2016 Standard Scenarios Report: A U.S. Electricity Sector Outlook

Wesley Cole, Trieu Mai, Jeffrey Logan, Daniel Steinberg, James McCall, James Richards, Benjamin Sigrin, and Gian Porro
National Renewable Energy Laboratory

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Technical Report
NREL/TP-6A20-66939
November 2016

Contract No. DE-AC36-08GO28308

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Prepared under Task No. SA15.1012

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Preface

This report is one of a suite of products aiming to provide a consistent set of technology cost and performance data, and to define a scenario framework that can be used in forward-looking electricity analyses by the National Renewable Energy Laboratory's (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 by (1) defining a set of prospective scenarios that bound ranges of technology, market, and policy assumptions and (2) assessing these scenarios in NREL's market models to understand the range of resulting outcomes, including energy technology deployment and production, energy prices, and carbon dioxide (CO_2) emissions.

This effort, 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 Systems (ReEDS) and dGen models (see http://www.nrel.gov/analysis/reeds/ and http://www.nrel.gov/analysis/dgen/). The work leverages significant activity already funded by EERE to better understand individual technologies, their roles in the larger energy system, and other market and policy issues that can impact the evolution of the electricity sector.

The specific products from this effort include the following:

- 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 presentation describing each of the technologies and providing additional context for their treatment in the workbook
- This 2016 Standard Scenarios report describing an outlook for the U.S. power sector using the Standard Scenario modeling results.

These products can be accessed at http://www.nrel.gov/analysis/data_tech_baseline.html.

NREL intends to consistently apply these products in its ongoing electric sector scenarios analyses to ensure that the analyses incorporate a transparent, realistic, and timely set of input assumptions and consider a diverse set of potential scenario 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 modeling and analysis team, including David Bielen, Stuart Cohen, Kelly Eurek, Bethany Frew, Jonathan Ho, Venkat Krishnan, and Matthew Mowers, was active in participating in the model development and analysis leading to this work. Numerous NREL colleagues reviewed and improved this report, including Doug Arent, Nate Blair, Aaron Bloom, Elizabeth Doris, Pieter Gagnon, Henry "Bud" Johnston, Parthiv Kurup, Eric Lantz, Mike Meshek, Dave Mooney, Robin Newmark, Gary Schmitz, and Mary Werner. Chad Augustine, David Feldman, Maureen Hand, Parthiv Kurup, Robert Margolis, Craig Turchi and Anna Wall were critical for ensuring cost and performance numbers were represented properly in the ReEDS model. We are grateful to Ian Hamos (DOE EERE), Dan Matuszak (DOE Office of Fossil Energy), Chris Namovicz (U.S. Energy Information Administration), Chris Nichols (National Energy Technology Laboratory), Cristian Rabiti (Idaho National Laboratory), Rich Tusing (DOE EERE), and Evelyn Wright (Sustainable Energy Economics) for providing feedback on this work. We especially thank Steve Capanna and Paul Donohoo-Vallett for their leadership and direction of this work. This report was funded by the EERE Office of Strategic Programs and the EERE Wind and Water Program Technology Office 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
CAES	compressed air energy storage
CAPEX	capital expenditure
CC	combined cycle
CCS	carbon capture and sequestration
CPP	Clean Power Plan
CT	combustion turbine
DC	direct current
dGen	Distributed Generation model
DOE	Department of Energy
DUPV	distributed utility PV
EIA	Energy Information Administration
ITC	investment tax credit
MATS	Mercury and Air Toxics Standards
NG	natural gas
NREL	National Renewable Energy Laboratory
OGS	oil-gas-steam
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PTC	production tax credit
PV	photovoltaic(s)
RE	renewable energy
ReEDS	Regional Energy Deployment System
RPS	renewable portfolio standard
TRG	techno-resource group (for wind modeling)
UPV	utility PV

Executive Summary

Since the mid-2000s, the U.S. power sector has been undergoing unprecedented change (see Figure 1). The shale gas revolution has led to an abundance of low-cost natural gas and, with it, a dramatic increase in gas-fired generation. Similarly, renewable generation technologies have experienced large reductions in cost and improvements in performance which, coupled with renewable energy policies, have aided in increasing investment and generation from renewable energy capacity. These increases in generation from natural gas and renewables have precipitated a decline in coal generation to levels not seen since the 1980s. The resulting energy mix has driven down power sector carbon dioxide (CO_2) emissions such that 2015 emissions were 21% below 2005 levels (EIA 2016c).

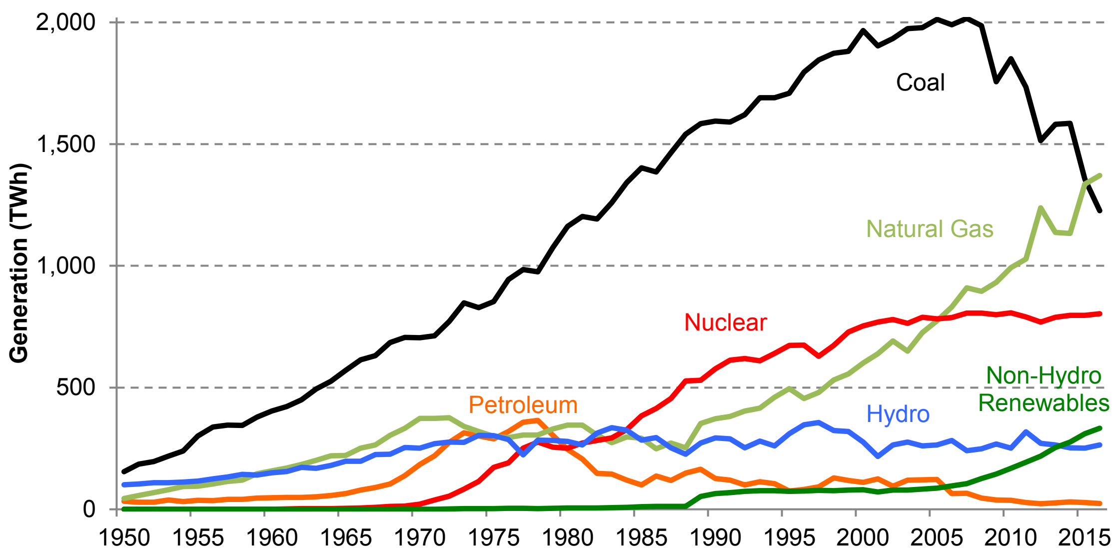

Figure 1. Historical generation by fuel type, 1950–2016 (EIA 2016d). Values for 2016 are based on a 12-month rolling average through April 2016.

The analysis presented in this report explores how the power sector might continue to evolve over the medium term to the long term and how changes in key power sector drivers, such as gas prices and the cost of renewable generation, could affect the future of the power system. Specifically, this report summarizes the implications of a suite of 18 forward-looking *Standard Scenarios* of the U.S. power sector simulated using the Regional Energy Deployment Systems (ReEDS) and Distributed Generation (dGen) capacity expansion models. The Standard Scenarios, which are now in their second year,[1] have been designed to capture a range of possible futures across a variety of factors that impact power sector evolution. The ReEDS and dGen models project utility- and distributed-scale power sector evolution, respectively, for the United States using the Standard Scenario specifications to define model inputs. Both models have been designed with special emphasis on capturing the unique traits of renewable energy, including variability and grid integration requirements. Detailed scenario results at the state-level have been included as part of this report at http://en.openei.org/apps/reeds/.

[1] Section A.2 in the appendix describes the changes in inputs and outputs from last year's set of Standard Scenarios. See Sullivan et al. (2015) for the 2015 Standard Scenarios report.

Based on the scenario results, this report explores four key areas of change in the U.S. power sector:

- Declining costs and increasing deployment of renewable energy
- Abundance of low-cost natural gas
- Rapid growth in rooftop photovoltaics (PV)
- Declining CO_2 emission intensity of electricity generation.

We discuss each of these areas in the context of recent trends and potential future changes based on the modeled scenario results. Highlights for each of these areas are discussed below.

Continued cost reductions and performance improvements are projected to drive growth in renewable generation. Renewable energy technology costs, especially those for wind and solar photovoltaics (PV), have come down significantly over the past several years, and further reductions in costs and improvements in performance are expected (NREL 2016). These declining costs coupled with policy support have led to increased deployment, with renewable sources (including hydropower) accounting for 14% of net U.S. generation in 2015. Given anticipated reductions in renewable energy technology costs and the extension of renewable generation tax credits, strong near-term growth in renewable generation is projected to continue (see Figure 2). However, growth in renewable generation is projected to slow following the expiration of the production tax credit and the decrease in value of the investment tax credit in the early 2020s. In the longer term, renewable generation is projected to increase in market share, even under low-cost natural gas conditions. In 2050, renewable energy penetrations reach 33%–59% of total generation, with the Mid-case Scenario reaching 44%.

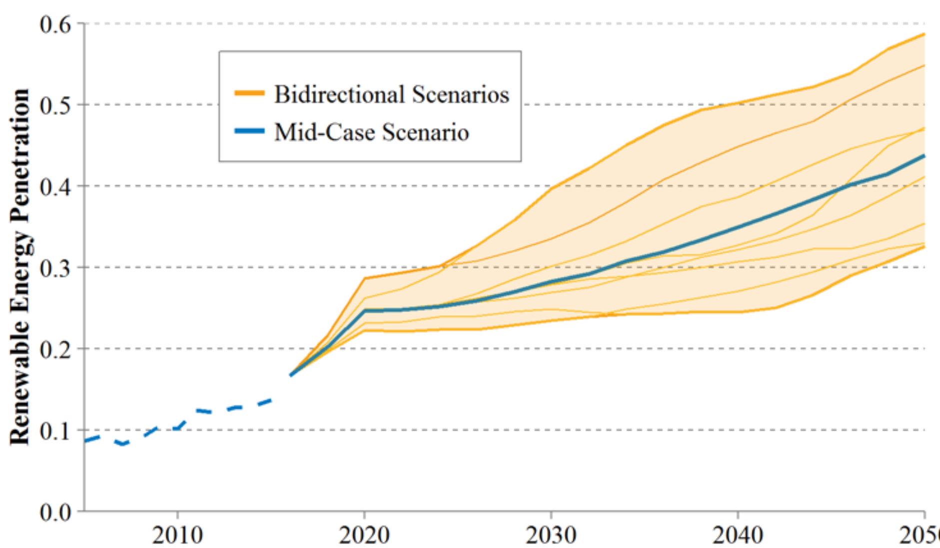

Figure 2. Renewable energy penetration across a subset of the scenarios explored. Penetration is defined as the share of generation provided by renewable energy. The Mid-case Scenario applies reference-level assumptions; the bidirectional scenarios explore lower-level and higher-level assumptions for fuel costs, technology capital costs, electricity demand, and retirements. The dashed line shows historical values (EIA 2016d).

The share of generation from natural gas is projected to continue to grow unless natural gas prices exceed current projections or carbon policy significantly restricts greenhouse gas emissions. The abundance of low-cost shale gas has drastically changed the landscape for the power sector. The annual average capacity factor for the country's fleet of combined-cycle generators rose from 35% in 2005 to over 56% in 2015. Natural gas generators are expected to be the leading source of electricity generation in the United States in 2016, surpassing coal units for the first time on an annual basis. Natural gas prices are largely expected to remain low over the medium term. As a result, generation from natural gas units is projected to continue to make up an increasing portion of the generation mix (see Figure 3), except for scenarios that target deep (~80%) cuts in greenhouse gas emissions or those in which natural gas prices exceed current projections.[2]

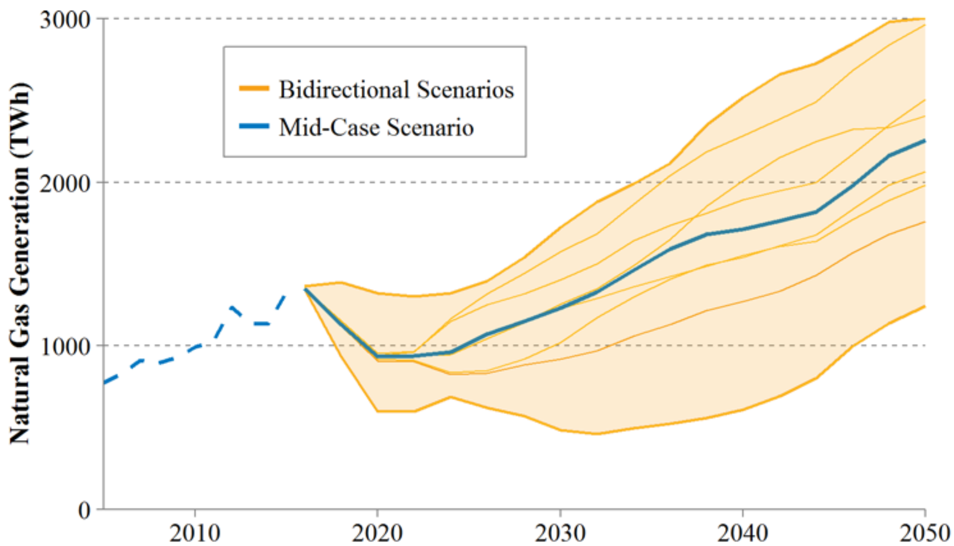

Figure 3. Natural gas generation across a subset of the scenarios. The Mid-case Scenario applies reference-level assumptions; the bidirectional scenarios explore lower-level and higher-level assumptions for fuel costs, technology capital costs, electricity demand, and retirements. The dashed line shows historical values (EIA 2016d).

[2] Natural gas price projections in this work are primarily based the Annual Energy Outlook 2016 Reference Scenario and the Low and High Oil & Gas Resource & Technology Scenarios (EIA 2016a).

The future of rooftop PV is heavily dependent on the evolution of retail electricity rate structures, system costs, net metering, and other policies supporting adoption. From 2010 to 2015, generation from distributed PV grew with a compound annual rate exceeding 40% (GTM Research and SEIA 2016). This growth was driven by a variety of factors, including declining costs of systems, policy and net-metering support, and new system financing options. System costs are anticipated to continue to decline (NREL 2016); however, the potential for growth in distributed PV generation is also strongly dependent on the evolution of retail electricity rate structures, and net metering and other types of policies, many of which are currently being reconsidered (Figure 4).

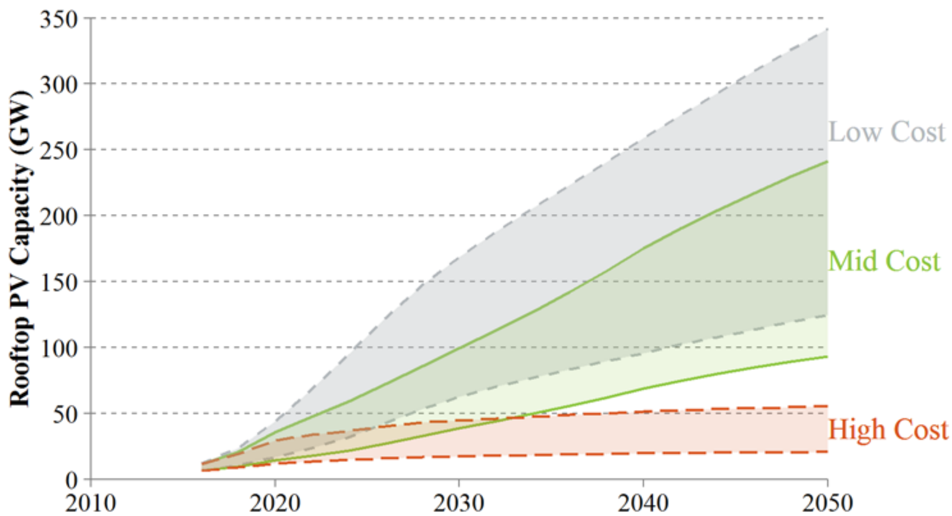

Figure 4. Range of rooftop PV capacity (in GW_{AC}) under low, mid, and high cost assumptions. The upper bound of each cost range represents full net energy metering policy implemented in every state through 2050, and the lower bound of each cost range represents a case where any excess generation from a rooftop PV system is given no value.

Power sector decarbonization will continue, but "business-as-usual" conditions are not projected to lead to the emissions reduction quantities necessary to limit global temperature rise to less than 2˚C.[3] From 2005 to 2015, power sector CO_2 emissions declined 21%, primarily due to coal-to-gas fuel switching, renewable energy growth, lower electricity demand growth, and direct or indirect effects of power-sector-related policies and regulations. Near-term emissions are projected to continue this decline or to remain steady. Over the medium term and the long term, the Clean Power Plan (as modeled) effectively caps the total power sector CO_2 emissions (see Figure 5). In some scenarios, reduction of CO_2 emissions exceeds that required by the modeled Clean Power Plan, but long-term emissions under business-as-usual conditions do not approach the levels that are anticipated to limit global temperature increases to 2°C.

[3] See IPCC (2014). Additionally, Rogelj et al. (2015) show CO_2 reduction pathways that limit warming to 1.5°C and 2°C with >50% probabilities. The carbon reductions shown in Figure 5 are much higher than those pathways defined by Rogelj et al.

