NREL
Transforming ENERGY

21st Century
POWER PARTNERSHIP
Accelerating the transformation of power systems

CLEAN GRID VISION:

A U.S. PERSPECTIVE

CLEAN ENERGY MINISTERIAL
Advancing Clean Energy Together

Technical Report
NREL/TP-5C00-78642
September 2021
Contract No. DE-AC36-08GO28308

CLEAN GRID VISION:
A U.S. PERSPECTIVE

Chapter 1. Clean Grid Scenarios

Ella Zhou, Greg Brinkman, Jonathan Ho, Ana Dyreson, Kaifeng Xu –
National Renewable Energy Laboratory

Suggested Citation:
Zhou, Ella, Greg Brinkman, Jonathan Ho, Ana Dyreson, and Kaifeng Xu. 2021. Clean Grid Vision: A U.S. Perspective – Chapter 1. Clean Grid Scenarios. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5C00-78642. https://www.nrel.gov/docs/fy21osti/78642.pdf.

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 | www.nrel.gov

Technical Report | NREL/TP-5C00-78642 | September 2021

NREL prints on paper that contains recycled content.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

NOTICE STATEMENT:

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36- 08GO28308. Funding provided by the Children's Investment Fund Foundation under Contract No. ACT-15-00008. The views expressed in the report do not necessarily represent the views of the DOE or the U.S. Government or any agency thereof.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

NREL prints on paper that contains recycled content.

Acknowledgments

The *Clean Grid Vision—A U.S. Perspective* is a part of the 2015–2021 Chinese Programme for a Low-Carbon Future, funded by the Children's Investment Fund Foundation Contract No. ACT-15-00008. It is supported by the National Renewable Energy Laboratory's (NREL's) 2016–2021 Memorandum of Understanding with China's State Grid Energy Research Institute (SGERI).

During the 6-year program, the project team conducted conferences, meetings, and tours in the United States, China, and Europe, with the support from various U.S. and international entities. These engagements enhanced our understanding of the issues discussed in this report, and we would like to thank the entities that made such exchanges possible:

- U.S. Department of Energy
- U.S. Department of State
- U.S. Federal Energy Regulatory Commission
- California Independent System Operator
- Electric Reliability Council of Texas
- PJM Interconnection LLC
- California Public Utilities Commission
- Public Utilities Commission of Texas
- Xcel Energy
- Electric Power Research Institute
- Regulatory Assistance Project
- International Energy Agency
- Energinet
- National Energy Administration of China
- State Grid Corporation of China
- China National Development and Reform Commission Energy Research Institute
- China National Renewable Energy Centre
- China Electric Power Research Institute
- China Electric Power Planning and Engineering Institute
- Tsinghua University
- North China Electric Power University.

Since the beginning of the program, an International Expert Group of senior-level experts has been assembled to provide guidance, feedback, and review of the strategic direction and research content of the program. The authors would like to acknowledge the valuable guidance and review provided by the International Expert Group during the preparation of the report. The Clean Grid Vision does not necessarily reflect their opinions or the opinions of their affiliated institutions. The members who have, at

times, served on the International Expert Committee between 2015–2021 and their affiliations as of 2021 are (in alphabetical order):

Fatih Birol	International Energy Agency
Roland Brundlinger	Austrian Institute of Technology
Leon Clarke	Pacific Northwest National Laboratory
Laura Cozzi	International Energy Agency
Paolo Frankl	International Energy Agency
Dolf Gielen	International Renewable Energy Agency
Toni Glaser	German Federal Ministry for Economic Affairs and Energy
Hannele Holtinnen	VTT Technical Research Centre of Finland
Peter Jorgensen	Energinet
Daniel Kammen	University of California, Berkeley
Valerie Karplus	Massachusetts Institute of Technology
Hans Jorgen Koch	Nordic Energy Research
Jiang Lin	Lawrence Berkeley National Laboratory
Mark O'Malley	Energy Systems Integration Group
Lynn Price	Lawrence Berkeley National Laboratory
Martin Schope	German Federal Ministry for Economic Affairs and Energy
Charlie Smith	Energy Systems Integration Group
Ryan Wiser	Lawrence Berkeley National Laboratory

SGERI developed the counterpart report, *Clean Grid Vision—A Chinese Perspective*. The collaborative research with SGERI during the course of the program provided the authors with insights into the Chinese power system and stimulated fresh thinking on some of the common challenges in energy transition.

In addition, this report benefited from thoughtful review by the following individuals at NREL: Douglas J. Arent, John Barnett, Ron Benioff, Jaquelin Cochran, Bethany Frew, Jessica Lau, Trieu Mai, Caitlin Murphy, Yinong Sun. Isabel McCan, Liz Breazeale, Chris Schwing, and Liz Craig provided editing, design, and outreach support. Finally, Elizabeth Weber, Patricia Statwick, and Katie Contos provided critical program support that enabled the daily operation of this multiyear cross-center international program.

Any error or omission in the report is the sole responsibility of the authors.

List of Acronyms

CO_2	carbon dioxide
CSP	concentrated solar power
DER	distributed energy resource
dGEN	Distributed Generation Market Demand
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERGIS	Eastern Renewable Grid Integration Study
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
IEA	International Energy Agency
LCOE	levelized cost of energy
NG-CC	natural gas combined cycle
NREL	National Renewable Energy Laboratory
PV	photovoltaic
ReEDS	Regional Energy Deployment System
RPM	Resource Planning Model
RTO	regional transmission organization
US-REGEN	U.S. Regional Economy, Greenhouse Gas, and Energy Model
VRE	variable renewable energy

Preface

The *Clean Grid Vision—A U.S. Perspective* is a part of the National Renewable Energy Laboratory's (NREL)'s 2015–2021 Chinese Programme for a Low-Carbon Future and collaborative research with China's State Grid Energy Research Institute (SGERI). This multiyear program seeks to build capacity and assist Chinese stakeholders to articulate low carbon pathways to achieve energy systems with a high share of renewable energy, energy efficiency, and low carbon emission.

The Clean Grid Vision comprises two major reports: *Clean Grid Vision—A U.S. Perspective*, written by NREL, and *Clean Grid Vision—A Chinese Perspective*, written by SGERI. The former summarizes NREL's lessons learned on some of the main issues in power system transition:

- Power system planning and operational analysis are discussed in Chapter 1, "Clean Grid Scenarios."
- Renewable grid integration challenges and modeling tools at the distribution network level are discussed in Chapter 2, "Distribution Issues and Tools."
- Grid reliability and stability challenges and the technologies to address them at the transmission-network level are discussed in Chapter 3, "Grid-Supporting Technologies."
- Recent dynamics in electricity demand such as energy efficiency, demand response, and electrification are discussed in Chapter 4, "Demand-Side Developments."
- Emerging issues in power market design and market evolution related to the increasing penetration of renewable energy are discussed in Chapter 5, "Power Market Trends."

The scope of *Clean Grid Vision—A U.S. Perspective* is limited to summarizing the main lessons learned and best practices through NREL's power system research in the past 6 years, with a focus on the U.S. power system. It can be compared to and contrasted with SGERI's report that focuses on China's power system.

As a summary report, most of the works cited here were conducted during 2015–2020. While some of the assumptions for these studies, especially the ones related to renewable energy and battery technology costs, are outdated, the main conclusions remain salient and offer valuable insights for planning and operating power systems and power markets with high levels of renewable energy.

More information on the Clean Grid Vision is available at www.nrel.gov/international/clean-grid-vision.html.

Suggested Citation – Chapter:
Zhou, Ella, Greg Brinkman, Jonathan Ho, Ana Dyreson, and Kaifeng Xu. 2021. *Clean Grid Vision: A U.S. Perspective – Chapter 1. Clean Grid Scenarios*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5C00-78642. https://www.nrel.gov/docs/fy21osti/78642.pdf.

Suggested Citation – Entire Report:
Zhou, Ella, ed. 2021. *Clean Grid Vision – A U.S. Perspective*. Golden, CO: National Renewable Energy Laboratory. www.nrel.gov/international/clean-grid-vision.html.

Table of Contents

List of Figures

List of Tables

Chapter 1: Clean Grid Scenarios

Highlights

- Renewable energy capacity and generation grow substantially in every modeled future.
- Future power systems will be operated differently. System operators can leverage a wide variety of sources of both technical and institutional flexibility. Technical sources can include storage, flexible generation, transmission, and demand-side flexibility. Institutional sources of flexibility include balancing authority cooperation, economic curtailment, and market incentives.
- Studies show that supply and demand can be balanced at 5-minute time resolution in high-renewable future power system scenarios. Additional modeling and analysis are needed to demonstrate grid reliability, reliance, and security.

1.1 Introduction

The United States is one of 196 parties around the world who have joined the Paris Agreement, which sets the goal of limiting global warming to well below 2, preferably to 1.5°C, compared to pre-industrial levels. The majority of carbon emissions are produced by energy consumption in the transportation, electricity, industry, commercial, and residential buildings sectors [1]. The electric power sector is likely easier and less costly to decarbonize compared to the other sectors, so power sector decarbonization and the electrification of other sectors (discussed in Chapter 4) are critical components of economy-wide decarbonization [2]–[4].

This chapter serves as a broad introduction to the type of future U.S. power systems envisioned in the *Clean Grid Vision*: one with high penetrations of variable renewable energy (VRE) generation (for example, more than 53% in the conterminous United States and up to 73% in the Eastern Interconnection) and a variety of resources that can be operated reliably to serve future load growth and/or transformations. VRE refers to generation capacity that is connected to a variable energy source, such as solar irradiance and wind speed. Such high VRE systems are integral to power sector decarbonization [2], [5]–[8], and they have some similar characteristics:

- Dramatic increase in VRE generation while coal plants phase out in the near term
- Expansion of transmission lines and increase in inter-regional electricity exchange
- Utilization of a wide range of flexible resources, including transmission, flexible generation, energy storage, and demand management
- Advanced engineering and operational measures, as well as policy, market, and business transformations that can facilitate greater integration of VRE [9]–[11].

The studies cited in this chapter show that the conterminous United States has adequate resources to support such systems with currently commercial technologies, and these systems can be operated cost-effectively to meet all sub-hourly demand and reserve requirements. The studies also provide meaningful insights into the potential challenges and corresponding solutions for a high VRE penetration power system. The scope of the *Clean Grid Vision* is limited to summarizing recent National Renewable Energy Laboratory (NREL) research in clean grid development, with a focus on the U.S. power system. As such, the chapter does not attempt to review all relevant models or grid integration studies in the world, though some are referenced to provide context as appropriate. This chapter focuses on resource adequacy and operational issues up to 5-minute intervals in the bulk power system. Distribution-level issues and transmission system reliability issues will be discussed in Chapter 2 and 3 of the *Clean Grid Vision*.

Studies that explore the bulk power system planning and operational factors at the timescales included in this chapter are often referred to as grid integration studies. Figure 1- 1 summarizes the high-level process for conducting such a study. These studies and their scenarios often involve an iterative process of data collection, stakeholder engagement, scenario development, power system modeling, and analysis and reporting. Stakeholder feedback can play a critical role in further informing or shaping the model assumptions and scenario analysis.

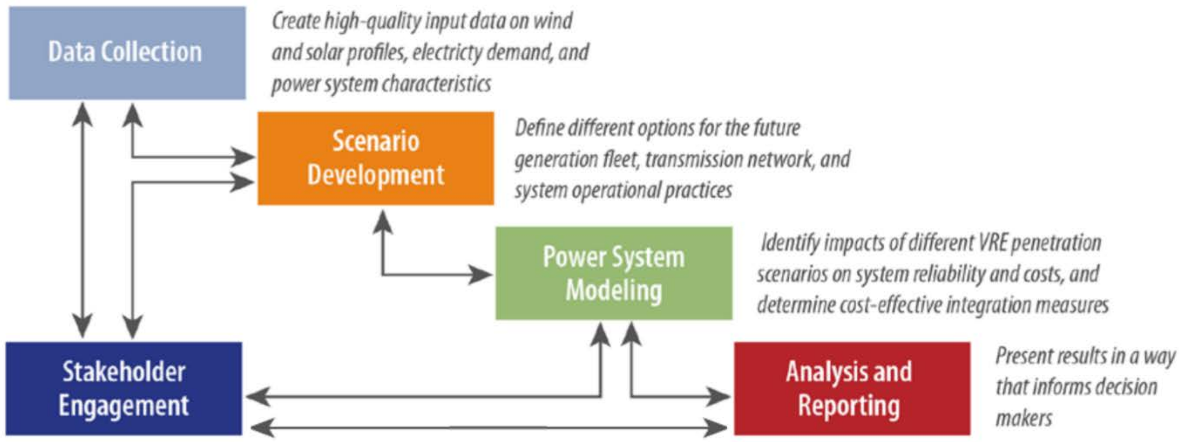


Figure 1- 1. Basic process for grid integration studies

Source: [12]

It is also important to know what the power system models can or cannot do and how to interpret the power system modeling results:

1. Models do not predict the future. We use scenario analysis to explore the interactions between factors that could impact future electricity generation, consumption, trade, prices, technology mixes, and other issues. Such factors could include natural gas prices, renewable energy technology costs, policies, and others. For that reason, we do not use a single scenario to represent *the* future or the most likely future, but rather use a range of diverse scenarios to illustrate the impacts of different assumptions and the scale of the necessary transformation.

2. We acknowledge the limitations of our models. Even the best-in-class models are limited by at least three factors: human behavior, uncertainties, and computational power. Typical energy optimization models are based on overall system equilibrium or least-cost optimization, but real-world producers and consumers do not always act in accordance with economic principles. Institutional, jurisdictional, behavioral, and social barriers often prevent the system from reaching an optimal solution [13]. In addition, power system modeling deals with a myriad of uncertainties. While some of these uncertainties (e.g., future natural gas prices) can be explored through the use of sensitivity analysis, more robust data (such as multiple weather years), or modeling techniques such as Monte Carlo simulations, other uncertainties from unexpected events or disruptive technologies are difficult to capture. Moreover, using agent-based modeling to simulate some aspects of human behavior or performing stochastic modeling to address uncertainties comes at great computational cost for large-scale systems. Therefore, there is often a trade-off between the amount of complexity one seeks to capture in a model and the size of the problem or the number of scenarios one may be able to explore with limited computational power.

3. Nevertheless, scenario analysis can inform decision-making. Even though energy scenarios tend to overestimate the extent to which the future will resemble the past [14], results from a range of scenarios obtained from multiple modeling tools can inform decision makers of the potential costs, risks, and benefits of a specific investment or policy. Such analyses may lead to considerations for how to reduce costs, mitigate these risks, or further leverage the benefits.

This chapter is divided into four sections following the introduction. Section 1.2 introduces several power sector capacity expansion and production-cost models that are used for grid integration studies to examine important planning and operational issues. Capacity expansion models provide a high-level long-term view of the evolving power systems by optimizing system capacity builds—usually of generation, transmission, and storage—over several years or decades. Production-cost models simulate power system operation on shorter timescales (usually hourly or sub-hourly) using detailed load, transmission, and generation data, and minimize system operation costs, while enforcing operating reserve requirements and other system constraints. Section 1.3 describes the capacity growth trends for various technologies in the U.S. power system up to 2050 according to NREL's 2019 Standard Scenarios [15]. Section 1.4 provides operational analyses of the U.S. Western and Eastern Interconnections under high levels of VRE and the main lessons learned about renewable integration. Section 1.5 concludes with a few general observations on planning and operation with high levels of VRE.

1.2 Models and Tools

This section introduces some of the main tools used at NREL for conducting the grid integration studies introduced in the latter sections of the chapter.

1.2.1 ReEDS

Developed by NREL, the Regional Energy Deployment System (ReEDS) [16], [17] is a capacity planning and dispatch model for the North American electricity system. ReEDS finds the least-cost mix of technologies that meets electric power demand, based on grid reliability requirements, technology resource constraints, and policy constraints. For the studies referenced in Section 1.3, the authors used the U.S. ReEDS, which includes 134 model balancing areas, subdivided into 356 wind and solar resource regions and roughly 300 representative transmission lines across the contiguous United States. ReEDS meets demand and maintains operational reliability over 17 time slices for each of the twenty-one 2-year periods from 2010–2050. The 17 time slices represent the morning, afternoon, evening, and overnight periods of a typical day in each season, plus a summer superpeak slice that represents the 40 highest load hours in the summer. The model solves a linear program following the schematic in Figure 1- 2.

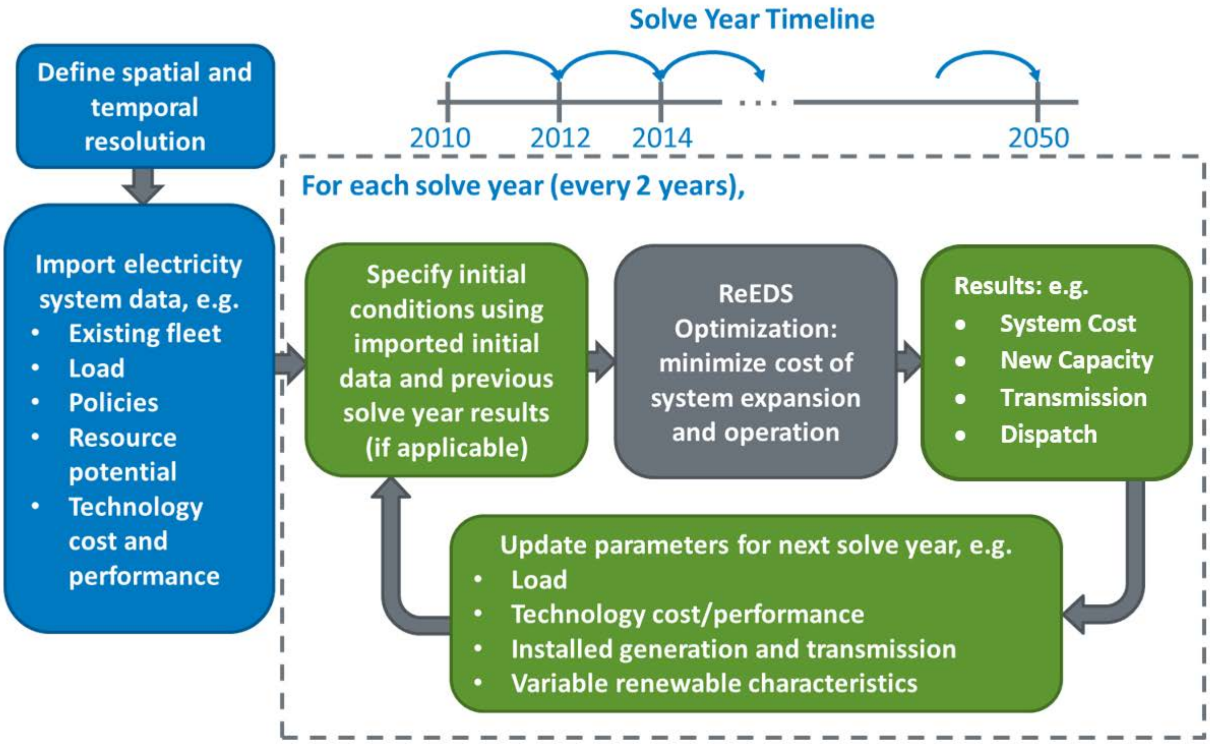


Figure 1- 2. Schematic of the ReEDS model structure

ReEDS's objective function minimizes both capital and operating costs for the electric system, including: (1) the net present value of the cost of adding new generation, storage, and transmission capacity; (2) the present value of operating expenses for all installed capacity throughout the simulation periods. It also determines the dispatch for each of the 17 time slices and contains statistical parameters (including capacity credit for system adequacy, forecast error-based reserve requirements, and curtailment estimates) to address intra-time slice variability and the uncertainty of VRE resources. The model also procures sufficient capacity with appropriate capacity credits for variable renewable resources to satisfy a planning reserve based upon the system peak load. Quick start and spinning reserves are held based on the underlying characteristics of the system.

ReEDS has served as the primary analytical tool for numerous high-impact studies, including the SunShot Vision Study [18], Renewable Electricity Futures Studies [19], Wind Vision [20], Hydropower Vision [21], and GeoVision [22], that investigated issues related to renewable integration, technology development, clean energy policy, and their impacts.

1.2.2 dGen and dGen-ReEDS linkage

The Distributed Generation Market Demand (dGen) model is a bottom-up agent-based model developed at NREL that simulates the potential adoption of distributed energy resources (DER, including distributed solar, wind, storage, geothermal) for residential, commercial, and industrial customers in the conterminous United States through 2050 [23]. The model leverages high-resolution geospatial information and algorithms for modeling the economics of distributed technologies, customer decision-making, and technology diffusion over each of the nineteen 2-year periods from 2014–2050.

The dGen model can be used independently to estimate the potentials for DER adoption [24] and analyze the sensitivity to economic and policy measures [25]. It can also be used with other models at NREL to generate forecasts of DER adoption for integrated resource planning, distribution hosting capacity analysis, or load forecasting.

ReEDS and dGen are optionally linked. For a given scenario, ReEDS is run with default distributed solar photovoltaic (PV) capacity for all solve years and passes the electricity prices to dGen. After dGen runs for the relevant solve years with this new information that characterizes the price suppression effect from PV, it passes the quantities and locations of the resulting installed DER capacity and capacity factors to ReEDS. ReEDS uses the new information to determine the amount of generation from each DER.

As part of an annual effort to create a consistent and transparent framework of technology representation and scenario framework, NREL produces a suite of products, including the Annual Technology Baseline, which contains cost and performance data for generation technologies, and the Standard Scenarios report, which captures a wide range of potential futures of the U.S. electric sector, including the adoption of DER technologies. As a product of the Standard Scenarios, the ReEDS-dGen linkage creates static distributed PV adoption profiles for use in power systems analysis. Figure 1- 3 illustrates the amount of distributed PV capacities across the NREL's ReEDS 2019 Standard Scenarios [15].

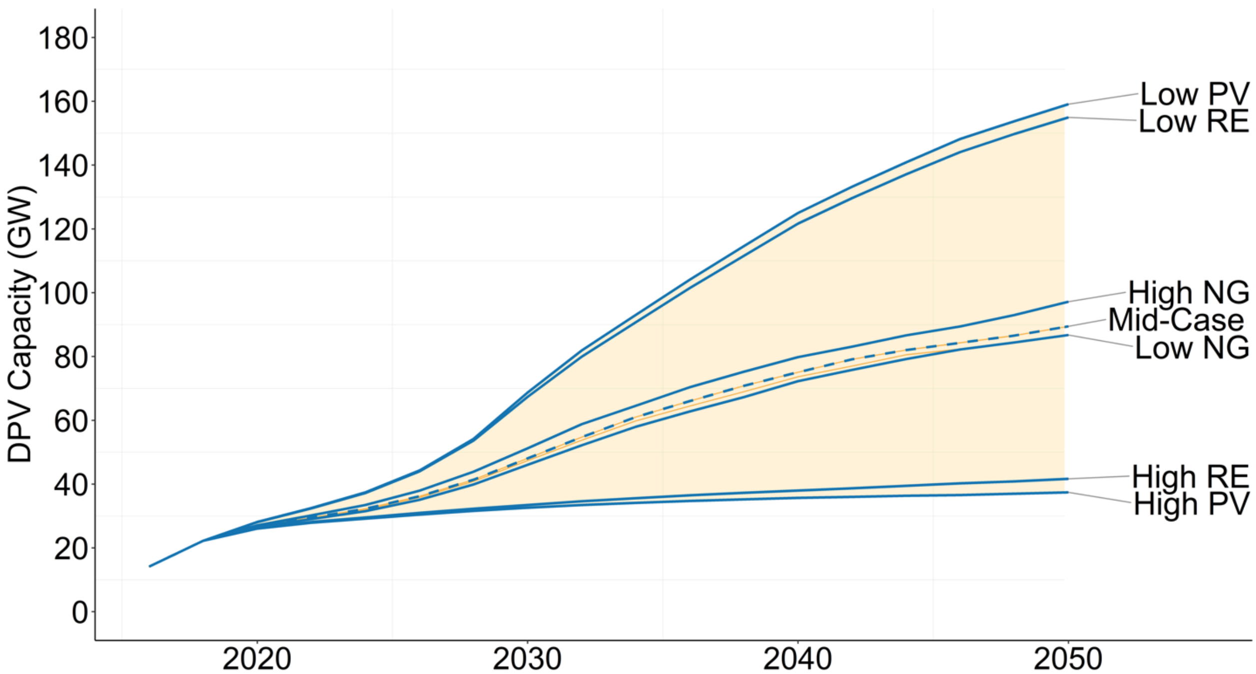


Figure 1- 3. Distributed PV capacities in 2019 Standard Scenarios. PV=photovoltaic; NG=natural gas; RE=renewable energy.

