corresponding alternative baseline cases) were estimated to be $45/MWh (Higher Fossil Technology Improvement), $46/MWh (Lower Fossil Fuel Costs), and $41/MWh (Higher Fossil Fuel Costs). In all cases, these values are comparable to the EIA and EPA estimates for the future rate impacts associated with low carbon and clean energy scenarios that would have sought similar levels of carbon reduction in the U.S. electricity sector, as depicted in the figure.

should be noted that these comparisons are not made on a perfectly consistent basis in that allocation of carbon allowance revenues to the utility sector to offset electricity price increases is typically assumed in low carbon analyses, including some of the analyses from EIA and EPA presented above, but not included in the RE Futures scenarios. This allocation is rapidly phased out in the latter years of the forecast horizon, which is why Figure A-18 shows a dramatic increase in electricity prices under a subset of the EIA analyses (2009c, 2010b) from 2025 to 2030. As a result, comparisons are best made between later-year retail price increases, when allowance allocations of this nature have diminished or ceased.

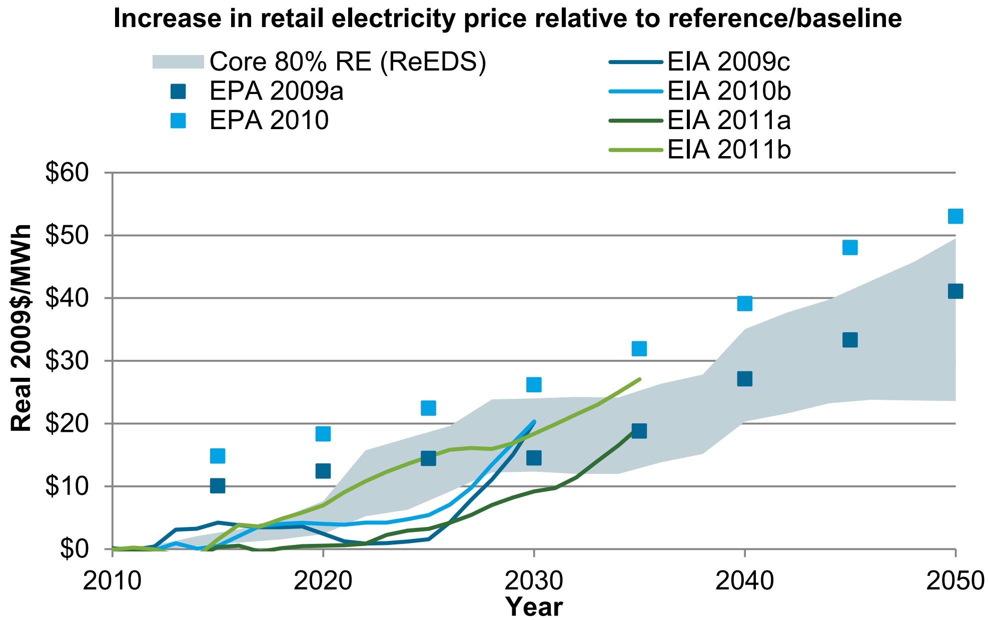


Figure A-18. Average increase in retail electricity rates relative to study-specific reference/baseline scenarios

These comparisons suggest that the 80%-by-2050 RE scenarios may not be significantly more costly than other means of achieving deep carbon emissions reductions in the U.S. electricity sector, based on a limited comparison to specific analyses conducted by EIA and EPA. At the same time, it should be recognized that the present analysis has substantial limitations. For example, RE Futures was not designed as a full portfolio analysis—the study did not seek to evaluate alternative means of achieving carbon emissions reductions or other policy goals. As such, the RE Futures analysis is unable to directly compare the relative costs of 80% renewable electricity scenarios to other means of achieving similar carbon reduction or other policy goals.[227]

[227] Section 4.5.1 briefly summarizes the broader carbon reduction modeling literature, based on the IPCC's Fourth Assessment Report (IPCC, 2007) and elsewhere (e.g., Edenhofer et al. 2010; Fawcett et al. 2009).

4.1.3 Criteria Air Pollution Implications

The specific criteria air pollution implications of the reductions in coal and natural gas generation were not evaluated in RE Futures, in part because environmental regulations are likely to become more stringent with time, thereby reducing pollution emissions below the baseline scenarios used in the present study and impacting emissions rates even in the 80% RE scenarios; RE Futures did not seek to predict the future scope of environmental regulations. Moreover, it should be recognized that retrofitting or replacing the most-polluting power stations in the United States with newer technology are additional options to reduce criteria air pollution. Finally, as noted earlier, increased reliance on variable generation will require the remaining conventional coal and natural gas plants to operate in a more flexible manner, and the operation of fossil plants in that fashion will increase, to some degree, the air pollution emissions from those plants on a per megawatt basis (e.g., Denny and O'Malley 2006). Several detailed operational integration studies of *up to 30%* wind electricity penetration have (implicitly) considered such impacts (e.g., EnerNex and Windlogics 2006; GE 2005, 2008, 2010; Piwko et al. 2007). As summarized in Mills et al. (2009), those studies found that the reduction in coal and natural gas generation caused by increased wind electricity supply offsets any "penalty" associated with running the remaining conventional plants in a more flexible fashion, leading to net reductions in emissions. No past study is known to have assessed this issue at the level of renewable energy penetration analyzed in RE Futures, however, and the emissions penalty associated with high-penetrations of renewable electricity was not assessed in RE Futures, in part because any such impacts will depend on future fossil generation plant designs and emissions controls, both of which are strongly influenced by policy choices. Further research on this topic is therefore warranted.

Notwithstanding the above important caveats, reduced criteria air pollution will likely be a significant implication of a high renewable electricity future.[228]

4.2 Reductions in Power-Sector Water use are Anticipated under an 80% Renewable Electricity Future

The electric sector is responsible for a significant fraction of total water withdrawals in the United States. Changes in energy regulations and policies as well as shifts in the mix of electricity generation can therefore be expected to have significant impacts on the management of local, regional, and national water resources. Realizing an 80%-by-2050 renewable electricity future can similarly be expected to have impacts on water resource use.

Water use for thermoelectric cooling is typically classified under two general categories: withdrawal and consumption. Withdrawal refers to the total amount of water removed from the ground or diverted from surface water sources for use. Typically, this represents a temporary removal of water, which is used to cool a power plant before being returned to its source at a warmer temperature. Water consumption, on the other hand, refers to the

[228] There are several potential implications of a reduction in criteria air pollution. Section 4.5.2 briefly summarizes literature on public health impacts associated with these emissions.

amount of withdrawn water that is evaporated during the cooling process and not directly returned to the source. Water withdrawals for thermoelectric power plant cooling accounted for 49% of all water withdrawals in the United States in 2005, compared to 31% for agricultural uses and 11% for public supply (Kenny et al. 2009).[229] Focusing on water consumption, the U.S. electric sector constituted just 3% of the national total in 1995 (the last year the U.S. Geological Survey collected data on water consumption), compared to more than 75% for the agricultural sector and 12% for public supply[230] (Solley et al. 1998). Water resource concerns are often local and regional in character, however, and even thermoelectric water consumption has been cause for concern in certain areas (Roy et al. 2003). Physical and legal limitations associated with high water withdrawals can lead to water-related power plant curtailments and shut downs even in water rich regions, such as the drought in 2007 that affected many plants in the U.S. Southeast (NETL 2009b). Consumption is an especially important consideration for water scarce regions, particularly relevant in the context of future energy resource development; consumed water is effectively removed from the system and not available for other uses (e.g., agriculture or drinking water).

The amount of water withdrawn and consumed for thermoelectric cooling depends on a variety of factors, including thermal efficiency and local climatic conditions (Turchi et al. 2010). However, the most important determinant is the choice of cooling technology (Macknick et al. 2011). Cooling technologies for conventional thermal power plants are generally of two types: "once-through" systems and re-circulation systems that utilize cooling towers. Each of these systems is a form of "wet cooling" and can utilize either saline water or freshwater. For this study, cooling systems are classified under four general types based on water source and power plant design: once-through cooling using freshwater (OTF); once-through cooling using saline water (OTS); re-circulation cooling using freshwater (CCF); and re-circulation using saline water (CCS). There are other variations of these cooling systems, such as pond-cooled systems, but these systems are considered a subset of the above categories. In addition to the above wet cooling technologies "dry-cooling" technologies exist that use an air-cooled condenser, and thus no water for cooling; these technologies currently make up a small percentage of total generation, but could see increased deployment in areas where water availability is a concern. Once-through and re-circulation cooling technologies have very different water consumptive factors, defined as the percentage of withdrawn water consumed in the thermal cooling process (typically through evaporation). Specifically, once-through cooling technologies withdraw high volumes of water per unit of electricity generation (typically 20,000 to 50,000 gal/MWh), but have relatively low consumptive rates (typically roughly 300 gal/MWh). Re-circulation technologies withdraw much lower volumes of water (typically roughly 500–1100 gal/MWh), but have relatively high consumptive rates (typically roughly 400–700 gal/MWh) (Fthenakis and Kim 2010). For

[229] These values include saline water used in power plant cooling. Considering freshwater only, Kenny et al. (2009) report values as 41% for thermoelectric, 40% for agriculture and livestock, 14% for public supply, and 5% for industry and mining.
[230] Freshwater only values from Solley et al. (1998) are 85% for agriculture and livestock, 8% for public supply, 4% for industry and mining, and 3% for thermoelectric.

the analysis presented here, consumptive factors were generally assumed to be 60% for recirculation cooling technologies (Solley et al. 1998) and 2% for once-through cooling technologies.[231]

The withdrawal and consumptive properties of once-through and re-circulation cooling technologies lead to different impacts on water resources. Once-through technologies (representing about half of total installed capacity) in 2005 made up 92% of total water withdrawals for thermoelectric power plant cooling, with re-circulation systems (representing the other half of total installed capacity) making up the remaining 8%[232] (Kenny et al. 2009; NETL 2009a). For consumptive use, however, estimates indicate that once-through technologies constituted approximately 45% of total water consumption for thermoelectric power plant cooling; re-circulation cooling technologies consumed the remaining 55%.

The importance of water withdrawals and consumption varies geographically due to regional water resource availability, environmental considerations, and water allocation requirements. Once-through cooling technologies are prevalent in the eastern states, where there are many older power plants[233] and often fewer concerns about water availability: 84% of all thermoelectric water withdrawals occur east of the Mississippi River. With the exception of the southeastern states (in particular Georgia), there are fewer concerns about water availability in eastern states than in western states (Sovacool and Sovacool 2009). All but one of the river basins in the western states (with the exception of the Columbia basin), on the other hand, are classified as “water stressed,” meaning that total water withdrawal rates are greater than 60% of mean annual runoff (Raskin et al.1997 and Waggoner et al. 1990). There is substantial competition for water in many of these stressed basins, and concerns about both the withdrawal and consumption of water are common.

To quantify the potential impacts of the 80% RE scenarios on water use both nationally and regionally, a model was developed to estimate water withdrawals and consumption in the electric sector based on ReEDS-estimated generation and capacity deployment. The model is able to calculate water demands from power plant operations (cooling and non-cooling water uses) in each of the 134 BAs in ReEDS. The model was calibrated to a U.S. Geological Survey 2005 base dataset consisting of county-level water withdrawal and electricity generation data (Kenny et al. 2009), with U.S. Geological Survey data used to calculate water withdrawal to power-generation ratios for the four types of water-cooling technologies identified earlier. Only operational water uses were calculated; no upstream water uses associated with mining, irrigation, or fuel processing were considered, for

[231] Because consumptive factors vary by region, the 60% and 2% default values are adjusted in several regions to better match actual practice (personal communication with E. Adams, Massachusetts Institute of Technology, Department of Civil and Environmental Engineering, 2010).
[232] Dry-cooled systems make up less than 1% of total installed capacity. Pond-cooled systems are assumed to be either once-through or re-circulating.
[233] Phase I of EPA regulations associated with Section 316(b) of the Clean Water Act affects cooling systems of new power plants, with the result that generally all newer power plants are built with re-circulation cooling systems instead of once-through systems (EPA 2009b).

either conventional or renewable energy technologies. Consequently, the *following estimates do not represent a full life cycle assessment of relative water demands, and further work is needed to assess life cycle water use, especially given the potentially sizable water demands associated with the biomass feedstocks used under the 80%-by-2050 renewable electricity futures.*[234] Consistent with the technology assumptions used in RE Futures, CSP and geothermal power plants were assumed to use dry-cooling; dry-cooled technologies withdraw and consume relatively small amounts of water, on the order of 10% of a re-circulating water-cooled system.[235] For each region, biopower facilities were assumed to use the same cooling technologies as existing coal facilities in the same region. For these renewable technologies, as well as for thermal generation, operational water consumption not associated with cooling (e.g., the water required to wash heliostats at a CSP facility) was also estimated, using coefficients from Macknick et al. (2011). All water withdrawals for non-thermal technologies were assumed to represent a consumptive use. New hydropower plants were assumed to be run-of-river, requiring no additional dams and were therefore also assumed to create no additional water use. Finally, although environmental management policies that lead to changes in water sources and/or cooling technologies can be modeled, no such policies were considered in RE Futures; instead, the distribution of water source and cooling technology were assumed to remain constant over time. Further documentation of the model can be found in Strzepek et al. (forthcoming).

