Outlooks for Wind Power in the United States: Drivers and Trends under a 2016 Policy Environment

Trieu Mai, Eric Lantz, Jonathan Ho,
Tyler Stehly, and Donna Heimiller
National Renewable Energy Laboratory

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Nomenclature or List of Acronyms

AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
AWEA	American Wind Energy Association
CPP	Clean Power Plan
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
IPCC	Intergovernmental Panel on Climate Change
ITC	investment tax credit
LCOE	levelized cost of energy
NREL	National Renewable Energy Laboratory
PTC	production tax credit
RPS	renewable portfolio standard
TRG	techno-resource group

Executive Summary

Over the past decade, wind power has become one of the fastest growing sources of electricity generation in the United States. Cumulative wind capacity grew from about 9 gigawatts (GW) in 2005 to approximately 74 GW by year-end 2015. On a percent-of-total-generation basis, wind grew from 0.4% to 4.7% over this same period. This trend indicates a clear increasing role for wind; however, significant variability in historical annual wind installations has occurred with year-to-year fluctuations in wind deployment strongly correlated to changes in energy policies, particularly the wind production tax credit (PTC) policy. Notwithstanding significant possibilities for wind power, including the potential for over one-third of U.S. electricity to come from wind power as was considered by the DOE's *Wind Vision*, much uncertainty exists with respect to the future of wind power in the United States.

Today, the U.S. wind industry faces an unprecedented set of circumstances including a wind PTC that spans multiple years but with declining value over time. This policy coupled with recent wind technology advancements and the potential for even lower wind power prices paints a promising picture for the future of U.S. wind power. However, headwinds to future wind capacity deployment exist primarily from competition with natural gas generation, declining solar technology costs, and continued low or negative growth in electricity consumption from energy efficiency and a recovering economy.

Given this complex environment, we use a modeling and scenario analysis approach to develop multiple outlooks for U.S. wind power. In contrast to some prior work where we quantify scenario costs or benefits (e.g., DOE *Wind Vision*), the current analysis focuses only on economic deployment of wind power and associated carbon dioxide (CO_2) emissions for each defined scenario. We note that none of the scenarios modeled represents a prediction or forecast, but the scenarios are used collectively to identify drivers and trends related to future wind deployment. We focus on existing (as of June 2016) policies only. We acknowledge that this approach does not capture all possibilities and that the policy landscape can change rapidly. However, observations offered from today's policy perspective may be useful in informing future energy sector decision-making. Although we model the Clean Power Plan, we find that in certain scenarios it has little impact on the overall results. In nearly all scenarios, we find allowance prices to be less than about \$10–\$11/metric ton CO_2. In particular, we find zero or near-zero allowance prices in scenarios with low wind technology costs, low natural gas prices or a combination thereof, thereby suggesting that our wind deployment results are unlikely to be dramatically altered by uncertainty in the Clean Power Plan, under these conditions. More broadly, we find that estimated wind deployment in most scenarios has limited sensitivity to the inclusion of the policy through the formal policy window (2022–2030) and in the very long run (2050).

Key observations from our scenario analysis are as follows.

In the near-term (through 2020), substantial growth in new wind capacity development is estimated in all scenarios. This growth is estimated to match or exceed the record growth in new installations observed over the past few years and supports deployment levels consistent with the DOE *Wind Vision* through 2020. Near-term growth in wind capacity is driven by the strong economic case for wind when the PTC is available at its full value. With the PTC, the primary factors that could limit wind growth over the next five years include slowing electricity demand,

siting challenges, and supply chain constraints. On the other hand, economic competition from other generation sources is not expected to play a strong factor during this period.

In contrast to the consistent finding of significant near-term wind growth in all scenarios, estimated wind capacity deployment during the 2020s is decidedly mixed between scenarios. In many scenarios, annual wind installations in the 2020s are found to be limited. We find that with the reduction and expiration of the PTC, natural gas-fired generation and solar generation are the primary electricity sources used to meet new electricity demand during this period. In some of the most pessimistic scenarios for wind, very little or no new growth in wind capacity is found through this entire decade and possibly beyond. From an upstream wind industry perspective, this stagnant growth period may cause manufacturing supply chain contractions, loss of workforce and expertise, and movement of key wind industry components overseas. These actions could jeopardize the long-run potential of U.S. wind power.

At the same time, our analysis finds that continued reductions in wind power prices or rising natural gas prices can mitigate the reduction in annual wind deployment after 2020. Additionally, if wind deployment in the near-term is less robust than some of our scenarios suggest, possibly due to supply chain or siting considerations, we find that annual wind deployment trends might be more stable than anticipated. In fact, in a scenario that matches most closely with an aggregate collection of industry forecasts and predictions, we estimate that wind deployment in the 2020s—although lower than installations estimated over the next five years (2016-2020)—is estimated to average nearly 6 GW/yr with growing opportunities towards the end of the decade. This growth is driven, in part, by continued wind technology advancements to lower costs. In two scenarios where wind is most economically competitive (e.g., our lowest cost wind scenario and a scenario with combined low wind costs and high natural gas costs), we find wind to exceed the post-2020 trajectory set forth in the DOE *Wind Vision*.

After 2030, we find a wide range of possible wind deployment futures. Across all scenarios, estimated 2050 installed wind capacity spans a range of multiple hundreds of gigawatts. In our scenarios of the current policy environment, two factors play the largest role in determining this range: future natural gas prices and wind technology costs. Natural gas prices can be volatile and hard to predict, but gas prices remaining at historically low levels over multiple decades would pose a substantial economic challenge to achieving significant wind deployment in the long term. However, if gas prices rise above their current floor levels, the economic case for wind grows and large-scale wind deployment is estimated to follow. Wind research and development to lower wind costs is critical in determining whether sustained growth in wind energy will continue over the next several decades.

In summary, the opportunity for U.S. wind power is likely to be affected by wide-ranging market, technology, and policy factors. *Reducing wind technology costs with innovations that continue to enable higher hub heights and larger rotors in particular is a key mechanism to hedge against potential challenging future conditions*, including competition from other generation sources. Notwithstanding significant uncertainities, scenarios considered here suggest wind power can continue to play a significant role in the U.S. electricity system and support efforts to move towards cleaner electricity generation. At the same time, robust supporting research and development efforts aimed at driving down costs in the near and medium term may be critical for U.S. wind power to play an expanded role in the long run.

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1 Introduction

Over the past decade, wind power has grown from a niche contributor in the U.S. electricity sector to one of the fastest growing electricity generation sources. Figure 1 shows how installed wind capacity grew by a factor of eight between 2005 and 2015, rising from about 9 GW to 74 GW with over 100 GW in the interconnection queue and a significant amount of under construction projects (Wiser and Bolinger 2016; AWEA 2016). Wind generation has increased at an even faster rate, highlighting simultaneous improvements to wind plant performance particularly in the most recent years (Wiser and Bolinger 2016); nation-wide wind penetration grew from 0.4% of total U.S. utility-scale generation in 2005 to 4.7% in 2015 (EIA 2016). Significantly higher penetration levels have been observed in certain regions, including more than 23% of 2015 in-state generation in three states (Iowa, Kansas, and South Dakota).

The historical growth in wind power was spurred by a wide range of factors, including technology advancements such as taller towers and larger rotors (Zayas et al. 2015), associated lower costs (Wiser and Bolinger 2016), and clean energy policies such as state renewable portfolio standards (Barbose 2016) and the wind production tax credit (PTC). While the long-term trend in Figure 1 indicates a clear increasing role for wind, variability in annual installations has also been observed with fluctuations strongly correlated to changes in the PTC policy (Shrimali, Lynes, and Indvik 2015). These periodic sways in annual wind deployment have had a negative impact on manufacturers, the supply chains, and labor force[1] and they indicate an uncertain future for U.S. wind power.

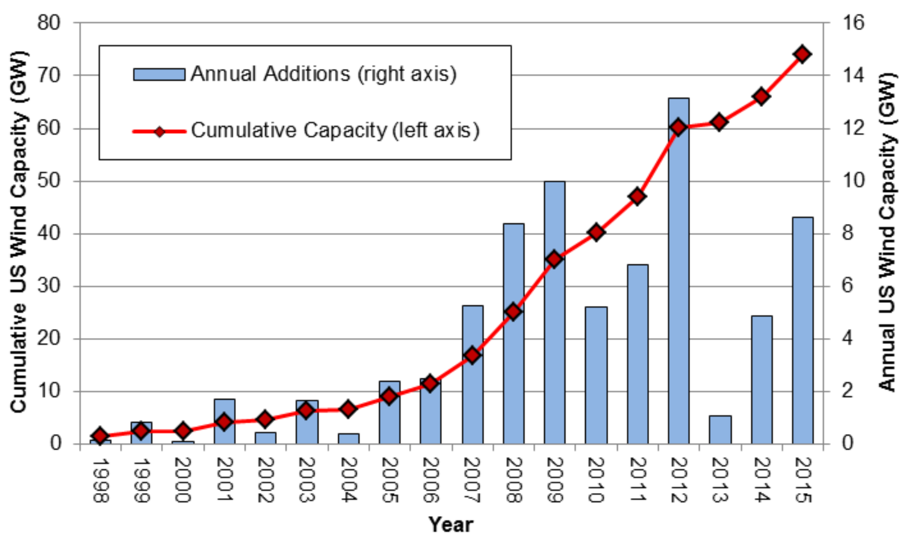

Figure 1. Historical wind installations in the United States

Data Source: *2015 Wind Technologies Market Report* (Wiser and Bolinger 2016) and *U.S. Wind Industry Annual Market Report Year Ending 2015* (AWEA 2016)

[1] The annual *Wind Technology Market Report* (e.g., Wiser and Bolinger 2016) provides details on wind industry manufacturing facilities, the industry labor force, and domestic content of wind-related equipment.

One key factor for wind power's outlook is the degree of technology advancements that have occurred amid a constantly changing market and policy environment. For example, the aforementioned historical growth in wind deployment followed a drop in the cost of wind energy—the nationwide generation-weighted average wind power purchase agreement price from $69/MWh in 2009 to $23/MWh in 2014 (Wiser and Bolinger 2016).[2] Future wind deployment will depend on how future prices evolve.[3] Of course, wind deployment depends on not only the cost of wind but also the cost of other generation technologies and fuels. In particular, whether or not natural gas prices remain at historically low levels will affect the competitiveness of wind. Similarly, the recent and anticipated decline in solar energy costs (Barbose and Dhargouth 2016; Bolinger and Seel 2016; NREL 2016) might lead to competition between these two low-carbon renewable energy sources. The rate of wind deployment will also depend on the need for new generation and capacity; therefore, wind's outlook can also be sensitive to growth in electricity consumption, energy efficiency investments, distributed generation adoption, and plant retirements. Finally, the future wind market share will be affected by the ability to expand transmission lines to access remote high-quality wind resource sites as well as the ability of utilities and system operators to economically integrate wind energy.

Energy policies are also expected to continue to impact the future U.S. wind industry. Three policies that have significantly influenced wind development in the past or have the potential to affect future wind capacity include state renewable portfolio standards, federal production tax credits, and the U.S. Environmental Protection Agency Clean Power Plan (CPP), which is intended to regulate power sector carbon emissions.

- **State Renewable Portfolio Standards:** In 2016, 29 states and the District of Columbia have mandatory renewable portfolio standards (RPS) targets, and RPS policies apply to 55% of total retail electricity sales (Barbose 2016). Historically, wind has been the primary renewable energy source used to comply with many state targets, and RPS demand for renewable energy is estimated to double from 2015 to 2030. Nonetheless, RPS-driven wind additions are not assured as some existing RPS targets reach their terminal levels, efforts to roll back RPS policies exist in multiple states, and as other renewable energy resources (e.g. solar) are relied on for compliance to a greater extent. On the other hand, multiple RPS extensions have recently been enacted or are being considered.[4]
- **Federal Renewable Tax Credits:** The federal wind production tax credit (PTC) was first enacted in 1992, and it has historically played a significant role in supporting wind energy. Since then, the PTC has been modified numerous times, and these changes have significantly affected annual wind capacity additions (Figure 1). Most recently, in December 2015, the PTC was extended through 2019, but with the value of the incentive reducing annually from 2016 to 2019. However, the recent PTC extension includes an

[2] These prices include the PTC in most cases.
[3] Prices of power purchase agreements can vary significantly between projects and regions. Average power purchase agreement prices can also vary between years with 2015 generation-average levelized power purchase agreements reaching nearly $40/MWh but dropping to below $20/MWh for a small number of samples in 2016 (Wiser and Bolinger 2016).
[4] RPS extensions since June 2016 include those in New York, Oregon, Rhode Island, and the District of Columbia. Our analysis includes the Oregon extension but excludes the others.

"under construction" provision allowing projects to qualify for the PTC based on when construction commences and not on the commercial operation date.[5] Mai et al. (2016) explored the impacts of the recent tax credit extensions on future wind and other renewable energy deployment through 2030 using the same modeling framework as that used in this analysis. It, along with other analysis of tax credit extensions (Larsen et al. 2016, Lantz et al. 2014), suggest the PTC can help spur significant deployment in the near term but can result in an abrupt drop off in wind deployment as the PTC ramps down or expires. The extent and duration of this post-PTC period of stagnant wind growth raises concerns that the wind industry could contract and limit the ability to deploy wind in the longer term.

