2020 Standard Scenarios Report: A U.S. Electricity Sector Outlook

Wesley Cole, Sean Corcoran, Nathaniel Gates, Trieu Mai, and Paritosh Das

National Renewable Energy Laboratory

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Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

Preface

This report is one of a suite of National Renewable Energy Laboratory (NREL) products aiming to provide a consistent and timely set of technology cost and performance data and define a scenario framework that can be used in forward-looking electricity analyses by NREL and others. The long-term objective of this effort is to identify a range of possible futures for the U.S. electricity sector that illuminate specific energy system issues. This is done by defining a set of prospective scenarios that bound ranges of technology, market, and macroeconomic assumptions and by assessing these scenarios in NREL's market models to understand the range of resulting outcomes, including energy technology deployment and production, energy prices, and emissions.

This effort, which is supported by the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), focuses on the electric sector by creating a technology cost and performance database, defining scenarios, documenting associated assumptions, and generating results using NREL's Regional Energy Deployment System (ReEDS) model and the Distributed Generation Market Demand Model (dGen). The work leverages significant activity already funded by EERE to better understand individual technologies, their roles in the larger energy system, and market and policy issues that can impact the evolution of the electricity sector.

Specific products from this effort include:

- An Annual Technology Baseline (ATB) workbook documenting detailed cost and performance data (both current and projected) for both renewable and conventional technologies
- An ATB summary website describing each of the technologies and providing additional context for their treatment in the workbook
- This Standard Scenarios report describing U.S. power sector futures using the Standard Scenarios modeling results.

These products can be accessed at atb.nrel.gov and www.nrel.gov/analysis/standard-scenarios.html.

These products are built and applied to analyses to ensure (1) the analyses incorporate a transparent, realistic, and timely set of input assumptions, and (2) they consider a diverse set of potential futures. The application of standard scenarios, clear documentation of underlying assumptions, and model versioning is expected to result in:

- Improved transparency of modeling input assumptions and methodologies
- Improved comparability of results across studies
- Improved consideration of the potential economic and environmental impacts of various electric sector futures
- An enhanced framework for formulating and addressing new analysis questions.

Future analyses under this family of work are expected to build on the assumptions used here and provide increasingly sophisticated views of the future U.S. power system with the potential to expand to other sectors of the U.S. energy economy.

Acknowledgments

We gratefully acknowledge the many people whose efforts contributed to this report. The ReEDS and dGen modeling and analysis teams, including Max Brown, Stuart Cohen, Kelly Eurek, Will Frazier, Pieter Gagnon, Nathaniel Gates, Danny Greer, Jonathan Ho, Scott Machen, Kevin McCabe, Matthew Mowers, Ben Sigrin, Dan Steinberg, and Yinong Sun, actively participated in the model development and analysis leading to this work. We thank Billy Roberts for creating the maps used in this work. We are grateful to comments from Peter Balash, Sam Baldwin, Paul Donohoo-Vallett, Zach Eldredge, Sara Garman, Carey King, Seungwook Ma, Cara Marcy, Chris Namovicz, Kara Podkaminer, and Paul Spitsen. The effort reported here was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, Office of Strategic Programs under contract number DE-AC36-08GO28308. All errors and omissions are the sole responsibility of the authors.

List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BNEF	BloombergNEF
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CONUS	contiguous United States
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
dGen	Distributed Generation Market Demand Model
DOE	U.S. Department of Energy
EERE	DOE's Office of Energy Efficiency and Renewable Energy
EFS	Electrification Futures Study
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
ERCOT	Electric Reliability Council of Texas
GW	gigawatt
GWh	gigawatt-hour
IEA	International Energy Agency
ISO	independent system operator
LCOE	levelized cost of energy
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NG	natural gas
NGCC	natural gas combined cycle
NGCT	natural gas combustion turbine
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OGS	oil-gas-steam
PV	photovoltaic(s)
RE	renewable energy
ReEDS	Regional Energy Deployment System
RGGI	Regional Greenhouse Gas Initiative
RTO	regional transmission organization
SPP	Southwest Power Pool
TW	terawatt
TWh	terawatt-hour
VRE	variable renewable energy

Executive Summary

This report summarizes the results of 45 forward-looking scenarios of the U.S. power sector. These annual Standard Scenarios, which are now in their sixth year, have been designed to capture a wide range of possible power system futures.

The Standard Scenarios are simulated using the Regional Energy Deployment System (ReEDS) and Distributed Generation Market Demand Model (dGen). The ReEDS and dGen models project utility-scale power sector evolution and distributed photovoltaic (PV) adoption, respectively, for the contiguous United States. The ReEDS model takes a system-wide, least-cost approach when making decisions, while dGen uses a customer-centric adoption approach. The ReEDS model emphasizes capture of the unique traits of renewable energy, including variability and grid integration requirements. Additionally, for select scenarios, the systems built by ReEDS and dGen are run using the PLEXOS production cost model to provide hourly outputs of system operation.

Scenario results are included as part of this report in the Standard Scenarios Results Viewer (see cambium.nrel.gov). Annual results are available for the full suite of scenarios, and hourly results are available for the subset of scenarios run in PLEXOS.

The scenarios include a reference scenario (called the Mid-case) that uses default or median assumptions in the models, including existing policies as of June 30, 2020. Figure ES-1 summarizes the generation and capacity results from this Mid-case scenario. The scenarios also include 45 other cases that incorporate sensitivities such as fuel prices, demand growth, retirements, technology and financing costs, and transmission and resource restrictions, resulting in a wide range of possible generation mixes (Figure ES-2).

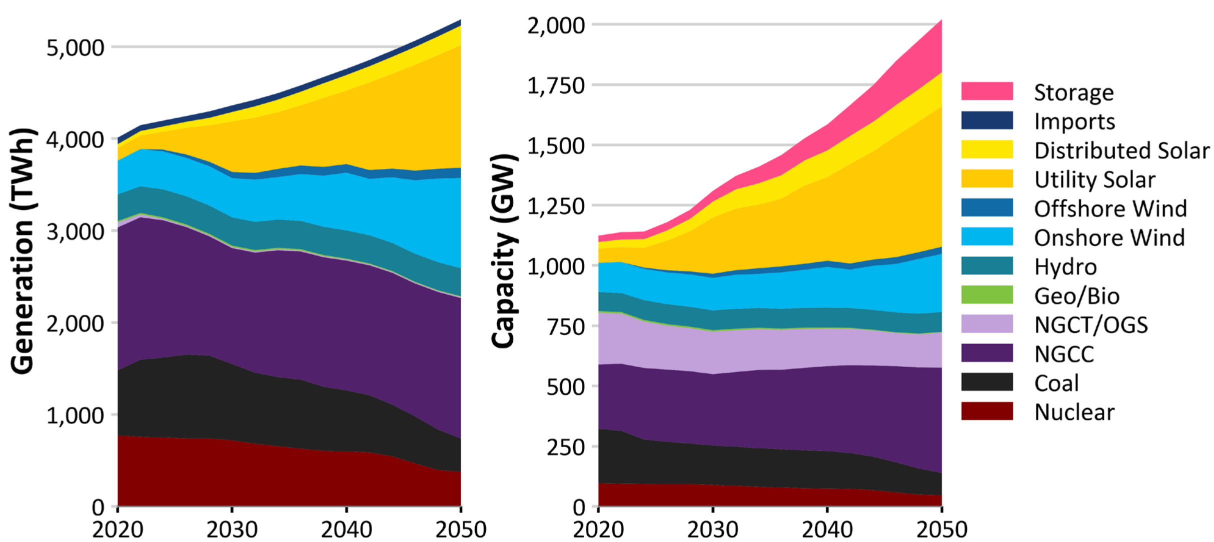

Figure ES-1. U.S. power sector evolution over time for the Mid-case scenario. Storage generation is not shown because storage always has negative net generation (due to losses). NGCC is natural gas combined cycle, NGCT is natural gas combustion turbine, OGS is oil-gas-steam, Geo/Bio is geothermal and biopower, TWh is terawatt-hours, and GW is gigawatts.

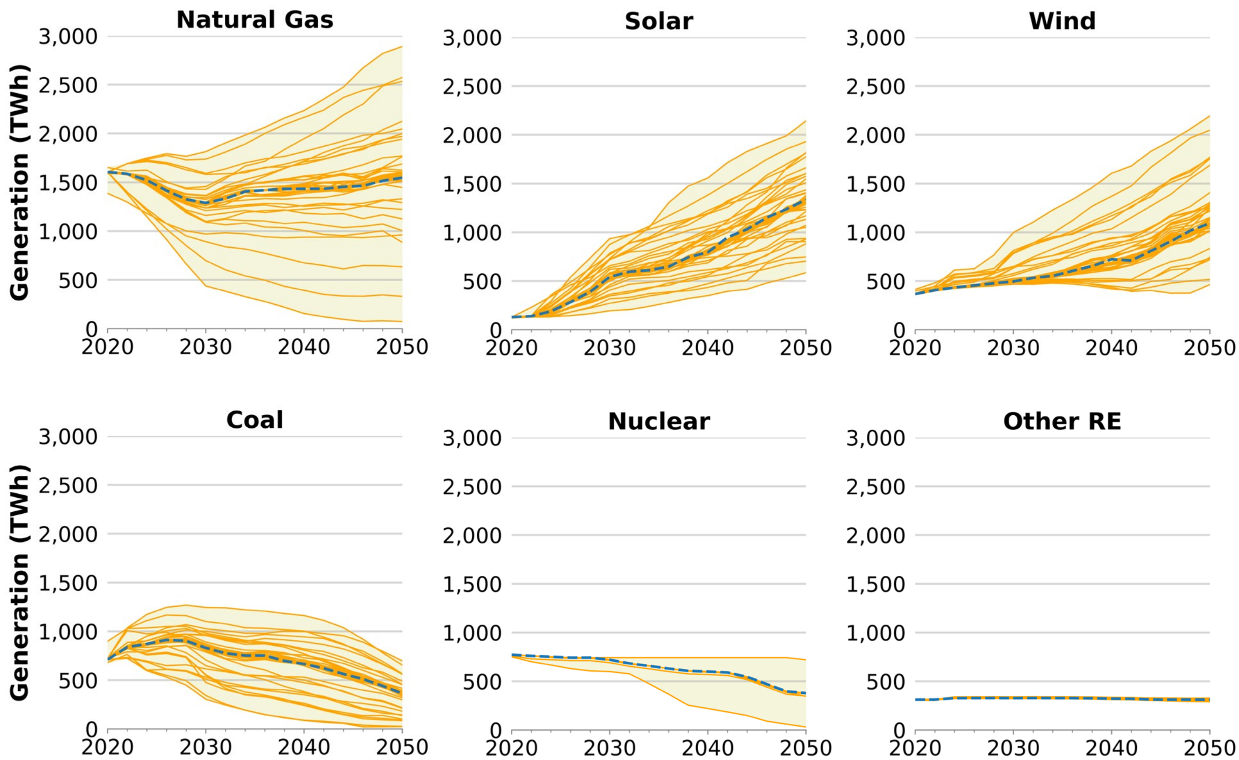

Figure ES-2. Generation across the suite of Standard Scenarios for the fuel types indicated. The Mid-case scenario is shown as the blue dashed line. Other RE includes biopower, concentrating solar power, geothermal, hydropower, and landfill gas.

This report summarizes many of the key scenario results and scenario assumptions. These scenarios are not meant to forecast or predict power sector deployment. Rather, our goal in providing these scenarios and associated outputs is to deliver context, discussion, and data that can inform stakeholder decision making about the future evolution of the U.S. power sector.

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1 Introduction

The U.S. electricity sector continues to undergo rapid change. To help us and others understand the implications, drivers, and key uncertainties associated with this change, we are introducing this sixth[1] installment of the Standard Scenarios. This year's Standard Scenarios consist of 46 power sector scenarios for the contiguous United States (CONUS) that consider the present day through 2050 and have been studied using two models from the National Renewable Energy Laboratory (NREL) along with a commercial production cost model:

- Regional Energy Deployment System (ReEDS): a long-term capacity expansion model from NREL (Brown et al. 2020)
- Distributed Generation Market Demand Model (dGen): a rooftop solar photovoltaic (PV) diffusion model from NREL (Sigrin et al. 2016)[2]
- PLEXOS: a production cost model from Energy Exemplar.[3]

The Standard Scenarios enable a quantitative examination of how various assumptions impact the future development of the power sector. The full suite of scenarios considers a wide range of assumptions.

The objective of this effort is not to predict the specific deployment trajectories for the various generator technologies but rather to consider a range of possible grid evolution pathways in an attempt to better understand key drivers, implications, and decision points that can contribute to better-informed investment and policy decisions. The Standard Scenarios are not "forecasts," and we make no claims that our scenarios have been or will be more indicative of actual future power sector evolution than projections made by others. Instead, we note that a collective set of projections from diverse analytical frameworks and perspectives could offer a more robust platform for decision making (Mai et al. 2013).

In addition, our modeling tools have been designed with an emphasis on capturing the unique traits of renewable energy generation technologies and the resulting implications for the rest of the power system. We aim to accurately capture issues related to renewable energy integration, including ensuring capacity adequacy and estimating curtailment and forecast error impacts on investment decisions. Other modeling and analysis frameworks will have different emphases, strengths, and weaknesses. The work we report here provides a perspective on the electricity sector that complements those provided by others; it also demonstrates how the model operates under a variety of input conditions and configurations.

Although the models used to develop the Standard Scenarios are sophisticated, they do not capture every factor that can impact the evolution of each scenario. For example, the models do not consider the build-out of natural gas pipelines, and they take a system-wide planning approach when making capacity build decisions rather than representing specific market actors or rules. Therefore, results should be interpreted within the context of model limitations. A more

[1] See atb.nrel.gov/electricity/archives.html for the previous Standard Scenarios reports and data.
[2] For more information about ReEDS and dGen, see www.nrel.gov/analysis/reeds and www.nrel.gov/analysis/dgen, respectively. For lists of published work using ReEDS and dGen, see www.nrel.gov/analysis/reeds/publications.html and www.nrel.gov/analysis/dgen/publications.html respectively.
[3] Only a subset of the scenarios were modeled in PLEXOS. Additional postprocessing of the PLEXOS results was performed in order to provide additional outputs such as marginal emissions rates.

complete list of model-specific caveats is available in the models' documentation (Brown et al. 2020, Section 1.4; Sigrin et al. 2016, Section 2.2).