For consistency, the model described in the preceding paragraph relied on a single data source for water withdrawals (Kenny et al. 2009). These data were then calibrated with the ReEDS-estimated dispatch of a historical (2006) year to estimate regional variations and calculate consumption values. From this calibration, the water withdrawal and consumptive factors for each cooling technology was found to vary widely between regions. However, even with these large regional variations, a simple comparison of water use factors by technology demonstrates how a shift from a predominance of thermal power plants (which include fossil and nuclear plants) to non-thermal electricity generators can reduce water use significantly. Figure A-19 and Figure A-20 show a range of water withdrawal and consumptive factors, respectively, by technology based on a literature survey of more than 40 published references (Macknick et al. 2011). Thermal plants, which include coal, nuclear, natural gas, and biopower, with once-through cooling systems, have withdrawal factors that range from 7,500 gal/MWh to 60,000 gal/MWh and consumptive factors that range from 20 gal/MWh to 400 gal/MWh. Thermal plants with

[234] Life cycle water demands would likely only be significant for dedicated crops, which may be rain-fed or may require additional irrigation; there would not likely be significant net increased water demands for biomass feedstocks derived from crop or forestry residues, municipal wastes, or other such sources. Depending on the rate and timing of irrigation, the water demands for irrigated dedicated crops can be substantial.

[235] The cost and performance estimates for CSP and geothermal were based on dry-cooling. Dry-cooling technologies also exist for some fossil plants and this potential was not considered in RE Futures because the cost and performance estimates for fossil technologies presented earlier represented wet-cooling and because most fossil, and particularly coal, plants in the scenarios represent existing plants and not new plants with new cooling technologies. However, if dry-cooling was used for fossil plants, the water benefits associated with the high renewable penetration scenarios reported in this section would be reduced.

re-circulating cooling technologies have much lower withdrawal factors (150–2,600 gal/MWh) but increased consumptive factors (130–1,100 gal/MWh). As shown in Figure A-19 and Figure A-20, natural gas CC plants have water use factors that are typically less than for thermal steam plants, but are still significantly higher than non-thermal or dry-cooled power plants.[236] Water use withdrawal rates for technologies that utilize dry-cooling, such as for CSP and geothermal plants assumed in RE Futures, were found to be only 0–270 gal/MWh.[237] Non-thermal technologies have water use factors that are orders of magnitude less than that of thermal technologies. The ranges in water withdrawal (and consumption, as it is assumed that all water withdrawn is also consumed for the non-thermal technologies) factors for PV and wind are 26–33 gal/MWh and 0–1 gal/MWh, respectively.

To represent a reasonable range of results, water withdrawals and consumption associated with power generation were estimated for each BA under four specific scenarios: Low-Demand Baseline, (low-demand) 80% RE-ITI, High-Demand Baseline, and High-Demand 80% RE.[238] Estimated water usage in 2050 associated with all cooling technologies (as well as water used for dry-cooling and non-thermal plant operations) was calculated, as was the type of water (freshwater and saline). For context, these figures were compared to total contiguous U.S. power sector water withdrawals and consumption in 2006, which were estimated to be 206,000 Mgal/day and 7,600 Mgal/day, respectively. National results from this analysis, in comparison to 2006 power generation water usage, are shown in Figure A-21.

[236] Water use factors for natural gas combustion turbine plants, not shown here but included in the RE Futures analysis, are significantly smaller than other thermal plants.
[237] Dry-cooled facilities were assumed in RE Futures for these renewable technologies, but recirculating cooling systems are also possible. Due to uncertainty in the literature, consumption values were conservatively assumed to equal withdrawal values. Ranges of water use for wet-cooled CSP systems are 750–1,000 gal/MWh. For geothermal-hydrothermal technologies, the range is approximately 1,700–4,000 gal/MWh, but nearly all of that water can be geothermal fluids, not freshwater.
[238] Although the analysis was not conducted for other scenarios, the results presented here for the 80% RE-ITI scenario are likely to be similar to results for other (low-demand) 80% RE scenarios. In addition, the optimization routine of the ReEDS model does not consider water constraints; therefore, the deployment decisions do not take water availability into account. The deployment results would change were these considerations included in the modeling.

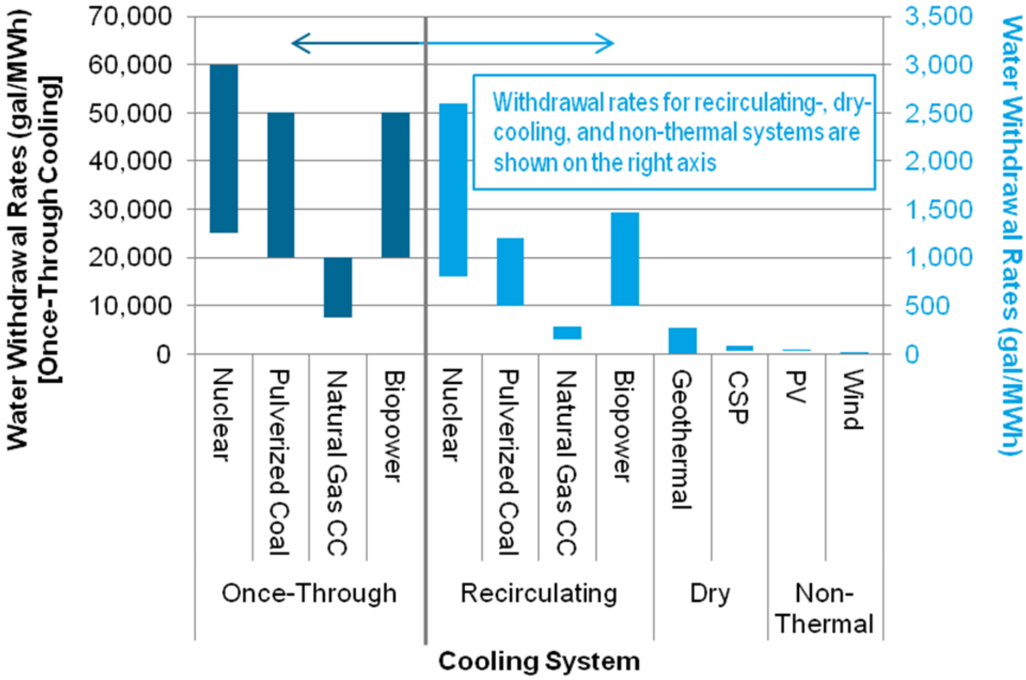


Figure A-19. Overview of water withdrawal factors by technology based on Macknick et al. 2011

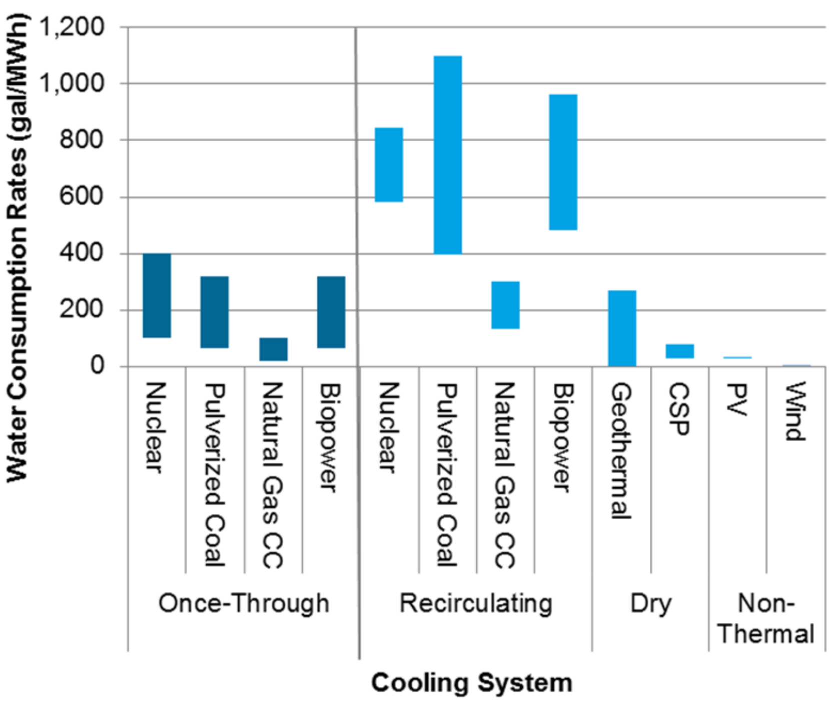
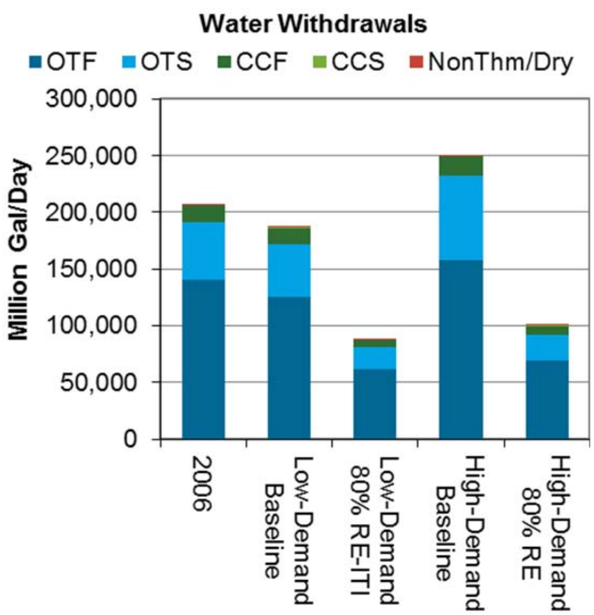
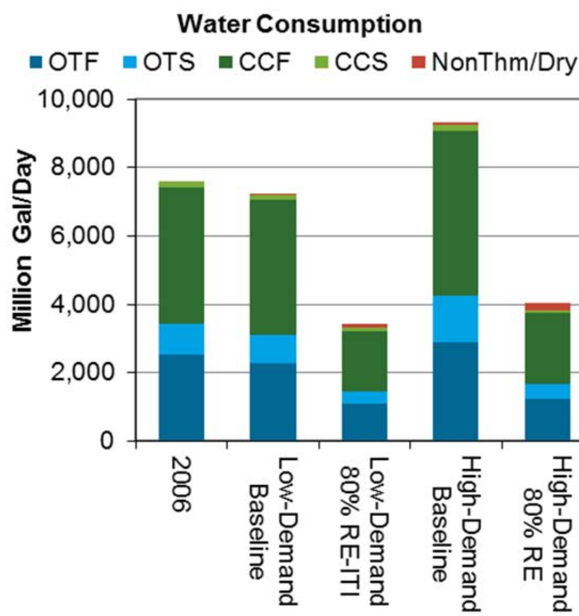


Figure A-20. Overview of water consumption factors by technology based on Macknick et al. 2011

Figure A-21(a) shows that, under the Low-Demand Baseline scenario, annual water withdrawals are estimated to decrease by 10% from 2006 to 2050, even though total electricity generation increases by 7% over the same time frame; the replacement of retiring coal and nuclear units with relatively low water-using natural gas and renewable energy technologies explains these opposing trends. Estimated reductions in water withdrawals were found to be much more significant under the 80% RE-ITI scenario, where electric-sector water withdrawals by 2050 were estimated to be 58% less than the 2006 figure and 53% less than the 2050 estimate under the Low-Demand Baseline scenario. The more-traditional high-demand scenarios were estimated to require much greater amounts of water withdrawals than the lower-demand scenarios. For example, national water withdrawal in 2050 under the High-Demand Baseline scenario was estimated to be 21% greater than water withdrawals in 2006. Even under these higher-demand assumptions, however, water withdrawals were found to decline from 2006 levels when 80%-by-2050 renewable electricity penetration was achieved; water withdrawals in 2050 under the High-Demand 80% RE scenario were estimated to be 51% less than 2006 power-sector withdrawals, and 60% less than 2050 withdrawals in the High-Demand Baseline scenario. Results are not proportional between low and high demand cases due to different types of technologies meeting demands. Again, these findings exclude any water demands required for bioenergy crops.



(a) Water withdrawals



(b) Water consumption

Figure A-21. Contiguous U.S. water use under Low-Demand 80% RE-ITI and High-Demand 80% RE, and corresponding baseline scenarios in 2050 in comparison to use in 2006

OTF, OTS, CCF, and CCS refer to once-through cooling using freshwater, once-through cooling saline water, re-circulation cooling using freshwater, and re-circulation cooling using saline water, respectively. NonThm/Dry refers to non-thermal or dry-cooled generation technologies.

The majority of water withdrawals, under all four scenarios, were found to be associated with freshwater cooling systems. Changes in saline water use, however, can have important regional implications, especially in water-stressed basins, if existing saline water uses are displaced by freshwater uses. Under the lower-demand scenarios, there were two coastal water-stressed regions in California that were found to have decreasing total water withdrawals and consumption relative to 2006 values, but in which freshwater withdrawals and consumption were higher under the 80% RE-ITI scenario than they were under the Low-Demand Baseline scenario. A similar situation was observed under the higher-demand scenarios with two regions located in California and Texas. In these instances, power plants using saline water were found to retire, driving down saline and total water withdrawals and consumption, but resulting in an increase in freshwater withdrawal and consumption associated with newly built plants. Though such a shift may be beneficial for marine environmental reasons, it may not be the preferred option due to the potentially greater value of freshwater resources (compared with saline water) in coastal water-stressed regions. These issues highlight the regional nature of water concerns.

Trends in water consumption were found to largely follow trends in withdrawals. Total water consumption for power generation under the 80% RE-ITI scenario and the High-Demand 80% RE scenario were found to be lower than both 2006 values and estimated water consumption in 2050 in the corresponding baseline scenarios. For the 80% RE-ITI scenario, water consumption in 2050 was estimated to be 53% lower than the 2050 consumption amount in the Low-Demand Baseline scenario, and 55% lower than 2006 consumption. For the High-Demand 80% RE scenario, reductions in 2050 water consumption were 57% and 47% compared with the High-Demand Baseline scenario and 2006 consumption, respectively. Whereas re-circulation cooling technology contributed to less than 8% of national water withdrawals for electric power generation, it is found to contribute to over 50% of water consumption due to power generation in all scenarios. Non-thermal water consumption was found to be very modest across all scenarios.