- **Clean Power Plan:** The CPP sets individual power sector carbon emissions targets for 47 states for all years between 2022 and 2030.[6] The EPA allows states a broad amount of flexibility in terms of their approach for compliance with the regulation. Options for state CPP compliance include mass-based approaches (carbon cap and trade programs) and carbon rate-based approaches (emissions performance standards). States can also choose to cooperate with other states through allowance trade or credit trade. However, significant uncertainties exist for the CPP, including from legal challenges to the new regulation. The U.S. Supreme Court has issued a stay on—but did not overturn—the rule.

Previous studies have shown that wind energy can make significant contributions to the U.S. electricity sector. The U.S. Department of Energy (DOE) *Wind Vision* study evaluated scenarios where wind served 10% of electricity consumption in 2020, 20% in 2030, and 35% in 2050 (DOE 2015), and it found significant potential economic, environmental, and public health benefits in such a scenario compared to one without any future wind deployment. Although we take a modified approach and focus only on wind deployment and CO_2 emissions, our analysis builds significantly from the scenario analysis conducted for the *Wind Vision* study.[7] In addition, the Renewable Electricity Futures Study by the National Renewable Energy Laboratory (NREL) found wind to be the primary renewable energy source used to meet the 80% renewable penetration level in 2050 that was the focus of the study (NREL 2012; Mai, Mulcahey et al. 2014). MacDonald et al. (2016) also examined scenarios with significant increases in wind and solar deployment, with an associated high-voltage transmission network expansion, to achieve deep reductions in carbon emissions. Using more-detailed grid simulations, multiple wind integration studies (e.g., GE Energy 2010; EnerNex 2011; Lew et al. 2012; Bloom et al. 2016) have highlighted the feasibility of integrating large amounts of wind and how wider geographic distribution in wind deployment can help ease this integration (Bloom et al. 2016; Bird, Milligan, and Lew 2013). This large body of work demonstrates the possibilities for large-scale wind

[5] The tax credit extensions also include extensions to the investment tax credit (ITC), which is primarily used to support solar technologies. An ITC is also available (in lieu of the PTC) for certain PTC-eligible technologies, including offshore wind projects. For offshore wind, the ITC would start at 30% for projects under construction by December 31, 2016, and it would ramp down by six percentage points annually through December 31, 2019. PTCs and ITCs for other renewable energy technologies are also included in the latest bill and are modeled in ReEDS, which was used for this analysis.

[6] The EPA does not specify targets for Alaska, Hawaii, or Vermont.

[7] Key differences between our analysis and the Wind Vision study include our more up-to-date policy representation and market outlooks. Unlike in the primary Wind Vision scenario, we do not prescribe any specific wind penetration levels. In fact, our assessment can be used to assess the conditions that might be needed to realize the wind penetration levels posited in the Wind Vision as opposed to assessing the impacts of achieving high wind penetrations.

penetration in the United States and the associated impacts to the electric system, the environment, and public health. However, they generally reflect end-point analyses and do not fully consider the market drivers behind or barriers against significant wind deployment.

In this report, we introduce multiple outlooks of the future of wind energy in the United States and we use these diverse scenarios to identify key drivers and trends. Specifically, we use high-resolution wind resource data and electric sector modeling to develop outlooks of future wind capacity deployment and assess the key driver for wind installations over multiple periods through 2050. The outlooks presented herein are based on the current (2016) policy environment only. We acknowledge that energy policies will assuredly change over the next 35 years, but the specific changes are unknown and restrict our assessment to existing policies only. We also estimate power sector carbon dioxide (CO_2) emissions under the range of modeled futures. Finally, we identify the potential role of wind for future policy compliance and how wind technology advancements might help lower compliance costs.

Our analysis highlights scenario results for the contiguous United States only. Select regional results, particularly focusing on the deployment potential for tall wind technologies, are presented in a companion report by Lantz, Mai, and Mowers (forthcoming) titled *Tall Wind Innovation and Potential Futures for U.S. Wind Power*. Our report and this companion report share common methodologies, assumptions, and scenarios.

The report is organized as follows. Section 2 summarizes our modeling methodology, scenario framework, and key assumptions. Additional data tables of wind cost assumptions are provided in the appendix. Section 3 describes the scenario analysis results, focusing on wind deployment, wind generation, CO_2 emissions, and estimated CO_2 allowance prices. We summarize our findings in Section 4.

2 Methods, Scenarios, and Assumptions

For this analysis, we apply a scenario analysis approach using the NREL Regional Energy Deployment System (ReEDS) model. The scenarios are designed to capture a small and specific, but important, range of possible future market conditions related to wind technology costs, natural gas prices, transmission expansion, and CO_2 allowance trading options. This section identifies the core model used, describes the scenario framework, and summarizes the key assumptions. The cited references provide details on the methods and assumptions.

2.1 Regional Energy Deployment System Model

The ReEDS model is a capacity expansion model of the electricity system in the contiguous United States. More specifically, it includes an optimization algorithm that generates scenarios for electric sector infrastructure—generation, transmission, and storage—and dispatch through 2050. The model is designed with high spatial resolution and statistical approaches to address many of the unique characteristics of wind and other renewable energy technologies, including regional resource limits, variations in resource quality and electricity consumption, and temporal variability and uncertainty. The primary outputs of the model include capacity and generation by technology type over time, transmission expansion, CO_2 and other air emissions, and system costs. In this report, we present the aggregate ReEDS results for the contiguous United States.

The companion report—Lantz, Mai, and Mowers (forthcoming)—highlights some of the subnational results.

ReEDS model details can be found in the model documentations (Eurek et al. 2016; Short et al. 2011). We use the 2016 final release version of ReEDS (v2016FR) for this analysis, which is consistent with the version used in the 2016 Standard Scenarios report (Cole et al. 2016). ReEDS has been the primary analytic tool used for scenario analyses focused on wind energy (Tegen et al. 2016; Lantz et al. 2016; Wiser et al. 2015; DOE 2015; DOE 2008), other renewable energy technologies (DOE 2016; Wiser, Millstein et al. 2016; Cole, Lewis et al. 2016; Mai, Hand et al. 2014; DOE 2012; NREL 2012), natural gas (Cole, Beppler et al. 2016; Logan et al. 2013), energy policies (Mai et al. 2016; Cole et al. 2015; Lantz et al. 2014; Mignone et al. 2012; Rausch and Mowers 2014), and other related topics.[8]

2.2 Scenario Framework

Table 1 lists the 16 scenarios included in our analysis and the key assumptions that are varied between each. The variations cover four primary areas: (1) future wind technology cost and performance, (2) natural gas prices, (3) CO_2 allowance trading, and (4) transmission expansion. In addition, we design four scenarios (Scenarios 13–16 in Table 1) to assess the conditions that might impact annual renewable deployment in the period after the PTC ramp-down. These include scenarios that vary the rate of wind cost declines from those assumed in the Reference scenario and scenarios that limit the wind deployment rate between 2017 and 2020 to reflect potential constraints that the ReEDS model imperfectly captures. The results and context behind each scenario is provided in Section 3.

All other assumptions not mentioned in Table 1 follow the reference scenario from NREL's 2016 Standard Scenarios report (Cole et al. 2016), which relies heavily on data assumptions from the Annual Energy Outlook (AEO) 2016 Reference case (EIA 2016) and the Annual Technology Baseline (ATB) 2016 Mid case (NREL 2016). For example, demand growth modeled in all 16 scenarios is consistent with the electricity consumption growth from the AEO 2016 Reference case and non-wind technologies—including solar, other renewable energy, and fossil technologies—cost projections are consistent with those from the Annual Technology (ATB) 2016 Mid case. Although wind deployment can be impacted by many of these factors and significant uncertainties exist, we do not model sensitivities for all possible market conditions.[9] Nonetheless, we do capture a wide range of futures across multiple areas, indicated in Table 1, that likely impact national or regional wind deployment. Sections 2.3–2.6 describe the assumptions within these areas in detail.

[8] More information about ReEDS, including related publications can be found at www.nrel.gov/analysis/reeds.
[9] The 2016 Standard Scenarios (Cole et al. forthcoming) includes a broader set of sensitivities than those modeled here.

Table 1. Summary of Scenarios

Scenario	Wind Cost	Natural Gas Price	CPP	Transmission	Wind Growth Limit
1. Reference	ATB 2016 Mid	AEO 2016 Reference	Mass-based, Full trade	Default	None
2. Reference-LowNGCost	*	AEO 2016 High O&G	*	*	*
3. Reference-HighNGCost	*	AEO 2016 Low O&G	*	*	*
4. Reference-NoTrade	*	*	Mass-based, No trade	*	*
5. Reference-NoTx	*	*	*	No post-2020 long-distance transmission	*
6. Reference-NoTrade-NoTx	*	*	Mass-based, No trade	No post-2020 long-distance transmission	*
7. LowWindCost	ATB 2016 Low	*	*	*	*
8. LowWindCost-LowNGCost	ATB 2016 Low	AEO 2016 High O&G	*	*	*
9. LowWindCost-HighNGCost	ATB 2016 Low	AEO 2016 Low O&G	*	*	*
10. LowWindCost-NoTrade	ATB 2016 Low	*	Mass-based, No trade	*	*
11. LowWindCost-NoTx	ATB 2016 Low	*	*	No post-2020 long-distance transmission	*
12. LowWindCost-NoTrade-NoTx	ATB 2016 Low	*	Mass-based, No trade	No post-2020 long-distance transmission	*
13. 20%LowerWindCost	20% lower in 2025	*	*	*	*
14. 40%LowerWindCost	40% lower in 2025	*	*	*	*
15. Reference-Delay	*	*	*	*	12.5 GW/yr wind cap, 2017–2020
16. LowWindCost-Delay	ATB 2016 Low	*	*	*	12.5 GW/yr wind cap, 2017–2020

Asterisks (*) denote the same assumptions from the Reference scenario.
O&G = Oil and Gas

2.3 Wind Resource, Cost, and Performance

Most of the scenarios rely on two primary wind technology cost and performance projections; the ATB 2016 Mid case is used in the reference family of scenarios and the ATB 2016 Low wind cost case is used in the Low Wind Cost family of scenarios. In the ATB 2016 Mid case, the levelized cost of energy (LCOE) for land-based wind[10] is assumed to decline by 16% from estimated 2014 LCOEs by 2030 and 22% by 2050. In contrast, land-based wind LCOEs decline to 33% and 37% from 2014 values by 2030 and 2050 respectively, under the ATB 2016 Low Cost projection.[11] For comparison, median anticipated LCOE reductions from a recent expert elicitation survey of 163 wind experts (Wiser, Jenni et al. 2016) were found to be 24% (below 2014 levels) by 2030 and 35% by 2050. The appendix provides the data breakdown for cost and performance for the two primary wind cost projects we use.

In addition to these two sets of wind technology cost and performance projections, two scenarios (20% Lower Wind Cost and 40% Lower Wind Cost) include variations from the ATB 2016 Mid projections. In these two cases, we follow the wind costs from the ATB 2016 Mid case through 2020, but we then apply further reductions such that the 2025 wind LCOE is 20% lower in one scenario and 40% lower in the other. Linear interpolations (in the amount of LCOE reduction from ATB 2016 Mid) are used between 2020 and 2025. For all years after 2025, we follow cost reduction trajectories that are parallel to the ATB 2016 Mid case. LCOE reductions are assumed primarily through capital cost reductions (i.e., wind capacity factor assumptions are the same in these two cases as in the reference scenarios). We develop these two wind technology cost projections for this analysis to understand the implications of the timing of cost improvements. A rationale for the assumed delayed timing of cost improvements is the focus on rapid deployment to capture the current PTC with a significant technology advancements following R&D and learning from this deployment. To be clear, unlike the ATB projections, we do not base them on a top-down literature assessment, nor do we ground them in a bottom-up engineering assessment.

Aside from differences in timing of cost reductions, the long-term cost reductions projected under the 20% Lower Wind Cost case largely match those from the ATB 2016 Low case. In contrast, the 40% Lower Wind Cost case achieves significantly lower wind costs than all other cases. Specifically, wind LCOEs in this case are 50% below 2014 levels by 2030 and 53% below by 2050. Although the cost reduction assumptions are significantly greater than those used in the other scenarios, they are—at least in the long term—aligned with the "low scenario" anticipated by experts surveyed in Wiser, Jenni et al. (2016).[12] They also serve to illustrate the level and timing of cost reduction required to achieve future wind deployment comparable to that in the *Wind Vision* "Central Study Scenario." Notably, scenarios using this more-aggressive (40% Lower Wind Cost) reduction trajectory result in wind deployment estimates that are in line with or exceed deployment found in the primary *Wind Vision* scenarios (DOE 2015).

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[10] Assumptions for offshore wind technologies can be found in the 2016 Annual Technology Baseline (NREL 2106). Our analysis focuses primarily on land-based wind. Offshore wind is modeled in ReEDS but, under the assumptions used, only small amounts of offshore wind are found in any of the scenarios.

[11] These estimated wind cost reduction trajectories are largely consistent with those used in the Wind Vision Study (DOE 2015). Specifically, the ATB 2016 Mid and Low cases are nearly identical to the Wind Vision "Central Wind Cost" and "Low Wind Cost" cases, respectively.

[12] The "low scenario" from Wiser, Jenni et al. (2016) included 44% lower land-based wind LCOEs (from 2014 levels) by 2030 and 53% by 2050.