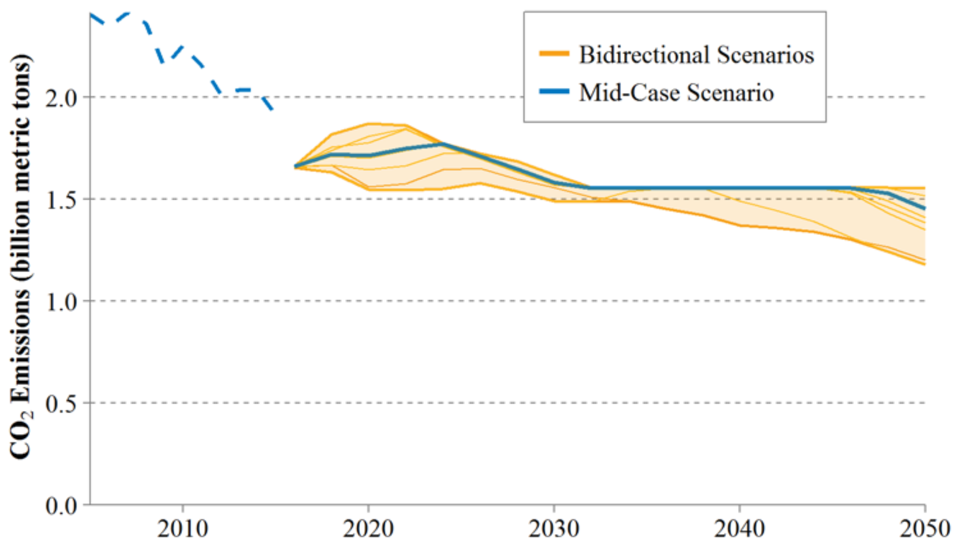

Figure 5. Power sector annual CO_2 emissions across a subset of the scenarios. The Mid-case Scenario applies mid-level assumptions; the bidirectional scenarios explore lower-level and higher-level assumptions for fuel costs, technology capital costs, electricity demand, and retirements. The dashed line shows historical values (EIA 2016c).

In addition to the bidirectional scenario ranges shown in the figures above, the analysis includes several scenarios that consider other key factors impacting the power sector, including constraints on water use, climate change effects, potential constraints on transmission build-out, and policies. These scenarios allow us to further explore the outlook in each of the four areas of change described above.

We anticipate that the Standard Scenarios and this associated report will provide context, discussion, and data to inform stakeholder decision making regarding the future direction of the U.S. power sector. As an extension to this report, the Standard Scenario outputs are presented in a downloadable format online using the Standard Scenarios' Results Viewer at http://en.openei.org/apps/reeds/. This report reflects high-level observations and analysis, whereas the Standard Scenarios' Results Viewer includes scenario results at the state level that can be used for more in-depth analysis.

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1 Introduction

The U.S. electricity system is an expansive network that serves hundreds of millions of customers, employs hundreds of thousands of individuals, and represents trillions of dollars of historical investment. It is a system that touches nearly every aspect of American lives. And, it is currently undergoing profound change.

The Standard Scenarios and this associated report, which are now in their second year,[4] present an examination of some of the key aspects of the change occurring, or anticipated to occur, in the power sector over the next several decades. The Standard Scenarios consist of 18 power sector scenarios that have been projected using the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) long-term capacity expansion model (Eurek et al. 2016) and the dGen rooftop photovoltaic (PV) diffusion model (Sigrin et al. 2016). These models have been designed with specific emphasis on representing renewable energy generation, including capturing the variability and integration of renewable energy.[5]

The Standard Scenarios provide a means for understanding changes in the power sector. They enable a quantitative examination of how ranges of values of specific inputs impact the development of the power sector. In this report, we use the Standard Scenarios as the basis for describing how the U.S. power sector might evolve in the context of four areas of change:

- Renewable energy cost declines and associated growth
- Abundant, low-cost natural gas
- Rapid growth in distributed rooftop PV
- Power sector decarbonization.

Ultimately, the actual evolution of the U.S. power sector will differ from the scenarios considered in this work. The objective of this analysis is not to predict the future grid evolution but to consider a range of possible futures in an attempt to better understand and articulate key drivers, important implications, and necessary decision points that can contribute to better-informed investment and policy decisions (Mai et al. 2013). Our analysis is one of many sets of power sector projections and contributes to the broader research in this area. These 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 others' scenarios. Instead, we note that a collective set of projections from diverse analytical frameworks and perspectives could offer the most robust platform for decision makers (Mai et al. 2013). In addition, our modeling tool and analysis has been designed with particular emphasis on capturing the unique traits, including variability and grid integration requirements, and cost and performance trends of renewable energy generation technologies and the resulting implications to the rest of the power system.[6] Thus, this work provides a perspective on the electricity sector that complements those provided by other organizations. Other modeling frameworks will have different emphases, strengths, and weaknesses.

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[4] See Sullivan et al. (2015) for the 2015 Standard Scenarios report.
[5] For a list of published work using ReEDS and dGen, see http://www.nrel.gov/analysis/reeds/related_pubs.html and http://www.nrel.gov/analysis/dgen/related_pubs.html respectively.
[6] The ReEDS and dGen model only represent the U.S. power sector and only exogenously consider other aspects of the broader energy economy.

The purpose of the Standard Scenarios and this associated report, then, is to provide context, discussion, and data to inform stakeholder decision making regarding the future direction of the U.S. power sector. As an extension to this report, the Standard Scenario outputs are presented in a downloadable format online using the Standard Scenarios' Results Viewer at http://en.openei.org/apps/reeds/. This report reflects high-level observations and analysis, whereas the Standard Scenarios' Results Viewer includes the scenario results that can be used for more in-depth analysis.

2 The Standard Scenarios

The Standard Scenarios comprise 18 power sector scenarios that are run using the ReEDS model (Eurek et al. 2016) and dGen model (Sigrin et al. 2016). The scenarios are summarized in Table 1, with more detail on specific scenario inputs provided in the appendix, including input changes from the 2015 version of the scenarios.[7] Although 24 scenario settings are shown in the table, the five scenarios in *blue italics* are part of the same Mid-case Scenario resulting in 18 distinct potential futures. These scenarios were selected in order to capture a reasonable breadth of trajectories of costs, performance, policy and other drivers, and thus enable the scenarios to cover a range of potential futures rather than a single outlook. For example, in addition to considering traditional sensitivities such as demand growth and fuel prices, we explicitly account for possible water constraints and select climate change impacts, and we assess a considerable number of other critical factors that impact the development of the power system such as transmission buildout, policies, and technology progress.

Table 1. Summary of the Standard Scenarios. The scenario settings listed in *blue italics* correspond to the settings used in the Mid-case Scenario, which is used in this analysis as a reference scenario reflecting "business-as-usual" conditions. Additional scenario details are provided in the Section A.1 in the appendix.

Group	Scenario	Notes
Electricity Demand Growth	*Reference Demand Growth*	AEO 2016 Reference
	Low Demand Growth	AEO 2016 Low Economic Growth
	High Demand Growth	AEO 2016 High Economic Growth
	Vehicle Electrification	PEV/PHEV adoption reaches 40% of sales by 2050; 45% of charging utility-controlled, 55% opportunistic
Fuel Prices	*Reference Natural Gas Prices*	AEO 2016 Reference
	Low Natural Gas Prices	AEO 2016 High Oil & Gas Resource and Technology
	High Natural Gas Prices	AEO 2016 Low Oil & Gas Resource and Technology
Electricity Generation	*Mid Technology Cost*	2016 Annual Technology Baseline (ATB) Mid-Case Projections[8]

[7] Some of the most significant model changes include a representation of the Clean Power Plan, the extended investment tax credit (ITC) and production tax credit (PTC), and the lower natural gas price trajectory from the Annual Energy Outlook 2016 Reference Scenario.

[8] Section A.3 in the appendix includes an alternative wind cost trajectory scenario based on the recent expert elicitation by Wiser et al. (2016).

Group	Scenario	Notes
Technology Costs	Low RE Cost	2016 ATB Renewable Energy Low-Case Projections
	High RE Cost	2016 ATB Renewable Energy High-Case Projections
	Nuclear Technology Breakthrough	50% reduction in nuclear capital costs over all years
Existing Fleet Retirements	*Reference Retirement*	Lifetime retirements based on ABB Velocity Suite database (ABB 2016)
	Extended Nuclear Lifetime	Relicensing to 80 years
	Accelerated Coal Retirement	Coal plant lifetimes reduced by 10 years
Policy/Regulatory Environment	*Current Law*	Includes policies as of April 1, 2016, including a mass-based representation of the Clean Power Plan[9]
	National Renewable Portfolio Standard (RPS)	43% of generated electricity from renewables by 2030, 80% by 2050
	Power Sector Carbon Dioxide (CO_2) Cap	Power sector emissions 30% below 2005 levels by 2025, 83% by 2050
	Extended Incentives for RE Generation	Extend ITC/PTC through 2030 for eligible technologies
Earth System Feedbacks	*No Climate Feedback*	No feedback due to changes in the climate
	Impacts of Climate Change	Temperature impacts on generators, transmission, and demand; derived from IGSM-CAM climate scenario
Resource and System Constraints	*Default Resource Constraints*	Used for the Mid-case Scenario[10]
	Reduced RE Resource	25% cut to each resource in input supply curves

[9] The Clean Power Plan is included in the current law and is implemented in the model as a mass-based policy with new source compliments and unrestricted national allowance trading. All the scenarios in this table include this CPP representation.
[10] See the ReEDS documentation (Eurek et al. 2016) for details on default resource and system constraints.

Group	Scenario	Notes
	Barriers to Transmission System Expansion	3x transmission capital cost No new AC-DC-AC interties 2x transmission loss factors
	Restricted Cooling Water Use	New construction may not use freshwater for cooling

The Mid-case Scenario as defined in Table 1 is a reference scenario reflecting business-as-usual conditions. This scenario uses default or central assumptions in the various categories (e.g., using reference case fuel prices and mid-case technology costs).[11] The resulting generation mix from this scenario is shown in Figure 6. In the Mid-case Scenario, natural gas and renewables continue to grow over time, with each contributing 28% of the generation mix in 2030 and 43% and 44%, respectively, in 2050. Due to the age-based retirement assumptions used in this work, older coal, oil-gas-steam (OGS), and nuclear plants are phased out over time, creating much of the new demand that drives the growth in natural gas and renewable energy generation.

In the Mid-case Scenario, coal generation declines from nearly 2,000 TWh in 2010 to just over 600 TWh in 2050 due to both age-based and under-utilization retirements. Similarly, nuclear generation is down by an order of magnitude by 2050 as most plants reach the end of their assumed 60-year operating lifetime and no new nuclear is found to be economic. Wind generation expands approximately 4-fold and solar expands 20-fold from the levels achieved in 2015.[12]

[11] Section A.1 in the appendix describes the Mid-case Scenario input assumptions in detail. In addition, section A.2 in the appendix discusses how Mid-case Scenario inputs and outputs have changed from last year.
[12] The larger growth in solar is largely due to solar having a smaller amount of generation in 2015. Wind generation was about four times that of solar in 2015 (~190 TWh to ~50 TWh respectively).

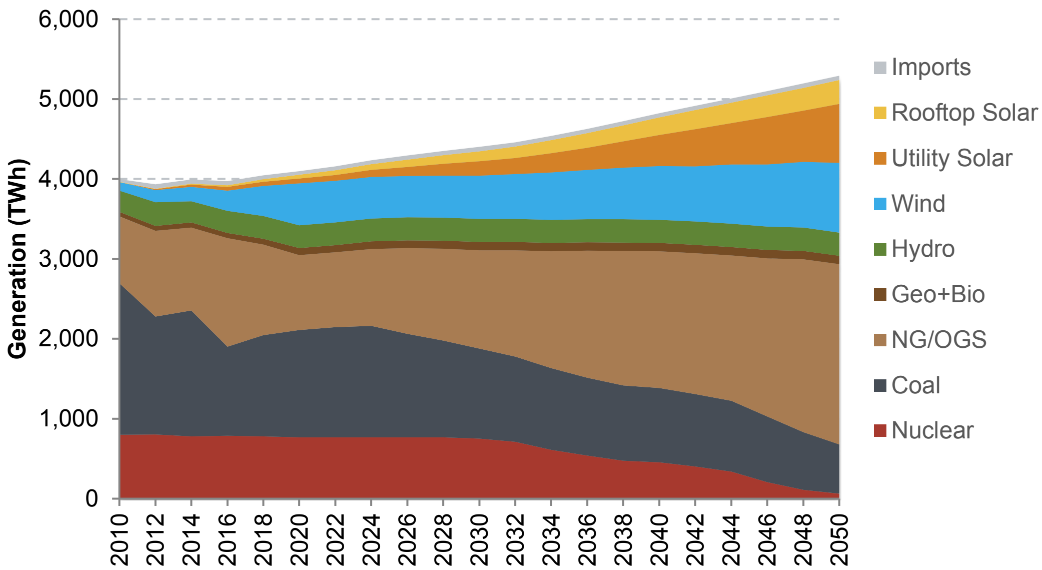

Figure 6. Mid-case Scenario projected generation mix over time. In this figure, imports includes electricity imported from Canada and Mexico; rooftop solar includes behind-the-meter distributed PV; utility solar includes utility PV and concentrating solar power; wind includes land-based and offshore wind; hydro includes run-of-the-river and traditional dams; Geo+Bio includes hydrothermal geothermal, near-field enhanced geothermal systems, dedicated biomass, co-fired biomass, and land-fill gas plants; NG/OGS includes natural gas combined-cycle plants, natural gas combustion turbines, and oil-gas-steam (OGS) plants; and coal includes integrated gasification combined cycle, pulverized sub and supercritical, and carbon capture and storage plants. Each of these technology types is individually modeled within ReEDS.

The remaining scenarios are classified as bidirectional and non-bidirectional scenarios. We make this distinction because most of the results presented in this report focus on the bidirectional scenarios. The bidirectional scenarios are the set of scenarios that include a low and high setting:

- Low and High Cost RE
- Low and High Natural Gas (NG) Price
- Low and High Demand Growth
- Low and High Retirements (Extended Nuclear Lifetime and Accelerated Coal Retirements, respectively).

These bidirectional scenarios are the set of sensitivities that are examined when considering the Mid-case Scenario because they represent significant uncertainties that can have substantial impacts on how the power sector evolves.[13] We present the Mid-case Scenario in context of the bidirectional scenarios to demonstrate how these uncertainties can influence and change a reference-type outlook.

[13] Power sector policy represents an additional major uncertainty, but it is does not have a "bidirectional" framework for inclusion in the bidirectional scenarios. However, some aspects of policy uncertainty are captured in the additional scenarios.

The non-bidirectional scenarios are a more custom set of scenarios with a generally more custom set of outputs that are considered. These scenarios are included in the set of Standard Scenarios both to examine specific uncertainties that are outside the scope of the traditional sensitivities in the bidirectional scenarios and to expand the overall solution space. The non- bidirectional scenarios consider sensitivities such as restricted ability to build transmission, more limited renewable energy resource, climate and water scenarios, and alternative policies and technologies (see Table 1).

3 Renewable Energy: Decreasing Costs and Increasing Deployment

Major renewable energy technologies in the historical and current U.S. electricity sector include biomass, geothermal, hydropower, solar, and wind. Among these technologies, hydropower comprised the largest share to total U.S. electricity generation; it exceeded 10% of total U.S. generation each year during 1950–1986 (see Figure 7). Since then, the share of annual generation from hydropower has declined as the growth in demand outpaced new hydropower development. Nonetheless, in 2015 hydropower remained the largest source of RE in the United States at 6.1% of total generation (265 TWh).[14] In contrast, non-hydro renewable energy technologies have historically been niche contributors at less than 1% (in aggregate) through 1988 and remaining at about 2% until the mid-2000s. Over the last decade, non-hydro renewable energy—particularly wind and solar—has begun to move into more of the mainstream for the U.S. power sector. The year 2014 represents the first year in which U.S. non-hydro RE generation exceeded hydropower generation (6.7% vs. 6.2%). This trend continued in 2015 with non-hydropower generation comprising 7.6% of total generation (4.7% wind, 1.6% biomass, 1.0% solar, 0.4% geothermal). How these trends unfold in the future will depend on a large number of factors, but one key factor will be whether and how RE technology cost and performance advance over time.