The ultimate purpose of the Standard Scenarios and this associated report is to provide context, discussion, and data to inform stakeholder decision-making regarding the future evolution of the U.S. power sector. As a key feature of this report, the state-level Standard Scenarios outputs are presented in a downloadable format online using the Standard Scenarios Results Viewer.[4] This report reflects high-level observations, trends, and analyses, whereas the Standard Scenarios Results Viewer includes detailed scenario results useful for more in-depth analysis.[5]

[4] See cambium.nrel.gov.

[5] The data viewer provides additional state-specific data from the scenarios; however, we note that as a national-scale model, ReEDS is not specifically designed to assess in detail the full circumstances of any individual state.

2 The Standard Scenarios

The 2020 Standard Scenarios comprise 45 power sector scenarios that are run using the ReEDS model (Brown et al. 2020) and the dGen model (Sigrin et al. 2016). Nine of the scenarios are new to this year's edition, and scenario assumptions have been updated since last year to reflect the many technology, market, and policy changes that have occurred in the power sector (see Appendix A.2 for a complete list of changes). The scenarios are summarized in Figure 1. Details about specific scenario definitions and inputs are provided in Appendix A.1.

The 45 scenarios were selected to capture a breadth of trajectories of costs, performance, and other drivers.[6] The diversity of scenarios is intended to cover a range of potential futures rather than focusing on a single-scenario outlook. For example, in addition to considering traditional sensitivities such as demand growth and fuel prices, we also assess a considerable number of other factors that can impact the development of the power system, such as transmission build-out and technology progress. We do not assign probabilities to these scenarios, nor do we identify which scenarios are more or less likely to occur.

This Standard Scenarios analysis also takes advantage of a tool that converts ReEDS scenario outputs into PLEXOS input data. PLEXOS is a commercially available production cost model that we use to model the hourly operation of a subset of scenarios: the ReEDS Mid-case, High RE Cost, Low RE Cost, Low Battery Cost, and Low Wind Cost scenarios. The ReEDS model uses a reduced-form dispatch that captures annual generation using 17 time-slices (four time blocks per day times, one day for each of the four seasons, plus a summer peak time-slice); thus, by using a production cost model at hourly resolution, we can examine results with greater temporal resolution and can more fully capture the range of operational conditions and constraints that exists across the year. The scenarios that were modeled hourly also included additional outputs, such as long-run marginal emission rates, as facilitated by the Cambium tool (Gagnon et al. 2020).

To enhance transparency in model results, we note that the ReEDS model used to generate these scenarios is publicly available.[7]

[6] Although the scenarios cover a wide range of futures, they are not exhaustive.
[7] See www.nrel.gov/analysis/reeds.

Electricity Demand Growth

- Reference Demand Growth
- Low Demand Growth
- High Demand Growth
- High Electrification with Demand Flexibility
- Reference with Demand Flexibility
- High Electric Vehicle Adoption

Fuel Prices

- Reference Natural Gas Prices
- Low Natural Gas Prices
- High Natural Gas Prices

Financing Assumptions

- Mid Finance Projections
- Shortened Cost Recovery
- Extended Cost Recovery

Existing Fleet Retirements

- Reference Retirement
- Accelerated Retirements
- Extended Lifetimes
- No Economic Retirements

Electricity Generation Technology Costs

- Mid Technology Cost
- Low RE Cost
- High RE Cost
- Low Onshore Wind Cost
- High Onshore Wind Cost
- Low PV Cost
- High PV Cost
- Low Geothermal Cost
- High Geothermal Cost
- Low CSP Cost
- High CSP Cost
- Low Hydro Cost
- High Hydro Cost
- Low Offshore Wind Cost
- High Offshore Wind Cost
- Low Battery Cost
- High Battery Cost
- Nuclear Technology Breakthrough
- Carbon Capture and Storage Breakthrough
- 2019 ATB Mid Technology Cost

Model Foresight

- No Foresight
- Perfect Foresight

Combination Scenarios

- Low Natural Gas Prices & Low RE Cost
- High Natural Gas Prices & Low RE Cost
- Low Natural Gas Prices & High RE Cost
- High Natural Gas Prices & High RE Cost
- Low RE Cost & Low Battery Costs
- Low RE Cost & High Battery Cost
- Low NG Prices & Low RE Cost & Low Battery Cost

Resource and System Conditions

- Default Resource Constraints
- Reduced RE Resource
- Barriers to Transmission System Expansion
- No Interstate Transmission
- Cooling Water Constraints
- Market for Curtailed Electricity

Figure 1. Summary of the 2020 Standard Scenarios. The Mid-case scenario uses the first item in each category (except for the Combinations Scenarios). Additional scenario details are in Table A-1 of the appendix. All scenarios reflect federal and state electricity policies based on enacted as of June 30, 2020. Because of differences in model structure, results from the Perfect Foresight scenario are only included in the Appendix.

3 The Mid-case Scenario

The Mid-case scenario uses the reference, mid-level, or default assumptions for scenario inputs (see Figure 1 for a summary of those assumptions and Table A-1 and Appendix A.1 for details about the assumptions). In this way, the Mid-case scenario represents a reference case and provides a useful baseline for comparing scenarios and assessing trends. Importantly, the Mid-case scenario does not necessarily reflect a most likely scenario. Section 3.1 provides some additional context for how the Mid-case scenario relates to projections from other organizations.

Figure 2 shows the generation and capacity mix through 2050 for the Mid-case scenario. Total generation grows steadily over time, and that increased generation is provided primarily by a mix of new natural gas combined cycle (NGCC), PV, and wind generation. As a result of both lifetime and economic retirements, the amount of coal and nuclear capacity declines over time, resulting in correspondingly less generation from these technologies. In the late 2040s, wind and PV generation increase more rapidly in part to compensate for the more rapid retirements that occur in this period. The generation fractions for renewables, fossil, and nuclear are 32%, 50%, and 18%, respectively, in 2030 and 55%, 38%, and 7% in 2050. Diurnal storage capacity reaches 220 GW in 2050, with a fleet-wide average duration of just over 6 hours.

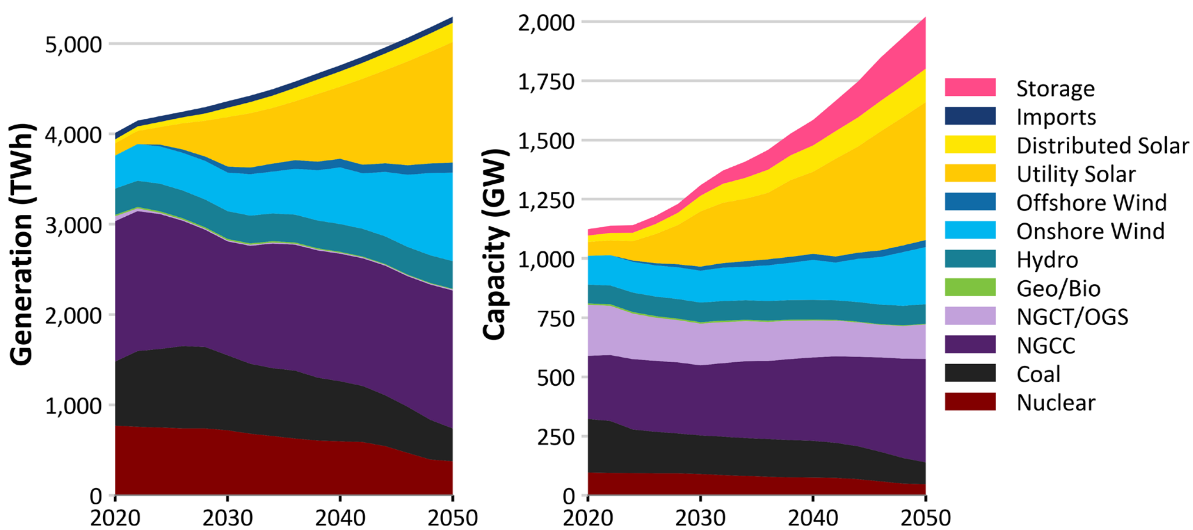

Figure 2. U.S. power sector evolution over time for the Mid-case scenario. Storage generation is not shown because storage always has negative net generation (due to losses). NGCC is natural gas combined cycle, NGCT is natural gas combustion turbine, OGS is oil-gas-steam, Geo/Bio is geothermal and biopower, and TWh is terawatt-hours.

Under the Mid-case scenario, the U.S. electricity system evolves toward one with higher shares of natural gas and renewable energy in all states (Figure 3).[8] The regional distribution of power plants is projected to be similar in 2050 to what it was in 2018, with the largest generation levels occurring in states with the greatest electricity consumption (e.g., California, Florida, and Texas). However, proportionally larger future renewable deployment is found in some states (e.g.,

[8] States with 100% clean energy standards do not necessarily have 100% of their generation from clean energy resources. We only require that the states satisfy their end-use sales with clean energy resources. Transmission and storage losses or exported energy can come from other resource types.

Nebraska and New Mexico) with particularly high-quality wind and solar resources or policies supporting high levels of renewables.[9]

For a summary of how the Mid-case scenario has changed over the various editions of the Standard Scenarios, see Appendix A.2.

[9] Specific state-level scenario results can be downloaded using the Standard Scenario Results Viewer for all scenarios at cambium.nrel.gov.

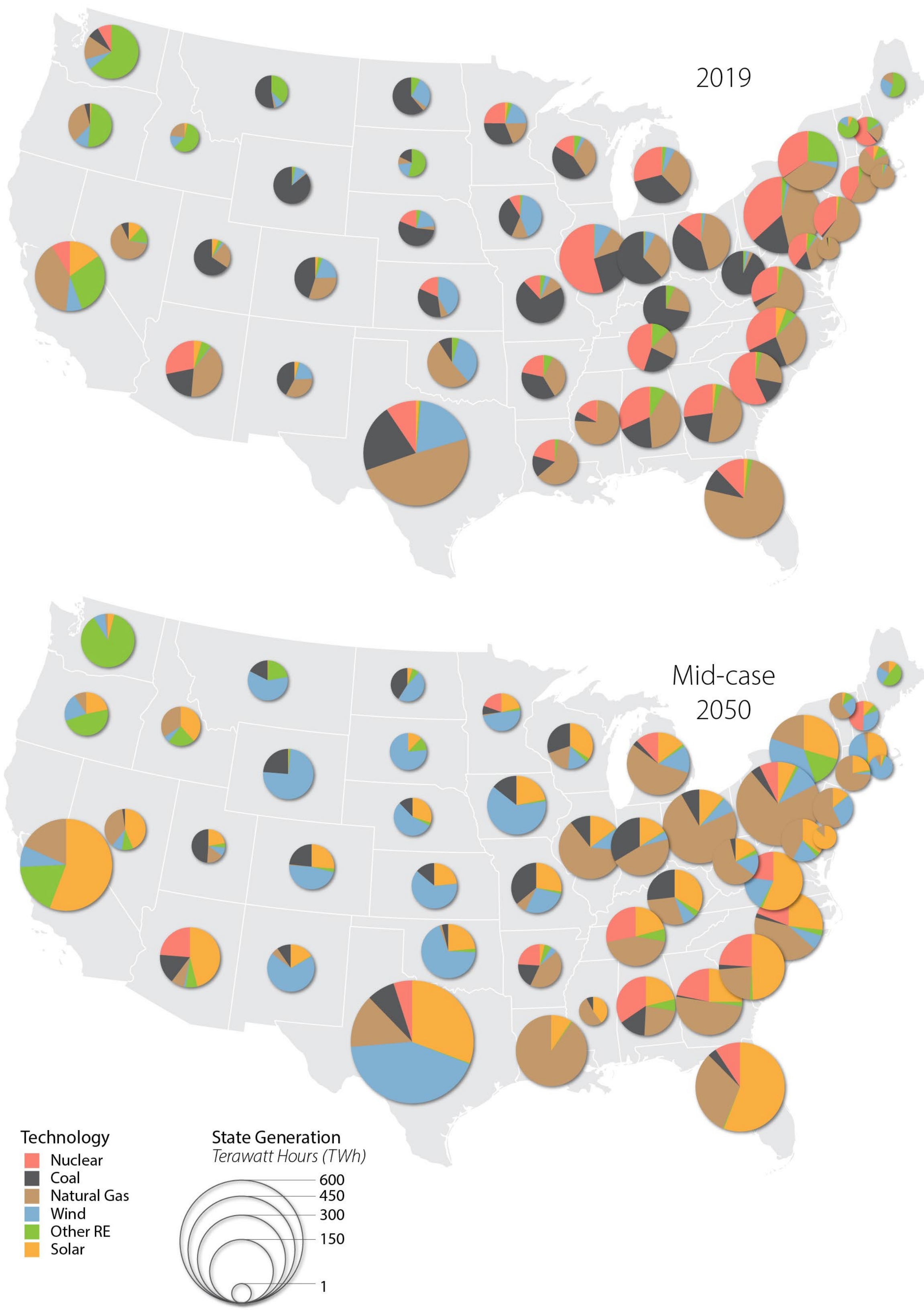

Figure 3. Evolution of the U.S. power system from the current system (top) to one powered primarily by wind, solar, and natural gas capacity (bottom) in all regions in the Mid-case scenario.

3.1 Hourly Outputs

To generate hourly outputs for 2020-2050, the systems produced by ReEDS for five of the scenarios were converted to a PLEXOS database and operated over the 8,760 hours of the year. Those five scenarios are Mid-case, High RE Cost, Low RE Cost, Low Battery Cost, and Low Wind Cost scenarios. The PLEXOS model enforces unit commitment and dispatch constraints at this hourly resolution, which provides more information than is available in a ReEDS scenario. Hourly outputs are available for all years and regions modeled by ReEDS, but only national results for the 2050 year are shown in this section.

Figure 4 shows the national average hourly marginal electricity prices that were postprocessed from the PLEXOS results for each hour and month for 2050. The prices show the component of the price that is from energy, capacity, ancillary services, and state portfolio requirements.[10] Prices are highest in the summer evenings and in winter mornings in January, with the magnitude of the price being primarily driven by the marginal cost of capacity.