Figure 2 (left) shows the LCOE reductions (from 2014 values) assumed in all four wind cost projections used. LCOE reductions in all cases are applied uniformly across all wind techno-resource groups (TRGs);[13] however, the extent to which reductions are realized through lower capital costs or improved energy production vary between TRGs and wind projection cases. For example, LCOE reductions in the higher TRGs (i.e., those with lower resource quality) are primarily driven by improved capacity factors such as through taller towers or larger rotors but with little change in capital costs.[14]

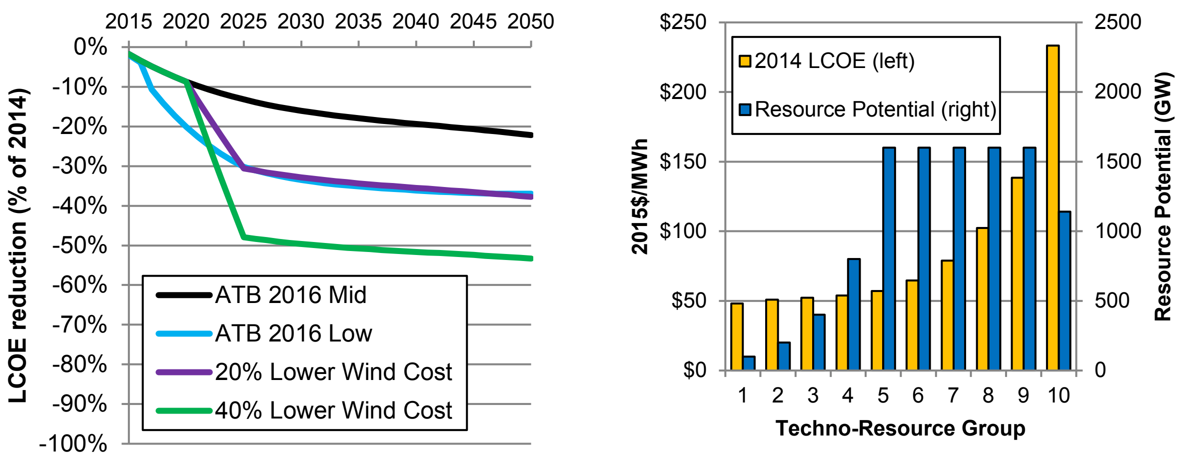

Figure 2. Wind LCOE reductions for all modeled sensitivities (left) and 2014 LCOE and resource potential for all techno-resource groups (right)

LCOEs for 2014 are calculated using ReEDS default financing assumptions and do not include the PTC. ATB 2016 Mid and ATB 2016 Low LCOE projections are largely consistent with wind technology assumptions in the "Central Wind Cost" and "Low Wind Cost" projections, respectively, from the *Wind Vision* Study (DOE 2015).

Ten TRGs are used in the ReEDS model to capture the range of wind resource quality and technologies that could be developed in different resource regions. Figure 2(right) shows the average 2014 LCOE and the nationwide technical resource potential for each TRG. To define the TRGs, we sort the high-resolution wind resource (by LCOE) and group them such that higher model resolution is applied to the lower-cost resource groups; the lowest-cost 100 GW are in TRG 1, the next 200 GW are placed in TRG 2, and the other TRGs are defined as shown in Figure 2(right). In total across all TRGs, the modeled resource potential for land-based wind is 10,640 GW.[15]

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[13] TRGs are ReEDS model groupings of different wind resources and wind technologies. TRGs reflect different wind resource types and, implicitly in the cost and performance assumptions, turbine and tower technology configurations. See DOE (2015) and Eurek et al. (2016) for details.
[14] The companion to this report by Lantz, Mai, and Mowers (forthcoming) provides details and motivation for tall wind.
[15] This resource potential is estimated after NREL standard exclusions (Lopez et al. 2012) are applied. Our analysis uses the same wind dataset, developed by AWSTruepower, as in the Wind Vision study (DOE 2015) but here we include all wind resource sites whereas in the Wind Vision, the lowest wind capacity factor regions were not included as input for the ReEDS modeling.

Although Figure 2 shows the *national* TRG resource potential distribution, *regional* distributions can vary substantially (Lantz, Mai, and Mowers forthcoming). Our model representation enables us to capture these regional differences in the deployment decisions. In addition, we also model regional variations in energy demand, policies, and quality of non-wind resources. We apply regional multipliers for all new capital infrastructure, including for the cost of new wind capacity, to capture variations in land costs, labor rates, and permitting costs. (DOE 2015).

2.4 Natural Gas Prices

Natural gas price assumptions are based on three scenarios from the AEO 2016 (Figure 3). Most scenarios, including the Reference scenario, rely on the natural gas prices from the AEO 2016 Reference case. As shown in Figure 3, delivered natural gas prices in this case start at historically low levels in 2015, near $3 per million British thermal unit (MMBtu), grow to about $5.50/MMBtu in the mid-2020s, and stay at approximately those levels through 2040. Prices in the Low Oil & Gas (O&G) Resource case, which is used in our High NG Cost scenarios, grow more rapidly and for longer; natural gas prices exceed $9/MMBtu by 2040 in this case. In contrast, under the High O&G Resource case (Low NG cost), natural gas prices remain below $4/MMBtu for all years between 2015 and 2040.

Figure 3 shows the natural gas prices directly from the AEO 2016 cases; however, ReEDS includes regional and national supply curves for gas to model the elasticity between natural gas prices and electric sector natural gas consumption. Thus, natural gas prices, while grounded in the AEO data, vary between scenarios and regions. For scenarios within the same base set of natural gas input assumptions—i.e., scenarios relying on one of the AEO Reference, Low O&G Resource, or High O&G Resource cases—these differences are typically much smaller in magnitude than the differences across the base natural gas resource assumptions shown in Figure 3.

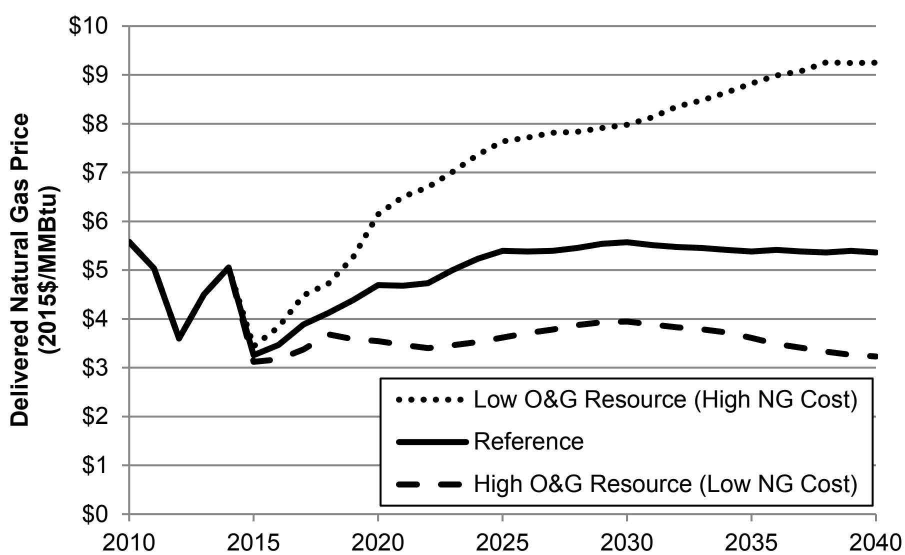

Figure 3. U.S. average natural gas prices from AEO 2016 cases

2.5 Policy Representation

In all scenarios, we include policies and regulations as of June 2016. These include state renewable portfolio standards (RPS), federal renewable tax credit extensions, and the Clean Power Plan. Significant legislative activity surrounding RPS policies has occurred in multiple states. For example, since June 2016, three states (New York, Oregon, and Rhode Island) and the District of Columbia have revised their RPS policies.[16] Eurek et al. (2016) describes the RPS representation in ReEDS, which includes a representation of renewable energy credit trading that is intended to represent legislated trading rules and historical practices.

Federal renewable tax credits, including the wind PTC and the solar investment tax credit (ITC), are modeled in ReEDS. Under the recent extensions, new wind installations or those that start construction in 2016 and are completed by 2020 can qualify for the full PTC, which is valued at 2.3 cents/kWh for energy production over the first 10 years of the plant life. The PTC ramps down to 80% of this full value in 2017, 60% in 2018, and 40% in 2019, and it expires thereafter. Our representation of the PTC and ITC, including the "commenced-construction" provision, is described in Mai et al. (2016).[17] Our tax credit representation also includes some, but not all, of the impacts of tax credits on project financing (Bolinger 2014; Mai et al. 2015). In particular, we assume a shift away from equity toward lower-cost debt financing as the PTC ramps down or expires.

We include the CPP in all scenarios[18] but acknowledge that there are significant uncertainties for the future of the carbon regulation. For example, there are ongoing legal challenges and the U.S. Supreme Court has issued a stay on the rule, although it did not overturn it. We note that, as described in the following sections, in some of our scenarios—particularly those with low natural gas costs and/or more-aggressive wind technology advancements—the CPP has no or little effect on wind deployment results. For this analysis, we assume in all scenarios that compliance with the CPP is achieved through a mass-based approach with the new source complement targets in all states. For all years after 2030, we maintain the mass targets at the 2030 levels. For most scenarios, we include allowance trading between all states. In a subset of the scenarios that we refer to as "No Trade" scenarios, we restrict all interstate allowance trading. Of course, other compliance scenarios are possible, but this approach provides a straightforward and transparent representation of the policy and it captures a range of possible outcomes.

[16] We include the recent RPS revision in Oregon in our analysis but not the Rhode Island, New York, and District of Columbia revisions.

[17] Motivated by recent guidance from the Internal Revenue Service (IRS 2016) that allows for a longer construction period for qualifying facilities, we adjust the model treatment of the PTC in ReEDS from that described in Mai et al. (2016) by allowing an effective three-year construction period instead of a two-year period. The IRS guidance allows for a four-year safe harbor; however, given that the construction period for most plants has been two years or less, we conservatively assumed three years in our PTC representation. It is unknown how the easing of the commenced-construction requirements might impact wind plant development schedules. It is possible that the longer four-year period and PTC ramp-down will reduce the steep reduction in annual wind deployment compared to what is shown by our scenario results.

[18] The companion report by Lantz, Mai, and Mowers (forthcoming) presents a set of scenarios without the CPP.

2.6 Transmission Representation

ReEDS co-optimizes transmission expansion with new generation expansion. The costs of new transmission lines needed to interconnect new wind and solar facilities are included in the ReEDS decision-making and are directly tied with the capital costs for new wind and solar capacity. The costs for these typically short-distance spur lines depend on region and TRG (DOE 2015). Expansion of long distance inter-regional transmission lines is also modeled in ReEDS. Unlike the spur lines, long-distance transmission expansion is not directly tied (in the ReEDS decision-making) to new renewable energy capacity, but it is instead modeled as part of the system-wide decision.

Given the long siting and construction periods needed for long-distance transmission lines, the default representation in ReEDS restricts new transmission expansion before 2020 to only known projects that are already under development. After 2020 and under the default model representation, inter-regional transmission expansion between neighboring model regions is an endogenous model decision based on assumed costs.[19] Most scenarios in our analysis rely on this default representation; however, in the scenarios referred to as "No Tx," we do not allow new *inter*-regional long-distance transmission after 2020. These scenarios represent an extreme bounding case for future transmission infrastructure only. In these sensitivities, we make no change from the default to the wind- or renewable project-specific spur line transmission costs.

2.7 Key Caveats and Limitations

As with any modeling analysis, our research includes several simplifications and assumptions. In this section, we note some of the key caveats and limitations resulting from these simplifications.

- **Limited Outlooks:** We do not model the entire possible parameter space of future technology and market conditions, which are highly uncertain and unpredictable. We do model a plausible range of conditions as described in Section 2.2.
- **Current Policies Only:** All scenarios include model representations of policies as of June 2016 only. Changes to energy policies are likely over the long-term horizon of our analysis.
- **Model Decision-Making:** The decision-making from ReEDS is from a system-wide perspective; the model does not take an agent-based approach to represent individual decision makers. ReEDS is also a least-cost optimization model and, therefore does not model non-economic decisions. Finally, ReEDS is a deterministic model and does not fully reflect real distributions or uncertainties in the parameters; however, the heterogeneity resulting from the high spatial resolution of ReEDS mitigates this to some degree and for some parameters, as do the multitude and range of scenarios modeled.
- **Demand for Wind:** Wind deployment can be sensitive to the cost competitiveness of wind and, importantly, the demand for new wind generation. In its economic decision-making, ReEDS implicitly considers the need for new generation and capacity but does not deploy new wind beyond these needs. For example, voluntary markets or corporate procurement of wind—that may or not be economic to the corporation—are not fully

[19] Transmission cost assumptions and a list of under construction projects in ReEDS are provided in the Wind Vision study (DOE 2015).

considered by the model. For this reason, all else being equal, ReEDS may underestimate wind deployment for certain market segments in its scenarios.

- **Deployment Rates:** The rate of deployment of wind, and other technologies, can be impacted by the current project pipeline and difficult-to-model manufacturing, supply chain, and siting considerations. As a result, ReEDS may overestimate the rate of wind deployment, particularly in the near-term when there is more-limited time to alleviate some potential deployment bottlenecks and when the PTC supports a cost-competitive environment for new wind.[20] On the other hand, we do not endogenously model technology learning in this analysis, which, all else being equal, would yield lower technology costs if successful near-term rapid deployment were achieved.[21]

While we acknowledge the above limitations in our approach and in other approaches that rely on similar modeling tools, ReEDS modeling enables us to consider complex interactions between different technology options and market conditions that would be difficult to consider rigorously. Any individual scenario is admittedly and undoubtedly limited in its accuracy, but the self-consistent modeling approach is designed to unveil key drivers of U.S. wind deployment and major trends in the future electricity system.