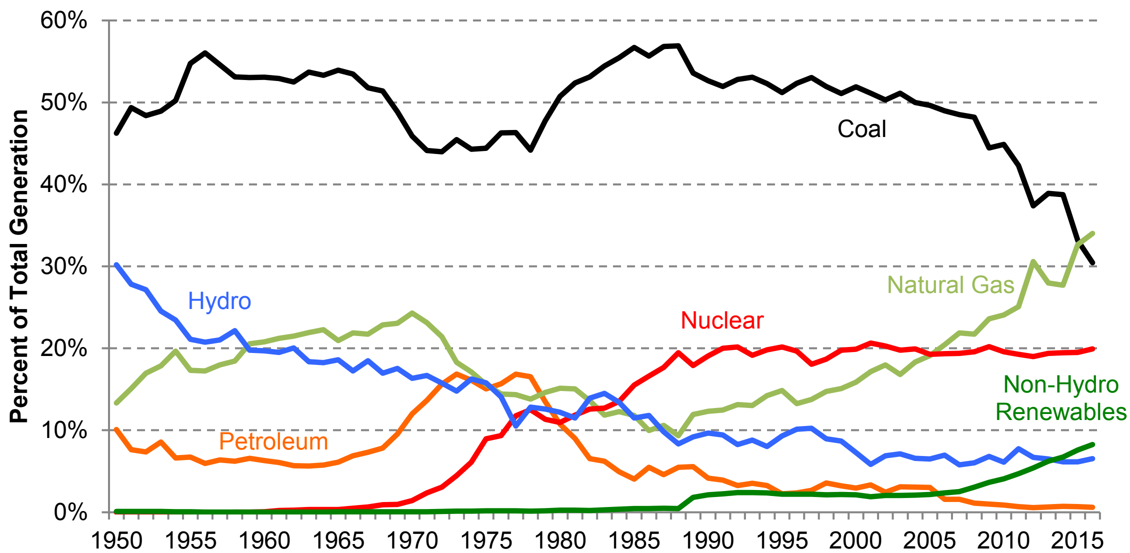

Figure 7. U.S. power sector generation mix from 1950–2015 (EIA 2016d). 2016 values are based on a 12-month rolling average through April 2016.

[14] The recently published Hydropower Vision study (DOE 2016) reviews the historical contribution of hydropower and assesses the potential for new hydropower in the United States.

3.1 Recent Trends

In the past several years, wind and solar costs have declined substantially. For example, Barbose and Darghouth (2016) and Feldman et al. (2015) track the consistent reductions in PV systems over the past several years. Wiser and Bolinger (2016) show reductions in wind costs since 2009 with notable improvements in wind energy production in most recent years. Projections from the most recent Annual Technology Baseline (ATB) (NREL 2016) show continued cost declines into the future for these two technologies (see Figure 8 and Figure 9) as well as continued performance improvements for wind (see Figure 10).[15] See the text box on page 11 for additional details, and Appendix A.3 for how these cost and performance improvements translate into a subsidized levelized cost of energy. Other renewable energy technologies in the ATB similarly show cost reductions over time (NREL 2016). These technology improvements coupled with the recent legislation that extended the PTC and ITC has created an environment where renewable energy is—in many cases—competitive with non-renewable options. This can be seen in that significant amounts of renewable energy continue to be added to the grid beyond the minimum requirements of RPSs (Barbose 2016).

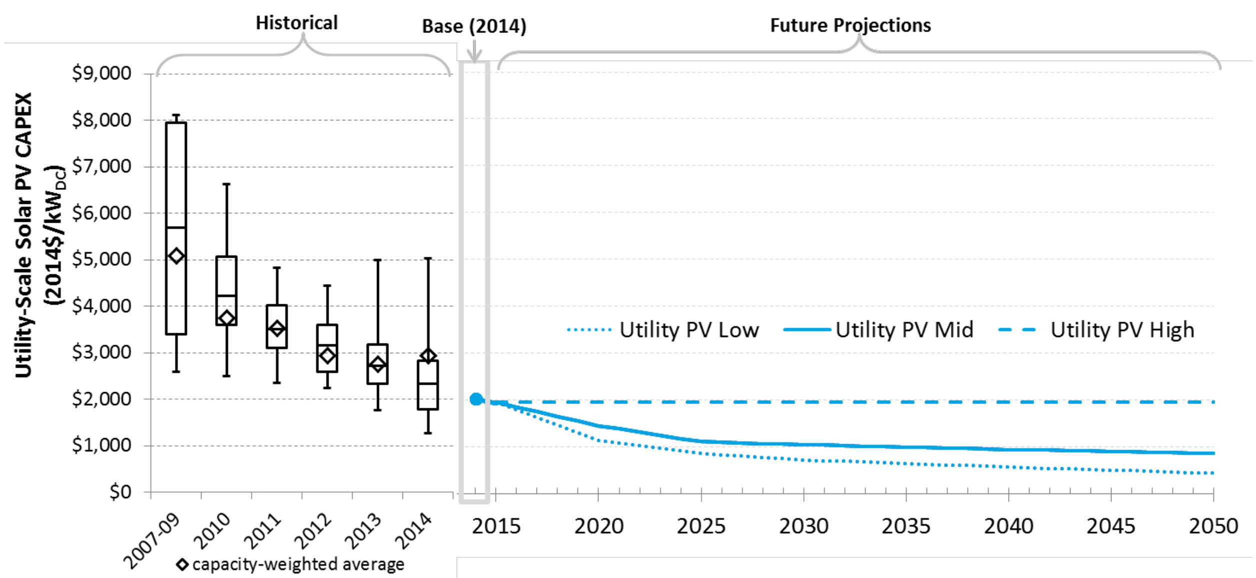

Figure 8. Utility-scale PV capital expenditures (CAPEX), both historical and projected (NREL 2016). The base year for projections used in the ATB is 2014. How the CAPEX translates into a subsidized LCOE is shown in Appendix A.3.

[15] In addition to including capital cost projections, the modeling work performed here incorporates multiple resource classes (to capture variations in resource quality), regional variations in performance and resource availability, regional capital cost differences, and regional policy incentives. Additional cost reductions for wind can also be found in Wiser, Jenni, et al. (2016).

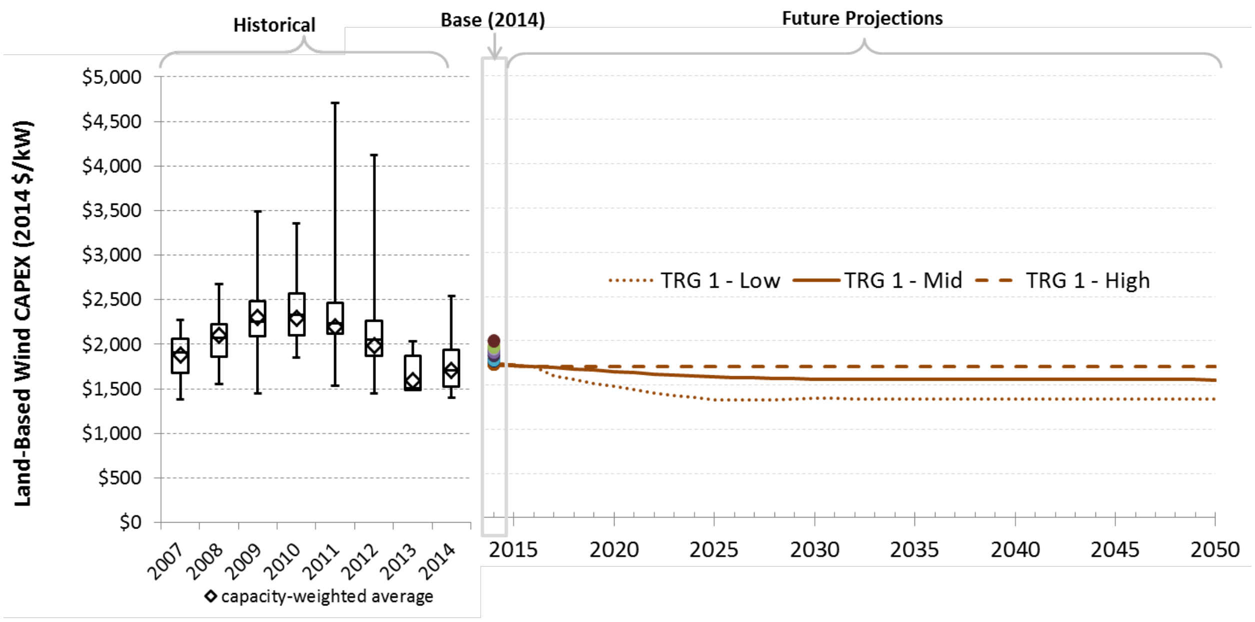

Figure 9. Land-based wind capital expenditures (CAPEX), both historical and projected (NREL 2016). 2014 is the base year for projections used in the ATB. The various points in the 2014 base year represent different techno-resource groups (TRGs). There are 10 TRGs, but only the projections for TRG 1, which has the highest quality resource, are shown after 2015 to reduce the number of lines. All projections are available in the 2016 ATB (NREL 2016). How the CAPEX translates into a subsidized LCOE is shown in Appendix A.3.

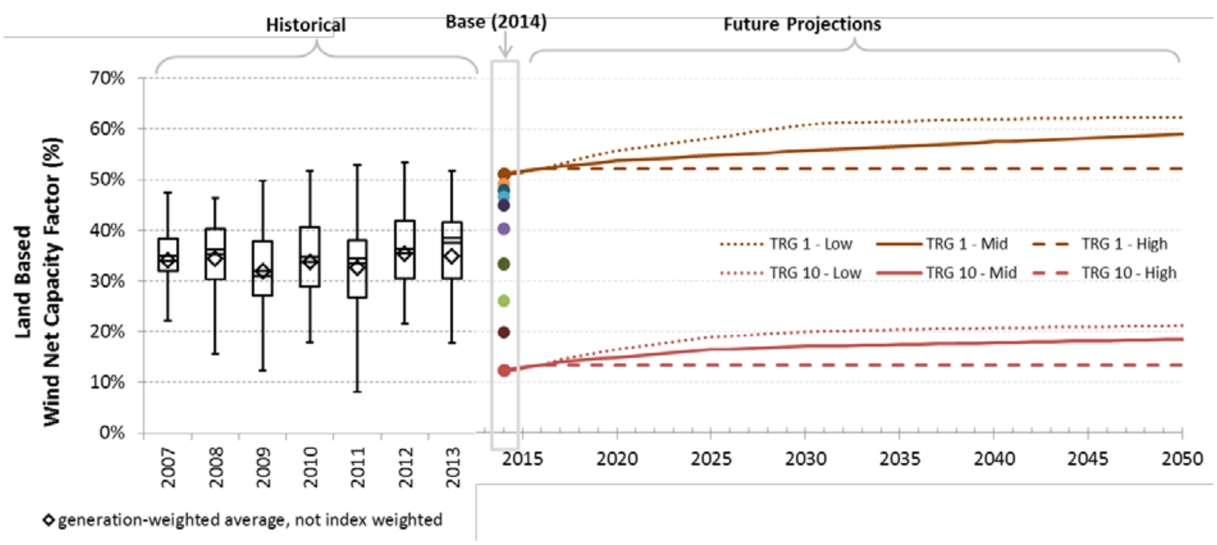

Figure 10. Land-based wind capacity factors, both historical and projected (NREL 2016). The base year for projections used in the ATB is 2014. The various points in the 2014 base year represent different TRGs. There are 10 TRGs, but only the projections for TRG 1 and TRG 10 (TRG 1 has the highest quality resource) are shown after 2015 to reduce the number of lines. All projections are available in the 2016 ATB (NREL 2016). How the capacity factor translates into a subsidized LCOE is shown in Appendix A.3.

Text Box 1. Alternative Wind Costs and Performance

Since the compilation of the 2016 Annual Technology Baseline (ATB), Wiser et al. (2016) have published a survey of 163 wind energy experts and reported the expected cost reductions from that group of experts under various conditions. The median survey results from Wiser et al. (2016) are considerably lower than they are for the 2016 ATB mid case (see), and they suggest a 2050 cost reduction that is comparable to the anticipated 2050 change in the ATB low case (NREL 2016). Based on this recent projection of wind costs, an additional scenario grounded in the Wiser et al. (2016) median result was developed to begin to understand the potential implications of these recent findings on the current Mid-case Scenario.

Overall, these lower wind costs lead to increased wind generation in both the short term and the and long term, with wind generation increasing by 39% in 2050 when using the Wiser et al. (2016) median cost projection instead of the ATB mid-case cost projection. In this instance, increased wind generation offsets primarily a combination of solar PV and combined cycle natural gas-fired generation roughly equally. Although future wind and solar PV costs remain uncertain, this outcome suggests the possibility for increasing levels of competition between wind and solar in the future as well as non-trivial changes in the relative future share of wind and solar, depending on one's expectations of cost trends for both technologies. See Section A.3 in the appendix for additional discussion.

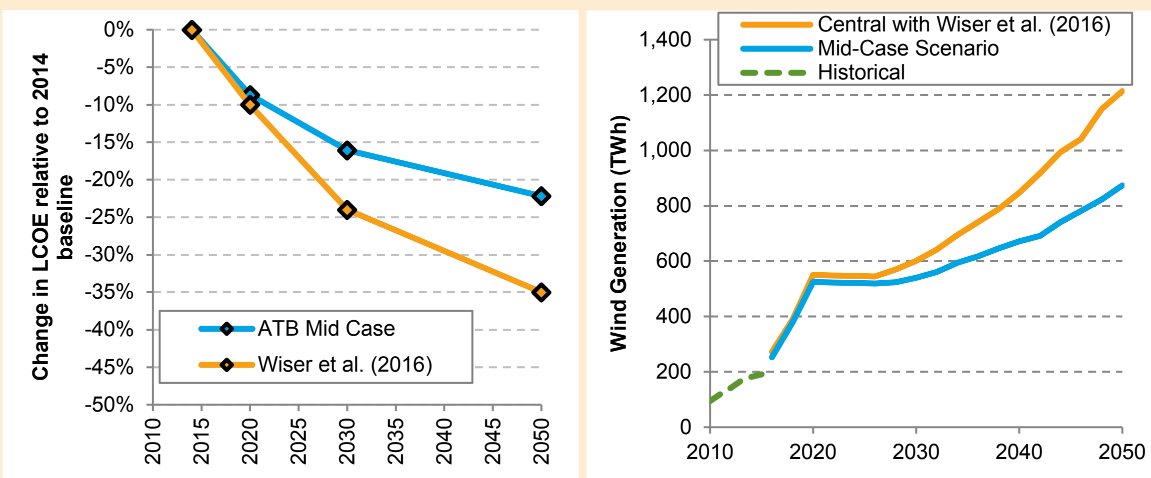

Figure 11. Impacts of wind cost reduction on wind generation.
The left figure shows projections for wind LCOE reductions through 2050 from the 2016 ATB mid case and the median survey results. The right figure shows the resulting wind generation from using the median survey wind costs instead of the 2016 ATB mid case costs in the Mid-case Scenario.

These cost reductions, coupled with policy incentives such at the tax credits and RPSs have created an environment with considerable potential for new deployment of renewable energy. Per Figure 7, these drivers have led to much of the recent rapid growth in renewable energy. Variable renewable energy[16] has been the primary source of the overall renewable energy growth. Wind and solar generation grew 240% between 2010 and 2015, achieving 5% annual penetration levels in 2015. Instantaneous levels have been much higher, particularly in certain regions. The Southwest Power Pool, the Bonneville Power Administration, and the Electric Reliability Council of Texas have all had instantaneous wind penetration of greater than 40%, and Xcel Energy Colorado has reached wind penetration levels of 66% (Goggin 2016). In the California independent system operator region, renewables have served more than 50% of instantaneous demand (California ISO 2016), with a substantial portion of that coming from solar energy. These experiences have shown that the power system can remain functional even at very high variable renewable energy penetration levels; however, open questions remain about the technical and market implications of sustained levels, at the seasonal or annual scale, of high variable generation. A large body of research has demonstrated there is still considerable capacity to integrate additional variable renewable energy capacity (Ahlstrom et al. 2015; Brinkman et al. 2016), but issues surrounding curtailment, and thereby costs, can become significant (Denholm and Hand 2011; Denholm, Clark, and O'Connell 2016).

3.2 Outlook

Although they are not assured, recent cost trends and policy support suggest that renewable energy growth is poised to continue. Figure 12 shows the renewable energy generation levels[17] through 2050 across the bidirectional scenarios, with the greater growth projected to occur from 2016 to 2020 in order to capitalize on the PTC and ITC incentives. After 2020, annual growth rates are in line with historical (2010–2016) growth rates (see Figure 13). The highest growth occurs with high natural gas prices, low renewable technology costs, and high demand growth, and vice versa for the lowest growth in renewable energy. Based on these scenarios, demand growth—either via increased consumption or from retirements of existing plants—can be just as significant for renewable energy deployment as improved technology costs. Understanding future electricity demand will be an important to continued renewable energy deployment.

[16] Variable renewable energy is defined as renewable energy where the energy production varies according to short-term environmental factors. In this work, when we refer to variable renewable energy, we primarily mean wind and solar PV.

[17] In this section, renewable energy generation includes hydropower, biopower, geothermal, landfill gas, solar PV (both distributed and utility-scale), concentrating solar power, and wind.