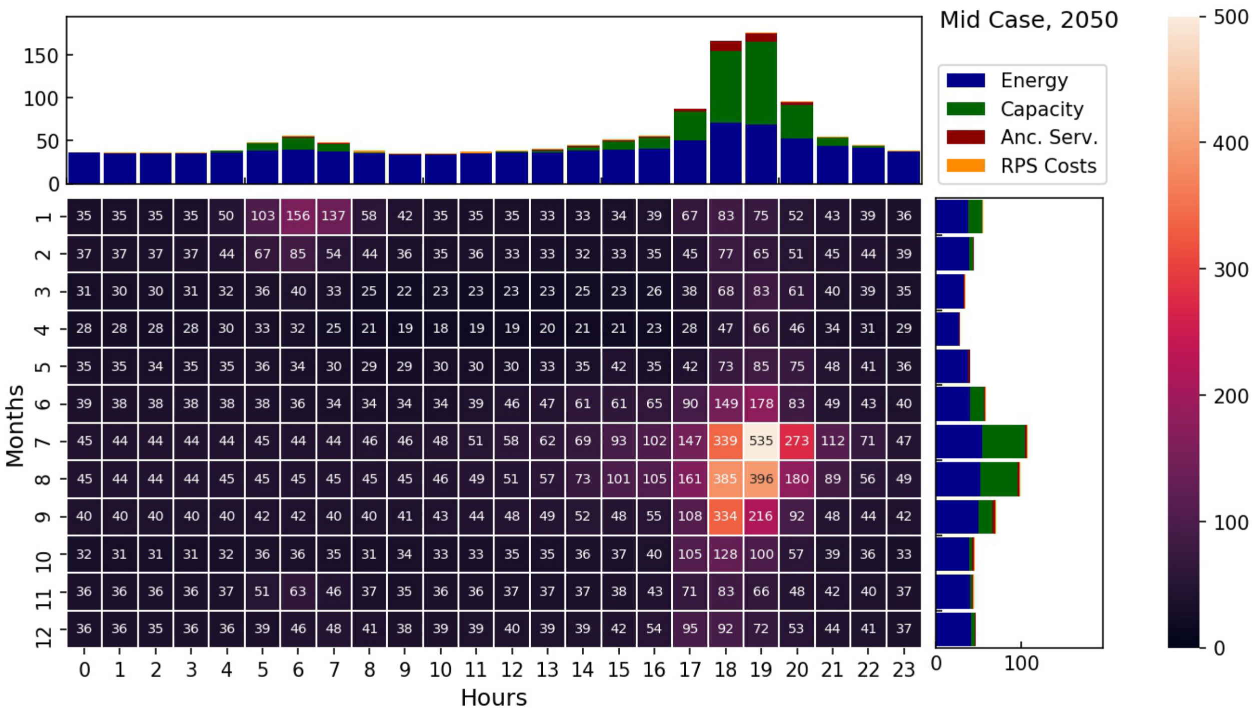

Figure 4. Hourly marginal costs ($/MWh) for the Mid-case in 2050, grouped by month-hour.

Figure 5 shows the curtailment patterns using the same hour-month structure for 2050. Seasonally, curtailment is highest in the spring and fall. The diurnal patterns show higher curtailment overnight and in the afternoon, and the lowest curtailment in the evening. The lower curtailment is correlated with the higher prices from Figure 4.

[10] The price component from the state portfolio requirements is the impact on electricity price from complying with state renewable or clean energy requirements, such as a renewable portfolio standard.

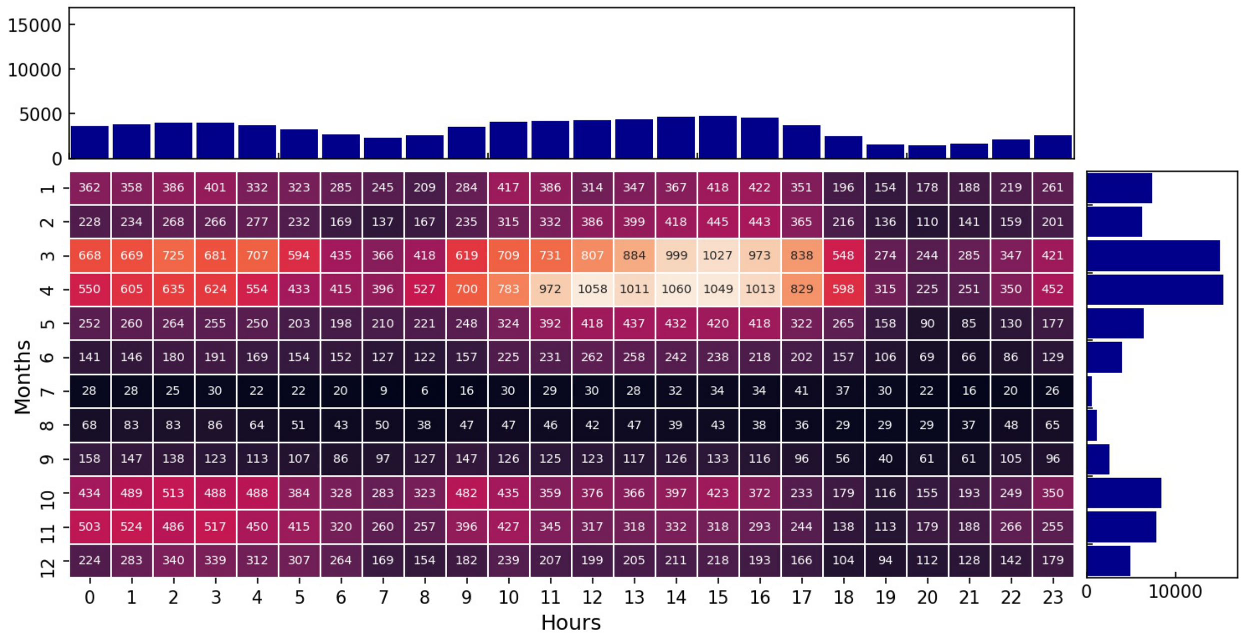

Figure 5. National curtailment patterns for the Mid-case in 2050 (GWh), grouped by month-hour.

Figure 6 shows the national average carbon dioxide (CO_2) emissions rate in 2050. Emission rates are lowest in the daytime in the spring and highest in the summer overnight. Seasonally, emission rates are higher in periods with higher demand.

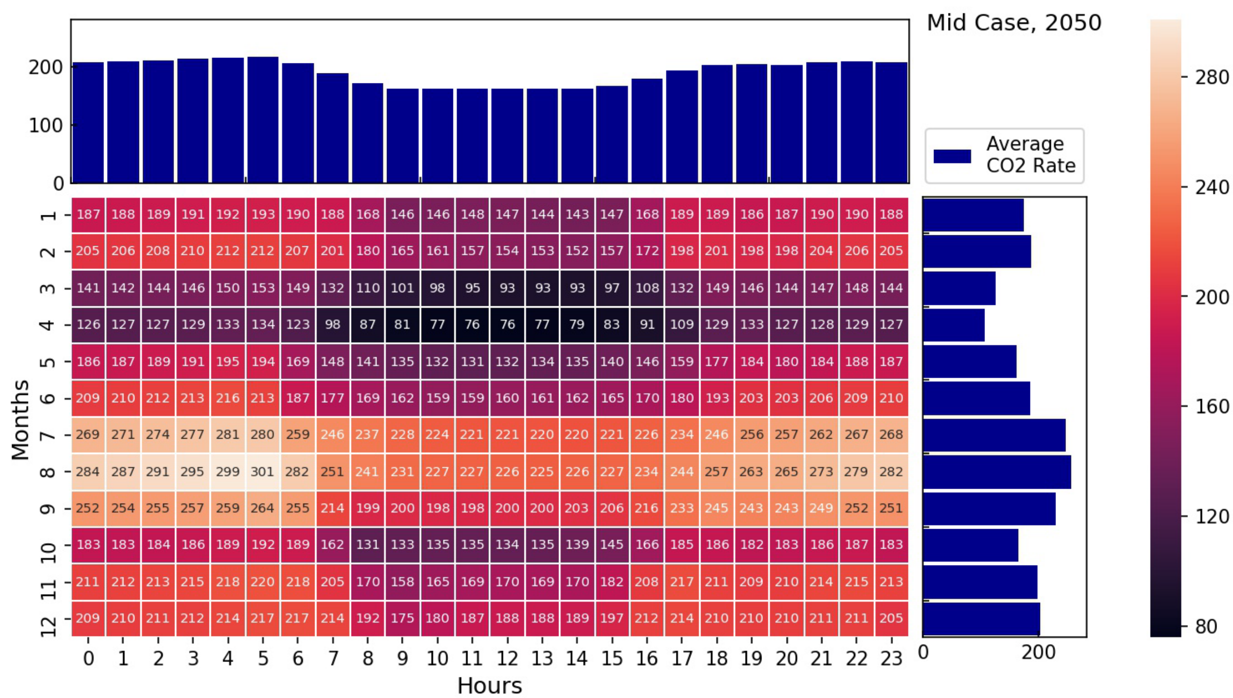

Figure 6. National average CO_2 emission rates (kg/MWh) for the Mid-case in 2050, grouped by month-hour.

3.2 Comparison to Other Reference Case Scenarios

Here, we compare the Mid-case projection with those from three well-known organizations—the U.S. Energy Information Administration (EIA), the International Energy Agency (IEA), and BloombergNEF (BNEF)—that have a much longer record of producing annual U.S. electricity sector outlooks. Although the Standard Scenarios and most of these organizations publish multiple scenarios that span a wide range of assumptions, this comparison uses only the "reference" scenarios. Figure 7 shows results from the:

- NREL Standard Scenarios Mid-Case,
- EIA Annual Energy Outlook (AEO) Reference case
- IEA World Energy Outlook New Policies Scenario
- BNEF New Energy Outlook scenario, which has been published since 2015.[11]

Note that the input assumptions, including the policies represented, may differ among these reference scenarios.

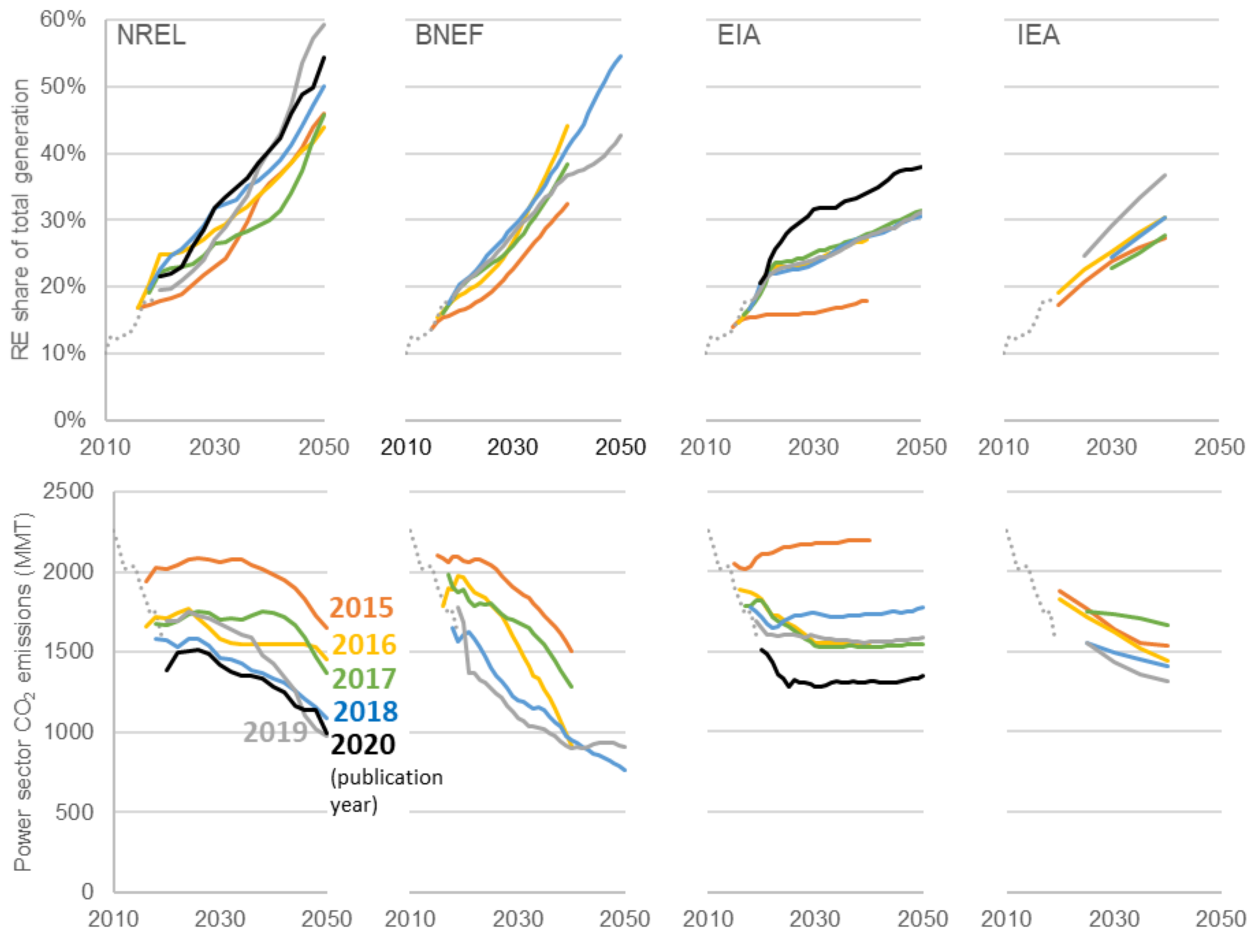

Figure 7. Renewable energy generation fraction (top) and power sector CO_2 emissions (bottom) from the organizations and publication years indicated.

[11] The IEA World Energy Outlook 2020 and the BNEF New Energy Outlook 2020 were not yet available at the time of this writing.

Although we have not exhaustively compared the scenarios, several trends emerge from an examination of the projections. First, all scenarios (from all organizations and for all publication years shown) show that the renewable energy generation fraction increases over time, where renewable energy generation is from technologies that use biomass, geothermal, hydropower, solar, and wind resources. For example, the range of renewable energy shares estimated from the most recent set of projections from the four organizations is 28%–32% in 2030, a narrow range of values that are all higher than the 18% renewable energy observed for 2019. This range widens over time (34%–40% in 2040 and 38%–54% in 2050), highlighting growing divergence between the projections into the future.