1.2.3 RPM

In addition to ReEDS, NREL has developed a more spatially resolved capacity expansion model—the Resource Planning Model (RPM)—to inform regional power system planning [26]. It includes an optimization model that solves for the least-cost investment and dispatch over a 20-year planning horizon from 2010–2030, based on energy balance, reserves, and many generation and transmission constraints. It also models hourly dispatch for a representative sample of days throughout a year. RPM allows a mix of nodal or zonal representation of regions in the Western Interconnection (Figure 1- 4). As a nodal model, RPM represents individual generation units and transmission lines and uses high spatial resolution to inform generator siting, especially for renewable resources. It has been used to investigate long-term capacity expansion scenarios in Arizona, impacts of the Navajo Generating Station's retirement [27], and potential trends in renewable deployment in Colorado and Los Angeles [28], [29].

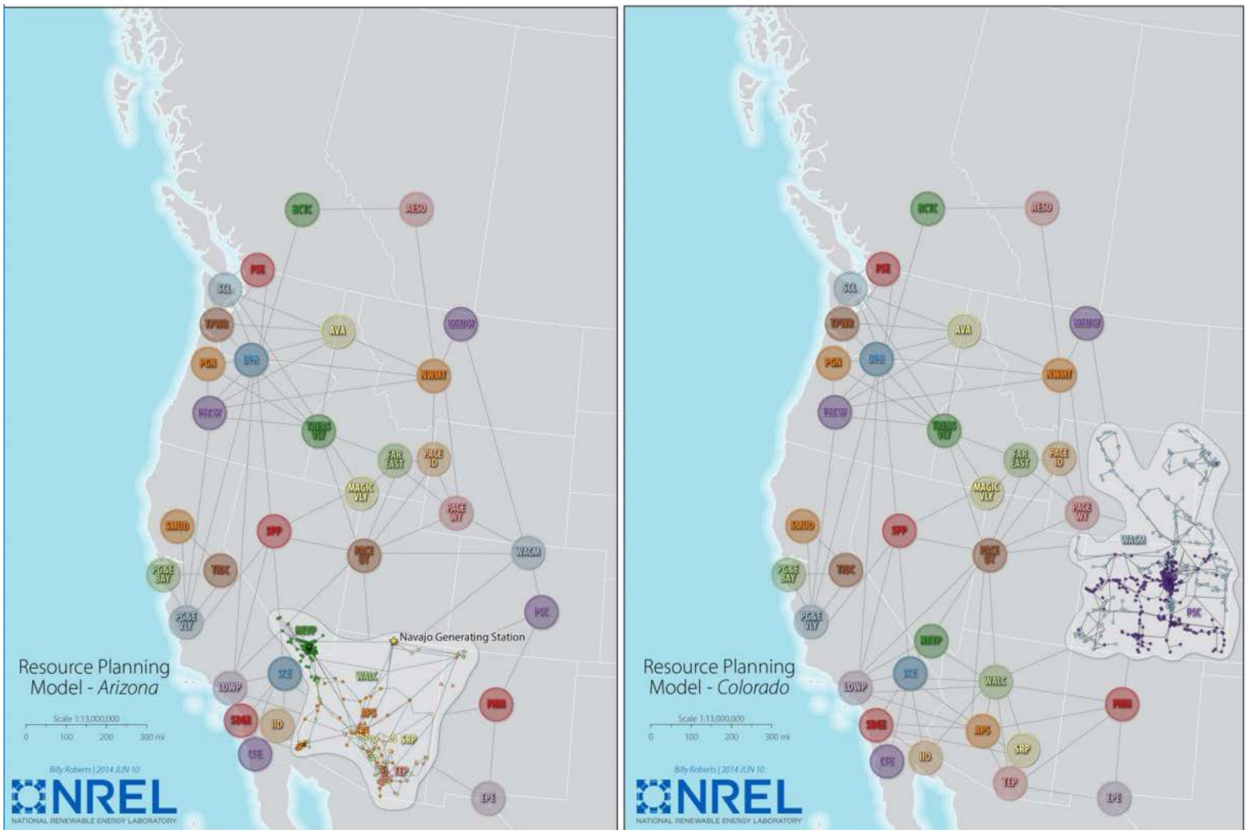


Figure 1- 4. (Left) Nodal representation of Arizona and zonal representation of the rest of the Western Interconnection in RPM; (Right) Nodal representation of Colorado and zonal representation of the rest of the Western Interconnection in RPM

1.2.4 PLEXOS Production Cost Model

PLEXOS is a commercial production cost model developed by Energy Exemplar. Production cost models optimize the operation of the electricity grid for least-cost provision of energy and operating reserves. Unlike capacity expansion models, production cost models do not consider the capital costs of new generation or transmission, instead assuming a predetermined infrastructure. PLEXOS can be used to study power system operation in more detail than is feasible with capacity expansion models. It can execute a chronological simulation at hourly to sub-hourly scales, accounting for ramp rates and other constraints between timesteps. A common configuration is a two-step solution: (1) day-ahead unit commitment that optimizes the scheduling of the generation fleet one day at a time with 24 hours of foresight into the next day using forecasted load and variable generation profiles; and (2) a real-time economic dispatch that uses the unit commitment information along with actual load and variable generation profiles to solve for the 5-minute dispatch of the system. Spatially, PLEXOS can solve DC optimal power flow to approximate AC optimal power flow at the nodal level. Alternatively, transmission can be aggregated to inter-regional to improve solve time, while generator level details are still respected (i.e., ramp rates). With the appropriate geospatial and temporal decomposition, PLEXOS can use mixed-integer programming to solve for the least-cost unit commitment and dispatch solution at sub-hourly resolution for a system as large as the entire North American electric power system. NREL has used PLEXOS for a number of grid integration studies covering the Western United States [30], the Eastern United States (Figure 1- 5) [31], and India [32], [33], as well as studies that investigate the value and impacts of various technologies such as battery storage [34], demand response [35], and concentrating solar power [36].

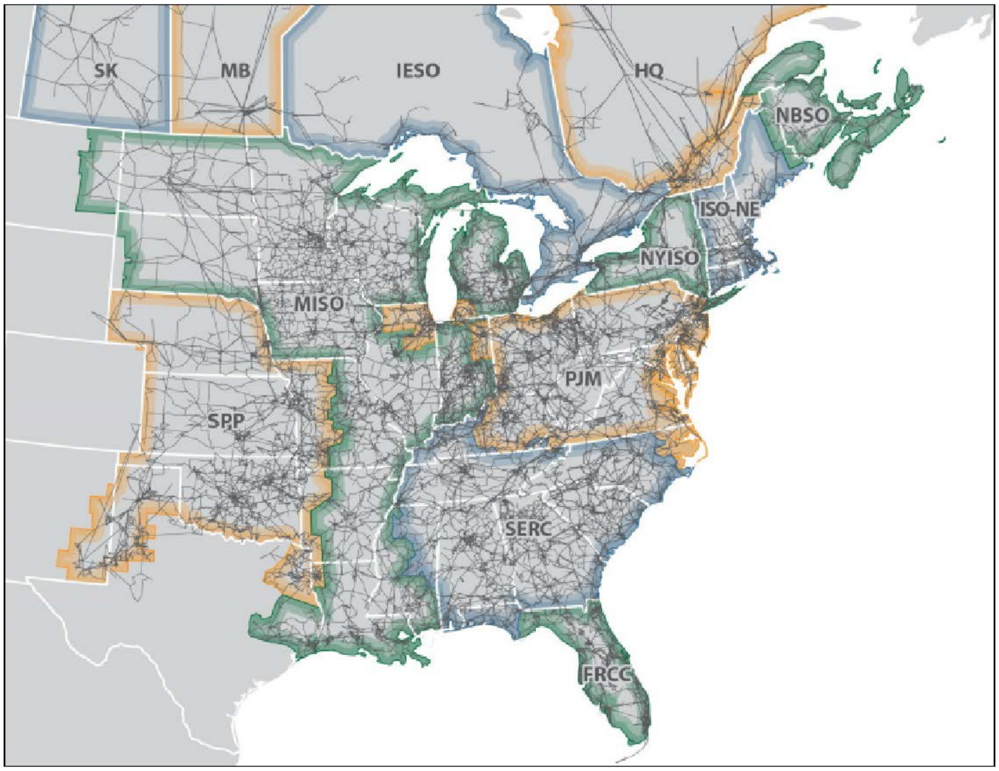


Figure 1- 5. Base transmission representation of the U.S. Eastern Interconnection

Source: [31]

1.2.5 Other Models

Many other capacity expansion and production cost models are used for various planning and grid integration studies. They are not the focus of the report, but we provide a non-exhaustive list of commonly used models here:

- The National Energy Modeling System [37] is used by the U.S. Energy Information Administration (EIA) as the bedrock for the *Annual Energy Outlook* [38]. It is an economy-wide modeling system for capacity expansion with several fuel supply and fuel market modules as well as demand-side modules. It represents the conterminous United States in 22 zones.
- MARKAL [39], short for MARKet ALlocation, is a dynamic optimization model for strategic energy planning developed by the Brookhaven National Laboratory with sponsorship from the U.S. Department of Energy (DOE) and the International Energy Agency (IEA). More than 40 countries have used the model to analyze energy planning and environmental policy-related issues. The U.S. MARKAL model [40], as adopted by the U.S. Environmental Protection Agency, has nine demand regions for the conterminous United States (fuel supply is divided into respective coal, oil supply regions).
- Integrated Planning Model, developed by ICF International, is a multiregional, dynamic, deterministic linear programming model that represents the electricity power markets, fuel markets, and emission markets. It conducts least-cost capacity expansion and electricity dispatch. In the United States, it has been used to support the U.S. Environmental Protection Agency's power sector policy analysis [41]

and the Federal Energy Regulatory Commission's (FERC's) cost-and-benefit analysis of regional transmission organization (RTO) policies [42].

- PROMOD [43], developed by Ventyx and now owned by ABB, is an electric market simulation model that produces a unit commitment and security-constrained economic dispatch while optimizing bid production costs. It performs detailed generator portfolio modeling with both zonal price and nodal locational marginal price forecasting; it can also perform transmission analysis including marginal losses. It has been used by system operators such as the Midcontinent Independent System Operator, PJM, and Southwest Power Pool to support their market impact and system planning studies [44].
- GridView [45], developed by ABB, is a security-constrained unit commitment and economic dispatch model with databases of the Western Electric Coordinating Council territory, the Eastern Interconnection, and Electric Reliability Council of Texas (ERCOT) in nodal details. It has been used to support DOE's SunShot study [46], as well as system operators' benefit analysis of the Western Energy Imbalance Market (EIM) [47], [48].
- EnergyPLAN [49], developed by Aalborg University, is an input/output model that couples the electric power, heating, cooling, industrial, and transportation sectors. It has been used to analyze large-scale integration of renewable energy in the national systems of various countries [50]–[53].
- U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN), developed by the Electric Power Research Institute (EPRI), is a U.S. electric sector capacity expansion model coupled with a computable general equilibrium model of the U.S. economy [54].

Many other models have been used to analyze power systems with high penetration of variable renewable generation and other innovative generation, transmission, or control technologies. These models include, but are not limited to, the UPLAN production cost model [55], Generation and Transmission Maximization production cost model [56], Aurora capacity expansion and production cost model [57], Global Change Assessment Model general equilibrium model [58], and Dispa-SET production cost model of the European heat and power system [59]. Comparisons of the long-term capacity expansion models are part of work between ReEDS, National Energy Modeling System, Integrated Planning Model, and US-REGEN modeling teams [60].

1.2.6 Input Data and Assumptions

The complete set of input assumptions for the 2019 Standard Scenarios and operational analysis of the Eastern Interconnection and Western Interconnection are documented in several technical reports [15], [61], [62]. The two primary sources of input for Standard Scenarios are the *Annual Energy Outlook 2019* [63] from EIA and the 2019 *Annual Technology Baseline* [64] developed at NREL. Further ReEDS inputs and sources are documented in detail in the *Regional Energy Deployment System (ReEDS) Model Documentation Version 2019* [16].

EIA's *Annual Energy Outlook* provides data on a range of electricity demand growth and fuel price assumptions. The *Annual Technology Baseline* provides current data and a range of projections through 2050 on various electricity generation technology and battery storage capital costs, capacity factors, and operation and maintenance costs. The *Annual Technology Baseline* also allows user-specific financial assumptions (e.g., inflation rate, capital recovery period, rate of return on equity) for adjusting the costs. Figure 1- 6 shows the range of levelized cost of energy (LCOE)[1] for generation technologies by 2030,

[1] LCOE is the ratio between the present value lifetime costs of an electric generating unit and the total energy produced during the lifetime of a plant and serves as an aggregate cost metric. LCOE is useful metric for comparing the economic competitiveness of generation technologies for providing energy. A limitation of LCOE is that it does

based on research and development efforts only, without market factors such as production tax credit phase-out.

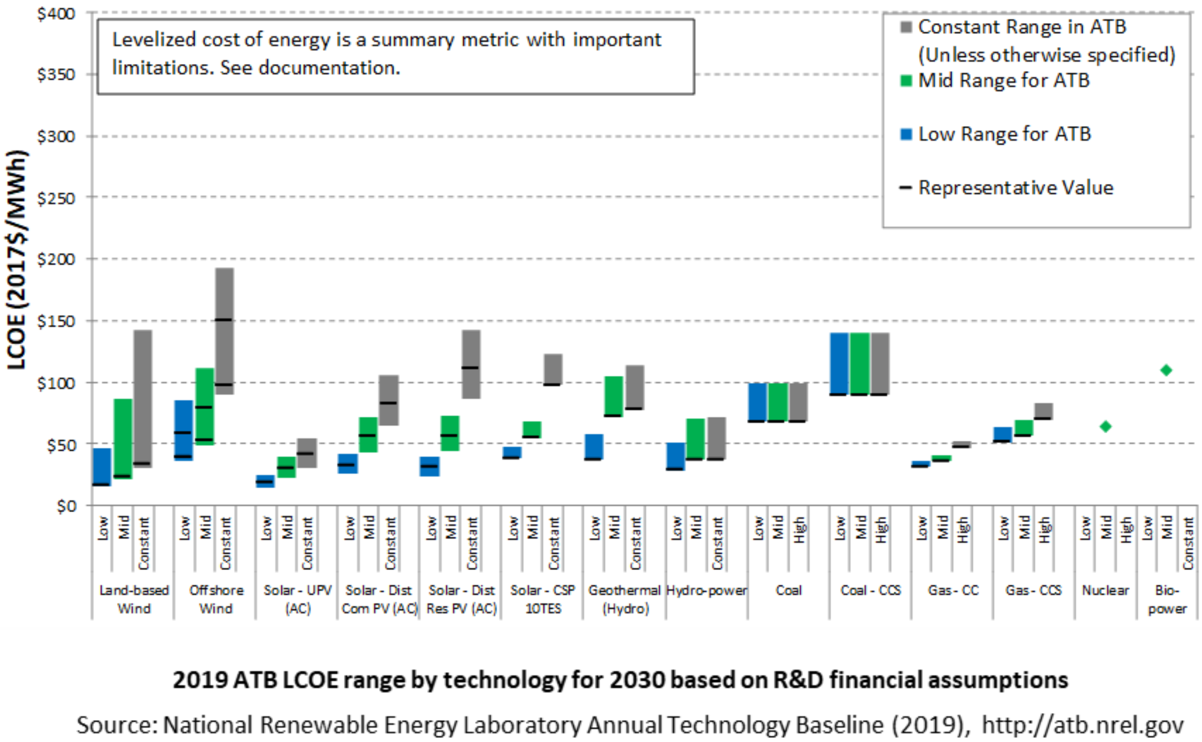


Figure 1- 6. 2030 LCOE range by technology in the 2019 Annual Technology Baseline

The inputs to the Standard Scenarios' reference scenario (Mid-Case) reflect the state, regional, and federal policies in place as of July 31, 2019, as well as mid-level assumptions (such as *Annual Energy Outlook* fuel price and *Annual Technology Baseline* technology costs) in the model. It serves as a useful point for comparison but does not necessarily represent the most likely scenario.

capture nonenergy values streams like capacity credit and should not be considered as the sole metric for the economic competitiveness of a technology.

1.3 U.S. Electricity Sector Transformation

The U.S. electric power system may evolve along many different paths with different mixes of generation and storage technologies. The NREL studies summarized here do not attempt to predict the exact composition of the future power system. Rather, we explore through sensitivity analysis the impacts of various factors, including fuel prices, technology costs, financial assumptions, retirements of existing fleet, and other changes in the power system evolution. While each country has unique power system transition pathways due to different resources, loads, and existing infrastructure, some of the technology cost trends and generation mix evolution in the U.S. power system may serve as a reference to other power systems.

1.3.1 Trends Across Studies

Studies such as EIA's *Annual Energy Outlook 2019* [63], IEA's *World Energy Outlook 2019* [65], and Bloomberg New Energy Finance's *New Energy Outlook 2019* [66] offer multiple scenarios based on interpretations of the potential technology, market, and policy conditions. While the specific results of these analyses differ significantly, together they highlight some important trends, such as the growth of renewables and the decline of coal and nuclear in the U.S. power mix.

Coal and nuclear capacity as a percentage of total installed capacity was projected to continue declining from current levels in all examined scenarios across these studies, as illustrated in Figure 1- 7. Coal capacity, in particular, was projected to steeply decline through the 2030s, reflecting the retirement of older coal plants. In 2018, 86% of the operating coal capacity in the United States was more than 30 years old [67]. These studies projected a similar decline in nuclear capacity, especially because most of the U.S. nuclear fleet was built in the 1970s and 1980s, with only 7% of the total operating nuclear capacity built after 1990 [67].

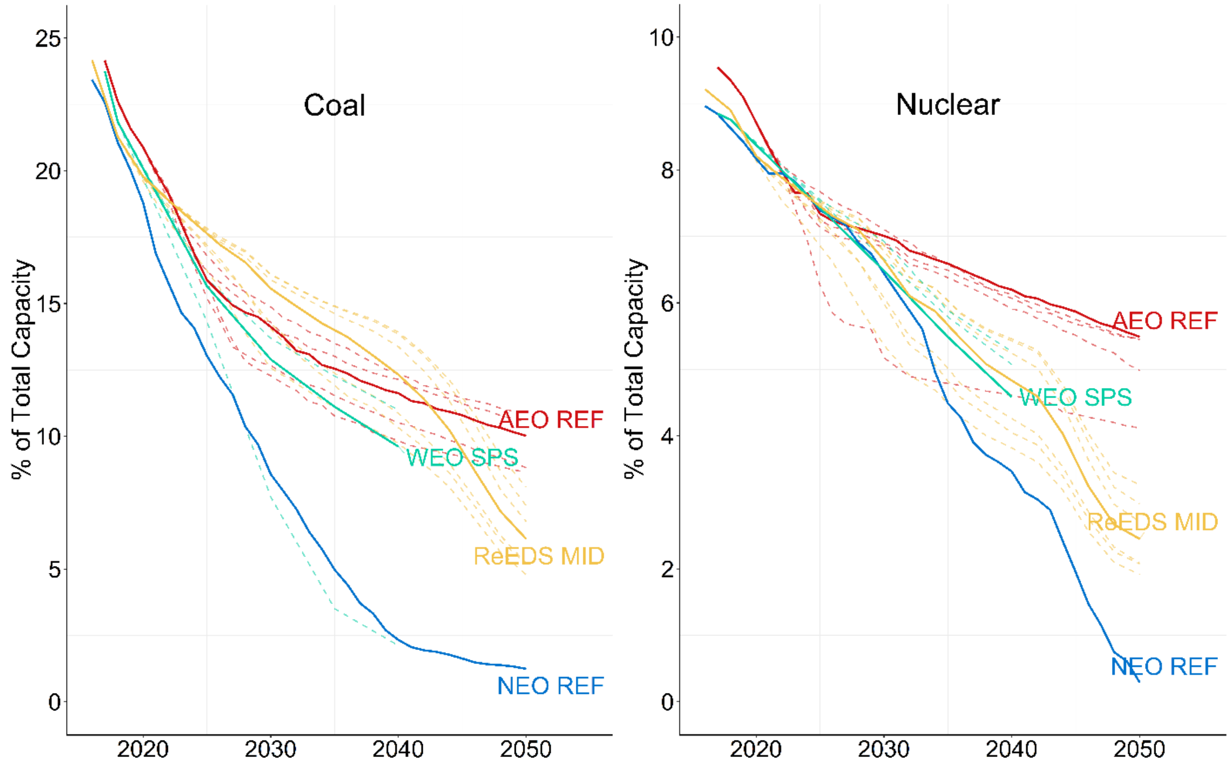


Figure 1- 7. Evolution of coal (left) and nuclear (right) capacity as a percentage of total installed capacity in the long-term scenarios in referenced literature

WEO SPS is *World Energy Outlook 2019* Stated Policy Scenario and ends in model year 2040; AEO REF is *Annual Energy Outlook 2019* Reference Case; NEO REF is *New Energy Outlook 2019* Reference Case; ReEDS MID is NREL's ReEDS *2019 Standard Scenarios'* Mid-Case. Full list of referenced scenarios is in Appendix 1-1.

In terms of generation, natural gas, wind, and solar were projected to meet much of the growing demand in the future. As shown in Figure 1- 8, natural gas would contribute 30%–40% of the total annual generation by 2040[2] in most of the reference scenarios across the studies. Wind and solar grow steadily in all scenarios examined. Most scenarios showed the future power system to comprise at least 20% of annual generation from wind and solar by 2040.

[2] We choose 2040 as the year for comparison here because the *World Energy Outlook 2019* only goes out to 2040.

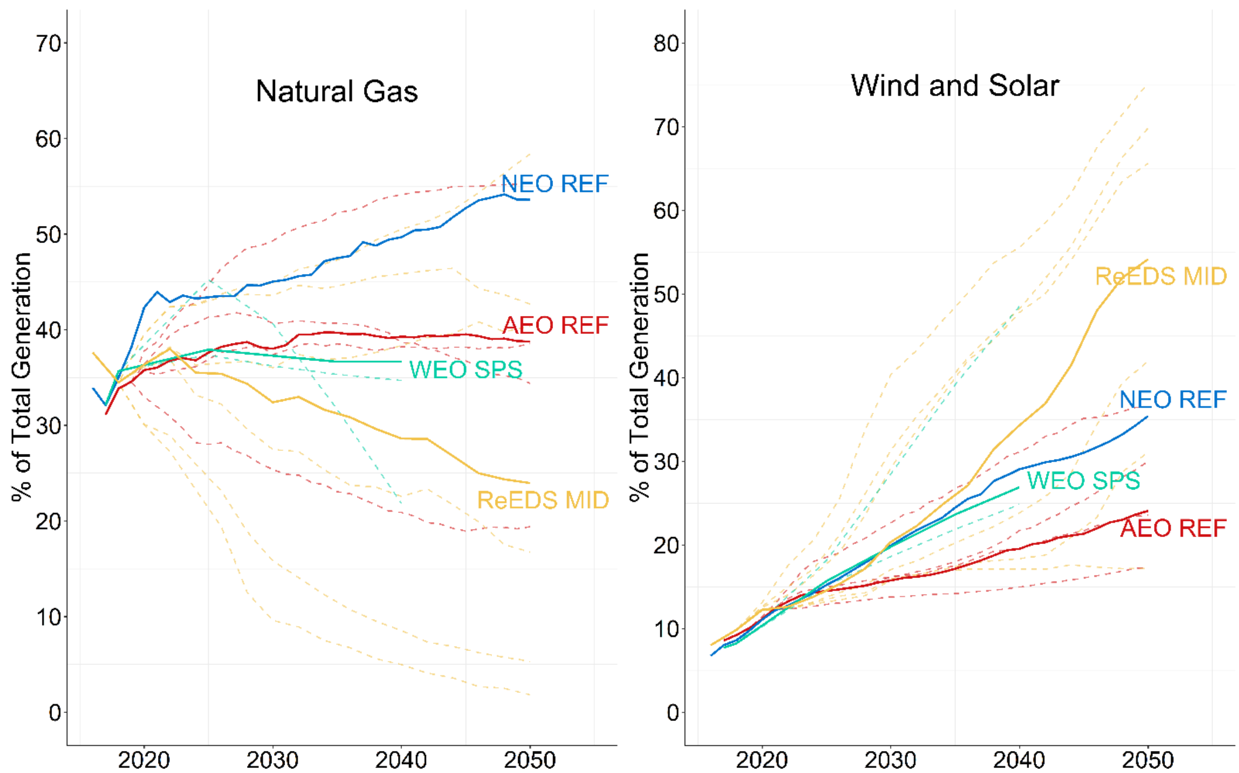


Figure 1- 8. Evolution of natural gas (left) and wind and solar, including solar PV and concentrating solar power, generation (right) as a percentage of total power generation in the long-term scenarios in the referenced literature.