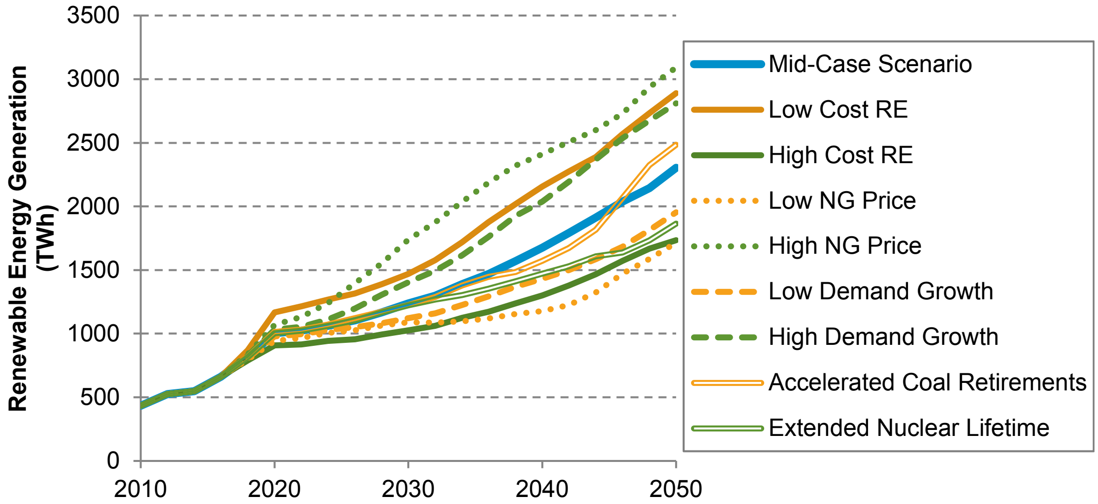

Figure 12. Renewable energy generation across the bidirectional scenarios

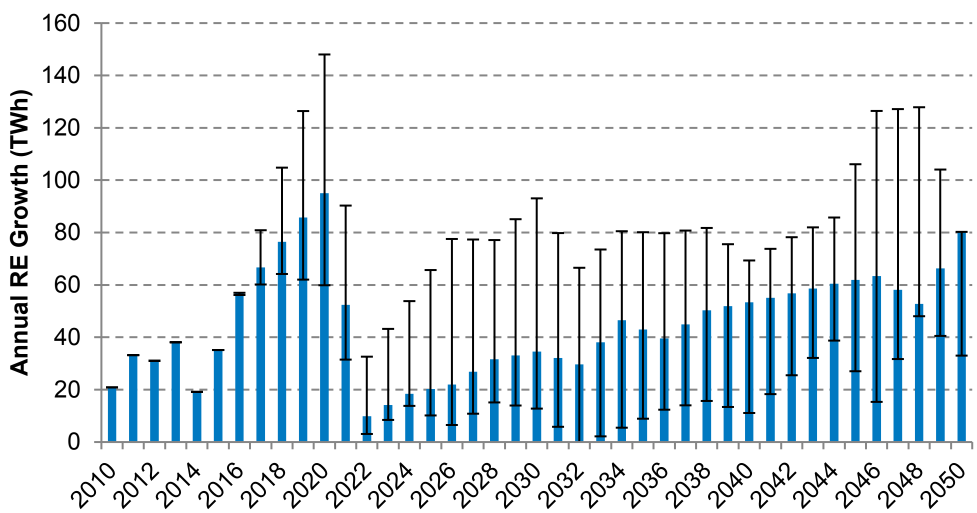

Figure 13. Annual growth in renewable energy generation. 2010–2015 values are taken from EIA data (EIA 2016d). The blue bars show the annual growth in the Mid-case Scenario, and the error bars show the minimum and maximum values in each year from the suite of bidirectional scenarios.

Historical generation in the figure uses a five-year rolling average for hydropower generation in order to remove the noise differences between wet and dry years.

The set of scenarios in Figure 12 and Figure 13 point toward rapid near-term change and then to continued but steady evolution into higher penetrations of renewable energy.[18] Total renewable energy penetration in these scenarios ranges from 23% to 40% in 2030, and variable renewable energy penetration ranges from 14% to 30% (see Figure 14). These penetration levels, while substantially higher than current levels, are in line with what integration studies have evaluated

[18] The Extended Incentives for RE Generation Scenario extends the PTC and ITC through 2030, which continues the higher growth rates of 2018–2020 through 2030.

to date (Ahlstrom et al. 2015; Brinkman et al. 2016). The 2050 penetration levels, however, go beyond what most integration studies have considered.[19] Although system changes would need to be implemented to accommodate this higher level of renewable energy, the long-term growth rate does provide some time to continue to increase system flexibility through increased cooperation, transmission expansion, demand response, storage, and other enabling technologies and institutional solutions.

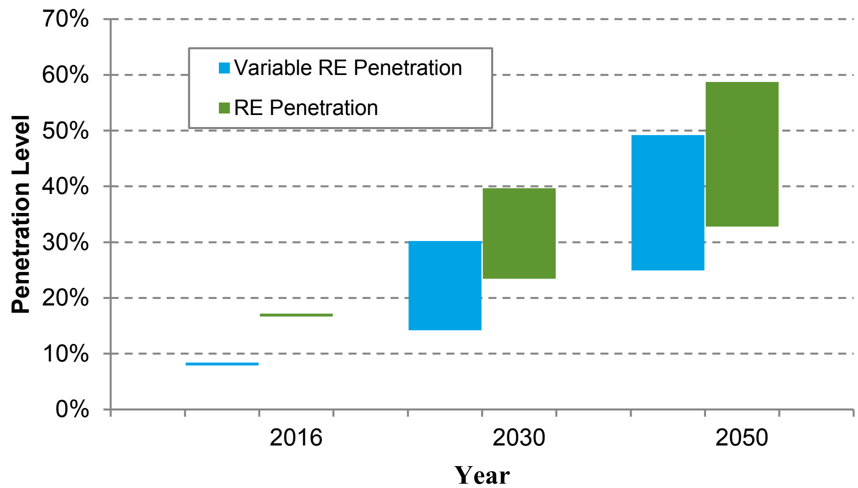

Figure 14. Renewable energy penetration levels across the range of bidirectional scenarios. For example, RE penetration is 33%–59% in 2050.

Outside the standard sensitivities considered in the bidirectional scenarios, several additional factors might help or hinder renewable energy deployment. For example, the Vehicle Electrification scenario, in which electric vehicles reach 40% of total vehicle sales by 2050, results in 12% more renewable energy generation in 2050 relative to the Mid-case Scenario. Electric vehicles provide both increased demand and the potential for increased flexibility, both of which provide greater opportunity for cost-effective deployment of renewable energy.

The Reduced RE Resource scenario and the Barriers to Transmission scenario both use sensitivities that have the potential to negatively impact renewable energy. The first reduces the amount of total renewable energy resource, representing a situation where environmental, land, or other constraints limit the resource that can be developed. The second makes transmission more costly and less effective, representing a situation where siting transmission and moving power is more challenging. In both of these scenarios, national renewable energy generation remains unchanged relative to the Mid-case Scenario. However, these alternate factors do have significant impact on regional deployment of renewable energy (see Figure 15). These regional shifts represent the allocation of renewable energy closer to the load centers in the case of higher cost transmission or closer to more abundant renewable energy sites in the case of reduced renewable energy resource.

[19] Some studies have looked at higher levels of renewable penetration (Mai et al. 2012; Jacobson et al. 2015; Brinkman et al. 2016), but the majority have not (Ahlstrom et al. 2015).

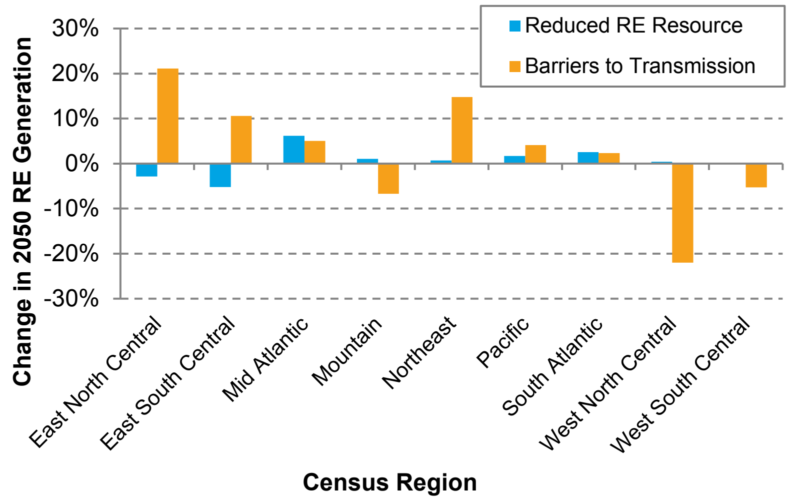

Figure 15. Regional change (relative to the Mid-case Scenario) in renewable energy generation by EIA census region

3.3 Key Insights

Renewable energy has experienced rapid cost declines and increased levels of deployment over the past decade. Current policies, coupled with recent cost reductions and anticipated future technology improvements have created conditions where renewable energy is anticipated to thrive in the near term. Based on the Standard Scenario outputs, renewable energy growth will continue over the long term, but the long-term annual additions are projected to be lower than the annual additions over about the next five years. Transformative changes to very high renewable energy penetration levels will likely not result unless there are additional cost reductions or policy drivers beyond those considered in the bidirectional set of the Standard Scenarios.

4 Natural Gas Abundance

The shale gas revolution caught many by surprise. As recently as 2008, energy planners were hard at work permitting the construction of dozens of new liquefied natural gas import terminals. As production of shale gas from several highly prolific plays surged, the need for these import terminals declined, and by 2012, these same planners were considering permits for liquefied natural gas export terminals. In mid-2016, shale gas accounted for nearly 60% of total dry natural gas production in the United States, up from less than 5% of the total in 2005 (Staub 2015). Given the massive changes that have occurred with regard to abundant low-cost natural gas, future scenarios of this fuel's impact should be made with some level of caution and modesty.

4.1 Recent Trends

Abundant low-cost natural gas has catalyzed unprecedented change in the U.S. power generation mix over the past decade. The annual average capacity factor for combined-cycle generators rose from 35% in 2005 to over 56% in 2015 as generators increasingly prioritized dispatch of natural gas units ahead of coal (EIA 2016b). Furthermore, natural gas generation is projected to exceed that of coal for the first full year ever in 2016, after having achieved top status in 7 of the 12 months of 2015 (Walton 2016). The U.S. generation mix in Figure 16 shows that recent changes are arguably the greatest in the modern history of the U.S. generation mix.

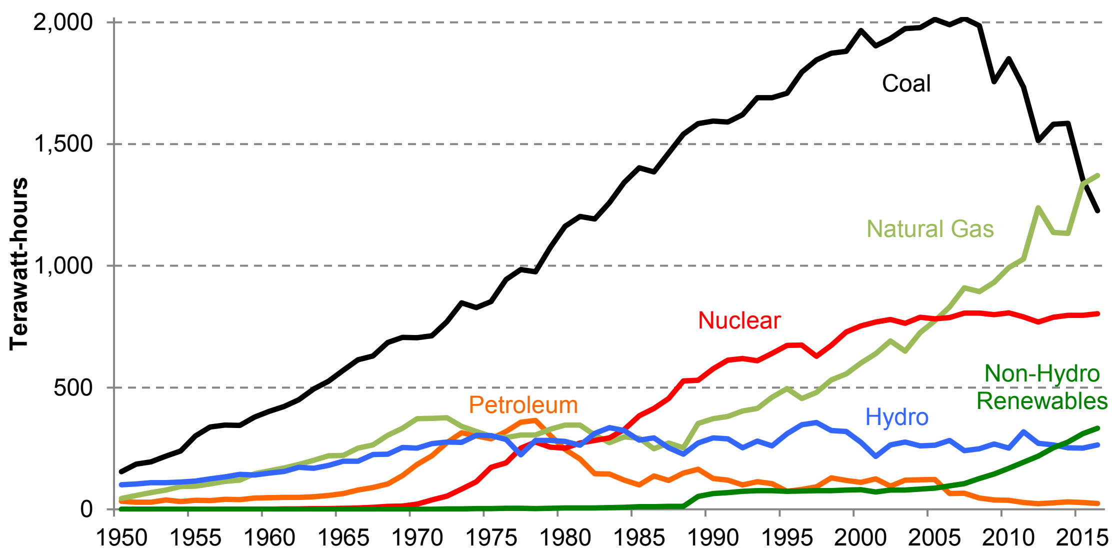

Figure 16. U.S. net generation by source, 1950–2016 (EIA 2016d). 2016 values are based on a 12-month rolling average through April 2016.

Despite increases in commodity prices, including natural gas prices, in mid-2016, the outlook for continued low-priced natural gas looks firm, given the currently high levels of underground storage (EIA 2016f) and continued declines in the cost to produce natural gas. It should also be noted, though, that exports of natural gas are increasing, both through pipelines and as liquefied natural gas. The United States is expected to become a net exporter of natural gas in the second half of 2017 (EIA 2016e). Natural gas price outlooks are notoriously difficult to estimate accurately beyond the near term due to variations in weather, production, storage, and other variables, but natural gas price projections have generally been declining over time as models have incorporated the impacts and resource assessments associated with shale gas. Figure 17 shows how EIA Annual Energy Outlook forecasts for natural gas prices have declined the last several years, leading to the lowest-cost outlook ever in 2016.

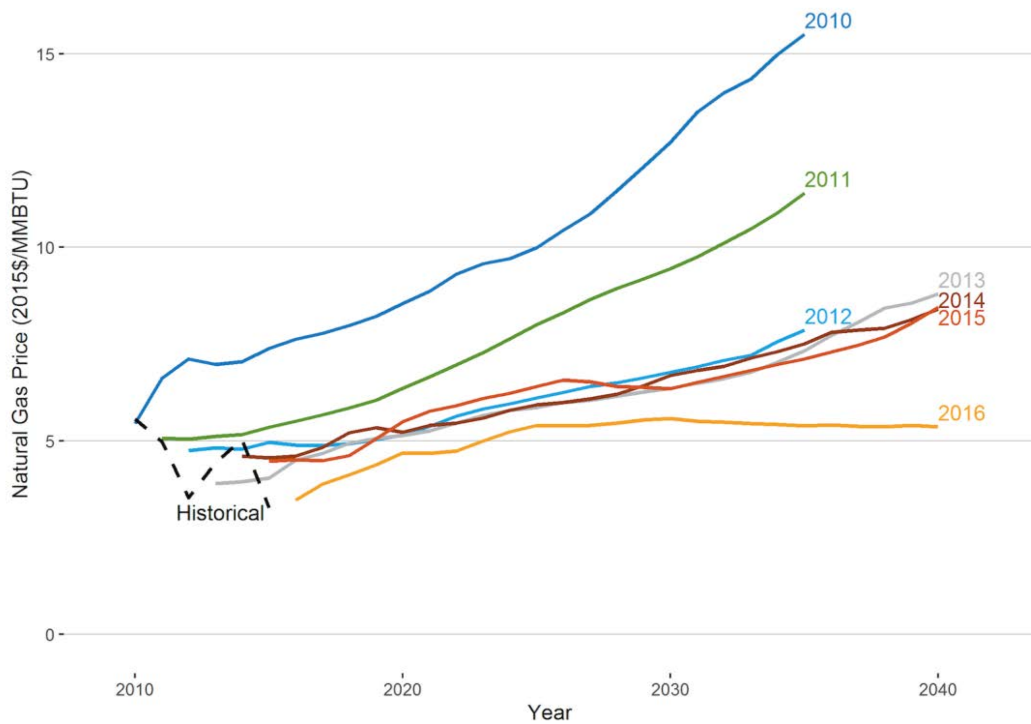

Figure 17. Variation in electricity-sector natural gas price forecasts in the Annual Energy Outlook from 2010 to 2016 (EIA 2016a)

Other factors are also likely to play a role in the use of natural gas for power generation. Public perception of natural gas development and storage, especially for natural gas produced using hydraulic fracturing, varies around the country with some regions exhibiting strong opposition. This opposition could grow in the face of major accidents or if ongoing research indicates that the full lifecycle greenhouse gas emissions of shale gas are higher than previously believed (Arent et al. 2015).

4.2 Outlook

The sustained low-price environment for natural gas creates substantial opportunity for the growth of natural-gas-fired generation in the power sector. Figure 18 shows the generation from natural gas units across the bidirectional scenarios. From 2020 to 2050, all scenarios see considerable growth, with average annual growth rates of 1%–3%.[20] Prior to 2020 natural gas generation declines slightly due to increasing natural gas prices over the short-term.

[20] These growth rates represent an average growth of 100–750 billion cubic feet per year in natural gas consumption in the electricity sector.