Power sector CO_2 emissions results from this collection of scenarios reveals similarly wide variations among organizations and publication years. The emissions trends are, of course, related to the renewable energy share but are also closely tied to the amount and mix of fossil fuel-fired generation in the projections. For example, the latest BNEF projection shows a steadily increasing share of natural gas-fired generation that primarily offsets coal-fired generation, leading to the most-rapid and largest emissions reductions shown. In contrast, the EIA's 2020 Reference case projects slow growth for natural gas-fired generation and a modest decline in coal-fired generation after 2030. The 2020 Standard Scenarios Mid-case results in a slight near-term rise in fossil fuel-based generation followed by a steady decline through 2050. For all organizations, more recent projections generally include lower power sector emissions than earlier versions for most years. This trend of lower projected emissions follows trends in actual U.S. power sector emissions, which have fallen sharply over the past decade.

4 Range of Outcomes across all Scenarios

In this section, we highlight the range of several key metrics across the full suite of scenarios. Because the Mid-case represents only one potential future, it is important to understand how the grid might evolve over a wide range of futures. Additionally, because sensitivities are performed off the Mid-case, there is a natural clustering of lines around the Mid-case. This clustering should not be interpreted as indicating a higher likelihood.

Figure 8 shows the generation by fuel type across the full suite of scenarios. Natural gas, solar, and wind show the largest range in 2050 generation across the scenarios. Natural gas has an especially wide range, with the largest deviations from the Mid-case coming from the natural gas price sensitivity scenarios. Coal and nuclear generation generally decline, and other renewable energy generation remains nearly constant.

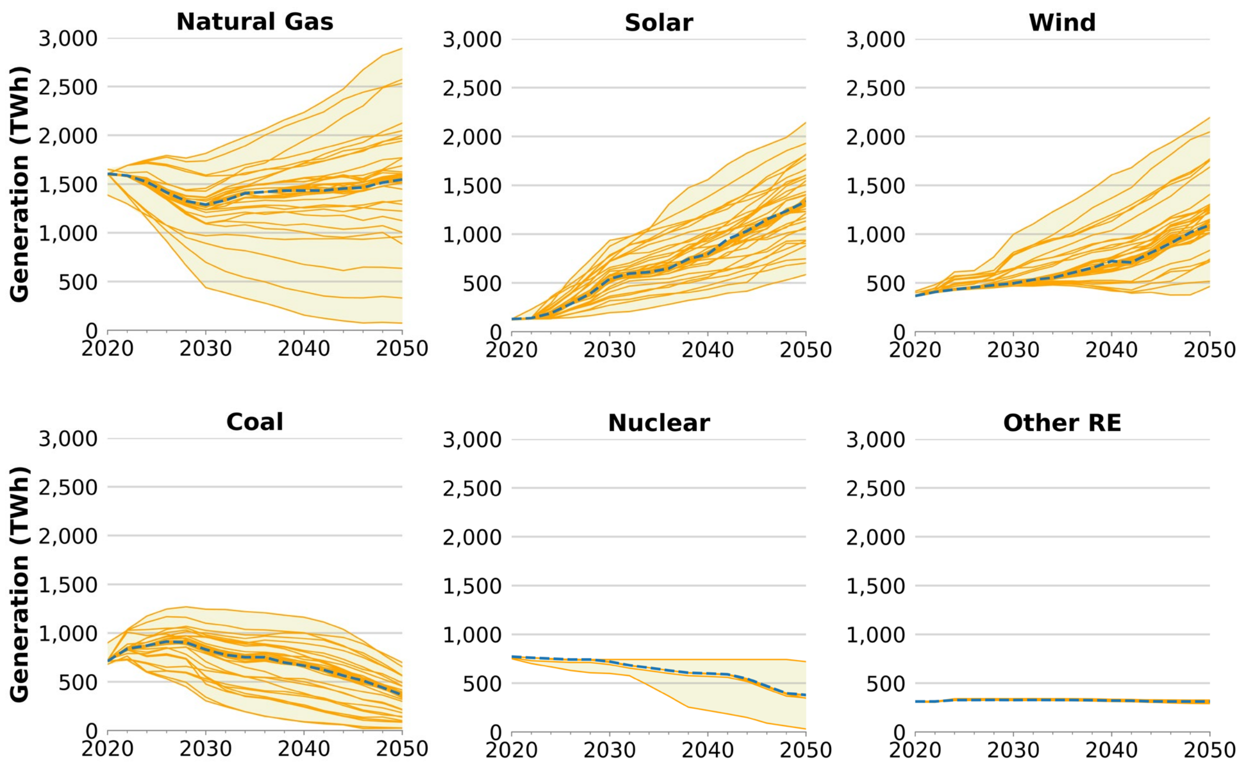

Figure 8. Generation by fuel type across the Standard Scenarios. The dashed line is the Mid-case scenario.

For capacity (see Figure 9), natural gas has a much narrower range than its generation range. That is largely because natural gas capacity is a high-value source of firm capacity, even in scenarios with limited natural gas generation. Solar has the widest range of 2050 deployment, followed by wind and storage. Solar also reaches the highest overall capacity levels in part because it generally has a lower capacity factor than the other technologies. Storage grows in all the scenarios, with the growth coming primarily from batteries. Other renewable energy is not shown in Figure 9 because the capacity largely follows the generation shown in Figure 8.

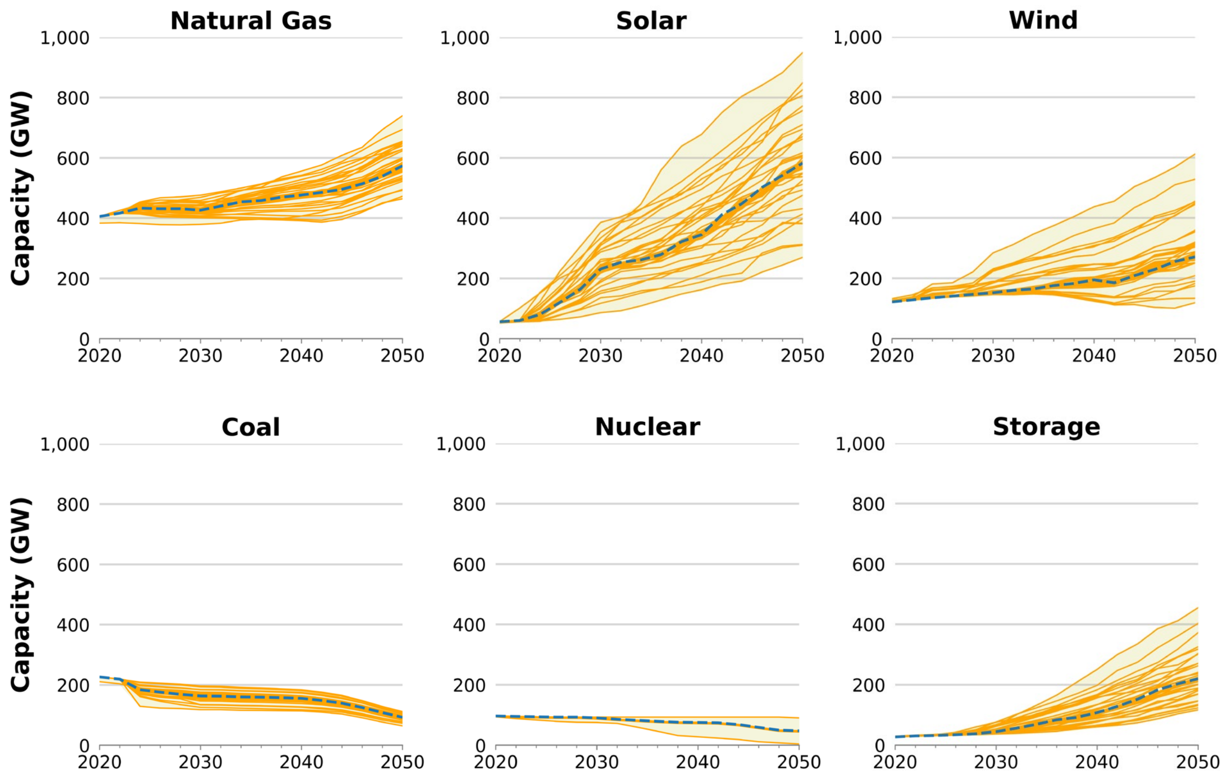

Figure 9. Capacity by fuel type across the Standard Scenarios. The dashed line is the Mid-case scenario.

Figure 10 shows the average battery duration of the fleet. In all scenarios the duration starts near two hours and by 2050 grows to a range of 4-5 hours.

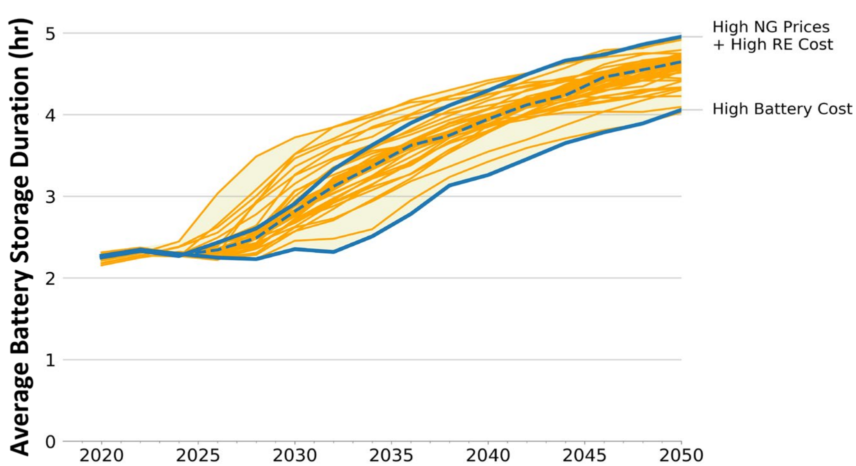

Figure 10. Average duration of installed battery storage capacity across the Standard Scenarios. The dashed line is the Mid-case scenario.

Distributed PV capacity is unique for only a subset of scenarios, ranging from 37 GW to 159 GW in 2050 (see Figure 11). Distributed PV adoption varies across scenarios as a function of PV prices and wholesale electricity prices. Scenarios with lower electricity prices will have lower adoption (because the value of offsetting utility electricity consumption is lower) and vice versa for higher electricity price scenarios.

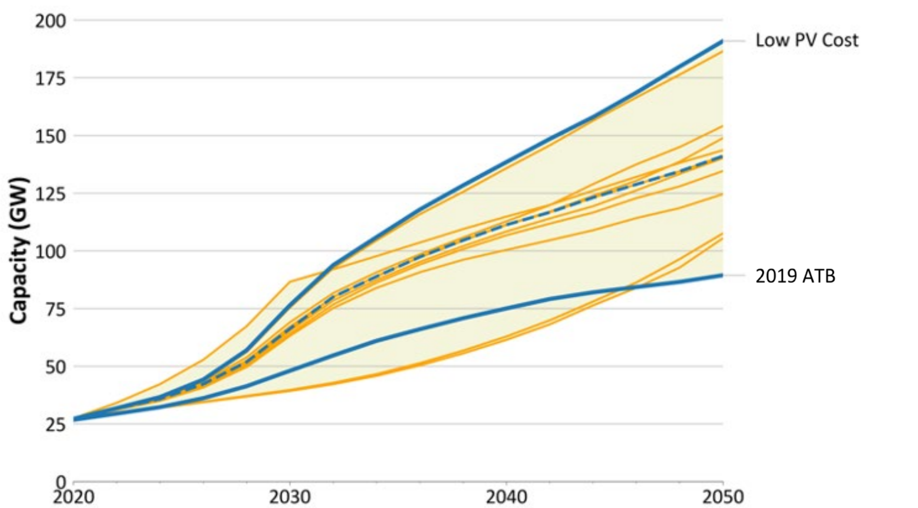

Figure 11. Distributed PV generation and capacity across the Standard Scenarios. Distributed PV build out is treated exogenously using outputs from dGen modeling.

Total renewable energy penetration, defined as renewable energy generation share of total generation, grows from approximately 20% in 2020 to 31%–83% in 2050 (see Figure 12). From the generation figures above (Figure 8), the increase in renewable energy penetration is primarily from wind and solar.

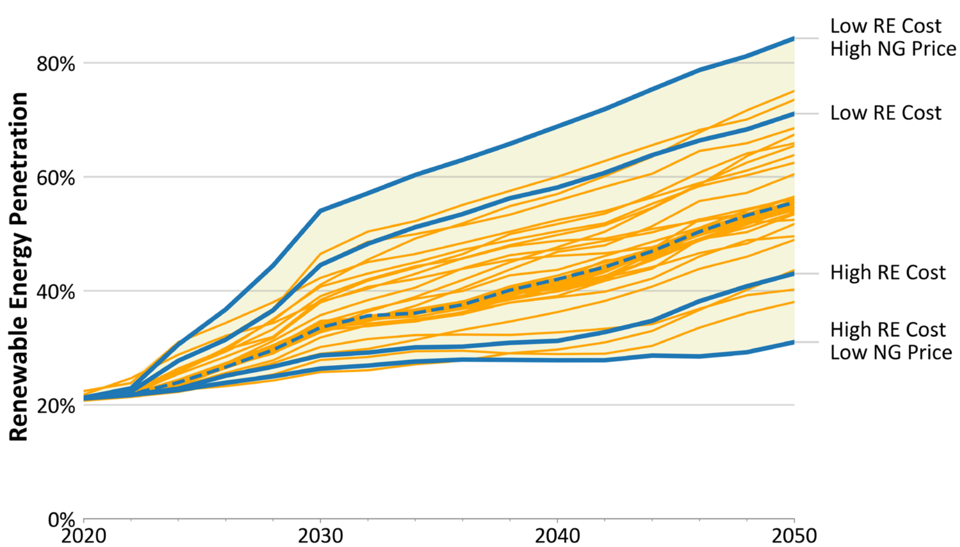

Figure 12. Renewable energy penetration over time across the Standard Scenarios. The highest and lowest renewable energy penetration scenarios in 2050 are labeled, along with the Low RE and High RE Cost scenarios. Renewable energy penetration is defined as renewable energy generation divided by total generation.

Figure 13 shows the trends in the prices of the four major grid services in the model. These model outputs, when coupled with information about the services that technologies can provide, are useful in understanding why the model is making certain decisions. The services are energy (ensuring there is enough energy in a time segment), planning reserve (ensuring there is enough capacity to meet the planning reserve requirement), operating reserve (ensuring there is enough capacity to deal with short-term contingencies and frequency regulation), and state policy provision[12] (providing generation to meet state generation constraints).