WEO SPS is *World Energy Outlook 2019* Stated Policy Scenario and ends in model year 2040; AEO REF is *Annual Energy Outlook 2019* Reference Case; NEO REF is *New Energy Outlook 2019* Reference Case; ReEDS MID is NREL's ReEDS *2019 Standard Scenarios'* Mid-Case. Full list of referenced scenarios is in Appendix 1-1.

1.3.2 General Trends in Standard Scenarios

NREL's 2019 Standard Scenarios showed that the U.S. electricity sector could evolve along several dimensions throughout 2050, with different generation mixes, transmission capacities, revenue structures, and planning reserve provisions. In the following sections, we will focus the discussion on wind and solar, natural gas, transmission expansion, and implications for carbon emissions in the Standard Scenarios. And in Section 1.3.8, we briefly discuss the role of other technologies in the power grid evolution, based on a series of studies conducted at NREL.

The past decade has seen rapid growth in VRE. In the 2019 Standard Scenarios' Mid-Case scenario, reflecting current policy as well as moderate fuel and technology cost assumptions, nearly all states in the conterminous United States were projected to transition toward power systems with higher shares of VRE generation, while total electricity demand also increases from 2018 levels (Figure 1- 9). Twelve states would reach more than 80% VRE penetration in 2050. Some states would have relatively similar VRE penetration across the range of scenarios the study examined driven by their state renewable portfolio standards, such as in New Mexico, California, and the northeastern states. Coal and nuclear generation were projected to decrease in all states. Natural gas generation would decrease in 32 states and increase in 16 states. Montana, Nebraska, Wyoming, and six other states would see over a 95% drop in gas generation in the Mid-Case in 2050 compared with 2018 levels, while Louisiana, Idaho, Vermont, and West Virginia would have the biggest percentage increase in gas generation (by over 300%).

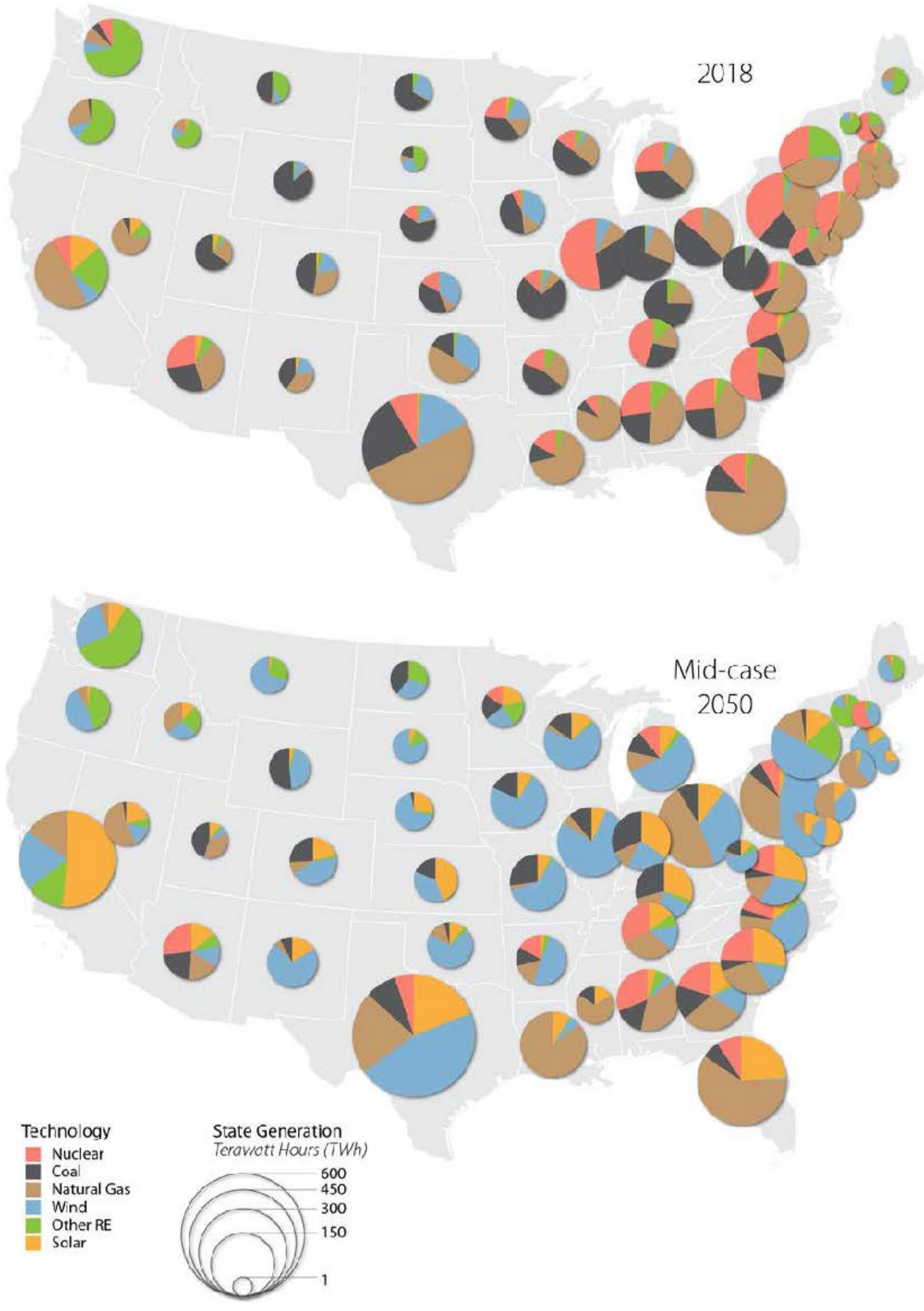


Figure 1- 9. Comparison of generation mix of the current U.S. power system (top) and the 2050 Mid-Case scenario by state in NREL's 2019 Standard Scenarios

1.3.3 Wind and Solar PV Would Grow Significantly in Most Scenarios

Wind and solar PV deployments showed significant increase in most scenarios. In this section, we first review the national trends for wind and solar PV development, then examine their geographical diversity, and, finally, examine their contribution to peak capacity and planning reserves.

In the 2019 Standard Scenarios' Mid-Case, wind and solar PV capacities in 2050 were projected to be more than five times and eight times greater than in 2018. Figure 1- 10 shows the generation and capacity mix throughout 2050 for the Mid-Case, where wind would account for 36% of total generation in 2050 relative to 7% in 2018, and solar PV would account for 17.5% of total generation in 2050 relative to 2.7% in 2018. Total demand for power was assumed to grow steadily at an average annual rate of around 1.8%. As the total capacity grows over time to meet the increasing demand, new capacity from natural gas combined cycle (NG-CC), wind, and solar PV would be built and coal and nuclear generation would be retired, especially in the late 2040s based on age-based retirements.

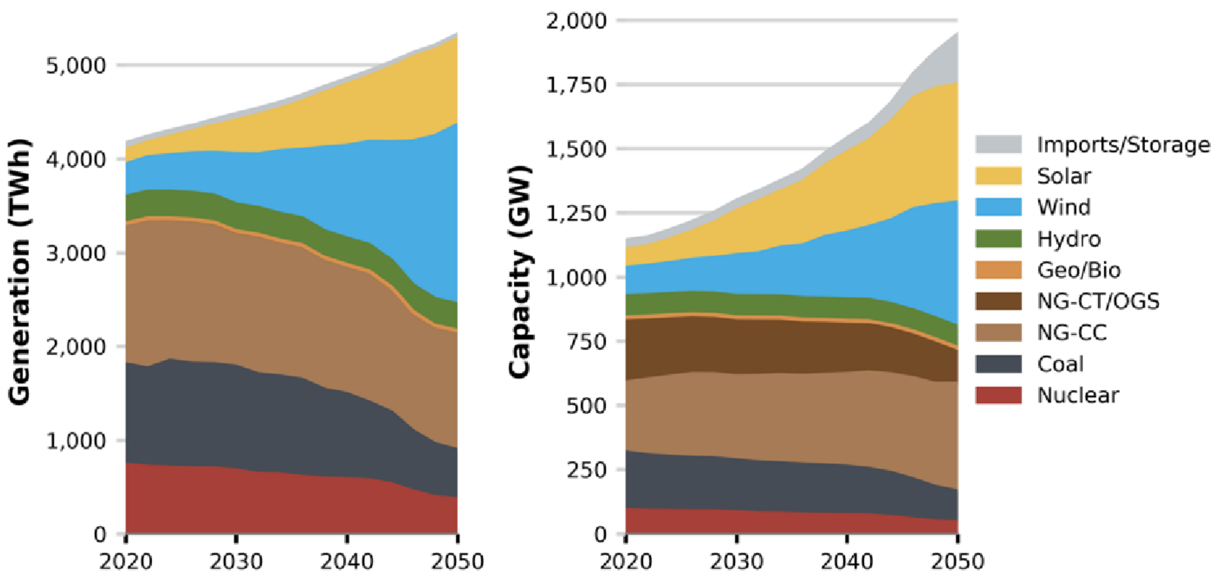


Figure 1- 10. U.S. power generation and capacity throughout 2050 in the 2019 Standard Scenarios' Mid-Case scenario

Annual generation (left) shows electricity imports from Canada and Mexico in grey while installed capacity (right) shows storage capacity in grey. NG-CC is natural gas combined cycle; NG-CT is natural gas combustion turbine; OGC is oil-gas-steam; Geo/Bio is geothermal and biopower.

In fact, the growth of wind and solar PV was a common trend in most of the scenarios in the 2019 Standard Scenarios (Figure 1- 11). Technology cost and fuel price assumptions would be the main drivers for wind and solar PV deployment and generation. Wind generation would reach nearly 48% in the scenario with high natural gas price assumptions (noted as High NG Price in the graph). Solar PV could reach over 31% of total generation in 2050 under Low PV Cost. Low renewable technology cost alone would drive wind to 35% of total generation and solar PV to over 29% of total generation.

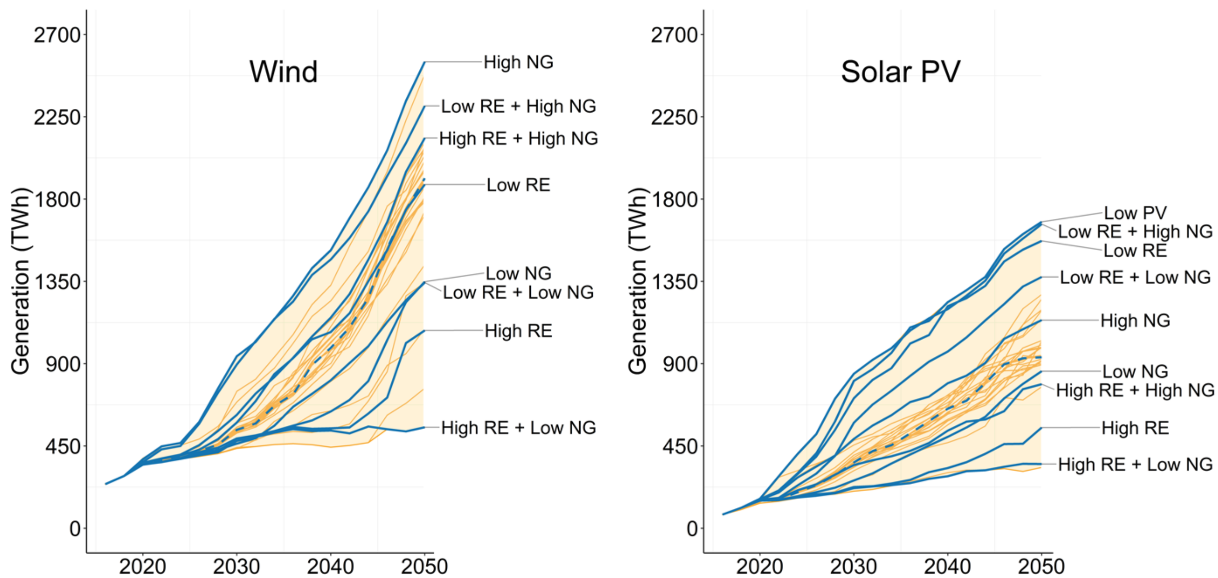


Figure 1- 11. Generation from wind (left) and solar PV (right) throughout 2050 in 2019 Standard Scenarios

Each line corresponds to a ReEDS scenario, and the shades show the range of values across all scenarios.

Combining the impact of natural gas price and renewable technology cost would have the biggest impact in VRE penetration. Figure 1- 12 shows that under the low renewable cost and high natural gas price assumptions (Low RE Cost + High NG Price scenario), the VRE penetration could reach as high as 74% without any additional policy interventions.

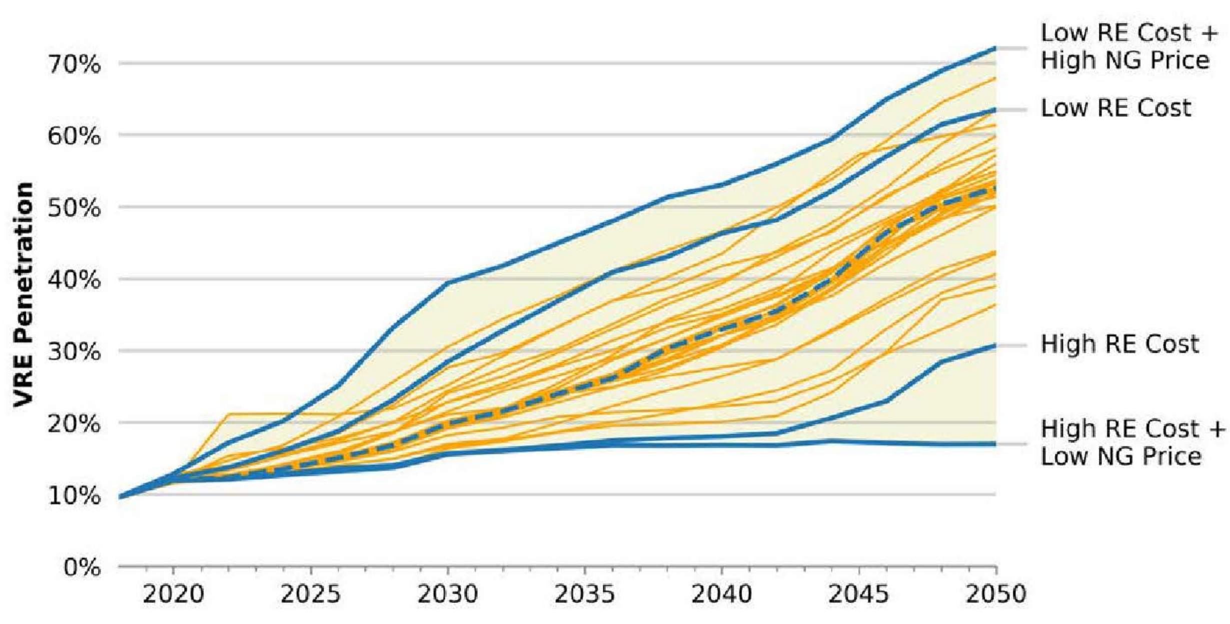
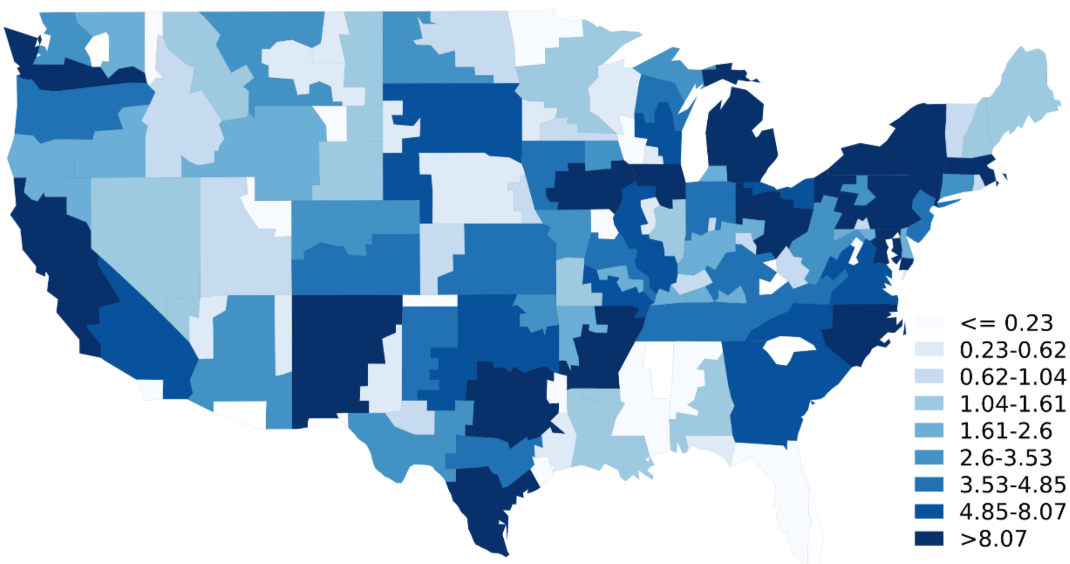


Figure 1- 12. VRE penetration in all modeled scenarios throughout 2050 in 2019 Standard Scenarios

The wind and solar PV generation would come from a variety of regions across the conterminous United States. Figure 1- 13 shows the projected installed capacity in 2050 for wind and solar PV, respectively, under Mid-Case in each of the 134 balancing areas in ReEDS. The diversity of renewable energy resources across resource regions contributes to overall system reliability in several ways. First, the geographical diversity and large footprint in which resources are available help to smooth the overall variability of wind and solar PV outputs. Second, such diversity improves the capacity credit, the expected fraction of capacity that a generator can reliably provide during high-risk hours,[3] of wind and solar PV output. Third, compared with a system where wind and solar PV generation are highly centralized in a limited geographical footprint, the diversified resource reduces the impact of an individual plant outage or a local weather event on the overall system operation, therefore enhancing system reliability.



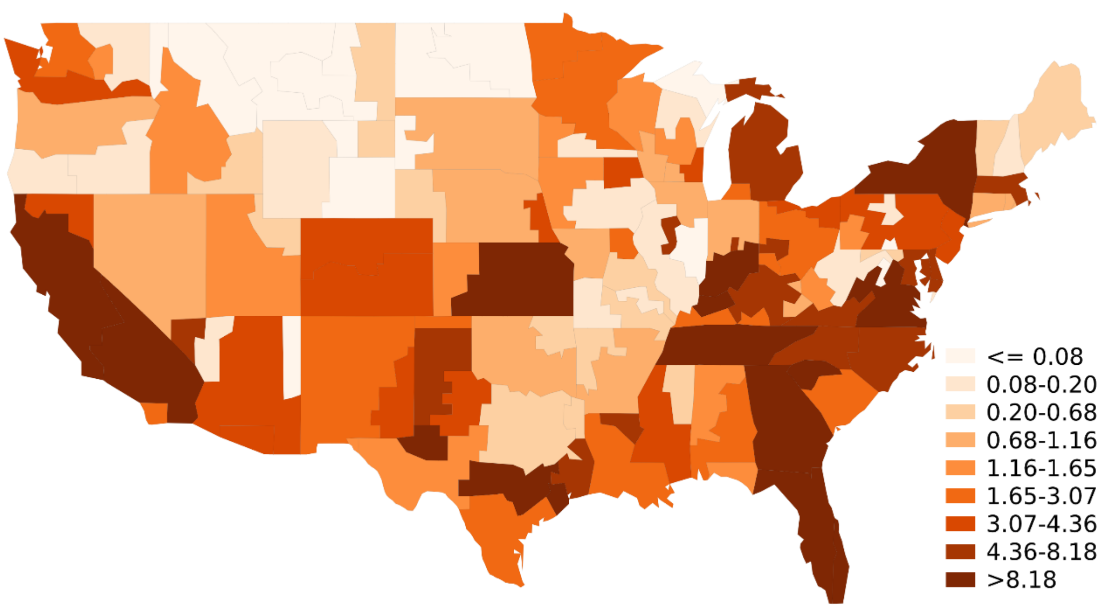


Figure 1- 13. Top: Installed wind capacity for all resource regions in 2050 in 2019 Standard Scenarios' Mid-Case scenario (GW); Bottom: Installed solar capacity for all resource region in 2050 in 2019 Standard Scenarios' Mid-Case scenario (GW)

3 High-risk hours are hours at a high probability of load loss, such as, but not limited to, peak net load hours.

Nevertheless, the contribution from wind and solar PV to the system planning reserve could be rather limited. Across the NREL Standard Scenarios, wind would contribute 3%–11% of planning reserve capacity in 2050 and solar PV 5%–14%, even though they would contribute 10%–35% and 7%–40% of the total capacity, respectively (Figure 1- 14). This is because the capacity credit of VRE, which we defined as the expected fraction of capacity that a generator can reliably provide during high-risk hours, is subject to a complex range of factors. At low VRE penetrations, high-risk hours tend to coincide with the peak load hours (e.g., summer afternoons). With higher VRE penetrations, the high-risk net peak hours are shifted to evenings due to the diurnal nature of PV. Low wind events are also capable of producing high-risk hours but are less predictable than the effects of PV. Other impacting factors include the impact of VRE spatial diversity, the transmission system network, the capacity and duration of storage, flexible generators, and responsive load, among others.

ReEDS models VRE capacity credit by considering hourly load and VRE resources and estimating the expected load-carrying capacity using the top 10 net load hours [16], that is, the hours with the highest total load minus VRE generations. Consistent with other literature on capacity credit [68], [69], we also observed the declining capacity credit of solar PV over time across the three interconnections in the United States (Figure 1- 15) [15]. This was due to two factors: (1) As more solar PV was added to the system, the coincidental generation from solar increased and the net demand (the difference between demand and VRE generation) shifted from the noon periods to the evening periods where solar has virtually no capacity credit. The Western Interconnection had much lower solar capacity credit due to the much higher penetration of solar PV in 2018. (2) It also reflected that after the initial deployment in high-resource-quality regions, solar PV deployment moved to regions with lower resource quality, which become cost-competitive on energy as PV deployment costs fell with time. However, unlike wind where future technology developments, such as increases in hub height and rotor diameter, improve the plants' performance and ability to provide capacity, PV technology performance (including cell conversion efficiency) of PV was not assumed to improve much over time in the model.