3 Scenario Results

In this section, we present select results from the modeled scenarios. We focus first on wind deployment, then on non-wind generation, electric sector CO_2 emissions, and CO_2 allowance prices. We do not present results exhaustively for all 16 scenarios, but we instead select those that are most relevant for our focus as described in Section 1. In particular, we present results in aggregate for all 48 contiguous U.S. states only. The companion report—Lantz, Mai, and Mowers (forthcoming)—presents regional results from a subset of these same scenarios.

3.1 Cumulative Wind Capacity Trends

By year-end 2015, installed wind capacity in the United States totaled about 74 GW. The vast majority of that capacity was deployed over the prior 10 years (see Figure 1), including a record year of 13 GW in 2012. However, significant variations in year-to-year wind installations existed during this period, including a drop to only about 1 GW of installed wind capacity in 2013. These annual variations correlate strongly with policy changes, particularly PTC expirations and extensions. Here, we present future wind capacity estimates in the modeled scenarios, including cumulative installed capacity and annual rates of wind deployment to assess the plausibility of continued growth, identify the drivers that might influence this growth, and raise some of the key considerations around deployment-driven stability for the U.S. wind industry.

Absent new energy policies, future wind deployment is likely to be most affected by the extent to which technology costs improve and how these improvements might influence the cost

[20] We model growth cost penalties in ReEDS for all major generation technologies, including wind. These include additional escalating capital cost multipliers when deployment in one year significantly exceeds the deployment in the prior year. Although these penalties are modeled to represent siting, supply chain, and similar impacts that might slow the rate of deployment, the penalties are not based on empirical data and may be insufficient to reduce annual deployment rates below what might be accomplishable.

[21] The wind technology cost and performance data used in all scenarios include some level of technology improvement and, therefore, imply some learning already. The amount of learning, however, is not modeled as correlated with deployment.

competitiveness of wind with alternative electricity sources. This is supported by our scenarios, where the greatest variations in future wind deployment are found between scenarios with different wind technology cost assumptions and between scenarios with different natural gas price assumptions.[22] Figures 4 shows future wind capacity estimated in four scenarios with different wind costs under the central natural gas price assumptions. Figure 5 shows the same across a range of natural gas sensitivities under our reference wind cost (left), and under low wind cost assumptions (right). For comparison, deployment data from the *Wind Vision* "Central Study Scenario" are included.

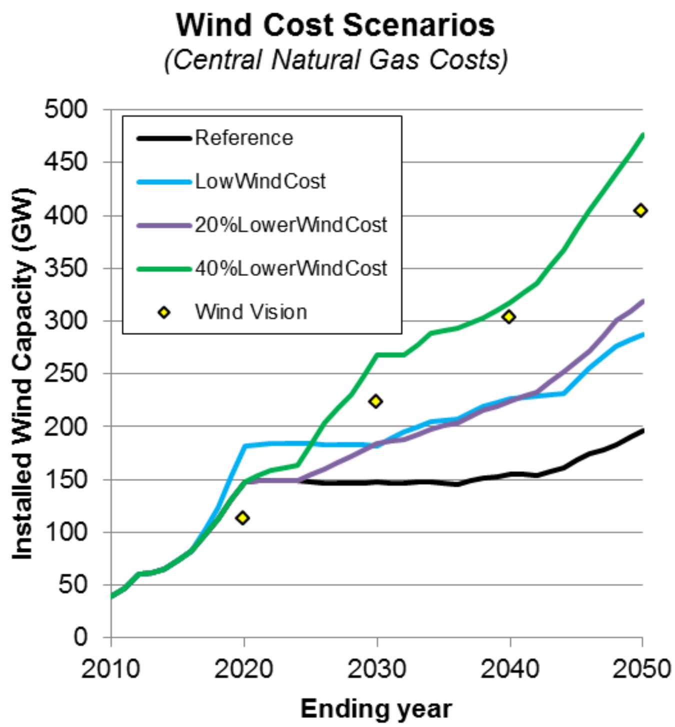

Figure 4. Installed wind capacity over time with different wind technology cost under central natural gas cost assumptions

Total installed wind capacity from the "Central Study Scenario" of the *Wind Vision* study (DOE 2015) is shown for comparison.

[22] Future costs of other technologies, particularly solar technologies, could also play an impactful role in determining future wind energy in the presence or absence of low carbon or clean energy policies, but we do not evaluate solar technology cost sensitivities in this analysis.

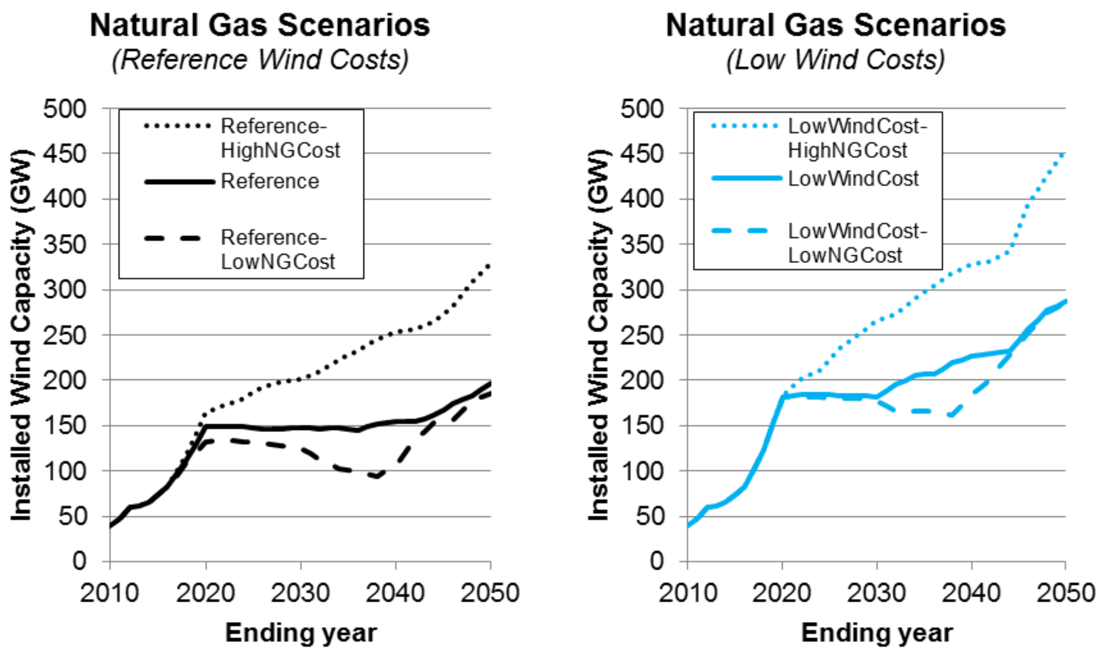

Figure 5. Installed wind capacity over time under a range of natural gas price assumptions, and under reference (left) and low wind cost assumptions (right)

Supported by the PTC, near-term wind deployment is estimated to exceed historical growth rates in all scenarios shown in Figures 4 and 5. Across all these scenarios, total installed wind capacity is estimated to range from 133 GW to 183 GW by year-end 2020, which reflects roughly a doubling of the 2015 wind fleet over the next five years. While this relative growth is substantial, it has a precedent; installed wind capacity more than doubled, albeit from a smaller starting base, over a six-year period from 2009 to 2015. It is worth noting that given the larger 2015 base, doubling current wind capacity over this time frame will likely require multiple years of record-breaking annual wind installations. Whether this doubling can be repeated will likely depend on difficult-to-model manufacturing capacity supply chain expansion and siting considerations. However, the rapid near-term growth in wind capacity projected in all scenarios suggest that with the PTC, wind energy costs are lower than or competitive with other new capacity and potentially even with the variable costs of some incumbent generators.

In the longer term, estimated wind capacity diverges significantly between scenarios. For example, 2050 wind capacity is estimated to reach 196 GW in the Reference scenario compared to 287 GW and 477 GW in the Low Wind Cost and 40% Lower Wind Cost scenarios respectively. This wide range—spanning multiple hundreds of GW of wind capacity—suggests that wind research and development to lower wind costs may be critical in determining whether sustained growth in wind energy will continue over the next three decades.

Figure 5 highlights the important role that future natural gas prices play for the future of U.S. wind. For example, with high natural gas prices, 2050 wind capacity is estimated to be 133 GW higher with reference wind costs (329 GW vs. 196 GW) and 168 GW higher with low wind costs (455 GW vs. 287 GW). Lower natural gas prices are estimated to have a lesser impact in 2050,

but as shown in Figure 5, low gas prices could result in declining wind capacity (through wind retirements[23]) from 2020 to 2040.

To put these deployment results in context, we compare our estimates with those from the *Wind Vision* study (DOE 2015). The *Wind Vision* study was a "comprehensive analysis to evaluate the future pathways for the wind industry," and it posited a high-wind future where wind energy served 10% of U.S. electricity demand in 2020, 20% in 2030, and 35% in 2050. To reach these penetration levels, the *Wind Vision* estimated that, under its central assumptions, 113 GW of installed wind would be needed by 2020, 224 GW by 2030, and 404 GW by 2050. Figure 4 shows how these *Wind Vision* deployment levels compare with the wind capacity estimates provided herein. In all scenarios modeled in our study, wind deployment exceeds the 2020 *Wind Vision* capacity estimate. The recent PTC extensions, which were not enacted when the *Wind Vision* analysis was conducted, play a significant role in this exceedance. In contrast, in nearly all scenarios, installed wind capacity after 2030 is estimated to fall short of the capacity from the *Wind Vision* central study scenario. This result suggests that under most conditions modeled new policies and regulations enacted or announced since the *Wind Vision* study (e.g., the PTC extensions) are insufficient to achieve the wind capacity levels found in the *Wind Vision*. An exception to this is the 40% Lower Wind Cost scenario, which shows installed wind capacity exceeding the *Wind Vision* levels in all years (Figure 4). This demonstrates how lower wind cost reductions (at about 50% below 2014 levels by 2030) may be needed to achieve the deployment levels posited under the *Wind Vision*. This result relies on natural gas prices remaining at historically low levels for multiple decades. We also find that the *Wind Vision* deployment levels can be achieved or exceeded with less-optimistic wind cost reductions if natural gas prices increase (Figure 5, LowWindCost-HighNGCost scenario).

In the above, we focus on scenarios with variations in wind technology cost and natural gas prices only. We also model other scenarios that vary our representation of allowance trading for the CPP and of transmission expansion. Estimated installed wind capacity in each of the other scenarios is well within the range of results presented above. In other words, wind technology costs and natural gas prices appear to be more-significant determinants of future wind deployment than the allowance trading and transmission expansion variations modeled. However, these other factors can play a larger factor in certain regions as is discussed in Lantz, Mai, and Mowers (forthcoming). Figure 6 shows the range of national wind capacity totals estimated for scenarios with variations in transmission and variations allowance trading under reference (left) and low (right) wind cost assumptions. A comparison of these ranges with the ranges from Figures 4 and 5 demonstrates the significantly greater impact that wind technology costs and natural gas prices can have on national future wind deployment. While the ranges are smaller in these scenarios, the deployment results, particularly in the Low Wind Cost scenarios, suggest lesser amounts of wind capacity will be installed without long-distance transmission expansion. On the other hand, a more-restrictive representation of the CPP (through compliance scenarios without allowance trading) might yield greater amounts of wind deployment.

[23] We assume a 24-year life for all wind plants. After 24 years, the wind capacity is assumed retired, but it can be repowered (during that year or in subsequent years) with the full capital costs in that future year and with any improved capacity factors assumed for that site. In addition, any interconnection costs that might be needed for a green-field site are not incurred with repowering; transmission infrastructure is assumed to be operational well beyond the generator lifetime. Due to its rarity, much uncertainty remains around actual repowering costs and therefore future repowering costs and considerations.

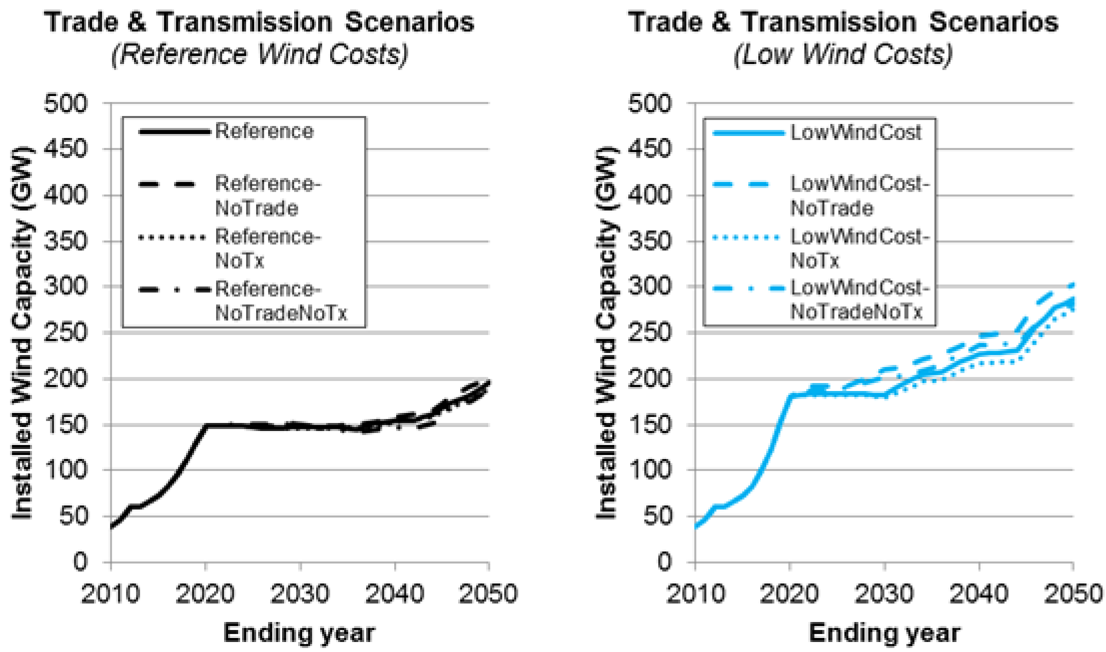

Figure 6. Installed wind capacity over time with different allowance trading and transmission expansion assumptions under reference (left) and low (right) wind cost assumptions.