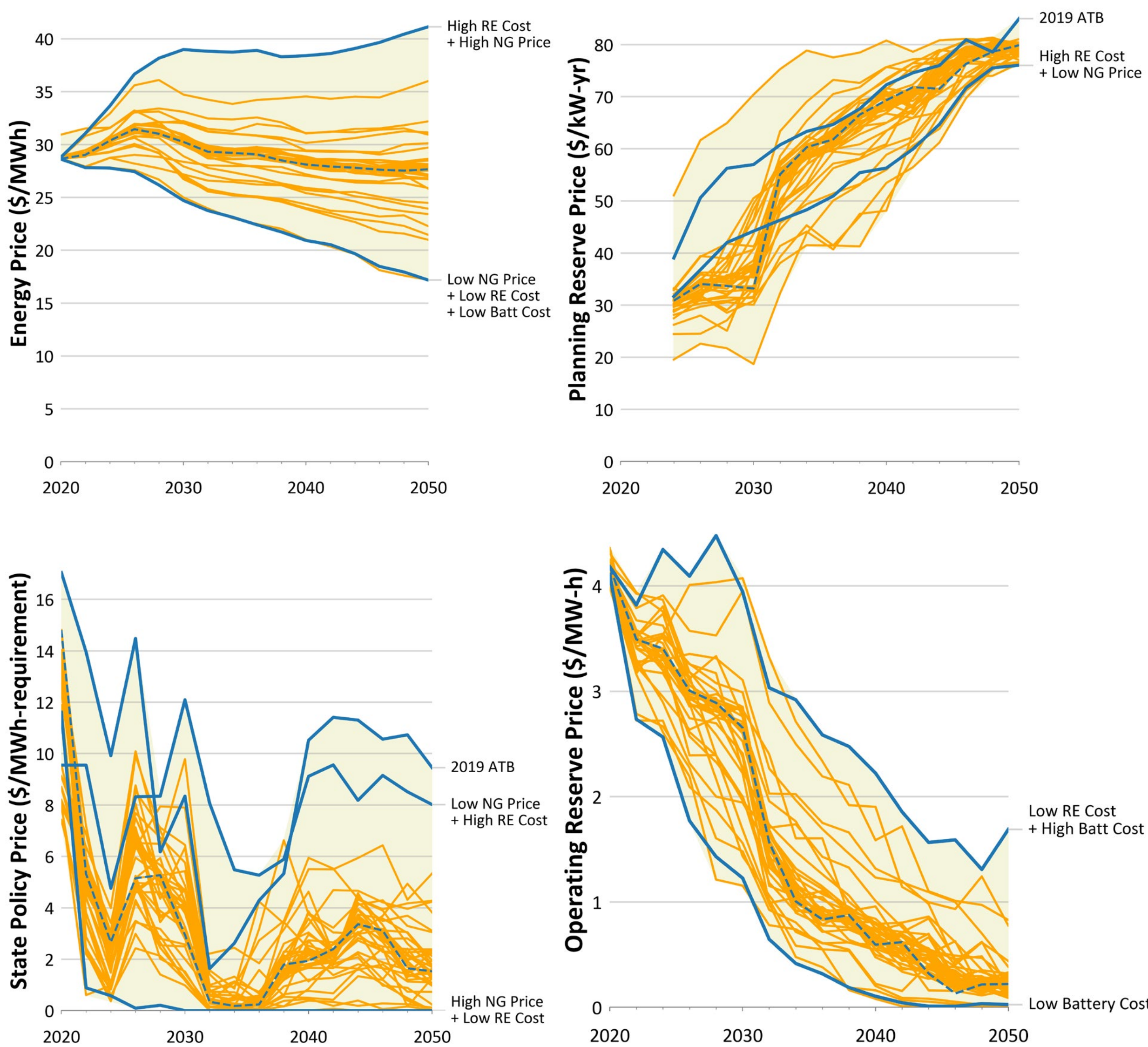

Figure 13. National annual average prices for the services indicated across the Standard Scenarios. The dashed line shows the Mid-case. Select high and low scenarios are also noted. The operating reserve price is the sum of the three operating reserve products: regulation, spinning, and flexibility.

[12] Not all policy constraints would be represented in this price. For example, carbon policies such as California's Assembly Bill 32 or the Regional Greenhouse Gas Initiative (RGGI) would result in higher energy prices.

Energy prices increase slightly over the near term in most scenarios, driven primarily by near-term projected increases in natural gas prices. Energy prices tend to are flat or declining in the long-term as natural gas prices remain relatively constant and zero-marginal-cost renewable energy penetration increases. Planning reserve prices grow over time as planning reserve margins tighten relative to today's levels (by 2050, the model has all regions exactly meeting the NERC recommended planning reserve levels). Operating reserve prices fall over time across all scenarios, driven by the increase in storage deployment (over 100 GW of storage are added in all scenarios—see Figure 9). Because storage can provide operating reserves at a low cost, and the operating reserve requirements are fairly small relative to the amount of storage deployed (Denholm, Sun, and Mai 2019), there is downward pressure on this price. State policy prices have mixed trends depending on the year and scenario, but they tend to follow the cost of building new renewable technologies (e.g., lower renewable energy cost scenarios result in lower state policy prices).

Figure 14 and Figure 15 show some aspects of interaction of prices with the energy and planning reserve provision values. Figure 14 shows the losses from wind and solar curtailment, transmission, and storage. Curtailment is zero-marginal-cost electricity that cannot be use cost-effectively, and therefore impacts only generators with zero marginal costs. Transmission and storage losses will impact any generator that is using those resources to move power across time or space.

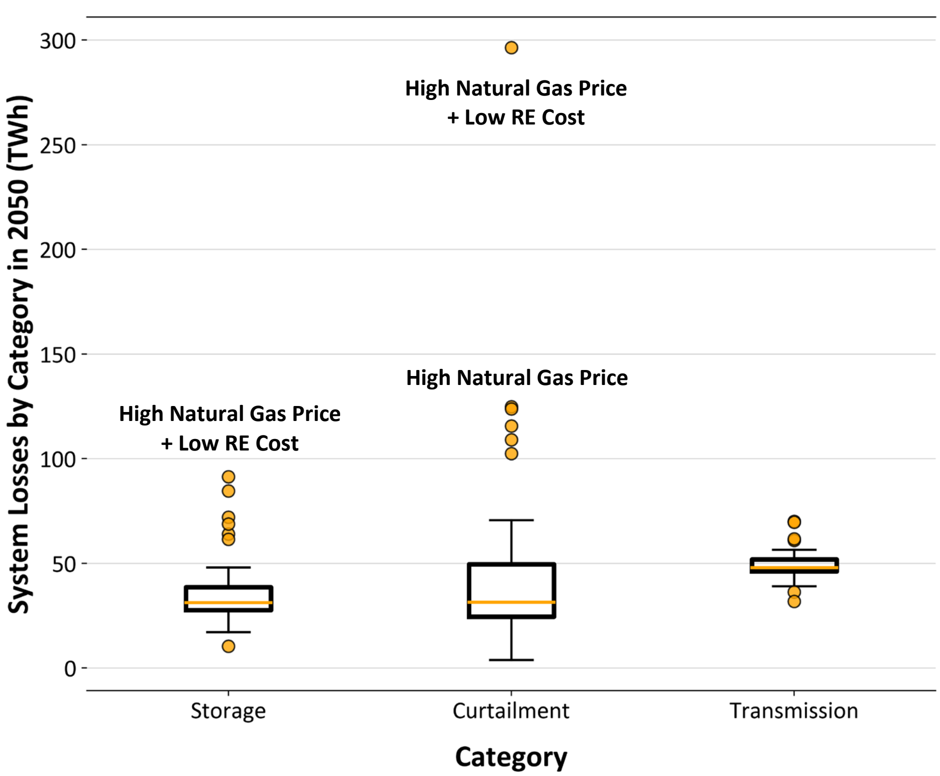

Figure 14. Storage, curtailment, and transmission (but not distribution) losses in 2050 across scenarios using a box-and-whisker plot. The boxes show the 25th-75th percentile, and the whiskers the 5th to 95th percentile. For reference, the Mid-case scenario has 5300 TWh of generation in 2050.

Figure 15 shows the average capacity credit of wind, solar, and battery resources. Most other resources will have a capacity credit of 100% and are therefore not shown.[13] The capacity credit is the fraction of nameplate capacity that is counted toward the planning reserve margin. Capacity credit for wind grows over time as increased PV deployment pushes the net load hours to times of greater wind generation, and as wind capacity factors improve. Solar capacity credit declines over time. Because these are average capacity credit and not marginal capacity credit, the values will not decrease to zero, even though marginal capacity credit of these resources may decrease to near zero. Storage capacity credit begins low because of a small amount of 2-hour storage that is built to meet mandates. It gradually grows as more 4-hour storage is deployed (refer back to Figure 10) and as increased PV deployment narrows peak periods.

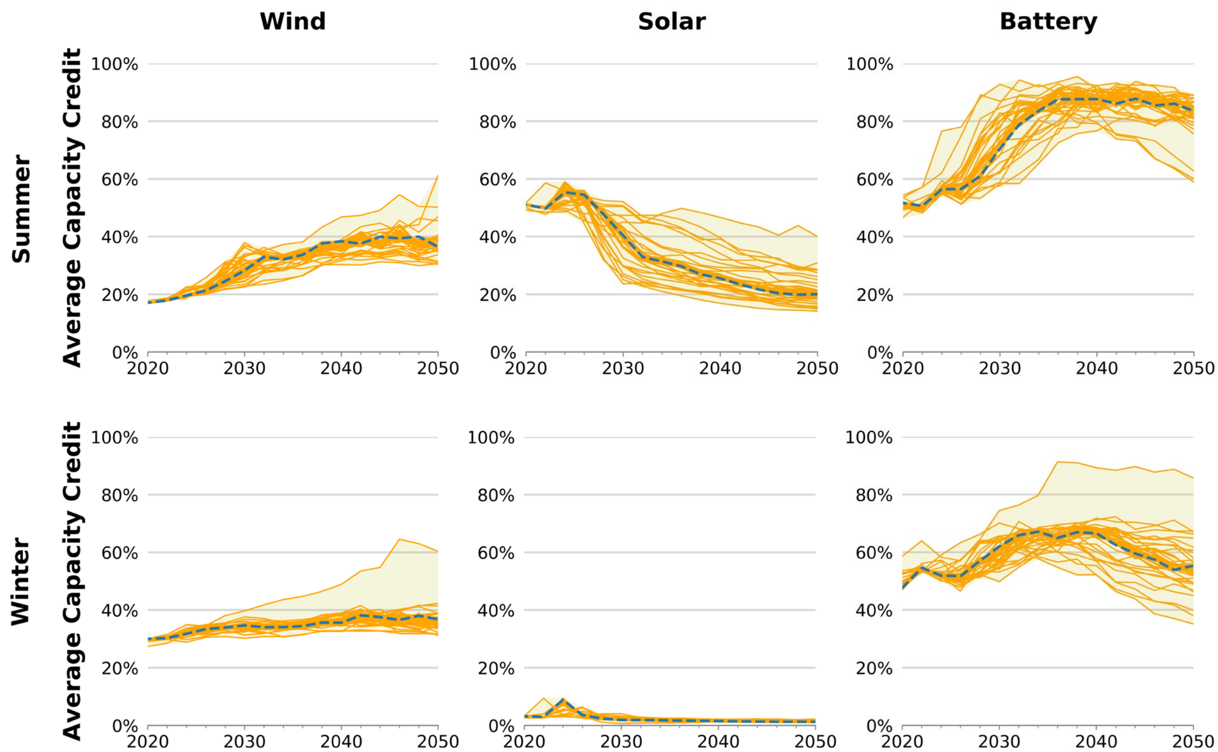

Figure 15. Average capacity credit in summer (top) and winter (bottom) for wind, solar and battery resources.

Figure 16 shows the transmission expansion across the scenarios. Higher levels of transmission development are correlated with both renewable energy deployment and higher natural gas prices. Higher renewable energy build-outs can benefit from more transmission that can move power from regions with high curtailment rates to load centers where that otherwise-excess energy can be consumed. Higher natural gas prices create high energy prices, which can lead to greater price arbitrage opportunities between regions. The scenario that includes the high transmission costs results in limited build-out of new transmission.

[13] Storage technologies might have less than 100% capacity credit depending on the resource mix and load shape for the region where the storage is located. Hydropower resources also have a range of capacity credits based on dispatchability and anticipated water availability.

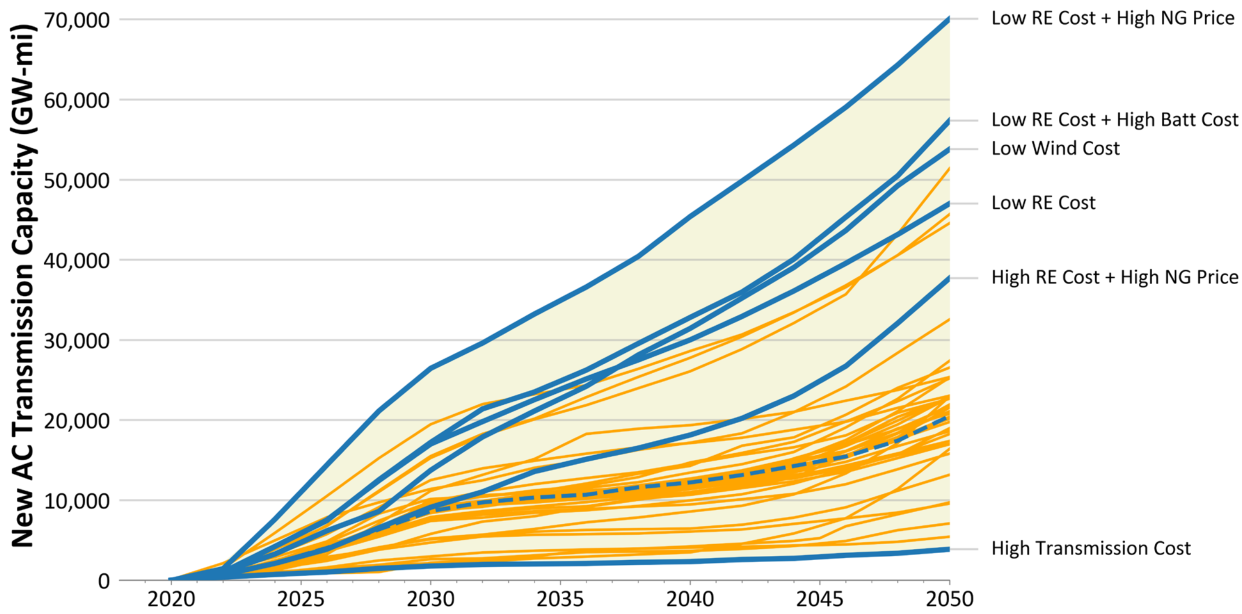

Figure 16. New long-distance AC transmission capacity over the Standard Scenarios. These values do not include spur lines for connecting wind and solar plants to the transmission system. For reference, the Mid-case scenario (dashed line) has 159,000 GW-mi of total long-distance AC transmission in 2050.