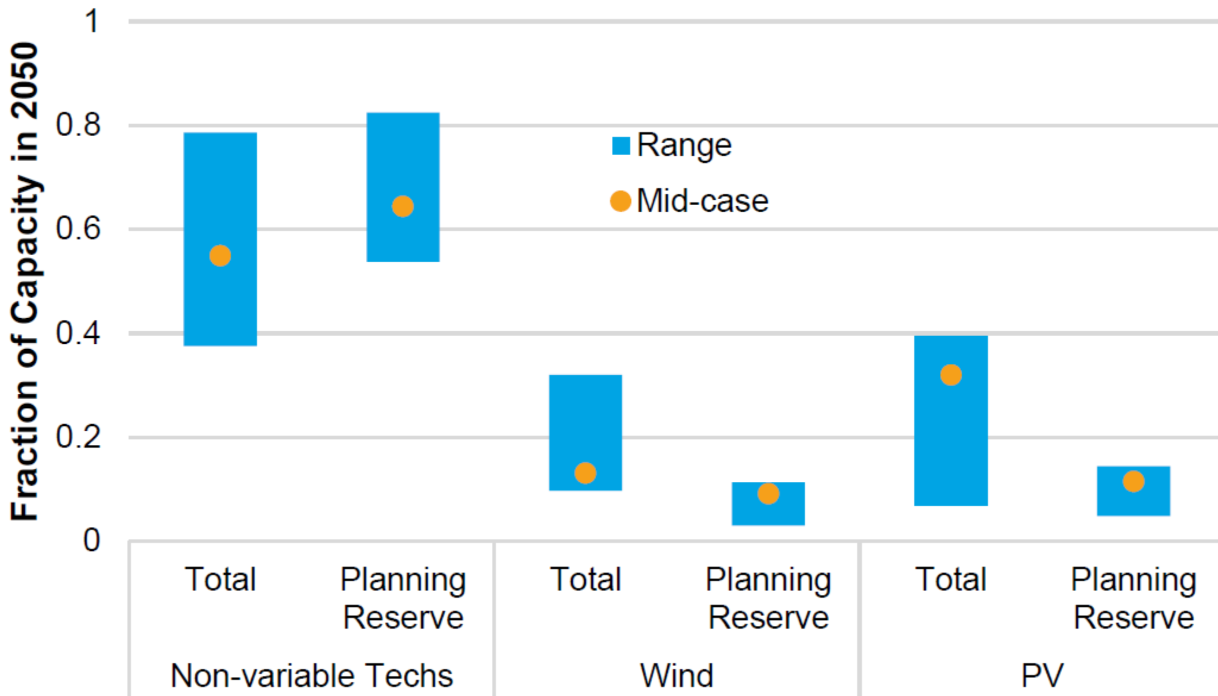


Figure 1- 14. Fraction of planning reserve contribution and total capacity from the specified technology types in 2050 in the summer in 2019 Standard Scenarios

The orange dots show the values from the Mid-Case scenario, and the bars show the range across all the scenarios.

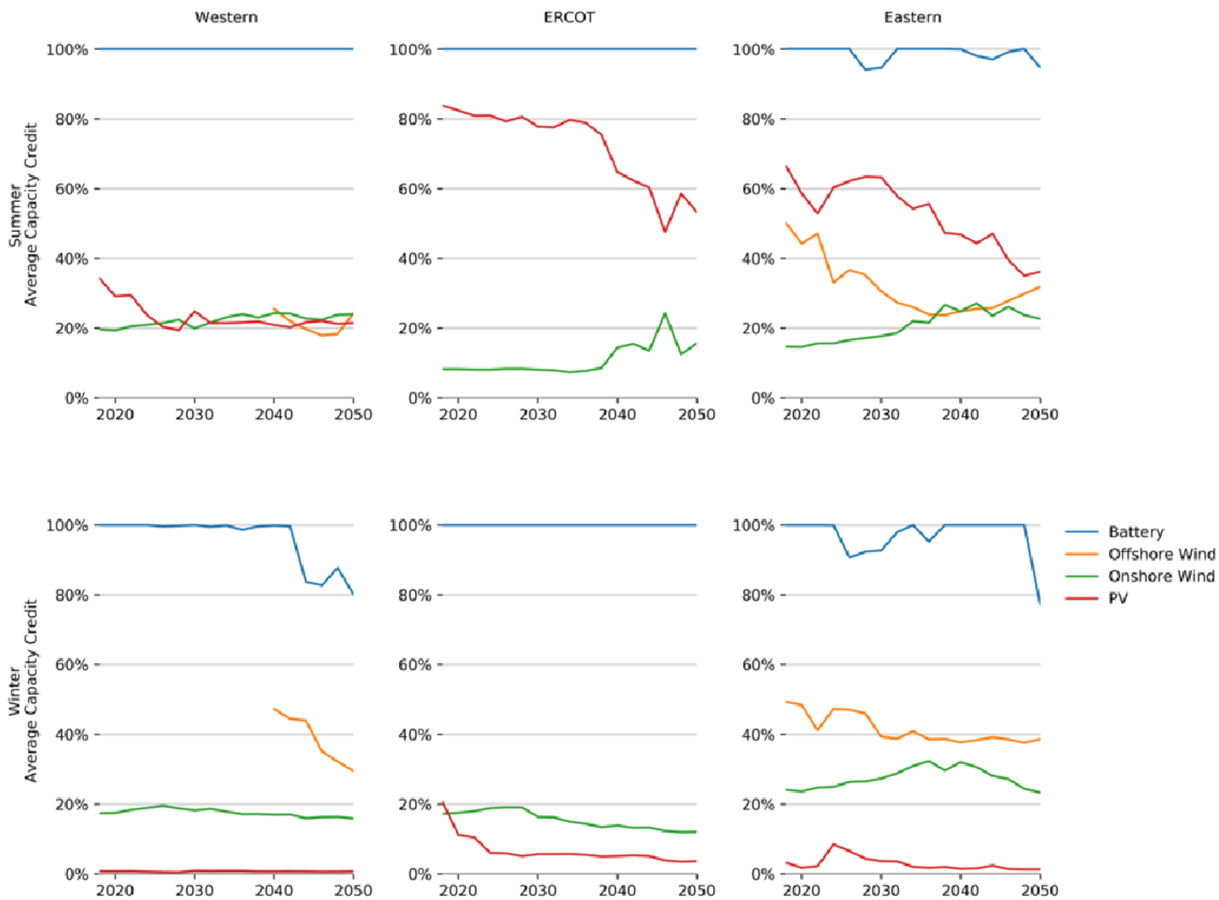


Figure 1- 15. Average capacity credit of utility PV, land-based wind, offshore wind, and 4-hour duration battery storage by season and interconnection in 2019 Standard Scenarios' Mid-Case scenario

1.3.4 Natural Gas

Natural gas, alongside wind and PV technologies, would see significant new capacity additions across scenarios and continue to play a significant but evolving role in the power system. Under 2019 Standard Scenarios' high VRE penetration scenarios, NG-CC and natural gas combustion turbines (NG-CT) contribute significantly toward the planning reserve. New installations for resource adequacy would shift around 2030 when, under reference storage cost assumptions, 4-hour battery storage would be economically competitive over natural gas combustion turbines and displace it as a peaking plant (Figure 1- 10). The gas generation fleet would adjust over time to providing planning reserves as a greater fraction of their revenue streams (Figure 1- 16).

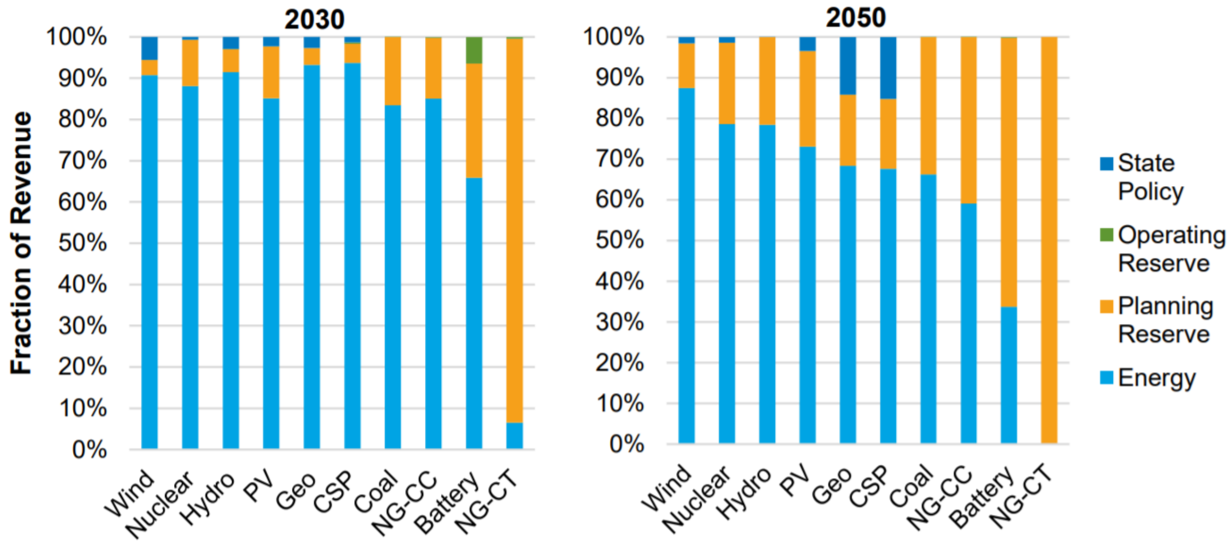


Figure 1- 16. Comparison revenue sources for technologies between 2030 and 2050 in 2019 Standard Scenarios' Mid-Case scenario show shifts toward providing planning reserves at increasing VRE penetrations.

Natural gas price assumptions would be a strong driver for the evolution of the power system. It is reflected in the model investment decisions, and a range of price results were strongly associated with the natural gas prices (Figure 1- 17). Natural gas generators were frequently the marginal unit in the ReEDS model in the Standard Scenarios. Because of this, natural gas fuel price sensitivities drove significant changes in model results.

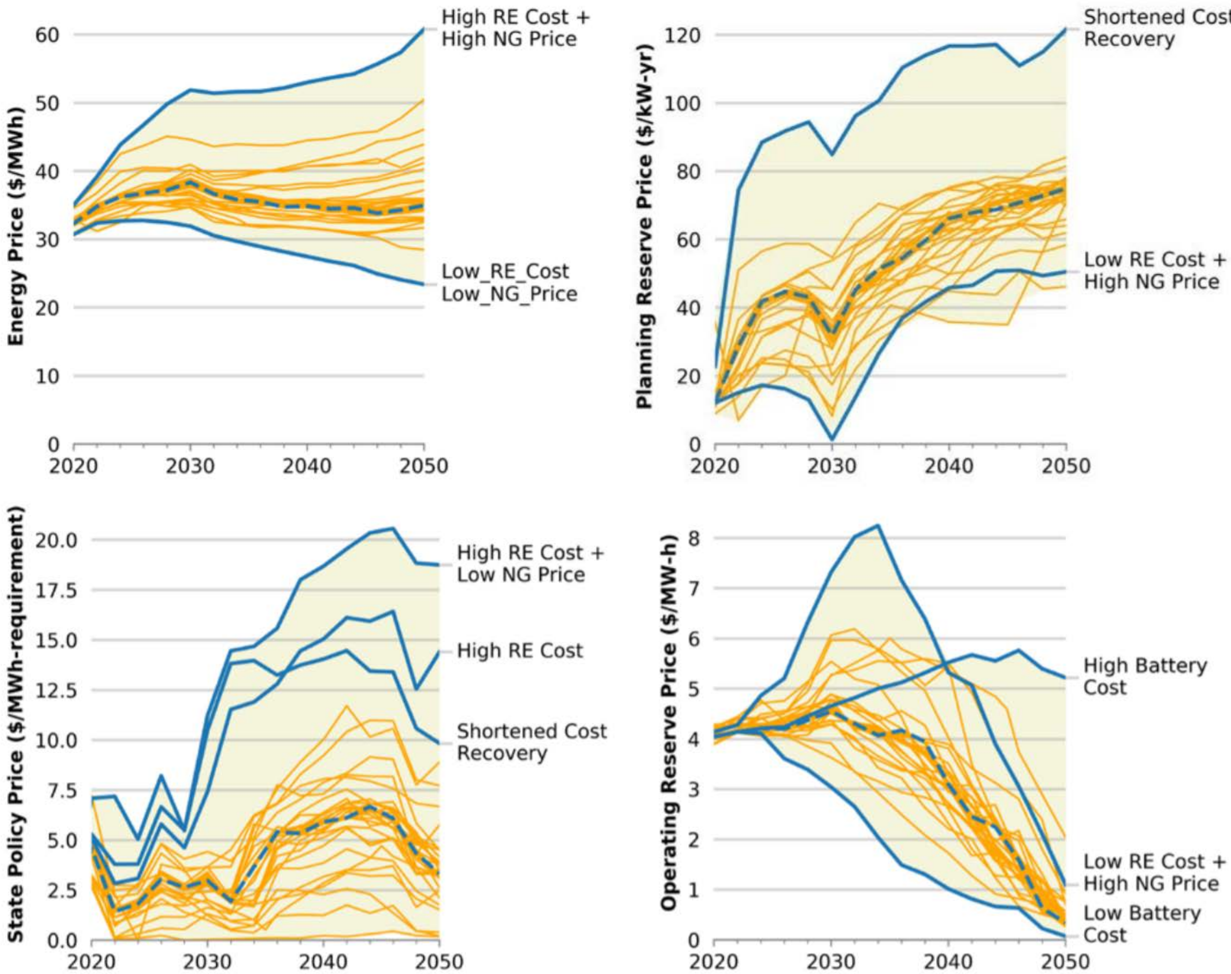


Figure 1- 17. National annual average prices for power system services are consistently sensitive to natural gas price assumptions in 2019 Standard Scenarios.

1.3.5 Transmission Would Help Enable VRE Deployment in Future Power Systems

Transmission capacity is an important consideration for the future power system. As Figure 1- 18 shows, high natural gas prices can drive the expansion in transmission capacity, because the model needs to find affordable (often renewable) resources at greater distance from load centers. In addition, high renewable energy cost assumptions lead to greater transmission expansion than low renewable energy cost assumptions. This is because, with low renewable energy costs, lower quality resources close to load are cost-competitive compared with more distant higher-quality resources. With high renewable energy cost, it is more cost-effective to share resources between regions and utilize the highest-quality renewable energy resources available.[4] This implies that if there are barriers to transmission expansion,[5] the development of wind would be reduced compared with Mid-Case, in favor of solar PV and NG-CC

[4] This is also partly driven by state renewable portfolio standard mandates.

[5] Represented in ReEDS in the High Transmission Cost scenario by barring any new interconnection interties, tripling the capital cost of any new inter-balancing authority transmission, and doubling the transmission loss rate from 1% to 2% per 100 miles.

generation that can be deployed closer to load centers. Transmission also has a profound impact on system balancing and renewable integration, which will be discussed in Section 1.4.

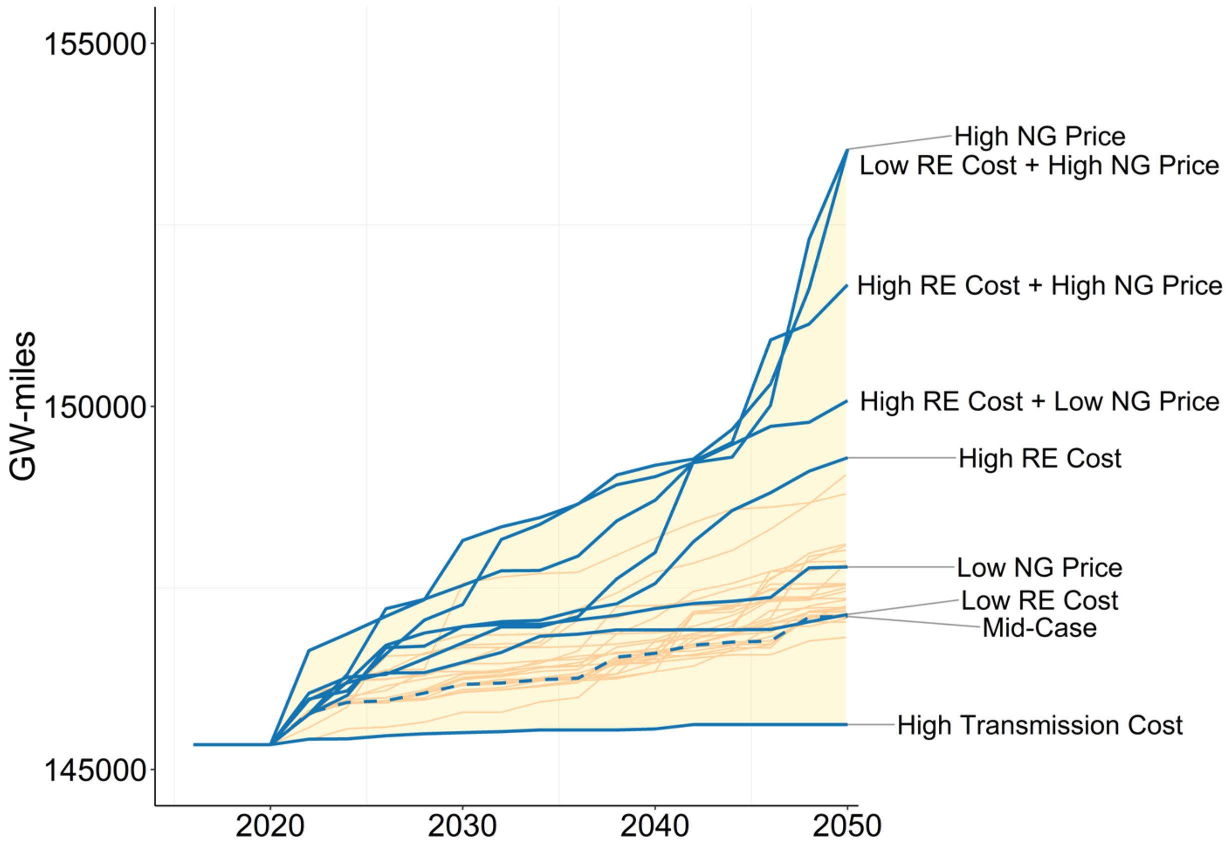


Figure 1- 18. Transmission capacity throughout 2050 in 2019 Standard Scenarios, where each line corresponds to a scenario and the shades show the range of values from all scenarios

1.3.6 Emissions Would Vary Widely Across the Scenarios

The different technology deployment levels across the Standard Scenarios resulted in a wide range of carbon dioxide (CO_2) emissions (Figure 1- 19).

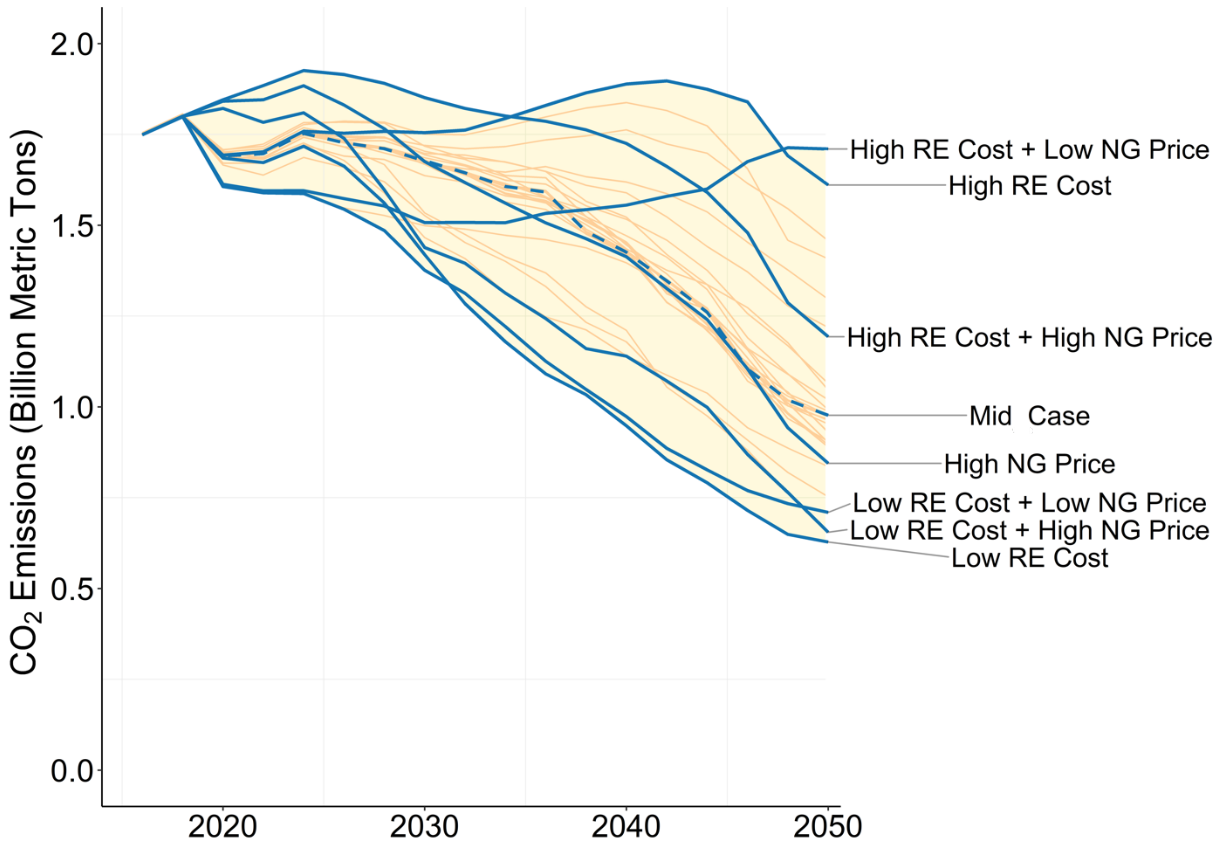


Figure 1- 19. CO_2 emissions from all modeled scenarios in 2019 Standard Scenarios throughout 2050

In general, projected CO_2 emissions for scenarios are consistent with their generation mixes. The cost of renewable energy technologies can have a significant impact on CO_2 emissions. In 2019 Standard Scenarios, higher VRE penetrations, primarily those driven by low renewable energy costs, had lower CO_2 emissions. On the other hand, high renewable energy technology cost could increase CO_2 emissions to above 1.6 billion metric tons by 2050 and result in cumulative emissions that more than doubled the cumulative emissions under Mid-Case. The Low RE Cost Low NG Price scenario had the lowest cumulative CO_2 emission of all scenarios studied, with only 81% of cumulative emissions in the Mid-Case. There were limited exceptions where higher VRE penetration did not lead to lower CO_2 emissions. For example, High NG Price had a higher VRE penetration than Mid-Case throughout 2050, but it would produce higher CO_2 emissions for all the simulation years up until 2030 because coal generators would have a higher utilization rate under high natural gas price assumptions.

1.3.7 System Costs

The net present value of total system costs (including capital cost, operation and maintenance cost, fuel cost, transmission cost, and water cost) are mainly driven by natural gas price and renewable energy technology cost assumptions (Figure 1- 20). The scenario with high renewable energy cost and high NG price assumptions[6] would have the highest total system cost, at \$4.76 trillion,[7] which is 8% higher than

---

[6] High RE Cost High NG Price Scenario

[7] This represents the present value of the total system cost from 2018 to 2050 with a real discount rate of 7% in alignment with Office of Management and Budget guidance for public investment and regulatory analysis [84].

the Mid-Case cost of $4.4 trillion. The total system cost of scenario with low renewable energy cost and low NG price assumption,[8] on the other hand, would be nearly 6% lower than the Mid-Case.