Although the estimates in Figure A-21 are focused on consumption and withdrawal at the national level, the importance of water usage is primarily a local and regional issue. In particular, even though electric sector water use in the western half of the contiguous United States is significantly less than in the eastern half (due in part to the significantly higher electricity demands in the east), most western states are water-stressed, whereas water availability is generally not of critical concern in many eastern states. To demonstrate the regional nature of water concerns, Figure A-22 shows estimated regional reductions (and increases) in water consumption (in Mgal/day) in 2050 for the 80% RE-ITI scenario compared with the Low-Demand Baseline scenario. To highlight further the local importance of water impacts, the figure focuses entirely on regions that are classified as water stressed; non-stressed regions are shown in gray.[239] Increases in water intensity (in gal/MWh) are also indicated in Figure A-22, where a plus sign (+) is placed in regions

[239] For the purposes of this analysis regions are simply classified as "water stressed" when total water withdrawal rates are greater than 60% of mean annual runoff. Other definitions may identify different regions than those highlighted in Figure A-22.

where the water intensity in the 80% RE-ITI scenario was higher than in the Low-Demand Baseline scenario. Other 80% renewable electricity scenarios evaluated may have somewhat different regional water use impacts, due to varying deployments of different renewable energy technologies, though the national water use trends presented earlier would largely hold for all 80% RE scenarios evaluated in Chapter 3.

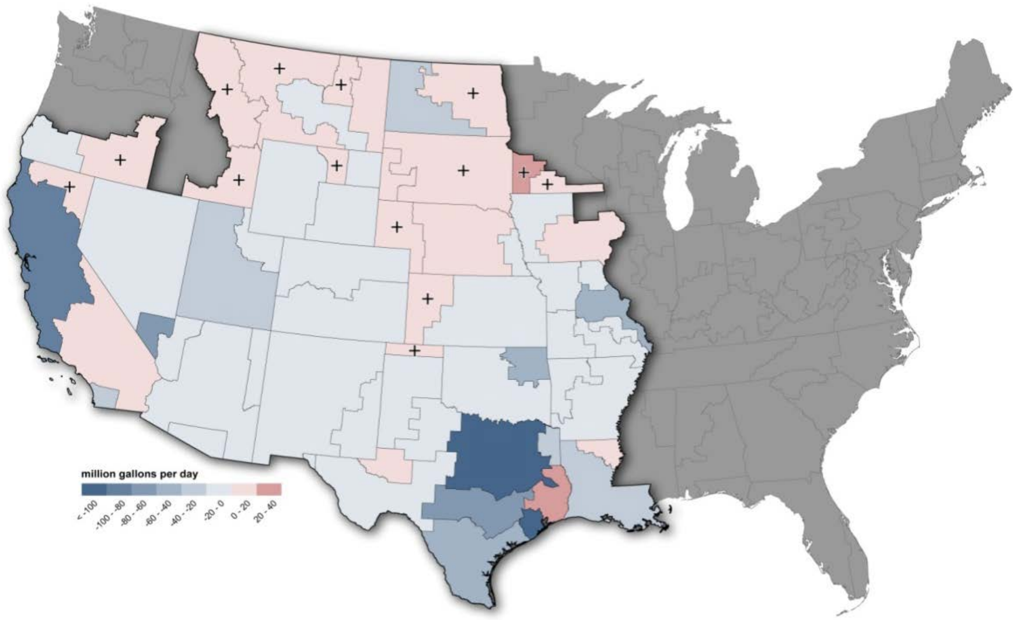


Figure A-22. Change in 2050 water consumption between 80% RE-ITI and Low-Demand Baseline scenarios

Gray areas denote regions that are not considered water-stressed. Colors indicate absolute changes in water consumption. Plus signs indicate areas where the water use rate (in gal/MWh) increased.

For a majority of water-stressed regions, total power-sector water consumption in 2050 was found to decline under the 80% RE-ITI scenario relative to the Low-Demand Baseline scenario. Total water consumption was estimated to increase on a percentage basis in some regions of the Northwest and Midwest largely due to the thermoelectric cooling demands of new biopower facilities in those regions; nonetheless, the absolute increase in water consumption in those cases was found to be modest. There were also regions in California, Oklahoma, and Texas that were found to witness potential increases in total water consumption—in these cases, this was due to new thermal power plants needed to meet electricity demand.

Large increases in renewable electricity generation in the arid Southwest may lead to concerns about local water conflict hotspots where the demands for process and cleaning water is greater than local water availability or where CSP or geothermal plants use wet-cooling rather than dry-cooling. As indicated by Figure A-22, however, water consumption was found to decline in most areas of the Southwest, despite the fact that many of these areas are net exporters of electricity and generate more electricity in the

80% RE-ITI scenario than they do in the Low-Demand Baseline scenario. This is because areas in the Southwest likely to see the most solar, geothermal, and other forms of renewable energy deployment also show declines in water use because of displaced conventional generation. As a result, the water intensity (in gallons per megawatt-hour) of electricity generation in the southwestern states was found to decline under the 80% RE-ITI scenario as more water-efficient renewable generating technologies were deployed in the region. Although this result is based, in part, on an assumption that CSP and geothermal plants operate with dry-cooling technology, even limited use of wet-cooling in these regions would not fully offset the estimated reduction in water consumption.

4.3 Many of the Environmental and Social Concerns Associated with Renewable Energy Technologies Relate to Land Use

Renewable generation facilities often require significant amounts of land to capture diffuse energy flows. Some of the land-use implications of the six low-demand core 80% RE scenarios and the High-Demand 80% RE scenario are summarized in Table A-10.

Table A-10. Land-Use Implications of Low-Demand Core 80% RE Scenarios and the High-Demand 80% RE Scenario[a]

Renewable Technology	Land Use Factor	Total Land Use (000s of km^2) Low-Demand Core 80% RE Scenarios	High-Demand 80% RE Scenario	Description[b]
Biopower	25,800 $GJ/km^2/yr$	44–88	87	Land-use factor uses the midrange estimate for switchgrass in Chapter 6 (Volume 2). Other waste and residue feedstocks are assumed to have no incremental land use demands.
Hydropower	1,000 MW/km^2	0.002–0.10	0.06	Assumed only run-of-river facilities, with land use based only on facility civil works with no flooded area. Although not evaluated here, inundated area associated with run-of-river facilities would increase these values.
Wind (onshore)[c]	5 MW/km^2	48–81 (total) 2.4–4 (disrupted)	85 (total) 4.2 (disrupted)	Most of the land occupied by onshore wind power plants can continue to be used for other purposes; actual physical disruption for all related infrastructure for onshore projects is approximately 5% of total.
Utility-scale PV	50 MW/km^2	0.1–2.5	5.9	Direct land use of modules and inverters.
Distributed Rooftop PV	0	0	0	Systems installed on rooftops do not compete with other land uses and no incremental land use is assumed here.
CSP[d]	31 MW/km^2	0.02–4.8	2.9	Overall land occupied by CSP solar collection fields (excluding turbine, storage, and other site works beyond mirrors).
Geothermal	500 MW/km^2	0.02–0.04	0.04	Direct land use of plant, wells and pipelines.
Transmission	See Description	3.1–18.6	18.1	Assuming an average new transmission capacity of 1,000 MW and a 50-m right-of-way.
Storage	See Description	0.017–0.030	0.025	Land-use factors of 1,100 m^2/MW, 500 m^2/MW, and 140 m^2/MW were assumed for PSH, batteries, and CAES, respectively. See Chapter 12 (Volume 2) for details.

[a] The data presented here represent impacts associated with new facilities required to meet the 80%-by-2050 renewable electricity target (they do not consider land-use impacts of existing generation facilities).
[b] See Volume 2 for additional details and references.
[c] Assuming the same 5 MW/km^2 for offshore wind projects (a conservative figure based on actual developments in Europe), those projects would require an additional total ocean area of 11,000–37,000 km^2, very little of which would be physically disturbed.
[d] The 31-MW/km^2 value was applied to the turbine capacity, and it corresponds to systems with a solar multiple of 2 and 6 hours of storage. Because systems built in ReEDS have variable solar multiples, the land use factors were scaled accordingly (e.g., the land use factor for a system with a solar multiple greater than 2 will be less than 31 MW/km^2).

Interpretation of the analysis presented in Table A-10 should be done with care. First, because the nature of the impacts varies substantially by technology, establishing fully comparable land-use impacts across technologies was not attempted. For example, although the land use of wind energy is often expressed as the total area of a wind power plant, only a small fraction (typically less than 5%) of that area is physically disturbed by turbine foundations, access roads, or other infrastructure; the remaining area can often retain its pre-existing application, such as farming or ranching. In contrast, an even greater area beyond the plant's physical boundaries may be visually impacted. Alternatively, for CSP and PV, the land-use factor of the power plant can be much higher, but the land-use intensity for these facilities is also much greater, with a larger fraction of the total area occupied by plant infrastructure. Second, although Table A-10 provides a single value for the estimated land-use factor for each technology, there is a significant range of reported values (e.g., Denholm et al. 2009b; Denholm and Margolis 2008). This is especially true for hydropower, where Fthenakis and Kim (2009) report a more than 1,000-fold difference between the land use for run-of-river plants (assumed in Table A-10) and reservoir hydropower projects. Third, Table A-10 presents *gross* land-use impacts associated with a number of 80%-by-2050 RE scenarios, ignoring the arguably more-important question of *net* impacts. Specifically, an 80% renewable electricity future would result in significant reductions in fossil and nuclear generation and related fuel supplies. The reduced burdens on land use associated with that displacement were not considered in Table A-10, but are significant.[240] Fourth, the values in Table A-10 are estimates of land use associated with generation facilities and fuel (in the case of biopower) and do not consider other upstream and downstream land-use implications (e.g., land use associated with technology supply chains).

With these caveats in mind, the largest land use associated with the 80%-by-2050 RE scenarios was found to come from dedicated biomass crops. Specifically, although nearly three-fourths of the biomass feedstock was predicted to come from wastes and residues (which were assumed to have no incremental land-use impacts), the remaining biomass supply was assumed to be derived from switchgrass, requiring an estimated 44,000–88,000 km^2 of land across the six low-demand core 80% RE scenarios, and 87,000 km^2 in the High-Demand 80% RE scenario. By comparison, the total area used for corn production in 2009 in the United States was about 350,000 km^2 (USDA 2010). Because biopower-related land use is estimated to be sizable, efforts are needed to assess the degree to which and conditions under which land is available to support such an expansion without undue competition with food production and other uses.[241]

Although land-use figures of the nature presented in Table A-10 are not strictly additive, the total land area required by the non-biomass renewable technologies was estimated to range from 52,000–81,000 km^2 across the six low-demand core 80% RE scenarios to 94,000 km^2 in the High-Demand 80% RE scenario. Much of that area derives from the aggregate footprint of wind power plants, much of which could continue to be used for other purposes, as described above. Focusing on the total disturbed area for wind energy leads to total land-use estimates for all non-biopower renewable technologies of 4,300–9,600 km^2 across the low-demand core 80% RE

[240] Taking a subset of these issues into consideration, for example, Fthenakis and Kim (2009) estimated the "life cycle" land disturbance of wind and solar energy to be lower than the impacts of coal-generated electricity, for which a significant land use is associated with coal mining.
[241] See Chapter 6 (Volume 2) for additional discussion of these issues.

scenarios, and up to 13,100 km^2 in the High-Demand 80% RE scenario. In addition to those demands, the increased transmission[242] among the low-demand 80% core RE scenarios and under the High-Demand 80% RE scenario yields land impacts that range from 3,000 km^2 to 19,000 km^2, while land impacts from the estimated deployment of new storage capacity is relatively minor, at less than 30 km^2 in total.

To put all of these land areas in context, the land area of the contiguous United States is 7,700,000 km^2, while the area of U.S. golf courses and major roads equal 10,000 km^2 and 49,000 km^2, respectively (Denholm and Margolis 2008). Under conservative estimates (i.e., assuming that the land uses across technologies are additive, ignoring the smaller fraction of land that would be physically disturbed, not accounting for land impact reductions through reduced fossil energy and uranium consumption, and selecting the highest land use scenarios), new renewable technologies required for 80% renewable electricity generation are estimated to impact less than 3% of the land area of the contiguous United States.

By comparison, the land use associated with non-renewable energy sources represents a continuous and additive process due to the need for continuous fuel supply. For example, each gigawatt-hour of energy sourced by coal in the United States requires the disturbance of (on average) about 340 m^2, but with a large variation depending on mining method and location (Fthenakis and Kim 2009).[243] Estimates of the impact of natural gas and uranium extraction and processing are about 100 m^2/GWh and 40 m^2/GWh, respectively (Fthenakis and Kim 2009). These reported area values do not include the footprint of the power plants, which are relatively small, or the area of other natural gas infrastructure, which can be large but is typically used for purposes well beyond electricity generation. These areas also do not include land set aside for nuclear waste disposal. Considering only the fuel mining, extraction, and processing steps, among the six low-demand core 80% RE scenarios, renewable energy displaces conventional generation that would otherwise require land transformation of approximately 13,000 km^2, with the large majority of that (12,000 km^2) due to coal mining. (This is based on a cumulative reduction in coal generation from the baseline scenario of approximately 35,000 TWh from 2011 to 2050, and reductions in natural gas and nuclear generation of approximately 14,000 TWh and 750 TWh, respectively, over the same period). In addition, after 2050, fossil energy and uranium extraction and processing would continue to require additional new land every year under a high conventional system, whereas the high renewable system would generally not require additional land area (except to meet net expansion of demand).