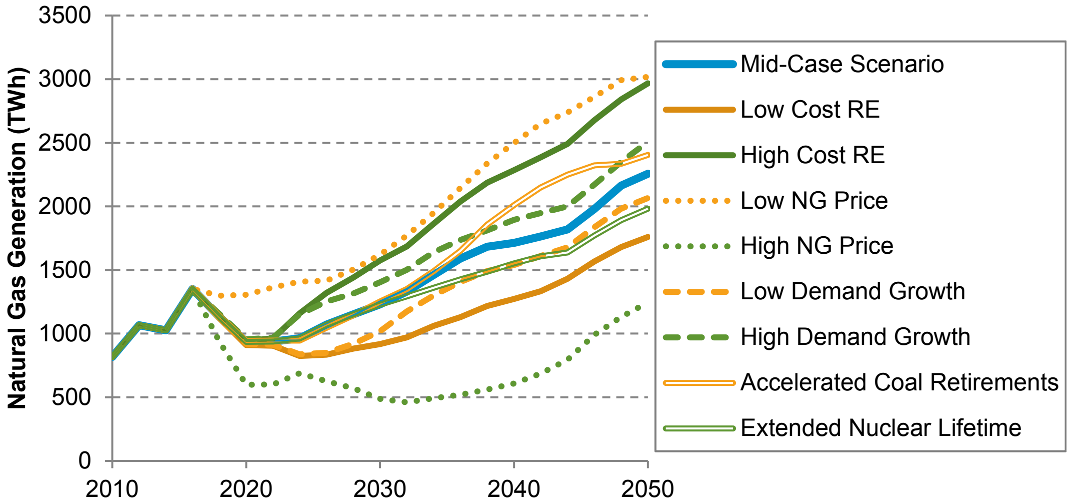

Figure 18. Range of generation from natural-gas-fired generators across the bidirectional scenarios

In these scenarios, the scenarios that produce the lowest and highest levels of natural gas generation are the High and Low NG Price scenarios respectively. As shown in Section 3, these scenarios also correspond to the highest and lowest levels of renewable energy generation respectively. High natural gas prices make renewable energy one of the most cost-effective options for new generation, but with low natural gas prices, increasing the utilization of existing gas is typically the lowest-cost option followed by new natural gas generation.

Renewable energy generators are also poised for significant growth under most scenarios (see Section 3). The combination of strong growth in natural gas and in renewable energy means that other generators are more likely to have more pressure to exit the market. And, if natural gas prices continue to be low, the combination of low variable costs from natural gas generators with significant amounts of renewable energy that have little or no variable costs will make it more challenging for traditional baseload generators to recover their costs under existing market rules of restructured electricity markets. These pressures, coupled with the fact that many baseload generators have already been in operation for many years and may require significant retrofits or upgrades, creates an environment where existing baseload generators might retire more quickly than otherwise anticipated. Figure 19 demonstrates this effect. Current operations have high levels of coal capacity with 1,000–2,000 TWh of natural gas and renewable energy generation. Future operations are projected to have much less coal capacity (due to lifetime-imposed retirements and underutilization retirements in ReEDS) with double the amount of natural gas and renewable energy generation. This evolution creates a fundamentally different electricity system, and it increases the value of coincident renewable energy generation that can be used to hedge against natural gas price volatility (Berry 2005; Bolinger, Wiser, and Golove 2006; Bolinger 2013).

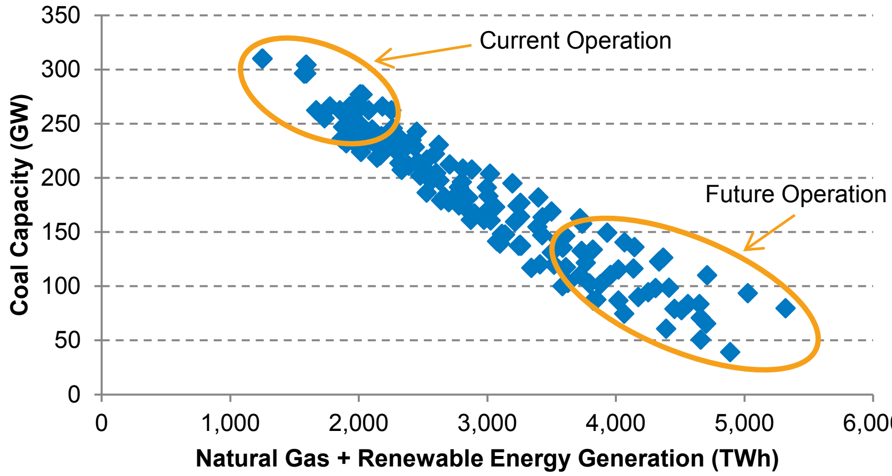

Figure 19. Coal capacity versus total natural gas and renewable energy generation. Each data point shows the results from a single solve year from each of the bidirectional scenarios.

Power sector decarbonization, however, can impact the long-term growth of natural gas generation (see Section 6 for details about decarbonization). Figure 20 shows how a power sector emissions cap can impact the outlook for long-term natural gas generation. The emissions cap lowers 2050 power sector emissions by 83% relative to 2005 emissions. The result is more near-term utilization of natural gas to accelerate decarbonization but a longer-term decline in natural gas generation as the cap becomes more stringent. Total natural gas generation has the potential to rebound over the long term due to an increase in generation from natural gas generators with carbon capture and sequestration (CCS). Thus, under deep power sector decarbonization, cost-effective CCS might offer the opportunity to reduce the decline, maintain existing levels, or even increase the market potential of natural gas power generation. The potential for CCS to have this role depends on costs, performance, and the policy environment.[21]

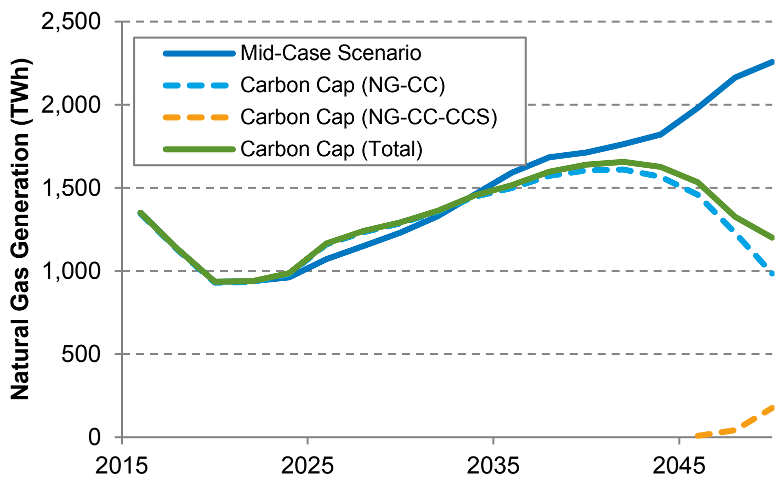

Figure 20. Natural gas generation in the Mid-case Scenario and in the Carbon Cap Scenario

[21] Others, including Cole et al. (2016) and Logan et al. (2013) have explored in detail the role of CCS in continuing natural gas market growth while simultaneously seeking deep decarbonization.

Natural gas has been a major source of uncertainty in power sector planning, and it will almost certainly continue to be so. Liquefied natural gas exports, rapidly growing pipeline exports to Mexico, potential fracking or methane leakage regulations, and uncertain oil markets create an environment where making definitive projections for natural gas usage and prices is difficult.

4.3 Key Insights

Low-cost natural gas has been driving considerable changes in the power sector. These changes are projected to continue, with natural gas prices projected to remain low for potentially several decades. These low natural gas prices create strong, sustained growth in natural gas generation. Strong growth in natural gas, coupled with continued renewable energy development, can lead to a future environment with less baseload capacity, putting more value on coincident renewable energy generation that is able to hedge against any natural gas price volatility. Deep decarbonization, however, has the potential to disrupt the continued growth of natural gas generation, even in the presence of low gas prices. However, that disruption can be offset if CCS technologies for natural gas become available.

5 Rapid Growth in Distributed Photovoltaics

Rooftop PV has been the fastest growing and most prolific distributed generation technology in recent years, and recent trends in the rooftop PV space suggest that it will continue to be a significant technology for many years.

5.1 Recent Trends

Annual installations of distributed PV (residential, commercial, and industrial) grew from 468 megawatts (MW) in 2010 to 2,448 MW[22] in 2015 (see Figure 21), which represents a compound annual growth rate of 40% per year (GTM Research and SEIA 2016). Total cumulative installations of distributed PV now exceed 8.5 GW. This growth can largely be attributed to declining PV installation costs, policy incentives, rate design and net metering incentives, improvements in financing options, and consumer sentiments. A recent assessment shows that residential PV is currently cost effective in 20 states when current rate design, net-metering policies, and incentives are considered (Munsell 2016). Historically, most of the cost reductions on solar installation have been through module price declines, but future cost reduction pathways are often targeted toward non-hardware costs, such as through the U.S. Department of Energy SunShot Initiative (DOE 2016). There is still considerable potential for growth, with recent estimates showing there is technical potential for ~900 GW of solar capacity on suitable rooftops in the United States, which represents a technical potential to generate 39% of the current U.S. annual electricity sales (Gagnon et al. 2016).

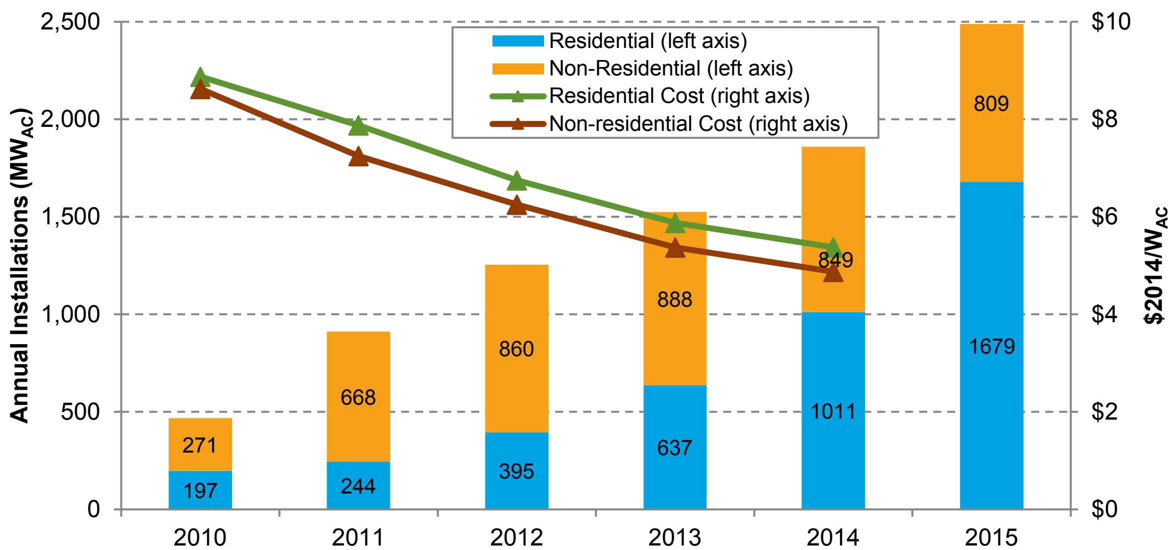

Figure 21. Annual installations and installed cost of residential and non-residential (<500 kW) distributed PV systems (Feldman et al. 2015; GTM Research and SEIA 2016)

[22] The PV industry typically reports PV capacity values in DC units. All DC units have been converted to AC units in this report using an assumed inverter loading ratio of 1.25 (AC capacity = DC capacity / 1.25).

Along with declining costs, policy incentives have promoted distributed PV installation. Renewable portfolio standards generally require regulated utilities in each state to purchase a certain amount of renewable generation (often through a renewable energy credit market) and have been drivers for renewable projects across the U.S. As of August 2015, 22 states and the District of Columbia have RPS provisions that create incentives for distributed generation.[23] These distributed resource provisions (1) call for a certain number of customer-sited resources used for RPS compliance, (2) apply a multiplier to renewable energy credits created by distributed resources, or (3) set targets on installed capacity of distributed resources (NC Clean Technology Center 2015).

The ITC has also provided incentives for strong growth in distributed PV. The ITC for solar resources was set to reduce from 30% to 10% for third-party-owned and commercial systems and from 30% to 0% for residential systems at the end of 2016, but that was recently extended through 2019. This credit is to be reduced to 26% in 2020, 22% in 2021, and 0% for residential system and 10% for third-party-owned and commercial systems in 2022.

Net metering is a policy approach that has helped accelerate distributed PV growth. Net metering typically allows owners of PV systems to receive credit at the retail rate for excess electricity generation sent to the electrical grid (SEIA 2016). However, net metering and associated rate designs are currently among the most contentious policy items associated with distributed PV resources (Inskeep et al. 2015). Utilities sometimes contend that excess generation from solar customers is not worth the full retail rate, and therefore net metering results in a cost-shifting from solar to non-solar customers, while others argue that net metering provides net benefits to the overall system. Utilities have proposed changing rate designs by increasing fixed charges, introducing demand charges, or reducing net metering credits to reduce this potential cross-subsidization. Net metering continues to be a prominent issue, with 19 states reviewing potential changes both for and against net metering and rate design provisions for solar customers (Inskeep et al. 2015). Net metering compensation and rate design are considered to be significantly (financially) material to the solar industry. For example, the Nevada Public Utilities Commission recently approved a proposal that reduces net metering compensation rates and increased fixed charges over 12 years, which has led to several solar companies closing offices inside the state (Pyper 2016).

Advancements in financing options allow for further PV deployment for consumers who cannot afford the upfront investment to purchase a system or do not have suitable roof space. Third-party ownership models allow consumers to deploy solar without any up-front cash through leases or power purchase agreements (i.e., where the consumer buys electricity from an installer at lower costs than the utility does). One estimate shows that 72% of distributed solar systems in 2014 were purchased through third-party financing options (Litvak 2015). Property Assessed Clean Energy (PACE) programs allow homeowners to finance energy efficiency, renewable energy, or water improvements through local government-backed loans that are repaid through increased property taxes on the building. Currently, legislation in 27 states allows PACE programs (PACENation 2016). Community solar programs allow consumers to buy generation from solar panels located off-site for customers who cannot or do not want to install PV systems on their homes or businesses. There are currently 89 community solar projects in 25 states with

[23] As of April 2016, there exist mandatory RPS policies in 29 states and the District of Columbia (Barbose 2016).

100 MW of installed capacity, but there is growing demand for access to community solar projects (O'Shaughnessy et al. 2015; Community Solar Hub 2016; GTM Research and SEIA 2016).

5.2 Outlook

With strong recent growth in distributed PV, the natural question for the future is, will it continue? And if so, to what degree? The future diffusion of rooftop PV will depend strongly on how rooftop PV is valued, as well as the cost and performance of the actual PV systems.[24] Figure 22 shows the reference case projections for rooftop PV deployment from the dGen model.[25] The projections use the low, mid, and high 2016 ATB PV cost projections for residential, commercial, and industrial rooftop PV systems, but they assume that current rate structures persist through 2050. Net energy metering is included until current caps are met, but otherwise system conditions are assumed to continue as they are now. These assumptions lead to increased rooftop PV deployment over the long term, with the mid-cost ATB trajectories yielding nearly 200 GW by 2050. The projections are highly sensitive to assumed system costs. If PV costs do not decline (high case), rooftop PV projections are significantly lower with approximately 40 GW estimated to be adopted by 2050, as shown in Figure 22.

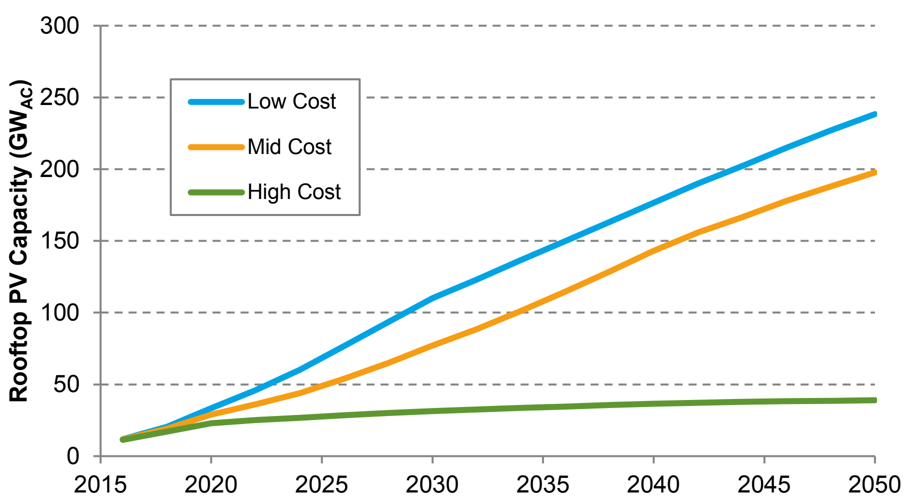

Figure 22. Rooftop PV capacity projections from the dGen model through 2050 using the ATB 2016 low, mid, and high cost projections

These projection levels can be even higher if the rooftop PV energy is given greater value. For example, net energy metering values all rooftop PV solar generation at the retail rate, whether or not it is consumed by the building owner bounds the upper ranges of the scenarios. By assuming net energy metering exists in all states for all time, the dGen model produces even higher levels

[24] Rooftop PV projections discussed in this section do not include any consideration for storage or demand response and how those technologies might aid or inhibit rooftop PV performance or value. Additionally, the method for valuing rooftop PV is not well defined, and differences in definition can lead to a wide range of compensation mechanisms for rooftop PV adopters.
[25] The dGen model includes a suite of distributed generation modules. The work presented in this report exclusively utilizes the dSolar module, which is a rooftop PV diffusion model that informs the rooftop PV projections used in ReEDS. For more information, see the dGen model documentation (Sigrin et al. 2016).

of rooftop PV deployment than those shown in Figure 22 (see Figure 23). Low-cost PV systems, combined with net energy metering extended to all regions and rate structures that do not change over time, show deployment levels of near 350 GW by 2050.