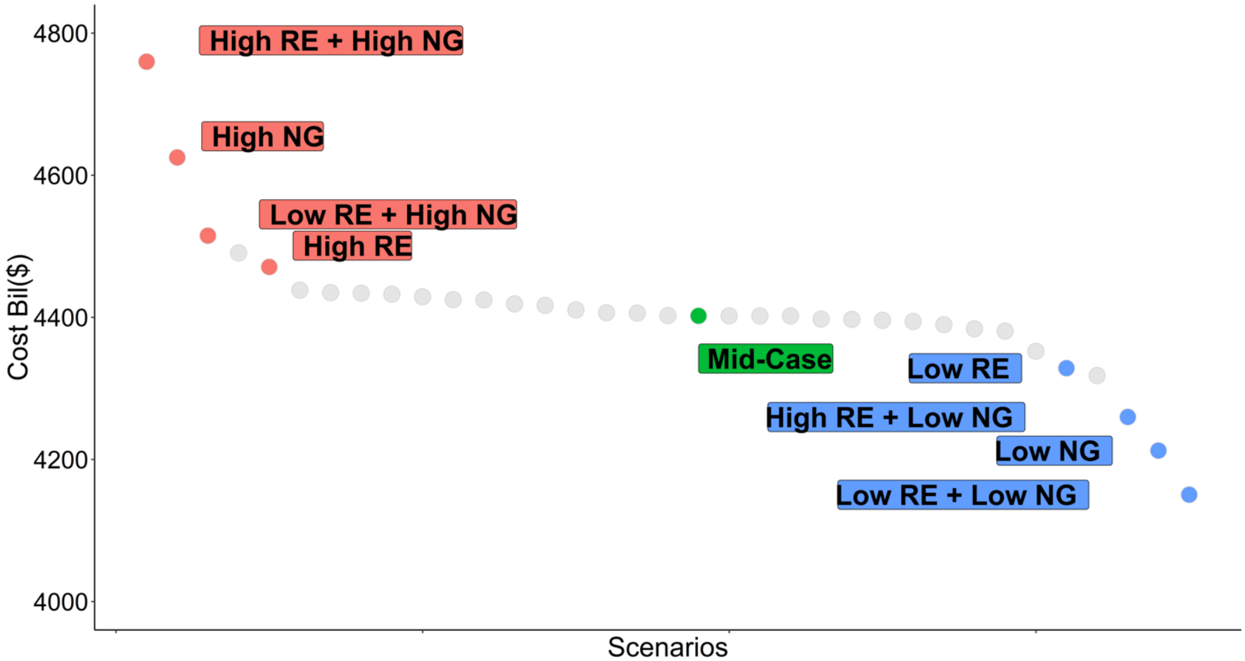


Figure 1- 20. Net present value of total system costs from 2018–2050 across scenarios

Each dot indicates a modeled scenario in Standard Scenarios 2019.

1.3.8 Many Other Technologies Could Play a Role in the Future Power System

Other technologies, such as hydropower, pumped storage, geothermal, battery storage, and aggregated demand response, could also play a role in the future power system. We focus on the supply-side technologies in this chapter, and Chapter 4 focuses on the demand side.

1.3.8.1 Hydropower and Pumped Storage Hydropower

Hydropower can offer dispatchable renewable generation and provide system flexibility and ancillary services. This means that hydropower plants can adjust their power output on demand, thus enhancing the ability of a power system to deploy its resources to respond to changes to the net load (i.e., the remaining load not served by variable generation). With over 1,800 MW of additions since 2010, hydropower is the third-largest new renewable capacity behind land-based wind and solar PV [15]. In the Standard Scenarios, hydropower deployment was positively correlated with high natural gas and high renewable energy technology costs. Hydropower deployment tended to decrease in scenarios with higher levels of VRE. Hydropower is geographically constrained and has site-specific costs and generation profiles.

The 2016 *Hydropower Vision* [21] showed that the total capacity of hydropower, including pumped storage hydropower, can grow from 101 GW in 2015 to 150 GW by 2050 under a credible scenario with reduced costs from technology innovation, improved financial terms, and environmental considerations.[9]

[8] Low RE Cost Low NG Price scenario

[9] The improved financial terms reflect lower risks and long asset life. The environmental considerations include critical habitat, ocean connectivity, migratory fish habitat, species of concern, protected lands, national rivers inventory, and low-disturbance rivers.

The combined impact of the three key drivers is greater than the effect of any individual driver (Figure 1-21).

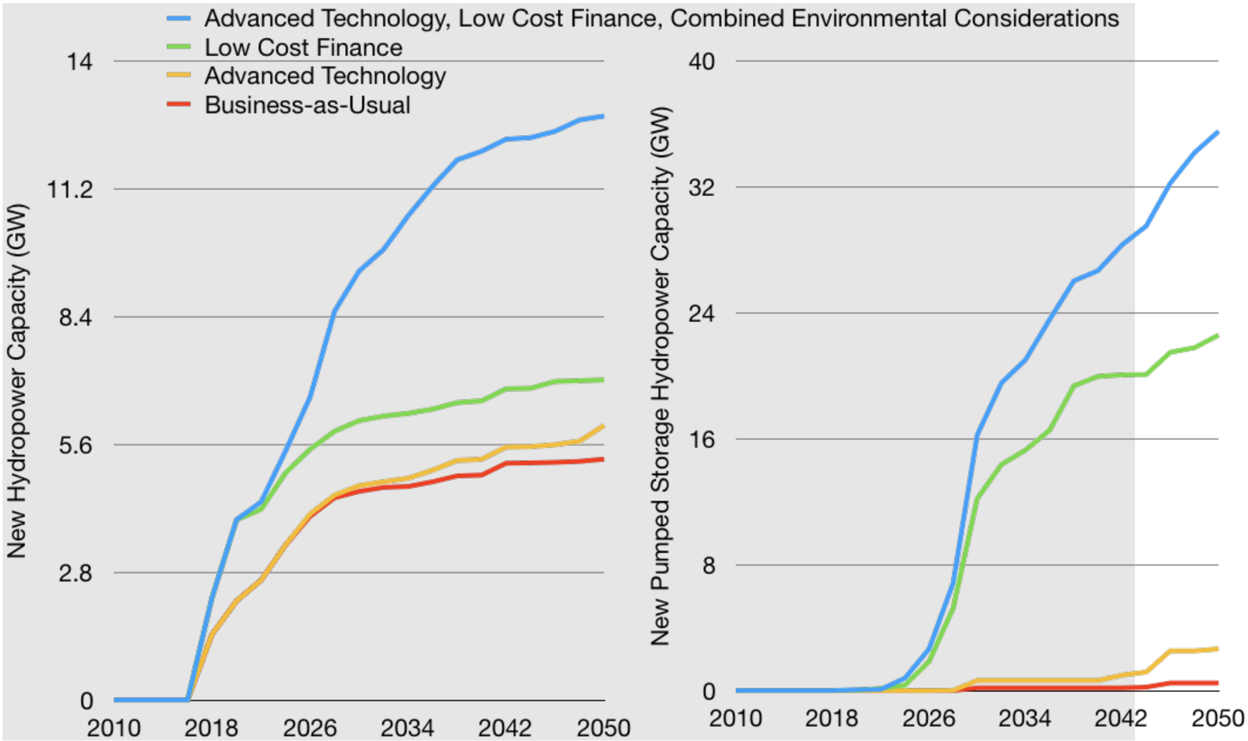


Figure 1- 21. New hydropower capacity (left) and new pumped storage hydropower capacity (right) in Hydropower Vision throughout 2050

Most of the expected growth of hydropower would come from upgrades or optimization of existing hydropower facilities (Table 1- 1). Pumped storage hydropower would see a higher growth under Low-Cost Finance and under Advanced Technology, Low-Cost Finance, and Combined Environmental Considerations. Pumped storage hydropower technology is complementary to VRE generation due to its ability to provide grid flexibility, reserve capacity, and system inertia. New advanced pumped storage has improved capabilities such as closed-loop adjustable-speed, which can facilitate VRE integration. Under Advanced Technology, Low Cost Finance, Combined Environmental Considerations, pumped storage hydropower provides more operating reserves (52%) than any other technology by 2050 [21].

Table 1- 1. New Hydropower and New Pumped Storage Hydropower Capacity by Subcategory in Hydropower Vision

Resource Category	Business-as-Usual Scenario (GW)		Advanced Technology, Low-Cost Finance, Combined Environmental Considerations Scenario (GW)	
	2030	**2050**	**2030**	**2050**
Total New Hydropower Generation Capacity	4.5	5.2	9.4	12.8
Upgrades and Optimization of Existing Hydropower Plants	4.5	5.2	5.6	6.3
Powering of Nonpowered Dams	0.04	0.04	3.6	4.8
New Stream-Reach Development	0	0	0.2	1.7
New Pumped Storage Hydropower Capacity	0.2	0.5	16.2	35.5
Total New Hydropower Capacity	4.7	5.7	25.6	48.3

1.3.8.2 Geothermal

Geothermal power development depends on access to subsurface thermal resources, and development depends highly on site-specific costs and technology improvements. Geothermal resources for electric power generation are divided between hydrothermal resources and enhanced geothermal systems. Hydrothermal resources are resources that have a combination of naturally occurring ground water, rock characteristics, and subsurface temperatures suitable for electric power generation. The existing geothermal capacity of 2.6 GW is composed entirely of hydrothermal resources and with resources concentrated in the western states [22]. In contrast, enhanced geothermal systems use subsurface engineering to make resources that lack ground water and/or subsurface geology suitable for electric power generation and would add substantial resource potential across the entire United States.

Under most of the Standard Scenarios, geothermal development would see limited growth compared to other VRE technologies, with little built beyond replacing the existing fleet after retirements occur. The resource available for development across all scenarios was limited to hydrothermal technologies. The highest development scenarios for geothermal assumed either low geothermal costs or high costs for other VRE technologies. Under the Low Geothermal Cost scenario, geothermal capacity would grow to 17 GW.

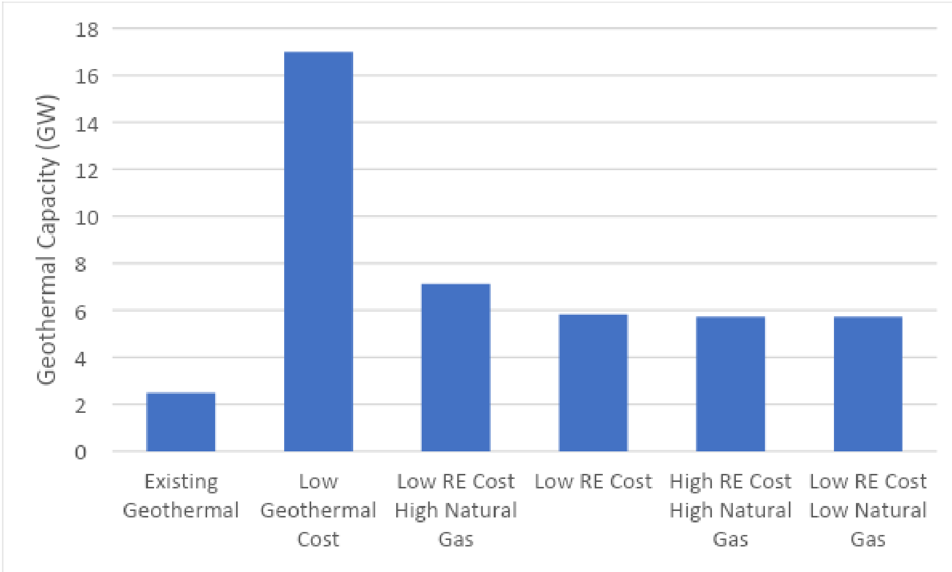


Figure 1- 22. Total U.S. geothermal capacity in 2050 under GeoVision cost and technology cost scenarios

The GeoVision study [22] examined barriers to geothermal development and the potential benefits of developing a renewable resource with firm capacity. The study found that technology improvements that reduce exploration, development, and operation costs were a key driver for additional deployment. Advancing enhanced geothermal systems to the point of commercial development was important for opening more geothermal resource to economic development. Nontechnical barriers to geothermal development included extended construction timelines, non-streamlined permitting processes, and land access issues. Addressing both technical and nontechnical barriers to geothermal development would expand geothermal capacity to nearly 61 GW of capacity and 8.5% of total generation. Progress on nontechnical barriers alone would expand hydrothermal geothermal resource capacity to almost 13 GW of capacity and 1.8% of generation [70].

1.3.8.3 Battery Storage

Battery (or electrochemical) storage is a fast-growing technology in the U.S. power sector. By the end of 2019, utility-scale battery storage[10] totaled 952 MW of power capacity, the majority of which is provided by lithium-ion-based batteries [71]. There is also an emergence of residential behind-the-meter battery storage (Figure 1- 23) and solar-plus-storage projects at various scales. From 2010 to 2018, average battery pack prices dropped 85% [72]. The price of battery storage is expected to continue to decline due to technology improvements and economies of scale in production. In the 2019 Standard Scenarios, using moderate *Annual Technology Baseline* technology cost projections, the overnight capital costs of 4-hour battery were assumed to drop below those of natural gas combustion turbines before 2030 in the Mid-Case.

Battery storage has a diverse set of applications, including energy management, load shifting, frequency regulation, grid stabilization, and voltage support, that can enhance the resiliency and efficiency of the grid [73]. Co-locating PV and storage subsystems can, at the utility scale, potentially reduce costs related to site preparation, land acquisition, permitting, interconnection, installation labor, and hardware (through

[10] Utility-scale battery storage is systems with larger than 1 MW in nameplate power capacity, which are typically connected to the transmission grid. Small-scale battery storage with less than 1 MW in power capacity also has commercial and residential applications and is typically behind the meter.

sharing switchgears, transformers, and controls) [74], and at the distribution level, maintain system voltages within acceptable limits [75].

Over the past decade, the U.S. power sector has demonstrated substantial progress in deploying battery storage technologies and valuing their role in VRE integration, ancillary service markets, energy management, infrastructure upgrade deferral, and other services (read more in Chapter 2 and Chapter 3).

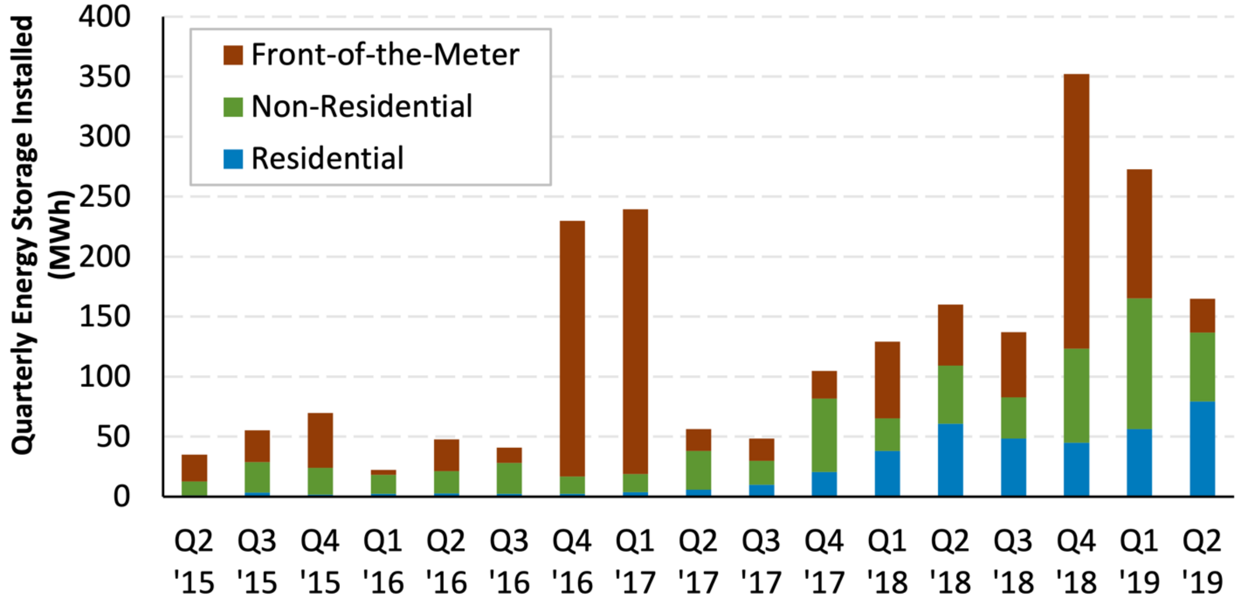


Figure 1- 23. U.S. energy storage installations by market segment [76]

The Standard Scenarios showed that battery storage deployment is correlated with VRE penetration and inversely correlated with the natural gas price (Figure 1- 24). Under Mid-Case, 164 GW of battery storage power capacity would be deployed by 2050. While under low battery cost assumptions (Low Bat Cost scenario), the system installed 302 GW of battery storage power capacity by 2050.

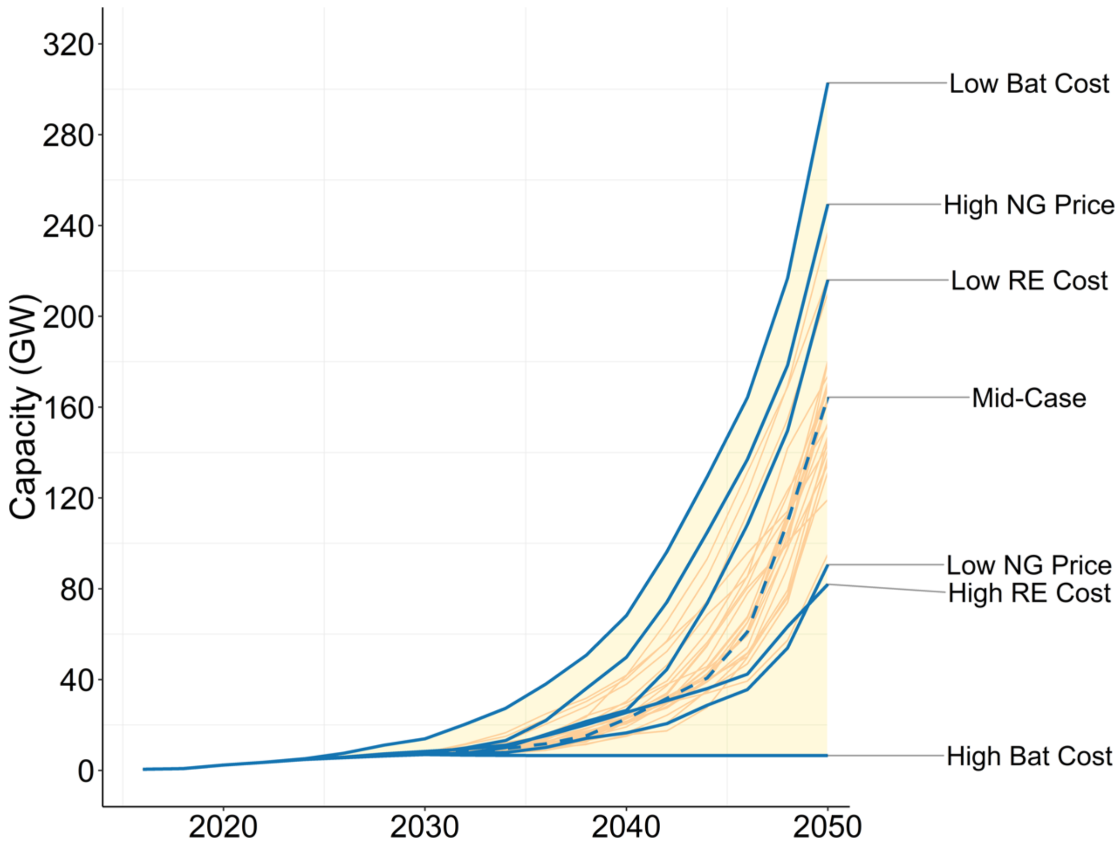


Figure 1- 24. Power capacity of battery storage deployed under all modeled scenarios in 2019 Standard Scenarios

1.4 Operational Analysis of High VRE Penetration Grids

NREL uses production cost modeling to understand the hourly-to-sub-hourly operation of potential future power systems at detailed spatial and temporal scales. Figure 1- 25 shows an overview of the interconnections (Western, Eastern, and ERCOT), as they are typically used in interconnection-level studies.

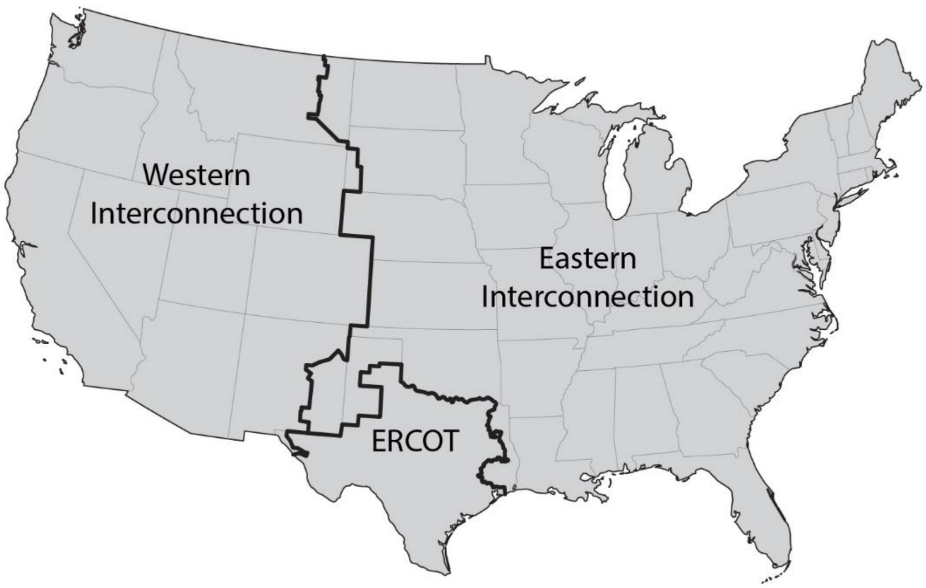


Figure 1- 25. U.S. electricity system interconnections

NREL completed a number of studies using production cost modeling. These include a high penetration of 80% renewables (nearly 50% wind and solar) for the conterminous United States [19], [77], and several operational studies focused on the Western and the Eastern Interconnections [61], [62]. A study of renewable integration in the North American power system [78] is currently underway, and recent work examines the potential benefits of increasing electricity transfer between the interconnections [79]. This section, drawing heavily from the Interconnection-level studies, summarizes the general lessons learned from these operational analyses. Table 1- 2 and the subsequent text highlights the specific high renewable penetration studies of focus by category.

Table 1- 2. Major NREL Studies Including High Penetrations of Renewables

	VRE Penetration as % of Energy Generation (wind + solar PV)	Renewable Penetration as % of Energy Generation (wind + solar PV + CSP + hydro)
Western Scenarios [62]	41%–45%	81%–88%
Eastern Scenarios [61]	64%–73%	66%–75%
Low Carbon Grid Study [80]	26%–44% (CA, pre-curtailment)	45%–65% (California, pre-curtailment)
Renewable Energy Futures [19], [77]	~50%	80%

Western

The *Western Wind and Solar Integration Study* [81] focused on the operational impact of 35% penetration of wind and solar in the states of Arizona, Colorado, Nevada, New Mexico, and Wyoming, and up to 23% in the other states in the Western United States. We reference Phase 2 of this project [30] for thermal cycling impacts. In the latter study, up to 33% wind and solar penetration was modeled. Scenario analysis included the following renewable energy penetrations as percentage of total energy: (1) No Renewables: 0% wind and solar; (2) TEPPC: 9.4% wind and 3.6% solar; (3) High Wind: 25% wind and 8% solar; (4) High Solar: 25% solar and 8% wind; and (5) High Mix: 16.5% wind and 16.5% solar.

Low-Carbon Grid Study: Analysis of a 50% Emissions Reduction in California [80] focused on the impacts of high VRE penetrations in California and the Western United States, meeting California's emissions goals. This study included sub-hourly modeling with nodal power flow representations in California and regional transmission aggregations in the rest of the Western United States. The main scenarios were: (1) Baseline: 45% pre-curtailment California renewable penetration with 26% pre-curtailment California VRE penetration; (2) Target: 65% renewable with 39% VRE; and (3) High Solar: 65% renewable with 44% VRE. The study included flexibility scenarios and variations on non-California generation.

Renewable Electricity Futures: Operational Analysis of the Western Interconnection at Very High Renewable Penetrations [62] is a study of the operational impacts of high VRE penetrations in the Western Interconnection at a sub-hourly timescale motivated by the Renewable Electricity Futures study [19], [77]. All scenarios assumed that all coal generators in the Western Interconnection would retire and that no additional fossil-fueled generation would be built after 2022. This high VRE study had three main scenarios: (1) High scenario had 82% renewable generation after curtailment, 41% of which was from VRE; (2) Higher Baseload scenario added additional concentrated solar power (CSP) and geothermal for a total of 88% renewable generation; and (3) Higher Variable Generation scenario added additional variable generation to the High Scenario for a total of 86% renewable generation. The study modeled transmission at the zonal level and determined transmission buildouts by iteratively running the production cost model beginning with the base transmission buildout and using shadow prices on congested transmission lines to determine which line expansions would reduce system costs.