3.2 Annual Wind Capacity Installations

In many of the scenarios shown in Figures 4 and 5, installed wind capacity flattens after 2020 for multiple years and, in some cases, for nearly two decades. To better understand this post-PTC period of stagnant wind growth, we examine the annual wind installation scenario results. Figure 7 shows annual wind installations historically (2001–2015) and for the Reference scenario through 2050. Two different metrics are shown: (1) the "annual net change" referring to the difference in installed capacity (from Figure 4) from one year to the next and (2) "annual new turbines" referring to the total capacity of new turbines installed in that year when including repowered capacity and new capacity on green-field sites. Note that the "net changes" in capacity can be negative, as wind turbines retire but "new turbine" capacity must be equal to or greater than zero. We focus on the latter metric, as it more directly applies to many aspects of the wind industry, including manufacturing and supply chain demands.

Figure 7 shows the rapid rate of wind deployment through 2020 in the Reference scenario, including an annual new turbine average rate of 15 GW/yr (during 2016–2020) and a peak rate of nearly 18 GW/yr during 2019 and 2020. This period, however, is followed by a 10-year period of stagnant new turbine demand; from 2021 to 2030, annual new turbines average less than 1 GW/yr, with peak years (2029 and 2030) of less than 3 GW/yr. From 2031 to 2050, new turbine installations exceed 5 GW/yr for nearly all years. In this long-term period, our results indicate that repowered capacity becomes the dominant share of new turbine demands in the Reference.

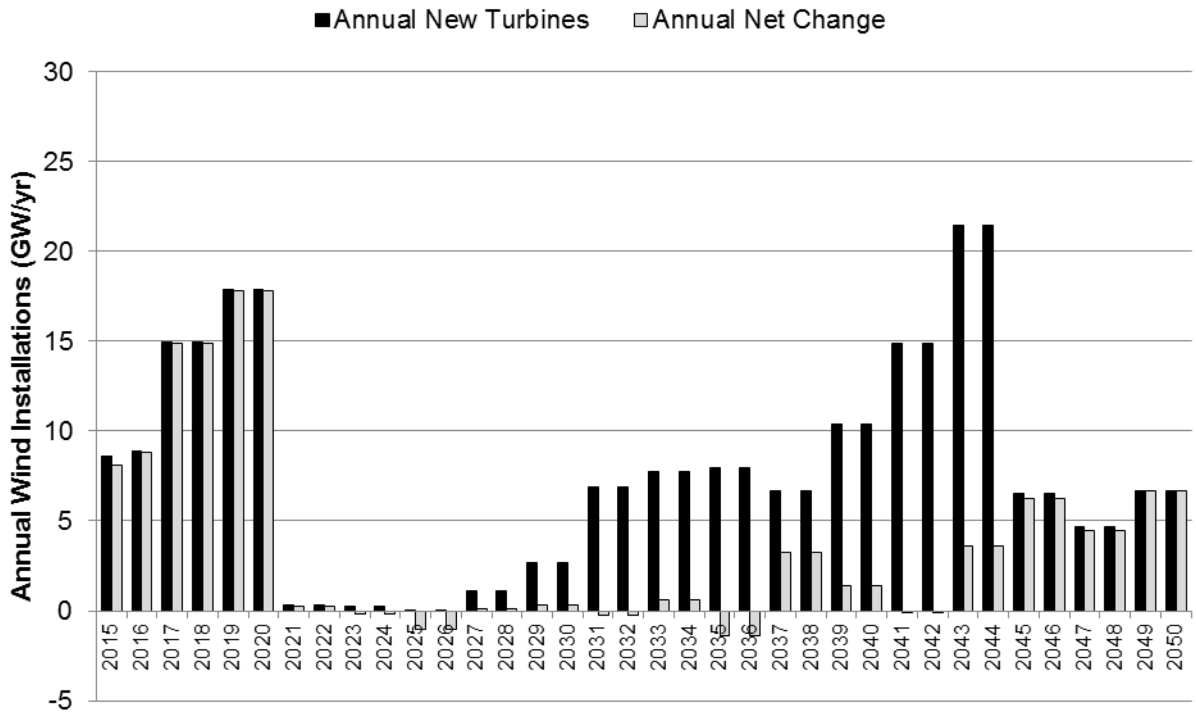

Figure 7. Annual wind capacity installations in the Reference scenario

From a wind industry perspective, the limited amount of wind capacity deployment over multiple years as found in the Reference scenario may cause factory closures, contractions in the wind supply chain, loss of workforce and expertise, movement of key industry components overseas, and other potential concerns that may have ripple effects for the future of U.S. wind. Nonetheless, while the Reference scenario projects a decade-long post-PTC period of stagnant growth, several factors can result in a different outcome with more-stable wind deployment. We discuss five factors below.

3.2.1 Wind Technology Costs

First, the Reference scenario potentially relies on overly pessimistic assumptions about future wind technology costs.[24] Figure 8 shows a comparison of estimated annual wind installations in the Reference scenario with three alternative scenarios with lower wind technology cost assumptions (see also Section 2.3). We focus only on annual new turbine capacity over 2016–2030 for this comparison. In the Low Wind Cost scenario, where the cost of wind energy is assumed to be lower than in the Reference scenario for all years (see Section 2.3), we find significantly greater wind deployment in the near term, with nearly 30 GW/yr of new wind capacity installed during 2019 and 2020. But for 10 years following that period, new wind capacity is similarly limited as in the Reference scenario, averaging 1 GW/yr.[25] While the cost of wind energy is lower in the Low Wind Cost scenario, the similarly lengthy period of stagnant

[24] Of course, the reference may also be too optimistic, in which case, the period of low wind deployment may be even more severe.
[25] After 2030, noticeably greater wind installations are estimated in the Low Wind Cost scenario than in the Reference scenario, as shown by Figure 4.

wind growth suggests that reducing wind energy costs may not be sufficient to avoid industry stagnation and that there may not be much demand for new wind capacity in the 2020s.

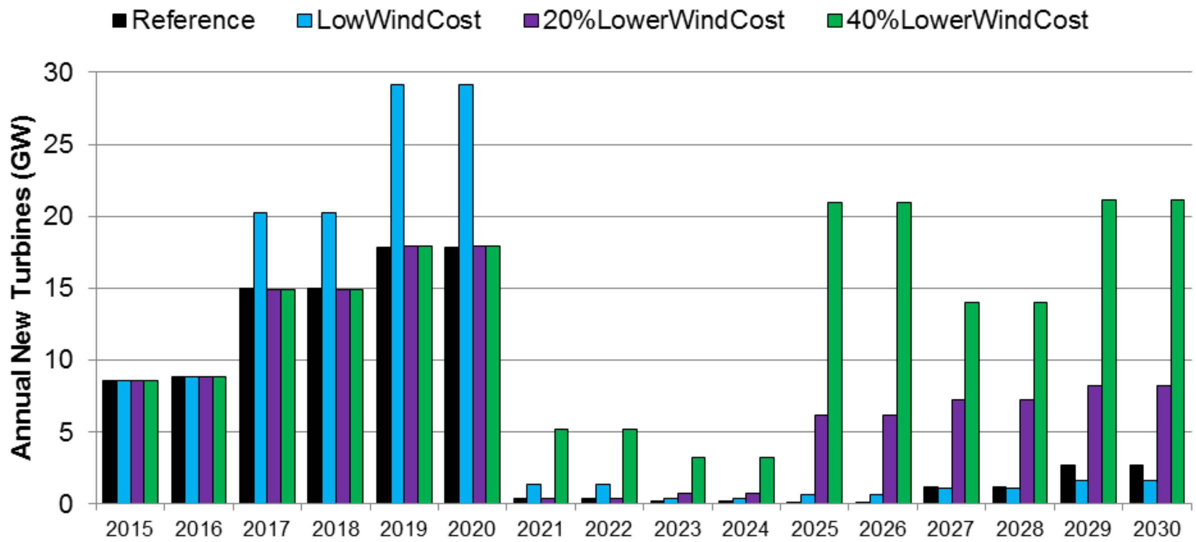

Figure 8. Annual wind capacity installations across wind technology cost sensitivities

One possible cause for the lack of demand during this period is the over-supply of wind capacity installed prior to 2021. In other words, the large growth in wind installations during 2017–2020 might reduce or eliminate the future need for any new generation to meet growth in electricity sales or to meet renewable or low carbon generation goals (e.g., to satisfy RPS requirements). To evaluate the extent that this near-term wind deployment is reducing annual wind deployment beyond 2020, we use two sensitivity scenarios that rely on the same wind cost assumptions as in the Reference scenario through 2020 (thereby resulting in the same deployment trends through 2020), but with greater wind cost reductions after 2020. Specifically, in one scenario, we assume wind energy costs are 20% below the Reference scenario by 2025 and 40% below in another (see Section 2.3). As shown in Figure 8, with these delayed wind cost reductions, the stagnant wind growth period could shrink dramatically. These delayed cost reductions could reflect a near-term focus on deployment while the PTC is available with cost reductions through technology innovation trailing behind. Applying an arbitrary cutoff of 5 GW/yr, we find that the stagnant period persists for only four years in the 20%-below case and to two years under the 40%-below period. The 40%-below period also reduces the severity during the two years and, not surprisingly, shows much greater wind growth from 2025 on.

3.2.2 Supply Chain and Siting Sensitivities

Supply chain- and/or siting- related deployment delays represent the second factor that might yield more-stable wind growth than our Reference scenario results (Figure 7) suggest. While our assessment suggests that with the PTC, wind energy is among one of the lower-cost resources, wind deployment over the next five years could be limited not by economic competition but also by supply chain or other deployment constraints. In other words, the modeled scenarios in Figure 8 may be over-estimating PTC-driven deployment in the near-term, as some of this near-term capacity could be delayed and instead built after 2020. To test this, we model a Reference-Delay scenario that is identical to the Reference scenario except annual deployment from 2017 to 2020

is limited to 12.5 GW/yr, which is similar to the record historical deployment in 2012.An analogous "Delay" is modeled for the Low Wind Cost scenario. Figure 9 compares the annual new turbine capacity in the Reference and Low Wind Cost scenarios with their "Delay" counterparts. The results indicate that slower wind deployment in the near term would result in reduced severity and duration of a stagnant wind growth period in the 2020s; however, multiple years of low wind capacity installations still remain, particularly with reference wind cost assumptions.

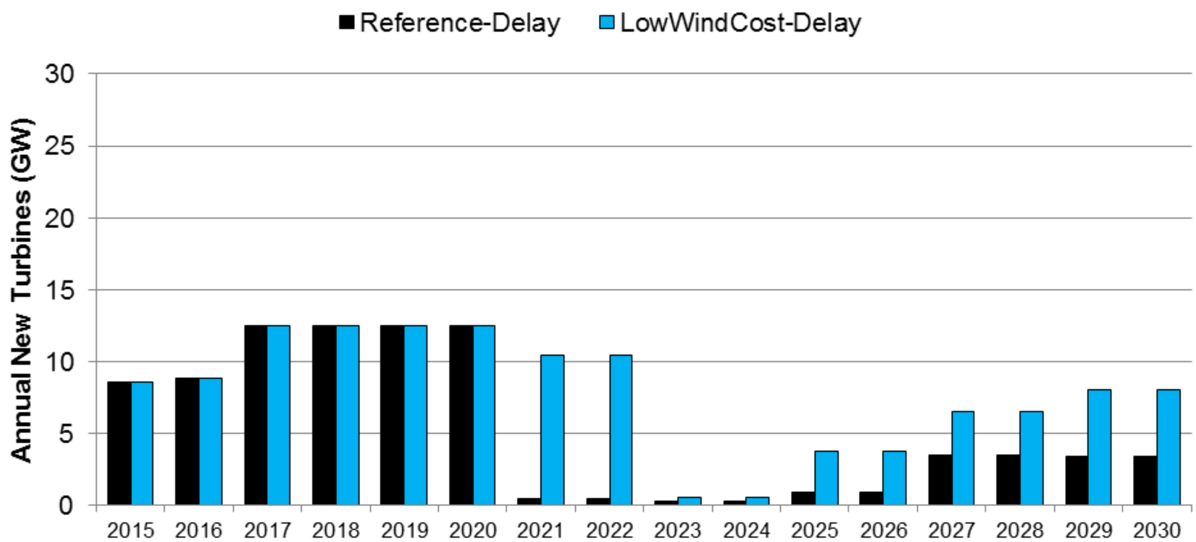

Figure 9. Annual wind capacity installations in supply chain sensitivities

3.2.3 Natural Gas Prices

Higher natural gas prices or other more-favorable market conditions for wind deployment in the 2020s could lead to more stable wind growth during this period. Figure 10 shows annual wind installations in the Reference and Low Wind Cost scenarios using higher natural gas price assumptions. Not surprisingly, greater wind deployment—during and after the PTC period—is found when natural gas prices are higher than assumed in the central scenarios. Although significant variations in wind annual installations remain in these cases, including a very large reduction in annual wind deployment immediately after 2020, a higher level of wind deployment is found throughout the 2020s. With higher natural gas costs, annual wind deployment exceeds 3.5 GW/yr in all years with reference wind costs and over 5 GW/yr with low wind costs.