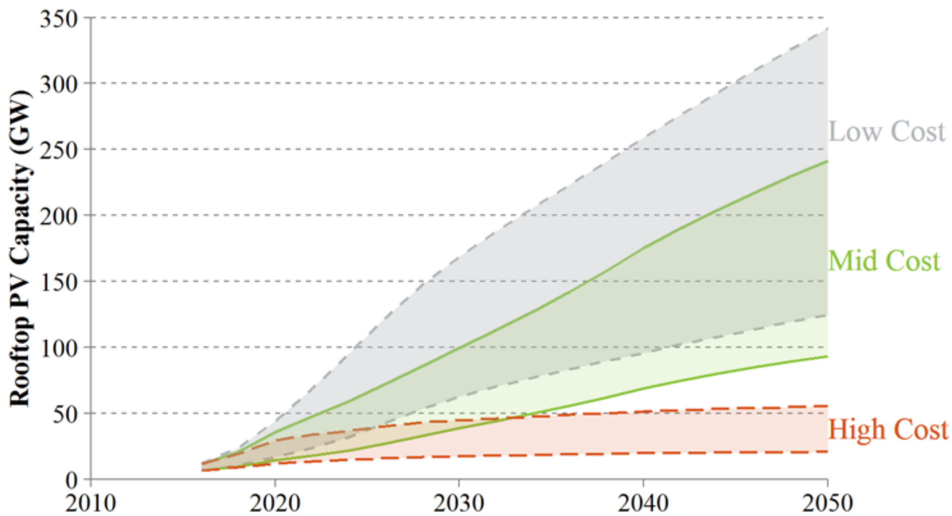

Figure 23. Rooftop PV capacity (in GW_{AC}) ranges from the dGen model through 2050 under various cost and policy assumptions. The upper bound of each cost range represents full net energy metering policy implemented in every state through 2050, and the lower bound of each cost range represents a case where any excess generation from a rooftop PV system is given no value.

However, it is improbable that utility rate structures will remain stagnant, especially in the face of rapidly increasing levels of PV generation (Darghouth et al. 2016). Once the grid reaches significant levels of PV penetration, the incremental value of new PV systems begins to decline.[26] Thus, direct financial compensation for rooftop PV generation might decline as adoption grows depending on policy approaches adopted. The mechanisms for adjusting rate structures, evaluating the appropriate value of PV generation, and assessing the costs and benefits on grid systems are complex and well beyond the scope of this work. However, as a first pass to provide a quantitative level for a reduced value of rooftop PV, we consider a set of scenarios where all excess generation from a PV system is given no value. These scenarios are used to elucidate a "lower bound" on the diffusion potential for PV systems under the three cost assumptions (see Figure 23).[27] Reducing the value of rooftop PV generation is found to significantly impact rooftop PV deployment over time.

Various other conditions relative to rooftop PV are explicitly not considered here. For example, the impact of rooftop PV on the transmission and distribution systems is not taken into account in these scenarios. Many feeders might require upgrades or have limited hosting capacity, or the ability to accommodate PV interconnection in the feeder network. Conversely, the potential benefits of rooftop PV in deferring infrastructure upgrades or providing ancillary services are not

[26] This declining incremental or marginal value is summarized with the well-known "duck curve." See Denholm et al. (2015)

[27] These scenarios are not meant to represent an absolute lower bound. For example, beyond not valuing excess generation, there could also be a migration to time-of-use rates that have low-cost midday electricity, which would further reduce the bill savings of PV.

fully considered. Additionally, these scenarios do not explicitly consider the potential feedback between rooftop PV and utility PV. Rooftop PV has the potential to substitute for utility PV, and significant buildout of utility PV can reduce the marginal value of new rooftop PV (Cole, Lewis, et al. 2016).

One level of consistency across the scenarios examined above is that rooftop PV deployment grows rapidly over the near term. The combination of localized policies—such as net energy metering and distributed solar carve-outs for renewable portfolio standards, declining system costs, and the extension of the investment tax credit—points to substantial near-term growth. The divergence primarily occurs after 2020, and it will strongly depend on how the many stakeholders respond to the growth in rooftop PV systems.

Ultimately, actual rooftop PV deployment will not follow any of the diffusion trends that we have discussed above. The combination of multiple actors and interest groups will lead to various approaches and changes in different regions of the country, resulting in a hybrid of what was discussed above. As with the situation that exists today, regional variations in rate structure or incentive level will likely exist in the future. In some regions, rates will be more favorable to distributed generation than others will. Rates can also evolve quickly with PV adoption in certain regions whereas others regions might not fully consider PV in their rate design. And incentives, such as net metering, will continue to evolve with some states continuing or implementing net metering, and others hastening its decline. The combination of these and many other factors will determine the trajectory that is followed.

5.3 Key Insights

Rooftop PV will likely continue to grow in the near term, and it has significant potential for growth over the long term. However, the growth potential is strongly dependent on how rate structures, PV system costs, and policy decisions unfold. Given the large variety of stakeholders, resolving how PV systems should be valued will likely result in regional differences and create a blend of diffusion rates across the country. Accurately predicting long-term (post-2030) rooftop PV deployment will remain challenging over the next couple of years due to the variety of paths that PV valuation might take. However, the need for robust assessments and sound understanding of the distributed PV market will be even greater over this period because many decisions will have to be made that will impact the future diffusion potential of distributed PV.

6 Power Sector Decarbonization

Power sector carbon dioxide (CO_2) emissions in the United States have grown over time until the mid-2000s. Since 2005, there has been a general decline in CO_2 emissions. Many open questions exist as to how future power sector emissions might evolve.

6.1 Recent Trends

Since the mid-2000s, CO_2 emissions have been on the decline (see Figure 24).[28] CO_2 emissions in 2015 were at the same level as they were in 1993 and were 21% below 2005 emissions. One of the primary factors driving the decline is that abundant low-cost natural gas has induced a significant amount of coal-to-gas fuel switching (see Section 4). Because natural gas generators have a CO_2 emission rate that is approximately half that of coal-fired generators (Heath et al. 2014), this switching allows the same of amount of electricity to be produced with a lower level of emissions. The economic recession that began in the late 2000s also led to reduced electricity demand, meaning less coal, natural gas, and other fuels had to be burned to meet electricity needs. Additionally, renewable energy generation has increased significantly over this period (see Sections 3 and 5), leading to a greater portion of electricity being supplied by carbon-free resources. Finally, several policies and regulations, such as the Mercury and Air Toxics Standards (MATS), have contributed either directly or indirectly to the recent decline in emissions.

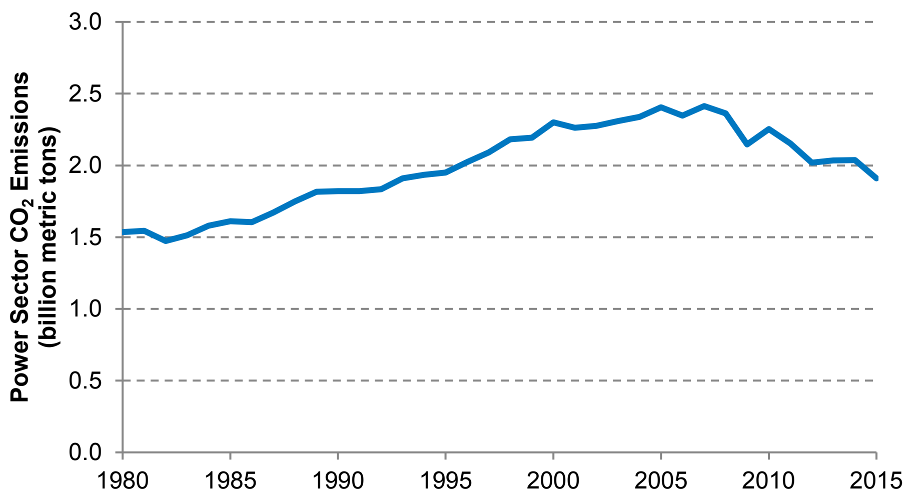

Figure 24. Power sector annual CO_2 emissions for 1980–2015 for the contiguous United States (EIA 2016c)

In addition to the decline in emissions, the Environmental Protection Agency's (EPA's) Clean Power Plan was finalized in August 2015. The Clean Power Plan is projected to decrease 2030 CO_2 emissions by approximately 32% from 2005 levels. The future of this plan is uncertain, however, due to the stay issued by the U.S. Supreme Court. Nonetheless, the plan does represent a significant move in the direction of limiting CO_2 emissions from the power sector and it demonstrates a trend that might continue.

[28] In this work, we consider only burner-tip CO_2 emissions. We do not consider any other aspects of lifetime emissions, though others have evaluate that work, including Wiser, Bolinger, et al. (2016) and Wiser, Millstein, et al. (2016).

6.2 Outlook

The range of CO_2 emissions in the bidirectional scenarios is shown in Figure 25. The scenarios show continued short-term reductions due to increased coal-to-gas switching and renewable energy deployment. The Clean Power Plan compliance period begins in 2022, and prior to that, CO_2 emissions are strongly dependent on natural gas prices—in some scenarios the coal-to-gas switching temporarily reverses directions as natural gas prices climb back in the $4–$6/MMBtu range—and renewable energy costs. After 2022, the Clean Power Plan (as implemented in ReEDS[29]) sets the ceiling for future CO_2 emissions,[30] which is why so many scenarios see the same constant emissions after 2030. As seen in Figure 25, several of the scenarios are below that ceiling, indicating that the system is exceeding requirements (as modeled) of the Clean Power Plan in those years.

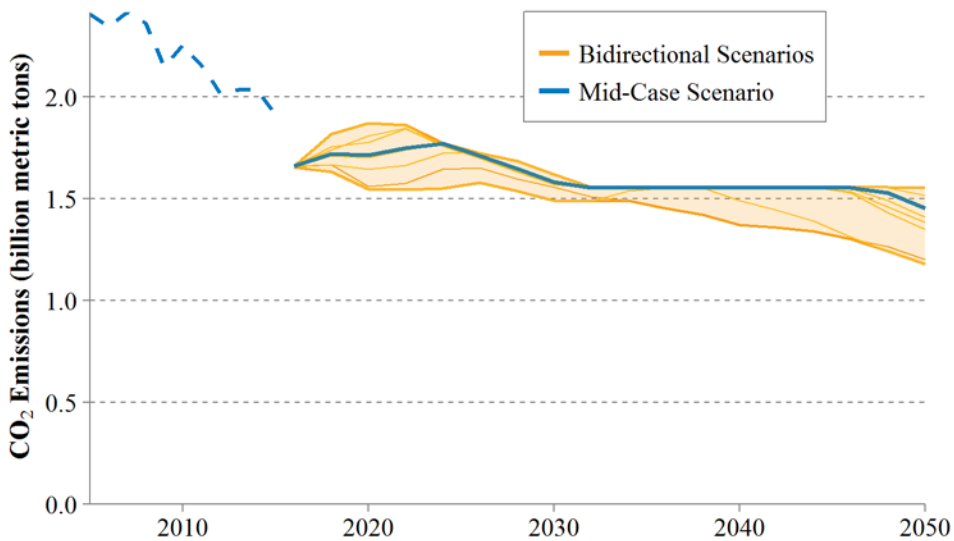

Figure 25. Range of power sector annual CO_2 emissions across the bidirectional scenarios. The dashed line shows historical values. The flat emissions trajectory post-2030 is due to assuming that the CPP emission levels are held constant over time.[31]

Figure 25 shows a wide range of potential emission outcomes in the near-term across the bidirectional scenarios. In some scenarios, emissions slowly increase from their 2016 levels until the Clean Power Plan compliance period begins, and in other scenarios, emissions continue to decrease from today's levels.[32] Taken as a whole, the modeled projections show that CO_2 emissions might not continue to decline prior to the Clean-Power-Plan compliance period

[29] The Clean Power Plan is in all the scenarios discussed in this work and is implemented in the model as a mass-based policy with new source complements and unrestricted national allowance trading.
[30] The ReEDS model has a representation for banked CO_2 allowances, so CO_2 emissions before 2030 can exceed the cap if banked allowances are sufficient to cover the difference between actual emissions and the cap.
[31] The CPP representation in ReEDS is one of many options for CPP compliance. If other compliance options are assumed, the constant emissions level observed here would likely change.
[32] The 2016 emissions shown in this work are output from the ReEDS model and are likely a lower-end estimate of what 2016 power sector emissions will actually be. ReEDS assumes renewable energy generators installed in 2016 are available for the entire year but in reality most renewable energy capacity built in 2016 is scheduled to come online in the latter part of the year. Thus, far power sector emissions are on track with ReEDS model outputs with power sector CO_2 emissions in first four months of 2016 being 15% lower than they are in the first four months of 2015 (EIA 2016c), but it is not clear whether that trend will continue through the remainder of the year.

(although declining emissions are still within the range of projections), but they might instead hold steady or even increase slightly, largely depending on whether and how quickly natural gas prices rise and renewable energy generation grows. If coal-to-gas switching continues, it might put more pressure on incumbent coal and nuclear generators; but, if coal-to-gas switching does not continue, relative dispatch of coal and gas could swing in the other direction due to rising natural gas prices.

In the longer term, the bidirectional scenarios suggest that CO_2 emissions either continue to decline or hold steady at the Clean Power Plan emissions limit. By 2050, power sector CO_2 emissions are 35%–51% below 2005 levels. These emission levels represent considerable reductions from where the system is and has been operating, but they are still far short of the deeper decarbonization levels that are seen as necessary for mitigating the impacts of global climate change.[33] Meeting deep decarbonization goals by mid-century will require something outside the suite of assumptions that are represented in the bidirectional scenarios.

Beyond the bidirectional scenarios, two scenarios in the set of Standard Scenarios do consider future situations with more substantial levels of decarbonization. These scenarios are the Carbon Cap scenario and the 80% National RPS scenario (see Figure 26).[34] The Carbon Cap scenario imposes a power sector emissions cap that limits 2050 CO_2 emissions to 83% below 2005 levels, and the 80% National RPS scenario requires that by 2050, 80% of load be met by renewable energy. Both scenarios reach approximately the same level of decarbonization. The primary difference between the two scenarios is the means by which the reduction comes. The 80% National RPS scenario achieves the reduction almost exclusively through the deployment of renewables while the carbon cap achieves the reduction via a mix of technologies, including natural-gas-fired carbon capture and storage technologies and a small amount of new nuclear power (see Figure 27). And, although both scenarios achieve essentially the same emissions reduction in 2050, the more-diversified mix in the Carbon Cap scenario has electricity prices that are 9% lower than they are in the 80% National RPS scenario under the technology cost and fuel price assumptions used for these scenarios.

[33] Rogelj et al. (2015) show pathways that limit warming to 1.5°C and 2°C with >50% probabilities. The carbon reductions in the bidirectional scenario are much higher than those pathways defined by Rogelj et al.
[34] These scenarios depict only power sector decarbonization. A more robust approach for implementing decarbonization would take an economy-wide approach and consider other factors such as widespread end-use electrification that could drive up electricity demand and energy efficiency mechanisms that can reduce demand.