Figure 17 shows the range is system cost changes across scenarios. For reference, the Mid-case scenario has a total system cost of $2,477 billion dollars, which is in net present value terms using a 5% discount rate. Most scenarios have system costs that are within 4% of the Mid-case system cost. Unsurprisingly, the scenarios with sensitivity combinations that move the generation mix in the same direction result in the highest and lowest system costs.

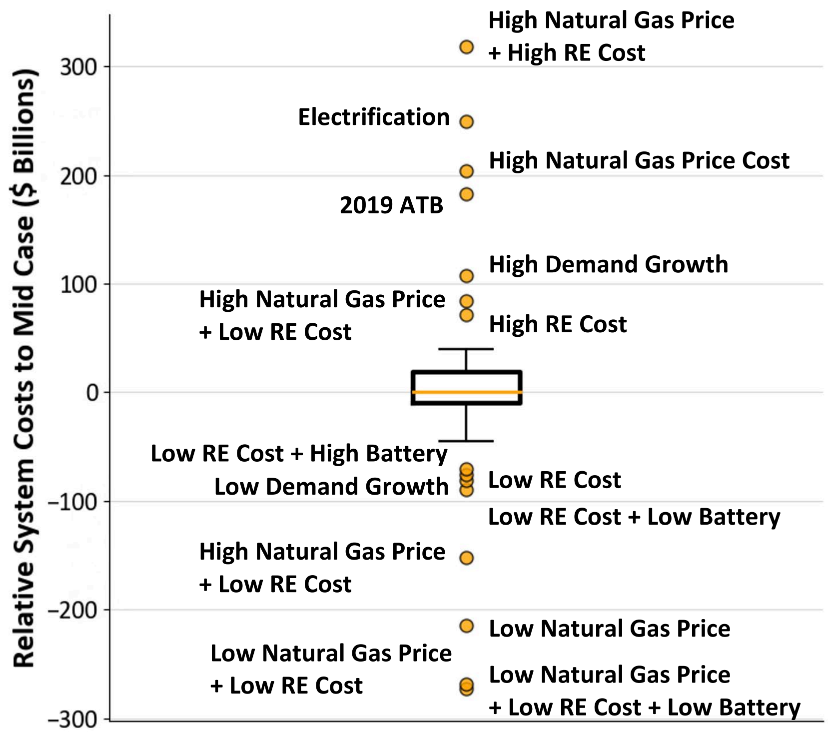

Figure 17. Changes in system costs relative to the Mid Case for the Standard Scenarios using a box-and-whiskers plot. The boxes show the 25th-75th percentile, and the whiskers the 5th to 95th percentile. System costs are the net present value (2019$) of the U.S. bulk power system from 2020 through 2050. The Mid-case has a system cost of $2,463 billion dollars.

Electricity sector CO_2 emissions are shown in Figure 18. Emissions in 2050 range from levels just below that projected in 2020 to an 81% reduction from modeled 2020 levels. In nearly all scenarios, emissions decline over time.

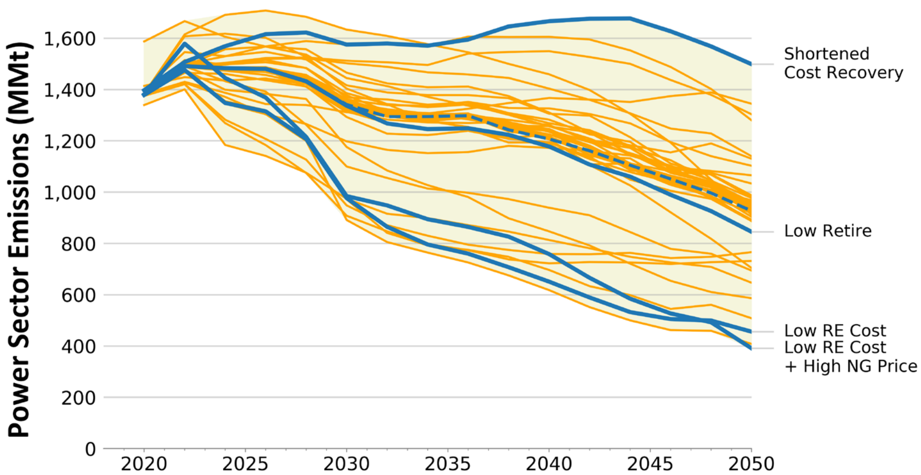

Figure 18. Power sector emissions over time across the Standard Scenarios. The highest and lowest emissions scenarios in 2050 are labeled, along with the low retirement scenario and the Low RE Cost scenario. The Mid-case scenario is the dashed line.

5 Summary

The Standard Scenarios provide outputs for a wide range of scenarios for the electricity power sector using complex electricity-sector models. The scenarios provide a framework for assessing trends and a data set to help advance thinking of how the power sector might evolve over time. Within NREL, we have found significant value in using the Standard Scenario to accelerate analysis and provide a baseline for related work. We share them with the hope that they can be of similar value to other power-sector stakeholders as they make decisions that will influence the constantly changing electricity sector.

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Appendix

A.1 Standard Scenarios Input Assumptions

This section describes the input assumptions used in the scenarios listed in Table A-1. For details about model assumptions, see the documentation for ReEDS (Brown et al. 2020) and dGen (Sigrin et al. 2016).

Table A-1. Summary of the 2020 Standard Scenarios. The scenario settings listed in *blue italics* correspond to those used in the Mid-case scenario, which is used in this analysis to reflect "business-as-usual" conditions.

Group	Scenario Setting	Notes
Electricity Demand Growth	*Reference Demand Growth*	*AEO2020 reference scenario growth rate*
	Low Demand Growth	AEO2020 low economic growth scenario growth rate
	High Demand Growth	AEO2020 high economic growth scenario growth rate
	Vehicle Electrification	Adoption of plug-in electric vehicles and plug-in hybrid electric vehicles reaches 40% of sales by 2050; 45% of charging utility-controlled, 55% opportunistic
	High Electrification with Base Flexibility	High level of electrification and base demand-side flexibility based on the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020)
	Reference Demand with Base Flexibility	Base demand-side flexibility based on the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020)
Fuel Prices	*Reference Natural Gas Prices*	*AEO2020 reference*[a]
	Low Natural Gas Prices	AEO2020 high oil and gas resource and technology[a]
	High Natural Gas Prices	AEO2020 low oil and gas resource and technology[a]
Electricity Generation Technology Costs	*Mid Technology Cost*	*2020 Annual Technology Baseline (ATB) moderate projections*
	Low RE[b] Cost	2020 ATB renewable energy advanced projections
	High RE Cost	2020 ATB renewable energy conservative projections
	Low Onshore Wind Cost	2020 ATB advanced projection for land-based wind

Group	Scenario Setting	Notes
	High Onshore Wind Cost	2020 ATB conservative projection for land-based wind
	Low PV Cost	2020 ATB advanced projection for PV
	High PV Cost	2020 ATB conservative projection for PV
	Low Geothermal Cost	2020 ATB advanced projection for geothermal
	High Geothermal Cost	2020 ATB conservative projection for geothermal
	Low CSP[c] Cost	2020 ATB advanced projection for CSP
	High CSP Cost	2020 ATB conservative projection for CSP
	Low Hydro Cost	2020 ATB advanced projection for hydro
	High Hydro Cost	2020 ATB conservative projection for hydro
	Low Offshore Wind Cost	2020 ATB advanced projection for offshore wind
	High Offshore Wind Cost	2020 ATB conservative projection for offshore wind
	Nuclear Technology Breakthrough	50% reduction in nuclear capital costs over all years
	Carbon Capture and Storage Breakthrough	Carbon capture and storage (CCS) cost and performance projections from Donohoo-Vallett et al. (2017)
	2019 ATB Mid Technology Cost	2019 Annual Technology Baseline (ATB) moderate projections for all technology cost and performance (but not fuel)
Battery Storage Costs	*Mid Battery Storage Cost*	*Moderate projection from 2020 ATB*
	Low Battery Storage Cost	Advanced projection from 2020 ATB
	High Battery Storage Cost	Conservative projection from 2020 ATB
Financing Assumptions	*Mid Finance Projections*	*Financing values from 2020 ATB with the 20-year capital recovery period*
	Shortened Cost Recovery	Capital recovery period of 10 years
	Extended Cost Recovery	Capital recovery period of 30 years

Group	Scenario Setting	Notes
Existing Fleet Retirements	*Reference Retirement*	*Lifetime retirements based on plant age; at-risk nuclear retired at 60 years, all other nuclear at 80 years; additional plant retirements determined by the model*
	Accelerated Retirements	Coal plant lifetimes reduced by 10 years; at-risk nuclear plants retired at 50 years, all nuclear plants at 60 years
	Extended Lifetimes	Coal plant lifetimes increased by 10 years; no retirement of underutilized coal plants; all nuclear plants have 80-year life
	No Economic Retirements	No endogenous plant retirements determined by the model
Foresight	*No Foresight*	*Model solves each two-year period without any look-ahead.*
	Perfect Foresight	Model solves for all years simultaneously.
Resource and System Conditions	*Default Resource Constraints*	*See ReEDS documentation (Brown et al. 2020) for details.*
	Reduced RE Resource	25% reduction to all resource classes in input supply curves
	Barriers to Transmission System Expansion	3x transmission capital cost 2x transmission loss factors
	Intrastate Transmission	New transmission is only allowed if it does not cross a state boundary.
	Cooling Water Constraint	Regional constraints on cooling water availability for thermal plants
	Market for Curtailed Electricity	Curtailed energy is purchased at \$10/MWh.
Policy/Regulatory Environment	*Current Law*	*Includes state, regional, and federal policies as of June 30, 2020*
Combination Scenarios	Low Natural Gas Prices & Low RE Cost	AEO2020 high oil and gas resource and technology and 2020 ATB renewable advanced projections
	High Natural Gas Prices & Low RE Cost	AEO2020 low oil and gas resource and technology and 2020 ATB renewable advanced projections

Group	Scenario Setting	Notes
	Low Natural Gas Prices & High RE Cost	AEO2020 high oil and gas resource and technology and 2020 ATB renewable conservative projections
	High Natural Gas Prices & High RE Cost	AEO2020 low oil and gas resource and technology and 2020 ATB renewable conservative projections
	Low RE Cost & Low Battery Costs	2020 ATB renewable advanced projections and 2020 ATB renewable low case projections
	Low RE Cost & High Battery Cost	2020 ATB renewable advanced projections and 2020 ATB renewable high case projections
	Low Natural Gas Prices & Low RE Cost & Low Battery Cost	AEO2020 low oil and gas resource and technology, 2020 ATB renewable advanced projections, and 2020 ATB renewable low case projections

[a] Natural gas prices are based on Annual Energy Outlook (AEO) 2020 electricity sector natural gas prices but are not identical because of the application of natural gas price elasticities in the modeling. See the next section, Fuel Prices.
[b] RE = renewable energy
[c] CSP = concentrating solar power

Fuel Prices

Natural gas input price points are based on the trajectories from AEO2020 (EIA 2020). The prices are shown in Figure A-1 (left) and are from the AEO2020 Reference scenario, the AEO2020 Low Oil and Gas Resource and Technology scenario, and the AEO2020 High Oil and Gas Resource and Technology scenario (EIA 2020). Actual natural gas prices in ReEDS are based on the AEO scenarios, but they are not exactly the same; instead, they are price-responsive to ReEDS natural gas demand. Each census region includes a natural gas supply curve that adjusts the natural gas input price based on both regional and national demand (Cole, Medlock III, and Jani 2016). Figure A-2 shows the output natural gas prices from the suite of scenarios.

The reference coal and uranium price trajectories are from the AEO2020 Reference scenario and are shown in Figure A-1 (right). Both coal and uranium prices are assumed to be fully inelastic. Figure A-1 shows the national prices for the resources, but input prices for ReEDS are taken from the AEO2020 census region projections.