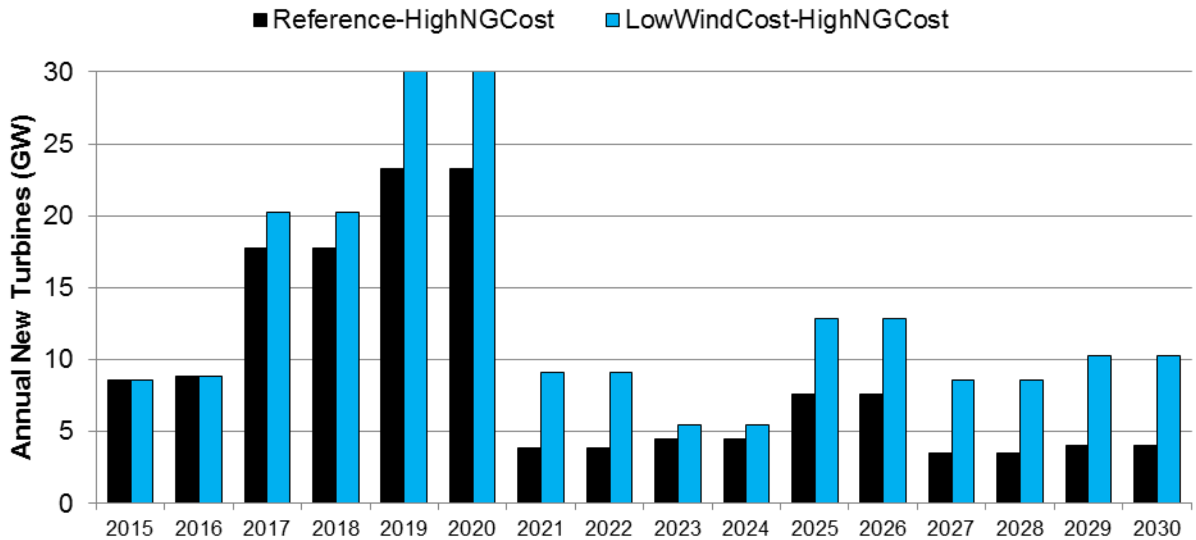

Figure 10. Annual wind capacity installations in high natural gas cost sensitivities

3.2.4 New Energy Policies

New energy policies might be implemented and spur greater adoption of low carbon, renewable, or wind technologies during the 2020s. These could include further extensions to the tax credits, new RPSs, or more-stringent regional or national carbon policies. The converse is also possible with the possible repeal of clean energy policies and regulations. The companion to this report—Lantz, Mai, and Mowers (forthcoming)—explores scenarios without the CPP. Given the large number of possibilities and the speculative nature of projecting new policies, we do not model any potential new policies in our analysis.

3.2.5 Demand for Wind Power

A fifth factor that might help mitigate the post-tax credit period of stagnant wind growth relates to expansion of new markets for wind energy that currently do not exist or that are not well-modeled. For example, expansion of voluntary markets for green energy or corporate demand for wind (O'Shaughnessy et al. 2015; Miller et al. 2015) could help spur wind capacity additions beyond those estimated above during the 2020s. In addition, increased electricity demand such as through greater economic activity or through electrification of other energy end-uses (e.g., electric vehicle adoption) could lead to a more consistent rate of wind capacity additions. We do not model these potentially important factors in our analysis.

3.2.6 Comparison with Other Forecasts and Projections

Although our scenarios do not represent forecasts or predictions, it is useful to compare our modeled projections with those from other sources. Figure 11 shows how the annual wind capacity additions in the Low Wind Cost Delay scenario compare with forecasts and projections by others. This scenario was chosen because it most closely aligns with the industry forecasts. In addition, it relies on a wind cost trajectory that roughly aligns with cost reductions estimated by Wiser, Jenni et al. (2016), which, to our knowledge, is the most recent and most robust expert elicitation survey of wind costs to date. Furthermore, it applies a cap on near-term wind deployment to reduce some of the model representation challenges with respect to the wind

supply chain and siting (Section 3.2.2). We do not assign or estimate a specific likelihood to any of our scenarios, but because of these reasons, the Low Wind Cost Delay scenario is used for this comparison. In the Appendix, we include figures that compare the average annual wind capacity additions across all 16 scenarios we modeled, and the additions from the Reference scenario, with the same forecasts and projections by others.

Figure 11 shows how the Low Wind Cost Delay scenario results are *qualitatively* consistent with the industry forecasts of robust growth in wind capacity through 2020 and are immediately followed by a decline in annual installations. This suggests (1) our finding that wind is economically competitive when the PTC is at its full value matches others' expectations and (2) there may be economic challenges to wind deployment after the PTC expires or ramps down. *Quantitatively*, our results are higher than most industry projections through 2020 and lower after 2020. Comparing our results over a 10-year projection period (2016–2025), our scenario estimates are close to industry expectations: 8.5 GW/yr compared with 6–8 GW/yr. Figure 11 also shows how after 2025, wind capacity additions begin to grow in the Low Wind Cost Delay scenario. Between 2021 and 2030, annual wind capacity additions average 5.9 GW/yr. The growth during this period falls short of capacity growth envisioned in the *Wind Vision* study (DOE 2015) but highlights the opportunities for wind during the 2020s if wind technology advancements can support lower costs after the expiration of the PTC.

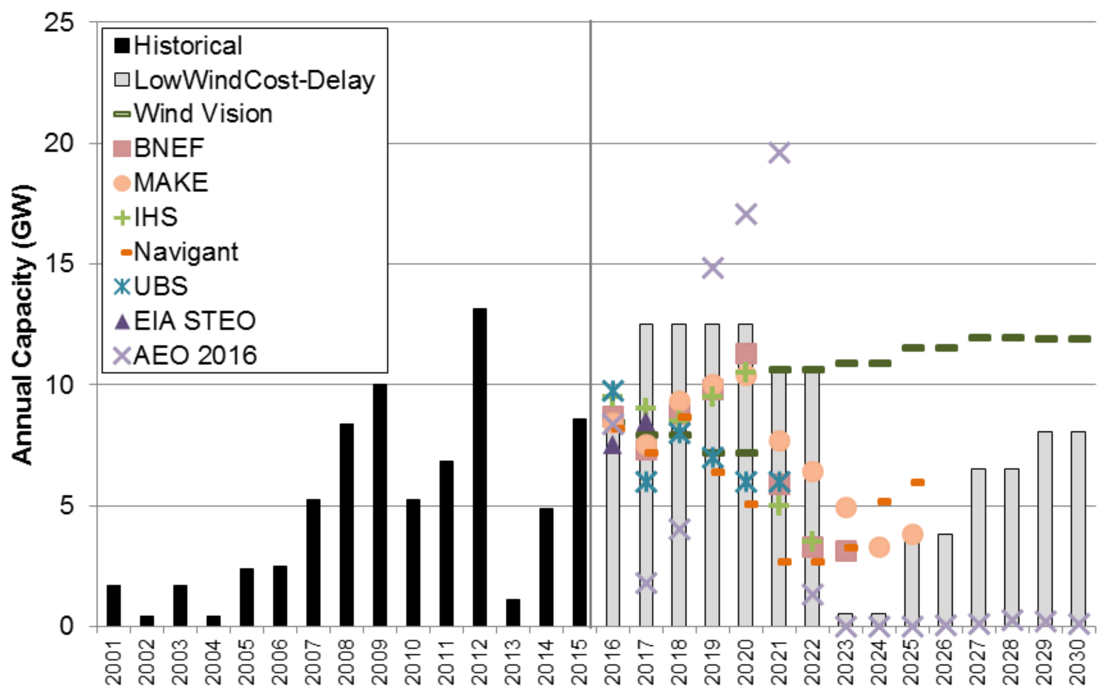

Figure 11. Comparison of projected and forecasted wind additions with the *average* annual additions across all modeled scenarios

Data for the forecasts from BNEF, MAKE, IHS, Navigant, UBS, and EIA STEO are taken directly from Wiser and Bolinger (2016). Data from the AEO 2016 Reference (EIA 2016) and *Wind Vision* study scenarios (DOE 2015) are also shown. Note that forecasts and projections were made at different times using different methods and assumptions; some of these forecasts may have since been updated.

3.3 Electric System Evolution

Wind is only one of multiple energy sources relied on by the U.S. electricity system. Figure 12 shows the installed capacity and annual generation mix in this system and how it might evolve over time under the Reference scenario.

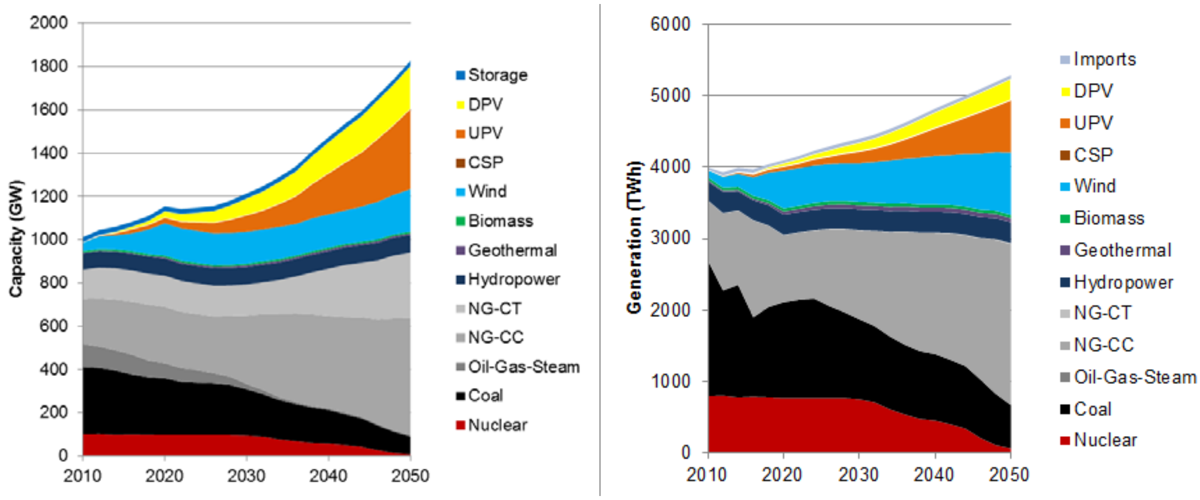

Figure 12. Installed capacity (left) and annual generation expansion in the Reference scenario

CSP = concentrating solar power, DPV= distributed photovoltaic, NG-CC = Natural Gas—Combined Cycle, NG-CT = natural gas–combustion turbines, UPV = utility photovoltaic, Imports = imported electricity from Canada

In the Reference scenario, growth in wind generation is estimated to outpace the growth in electricity demand, increasing from about 4.7% of total U.S. utility-scale generation (EIA 2016) to 12% in 2030 and 16.5% in 2050. The Reference scenario also projects other recent growth trends continuing over the long term, including increases in natural gas and solar generation. Natural gas and solar generation are estimated to be 43% and 20% respectively in 2050. The growth of these three energy sources—wind, solar, and natural gas—offset estimated declines in coal and nuclear generation and meet increases in electricity consumption. Other sources of generation are estimated to remain relatively flat over the study period.

As in the wind deployment results presented in Section 3.1, estimated generation by technology type also varies significantly between scenarios. Because deployment is observed primarily for only three technology types—wind, solar, and natural gas—the tradeoffs in annual generation are found to be largely between these same technologies as well as with coal generation from existing coal plants. For example, Figure 13 shows the difference in annual generation between the Low Wind Cost and Reference scenarios, wherein positive values indicate greater generation in the Low Wind Cost scenario. For most years, greater wind generation found in the Low Wind Cost scenario comes at the expense of natural gas and solar generation in the Reference scenario. Wind generation is estimated to reach 15.5% in 2030 and 25% in 2050 in the Low Wind Cost scenario.

Through the early 2020s, the greater wind generation in the Low Wind Cost scenario also helps reduce coal generation compared to the Reference scenario. However, starting in the mid-2020s, we find greater coal generation in the Low Wind Cost scenario than we do in the Reference

scenario. Greater coal generation is allowed despite a binding CPP as the reductions in natural gas generation make room for greater amounts of carbon-emitting sources. Despite this increase in coal generation, on net, the Low Wind Cost scenario is estimated to have lower cumulative CO_2 emissions (see Section 3.3) as a result of greater overall wind generation. Lower wind costs can also help lower allowance prices as discussed in Section 3.4.