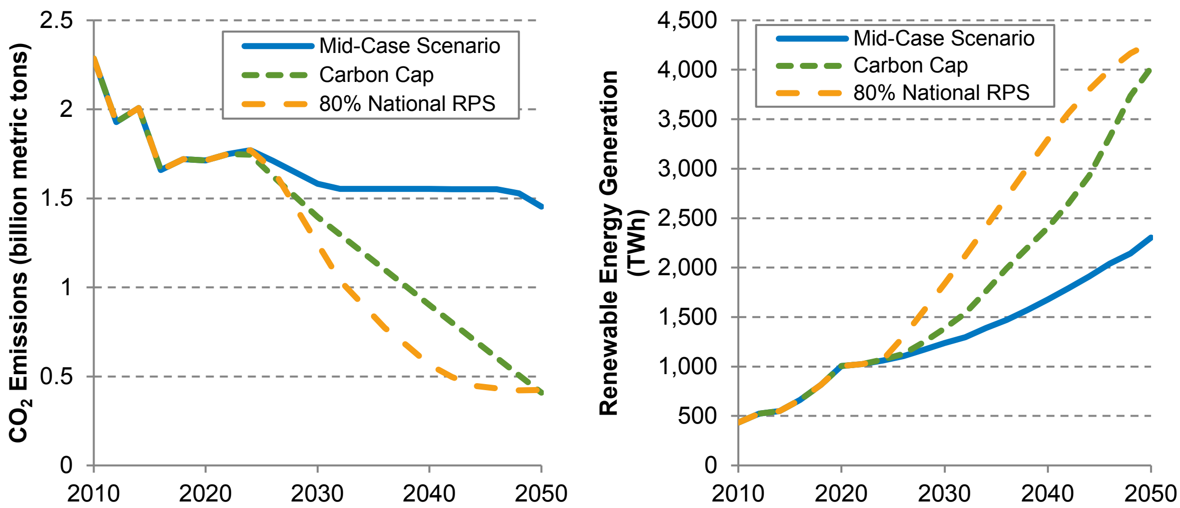

Figure 26. Power sector annual CO_2 emissions and corresponding renewable energy generation in the Mid-case, Carbon Cap, and 80% National RPS scenarios

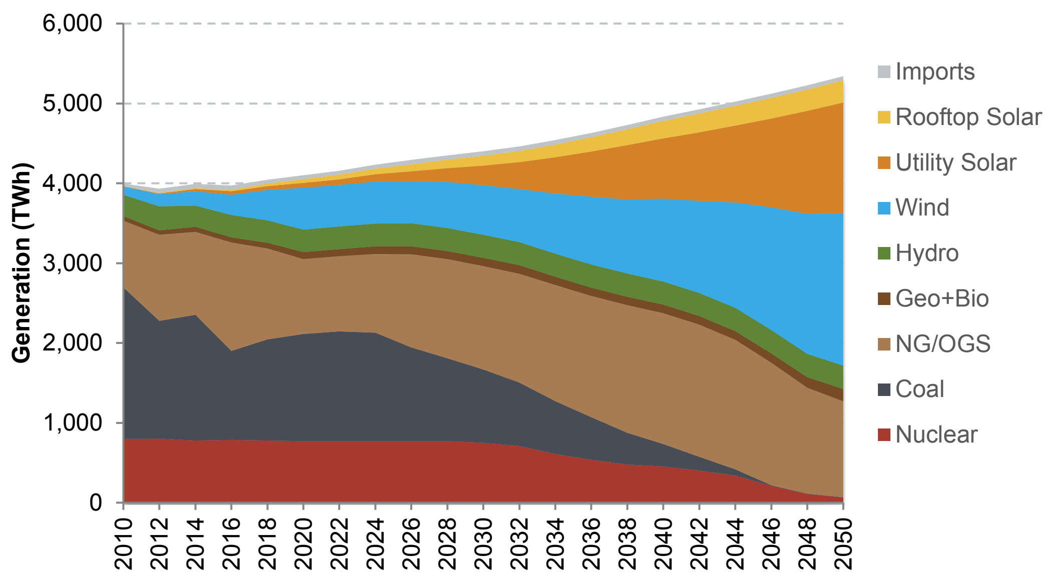

Figure 27. Generation mix in the Carbon Cap scenario. In 2050, just over 3% of demand is met by natural gas carbon capture and sequestration (CCS) plants.

The Carbon Cap scenario generation mix shown in Figure 27 shows a future where renewable energy, supplemented with natural gas generation, provides the majority of the electricity generation. However, nuclear power also has considerable potential in the deep decarbonization of the power sector. Nuclear power is currently high-cost relative to other technologies (Lazard 2015; NREL 2016), but its cost effectiveness is strongly dependent on many regional factors, such as market structures, local natural gas prices, and renewable energy resource quality. The Nuclear Technology Breakthrough scenario shows a business-as-usual future in which nuclear power becomes cost-competitive through the development and commercialization of small modular reactors or other next-generation technology developments. Nuclear costs are assumed to be 50% lower than they are under the Mid-case Scenario cost assumptions, and when they reach this level, they are cost-competitive without an additional carbon policy and 22 gigawatts (GW) of new nuclear capacity is added to the system. In the face of deeper emissions reductions such as in the Carbon Cap scenario, nuclear energy would require much less cost reduction to be cost-competitive at a large scale.

6.3 Key Insights

The power sector has been decarbonizing, primarily due to a shift from coal-fired generation to natural-gas-fired generation. Renewable energy growth, demand reduction, and power-sector policies have also played a role. However, even in the face of forward-looking CO_2 emission regulation such as the Clean Power Plan and renewable energy policies such as state renewable portfolio standards (RPSs) and the production tax credit (PTC) and investment tax credit (ITC), power sector CO_2 emissions will not continue to decline to the levels at or below those that have been suggested are necessary to avoid the consequences of climate change. If power sector decarbonization were deemed a priority, additional actions would be needed to achieve deeper levels of decarbonization.

7 Summary

The U.S. power sector continues to undergo substantial change. The work presented in this report considered four areas of change, using the Standard Scenarios as a backdrop for considering those changes. The current grid environment is one of abundant and low-cost natural gas, which has led to substantial coal-to-gas fuel switching and rapid growth of natural gas. This strong growth in natural gas has happened alongside the rapid recent growth in renewable energy. Total renewable energy is still somewhat modest but is poised for continued and rapid near-term growth. The longer-term outlook for renewable energy shows consistent growth, but the outlook for continued low-cost natural gas makes for a more challenging environment for all other technologies, including renewable energy. Conversely, low-cost renewable energy could be competitive even in a low natural gas price environment and, if historical gas price volatility repeats, much more significant renewable energy growth is possible.

In the realm of renewable energy, both distributed generation and utility-scale plants have experienced strong growth. Whether distributed generation continues to keep pace with utility-scale systems in terms of deployment is unclear and will depend largely on how utilities and other stakeholders respond to the increased penetration of distributed generation systems as well as how quickly the cost of distributed systems comes down.

Both the coal-to-gas fuel switching and the growth of renewable energy have led to a reduction of emissions over the last decade. This reduction is anticipated to continue under all scenarios due to the Clean Power Plan, but steeper decarbonization is possible given the right set of circumstances. Truly deep decarbonization, however, is not likely to be achieved without additional drivers beyond those considered in this work.

As the grid continues to evolve, understanding how today’s choices might impact the future evolutions of the grid system will continue to be an area of importance. Assumptions of what the future will look like will continue to change, and techniques and methods for making projections will continue to improve. The discussion and scenarios presented here, which we expect to update annually, are intended to inform that discussion and help lead to improved decision making.

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Appendix

A.1 Standard Scenario Input Assumptions

This section describes the input and other assumptions used in the scenarios listed in Table 1. For details on model assumptions, see the ReEDS documentation (Eurek et al. 2016) and the dGen documentation (Sigrin et al. 2016).

A.1.1 Fossil Fuel Prices

The natural gas input price points are based on the trajectories from the AEO 2016 (EIA 2016a). The prices are shown in Figure 28 and are from the AEO 2016 Reference scenario, the Low Oil and Gas Resource and Technology scenario, and the High Oil and Gas Resource and Technology scenarios (EIA 2016a). 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).

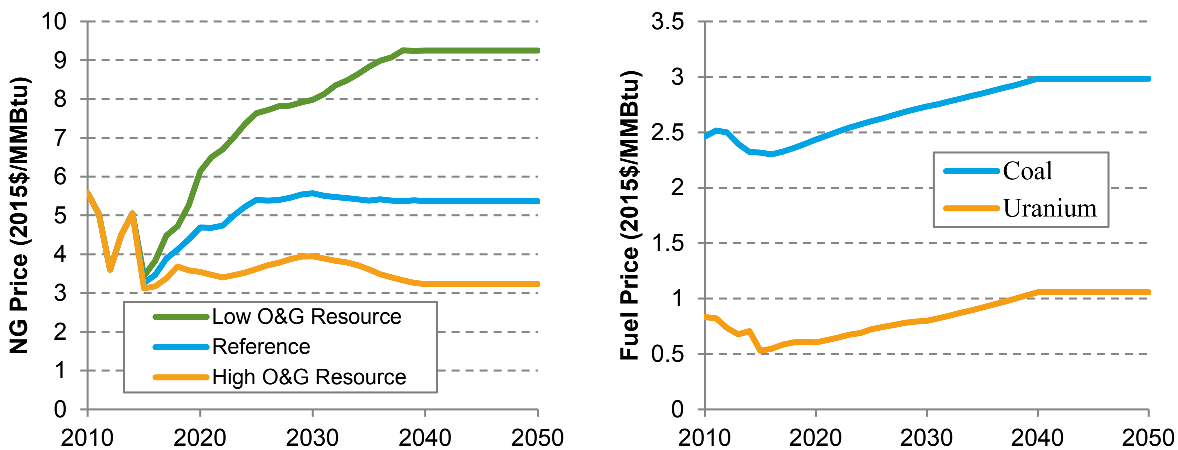

Figure 28. Fuel price trajectories used in the Standard Scenarios

The reference coal and uranium price trajectories are from AEO 2016 Reference scenario and are shown in Figure 28. Both coal and uranium prices are assumed to be fully inelastic. Because AEO 2016 fuel prices are only projected through 2040, fuel prices from 2040 to 2050 are held constant at the 2040 values.

A.1.2 Demand Growth

The Mid-case Scenario is based on the AEO 2016 Reference scenario load growth. The high and low load growth scenarios are also from AEO 2016 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 29). For the years after the AEO 2016 horizon (which ends in 2040), we assume an annual growth rate equal to the average growth rate from 2030 to 2040.

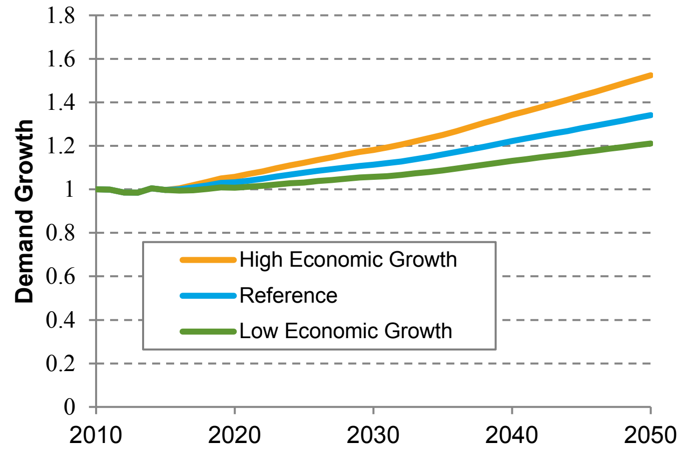

Figure 29. Demand growth trajectories used in the Standard Scenarios

A.1.3 Technology Cost and Performance

Technology cost and performance assumptions are taken from the 2016 ATB (NREL 2016). The ATB includes low, mid, and high cost and performance projections through 2050 for the generating technologies used in the ReEDS and dGen models.

A.1.4 Existing Fleet Retirements

Retirements for conventional power plants are taken from the ABB Velocity Suite database (ABB 2016), which use age-based retirements unless an official retirement date has been announced. All other generator types use strictly age-based retirement schedules.

The Accelerated Coal Retirements scenario reduces coal plant lifetimes by 10 years. The Extended Nuclear Lifetime scenario assumes all nuclear plants (except those with an announced retirement date) receive a second relicense that that gives them an 80-year life.

A.1.5 Vehicle Electrification

The Vehicle Electrification scenario assumes 40% of passenger vehicle sales are sales of electric vehicles in 2050. The charging profile was defined for this scenario such that 55% (energy-basis) was owner-controlled (static, evening-weighted) and the utility/model could control timing of the remaining 45%. Figure 30 shows the charging load atop the base load for 2050 in this scenario. (Note that the dynamic-charging portion has been assigned in this figure, based on the scenario outcome.) For details on how the charging demand and profiles were developed, see Appendix K of the Renewable Electricity Futures Study, Volume 3 (Hostick et al. 2012).

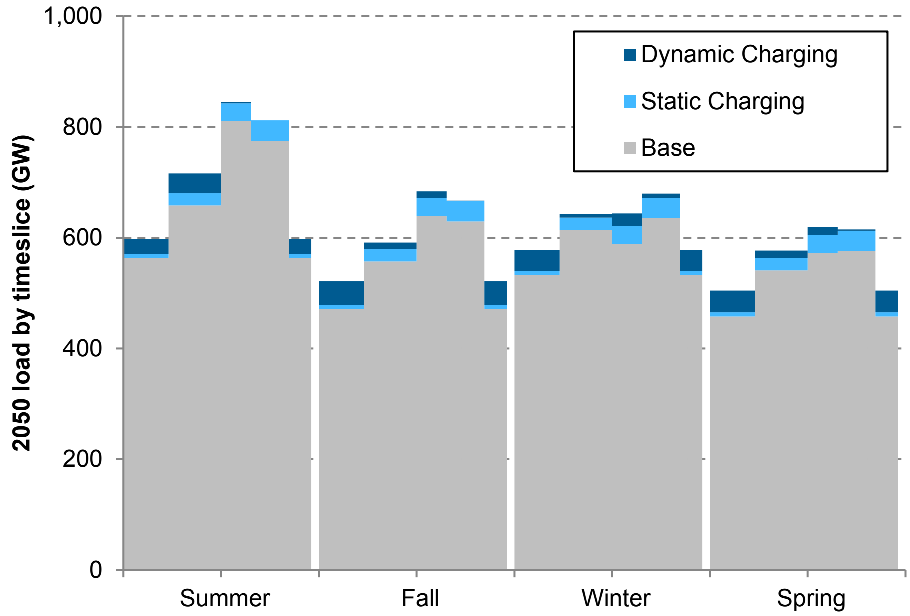

Figure 30. Electric vehicle charging demand under the Vehicle Electrification scenario. Each block represents the load adjustments for each ReEDS time slice.

A.1.6 Extended Incentives for Renewable Energy Generation

The Extended Incentives scenario assumes the PTC and ITC are extended through 2030 for utility-scale projects after the ramp-down periods occur (this scenario does not include an ITC extension for non-utility rooftop PV systems). The extensions used in this scenario are of the $23/MWh PTC for wind, geothermal, and biopower, the $11/MWh PTC for new hydropower, and the 30% ITC for solar, both to 2030—after which the ITC declines to 10% as planned. As the past program did, the PTC applies to the first 10 years of operation for new construction.

A.1.7 National Renewable Portfolio Standard

The 80% National RPS scenario presents a future with a nationwide RPS on electricity production. The assumed standard ramps from 1% in 2010 to 80% in 2050, with growth leveling off at that level. Eligible technologies include hydropower, wind, solar, geothermal, biopower (including any biomass cofired with coal), and landfill gas. The 80% RPS echoes scenarios in the Renewable Electricity Futures study (NREL 2012).

A.1.8 Power Sector CO_2 Cap

This Carbon Cap scenario implements a national electric-sector cap on direct CO_2 emissions based on a power-sector CO_2 reduction target of 30% below 2005 levels by 2020 and 83% below 2005 levels by 2050 (Figure 31). We assume the cap to be implemented via freely allocated credits, rather than auction, so there is no direct cost associated with emitting CO_2. However, complying with the cap does require the model to adjust its investment and operation decisions.

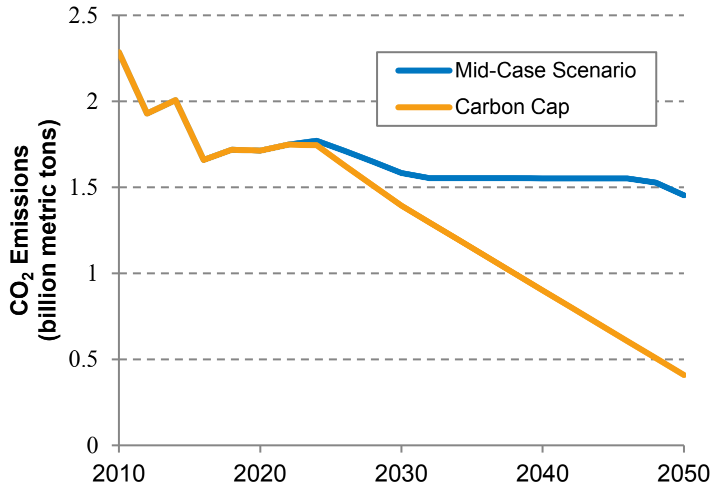

Figure 31. Comparison of prescribed electric sector CO_2 cap to the CO_2 emissions path in the Mid-case Scenario

A.1.9 Impacts of Climate Change

This impacts scenario, in contrast to the Carbon Cap scenario, applies no carbon signal, but instead adjusts demand and operating parameters in response to the shifting ambient temperature distribution of a changing climate. Climate influences demand for electricity services directly through adjusted space-conditioning needs, and ambient temperature can affect both power plant operation and transmission line carrying capacities. This scenario applies estimates for those effects based on a reference (business-as-usual) climate change scenario. The scenario assumes 3°C of warming per doubling of CO_2 emission from preindustrial levels. Total load increases by about 100 TWh by 2050 compared to the Mid-case Scenario (primarily during the summer afternoon hours), and power plant heat rates and transmission line carrying capacities are slightly derated to account for the higher ambient temperatures.

A.1.10 Reduced RE 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, concentrating solar power, geothermal, hydropower, and biopower technical potential by 25%. The reduction is applied uniformly across geography and resource classes. This scenario provides a sensitivity to estimates of technical potential for renewable energy resources.

A.1.11 Barriers to Transmission System Expansion

The ReEDS model assumes new transmission lines can be constructed as needed, at costs taken from the EIPC report (EIPC 2012) on regional transmission development. Those cost assumptions do include regional multipliers that imply higher siting and construction costs in certain regions, notably California and the Northeast. 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% per hundred miles to 2%. Renewable generator spur line costs are not affected. The higher rate of transmission losses is a general discouragement to relying on the transmission system to transmit power long distances.

A.1.12 Restrictions on Thermoelectric Water Use

In the Mid-case Scenario, power plants can obtain cooling water from freshwater resources made available when other power plants retire, unappropriated fresh surface water, potable groundwater, appropriated freshwater, wastewater, and brackish groundwater. The restricted cooling water scenario does not allow new power plants to use any type of freshwater as cooling water, leaving only wastewater and brackish groundwater as options. This scenario highlights the challenges of the water-energy nexus and provides insights into water availability challenges.