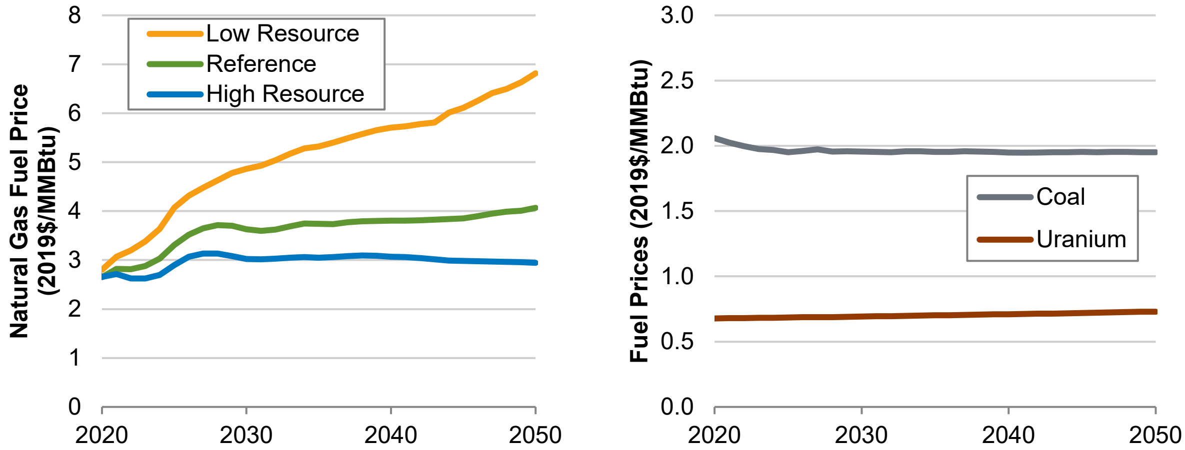

Figure A-1. Fuel price input trajectories used in the Standard Scenarios

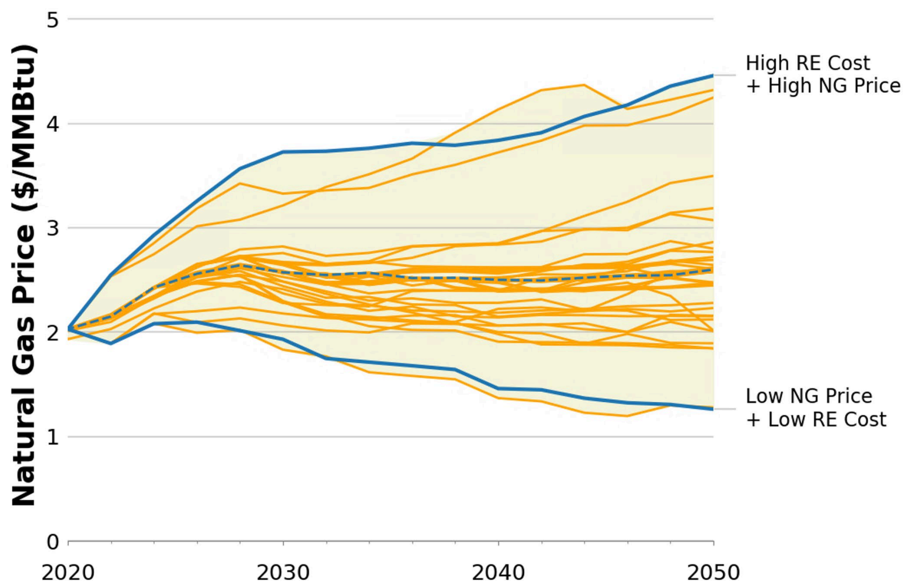

Figure A-2. Natural gas price outputs from the suite of ReEDS scenarios.

Demand Growth and Flexibility

The Mid-case scenario is based on the AEO2020 Reference scenario load growth (EIA 2020). The high- and low-load growth scenarios are also from AEO2020, based on the Low and High Economic Growth scenarios, which use lower/higher rates of population growth, productivity, and lower/higher inflation than the Reference scenario (see Figure A-3). We assume inelastic electricity demand in all scenarios presented.

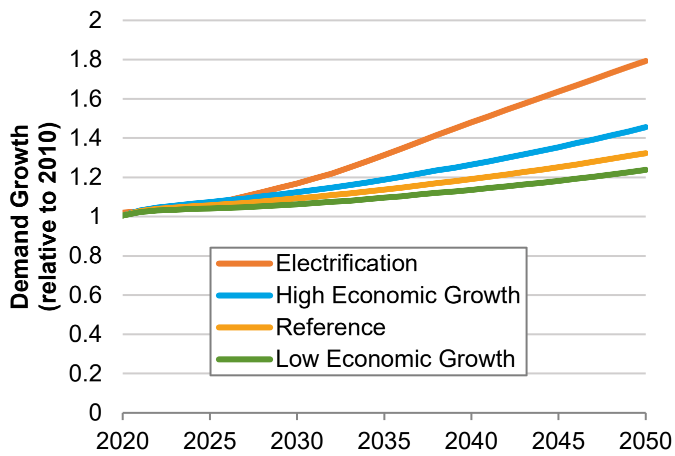

Figure A-3. Demand growth trajectories used in the Standard Scenarios. Electrification refers to the High Electrification with Demand Flexibility scenario.

The High Electrification with Demand Flexibility scenario is based on the Electrification Futures Study, or EFS (Mai et al. 2018), where future load growth is greater than in any of the AEO2020 scenarios because of an increase in fuel-switching from nonelectric to electric sources at the point of final consumption across all end-use sectors (i.e., residential and commercial buildings, transportation, and industry). Specifically, we use the EFS High Electrification with Moderate end-use technology advancement scenario (Jadun et al. 2017). In addition to greater annual load growth, end-use electrification in this scenario also changes load profiles, particularly in response to electric vehicle charging and electric space heating demands. Also, ReEDS endogenously accounts for demand-side flexibility, which is modeled as constrained load shifting, using the "Base" flexibility assumptions from the EFS (Sun et al. 2020). Under the High Electrification with Base Flexibility scenario, about 4% of annual load is assumed to be flexible. The source of this flexibility is primarily from managed electric vehicle charging, but flexibility from the buildings sector is also considered.

The Reference with Demand Flexibility scenario is assumed to have the same annual load growth as in the Mid-Case (i.e., from the AEO2020 Reference scenario) but, like the High Electrification scenario, it includes demand-side flexibility from the EFS (Mai et al. 2018; Sun et al. 2020). Specifically, the Base Flexibility level from the EFS Reference electrification scenario of that study is applied to the AEO2020 Reference demand growth. In this scenario, 2% of annual demand is assumed to be flexible, with the buildings sectors providing the largest share of the flexibility.

Technology Cost and Performance

Except for the 2019 ATB scenario, technology cost and performance assumptions are taken from the 2020 ATB (NREL 2020). The ATB includes advanced, moderate, and conservative cost and performance projections through 2050 for the generating and storage technologies used in the ReEDS and dGen models. The Low RE Cost scenario uses the advanced projections for all renewable energy technologies, and the High RE Cost scenario uses the conservative projection. The Low and High PV Cost scenarios use the advanced and conservative projections, respectively, for both utility and distributed PV technologies, and the Low and High Wind Cost scenario uses the advanced and conservative projections, respectively, for both land-based and offshore wind technologies. The Low and High Geo Cost, Hydro Cost, CSP Cost, and Offshore Wind Cost scenarios use the advanced and conservative projections for the technology defined in the scenario name. The Low and High Battery Cost scenarios use the advanced and conservative battery projections, respectively. Combination scenarios simply use the combined assumptions that their names imply. For example, the Low RE Cost + Low Battery Cost scenario uses advanced projections for the renewables and advanced projections for batteries.

The 2019 ATB scenario uses the mid cost and performance assumptions from the 2019 ATB (NREL 2019). All other inputs, including fuel prices, are unchanged.

Existing Fleet Retirements

Conventional power plants (i.e., gas, coal, nuclear, and oil plants) are required to retire at their age-based retirement date unless (1) the model deems it cost-optimal to retire them before their age-based retirement date or (2) the plant has announced it will retire in a certain year.

Plant online dates are taken from the National Energy Modeling System (NEMS) plant database for the AEO2020 (EIA 2020). And Tables A-2 and A-3 show the plant lifetime assumptions used in ReEDS. For the No Endogenous Retirements scenario, conventional power plants are only retired when they meet their age-based retirement date.

Table A-2. Lifetimes of Renewable Energy Generators and Batteries (Brown et al. 2020)

Technology	Lifetime (Years)	Source
Land-based wind	30	Wind Vision (DOE 2015)
Offshore wind	30	Wind Vision (DOE 2015)
Solar PV	30	SunShot Vision (DOE 2012)
CSP	30	SunShot Vision (DOE 2012)
Geothermal	30	GeoVision Study (DOE 2019)
Hydropower	100	Hydropower Vision (DOE 2016)
Biopower	50	2020 NEMS plant database (EIA 2020)
Marine hydrokinetic	20	Previsic et al. (2012)
Battery	15	Cole and Frazier (2020)

Table A-3. Lifetimes of Conventional Energy Generators (Brown et al. 2020)

Technology	Lifetime for Units Less than 100 MW (Years)	Lifetime for Units Greater than or Equal to 100 MW (Years)
Natural gas combustion turbine	50	50
Natural gas combined cycle and CCS	60	60
Coal, all techs, including cofired	65	75
Oil-gas-steam (OGS)	50	75

The nuclear retirement lifetimes are defined by dividing the currently operating reactors into one of two bins. Any plants participating in a restructured market and all single-reactor plants are assigned to Bin 1. The remaining plants, which are all multi-reactor plants in a traditional regulated environment, are assigned to Bin 2. The only exception to this categorization is that the two plants that have announced their intent to seek a second operating license renewal from the Nuclear Regulatory Commission are included in Bin 2.

Table A-4 (next page) breaks down the bins and shows total capacity in each case. These bins are not meant to be predictions of which plants are more "at-risk" or are more likely to retire. Rather, they represent a simple categorization that reflects the current discussion, which points to more economic pressure for restructured and single-reactor units (Haratyk 2017; Steckler 2017). Current under-construction nuclear power plants are assumed to come online according to the online dates in the AEO2020 NEMS database (EIA 2020).

The Mid-case scenario uses a mix of 60- and 80-year plant lifetimes for nuclear power plants (see Table A-5). The Accelerated Retirements scenario shortens the nuclear lifetimes, as shown in Table A-5, and decreases coal plant lifetimes by 10 years. The Extended Lifetimes scenario sets all nuclear power plant lifetimes to 80 years and increases coal plant lifetimes by 10 years.

Table A-4. Nuclear Power Plant Capacity (GW) in Each Bin

Reactor Type	Bin 1	Bin 2
Restructured, single reactor	8.7	—
Restructured, multiple reactors	27.5	2.0[a]
Regulated, single reactor	15.7	—
Regulated, multiple reactors	—	42.1
Total	**51.9**	**44.1**

[a] Because the Peach Bottom Atomic Power Station (2.0 GW) has been granted a second license renewal, it is assigned to Bin 2 even though it is in a restructured market.

Table A-5. Nuclear Power Plant Lifetime (Years) for Each Scenario by Bin

Scenario Name	Bin 1	Bin 2
Accelerated Retirements	50	60
Mid-case	60	80
Extended Lifetimes	80	80

Vehicle Electrification

The Vehicle Electrification scenario assumes 40% of passenger vehicle sales are electric vehicles in 2050. The charging profile defined for this scenario assumes 55% (energy-basis) was owner-controlled (static, evening-weighted) and the utility (model) could control timing of the remaining 45%. The dynamic-charging portion is a model decision, and ReEDS can choose how to distribute the charging across the day. For details about how the charging demand and profiles were developed, see Appendix K of the *Renewable Electricity Futures Study*, Volume 3 (Hostick et al. 2012).[14]

Reduced Renewable Energy Resource

This scenario reduces the amount of renewable energy resource available in the model for building new renewable energy generators. Specifically, the scenario reduces modeled wind, PV, CSP, geothermal, hydropower,[15] and biopower technical potential by 25%. The reduction is applied uniformly across geography and resource classes (i.e., all regions and classes experience the same 25% reduction). This scenario provides a sensitivity to estimates of technical potential for renewable energy resources.

Cooling Water Constraints

In the Mid-case scenario, the representation of cooling water supply and demand is inactive in order to reduce computational complexity under conditions where cooling water constraints are observed to have limited impact on national-scale power sector outcomes. The Cooling Water Constraints scenario activates a water supply and demand representation that differentiates applicable technologies by cooling technology and water source while enforcing constraints that

[14] The *National Economic Value Assessment of Plug-In Electric Vehicles* (Melaina et al. 2016) uses ReEDS and other models to provide another assessment of electric vehicles and their impacts to the electricity system under different charging regimes.
[15] This reduction does not apply to pumped-storage hydropower.

require the purchase and use of water supply from sources including fresh surface water, fresh groundwater, brackish/saline surface water, brackish/saline groundwater, and wastewater. This scenario prohibits new power plants from using freshwater beyond what is used by the existing fleet, highlighting the potential for reduced future freshwater availability to the power sector.

Barriers to Transmission System Expansion

The ReEDS model assumes new transmission lines can be constructed as needed, at costs taken from the Eastern Interconnection Planning Collaborative (EIPC 2012) on regional transmission development and extrapolated to the contiguous United States (DOE 2015). Those cost assumptions include regional multipliers that imply higher siting and construction costs in certain areas, notably California and the Northeast. Only existing transmission connections can be expanded except for AC-DC-AC interties, where expansion is not allowed. This scenario takes the EIPC-sourced siting difficulties a step further, reflecting a concern that transmission-line siting is and will continue to be difficult and expensive (Vajjhala and Fischbeck 2007). As a proxy for explicit barriers to transmission expansion, this scenario bars any new interconnection interties, triples the capital cost of any new inter-balancing authority transmission capacity, and doubles the transmission loss rate from 1% to 2% per 100 miles. Renewable generator spur line costs are unaffected. The higher rate of transmission losses generally discourages relying on the transmission system to transmit power long distances.

No Interstate Transmission

The No Interstate Transmission scenario does not allow the model to build new transmission across state lines unless that transmission was already under construction. New transmission builds between regions within a state are allowed as usual.

Nuclear Technology Breakthrough

This scenario explores a future in which nuclear fission-generating technologies see increased technological advancement. The Nuclear Breakthrough scenario implements a 50% reduction in the overnight capital costs for new nuclear power plants. Other cost and performance assumptions for nuclear power plants remain unchanged.

Carbon Capture and Storage Technology Breakthrough

This scenario explores a future in which carbon capture and storage (CCS) technologies see increased technological advancement. The CCS Breakthrough scenario uses the cost and performance projections for coal and natural gas combined cycle technologies specified in the *Impact of Clean Energy R&D on the U.S. Power Sector* report (Donohoo-Vallett et al. 2017).

For new coal-CCS capacity, capital costs are reduced 37% by 2030 and 49% by 2038 from $6,550/kW (2014$). Fixed and variable operation and maintenance (O&M) costs are assumed to be 6% lower in 2030 and 14% lower in 2040 than in the Mid Case. Heat rates are assumed to be 15% lower by 2030 and 31% lower by 2040 than in the Mid Case.

For new NGCC-CCS capacity, capital costs are reduced 16% by 2030 and 26% by 2040 from $2,100/kW (2014$). Fixed O&M costs are assumed to be 49% lower in 2038 and variable O&M costs 42% higher in 2038 than in the Mid-Case scenario. Heat rates are assumed decline to 8.1 MMBtu/MWh by 2038.

To account for the permitting and construction periods required for these facilities, we assume new CCS plants can be installed only starting in 2024. Cost and performance metrics do not deviate from the Mid-Case until this year. Cost and performance metrics for intermediate years between 2024 and the targeted technology improvement year are found using linear interpolation.