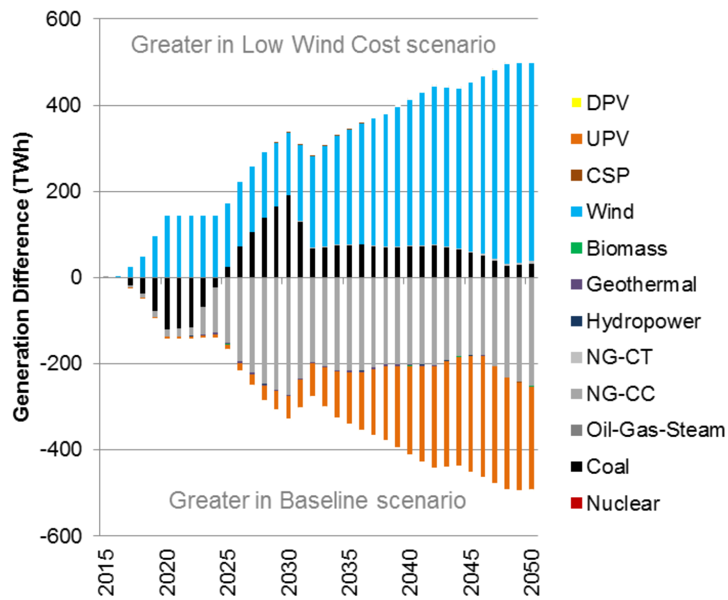

Figure 13. Annual generation difference between the Low Wind Cost and Reference scenarios

Figure 14 shows how variations in natural gas prices can result in different 2030 generation mixes. A combination of wind, solar, and coal generation replace the lower levels of natural gas generation when prices are high and the converse occurs when prices are low. Figure 15 also shows 2030 generation differences from the Reference when allowance trading is more restrictive, without long-distance transmission expansion after 2030, and with both. While the variations in these trading and transmission scenarios are smaller, they point to how without allowance trading the CPP can be more stringent and restrict a greater amount of coal generation (56 terawatt-hours). However, we acknowledge a wide spectrum of compliance options exist and that the future of the CPP itself is uncertain. Coal generation estimates can be particularly sensitive to these different possibilities.

Interestingly, while the scenario without new transmission expansion after 2020 (Reference-NoTx) results in nearly the same 2030 generation mix as in the Reference scenario, when combining this with restrictive allowance trading (Reference-NoTradeNoTx), a much greater difference is found (a reduction of 90 terawatt-hours of coal generation compared to the Reference scenario). This result highlights how even without allowance trading, the greater ability to import and export power through interstate transmission expansion represents an indirect way to shift carbon abatement between states. In other words, transmission expansion might allow a state to reduce its emissions through reductions of in-state generation and corresponding increases in electricity imports. The extent to which a state can accomplish this will depend on the ability of neighboring states to increase their generation (and any associated emissions with that generation). Changing imports and exports and transmission expansion

would also potentially have secondary impacts to various local stakeholders that are outside of the scope of our analysis. Nonetheless, the scenario results suggest complex interactions between electricity trade, transmission expansion and allowance trading. But, more research is needed to fully understand these complexities.[26]

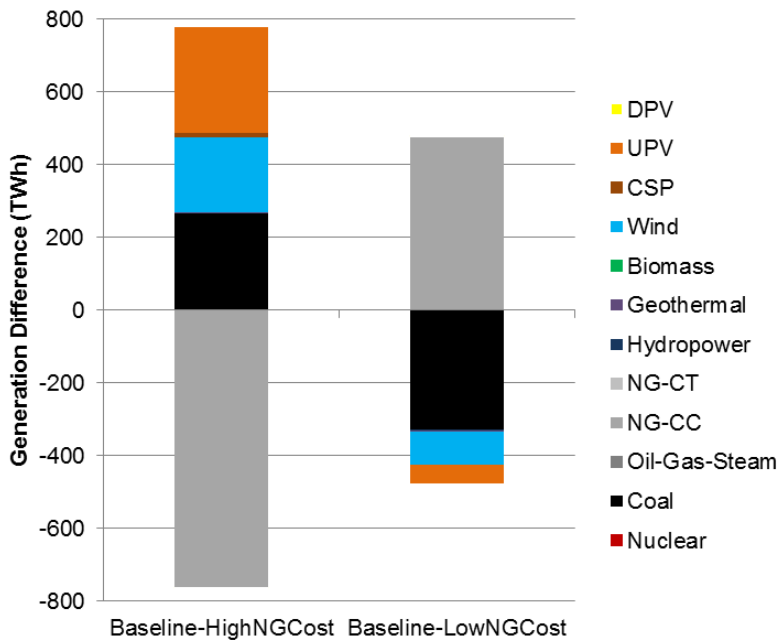

Figure 14. 2030 generation difference from the Reference under natural gas variations

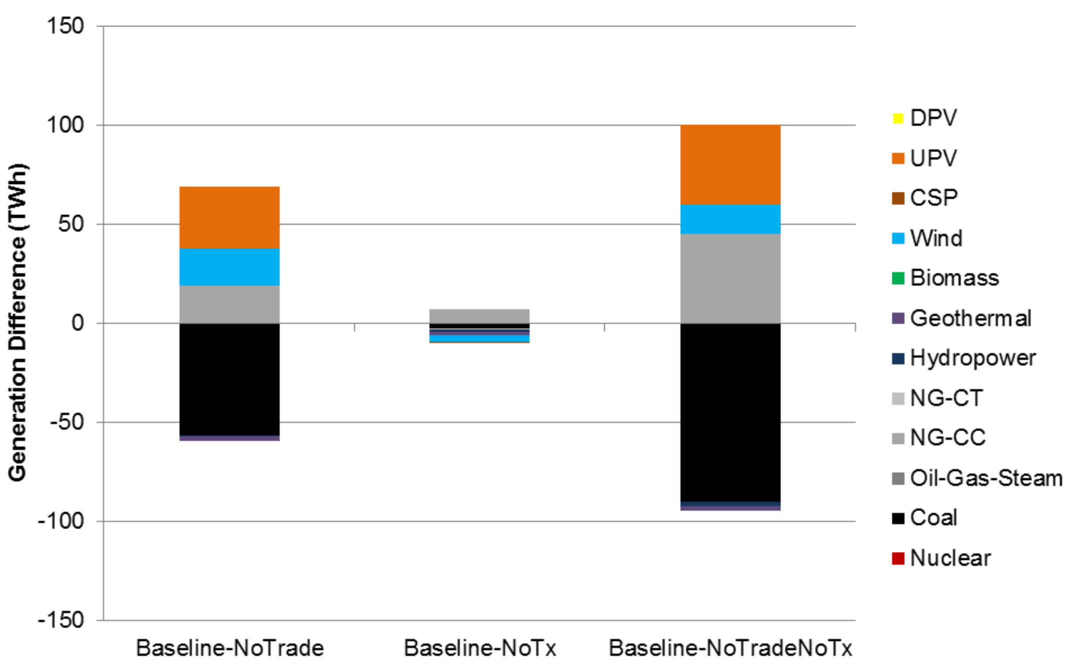

Figure 15. 2030 generation difference from the Reference under different allowance trading and transmission expansion scenarios

[26] Bielen, Steinberg, and Eurek (2016) use a reduced-form model of the power sector to analyze the imperfect substitution of electricity and allowance trading.

3.4 CO_2 Emissions

Figures 16 and 17 show CO_2 emissions from direct combustion activities in the U.S. electricity sector as estimated in multiple scenarios modeled. In nearly all scenarios, we project continued emissions decline in the near-term as a result of (1) continued coal-to-gas switching and (2) tax credit-driven wind and other renewable energy deployment. From the mid-2020s to the late 2040s, we find emissions to follow the trajectory set forth by the CPP in most, but not all, scenarios.[27] By 2050, emissions fall below the assumed CPP level in all cases shown in Figures 16 and 17.

The above-described trends generally hold across most scenarios; however, there are important exceptions. For example, variations in emissions are caused by whether the CPP is binding. In particular, emissions fall below the CPP targets for multiple years under the low natural gas price scenarios as a result of economic coal-to-gas switching found in these cases. This result suggests that if natural gas prices remain at historically low levels (e.g., below $4/MMBtu) over multiple decades, the additionality of the CPP to reduce emissions may be small.[28] Alternatively, with high natural gas prices, we find higher CO_2 emissions through the early 2020s resulting from less coal-to-gas switching before the compliance period begins (2022). Higher natural gas prices, however, are estimated to result in lower CO_2 emissions in the very long run through greater reliance on renewable energy in general, and wind energy in particular, during this period.

Figures 16 and 17 also show how electric sector CO_2 emissions can vary under different wind technology advancement futures. With sufficiently low wind energy costs, such as in the 40% lower scenario, wind deployment and the associated wind energy production can offset sufficient fossil generation to lower emissions below CPP levels. Different wind technology advancements can also change the number of early-action allowances generated from the EPA Clean Energy Incentive Program[29] and change banking and borrowing behavior. As a result, there are some minor variations in CO_2 emissions estimates between the different wind technology cost scenarios, particularly over the next decade. These variations are smaller than the effects described previously.

Finally, we note that while electric sector emissions generally decline or remain flat over the next several decades, in none of the scenarios do emissions fall below levels that climate scientists have estimated would be necessary to combat the worst effects of climate change, e.g., 80% below 2005 levels (IPCC 2014).

[27] The CPP establishes emissions or emission rate targets from 2022 to 2030 only. For all years after 2030, we maintain the 2030 target.

[28] The results shown are for scenarios without restrictions to allowance trading. They may not hold under more-restrictive trading assumptions or under different compliance variations.

[29] See https://www.epa.gov/cleanpowerplan/clean-energy-incentive-program.

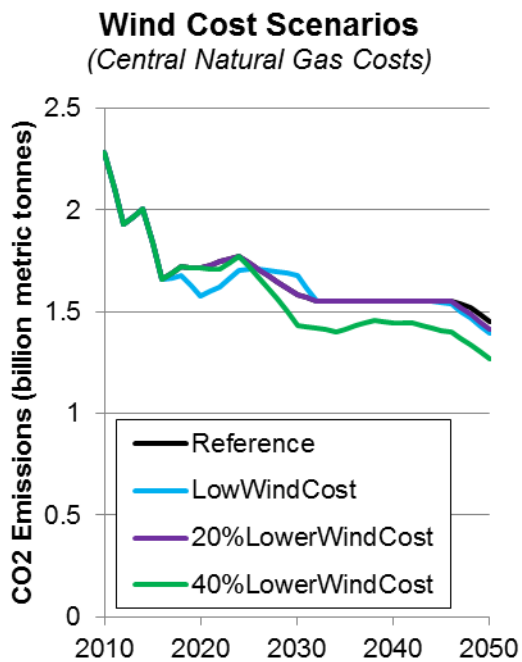

Figure 16. Electric sector CO_2 emissions over time with different wind technology cost and central natural gas cost assumptions

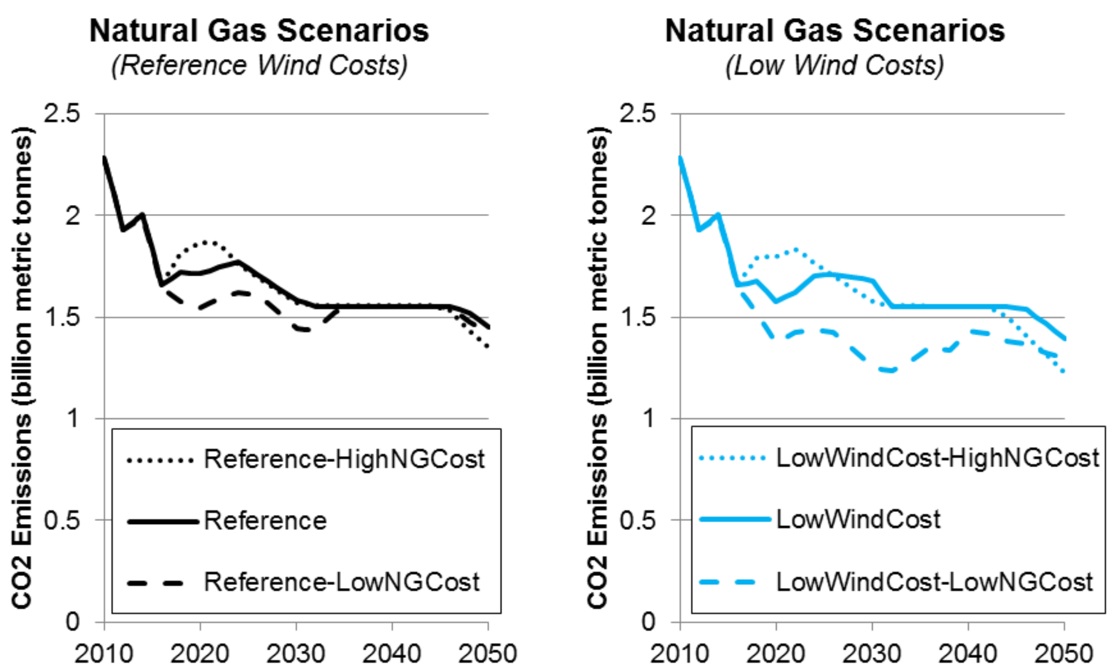

Figure 17. Electric sector CO_2 emissions over time with a range of natural gas price assumptions under reference (center) and low wind cost (right) assumptions

3.5 Allowance Prices

In Section 3.4, we show how the CPP sets a ceiling on CO_2 emissions across all scenarios. In this section, we explore how changes in future wind costs and natural gas prices might impact the costs of compliance.

Figures 18 and 19 show the allowance price from 2022 to 2030 for a range of wind technology cost and natural gas price sensitivities. As indicated above, with sufficiently low wind or natural gas costs, power sector CO_2 emissions drop below the CPP levels yielding allowance prices at or near zero.[30] Conversely, allowance prices are highest when high natural gas prices are combined with reference wind cost assumptions. In this instance, allowance prices reach nearly $20/metric ton CO_2 during the mid-2020s. In intermediate scenarios, allowances are less than $10–$11/metric ton CO_2.