In addition to the magnitude of land use, another important consideration is the "value" of the land-use impact; this impact will vary regionally and with public perception of land uses. Consistent methodologies to evaluate the relative impact of energy generation land use do not

[242] As noted in Table A-10, the land-use values for transmission assumed a 50-m right-of-way. However, the disrupted land for new transmission lines can be smaller than that reported here (e.g., through having new lines along railway tracks).

[243] Fthenakis and Kim (2009) shows that the overall range of estimates for coal land use is as low as 2 m^2/GWh for one underground mining estimate to 1450 m^2/GWh for one above ground mining estimate. The value used in this study (340 m^2/GWh) is based on the weighted average of surface and underground mining.

exist, but such methodologies are necessary in order to provide a more direct comparison among these technologies.

4.4 Other Environmental and Social Implications of Renewable Energy Technology Deployment

In addition to land-use concerns, renewable energy can have certain detrimental environmental and social impacts. The environmental impacts of renewable energy deployment are as diverse as the technologies themselves. Some of the most prominent concerns are *briefly* highlighted here, and listed in Table A-11. Additional details and citations on the impacts and their possible mitigation are provided in Volume 2.

- **Biopower:** For biopower, a principal concern is that the cultivation of biomass could lead to significant secondary GHG emissions, conflicts with land used for food production, and loss of biological diversity when undisturbed lands are cultivated for biomass. Additionally, the consumptive water use of biopower plants during electricity production is comparable to that of coal, and water may be used to grow certain biomass feedstocks. Finally, biopower facilities emit air pollutants of various types and quantities, depending on the specific characteristics of the fuel and plant. Some of the land-use impacts noted can be mitigated if appropriate management practices are employed.
- **Geothermal Energy:** Some site-specific concerns can and do exist, including water use and environmental contamination, the potential for subsidence (a slow sinking of the land surface) and induced seismic activity. Newer geothermal energy technologies and power plants, including those employing dry-cooling, have largely alleviated concerns over water use for cooling.
- **Hydropower:** New hydropower reservoirs require the flooding of land and river habitats and, in some circumstances, can lead to the displacement of human populations. Hydropower facilities may also impact the health and movements of migratory fish, and degrade river habitats below the dams and in the resulting reservoirs. As a consequence of these concerns, RE Futures assumed that all new hydroelectric power plants were run-of-river facilities, of varying designs, with federal and environmental exclusions applied.
- **Ocean Energy:** Ocean energy technologies are still in development, and a comprehensive understanding of their environmental and social impacts does not yet exist. However, potential concerns include the ecological impacts of the withdrawal of wave and tidal energy from the oceans, direct interactions between the generation technologies and marine life, visual impacts, and conflicts with other uses of oceans.
- **Solar Energy:** The main concerns associated with solar energy technologies include water use (primarily CSP with wet-cooling but also in PV manufacturing) and land use (utility-scale PV and CSP). Water demand for CSP operation is a concern because wet-cooled CSP plants use a similar amount of water as conventional thermal generators. CSP systems can be designed to use dry-cooling, thereby reducing water demand by approximately 90% while adding 5%–10% to the capital cost of a project. Proper siting of PV manufacturing facilities can help mitigate water use concerns. Finally, land-use

concerns can also be reduced through careful site selection to avoid sensitive ecological areas and potential conflicts with other land uses.

- **Wind Energy:** For wind energy, the main social concerns are visual, landscape, and noise impacts, whereas the principal ecological concerns are related to wildlife. With regard to ecological concerns, implications for bird and bat populations through direct collisions with turbines and habitat disruption are most commonly voiced, but as turbines have been deployed offshore, concerns about marine life have also been raised. Better-informed siting practices and regulations offer the greatest potential for the mitigation of both ecological and social concerns.

Table A-11. Principal Environmental Concerns Associated with Renewable Energy Technologies[a]

Technology	Principal Environmental and Social Concerns
Biopower	• Land-use changes, with potential negative implications for GHG emissions, food supply, and biodiversity • Water use for power plant operation and for biomass feedstock supply • Emissions of air pollutants
Geothermal Energy	• Local water use and environmental contamination • Subsidence (slow sinking of the land surface) • Induced seismic activity
Hydropower	• Flooding of land and river habitats, potential displacement of human populations • Health and movements of migratory fish • Degradation of river habitats below dams and habitats in reservoirs
Ocean Energy	• Concerns regarding direct interactions between generators and marine life • Ecological impacts of withdrawal of wave and tidal energy • Potential visual impacts and conflicts with other uses of oceans
Solar Energy	• Managing water use for CSP plants and PV manufacturing facilities • Land-use change with impacts on ecosystems and competing land uses
Wind Energy	• Visual, landscape, and noise impacts of wind turbines • Impacts on bird and bat populations; habitat disruption

[a] See Volume 2 for additional discussion, literature references, and mitigation approaches.

Addressing the environmental and social concerns associated with renewable energy facilities, feedstocks, and related infrastructures is an essential part of national, regional, and local planning and siting processes. Even if environmental impacts are minimized through proper planning and siting procedures and community involvement, some impacts will remain. In part as a result, renewable energy projects, as with other forms of energy development, often face lengthy siting and permitting processes, in large measure because of concerns about local impacts. Efforts to better understand the nature and magnitude of those impacts, and measures to minimize and mitigate the impacts, will likely be needed to support the continued growth of renewable electricity generation.

4.5 Indirect Implications of High Renewable Electricity Futures

There are a variety of indirect (or downstream) implications that may result from the direct electric sector cost, environmental, and social implications identified above. For example, incremental investment in generation capacity and associated infrastructure will have implications related to economic activity and employment in the energy industry. Reductions in fossil energy consumption will have environmental implications beyond air emissions, including related to water quality, terrestrial and marine contamination, and waste disposal, not only associated with electricity generation facilities but also for activities related to fuel extraction and transportation. Further, air emissions reductions will have implications for human health and climate change. Identification, and in some cases quantification, of these indirect implications is an active area of wide-ranging research. While this analysis does not attempt to evaluate these indirect impacts of high renewable electricity futures in a comprehensive manner, examples of these implications are described in this section and include reductions in global damages associated with carbon emissions, public health and environmental benefits from reductions in criteria emissions, and reductions in price risks with fossil fuel consumption.

4.5.1 Reductions in Global Damages Associated with Carbon Emissions

Under Executive Order 12866, released in 1993, U.S. agencies are required, to the extent permitted by law, to assess even difficult-to-quantify costs and benefits during regulatory proceedings. To that end, a broad, Interagency Working Group (IWG)[244] developed estimates of the global social cost of carbon that regulatory agencies in the United States are to use in their regulatory deliberations when assessing the potential social benefits of reducing carbon emissions (IWG 2010). The global social cost of carbon is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year, reflecting (among other things) impacts on agricultural productivity, human health, property damages, and ecosystem services.

The IWG developed four trajectories for the global social cost of carbon covering the 2010–2050 time period, as summarized in Table A-12.[245] Three of these are based on average values from three integrated assessment models, at discount rates of 2.5%, 3%, and 5%. The fourth represents the 95th percentile of the estimates for the global social cost of carbon across all three models at a 3% discount rate, and it is intended to represent higher-than-expected impacts from climate change.

[244] U.S. agencies actively involved in the process included the Environmental Protection Agency and the Departments of Agriculture, Commerce, Energy, Transportation, and Treasury. The Council of Economic Advisors and the Office of Management and Budget convened the process, with active participation from the Council of Environmental Quality, National Economic Council, Office of Energy and Climate Change, and Office of Science and Technology Policy.

[245] The IWG acknowledged the substantial uncertainties involved with such estimates and the need to update the estimates over time to reflect the growing knowledge of the science and economics of climate impacts. The IWG notes that these estimates apply to regulatory decisions that are expected to have small or “marginal” impacts on cumulative global emissions, and reflect the U.S. contribution to and share of global costs of carbon emissions. The social cost of carbon estimated by the IWG, summarized in Table A-12, reflects the impact of incremental CO_2 emissions on global damages.

Table A-12. Estimated Global Social Cost of Carbon Dioxide (2007$/t$CO_2$)

Year	Average, 5% Discount Rate	Average, 3% Discount Rate	Average, 2.5% Discount Rate	95th Percentile, 3% Discount Rate
2010	4	21.4	35.1	64.9
2020	6	26.3	41.7	80.7
2030	9	32.8	50.0	100.0
2040	12	39.2	58.4	119.3
2050	15	44.9	65.0	136.2

In addition to the IWG analysis on global damages associated with carbon emissions, there exists a large body of work on carbon mitigation. The broader carbon reduction modeling literature is summarized in the IPCC's Fourth Assessment Report (IPCC 2007) and elsewhere (e.g., Edenhofer et al. 2010; Fawcett et al. 2009). Specifically, IPCC (2007) reported the results of a wide range of modeling studies, including results on carbon prices needed to meet varying climate stabilization levels. Edenhofer et al. (2010) and Fawcett et al. (2009) also provide carbon price estimates based on multi-model analyses.

Though not analyzed in RE Futures, the carbon emissions reductions anticipated under higher renewable electricity generation scenarios (see Section 4.1) could reduce climate change related damages and be compared to the broader literature on the economics of carbon mitigation.

4.5.2 Public Health and Environmental Impacts of Reductions in Criteria Pollution

The National Research Council (NRC 2010) leveraged existing literature to define and, where possible, quantify the external effects of energy systems, including electricity generation technologies. External effects were considered over the entire life cycle of each technology, including fuel and raw material extraction, energy production, distribution and use, and disposal of waste products. Quantitative damage estimates focused on air pollutant emissions, and specifically particulate matter, sulfur dioxide (SO_2), and oxides of nitrogen (NO_x). Damages evaluated by the NRC study included human morbidity and mortality, grain crop and timber yields, building materials, recreation, and visibility of outdoor vistas. Other research similar to the NRC effort includes the European Union's Externalities of Energy and New Energy Externalities Development for Sustainability studies (e.g., European Commission 2003; Ricci 2008). Others have carried out related research, sometimes in the specific context of renewable energy generation (e.g., Owen 2004; Sundqvist 2004; Fthenakis and Alsema 2006; Rafaj and Kypreos 2007).

Although the NRC (2010) study is the most recent and authoritative synthesis of externalities estimates for electricity generation technologies in the United States, there are limitations to the broader use of its estimates in the context of RE Futures. Chief among these limitations is that externalities associated with the deployment of renewable electricity technologies were only considered qualitatively: wildlife impacts were cited for wind energy, land use and heavy metal releases for solar, and land use and water emissions from field runoff for biopower. As importantly, for reasons discussed in Section 4.1.3, RE Futures did not seek to quantify the reductions in criteria air pollution emissions that might occur as a result of higher levels of renewable generation. Moreover, even for the non-renewable technologies where impact quantification was conducted by the NRC, significant uncertainties exist in the resulting cost figures. In addition, the impact estimates provided by the NRC for conventional, non-renewable technologies underestimate damages because the scope of the NRC study was limited. Due to data and methodological limitations, for example, the NRC was unable to quantify economic damages associated with many impact categories for conventional fossil and nuclear energy generation as well as upstream impacts associated with coal and natural gas extraction, mining, production, and transport.[246]

Focusing solely on particulate matter, SO_2, and NO_x, the NRC (2010) estimated that in 2005 the emissions from 406 U.S. coal-fired power plants caused aggregate damages of $62 billion, mostly from a relatively small subset of the most polluting facilities and primarily from SO_2 emissions. Averaged over the electricity generated from all coal facilities, damages were estimated to be $32/MWh. Based on a variety of assumptions, the NRC (2010) estimated that these damages might decrease to $38 billion/yr by 2030, or $17/MWh. Pollution damages from gas-fueled plants tend to be lower than those from coal plants; the NRC's sample of 498 gas facilities produced damages in 2005 estimated at $740 million, or $1.6/MWh when weighted by plant-specific net generation. Based on a variety of assumptions, the NRC (2010) estimated that these damages might decrease to $650 million by 2030, or $1.1/MWh. Table A-13 presents some of these results by the select pollutants analyzed by the NRC, focusing on the 2005 results.

Table A-13. Damage Estimates for Coal and Natural Gas Facilities in the United States in 2005 (NRC 2010)

Pollution Damages Per-Unit Damages (2007$/MWh)	Coal (406 plants)	Natural Gas (498 plants)
SO_2	$38/MWh	$0.18/MWh
NO_x	$3.4/MWh	$2.3/MWh
$PM_{2.5}$	$3.0/MWh	$1.7/MWh
PM_{10}	$0.17/MWh	$0.09/MWh
Total, Equally Weighted	$44/MWh	$4.3/MWh
Total, Weighted by Net Generation	$32/MWh	$1.6/MWh
Total Aggregate Damages (Billion 2007$)	$62 billion	$0.74 billion

The pollutant-specific damages in dollars per megawatt-hour, as well as the total equally weighted damages, are estimated by weighing all plants equally. The total damages weighted by net generation is weighted by the electricity generated by each plant to produce a weighted damage per kilowatt-hour.

[246] Upstream and downstream impacts associated with conventional technologies not quantified by the NRC include heavy metal releases; GHG; radiological releases; waste products, land use, and water quality impacts associated with power production and upstream fuel production; noise; aesthetics; and many other impact categories.

Though not analyzed in RE Futures, renewable electricity supply is also expected to reduce criteria air pollution, yielding potential public health and environmental benefits.