A.1.13 Nuclear Technology Breakthrough

This scenario explores a future in which nuclear fission-generating technologies have growing public support and 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.

A.2 Changes Since Last Year

Since last year's Standard Scenarios report, a variety of modeling changes have occurred in the ReEDS and dGen models. Many of these key changes are summarized in Table 2.

Table 2. Key Differences in Model Inputs and Treatments for Three Different Model Versions. The 2015 Standard Scenarios Version was used for the 2015 Standard Scenarios report (Sullivan et al. 2015), the 2016 Early Release Version was used by Mai et al. (2016), and this report uses the 2016 Version.

Key Differences	2015 Standard Scenarios Version (December 2014)	2016 Early Release Version (December 2015)	2016 Version (May 2016)
Fuel prices	AEO 2014	AEO 2015	AEO 2016
Demand growth	AEO 2014	AEO 2015	AEO 2016
RE technology cost and performance	ATB 2015	—	ATB 2016
Non-RE technology cost and performance	AEO 2014	AEO 2015	AEO 2016
Wind characterization	Higher quality resource only using 5 TRGs	—	All wind resources using 10 TRGs
Hydropower characterization	Resource potential from Wind Vision (DOE 2015)	—	Conventional and pumped hydroelectric storage resource from Hydropower Vision (DOE 2016), more technology types
Utility PV (UPV) and distributed utility PV	No resource limit, no interconnection costs,	Resource supply curve, 9 UPV/DUPV resource	Report PV capacity in AC units

Key Differences	2015 Standard Scenarios Version (December 2014)	2016 Early Release Version (December 2015)	2016 Version (May 2016)
(DUPV) characterization	local penetration limit for DUPV, DUPV allowed to serve local demand only	classes, updated performance (PVWatts 5), removed limits and flow restrictions for DUPV	
Rooftop projections	From SolarDS SunShot Vision 2012 scenarios (DOE 2012)	Modified with new tax extensions and dGen updates (Mai et al. 2016)	Updated ATB 2016 / AEO 2016 inputs in dGen, report PV capacity in AC units
Finance	50% debt fraction	Default 60% debt fraction, debt fraction varies by tax credit level (Mai et al. 2015)	—
Battery costs	EPRI Handbook	Battery life shortened to 15 years	—
State RPSs	Policies as of 2014	Policies as of January 2016	Policies as of March 2016 (CA and OR 50% RPS included), improved renewable energy credit trading and eligibility representation, RPS policies based on sales instead of consumption
Clean Power Plan (CPP)	No CPP	CPP final rules included	Added Clean Energy Incentive Program and allowance banking
Renewable energy tax credits	Policies as of 2014	Includes 2016 extensions and ramp-down	Modified PTC based on May 2016 Internal Revenue Service guidance
Regional greenhouse gas policies	California AB-32 carbon cap only	Regional Greenhouse Gas Initiative carbon cap added	—
Criteria Air Regulations	Modified EPA Clean Air Interstate Rule sulfur dioxide (SO_2) limits	Regional EPA Cross-State Air Pollution Rule SO_2 and nitrogen oxides (NO_x) caps, impacts of MATS modeled, updated emissions factors	—
Retirements	ABB Velocity Suite, December 2013	ABB Velocity Suite, September 2015	ABB Velocity Suite, April 2016
Prescribed builds	Under construction facilities from varied	Under construction units of all types from ABB Velocity Suite	ABB Velocity Suite, April 2016

Key Differences	2015 Standard Scenarios Version (December 2014)	2016 Early Release Version (December 2015)	2016 Version (May 2016)
	sources	(September 2015)	
Imports from Canada	National Energy Board Energy Futures 2013 Reference Scenario	—	National Energy Board Energy Futures 2016 Reference Scenario
Curtailments	$1/MWh cost of curtailed energy, no rooftop PV curtailment	Removed curtailment cost, allowed rooftop PV curtailment	Update storage curtailment reduction parameters
Historical coal/gas calibration	—	Added $8/MWh variable O&M to existing coal generation	—
Competitive electricity price	—	Added competitive electricity price output based on marginal values of load balance, reserve margin, and operating reserve constraints	—

Unlike last year's report on the Standard Scenarios (Sullivan et al. 2015), this year's report does not include a Renewable Energy Technology Improvement scenario based on the DOE's Office of Energy Efficiency and Renewable Energy program goals. The program goals continue to evolve at a timeline that is independent of this annual work.

Based on the model and input changes from Table 2, model outputs have also changed. Figure 32 summarizes some of the key changes from the 2015 Mid-case Scenario (previously called the Central Scenario) to the 2016 Mid-case Scenario. The lower natural gas prices in this year's Mid-case Scenario, coupled with the representation of the Clean Power Plan, are the primary drivers of the increased natural gas generation, decreased coal generation, and decreased emissions relative to last year's Mid-case Scenario. The effect of the ITC and PTC extension is also apparent in the near-term growth of renewable energy in this year's version relative to last year's version.

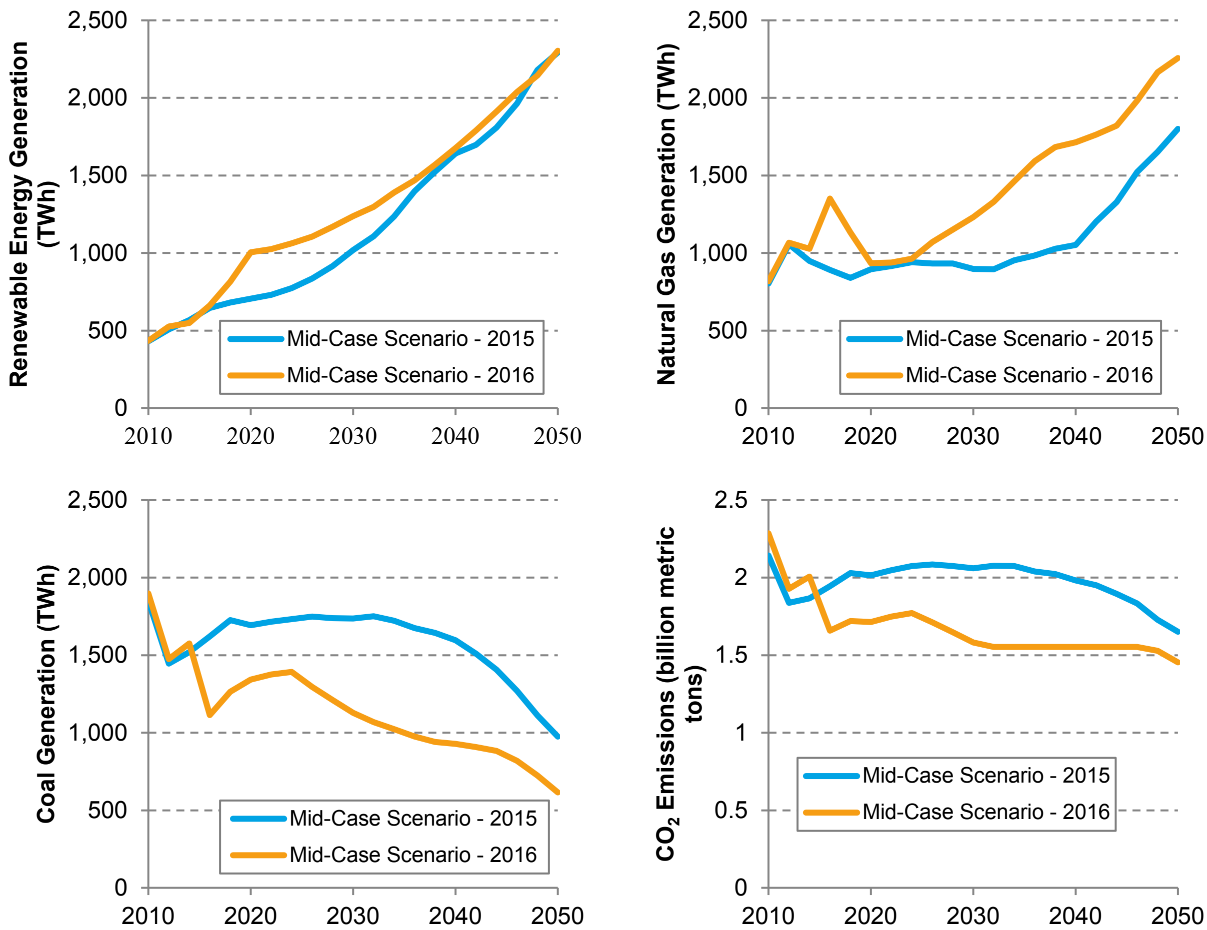

Figure 32. Summary of changes from the 2015 Mid-case Scenario to the 2016 Mid-case Scenario

A.3 Impact of Wind and Solar Cost Inputs

As discussed in Section 3.1, wind and solar PV costs have been declining rapidly, with forward-looking cost projections anticipating additional reductions. The mid-case cost projections applied in many of the scenarios in this work, which are from the 2016 ATB (NREL 2016), suggest a future in which the levelized cost of wind and PV overlap significantly (Figure 33). Given the relatively low penetration of PV in electricity markets today, the large amount of high quality resource, and the anticipated deployment of rooftop PV, capacity growth opportunities for PV are substantial even when its costs overlap significantly with wind power. In addition, because ReEDS is a least-cost optimization model, it is sensitive to the lowest-cost generation resource.[35] Robust growth in PV is projected to continue due in part because the lowest *subsidized*[36] LCOE

[35] Several factors other than LCOE come into play here, including the coincidence of generation and load, the ability to access transmission, the cost of addition transmission, the relative resource quality of wind and solar in areas with new capacity needs, and state-level policy incentives. These and other factors are represented within the ReEDS model.

[36] Utility and commercial PV systems continue to receive a 10% ITC after the ITC steps down in 2022. This 10% ITC does not currently have an expiration date.

for PV drops below the lowest LCOE for wind in the late 2020s. This condition is even more pronounced in the Low RE Cost scenario.

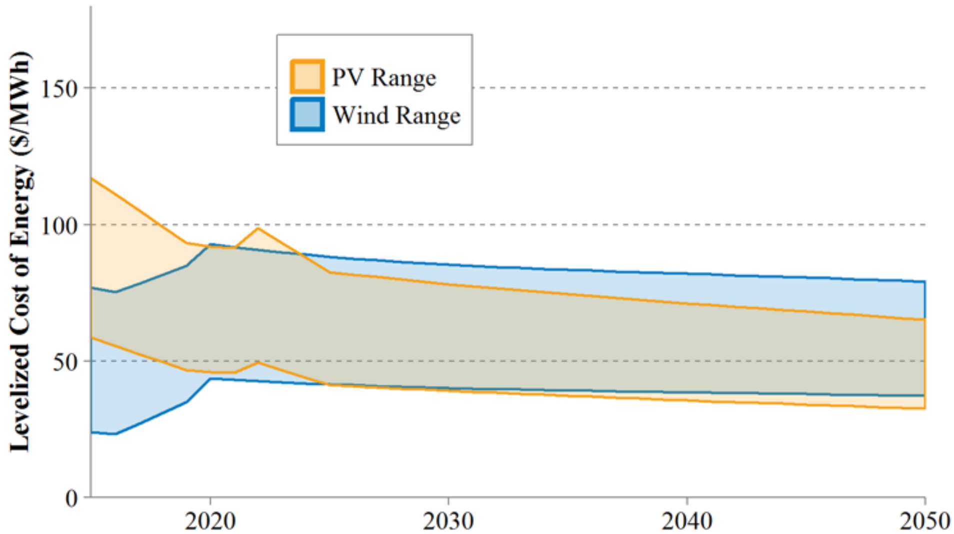

Figure 33. Subsidized levelized cost of energy for land-based wind and PV from 2015 to 2050. Cost and performance data are from the 2016 Annual Technology Baseline. The wind range does not include the lowest quality resource sites (TRGs 9 and 10).

Notwithstanding these dynamics under the 2016 ATB mid case, as noted in Text Box 1, Wiser et al. (2016) have conducted and recently published an elicitation of wind energy experts showing anticipated median cost reductions for wind power that are considerably lower than those in the 2016 ATB mid case (see Figure 34). If the median wind costs from Wiser et al. (2016) are used in place of the ATB mid case wind costs, the growth in wind and PV throughout the analysis period occurs more evenly than what was observed in the Mid-case Scenario (see Figure 34), even as total renewable generation remains relatively comparable in these two scenarios. Ultimately, the relative share of wind and PV is sensitive to the level of cost reduction anticipated for the two technologies as well as how the rest of the power sector evolves (see Mai, Lantz et al. (2016) for additional scenarios and discussion of this issue). The range of wind and PV generation across the bidirectional scenarios can be seen in Figure 35, demonstrating how the additional assumptions from the bidirectional scenarios can significantly alter wind PV generation.

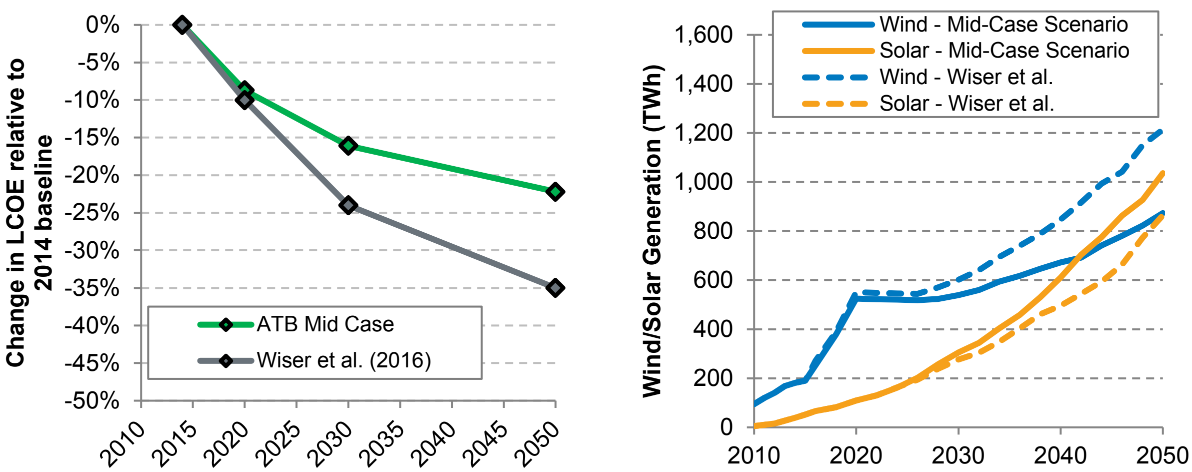

Figure 34. Impacts of wind cost reduction on wind and solar generation. The left figure shows projections for wind LCOE reductions through 2050 from the 2016 ATB mid case and the median elicitation results. The right figure shows the resulting wind and solar generation based on 2016 ATB mid case (Mid-case Scenario) and the median elicitation wind costs.

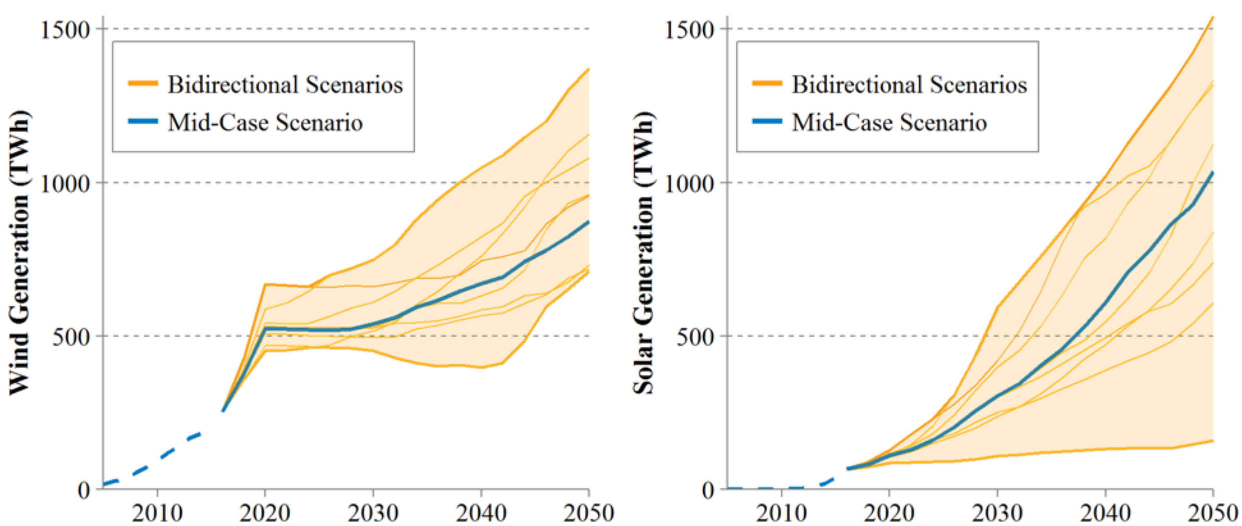

Figure 35. Wind and solar generation across the bidirectional scenarios.