Eastern

In *Operational Analysis of the Eastern Interconnection at Very High Renewable Penetrations* [61], the authors studied the operation of the Eastern Interconnection (Figure 1- 26) with very high levels of renewables. This study followed the Eastern Renewable Grid Integration Study (ERGIS) [31],which focused on four scenarios with moderate renewable integration levels: Low VG, RTx10 (10% VRE with some intraregional transmission expansion), RTx30 (30% VRE with same intraregional transmission expansion), and ITx30 (30% VRE with interregional transmission). Specifically, the goals of the high VRE operational study were to analyze the ability of the system to operate at 5-minute intervals, identify operating practices that impact flexibility, and quantify system stress. The percentage of VRE was higher in this study than in the Western one, based on two primary factors: the Eastern Interconnection has much less hydropower, geothermal power, or CSP availability; the cost projections of wind and solar PV technologies had further dropped.

The Eastern Interconnection operational study considered the following scenarios: (1) Base 70%: 71% renewable penetration, including hydro; (2) Base 75%: 75% renewables with 73% variable generation; (3) Hurdle Rate[11] 70%: Base 70% with the addition of a $10 per MWh penalty for transfers between regions; (4) Must Run 70%: Base 70% with 25% of all coal and nuclear plants modeled as must-run, approximately representing the contemporary nuclear fleet's inflexibility; and (5) VG Limit 70%: Base 70% with a requirement that 25% of load is served locally by non-inverter-based generation at every interval.

Unlike the earlier ERGIS study, this operational study aggregated transmission to the zonal level. Thirty-three zones were modeled (Figure 1- 26). The transmission buildout was based on the ITx30 Scenario from [31].

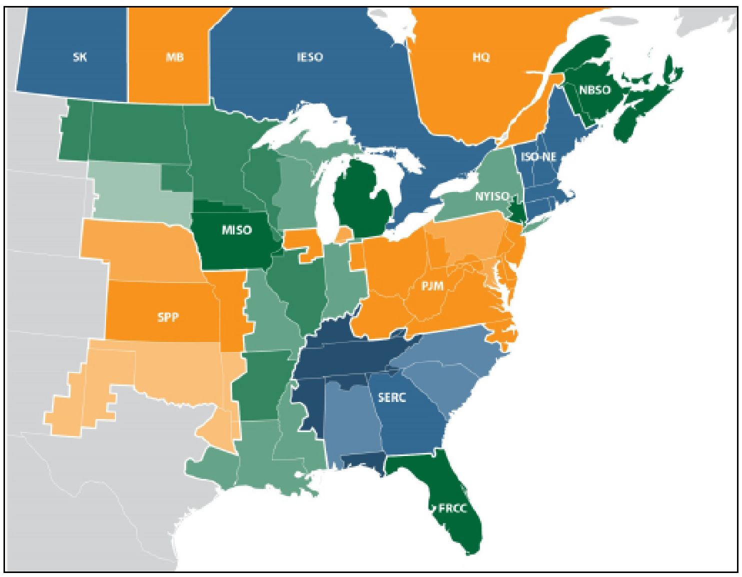


Figure 1- 26. Eastern U.S. interconnection subregions used as both transmission zones and load zones [49]

1.4.1 Operating a High VRE Penetration Grid Is Possible With Challenges

The analysis results from these studies showed that the grid could be operated with very high levels of renewable generation, for the scenarios examined with the assumed generation and storage technologies buildout using existing commercial technologies.

Western

The high-penetration Western Interconnection study [62] modeled operation at 5-minute intervals for scenarios with 81.5% to 87.6% in after-curtailment renewable (including hydro) penetration and with VRE penetration of 41.3% and 44.6%. No unserved load occurred in any of the scenario simulations in

[11] Hurdle rate, as modeled in the study, represents a barrier for power exchange between regions.

the study. Over 99.999% of the reserves were served in these scenarios, indicating that a reserve shortage that could lead to unserved load in a contingency event would be very unlikely. In a system without coal-fired power plants, nuclear and geothermal ran at consistently high capacity factors, while the wind, PV, and CSP generation reduced the peak power requirement. During periods with high demand and no curtailment (July example, Figure 1- 27), system flexibility in the simulation was sourced by hydropower that ramped during overnight and daytime hours, and gas combustion turbines and CSP, which provided ramping at sunsets. During periods with low demand and high curtailment (March example, Figure 1-28), the dispatch of fossil-fueled generators no longer followed a diurnal pattern. Because of the excess generation throughout most of the period, gas combined cycles were turned down except for the March 25–26 nighttime with low wind, and gas combustion turbines were not utilized every day to provide the evening ramp, even though they still were used to provide some flexibility during the morning of March 25 and the evening of March 30.

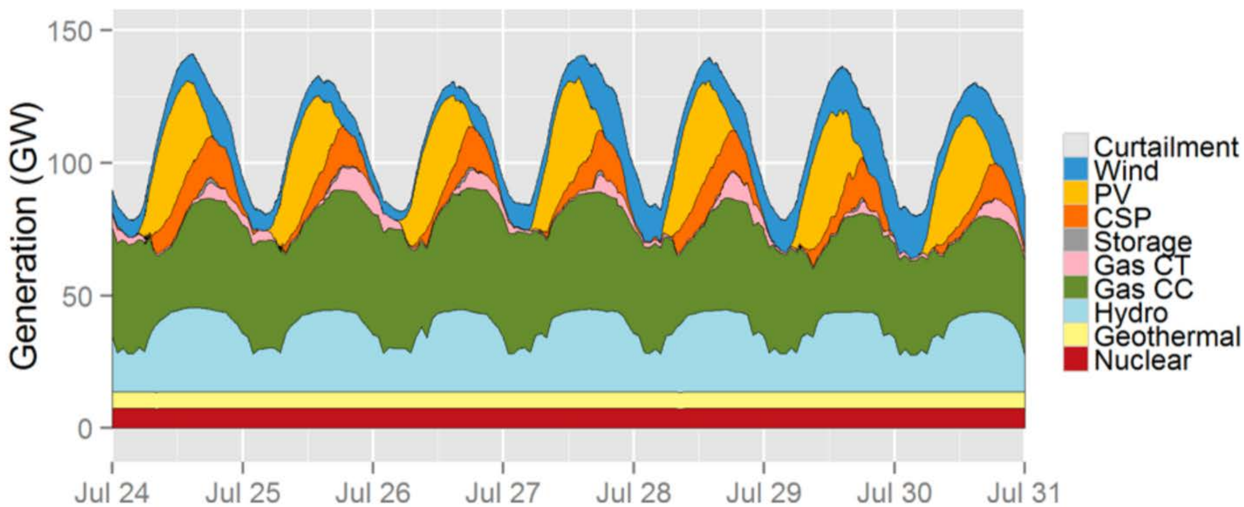


Figure 1- 27. U.S. Western Interconnection analysis, July dispatch stack, High scenario [62]

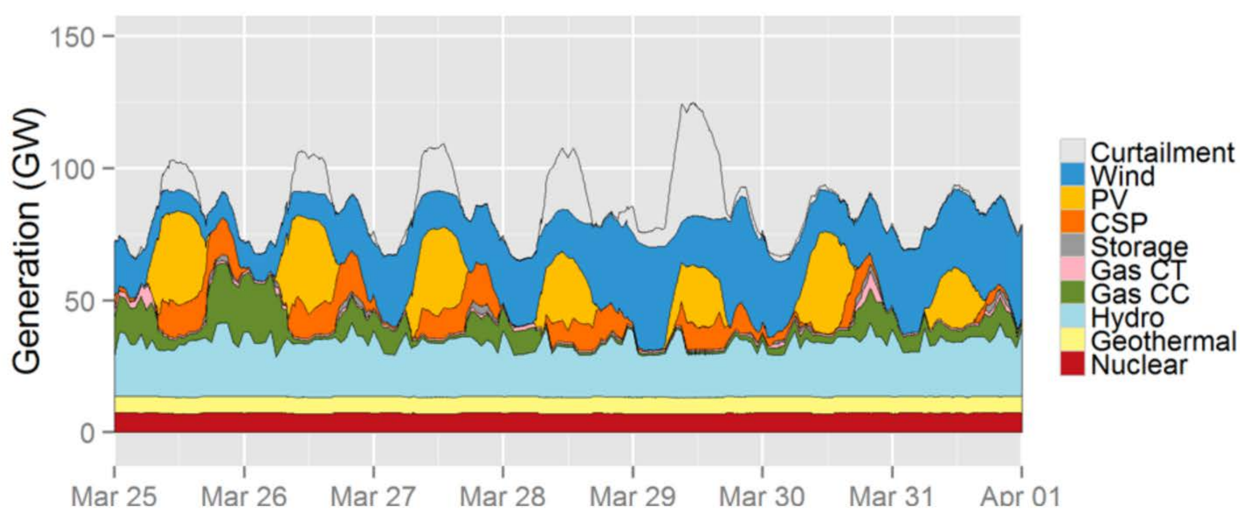


Figure 1- 28. U.S. Western Interconnection analysis, March dispatch stack, High scenario [62]

Eastern

NREL operational analysis of the Eastern Interconnection [61] showed that operational simulation of the grid at 5-minute time resolution with 70.8%–75.3% of renewable (including hydro) penetration and 68.2%–72.7% of after-curtailment VRE penetration was possible. No unserved energy occurred in the base scenarios, and more than 99.99% of reserves were served in all scenarios, indicating that sufficient generation capacity was available and committed to serve load and typical contingencies.

During periods of high load (peak load is about 600 GW in the system on July 31), gas combined cycles and combustion turbines served as the main providers of system flexibility; the coal and nuclear generators were backed down during midday periods to accommodate the increase in solar generation and were ramped up into evening periods (Figure 1- 29). Because of the high penetration of VRE, even during this high peak load period of the year, curtailment occurred during the daytime and some of the early morning periods between July 30 and July 31. Some export to Canada occurred during the daytime periods where the total generation is larger than the load.

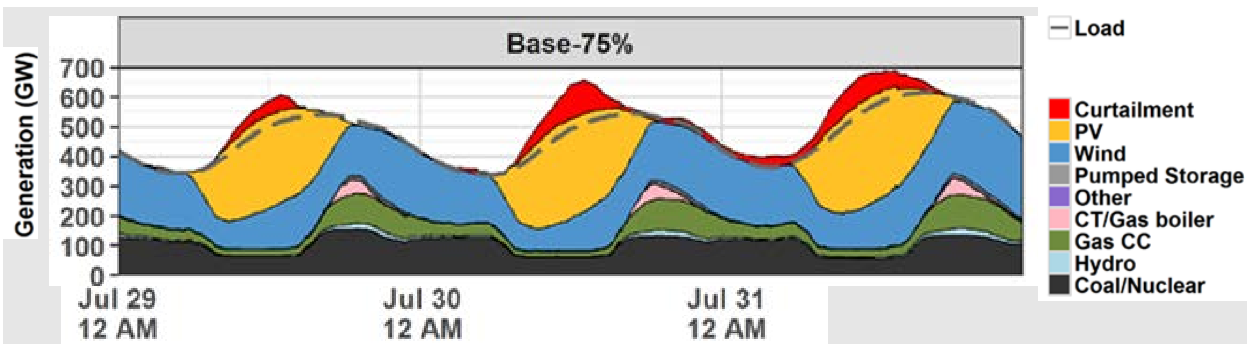


Figure 1- 29. U.S. Eastern Interconnection analysis peak dispatch stack, Base-75% scenario where renewable energy accounts for 75% of generation [61]

1.4.2 Curtailment

Operational studies provide insight on locational and temporal curtailment patterns under high VRE penetrations. In general, curtailment is more closely correlated with solar PV generation than wind generation, both on a daily and seasonal basis. While curtailment can be an economic challenge for generator owners, it can also provide a valuable source of flexibility (and ancillary service availability) in high renewable scenarios (Section 1.4.3.2).

Western

In the high-penetration Western Interconnection study results [62], renewable penetration levels of 81.5% to 87.6% yielded curtailment rates of 6.7% to 11.4% of possible renewable generation, consistent with the earlier Renewable Energy Futures [66] study where renewable penetration of 80% resulted in around 8%–10% of curtailment as a fraction of wind, solar, and hydropower generation.

The diurnal curtailment profile for all three scenarios largely followed the solar profile, though there was significant wind curtailment as well as solar (Figure 1- 30). Seasonally, curtailment was highest in the spring with a secondary peak in the fall (Figure 1- 31). Adding variable generation (Higher VG) to the scenario with 82% of generation from renewable energy and 41% from VRE (High) resulted in more curtailment than if, instead, CSP and geothermal were added (Higher Baseload).

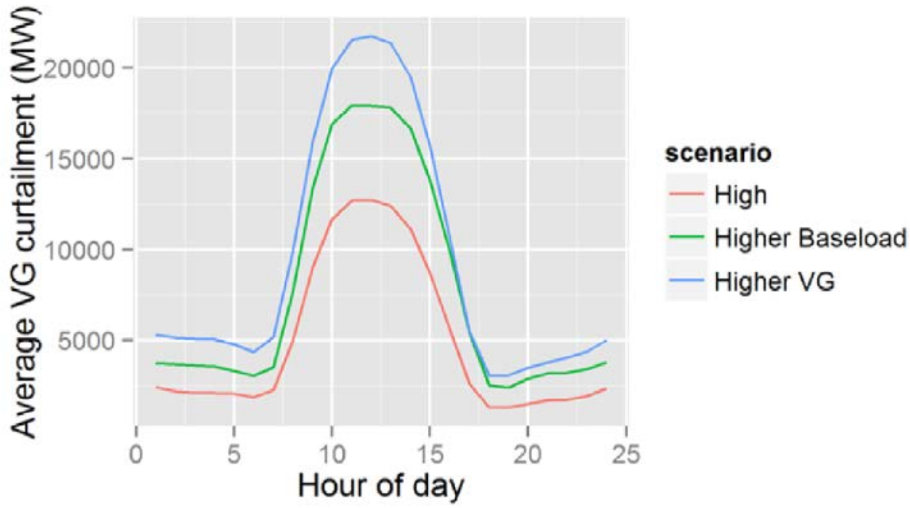


Figure 1- 30. Average hourly curtailment diurnal profile from the Western Interconnection analysis [62]

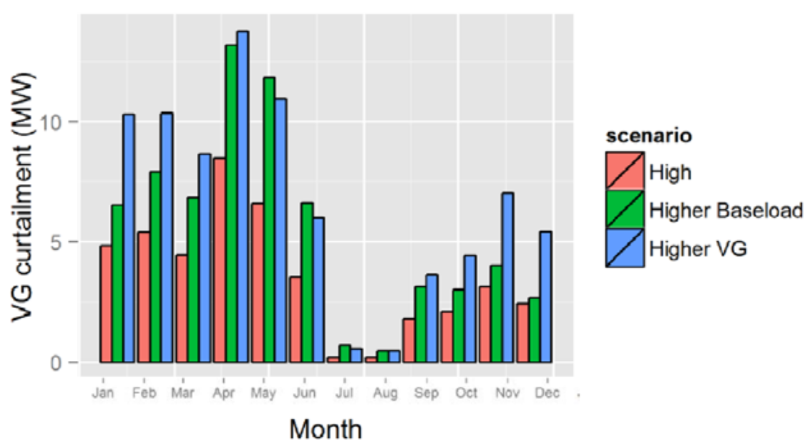


Figure 1- 31. Monthly curtailment from the Western Interconnection analysis [62]

A majority of the curtailment was concentrated in a small number of hours of the year, midday in the spring. While additional transmission capacity could have alleviated some curtailment, much of the curtailment occurred during hours when the entire interconnection had energy prices near zero.

Eastern

Curtailment trends related to VRE penetration in the Eastern Interconnection were identified first at moderate VRE penetration in the earlier ERGIS study [31].Curtailment had a definite seasonal pattern, peaking in March-April and again in September-October. Daily curtailment profiles were also clear, having early morning and midday peaks (Figure 1- 32). Curtailment in the Florida Reliability Coordinating Council (FRCC) region was significant in the scenario with 30% VRE penetration and same intra-regional transmission as in the reference low VRE case (RTx30 scenario) and was due to high solar generation in this high solar potential region. As such, FRCC solar penetration was limited to 35% in the later high VRE penetration study [61].

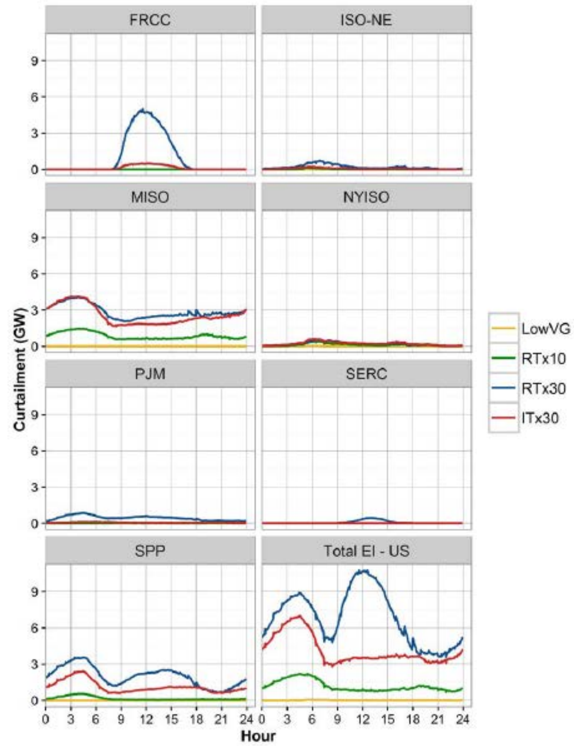


Figure 1- 32. Annual average hourly curtailment under moderate VRE penetrations from the ERGIS analysis, by RTO region and for the entire Eastern Interconnection [61]

Curtailment in the high-penetration study [61] was consistent with previous studies of the Eastern Interconnection; curtailment of VRE generation ranged from 7.3% to 10.2% at these high penetration levels. Seasonal curtailment patterns also showed peaks in March-April, and, to a lesser extent, September-October. Diurnal curtailment had a strong solar-driven profile. The marginal curtailment for the additional renewable generation added between the Base 70% and Base 75% scenarios was 34%, indicating that at increasing VRE penetrations there could be value for adding other sources of system flexibility (e.g., storage, demand response, or other technologies) to reduce curtailment.

Figure 1- 33 shows that curtailment occurred during about half of the year in some parts of the interconnection. Curtailment was lowest in the Base scenario with 71% renewable penetration, including hydro (Base 70% scenario) and highest in the scenario with the same renewable penetration but required 25% of load being served locally by non-inverter-based generation at every 5-minute interval (VG Limit 70% scenario).

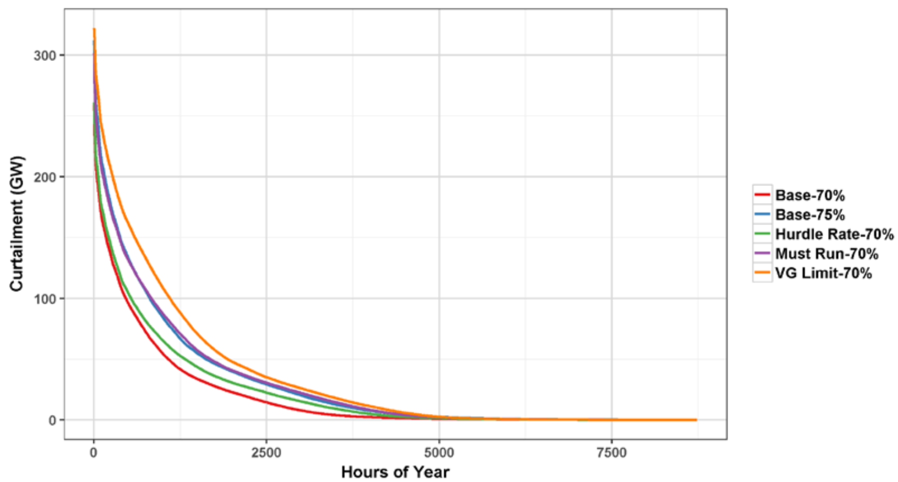


Figure 1- 33. VRE curtailment duration curve from the Eastern Interconnection high VRE penetration analysis [61]

1.4.2.1 Ramping

Increasing VRE penetrations can cause periods of high net load ramps, which are mitigated by a variety of resources.

Western

In the *Low Carbon Grid Study* [62], the steepest net load ramp was on February 8 and was largely caused by PV reductions at sunset. In this case, the net load increase was met largely by increasing imports, storage discharging, and natural gas ramping *(*Figure 1- 34*)*.

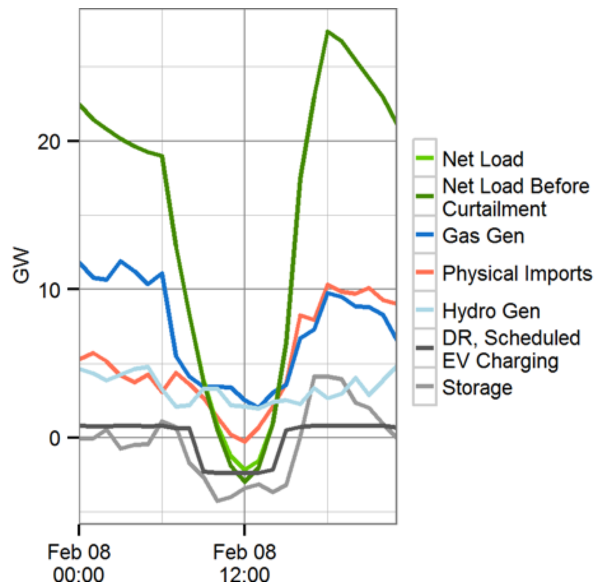


Figure 1- 34. All sources of ramping during the steepest net load of the year in the case of 65% renewable with 39% VRE and assuming enhanced flexibility by relaxing import/exports constraints, adding storage, and allowing hydro to provide reserves fully (Target Enhanced Flexibility) in [80]

1.4.2.2 Thermal Plant Cycling Impacts

NREL studied the impact of high VRE penetration on thermal plant cycling by examining thermal units' operation with a focus on gas combined cycles and gas combustion turbines. This section summarizes these operational changes and the associated thermal plant cycling costs.

Western

[30] used production cost modeling and a data set of thermal cycling costs to analyze thermal cycling costs of moderate penetrations of wind and solar in the Western Interconnection. Cycling costs were estimated by low and high bound estimates of cycling costs for each of seven generator types. The wear-and-tear cycling costs on the system increased by $35–$157 million (2011 nominal dollars) for the moderate VRE system compared to a system without VRE. The low end of this estimate was for the no-VRE system compared to the 16.5% solar and 16.5% wind system (High Mix), with low bound estimates for plant cycling costs. The high end of this estimate was for the no-VRE system compared to the 25% solar and 8% wind system (High Solar), with the high bound estimates for plant cycling costs. At a system level, this cost impact was small compared to the total production cost of around $7 billion and was significantly outweighed by the production cost savings due to VRE. At a plant level, however, the cycling costs were significant. Cycling costs were $0.47–$1.28 / MWh for an average generator compared to average steady-state variable operation and maintenance costs of $2.43–4.68/MWh.

From the high-penetration Western Interconnection study [62], Figure 1- 35 shows how the natural gas fleet[12] generation varied through the year for the scenario with 68 TWh of additional VRE (Higher VG). Figure 1- 36 shows duration curves to compare the renewable scenarios. Under the scenario with additional CSP and geothermal (Higher Baseload) and the scenario with additional VRE (Higher VG), gas combustion turbines, which are the fastest-moving generators, did not change significantly. NG-CC usage, however, did vary; NG-CC fleet generation was displaced by additional dispatchable renewables in

[12] The modeled thermal fleet in the Western Interconnection study did not have any coal.

the scenario with higher CSP and geothermal and, to a lesser extent, by VRE in the scenario with higher VRE.