4.5.3 Reductions in Price Risks Associated with Fossil Fuel Consumption

Traditional energy planning focuses on finding least-cost sources of supply. In balancing different electricity supply options, however, electricity retailers, resource planners, and policymakers also consider the unique risk profiles of each generating source and different portfolios of multiple generation sources. Though renewable energy sources are not free of risk (issues of short-term output variability, for example, were addressed extensively in Chapters 2–4 and Volume 4), one beneficial aspect of these technologies is that they often rely on fuel streams that are not subject to resource exhaustion or severe long-term price variability and uncertainty. Fossil energy generation, and especially natural gas, on the other hand, rely on fuels that can and have experienced substantial price volatility, and for which price forecasts have been decidedly poor (see Figure A-9).

Increased use of renewable electricity may mitigate those risks in two ways. First, by reducing demand for exhaustible fossil energy, the use of renewable energy can place downward pressure on natural gas and coal prices, with benefits to energy consumers. Second, by providing electricity purchasers with a long-term fixed-price source of supply (at least when sold under a traditional power sales contract), the use of renewable energy can directly offset the use of fuel streams with uncertain and variable prices.

Achieving higher levels of renewable electricity generation would reduce demand for natural gas and coal, placing downward pressure on prices for those two commodities. The magnitude of the estimated price reduction will depend on the shape of the natural gas and coal supply curves, and the degree of demand reduction. To be clear, the direct impacts of these gas and coal price reductions do not necessarily represent an increase in aggregate economic wealth; they may be more accurately understood as a reduction in costs for consumers with a corresponding reduction in sales revenue by natural gas and coal producers. Additionally, the exact magnitude of this price reduction effect is subject to considerable uncertainty. Regardless, a large number of modeling studies and some empirical literature have demonstrated that these effects may provide significant consumer savings (e.g., Wiser and Bolinger 2007), and though not necessarily leading to an aggregate net increase in economic wealth, the policy community may nonetheless be interested in understanding the potential magnitude of consumer savings involved.

The consumer benefits of these lower fuel prices for the remaining coal and natural gas electricity generation in the 80% RE scenarios were included in the electricity system cost and retail electricity price results presented in Section 3. The spillover consumer benefits of these price reductions in other (non-electric) segments of the energy economy, however, were ignored in the results presented in Section 3. Those spillover benefits can be estimated by considering natural gas and coal demand outside of the electricity sector.[247]

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[247] Note that the fossil energy price savings presented in Section 3.3.4 may overestimate the savings to non-power sector consumers because they ignore any rebound effect in the use of natural gas or coal outside of the electricity sector that may be caused by the lower prices.

In addition to reducing fossil energy prices through lower electric sector consumption, achieving higher levels of renewable electricity generation may also directly hedge against fuel price volatility. A variety of methods have been used to assess and sometimes quantify the benefits of fixed-price renewable energy contracts relative to variable-price fossil generation contracts, as well as the benefits of electricity supply diversity more generally. These methods have included risk-adjusted discount rates (e.g., Awerbuch 1993); Monte Carlo and decision analysis (e.g., Wiser and Bolinger 2006); portfolio theory (e.g., Bazilian and Roques 2008); market-based assessments of the cost of conventional fuel-price hedges (e.g., Bolinger et al. 2006); and various diversity indices (e.g., Stirling 1994, 2010). Many of these methods have proven controversial, and a single, standard approach to benefit quantification has not emerged. The results of the Lower Fossil Fuel Costs and Higher Fossil Fuel Costs scenarios summarized earlier provide an illustration of the benefits of renewable energy in offsetting fossil energy price risks. Specifically, due to the lower capacity and use of fossil technologies in the 80% RE scenarios, fossil fuel prices have a relatively smaller impact on the 80% RE scenarios than on the baseline scenarios. As shown in Section 3.3.4, for example, when base fossil fuel prices were altered by +/- 30%, retail electricity prices in 2050 under the baseline scenario changed by -3.3% and +3.1%, whereas the range was considerably narrower in the 80% RE scenarios: -0.3% to +0.8%.[248]

4.6 Summary of Environmental and Social Implications of High Renewable Electricity Futures

Most of the environmental and social implications of high renewable electricity generation scenarios presented above are directly or indirectly associated with the reduction in electric sector fossil energy consumption. The analysis demonstrated that a transformation of the U.S. electricity system from one dominated by fossil energy to one significantly relying on renewable generation could lead to significant reductions in greenhouse gas emissions, criteria pollutant emissions, and water use. Renewable technologies also have environmental and social impacts, including land-use impacts.

The above analysis does not attempt to identify *all* of the implications of high renewable electricity futures. As such, a full accounting of the costs and benefits of high levels of renewable generation was not possible. In addition, weighing the costs and benefits of future energy choices is extremely difficult because there are substantial challenges to placing all costs and benefits on a consistent basis (e.g., not all costs and benefits can be easily monetized). Finally, there are significant inherent uncertainties with respect to future electricity demand, technology improvements, fossil energy prices, social and institutional choices, and regulatory and legislative actions related to the scenarios examined that in turn contribute to significant uncertainty in the implications reported above.

[248] For the alternative fossil fuel cost scenarios presented in Section 3.3.4.1, 2050 natural gas prices varied by approximately +/- $1.5/MMBtu and 2050 coal prices varied by approximately +/- $0.4/MMBtu for the baseline and 80% RE scenarios. Retail electricity prices in 2050, however, varied considerably more in the baseline scenarios (+/- $4/MWh) compared with variations in the 80% RE scenarios. (+/- $1/MWh).

5. Conclusions

The analysis presented in Chapters 1–4 primarily focuses on the deployment of renewable technologies and the operational characteristics of systems with high renewable electricity penetration. The analysis relies on a large number of scenarios modeled using the ReEDS model, a state-of-the-art techno-economic capacity expansion model, and GridView, a commercially available hourly production cost model. This appendix supplements Volume 1 by examining other implications of high renewable electricity deployment. In particular, the appendix summarizes the major technology cost and performance assumptions used in the scenario modeling, describes the direct electric sector cost implications of the various scenarios explored, and assesses some of the direct environmental and social implications of high renewable penetration, including those associated with reduced fossil energy consumption.

The analysis is also subject to the uncertainties described earlier, along with modeling and data limitations. Despite these uncertainties and limitations, the findings can provide insights into some of the major implications of high renewable electricity deployment. These findings are summarized as follows:

- Achieving very high levels of renewable electricity penetration requires increased *direct electric sector* investments, including higher system costs and electricity prices, if renewable technologies have incremental or evolutionary improvements.
- Moderate to high levels of renewable electricity penetration may be achieved without significant direct electric sector incremental cost. For example, with evolutionary renewable technology improvements (RE-ETI), the 2050 retail electricity price of the 30% RE scenario and the present value of system cost (3% discount rate, 2011–2050) of the 50% RE scenario were slightly lower than that of the baseline scenario with more limited incremental renewable technology improvements (RE-ITI).
- For the low-demand 80%-by-2050 renewable electricity scenarios, additional direct electric sector investments were estimated to result in average annual retail electricity price increases of 0.8%–1.2% per year (2011–2050, in real dollar terms), compared to a rate of 0.3% per year in the baseline scenario.
- There are multiple technology pathways to achieving high renewable electricity penetration *with similar direct electric sector costs*: System constraints, including constraints to transmission, system flexibility, and resource accessibility, were found to have only modest impact on direct electric system costs.
- Among all drivers examined, reduced technology cost reflecting future renewable technology improvements most significantly influence the incremental system cost of achieving high levels of renewable electricity generation.
- Higher demand growth raises direct electric sector costs for the baseline and high renewable scenarios. The *incremental* cost associated with 80% renewable electricity generation, in comparison to the high demand baseline, however, is reduced with higher demand growth.

- The incremental direct electric sector cost associated with 80% renewable electricity generation by 2050 is inversely related to fossil fuel prices. The same relationship was found with respect to fossil technology costs, but to a lesser degree. In addition, due to the lower capacity and use of fossil technologies in the 80%-by-2050 RE scenarios, the cost associated with high renewable generation is much less sensitive to changes in fossil energy price than the cost of the baseline scenario.
- Relative to 2010 levels, the low-demand 80%-by-2050 scenarios resulted in reductions in annual power sector fossil energy consumption of roughly 80% for both coal and natural gas.
- At 80% renewable electricity, annual GHG emissions in 2050 in the U.S. power sector were reduced by approximately 80% on a direct combustion basis and on a full life cycle basis, excluding impacts associated with land-use change.
- The 80%-by-2050 renewable electricity scenarios result in electricity price increases that are within the range of increases (relative to the study-specific baselines) shown in independent analyses of scenarios with similar carbon reductions.
- At 80% renewable electricity, annual power sector water withdrawal and consumption declines by roughly 50%, excluding any upstream or downstream water use, such as from manufacturing, fuel extraction, and water use that may be required for bioenergy crops.
- Replacing fossil energy generators with renewable technologies is one way to reduce criteria air pollutants, including particulate matter, SO_2, and NO_x.
- There are varied environmental and social concerns associated with renewable technologies, many of which are related to land-use impacts. At 80% renewable electricity, *gross* land-use impacts total less than 3% of the land area of the contiguous United States. *Net* land-use impacts are expected to be lower, as are the impacts when only disrupted lands are considered.
- There are varied indirect implications that may result from the direct electric sector cost, environmental, and social implications identified. For example, air emissions reductions will have implications for human health and climate change. Quantification of these indirect implications is an active area of wide-ranging research.

In summary, renewable expansion under the assumptions used and at the levels evaluated in RE Futures, along with the increased transmission expansion and operational challenges, were found to require additional electric sector investments compared with a baseline scenario that represented a future electric system that remains largely dominated by conventional generation. The results from the analysis find that the incremental cost of achieving high renewable deployment was greatly affected by the extent of renewable technology improvement assumed and was largely insensitive to reasonable projections of other electric system parameters, including transmission, system flexibility, resource accessibility, fossil energy prices, and fossil technology costs.

Direct environmental and social implications are also associated with the high renewable futures examined, and are not reflected in the cost implications described above. Further, there are a variety of indirect implications that may result from the direct electric sector cost, environmental, and social implications identified. Research is critically needed to systematically assess the relative impacts of different forms of energy supply in the context of a robust comprehensive framework that assesses both direct and indirect impacts. Such research could inform national energy policy decisions as well as local siting and permitting processes related to proposed generation facilities and supporting infrastructure.

Appendix B. Models Used in RE Futures

1. Introduction

Three primary models were used in RE Futures: the Regional Energy Deployment System (ReEDS) model (Short et al. 2011); the Solar Deployment System (SolarDS) model (Denholm et al. 2009a); and the GridView model (ABB 2008 and Feng et al. 2002). The first two models were developed at NREL; the GridView model is a commercially available model developed by ABB.

ReEDS is a capacity expansion model that forecasts the deployment of supply-side generation and transmission capacity for the electricity sector in the contiguous United States over the next 40 years (until 2050). Because ReEDS is not designed to account for distributed generation, the deployment of distributed (residential and commercial) rooftop PV capacity is exogenously input into ReEDS from the SolarDS model as described in Chapter 1, Section 1.2.1. More comprehensive model descriptions of these two NREL models can be found in the references.[249]

ReEDS considers grid operation and renewable integration issues within its framework. To study these issues using finer temporal resolution and with a more accurate representation of transmision flow, the GridView model was used. For RE Futures, the 2050 generation and transmission capacity, as projected by ReEDS and SolarDS, was imported into GridView, which was then run to determine the operational feasibility of the capacity expansion scenarios. Gridview performs these functions through hourly simulations of the electric power system and optimal DC power-flow modeling. The integration of the ReEDS and SolarDS results into GridView required modifications of the original GridView code and input databases so that the model could be run over a larger geographic scope with significant transfer of power between interconnections. New algorithms in GridView were necessary to accurately model the high renewable scenarios central to this study due to the presence of new technologies.[250] This appendix lists the assumptions and modifications to GridView for RE Futures. The reader is directed to the GridView User's Manual (ABB 2008) and Feng et al. (2002) for further model documentation and description.

This appendix details the assumptions used in the GridView unit commitment and dispatch modeling. GridView was used to model the operation of the electric power system in 2050. The database was created by starting with databases representing the existing transmission and

[249] A few differences exist between the ReEDS model version used for RE Futures and the version presented in Short et al. (2011), including, in particular, retirement assumptions for coal and natural gas powered plants (which include age-based retirements for all technologies including coal in Short et al. (2011), but only usage-based retirements for coal technologies here), technology cost and performance assumptions (which are detailed in Appendix A in this volume, Volume 2, and Black & Veatch [2012]), and fuel price assumptions (which are detailed in Appendix A for the present study). For the analysis presented in this report, the model assumptions described in this volume supersede those presented in Short et al. (2011). The structure and major algorithms of the ReEDS model described in Short et al. (2011) are the same as those used here.

[250] These technologies include compressed air energy storage (CAES), optimal dispatch of concentrating solar power (CSP) with thermal storage, and optimal charging of plug-in hybrid and electric vehicles (PEVs).

generation infrastructure in the three interconnects[251] and by expanding and retiring the system as projected by ReEDS (subject to the assumptions described in this appendix). The generators are optimally dispatched (to minimize the total production cost) for all three interconnects simultaneously, with HVDC lines connecting the interconnects based on projections from the ReEDS model.

The GridView model of the 48 contiguous states has approximately 65,000 buses and 85,000 transmission lines. Due to computational limitations and the spatial resolution of the outputs from the ReEDS model, transmission constraints were not enforced on each transmission line in GridView. Instead, the total transfer capacities between ReEDS BAs were estimated and enforced in GridView as interface limits that constrain the sum of transmission across all lines that represent each interface during each hour.