Financing Costs

The Mid-case scenario uses the financing assumptions from the 2020 ATB (NREL 2020) market factors, except that the Mid-case uses a 20-year cost recovery period rather than a 30-year period. The interest and equity rates in the ATB change over time. Other financial assumptions, such as debt fractions and Modified Accelerated Cost Recovery System schedules are technology-specific and vary over time. The Extended Cost Recovery scenario uses these same technology-specific financing assumptions, but it uses a 30-year cost recovery period for all technologies in place of the 20-year recovery period. The Shortened Cost Recovery scenario uses a 10-year cost recovery period.

Perfect Foresight

All scenarios except for the Perfect Foresight scenario use a sequential, myopic approach. For example, the model will solve for 2020, update relevant parameters, and then solve for 2022, update parameters, solve for 2024, etc., through 2050. In the Perfect Foresight scenario, the model is solved intertemporally such that all years are solved at the same time. This framework enables the model to have perfect foresight (e.g., the model has perfect information about costs in 2040 while it makes build decisions in 2020). The Perfect Foresight scenario includes relative growth constraints of 10% per year for wind and PV technologies in order to limit wind and PV buildout during years before the renewable energy tax credits expire.

The intertemporal solution results in a much larger model size and is more difficult to solve. Because of this added difficulty, the Perfect Foresight scenario only solves for even years through 2030. After 2030, the model only considers 2035, 2040, 2045, and 2050.[16]

Because of the different solution structure, we did not include the Perfect Foresight scenario in the figures shown in the body. The Perfect Foresight results (along with the Mid-case for comparison) is shown in Figure A-4. The foresight results in additional near-term wind and PV builds to take advantage of the tax credit before its expiration. The additional solar and wind generation displaces coal and natural gas generation.

[16] Because the online scenario viewer (cambium.nrel.gov) only shows data for even years, the 2035 and 2045 solutions will not show up in the viewer.

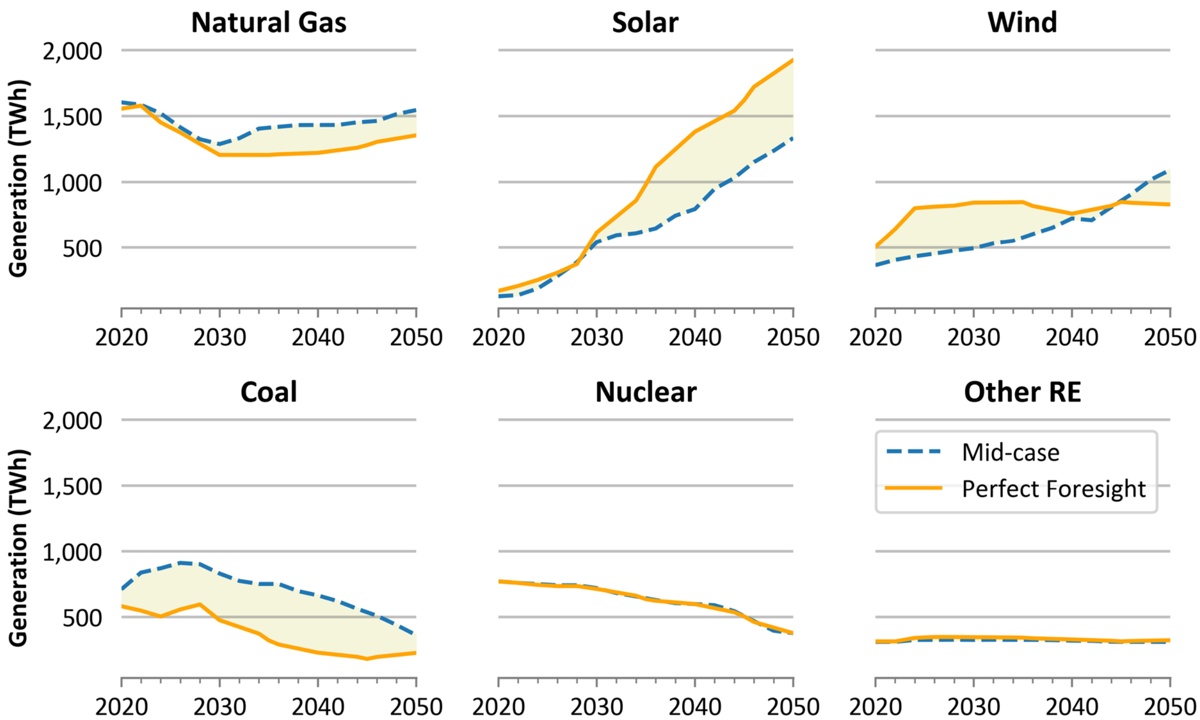

Figure A-4. Generation by fuel type in the Mid-case and the Perfect Foresight Scenario.

Market for Curtailed Electricity

This scenario is intended to represent a future in which entities are willing to pay to use electricity that would otherwise be curtailed. In effect, this sets a floor on the price of electricity. The scenario assumes a purchase price of $10/MWh (in 2019$) in all time periods and regions. As an example, consider a PV plant that can generate 100 MW of power over the course of two hours. If in the first hour the market price for energy is $30/MWh, the plant would sell its full 100 MW output at $30/MWh. If in the second hour, the market price for energy is $0/MWh, the plant would normally curtail its output and simply not generate for that hour. However, because there is a floor price of $10/MWh, the plant will produce 100 MW of power and sell it for $10/MWh, but that power would not count toward meeting the regular electricity load because a separate entity is off-taking that power. This type of scenario is discussed most frequently in the context of hydrogen production, where renewable energy that would normally be curtailed might be used to run an electrolyzer to produce electricity. Other use cases of curtailed energy also apply.

A.2 Changes from the 2019 Edition

Since last year's Standard Scenarios report (Cole et al. 2019), various key modeling changes have been made in the ReEDS and dGen models. These changes are summarized in Tables A-6 and A-7.

New scenarios in this year's report include the following scenarios:

- High Electrification with Demand Flexibility

- Reference with Demand Flexibility
- Carbon Capture and Storage Breakthrough
- No Economic Retirements (in 2019, all scenarios but one had no economic retirements; in 2020, that is reversed)
- Cooling Water Constraints
- No Interstate Transmission
- Market for Curtailed Electricity
- Low RE Cost + Low Battery Cost
- Low RE Cost + High Battery Cost
- Low RE Cost + Low NG Price + Low Battery Cost

Specific assumptions for these scenarios are documented in Section A.1.

Table A-6. Key Differences in Model Inputs and Treatments for ReEDS Model Versions. The 2019 version (Brown et al. 2020) was used in the 2019 Standard Scenarios report (Cole et al. 2019), and the 2020 version is used for this report.

Inputs and Treatments	2019 Version (July 2019)	2020 Version (July 2020)
Fuel prices	AEO2019	AEO2020
Demand growth	AEO2019	AEO2020
Generator technology cost, performance, and financing	ATB 2019[a]	ATB 2020[a]
Regional Greenhouse Gas Initiative (RGGI)	Virginia not included in RGGI	Virginia included in RGGI
Endogenous retirements	Off by default; when turned on, plants retire when they cannot recover their fixed O&M	On by default; when turned on, plants retire when they cannot recover at least half of their fixed O&M
Coal fixed O&M	Escalate from online year	Escalates from 2019 using assumptions from AEO2019
Nuclear fixed O&M	Escalate from 2010	Escalates from 2019 using assumptions from AEO2019
Wind, solar, and load data	Includes 2012 data only	Includes data for 2007–2013; dispatch is done using 2012 data and capacity credit calculations are done using 2007–2013 data (Cole et al. 2020)
Electrification	Not included	Includes three levels of electrification
Demand-side flexibility	Not included	Includes three levels of flexibility

Inputs and Treatments	2019 Version (July 2019)	2020 Version (July 2020)
Renewable fuel combustion turbine	Not included	Includes combustion turbine that runs on a generic renewable fuel with a minimum 6% capacity factor
Upgrades	Not included	Thermal technologies can be upgraded (e.g., by adding CCS).
Storage curtailment recovery	Assume that every 1 MWh of storage charging reduces curtailment in that region by 0.5 MWh	Uses hourly net load profiles and a dispatch algorithm to determine the amount of curtailment that can be recovered by storage
Battery storage durations	4-hour batteries only	Includes 2-, 4-, 6-, 8-, and 10-hour battery storage
Storage capacity credit	Calculated using one year of hourly data, applies a linear approximation in the optimization model	Calculated using seven years of hourly data; capacity credit bins by duration allow for nonlinear changes in the optimization model; one-hour buffer accounts for uncertainty in forecasts and ability to dispatch
Wind and solar capacity credit	Calculated using one year of hourly resource and load data	Calculated using seven years of hourly resource and load data
Wind supply curve	Exclusions based on land-use land-cover categories as specified in Lopez et al. (2012)	Spatially-explicit modeling of multiple exclusions and setbacks from buildings, roads, transmission rights-of-way, and radar along with other exclusion layers
Wind degradation	Not included	Annual degradation of 0.27% per year represented based on empirical data (Hamilton et al. 2020)
PV degradation	0.5%/yr	0.7%/yr per the ATB 2020
Wind and solar curtailment	Modeled using convolutions of resource and load data at a time-slice resolution	Modeled using a simplified hourly dispatch model
Pumped-hydro capital cost	Static over time	Declines over time per Hydropower Vision (DOE 2016)
Storage energy arbitrage value	Calculated at the ReEDS 17-time-slice resolution	Calculated using hourly prices
Minimum capacity factor for NGCT	None	1% per PLEXOS runs of the 2019 Standard Scenarios
Tax credits	Use a three-year safe harbor construction period; tax credits for CCS not represented	Use a four-year safe harbor construction period; December 2019 production tax credit update represented; tax credits for CCS represented (use of captured carbon is not considered)

Inputs and Treatments	2019 Version (July 2019)	2020 Version (July 2020)
State policies	Policies as of July 2019	Policies as of June 2020
Nuclear power plant assistance	Assistance for Illinois and New York represented	Assistance for Connecticut, Illinois, New Jersey, New York, and Ohio represented
Outage rates	Outage rates based on 2003–2007 Generating Availability Data System data	Outage rates based on 2014–2018 Generating Availability Data System data

[a] As noted in the scenario descriptions, the default cost recovery period in ReEDS is 20 years, while it is 30 years in the ATB.
[b] This change was made based on tests performed in PLEXOS to examine the potential of storage to recover curtailed renewable energy.

Table A-7. Key Differences in dGen Model Versions. The 2019 version was used in the 2019 Standard Scenarios report, and the 2020 version is used for this report.

Inputs and Treatments	2019 Version	2020 Version
Demand growth	AEO2019	AEO2020
Technology cost	ATB 2019	ATB 2020
Tariff set	Curated in January 2019	Curated in June 2020
Wholesale electricity prices	ReEDS 2019	ReEDS 2020
State and utility net energy metering policies	Updated in March 2018	Updated in June 2020[a]

[a] If states or utilities

have no mandated expiry dates for net energy metering, a distributed solar penetration threshold was implemented, which was determined from values of peer states.

A.3 Model Interactions

The Standard Scenarios use three different models (dGen, ReEDS, and PLEXOS) to produce the suite of outputs reported here and included in the Standard Scenarios Results Viewer. dGen produces projections for rooftop PV deployment over time using electricity prices from ReEDS.[17] The dGen projections for rooftop PV are fed in as exogenous inputs in the ReEDS model. ReEDS then projects the grid evolution through 2050, resulting in most of the outputs that are reported here. For a select set of scenarios, the systems produced by ReEDS are converted to PLEXOS databases (Frew et al. 2019) and run through PLEXOS. PLEXOS applies a mixed-integer programming technique to solve an hourly unit commitment and dispatch problem for each of those ReEDS-produced systems.

A.4 Additional Deployment Results

The "Other RE" category from Figure 9 includes hydropower, biopower, and geothermal, and the storage category in Figure 9 includes both PSH and batteries. Figure A-5 provides additional detail on the deployment results for these technologies.

[17] The reason that not all scenarios are uniquely modeled in dGen is that many of the electricity prices from ReEDS scenarios are similar, so the resulting dGen projections would also be similar.

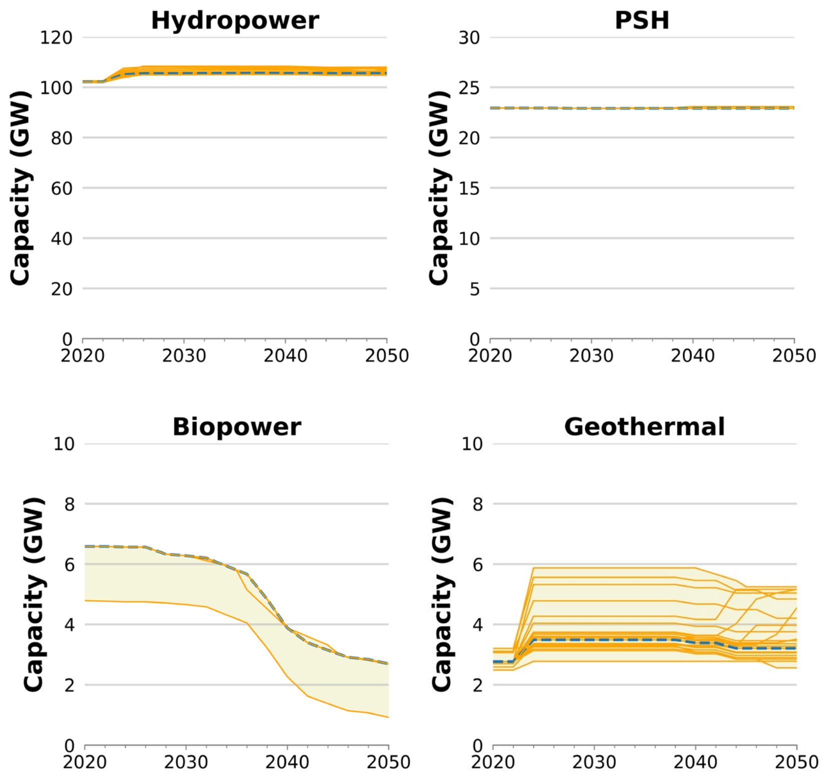

Figure A-5. Capacity by fuel type for the other RE technologies across the Standard Scenarios. The dashed line is the Mid-case scenario. Note that the scale is different in the charts.