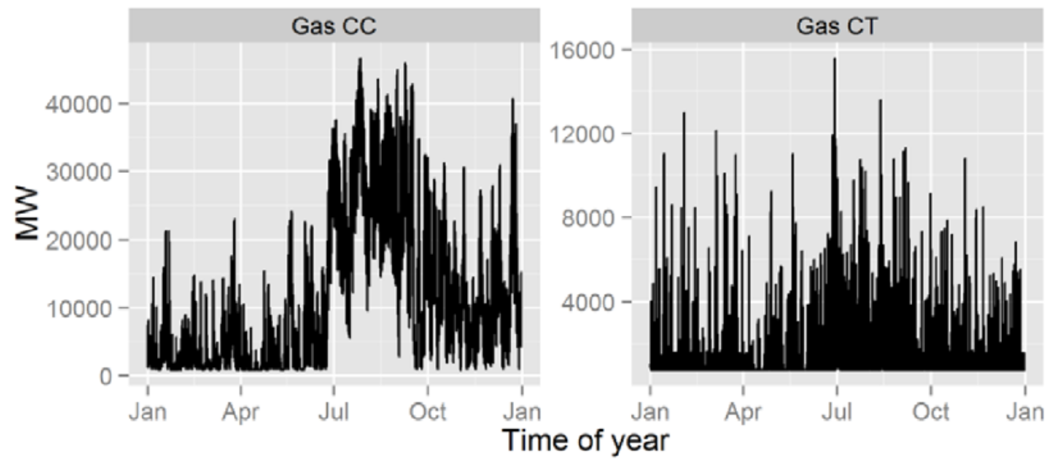


Figure 1- 35. Natural gas fleet output in the Western Interconnection analysis, High scenario [62]

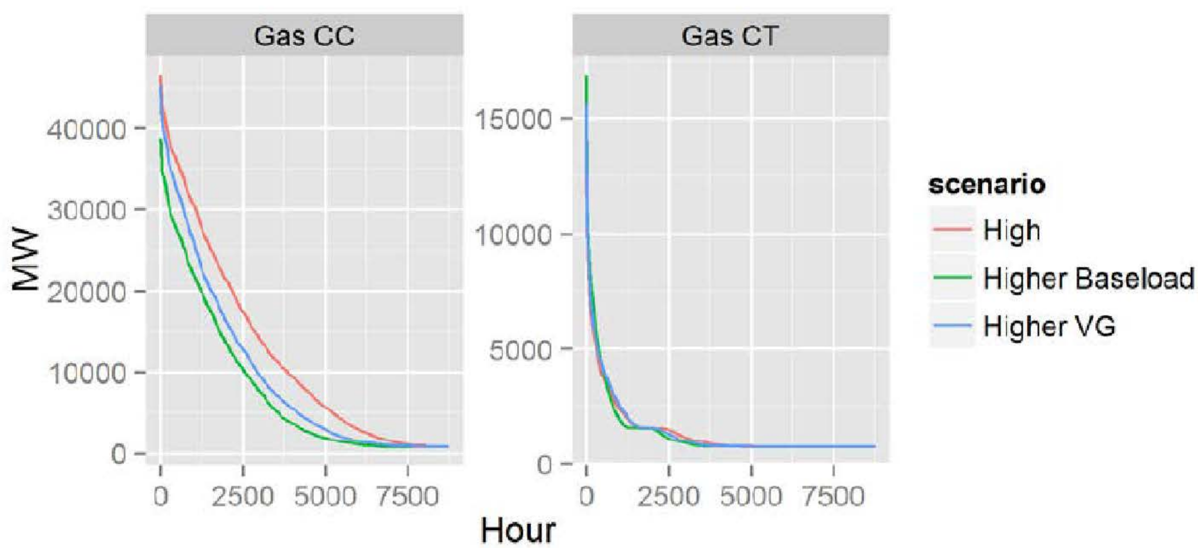


Figure 1- 36. Duration curve of gas generation in three scenarios from [62]

Eastern

From moderate VRE penetrations in ERGIS [31], the authors found that thermal plant types were impacted differently by the increase in variable generation modeled (Figure 1- 37). Coal plants had more starts and shorter operating periods with increasing VRE. The effect was stronger for NG-CC units. Combustion turbines, however, had some decrease in capacity starts and stayed online for about the same amount of time (less than one day), regardless of VRE scenario. Note that the combined cycle and combustion turbine starts were higher in the scenario with only intra-regional transmission expansion (RTx30) compared to the scenario with additional inter-regional transmission (ITx30). This was due to the high penetration of solar PV in RTx30 scenario and the expanded inter-regional transmission connections in ITx30. The high solar PV penetration in RTx30 resulted in a more variable net load and caused the combined cycle units to cycle in response. With more inter-regional transmission in ITx30, the net load was also balanced by importing from adjacent regions rather than ramping thermal units.

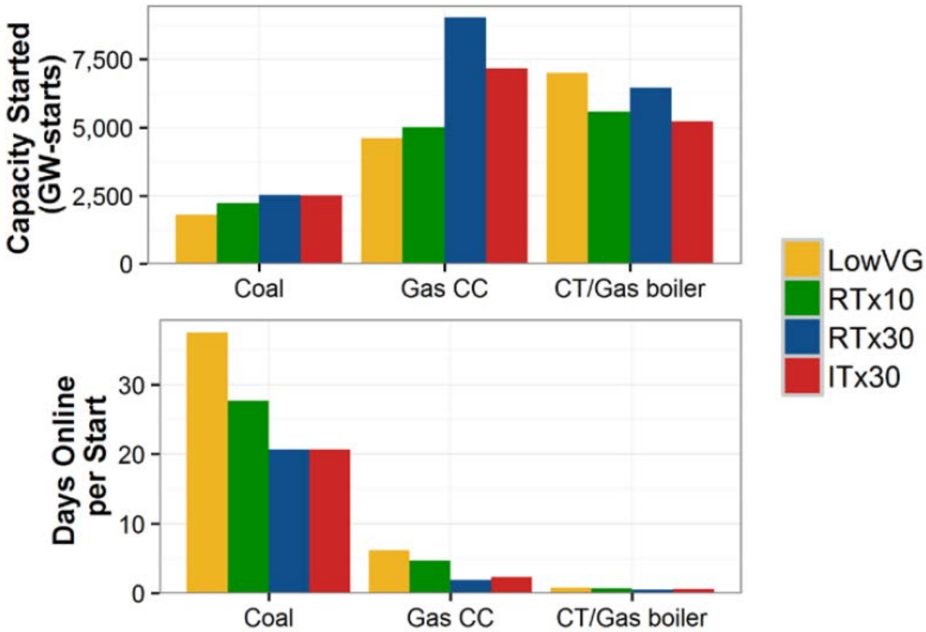


Figure 1- 37. Capacity-starts (capacity in GW multiplied by number of starts, for each unit by fuel time (top) and the average number of days online per start by fuel type (bottom) [31]

In the high-VRE study [61], coal/nuclear capacity-starts were relatively consistent across scenarios (Figure 1- 38). Combustion turbine starts were highest in the highest VRE scenario with 75% renewable energy and 73% VRE penetration (Base 75%) and similar in the 71% renewable scenario (Base 70%). Combustion turbine starts decreased by up to 20% in the other scenarios that had more coal, nuclear, and combined cycle units online, so that combustion turbines were not needed. A hurdle rate for transfers between regions caused more in-region thermal to be committed in Hurdle Rate 70%, 25% of the coal/nuclear plants were must-run in the Must-Run 70% scenario, and 25% of in-region load had to be served by non-inverter-based technology in VG Limit 70% scenario. Gas combined cycle capacity starts were relatively similar in most scenarios, but lowest in the VG Limit 70% scenario.

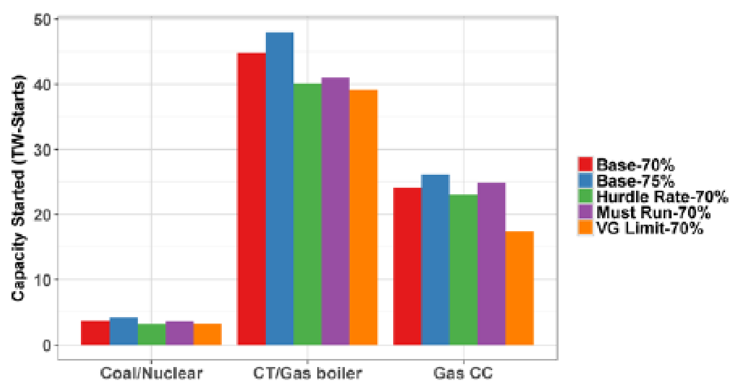


Figure 1- 38. Annual capacity started for coal and nuclear, NG-CC, and gas combustion turbines in the Eastern Interconnection analysis [61]

Focusing further on combustion turbines, Figure 1- 39 shows the diurnal pattern of combustion turbine starts. Combustion turbines started in the early morning and late afternoon during periods of high net load ramps. The sunrise ramps were likely due to the commitment decisions in the day ahead, which turned off combined cycle plants for the middle of the day. The combustion turbines generally ran for only 1 hour in the morning. The sunset starts were more long-lasting, as combustion turbines contributed to peak generation for around 4 hours and may have remained online to overcome wind forecast error in the evening.

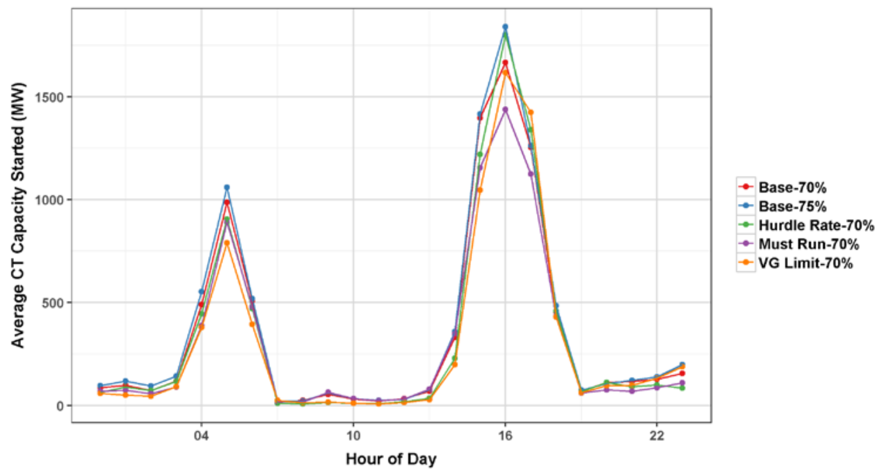


Figure 1- 39. Average hourly combustion turbine starts in the Eastern Interconnection analysis [61]

1.4.2.3 Wholesale Price Impacts

High renewable penetrations can lead to more times when zero-marginal cost renewable resources, which have no fuel costs, set the wholesale prices to zero.

Western

Simulated wholesale prices went to zero during 20%–30% of hours in the high renewable penetration scenarios examined in the Western Interconnection study (Figure 1- 40) [62].

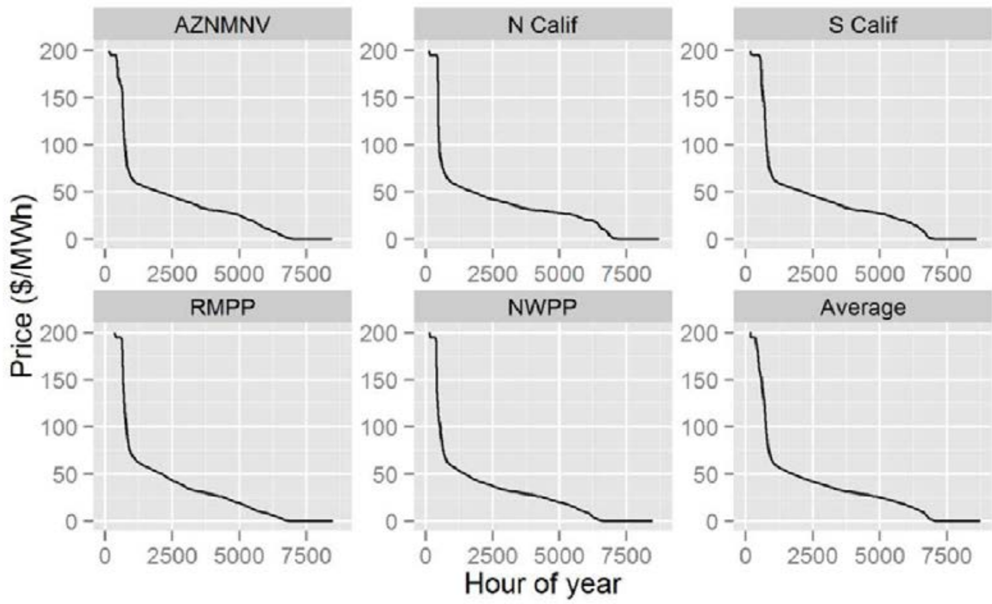


Figure 1- 40. Hourly wholesale price duration curve from Western Interconnection analysis, High scenario [62]

Eastern

High-VRE scenarios showed consistent price duration curves across regions in the Eastern Interconnection study [61]. Hours with zero marginal prices, indicating curtailment and potential revenue concerns for thermal generators online, were most prevalent in FRCC and Southwest Power Pool (Figure 1- 41).

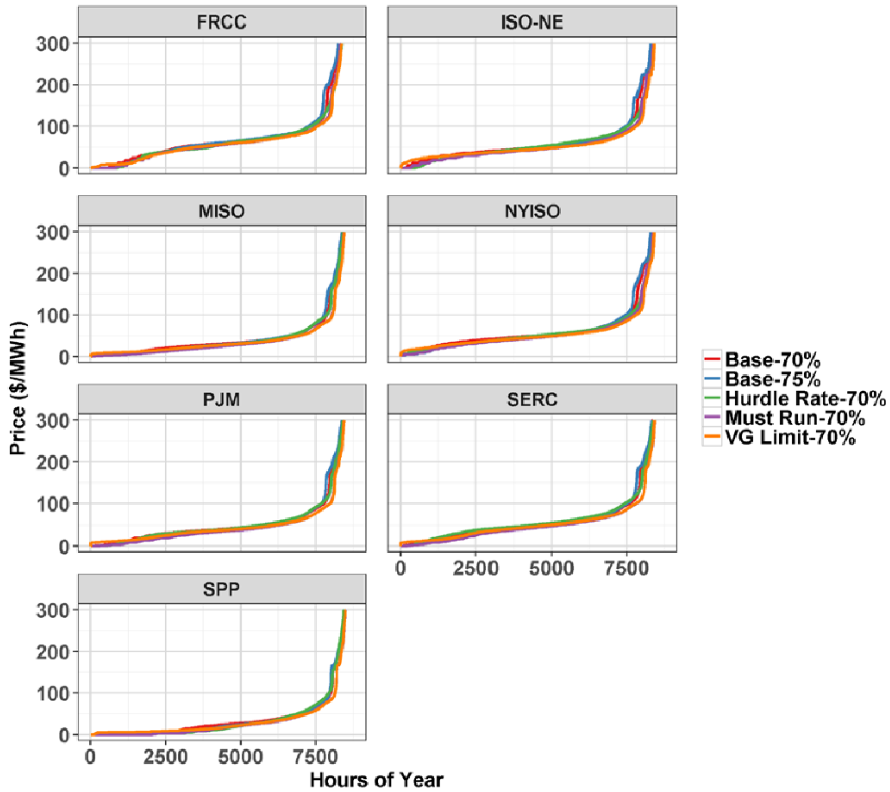


Figure 1- 41. Hourly wholesale price duration curve by RTO region for Eastern Interconnection analysis [61]

1.4.3 Power System Design Could Facilitate High Renewable Integration

Through the operational studies, we identified several opportunities for system designs to reduce some of the stressors of a high-VRE penetration system.

1.4.3.1 Balancing Area Coordination

Western

To understand the importance of balancing area coordination, the Western Interconnection study [62] included a HighLoFlex scenario that assumed that gas combined cycles must be committed in the day-ahead market and had a minimum run time of 24 hours; a High LoFlex no-day-ahead scenario, which has the same minimum run time requirement, no day-ahead commitment market, and, in addition, simulated limited transfers between balancing authorities using a penalty of $40/MWh on transfers between balancing authorities; and a High LoFlex no DA/RT scenario, which simulated the same minimum run time requirement, same transfer penalty, but with no day-ahead commitment or real-time dispatch market. These penalties (known as hurdle rates) caused significant changes in production costs. The study reported the production cost increases that resulted from inefficient dispatch across regions, not including the penalty costs themselves (which were internal to the optimization). The production cost increases were 7.3% with the added transfer penalty (High LoFlex, no day-ahead) and 24% with added transfer penalty and no day-ahead or real-time markets (High LoFlex no day-ahead/real time) relative to the baseline scenario (High LoFlex). The operational changes that increased costs in these scenarios were increased gas combined cycle usage within some regions and significant curtailment in others. In the later cases, the hurdle rate made it more economical to curtail wind and solar energy rather than transfer it between regions. Specifically, curtailment went from 7% in the baseline case (High LoFlex) to 9% with added transfer penalty (High LowFlex no DA) and 17% with added transfer penalty and no day-ahead or real-time markets (High LowFlex no DA/RT).

Eastern

In [61], the scenario where friction between neighboring regions was represented by a hurdle rate of $10 per MWh (Hurdle Rate 70%) increased curtailment only slightly from 7.3% to 8.8%. While different systems are not directly comparable, the smaller curtailment effect can be attributed partly to the lower hurdle rate modeled in the Eastern Interconnection.

The Interconnections Seam Study [79] also demonstrated the value of increasing the transmission capacity between the interconnections and sharing generation resources and flexibility across regions. This is particularly true at high VRE penetration, resulting in benefit-to-cost ratio as high as 2.9.

1.4.3.2 Renewables' Contribution to Reliability

While curtailment is a measure of system economic stress (Section 1.4.2) because zero marginal cost resources are not being utilized, it can also be considered a source of grid flexibility. Renewables can also contribute to reliability through provision of specific ancillary services.

Eastern

The study found that under the high VRE penetration scenarios in the Eastern Interconnection [61], curtailment was mostly a grid resource, rather than a stressor. To determine how much the curtailment was scheduled in the day-ahead market as a known source of flexibility, the study examined the amount of curtailment in the day-ahead market solutions versus the real-time market solutions. In all scenarios, a majority of the curtailment was scheduled in the day-ahead, with only 26%–40% occurring only in the real time simulation. Figure 1- 42 compares the scheduled and real-time (actual) curtailment for each hour. Points above the red 1:1 line indicate times of stress when sub-hourly variability caused unscheduled curtailment.

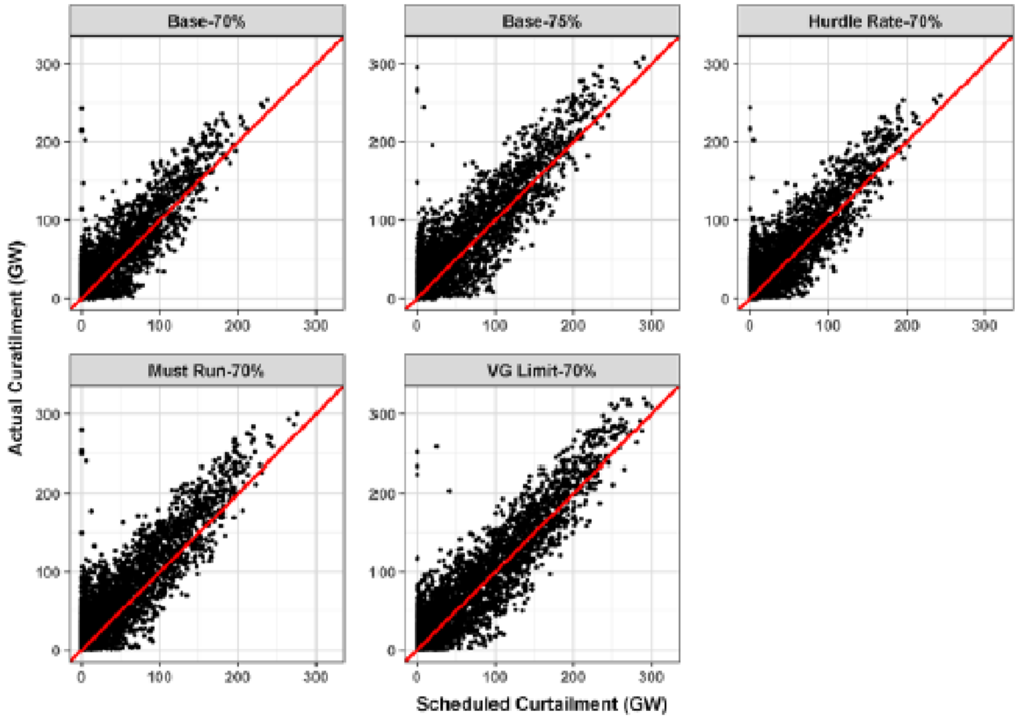


Figure 1- 42. Real-time (actual) curtailment compared to the amount of curtailment scheduled in the day-ahead unit commitment step of the simulation for the Eastern Interconnection analysis [61]

1.4.3.3 Thermal Fleet Flexibility

Western

The Western Interconnection study [62] included a sensitivity scenario to explore the implications of a less-flexible thermal fleet. The High LoFlex scenario required gas combined cycle generation to be committed in the day-ahead market and have a minimum run time of 24 hours, essentially making it behave as coal plants would. This reduction in combined cycle flexibility was compensated by an increase in gas combustion turbine generation, particularly in the morning hours. Production costs increased by 3.8% compared with the reference scenario (High), due to the increased use of more-expensive combustion turbines and operating the combined cycles at part-load. Curtailment impacts of the less-flexible scenario (High LoFlex) were minimal. As such, this scenario revealed the benefits of thermal flexibility but did not show specific impacts on renewable curtailment. The impacts of thermal flexibility on renewable curtailment are discussed in [82].

Eastern

The Eastern Interconnection study [61] explored a scenario with decreased thermal fleet flexibility by requiring 25% of coal and nuclear capacity to act as must-run (Must Run—70%). Curtailment increased from 7.4% to 11.4% in this scenario compared with the reference scenario (Base 70%).

1.4.3.4 Role of Other Technologies

Western

To explore the role that storage technologies could play in high VRE scenarios, the Western Interconnection study [62] included a High Storage scenario, adding 10 GW of 12-hour storage across the regions that experienced the highest curtailment (Arizona, Colorado, and the Northwest) in the other scenarios. The increased storage capacity reduced wind and solar curtailment rate—from 6.7% in the reference scenario[13] to 5.1%—and decreased the usage of gas combined cycles and gas combustion turbines to a lesser extent. Storage losses offset about one-third of the reduced curtailment. The storage was dispatched during a 6-hour period in the evenings (as shown in Figure 1- 43 [March 25-31]) and Figure 1- 44 (typical diurnal pattern). The 6-hour charge/discharge cycle suggested that a 6-hour storage device would have been sufficient, rather than the 12-hour one the study modeled. This storage scenario also showed that production costs were decreased by 5.3% due to reduced generator start-up costs in the evening, reduced fuel costs, and some arbitrage between combined cycle and combustion turbine usage compared to the reference scenario (High).