2. Transmission Assumptions

The total transmission transfer capacity between ReEDS BAs was estimated using GridView and the databases for each interconnect. These existing transmission limits were used as inputs for the ReEDS modeling. When ReEDS modeled additional transmission capacity between regions, this capacity was then input into the GridView model using the set of assumptions described below.

When ReEDS modeled additional capacity between regions, new lines were added to the GridView input database. Each of these lines in GridView was assigned a voltage level based on the amount of additional capacity modeled by ReEDS and the location (see Short et al. (2011) for a description of the maximum assumed voltages for new transmission lines by area). The minimum voltage level required to transmit the capacity was used, unless that voltage is higher than the maximum assumed voltage for each BA. Multiple lines were built where necessary to supply the capacity. The new lines were terminated at both ends with new buses. These new buses were connected to existing buses by new transmission lines (and transformers, if necessary). The number of these new lines in GridView depends on the total new capacity connected to the ReEDS BA and the maximum capacity that can be carried by each of the new lines that connect the new and existing buses. Existing buses are chosen based on the voltage (highest first) and the number of connected transmission lines (most first). The parameters of all new lines and transformers (capacity, resistance, and reactance) were estimated using per-mile parameters by line voltage from the Joint Coordinated System Plan study.[252] Reactance for lines greater than 180 miles in length was assumed to be equivalent to a 100-mile line to represent a series capacitor that would be required to prevent voltage problems.

[251] The data sources for the three asynchronous interconnections are (1) the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee, (2) the Electric Reliability Council of Texas, and (3) the North American Electric Reliability Council Multiregional Modeling Working Group, with proprietary updates from ABB. Location information is from the Transmission Atlas by Energy Visuals, Inc.
[252] For more information, see http://www.jcspstudy.org/.

3. Generation Assumptions

3.1 Conventional Fossil-Fuel Generators (Coal, Natural Gas)

Conventional generators in the 2050 scenario are a combination of units that exist today and new units projected to be built by ReEDS. If the ReEDS 2050 projection had lower capacity for a given unit type compared to the existing units in the GridView database, then units were retired (oldest units first) until the correct capacity was reached. If the ReEDS 2050 projection had more capacity than the existing units did, additional units were built in the GridView database. ReEDS did not project any new coal capacity in the subset scenarios simulated by GridView. For the new natural gas units, combined cycle units were built up to 200 MW per unit until the projected capacity is reached. Combustion turbines were sized up to 100 MW in capacity. Existing natural gas units are all assumed to be replaced with new identically sized units, based on the 30-year lifetime assumption. These units have the same properties (except the maximum capacity) as the new units described below.

In GridView, each new unit was placed at an existing bus that had a unit that was retired, if available. If no more of these buses were available, the units were placed at the highest-voltage buses in the area. GridView heat rates, forced outage rates, and planned outage rates were equivalent to the ReEDS assumptions for these values. Startup costs and minimum on and off times were taken from the Western Electricity Coordinating Council assumptions in the *2008 Annual Report of the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee*, using the “CT Large” and “CC Recent” categories. All combustion turbines were assumed in GridView to be quick-start, meaning that they can be operated during dispatch even if they were not committed during the unit commitment cycle. Thermal unit maintenance was scheduled using the GridView maintenance-scheduling algorithm.

3.2 Nuclear Generators

All nuclear generators were assumed in GridView to have a minimum generation level of 98% of the maximum capacity, regardless of the minimum generation level in the original database. Nuclear generators were retired in GridView in order of descending age to match the ReEDS capacity by interconnect, leading to retirement of the same generators as the ReEDS assumptions. New nuclear generators were not considered in RE Futures.

3.3 Compressed Air Energy Storage

GridView dispatched CAES units using an algorithm to minimize overall production cost to the system. The capacity of the units in GridView matched the ReEDS projections. Heat rate, compressor efficiency, and storage capacity in GridView also matched the ReEDS assumptions for the associated scenarios. The ReEDS model enforces annual renewable generation requirements. GridView cannot enforce these annual constraints therefore curtailment occurs whenever it is economically optimal without regard for the renewable generation requirement. In ReEDS, CAES is primarily built to reduce curtailment. However, GridView simulates very low LMPs in many areas throughout the year under the high renewable penetration scenarios, and the optimal solution rarely dispatches the CAES units because it is often less costly to operate other units (e.g. coal) than a CAES unit, even if the CAES unit has compressed air available. Therefore, it was assumed that CAES fuel prices were artificially low to encourage usage of

CAES to reduce curtailment. This ensures that CAES units are modeled as intended by the ReEDS capacity expansion optimization. Using fuel prices from ReEDS, input fuel costs per unit of energy are lower for a coal unit compared to a CAES unit with available pre-compressed air. Because coal or zero marginal cost units are typically on the margin most of the time in RE Futures (and there is no incentive other than production cost to operate renewables), the CAES units would rarely be run without the assumption of lower fuel costs. These units were placed at buses in the system using the same method as for fossil-fuel generators.

3.4 Biomass and Co-firing

Heat rate, forced outage rates, and minimum generation levels for biopower and co-firing were assumed in GridView to be identical to ReEDS assumptions. Biomass fuel costs were assumed to be low ($0.50/MMBtu) to represent a market mechanism to encourage the biomass units to be dispatched before fossil energy units for the hourly simulation as GridView cannot enforce an annual renewable requirement. Startup costs were also assumed to be relatively low at $5,000 per unit, with unit size less than 200 MW for the same reason. Biomass units are placed at buses in the system using the same method as for fossil-fuel generators. Units that co-fire coal and biomass were modeled as coal units in GridView. It was assumed that these units always co-fired with the maximum allowable fraction of biomass (0.15). Generation from biomass at co-firing units was assumed to be:

$$biomass\ generation = \frac{cofire\ capacity}{coal+cofire\ capcity} \times cofire\ fraction \times (coal + cofire\ generation)$$

For example, if there were 40 GW of coal capacity and 60 GW of co-firing, the biomass consumed would be (60/100 * 0.15 * annual generation from all coal and co-fire units in GridView).

3.5 Hydropower and Pumped-Storage Hydropower

GridView was allowed to dispatch existing hydropower units to minimize the system production cost, subject to minimum generation constraints to match the ReEDS assumptions. Minimum generation levels at each unit were assumed to be 55% of the average monthly output. New hydropower capacity built by ReEDS was assumed to be run-of-river plants that were not dispatchable. They produced consistent output for every hour of each month. Available monthly generation for existing and new hydropower units match the equivalent seasonal generation limits in ReEDS. New pumped-storage hydropower units in GridView were assumed to have 8 hours of available storage, and the efficiency and other parameters match the ReEDS assumptions.

3.6 Geothermal Energy Technologies

Geothermal capacity and annual generation were assumed in GridView to be identical to ReEDS projections. Geothermal units were assumed to be distributed equally to all high-voltage (greater than 200 kV) buses in each BA. Geothermal units were assumed to have constant generation throughout the year, but could be reduced to 90% of maximum power if desired by the system operator.

3.7 Solar Energy Technologies

3.7.1 Concentrating Solar Power (CSP) Technology

Hourly resource data for CSP units were obtained from Clean Power Research for 2006. These data were processed using the System Advisor Model[253] for a CSP unit without storage, and this input profile was used in GridView for CSP units with and without storage. For CSP units with storage, GridView optimized the dispatch of thermal energy to and from the storage tanks to produce electricity, considering losses involved in thermal storage. For CSP units with thermal storage, capacity and annual generation in GridView were matched to the ReEDS projections, while other parameters matched Solar Advisor Model defaults. Maximum and minimum generation levels were assumed to be the rated capacity of each unit multiplied by 1.1 and 0.15, respectively. Storage tank losses and pump losses were assumed to be 0.0097 and 0.02 multiplied by the rated capacity, respectively. Pump losses only occur when energy is going to or from the storage tank. Startup losses of the steam turbine were 0.2 multiplied by the rated capacity. Storage round-trip efficiency was assumed to be 95%.

The CSP capacity was modeled as individual discrete units in GridView, with the number of units depending on the capacity in each area. If capacity was less than 200 MW, one CSP unit was placed in the area. If capacity was between 200 MW and 1 GW, three units were placed in the area. If capacity was larger than 1 GW, eight units were placed in the area. Although areas with large CSP capacities could end up with large CSP units, there will be eight units in these areas and this will prevent the output from being too discrete. The CSP units were placed at buses with the highest voltage, secondarily sorted by the number of transmission lines attached to the bus.

GridView often curtails CSP more than other energy sources because the stored energy is more valuable than variable renewable electricity that cannot be stored. The model chooses to dispatch the variable sources first and keep energy in the CSP tanks when possible. Consider the following example. At midnight, all large thermal units are at minimum generation, and the system can use 100 MW of zero marginal cost energy. Wind is available, and CSP tanks are full. The model will dispatch 100 MW of wind energy and little or no CSP because the energy in the CSP tanks could be important later in the night or early in the morning if the wind is no longer available, load increases, or a generator or transmission outage occurs. In the morning, the CSP energy storage tanks will still have energy in them if the aforementioned conditions do not occur. In the spring, the tanks can be nearly full in the morning. These CSP units with thermal storage have oversized thermal fields, so if the solar input is at its maximum, the power block can only convert approximately one-third of the input energy into electricity. The rest must go to storage. Therefore, if the storage tank is full, the unit will curtail up to two-thirds of the input solar energy at peak solar input.

3.7.2 Solar Photovoltaic (PV) Technology

PV data were developed for GridView as follows. Hourly resource data for PV units were obtained from Clean Power Research for 2006. This data was processed using the Solar Advisor Model to obtain hourly generation estimates for utility and distributed PV applications. Utility

[253] https://sam.nrel.gov

PV was assumed to produce a profile of a 1-axis tracking machine from the best Typical Meteorological Year 3 location within each BA. Distributed PV profiles were estimated using the projected parameters of distributed PV capacity from the SolarDS model as inputs to the Solar Advisor Model using the average output from systems at all Typical Meteorological Year 3 locations in the BA. The profiles from these types of PV were normalized to the annual generation projected by ReEDS. Because forecast data were unavailable, perfect forecasts were assumed for the unit commitment phase. Imperfect forecasts would lead to less efficient commitment, and thus increase PV curtailment moderately. Short-term PV forecasts errors were considered by assuming that the increased operating reserve requirements of solar generation are similar to wind (per MW of generation). Future work will need to analyze the impacts of solar forecasting on grid operation.

3.8 Wind Energy Technologies

Wind data were developed for GridView as follows. Hourly resource data for the wind generators were obtained from the Eastern Wind Integration and Transmission Study (EnerNex 2010) and the Western Wind and Solar Integration Study (GE Energy 2010). Wind sites from these studies were chosen by priority of annual capacity factor until the total capacity reached the capacity projected by ReEDS. The profiles from these chosen sites were summed and then normalized to the annual generation projected by ReEDS. Day-ahead forecasts were used for unit commitment within GridView, and actual modeled wind generation was used for the economic dispatch. Several BAs in Texas and the southeastern United States did not have data from the Eastern Wind Integration and Transmission Study or the Western Wind and Solar Integration Study, so nearby BA profiles were used for these BAs. Wind generators were distributed to all high-voltage buses (greater than 200 kV) within each BA.

4. Demand-Side Flexibility Assumptions

4.1 Electric Vehicle Charging

GridView optimized the charging times for the PEVs that can be utility-charged, while the rest of the PEV charging simply increased the hourly demand. GridView optimized charging times to fill valleys in net demand, subject to prices remaining within reasonable levels. If real-time prices were above $200/MWh, the GridView model would re-optimize the planned charging profile.

4.2 Interruptible Load

Interruptible load was modeled in GridView as a thermal generator with infinite flexibility (meaning a response time of less than an hour because GridView has an hourly time resolution) and very high cost ($500/MWh). This allows the interruptible load to primarily provide reserves, although if a generator contingency or forecasting error would cause unserved load or prices above $500/MWh, the interruptible load could be dispatched. This method does not limit the number of times that interruptible load can be used to provide ancillary services or actual energy per year.

5. Other Assumptions

5.1 Reserves

Assumptions regarding operating (spinning and non-spinning) reserves in the GridView model are discussed in Volume 4.

5.2 Fuel Costs

Fuel costs for GridView were assumed to match the ReEDS fuel price outputs by NERC "subregion" for coal, natural gas, and uranium. Biomass (and gas used for CAES units) was assumed to be inexpensive to provide incentive for operating renewable electricity generation and using storage to reduce curtailment. These assumptions are described in more detail in the above sections on generation assumptions. As noted there, this was done to enable the hourly modeling of the dispatch of biomass power in GridView but did not impact the ReEDS-estimated system costs or electricity prices.

5.3 Load and Losses

Hourly end-use demand profiles for 2050 for use in GridView were projected using the methodology described in more detail in Volume 3. Transmission losses were estimated using the GridView loss model with a distributed reference bus. Distribution losses were estimated at approximately 2.6% based on the transmission losses projected by GridView for a reference scenario and the total transmission and distribution losses experienced today; the distribution losses were added to the end-use demand to make the GridView load input.

5.4 Iterative Changes

Each scenario was run for two iterations in GridView. The first iteration used the assumptions listed above. After the first iteration was complete, two changes were made. The first involved the distribution of renewable generators onto buses in the transmission network. Due to power-flow constraints, a small number of buses may have significant, negative locational marginal pricings (LMPs) (less than -$10/MWh) during a significant portion of the year (more than 100 hours). If these buses are included in the distribution of renewable generators, the model sees average LMPs much lower than the real average for the BA, and curtails more than it should. These buses were eliminated from the distribution of renewable generators for the second iteration. The second change that was made after the first model iteration involved the transmission capacity between BAs. Due to the physics of power flow, congestion along one path limits flow along all parallel paths. Because ReEDS is not a power flow model, it builds all capacity between two hypothetical areas by building a line directly between them. This leads to congestion in GridView along some of the smaller paths, limiting flows along paths where ReEDS builds additional transmission. The shadow price of transmission interface constraints is used to determine which lines need additional capacity. If the annual shadow price is higher than the annual cost of transmission capacity, the line is increased in capacity by 1 GW. This small increase in overall transmission capacity expansion represents capacity that ReEDS would have placed on parallel paths if it had power-flow capabilities. Because some of the additional transmission capacity projected by ReEDS is uncongested according to the power flow model in GridView, the additional capacity represents a change in the location of ReEDS transmission additions, not an overall increase in usable capacity, which would add to the overall cost.

Appendix C. Estimation of Life Cycle Greenhouse Gas Emissions

1. Methods

To estimate aggregate greenhouse gas (GHG) emissions for the RE Futures scenarios, both ReEDS model output and literature estimates of life cycle GHG emissions were leveraged. The life cycle assessment (LCA) literature typically reports GHG emissions normalized per kilowatt-hour of electricity generation or per kilowatt-hour of installed capacity. Both normalization metrics, applied to different life cycle phases, were used to estimate the contribution of each energy source to total life cycle GHG emissions for the RE Futures scenarios.

Normalized life cycle GHG emission estimates were extracted from published LCA literature as part of an exhaustive literature search conducted under NREL's LCA Harmonization project.[254] All collected literature was first categorized by content (with key information from every collected reference recorded in a database) and added to a bibliographic database. Then, screens were applied to select only those references that met stringent quality and relevance criteria. Only those references that passed both of the below-described screens were considered in the analytical phases of the LCA Harmonization project, and only those references were used to support the analysis done for RE Futures. In all, more than 2,000 references have been processed through this system, yielding approximately 300 references that were ultimately used to support estimation of GHG emissions from RE Futures scenarios.

A first (light) screen eliminated references based on these criteria:

- The technology in question does not produce electricity
- The study does not present a full LCA, in that less than two phases of the life cycle are explored (with exceptions for PV and wind energy, given that the literature demonstrates that the vast majority of lifecycle GHG emissions occur in the manufacturing phase [Frankl et al. 2005; Jungbluth et al. 2005]).
- Conference papers less than or equal to five, double-spaced pages in length (or equivalent)
- Trade journal articles less than or equal to three pages in length
- PowerPoint presentations, posters, or abstracts
- References published before 1980

Considering all technologies, 60% of the total number of reviewed references passed this screen.

The more rigorous, second (quality) screen evaluated references based on additional criteria:

- Whether quality LCA and GHG accounting methods are used
- Whether there is a complete reporting of the technology investigated and of inputs and results of the analysis
- Whether the evaluated technology is of modern relevance

[254] For more information, see http://www.nrel.gov/analysis/sustain_lcah.html.

Considering all technologies, approximately 25% of the total number of reviewed references passed this screen (42% of those that passed the first screen).

References that passed both screens and that provided GHG emission estimates disaggregated by life cycle stage were used to support the analysis of GHG emissions from RE Futures scenarios (n=296). *Because many references reported more than one estimate of life cycle GHG emissions (e.g., a reference may have evaluated multiple technologies or scenarios), the total number of estimates analyzed was much greater than 296*. Only estimates that were provided in numerical form were analyzed; estimates only displayed graphically were not accepted due to potential transcription inaccuracy.

GHG emissions estimates disaggregated per life cycle phase were reassembled into four general life cycle stages that correspond to ReEDS output, as follows:

- One-time upstream emissions, which include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, and on-site construction: Emissions for this life cycle stage used in the analysis were median estimates taken from the LCA literature.
- Ongoing non-combustion emissions during the operating phase, which include fuel cycle emissions (where applicable) and emissions resulting from non-combustion-related O&M activities: Emissions for this life cycle stage used in the analysis were median estimates taken from the LCA literature.
- Ongoing combustion emissions, resulting from combustion at the power plant (where applicable) for the purpose of electricity generation: Emissions for this life cycle stage used in the analysis are outputs of ReEDS, based on generation technology, electricity generation, heat rate assumptions, and the carbon content of the fuel.
- One-time downstream emissions, which include emissions resulting from project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site materials: Emissions for this life cycle stage used in the analysis were median estimates taken from the LCA literature.

One-time emissions (upstream and downstream) were related to the embodied emissions of the facility, which are largely determined by the capacity of the technology deployed. ReEDS reports capacity by technology installed or decommissioned in a given year. Multiplying literature-estimated, one-time upstream GHG emissions normalized per kilowatt of installed capacity by ReEDS-estimated capacity yields an estimate of GHG emissions associated with the addition of that technology's capacity in that year. An analogous method was used to estimate GHG emissions associated with facility decommissioning in a given year.

Ongoing emissions are mainly related to the production of electricity. ReEDS explicitly reports *combustion-related* CO_2 emissions by technology each year. Combustion of biomass produces GHG emissions. However, because the carbon emitted during combustion was absorbed during photosynthesis in feedstock production, these emissions were assumed to cancel when summed over the life cycle. *Unaccounted for in RE Futures were potential GHG emissions associated with changes in land use directly or indirectly induced by the cultivation of a biomass feedstock*.

ReEDS also reports electricity generation by each technology in a given year. Estimates of GHG emissions associated with the fuel cycle and other non-combustion-related ongoing activities were derived by multiplying literature-estimated, ongoing non-combustion-related GHG emissions normalized per kilowatt-hour by ReEDS-estimated generation.

Summing year- and technology-specific GHG emissions associated with the four life cycle phases over all years of the period studied in RE Futures (2011–2050) and all technologies yielded estimates of cumulative life cycle GHG emissions for that scenario. GHG emissions per year or per technology can also be calculated.

Tables C-1 through C-4 report all literature-based data inputs, ReEDS outputs, and intermediate and final calculations in estimating life cycle GHG emissions for each technology, year, and RE Futures scenario (Low-Demand Baseline scenario and 80% RE-ITI scenario). Complete documentation of the results of the LCA Harmonization project for seven technologies that supported the GHG analysis completed for RE Futures can be found for these technologies in the following publications: nuclear energy (Warner n.d.); wind energy (Dolan n.d.); natural gas (O'Donoughue et al. n.d.); coal (Whitaker et al. n.d.); concentrating solar power (Burkhardt et al. 2012); crystalline PV (Hsu et al. n.d.); and thin film PV (Kim et al. n.d.). Results reported in these publications may differ somewhat from those reported in Tables C-1 through C-4, owing to the ongoing nature of this research.

Table C-1. Life Cycle Greenhouse Gas Emission Factors, Capacity, Generation, and Total Greenhouse Gas Emissions for Technologies Deployed in the Low-Demand Baseline Scenario, 2050

Technology	(A) One-Time Upstream GHG Emission Factor (g CO_2e/ kW)	(B) Ongoing Non-Combustion GHG Emission Factor (g CO_2e/ kWh)	(C)[a] Ongoing Combustion GHG Emission Factor (g CO_2e/ kWh)	(D) One-Time Downstream GHG Emission Factor (g CO_2e/ kW)	(E) New Capacity Installed in 2050 (GW)	(F) Capacity Decommissioned in 2050 (GW)	(G) Generation in 2050 (TWh)	(H)[b] GHG Emissions in 2050 (10^6 tonnes CO_2e)
Coal-Old[c]	315,000	62.30	964	15,200	0	0.000481	2,010	2,060
Coal-New[d]	257,000	48.00	964	—	0	0	18.3	18.5
Coal-IGCC[e]	178,000	40.00	840	15,000	0	0	3.75	3.30
Gas-CT[f]	6,800	85.80	567	98.6	7.34	8.03	19.3	12.7
Gas-CC[g]	160,000	74.40	373	6,390	3.27	5.30	665	298
Oil-Gas-Steam[h]	—[i]	—	712	—	0	0.00744	0.118	0.0837
Co-fire-Old[j]	—	62.00	850	82.7	0	0	217	198
Co-fire-New[k]	—	49.80	931	82.7	0	0	5.27	5.17
Biopower[l]	258,000	60.20	0	120	0.000732	0	15.0	0.903
Landfill Gas[m]	—	—	-1,550	—	0	0	21.6	-33.4
CAES[n]	—	_	265	—	0.0146	0	3.07	0.813
Nuclear[o]	350,000	10.60	n/a[p]	175,000	0	0	448	4.75
Hydropower[q]	—	—	n/a	-—	0	0	352	0
Geothermal[r]	836,000	9.70	n/a	—	0	0	118	1.14
PV[s]	1,630,000	0	n/a	37,800	0.00785	0	16.8	0.0128
CSP[t]	2,970,000	2.50	n/a	239,000	0	0	1.41	0.00354
Wind-Onshore[u]	619,000	1.41	n/a	22,400	0.00623	0	254	0.363
Wind-Offshore[v]	660,000	0.13	n/a	39,200	0	0	11.4	0.00503
Total					10.6	13.3	4,180	2,570

[a] Combustion-related CO_2 emission factors for each electricity generation technology in lbs/Btu are reported in Short et al. (2011) and were used to calculate the emission factors reported here.
[b] GHG emissions for the year 2050 were calculated as follows, using the variables given in the column headings (*a calculation of the GHG emissions in year 2050 [column H] based on the table-reported values may not exactly match the values presented in the table due to independent rounding*):

$$H = (A \times E + D \times F) \div 10^6 + ((B + C) \times G) \div 10^3$$

[c] "Coal – Old" refers to pulverized coal plants built before 1990, some of which are subcritical and some supercritical designs (mostly subcritical). It also includes plants that have and do not have SO_x scrubbers. Conversion of these plants to biomass co-firing was assumed to incur negligible GHG emissions that are not considered here. Because the proportions of subcritical and supercritical plants are unknown, upstream, ongoing non-combustion, and downstream emission factors are based on subcritical LCA literature.

[d] Pulverized coal with supercritical plant design (no downstream GHG emission factors were found in the LCA literature and were therefore not evaluated)

[e] Integrated gasification combined cycle coal plant

[f] Simple-cycle natural gas combustion turbine

[g] Combined cycle natural gas plant

[h] Oil-gas-steam power plant LCA literature was not evaluated and therefore only the combustion stage was considered.

[i] Dash marks represent life cycle stages that were not evaluated.

[j] Co-firing of biomass and pulverized coal, assuming a 15%–85% ratio by energy content, respectively. Combustion GHG emissions of the biomass portion are assumed to be zero.

[k] Co-firing of biomass and supercritical pulverized coal, assuming a 15%–85% ratio by energy content, respectively. Combustion GHG emissions of the biomass portion are assumed to be zero.

[l] Dedicated biopower. Combustion GHG emissions were assumed to be zero.

[m] Landfill gas LCA literature was not evaluated and therefore only the combustion stage was considered. Combustion CO_2 emissions represent avoided landfill gas methane emissions and are therefore negative. The combustion CO_2 emission factor (column C) was back-calculated by dividing the ReEDS-estimated CO_2 emissions by the total electricity generation for that technology.

[n] Compressed air energy storage (CAES) LCA literature was not evaluated and therefore only the combustion stage was considered. ReEDS assumes CAES is produced from simple-cycle natural gas combustion turbines, but because of the compressed air environment, there is an improved heat rate and thus a lower CO_2 emission factor than gas combustion turbines.

[o] Life cycle GHG emission factors for nuclear were calculated using a capacity-weighted average (based on current U.S. fleet) of pressurized and boiling water reactors and includes literature for the more general category of "light water reactors."

[p] The combustion stage is marked "not applicable" (n/a) for technologies in which combustion is not the means for producing electricity.

[q] Hydropower LCA literature was not evaluated and therefore no life cycle GHG emission factors were considered.

[r] Geothermal was assumed to be flashed steam hydrothermal plants.

[s] Utility- and distributed-scale PV LCA literature were evaluated collectively assuming the GHG emission factors reasonably represent both.

[t] Concentrating solar power (CSP) assumes parabolic trough design with thermal storage. The CSP LCA literature did not provide estimates for systems without storage; the estimates for systems with storage were assumed to be reasonably representative of both. It was further assumed that trough systems have similar life cycle GHG emissions as tower-based CSP which is a reasonable approximation given the available literature for both.

[u] Utility-scale onshore wind; distributed generation wind power systems were not considered.

[v] Utility-scale offshore wind in shallow water; deep offshore wind power systems were not considered.