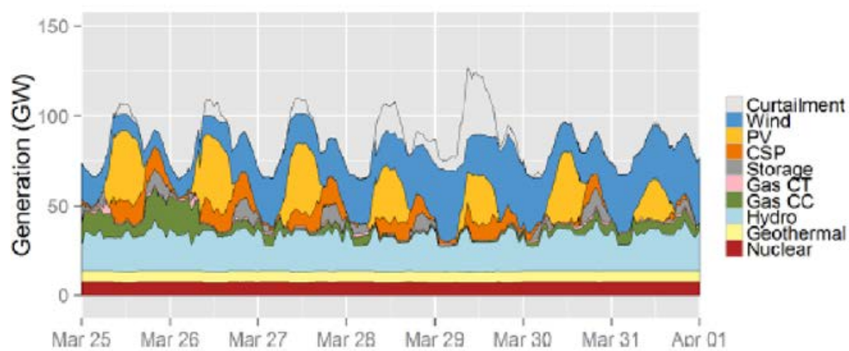


Figure 1- 43. March dispatch stack from Western Interconnection analysis, High Storage sensitivity [62]

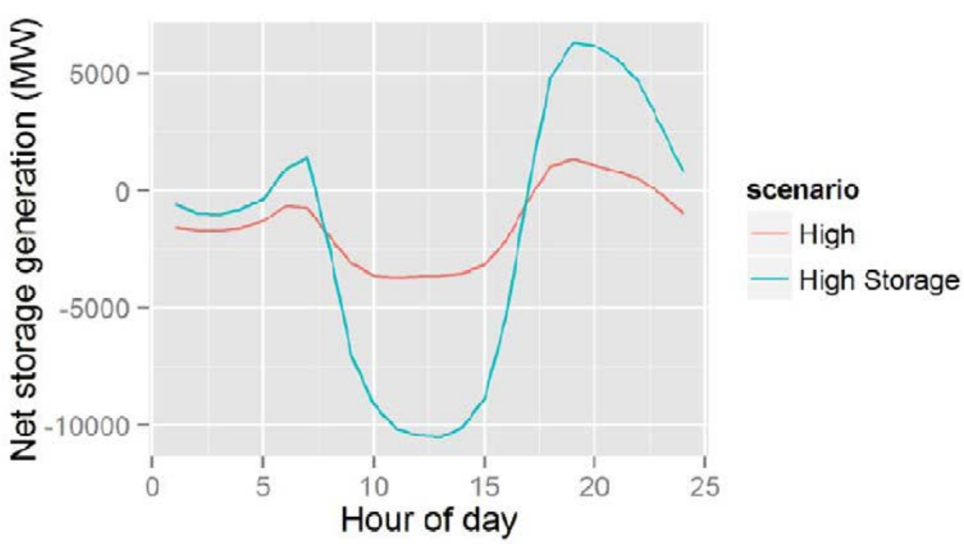


Figure 1- 44. Diurnal storage dispatch, High and High Storage cases [62]

1.4.3.5 Policy and Market Solutions

Western

A key conclusion of the *Low Carbon Grid Study* [80] was that a more flexible grid resulted in less curtailment, lower operational costs, and lower emissions. The study modeled grid flexibility as "Conventional" and "Enhanced" by varying four assumptions. In the Conventional flexibility scenarios,

[13] Reference scenario here is High scenario, with after-curtailment renewable energy penetration of 81.5%.

the model required that 70% of out-of-state renewable, nuclear, and hydro generation that is accounted for in California renewable portfolio standard be imported to California and that 25% of generation in California come from local fossil and hydro. In the Enhanced flexibility scenarios, the model did not enforce those requirements. Flexibility was also modeled by varying the amount of storage in California (more storage = more flexible) and the limits on the amount of reserve provided by hydro (less constrained = more flexible).

The study found both cost savings and curtailment savings due to a flexibility increase with renewable penetrations. Among the range of scenarios analyzed, the largest curtailment impact due to grid flexibility was in the Target High Solar scenario (28% California solar penetration) where curtailment decreased from 10% to 1% with increased flexibility. In that scenario, production costs also decreased by $570 million. The more flexible system could displace more imports, sell more power, use energy storage, and turn down thermal generators to limit curtailment.

Eastern

When modeling a day-ahead hourly commitment followed by a 5-minute real-time market in the Eastern Interconnection [61], the authors observed that the short morning ramps of combustion turbine plants were likely due to combined cycle commitment decisions. The authors expect (but did not model) that market operations that encourage staggered commitment or have a higher resolution day-ahead commitment could decrease combustion turbine startups.

1.5 Conclusions

NREL's previous scenario analyses showed that the future power system can evolve in many ways. Different generation and storage technologies can play a role in the supply side, depending on future fuel cost, technology cost and performance, and policy and market environments. Nevertheless, the growth of variable renewable generation is a consistent trend across scenarios. VRE penetration can reach 53% and 74% in the 2050 conterminous U.S. power system under the 2019 Standard Scenarios' Mid-Case and low renewable cost assumptions. Our key conclusions are as follows:

- Wind and solar generation grow substantially in every modeled future. Even with mid-cost assumptions, wind and solar generate more than half of the electricity in 2050.
- Many technologies will likely play a significant role in the future grid. These technologies could include transmission infrastructure, storage, demand response, hydropower, nuclear, and natural gas, in addition to wind and solar.
- Challenges from additional variability and uncertainty can likely be mitigated by a variety of sources of both technical and institutional flexibility. Technical sources can include storage, flexible generation, transmission, and demand-side flexibility. Institutional sources of flexibility include balancing authority cooperation, economic curtailments, and market incentives.
- Considering these sources of flexibility, modeling demonstrated that supply and demand can be balanced at 5-minute time resolution in these high-renewable future scenarios. Demonstrating comprehensive grid reliability will require additional modeling and analysis, including dynamic power flow studies and contingency analyses; however, recent tests are beginning to show that wind, solar PV, and battery storage systems can offer active and reactive power control in similar ways to traditional synchronous generators, which can alleviate some reliability challenges in high penetration renewable scenarios. Reliability issues on the transmission level will be discussed in Chapter 3, and distribution issues and tools will be discussed in Chapter 2.

Recent works on high-penetration VRE power systems include the Storage Futures Study [83], which explores the role and impact of energy storage in the evolution and operation of the U.S. power system; the Los Angeles 100% Renewable Energy Study [29], a highly detailed cross-sector analysis of the city's pathways to meet reliable, 100% renewable electricity by 2045; the National Academies of Sciences [8] identified the major needs for future U.S. power system; and [2] provides energy-system pathways for the United States to reach net-zero emissions by 2050. These studies contribute to the growing body of literature on power system transition that, in general, find consensus on the high-level conclusions outlined above. Additional work may be needed to address potential public policy, capacity building, supply chain, financing, and other issues during the transition outside of the scope of this report.

References

[1] EPA (U.S. Environmental Protection Administration). 2021. “Sources of Greenhouse Gas Emissions.” Accessed January 26, 2021. https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.

[2] E. Larson *et al.* 2020. “Net-Zero America: Potential Pathways, Infrastructure, and Impacts.” Princeton, NJ: Priceton University.

[3] Jenkins, J.D., M. Luke, and S. Thernstrom. 2018. “Getting to Zero Carbon Emissions in the Electric Power Sector.” *Joule* 2 (12): 2498–2510. doi: 10.1016/j.joule.2018.11.013.

[4] Tokimatsu, K., R. Yasuoka, and M. Nishio. 2017. “Global zero emissions scenarios: The role of biomass energy with carbon capture and storage by forested land use.” *Appl. Energy* 185 (January): 1899–1906. doi: 10.1016/j.apenergy.2015.11.077.

[5] Capros, P. *et al.* 2019. “Energy-system modelling of the EU strategy towards climate-neutrality.” *Energy Policy* 134 (November): 110960. doi: 10.1016/j.enpol.2019.110960.

[6] Jafari, M., M. Korpas, and A. Botterud. 2019. “Power System Decarbonization: Impacts of Energy Storage Duration and Interannual Renewables Variability.” *Renew. Energy* 156 (November): 1171–1185. doi: 10.1016/j.renene.2020.04.144.

[7] Davis, S.J. *et al.* 2018. “Net-zero emissions energy systems.” *Science* 360 (6396). American Association for the Advancement of Science. doi: 10.1126/science.aas9793.

[8] National Academies of Sciences, Engineering, and Medicine. 2021. “The Future of Electric Power in the United States.” Washington, DC: The National Academies Press. https://doi.org/10.17226/25968.

[9] Daggash , H.A., and N. Mac Dowell. 2019. “Structural Evolution of the UK Electricity System in a below 2°C World.” *Joule* 3 (5): 1239–1251. doi: 10.1016/j.joule.2019.03.009.

[10] Kroposki, B. *et al.* 2017. “Achieving a 100% Renewable Grid: Operating Electric Power Systems with Extremely High Levels of Variable Renewable Energy.” *IEEE Power Energy Mag.* 15 (2): 61–73. doi: 10.1109/MPE.2016.2637122.

[11] Hodge, B.S. *et al.* 2020. “Addressing technical challenges in 100% variable inverter-based renewable energy power systems.” *WIREs Energy Environ.* 9 (5). doi: 10.1002/wene.376.

[12] Katz, J., and I. Chernyakhovskiy. 2020. *Variable Renewable Energy Grid Integration Studies: A Guidebook for Practitioners.* Golden, CO: NREL. https://www.nrel.gov/docs/fy20osti/72143.pdf.

[13] Mai, T., J. Logan, N. Blair, P. Sullivan, and M. Bazilian. 2013. *RE-ASSUME A Decision Maker’s Guide to Evaluating Energy Scenarios, Modeling, and Assumptions*. Paris: IEA-Renewable Energy Technology Deployment. http://iea-retd.org/wp-content/uploads/2013/07/RE-ASSUME_IEA-RETD_2013.pdf.

[14] Paltsev, S. 2016. "Energy Scenarios: The Value and Limits of Scenario Analysis." *WIREs Energy and Environment*, *6*(4). http://ceepr.mit.edu/files/papers/2016-007.pdf.

[15] Cole, W., N. Gates, T. Mai, D. Greer, and P. Das. 2019. “2019 Standard Scenarios Report: A U.S. Electricity Sector Outlook." Golden, CO: NREL. https://doi.org/10.2172/1580330

[16] Brown, Maxwell *et al.* 2020. *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2019.* Golden, CO: NREL. https://www.nrel.gov/docs/fy20osti/74111.pdf.

[17] Short, W. *et al.* 2011. “Regional Energy Deployment System (ReEDS).” Golden, CO: NREL. https://www.nrel.gov/docs/fy12osti/46534.pdf.

[18] DOE. 2012. *SunShot Vision Study.* Washington, DC: DOE. https://www.energy.gov/sites/prod/files/2014/01/f7/47927.pdf.

[19] Mai, T *et al.* 2014. “Renewable Electricity Futures for the United States.” *IEEE Trans. Sustain. Energy* 5 (2): 372–378. doi: 10.1109/TSTE.2013.2290472.

[20] Wiser, R. *et al.* 2015. “Wind Vision: A New Era for Wind Power in the United States.” *Electr. J.* 28 (9): 120–132. doi: 10.1016/j.tej.2015.09.016.

[21] DOE. 2016. *Hydropower Vision: A New Chapter for America’s Renewable Electricity Source.* Washington, DC: DOE. https://www.energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

[22] DOE. 2019. *GeoVision: Harnessing the Heat Beneath Our Feet*. Washington, DC: DOE. https://www.energy.gov/sites/prod/files/2019/05/f63/GeoVision-full-report.pdf.

[23] Sigrin, B., M. Gleason, R. Preus, I. Baring-Gould, and R. Margolis. 2016. “The Distributed Generation Market Demand Model (dGen): Documentation.” https://www.nrel.gov/docs/fy16osti/65231.pdf.

[24] Sigrin, B., and M. Mooney. 2018. “Rooftop Solar Technical Potential for Low-to-Moderate Income Households in the United States." Golden, CO: NREL. https://www.nrel.gov/docs/fy18osti/70901.pdf.

[25] Gagnon, P., W. J. Cole, B. Frew, and R. Margolis. 2017. “The impact of retail electricity tariff evolution on solar photovoltaic deployment.” *Electr. J.* 30 (9): 22–28. doi: 10.1016/J.TEJ.2017.10.003.

[26] Mai, T., E. Drury, K. Eurek, N. Bodington, A. Lopez, and A. Perry. 2020. “Resource Planning Model: An Integrated Resource Planning and Dispatch Tool for Regional Electric Systems." Golden, CO: NREL. https://www.nrel.gov/docs/fy13osti/56723.pdf.

[27] Hurlbut, D. *et al.* 2016. “Navajo Generating Station and Federal Resource Planning; Volume 1: Sectoral, Technical, and Economic Baseline." Golden, CO: NREL. https://www.nrel.gov/docs/fy17osti/66506.pdf.

[28] Barrows, C., T. Mai, S. Haase, J. Melius, and M. Mooney. 2016. “Renewable Energy Deployment in Colorado and the West: A Modeling Sensitivity and GIS Analysis.” Golden, CO: NREL. https://www.nrel.gov/docs/fy16osti/65350.pdf.

[29] Cochran, J., and P. Denholm, Eds., *The Los Angeles 100% Renewable Energy Study*.

Golden, CO: NREL, 2021. NREL/TP-6A20-79444. https://maps.nrel.gov/la100/.

[30] Lew, D. *et al.* 2013. *The Western Wind and Solar Integration Study Phase 2*. Golden, CO: NREL. https://www.nrel.gov/docs/fy13osti/55588.pdf.

[31] Bloom, A. *et al.* 2016. *Eastern Renewable Generation Integration Study*. Golden, CO: NREL. https://www.nrel.gov/docs/fy16osti/64472.pdf

[32] Palchak, D. *et al.* 2017. *Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Volume II--Regional Study*. Golden, CO: NREL. https://www.nrel.gov/docs/fy18osti/68744.pdf.

[33] Palchak, D. *et al.* 2017. *Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I—National Study.* Golden, CO: NREL. https://www.nrel.gov/docs/fy17osti/68530.pdf.

[34] Denholm, P. *et al.* 2013. *The Value of Energy Storage for Grid Applications*. Golden, CO: NREL. https://www.nrel.gov/docs/fy13osti/58465.pdf.

[35] Hummon, M. *et al.* 2013. *Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model.* Golden, CO: NREL. http://www.nrel.gov/docs/fy14osti/58492.pdf.

[36] Denholm, P., J. Jorgenson, M. Miller, E. Zhou, and C. Wang. 2015. "Methods for Analyzing the Economic Value of Concentrating Solar Power with Thermal Energy Storage." Golden, CO: NREL. doi: 10.2172/1215267.

[37] EIA. 2020. "NEMS Documentation." Accessed April 22, 2020. https://www.eia.gov/outlooks/aeo/nems/documentation/.

[38] EIA. 2020. "Annual Energy Outlook 2020 with projections to 2050." Accessed February 25, 2020. www.eia.gov/aeo.

[39] Loulou, R., G. Goldstein, and K. Noble. 2004. "Documentation for the MARKAL Family of Models." http://www.etsap.org/tools.htm.

[40] Lenox, C., R. Dodder, C. Gage, D. Loughlin, O. Kaplan, and W. Yelverton. 2013. *EPA U.S. Nine-region MARKAL Database, Database Documentation.* Cincinnati, OH: EPA. https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=278925.

[41] EPA. 2018. "Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model." Washington, DC: EPA. https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-january-2020-reference-case.

[42] ICF Consulting. 2002. "Economic Assessment of RTO Policy." https://www.ferc.gov/sites/default/files/2020-05/RTOStudy_final_0226.pdf.

[43] ABB. 2020. "PROMOD." Accessed Apr. 28, 2020. https://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/promod.

[44] Celebi, M., J. Pfeifenberger, O. Aydin, K. Diep, and J. Sustman. 2013. *Integrated System*

Nodal Study: Costs & Revenues of ISO Membership. Boston, MA: The Brattle Group. https://www.wapa.gov/regions/UGP/PowerMarketing/Documents/ISNodalStudyRedacted 030813.pdf.

[45] ABB. 2020. "GridView." Accessed April 28, 2020. https://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/gridview.

[46] Brinkman, G. *et al.* 2012. *Grid Modeling for the SunShot Vision Study*. Golden, CO: NREL. https://dx.doi.org/10.2172/1036369.

[47] Orans, R., A. Olson, and J. Moore. 2011. "WECC EDT Phase 2 EIM Benefits Analysis & Results." San Francisco, CO: Energy and Environmental Economics, Inc. https://www.ethree.com/wp-content/uploads/2017/02/WECC_E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN21-1.pdf.

[48] Chang, J.W. *et al.* 2016. "Senate Bill 350 Study Volume V: Production Cost Analysis." Boston, MA: The Brattle Group. https://www.caiso.com/Documents/SB350Study-Volume5ProductionCostAnalysis.pdf.

[49] Lund, Henrik, and Jakob Zinck Thellufsen. 2019. "EnergyPLAN Advanced Energy Systems Analysis Computer Model Documentation Version 15." Aalborg, Denmark: Aalborg University. https://www.energyplan.eu/wp-content/uploads/2019/09/EnergyPLAN-Documentation-Version15.pdf.

[50] Liu, W., H. Lund, and B. V. Mathiesen. 2011. "Large-scale integration of wind power into the existing Chinese energy system." *Energy* 36 (8): 4753–4760. doi: 10.1016/j.energy.2011.05.007.

[51] Lund, H., and E. Münster. 2003. "Modelling of energy systems with a high percentage of CHP and wind power." *Renew. Energy* 28 (14): 2179–2193. doi: 10.1016/S0960-1481(03)00125-3.

[52] Dranka, G.G., and P. Ferreira. 2018. "Planning for a renewable future in the Brazilian power system." *Energy* 164 (December): 496–511. doi: 10.1016/j.energy.2018.08.164.

[53] Connolly, D., H. Lund, B. V. Mathiesen, and M. Leahy. 2011. "The first step towards a 100% renewable energy-system for Ireland." *Appl. Energy* 88 (2): 502–507. doi: 10.1016/j.apenergy.2010.03.006.

[54] EPRI. 2018. "US-REGEN Model Documentation." Palo Alto, CA: EPRI. https://www.epri.com/research/products/3002010956.

[55] LCG Consulting. 2020. "UPLAN Network Power Model." Accessed April 28, 2020. http://www.energyonline.com/products/uplane.aspx.

[56] ANL (Argonne National Laboratory). 2018. "Generation and Transmission Maximization (GTMax) Model." Accessed February 22, 2018. https://ceeesa.es.anl.gov/projects/Gtmax.html.

[57] Energy Exemplar. 2020. "AURORA Electric Modeling Forecasting and Analysis Software." Accessed April 28, 2020. https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/.

[58] Joint Global Change Research Institute. 2020. "Global Change Assessment Model." Accessed April 28, 2020. http://www.globalchange.umd.edu/gcam/.

[59] Kavvadias, K., I. H. Gonzalez, A. Zucker, and S. Quoilin. 2018. *Integrated modelling of future EU power and heat systems The Dispa-SET v2.2 open-source model*. Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-77866-7, doi:10.2760/860626, JRC110305.

[60] Cole, W. *et al.* 2017. *Variable Renewable Energy in Long-Term Planning Models: A Multi-Model Perspective*. Golden, CO: NREL. https://www.nrel.gov/docs/fy18osti/70528.pdf.

[61] Novacheck, J., G. Brinkman, and G. Porro. 2018. "Operational Analysis of the Eastern Interconnection at Very High Renewable Penetrations." Golden, CO: NREL. https://www.nrel.gov/docs/fy18osti/71465.pdf.

[62] Brinkman, G. 2015. "Renewable Electricity Futures: Operational Analysis of the Western Interconnection at Very High Renewable Penetrations." Golden, CO: NREL. https://www.nrel.gov/docs/fy15osti/64467.pdf?gathStatIcon=true.

[63] EIA. 2019. "Annual Energy Outlook 2019 with projections to 2050." Washington, DC: EIA. https://www.eia.gov/outlooks/archive/aeo19/

[64] NREL. 2020. "NREL Annual Technology Baseline (ATB)." Accessed April 28, 2020. https://atb.nrel.gov/.

[65] IEA. 2019. *World Energy Outlook 2019.* Paris, France: IEA. https://webstore.iea.org/world-energy-outlook-2019.

[66] Bloomberg New Energy Finance. 2019. *New Energy Outlook 2019*. New York City, NY: Bloomberg.

[67] EIA. 2019. "Form EIA-860 detailed data with previous form data (EIA-860A/860B)." Accessed August 8, 2019. https://www.eia.gov/electricity/data/eia860/.

[68] Zhou, E., W. Cole, and B. Frew. 2018. "Valuing variable renewable energy for peak demand requirements." *Energy* 165: 499–511. doi: 10.1016/J.ENERGY.2018.09.009.

[69] Dent, C.J. *et al.* 2016. "Capacity value of solar power: Report of the IEEE PES task force on capacity value of solar power." *2016 Int. Conf. Probabilistic Methods Appl. to Power Syst. PMAPS 2016 - Proc.* doi: 10.1109/PMAPS.2016.7764197.

[70] Augustine, C., J. Ho, and N. Blair. 2019. *GeoVision Analysis Supporting Task Force Report: Electric Sector Potential to Penetration.* www.nrel.gov/publications.

[71] EIA. 2020. "Electric Power Monthly Table 6.07.C. Usage Factors for Utility Scale Storage Generators." Accessed March 17, 2020. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_c.

[72] Feldman, D., and R. Margolis. 2019. "Q1/Q2 2019 Solar Industry Update." Golden, CO: NREL. https://www.nrel.gov/docs/fy19osti/74585.pdf

[73] Zhang, Y. *et al.* 2017. “Grid-Level Application of Electrical Energy Storage: Example Use Cases in the United States and China.” *IEEE Power Energy Mag.* 15 (5): 51–58. doi: 10.1109/MPE.2017.2708860.

[74] Fu, R., T. Remo, and R. Margolis. 2018. “2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark.” Golden, CO: NREL. https://www.nrel.gov/docs/fy19osti/71714.pdf.

[75] Ratnam, E.L., S. R. Weller, and C. M. Kellett. 2015. “An optimization-based approach to scheduling residential battery storage with solar PV: Assessing customer benefit.” *Renew. Energy* 75 (March): 123–134. doi: 10.1016/j.renene.2014.09.008.

[76] Feldman, D., M. Zwerling, and R. Margolis. 2019. “Q2/Q3 2019 Solar Industry Update." Golden, CO: NREL. https://www.nrel.gov/docs/fy20osti/75484.pdf

[77] Mai, Trieu, Debra Sandor, Ryan Wiser, and Thomas Schneider. 2012. *Renewable Electricity Futures Study*. Golden, CO: NREL. https://www.nrel.gov/analysis/re-futures.html.

[78] NREL. 2019. *North American Renewable Integration Study.* Golden, CO: NREL. https://www.nrel.gov/analysis/naris.html.

[79] Bloom, A. *et al.* 2020. *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study.* Golden, CO: NREL. https://www.nrel.gov/docs/fy21osti/76850.pdf

[80] Brinkman, G., J. Jorgenson, A. Ehlen, and J. H. Caldwell. 2016. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California.* Golden, CO: NREL. https://www.nrel.gov/docs/fy16osti/64884.pdf

[81] GE Energy. 2010. “Western Wind and Solar Integration Study Phase 1." Golden, CO: NREL. https://www.nrel.gov/docs/fy10osti/47434.pdf.

[82] Frew, B. *et al.* 2021. “The curtailment paradox in the transition to high solar power systems.” *Joule* (April). doi: 10.1016/j.joule.2021.03.021.

[83] Denholm, P., W. Cole, A. W. Frazier, K. Podkaminer, and N. Blair 2021. *The Four Phases of Storage Deployment: A Framework for the Expanding Role of Storage in the U.S. Power System.* Golden, CO: NREL. https://www.nrel.gov/docs/fy21osti/77480.pdf.

[84] DOE. 2019. “2019 Discount Rate." Accessed April 28, 2020. https://www.energy.gov/sites/prod/files/2019/05/f62/2019discountrates.pdf.

Appendix A. Referenced Studies and Scenarios

Table A- 1. Referenced Studies and Scenarios

AEO	*Annual Energy Outlook 2019*
AEO REF	AEO Reference Case
AEO HOGT	AEO High Oil and Gas Resource and Technology
AEO LOGT	AEO Low Oil and Gas Resource and Technology
AEO HOI	AEO High Oil Price
AEO LOI	AEO Low Oil Price
WEO	*World Energy Outlook 2019*
WEO CPS	WEO Current Policies Scenarios
WEP NPS	WEO New Policies Scenarios
WEO SDS	WEO Sustainable Development Scenarios
ReEDS	*ReEDS Standard Scenarios 2019*
ReEDS MID	ReEDS Mid-case
ReEDS LRC	ReEDS Low Renewable Cost
ReEDS HRC	ReEDS High Renewable Cost
ReEDS LNP	ReEDS Low Natural Gas Price
ReEDS HNP	ReEDS High Natural Gas Price
ReEDS HNP+LRC	ReEDS High Natural Gas Price plus Low Renewable Cost
ReEDS LNP+HRC	ReEDS Low Natural Gas Price plus High Renewable Cost
NEO	*New Energy Outlook 2019*
NEO REF	NEO Reference Case

CLEAN GRID VISION:
A U.S. PERSPECTIVE

CLEAN ENERGY MINISTERIAL
Advancing Clean Energy Together

21stcenturypower.org

The 21st Century Power Partnership is a multilateral effort of the Clean Energy Ministerial and serves as a platform for public-private collaboration to advance integrated policy, regulatory, financial, and technical solutions for the large-scale deployment of clean energy in combination with deep energy efficiency and smart grid solutions.

15013 Denver West Parkway
Golden, CO 80401
303-275-3000 | www.nrel.gov

NREL/TP-5C00-78642 | September 2021

NREL prints on paper that contains recycled content.