Table C-2. Life Cycle Greenhouse Gas Emission Factors, Capacity, Generation, and Total Greenhouse Gas Emissions for Technologies Deployed in the Low-Demand Baseline Scenario, Cumulatively through 2050

Technology	(A) One-Time Upstream GHG Emission Factor (g CO_2e/kW)	(B) Ongoing Non-Combustion GHG Emission Factor (g CO_2e/kWh)	(C)[a] Ongoing Combustion GHG Emission Factor (g CO_2e/kWh)	(D) One-Time Downstream GHG Emission Factor (g CO_2e/kW)	(E) Cumulative Newly Installed Capacity through 2050 (GW)	(F) Cumulative Capacity Decommissioned through 2050 (GW)	(G) Cumulative Capacity through 2050 (GW)	(H) Cumulative Generation through 2050 (TWh)	(I)[b] Cumulative GHG Emissions through 2050 (10^6 tonnes CO_2e)
Coal-Old	315,000	62.30	964	15,200	0	4.08	272	80,600	82,700
Coal-New	257,000	48.00	964	—	0	0	2.47	742	751
Coal-IGCC	178,000	40.00	840	15,000	0	0	0.529	150	132
Gas-CT	6,800	85.80	585	98.6	341	201	240	567	382
Gas-CC	160,000	74.40	384	6,390	149	155	155	23,400	10,700
Oil-Gas-Steam	— [c]	—	712	—	0	131	0.354	166	118
Co-fire-Old	—	62.00	836	82.7	29.2	0	29.2	6,910	6,200
Co-fire-New	—	49.80	866	82.7	0.711	0	0.711	200	183
Biopower	258,000	60.20	0	120	0.233	0	2.12	587	35.4
Landfill Gas	—	—	-1,550	—	0	0	2.73	864	-1,330
CAES	—	—	265	—	6.65	0	6.76	66.5	17.6
Nuclear	350,000	10.6	n/a[d]	175,000	0	43.3	56.6	25,600	279
Hydropower	—	—	n/a	—	0.383	0	78.8	13,900	—
Geothermal	836,000	9.70	n/a	—	13.4	0	15.8	3,470	44.8
PV	1,630,000	0	n/a	37,800	8.37	0	8.37	594	13.7
CSP	2,970,000	2.50	n/a	239,000	0	0	0.446	56.6	0.141
Wind-Onshore	619,000	1.41	n/a	22,400	42.1	0	80.0	9,650	39.7
Wind-Offshore	660,000	0.13	n/a	39,200	2.66	0	2.66	384	1.93
Total					594	534	955	168,000	100,000

[a] Because the heat rates assumed in ReEDS evolve over time, the combustion emission factors represent a generation-weighted average over the time period of the study.

[b] Cumulative GHG emissions through the year 2050 were calculated for as follows, using the variables given in the column headings (*a calculation of the GHG emissions through year 2050 [column I] based on the table-reported values may not exactly match the values presented in the table due to independent rounding*):

$$I = (A \times E + D \times F) \div 10^6 + \left((B + C) \times H\right) \div 10^3$$

[c] Dash marks represent life cycle stages that were not evaluated.

[d] The combustion stage is marked "not applicable" (n/a) for technologies in which combustion is not the means for producing electricity.

Table C-3. Life Cycle Greenhouse Gas Emission Factors, Capacity, Generation, and Total Greenhouse Gas Emissions for Technologies Deployed in the 80% RE-ITI Scenario, 2050

Technology	(A) One-Time Upstream GHG Emission Factor (g CO_2e/kW)	(B) Ongoing Non-Combustion GHG Emission Factor (g CO_2e/kWh)	(C) Ongoing Combustion GHG Emission Factor (g CO_2e/kWh)	(D) One-Time Downstream GHG Emission Factor (g CO_2e/kW)	(E) New Capacity Installed in 2050 (GW)	(F) Capacity Decommissioned in 2050 (GW)	(G) Generation in 2050 (TWh)	(H)[a] GHG Emissions in 2050 (10^6 tonnes CO_2e)
Coal-Old	315,000	62.30	964	15,200	0	3.56	38.8	39.9
Coal-New	257,000	48.00	964	—	0	0	0	0
Coal-IGCC	178,000	40.00	840	15,000	0	0.0425	1.92	1.69
Gas-CT	6,800	85.80	572	98.6	3.96	6.11	10.6	7.02
Gas-CC	160,000	74.40	386	6,390	0	3.12	97.3	44.8
Oil-Gas-Steam	— [b]	—	712	—	0	0.000155	0	0.00120
Co-fire-Old	—	62.00	819	82.7	0	6.70	376	336
Co-fire-New	—	49.80	839	82.7	0	0.00613	21.9	19.5
Biopower	258,000	60.20	0	120	2.21	0	582	35.6
Landfill Gas	—	—	-1,550	—	0	0	21.6	-33.4
CAES	—	—	265	—	1.31	0	8.86	2.35
Nuclear	350,000	10.60	n/a[c]	175,000	0	0	350	3.71
Hydropower	—	—	n/a	—	0.0717	0	496	—
Geothermal	836,000	9.70	n/a	—	0	0	179	1.74
PV	1,630,000	0	n/a	37,800	6.45	0	281	10.5
CSP	2,970,000	2.50	n/a	239,000	7.38	0	288	22.6
Wind-Onshore	619,000	1.41	n/a	22,400	5.89	0	1,160	5.28
Wind-Offshore	660,000	0.13	n/a	39,200	0.324	0	458	0.415
Total					27.6	19.5	4,370	498

[a] GHG emissions for the year 2050 were calculated as follows, using the variables given in the column headings (*a calculation of the GHG emissions in year 2050 [column H] based on the table-reported values may not exactly match the values presented in the table due to independent rounding*):

$$H = (A \times E + D \times F) \div 10^6 + ((B + C) \times G) \div 10^3$$

[b] Dash marks represent life cycle stages that were not evaluated.

[c] The combustion stage is marked “not applicable” (n/a) for technologies in which combustion is not the means for producing electricity.

Table C-4. Life Cycle Greenhouse Gas Emission Factors, Capacity, Generation, and Total Greenhouse Gas Emissions for Technologies Deployed in the 80% RE-ITI Scenario, Cumulatively through 2050

Technology	(A) One-Time Upstream GHG Emission Factor (g CO_2e/kW)	(B) Ongoing Non-Combustion GHG Emission Factor (g CO_2e/kWh)	(C)[a] Ongoing Combustion GHG Emission Factor (g CO_2e/kWh)	(D) One-Time Downstream GHG Emission Factor (g CO_2e/kW)	(E) Cumulative Newly Installed Capacity through 2050 (GW)	(F) Cumulative Capacity Decommissioned through 2050 (GW)	(G) Cumulative Capacity through 2050 (GW)	(H) Cumulative Generation through 2050 (TWh)	(I)[b] Cumulative GHG Emissions through 2050 (10^6 tonnes CO_2e)
Coal-Old	315,000	62.30	964	15,200	63.6	153	14.0	32,000	32,900
Coal-New	257,000	48.00	964	—	0	0	0	27.1	27.4
Coal-IGCC	178,000	40.00	840	15,000	0	0.144	0.385	135	119
Gas-CT	6,800	85.80	615	98.6	240	162	179	241	170
Gas-CC	160,000	74.40	392	6,390	53.3	127	87.3	9,540	4,460
Oil-Gas-Steam	— [u]	—	712	—	0	132	0.00569	156	111.0
Co-fire-Old	—	62.00	819	82.7	138	55.7	82.7	22,900	20,200
Co-fire-New	—	49.80	836	82.7	3.18	0.0931	3.09	903	801
Biopower	258,000	60.20	0	120	77.5	0	79.4	7,950	499
Landfill Gas	—	—	-1,550	—	0	0	2.73	864	-1,330
CAES	—	—	265	—	91.2	0	91.3	214	56.8
Nuclear	350,000	10.60	n/a[v]	175,000	0	43.3	56.6	25,000	272
Hydropower	—	—	n/a	—	35.6	0	114	16,900	0
Geothermal	836,000	9.70	n/a	—	21.6	0	24.1	6,170	77.9
PV	1,630,000	0	n/a	37,800	168	0	168	5,920	274
CSP	2,970,000	2.50	n/a	239,000	56.0	0	56.5	2,070	171
Wind-Onshore	619,000	1.41	n/a	22,400	310	0	349	31,400	236
Wind-Offshore	660,000	0.13	n/a	39,200	112	0	112	8,840	77.8
Total					1,370	673	1,420	171,000	59,100

[a] Combustion-related CO_2 emission factors for each electricity generation technology in lbs/Btu are reported in Short et al. (2011) and were used to calculate the emission factors reported here.
[b] Cumulative GHG emissions through the year 2050 were calculated for as follows, using the variables given in the column headings (*a calculation of the GHG emissions through year 2050 [column I] based on the table-reported values may not exactly match the values presented in the table due to independent rounding*): $I = (A \times E + D \times F) \div 10^6 + ((B + C) \times H) \div 10^3$

2. Limitations and Caveats

Several limitations should be understood when interpreting the results of Tables C-1 through C-4. Three of the most important limitations are:

- The analysis employs point estimates of life cycle GHG emissions, and thus produces a point estimate life cycle GHG result. This is not to suggest that the estimate is known with a high degree of accuracy or precision. The differential between the Low-Demand Baseline scenario and the 80% RE-ITI scenario was of more interest in RE Futures than the absolute GHG emissions of any specific scenario. Any inaccuracy or lack of precision in individual-technology point estimates were unlikely to cause dramatic errors in the overall result, except perhaps errors related to assumptions about indirect land use and biomass, as discussed below. The accuracy of the results reported in this appendix were further enhanced by leveraging the broadest possible extent of existing literature on this topic rather than by selecting an estimate from a single study; the accuracy of the results presented here are nevertheless limited by available previous research and deficiencies in any individual previous work. Formal analysis of uncertainty—characterized in RE Futures by the limited precision of reporting of the results, to three significant figures—was outside the scope of this analysis.
- The estimates of GHG emission by life cycle phase were assumed to be constant during the study period, except those due to heat rate improvements as specified as ReEDS inputs. Two trends suggest that this simplification overestimates GHG emissions from renewables in later years and thus underestimates the GHG emissions reduction of high-penetration renewable scenarios. First, a downward trend in GHG emissions associated with component manufacturing and plant construction due to learning effects might be expected. Given the relative immaturity of many renewable technologies compared to conventional ones, the learning-induced downward trend would likely reduce GHG emissions from renewables more than would conventional electricity generation technologies. Second, in the 80% RE-ITI scenario, a less GHG-intensive (decarbonized) electric sector that powers manufacturing and construction activities would reduce GHG emissions for all technologies. Because renewable technologies' life cycle GHG emissions are more weighted toward upstream processes, the GHG emissions from renewables should be reduced relatively more than those from conventional electricity generation technologies whose proportion of upstream emissions are relatively smaller. Accounting for these two factors alone would, all else being equal, tend to increase the estimated GHG emissions benefits of achieving the 80%-by-2050 renewable energy target.
- Unaccounted for in RE Futures were potential GHG emissions associated with changes in land use directly or indirectly induced by the cultivation of a biomass feedstock. There is considerable scientific debate regarding the magnitude of land use change-related GHG emissions, and even whether the land use change effects would result in net positive or net negative GHG emissions (which depend on context-specific factors not determined in the RE Futures scenarios). This is an important limitation of the present calculations, and further work is recommended to understand the GHG implications of the direct and indirect land use impacts associated with biomass feedstocks, especially within the context of large-scale use of biomass feedstocks. However, the overall conclusion that

scenarios of high penetration renewables should significantly reduce GHG emissions compared to baseline scenarios remains valid even if GHG emissions related to bioenergy are increased by several factors owing to land use change-related effects.

Other limitations include:

- Not all technologies were evaluated over the complete life cycle. Hydropower, oil-gas-steam, landfill gas, and CAES storage systems, for example, were only evaluated for their combustion-related emissions of CO_2 because they were out of scope of the LCA Harmonization study. Because their contribution to installed capacity and generation is small, both individually and collectively, this limitation should not significantly directionally bias the results, although a slight underestimate of total GHG emissions is expected.
- Assumptions were made to align the technology definitions of the available LCA literature with ReEDS definitions. These include assuming that:
  - Retrofitting old coal plants with SO_x scrubbers produces negligible GHG emissions.
  - Scrubbed and unscrubbed (for sulfur dioxide) pulverized coal plants produce the same life cycle GHG emissions associated with ongoing non-combustion and downstream activities.
  - All old coal plants (both sub- and super-critical) have the same GHG emissions associated with one-time downstream activities.
  - Concentrating solar power (CSP) systems with and without storage produce the same life cycle GHG emissions.
  - Trough CSP produces the same GHG emissions as tower-based CSP.
  - Utility- and distributed-scale PV produce the same GHG emissions.
  - The process and materials required to retrofit coal power plants to biomass co-firing produces negligible additional life cycle GHG emissions.

These assumptions introduce some uncertainty, but they are not expected to directionally bias the results to any significant degree.

- The life cycle GHG emission factors used in the analysis are based on as-published estimates. With the exception of putting the estimates on a common functional basis (g CO_2e/kWh), no additional harmonization of methods was performed. Inconsistent methods can lead to greater variability among reported results than would result if studies used common definitions, scope, boundaries, and other methods. Harmonization of methods is the subject of ongoing research under the LCA Harmonization project, the results of which were not yet available to inform the RE Futures analysis presented here. Though the lack of methodological consistency introduces some uncertainty, it is not expected to directionally bias the results.
- GHG emission estimates reported in the literature are sometimes reported as CO_2, CO_2e, or the mass of individual GHG species. Estimates of CO_2 and CO_2e were both used in the same pool to calculate the median GHG emission factors. Studies reporting individual

GHGs were converted to CO_2e using the latest Intergovernmental Panel on Climate Change global warming potentials. Not accounting for all GHG emissions leads to an underestimation of total GHG emissions from the RE Futures scenarios but is not expected to be significant in magnitude.

- The GHG emission factors calculated from the LCA literature represent a work in progress, as additional literature is continuously being analyzed and added to the pool. However, given the quantity of literature already analyzed, the results are not anticipated to change significantly because of ongoing literature review and analysis.

Appendix D. Project Participants and Contributors

The National Renewable Energy Laboratory coordinated preparation of this report, which is the culmination of contributions from more than 110 individuals and more than 35 organizations representing industry, utilities, universities, electric system operators and transmission organization, energy regulators, the government, and other sectors. The Project Leaders regret the inadvertent omission of any project participants and contributors, whether their input to the project involved contributing to project design, conducting analysis, authoring or contributing content, reviewing manuscript drafts, or producing the report.

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Volume 1. Exploration of High-Penetration Renewable Electricity Futures

For the suggested citation of Volume 1, see the title page of this volume.

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