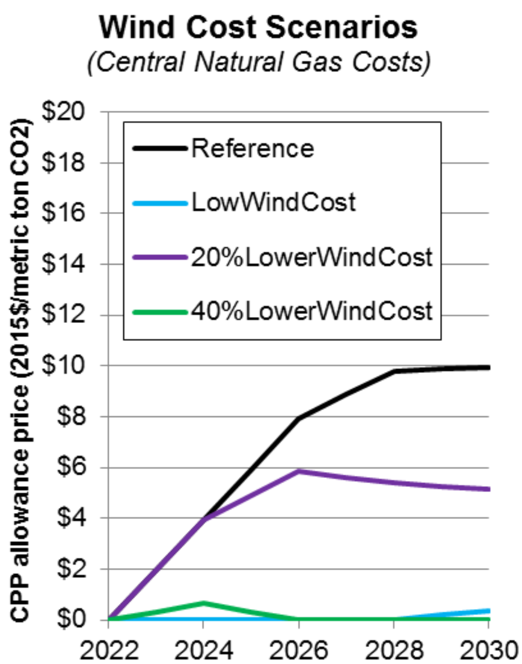

Figure 18. Allowance prices over time with different wind technology cost and central natural gas cost assumptions

[30] Under these circumstances, whether or not the CPP is included has little material impact on the wind deployment results and, therefore, these scenarios offer outlooks for U.S. wind power in a future without the CPP.

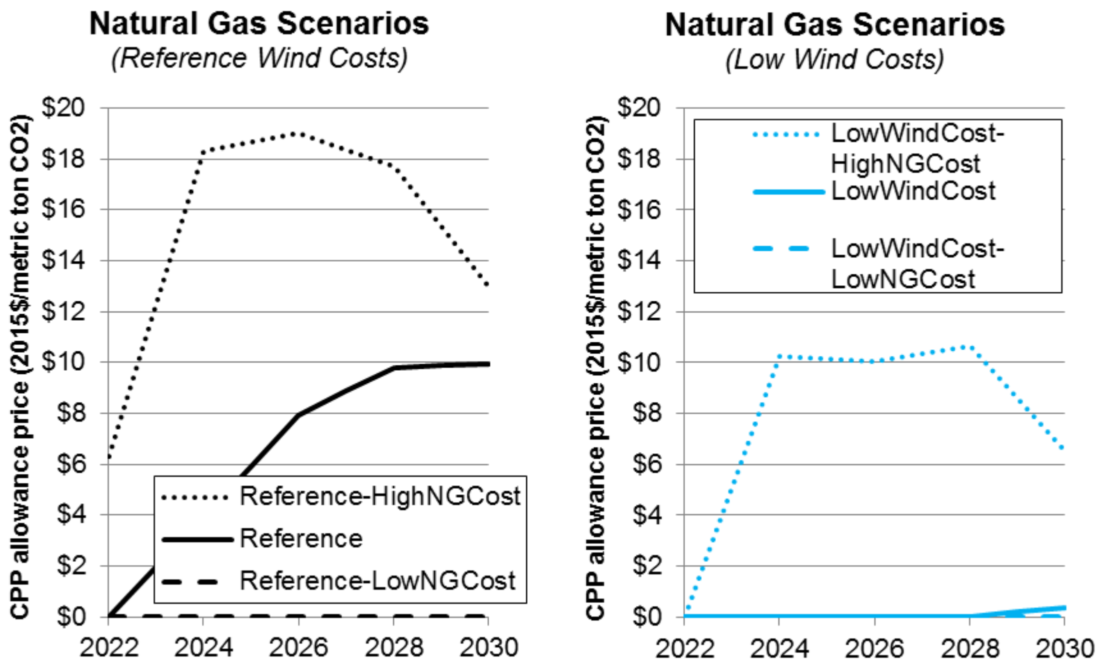

Figure 19. Allowance prices over time with a range of natural gas price assumptions under reference (center) and low wind cost (right) assumptions

All of the scenarios shown in Figures 18 and 19 assume allowances can be traded among all states. As a result, all states share a single allowance price. In contrast, when allowance trading is restricted, greater variations in allowance prices would exist between states and compliance costs are, on average, expected to rise. Figure 20 shows emissions-averaged allowance prices in the allowance trading and transmission expansion sensitivity scenarios. Under the reference wind cost assumptions, nationwide average allowance prices are typically higher when interstate allowance trading is restricted. This is particularly prevalent in the early-2020s when the full trading scenarios yield zero or near-zero allowance prices. An inability to build new transmission lines also impacts allowance prices, particularly when allowance trading is restricted. From the mid-2020s to 2030, without transmission expansion allowance prices are about $1/ton higher. This result again suggests the partial substitution between electricity and allowance trading (Bielen, Steinberg, and Eurek 2016).

The effects of allowance trading and transmission expansion on compliance costs are even greater with low wind costs. Figure 20 shows how the more-significant wind deployment found in the low wind cost scenarios can render the CPP non-binding in the 2020s if the allowances can be traded between states, but when trading is restricted, allowance prices can rise to up to about $8/ton CO_2 on average. Again, allowance prices are highest without trading and without long-distance expansion. In addition, we note that the reported allowance prices reflect a narrow range of compliance scenarios modeled; we did not model scenarios with rate-based CPP compliance approaches or with alternative trading variations. In these scenarios, estimated compliance costs will differ from those reported here. In addition, the choice of CPP scenarios modeled do not reflect likely compliance scenarios, nor are they based on known or projected state plans. We also did not model any scenarios without the CPP; however, the companion to this report—Lantz, Mai, and Mowers (forthcoming)—explores several scenarios without the CPP.

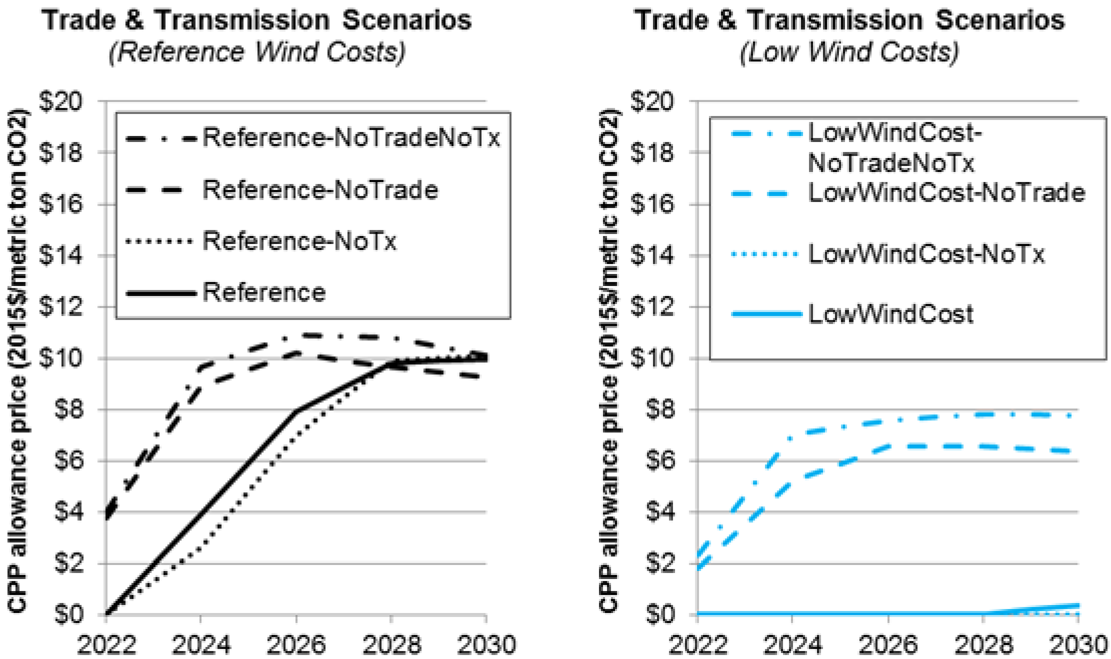

Figure 20. Comparison of allowance prices with and without trading and transmission expansion under reference wind costs (left) and low wind costs (right)

4 Summary

Today, the U.S. wind industry faces an unprecedented set of circumstances. Renewable tax credits coupled with recent wind technology advancements and the potential for even lower wind power prices paints a promising picture for the future of U.S. wind power. However, headwinds to future wind capacity deployment exist primarily from competition with natural gas generation, reduction and expiration of federal tax credits, declining solar technology costs, continued low or negative growth in electricity consumption from energy efficiency and a recovering economy.

Given this complex environment, we use a modeling and scenario analysis approach to develop multiple outlooks for U.S. wind power and identify drivers and trends related to future wind deployment. Key observations from our scenario analysis are as follows.

In the near-term (through 2020), substantial growth in new wind capacity development is estimated in all scenarios with deployment levels consistent with the DOE *Wind Vision* through 2020. This growth is driven by the strong economic case for wind when the PTC is available at its full value. With the PTC, the primary factors that could limit wind growth over the next five years include slowing electricity demand, siting challenges, and supply chain constraints.

In contrast to the consistent finding of significant near-term wind growth in all scenarios, estimated wind capacity deployment during the 2020s is decidedly mixed between scenarios. In many scenarios, annual wind installations in the 2020s are found to be limited. We find that with the reduction and expiration of the tax credit, natural gas-fired generation and solar generation are the primary electricity sources used to meet new electricity demand during this

period. In some of the most pessimistic scenarios, very little or no new growth in wind capacity is found through this entire decade and possibly beyond. From an upstream wind industry perspective, this stagnant growth period poses multiple risks, including factory closures, contractions in the wind supply chain, loss of workforce and expertise, and movement of key industry components overseas. These actions could jeopardize the long-run potential of U.S. wind power. However, we find that consistent additions of new wind capacity during the 2020s are found under certain conditions, particularly with greater wind technology advancements, potentially mitigating these risks under some circumstances.

After 2030, we find a wide range of possible wind deployment futures. Across all scenarios, estimated 2050 installed wind capacity spans a range of multiple hundreds of gigawatts. In our scenarios of the current policy environment, two factors play the largest role in determining this range: future natural gas prices and wind technology costs. And although we did not model potential changes in future electricity demand growth or power plant retirements, these uncertain factors can also play a role in the future of U.S. wind power. Wind research and development to lower wind costs provides a hedge against potentially challenging future conditions, including competition from other generation sources. Critical innovations anticipated to drive down wind technology costs include those that enable continued turbine scaling (larger rotors and taller towers) as well as more efficient plant operation and optimization. The impact of successful technology innovations targeting low and medium quality wind resource regions is explored in more detail in the forthcoming companion report by Lantz, Mai, and Mowers.

Notwithstanding these uncertainties, scenarios considered here suggest wind power can continue to play a significant role in the U.S. electricity system and help achieve CO_2 emissions reductions. But, the potential for U.S. wind power to expand its contribution in the long run may hinge on its ability to continue to deploy in the near and medium term. As market, technology, and policy conditions evolve—and new data representing these conditions become available—the outlooks for wind power in the United States will undoubtedly change. This report takes multiple snapshots of the future based on today's perspective and using a specific set of methods and assumptions. Future work is needed to refine these outlooks and inform improved decision-making.

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Appendix

Tables A-1 through A-6 show land-based wind technology cost and performance assumptions used in this analysis. Unless otherwise noted, real 2015 dollars are used. See the 2016 Standard Scenarios report (Cole et al. forthcoming) and the 2016 Annual Technology Baseline (NREL 2016) for data on other assumptions, including assumptions for other technologies. Years shown are representative of the commercial operation dates.

Table A-1. Overnight Wind Capital Costs in the Reference Scenario

$/kW	2016	2020	2025	2030	2040	2050
TRG1	1663	1610	1550	1525	1521	1516
TRG2	1716	1665	1605	1581	1578	1565
TRG3	1707	1650	1591	1569	1559	1539
TRG4	1720	1646	1584	1557	1550	1531
TRG5	1733	1661	1600	1575	1570	1553
TRG6	1772	1711	1679	1646	1627	1579
TRG7	1825	1810	1827	1870	1841	1784
TRG8	1889	1929	1982	2038	1997	1938
TRG9	2011	2133	2232	2266	2231	2168
TRG10	2201	2342	2486	2509	2524	2548

Table A-2. Wind Fixed O&M Costs in the Reference Scenario

$/kW-yr	2016	2020	2025	2030	2040	2050
TRG1	51.55	50.97	50.25	49.53	48.09	46.65
TRG2	51.55	50.97	50.25	49.53	48.09	46.65
TRG3	51.55	50.97	50.25	49.53	48.09	46.65
TRG4	51.55	50.97	50.25	49.53	48.09	46.65
TRG5	51.55	50.97	50.25	49.53	48.09	46.65
TRG6	51.55	50.97	50.25	49.53	48.09	46.65
TRG7	51.55	50.97	50.25	49.53	48.09	46.65
TRG8	51.55	50.97	50.25	49.53	48.09	46.65
TRG9	51.55	50.97	50.25	49.53	48.09	46.65
TRG10	51.55	50.97	50.25	49.53	48.09	46.65

Table A-3. Wind Net Capacity Factor in the Reference Scenario

	2016	2020	2025	2030	2040	2050
TRG1	52.23%	53.78%	54.78%	55.78%	57.53%	59.03%
TRG2	50.54%	52.14%	53.14%	54.14%	55.89%	57.14%
TRG3	49.06%	50.46%	51.46%	52.46%	53.96%	54.96%
TRG4	47.91%	48.91%	49.79%	50.66%	52.16%	53.16%
TRG5	45.53%	46.53%	47.40%	48.28%	49.78%	50.78%
TRG6	40.87%	41.99%	43.39%	44.04%	45.13%	45.38%
TRG7	34.23%	35.90%	37.92%	39.82%	40.69%	40.87%
TRG8	27.07%	29.06%	31.15%	32.84%	33.43%	33.61%
TRG9	21.04%	23.27%	25.33%	26.45%	27.04%	27.22%
TRG10	13.42%	14.91%	16.43%	17.08%	17.78%	18.48%

Table A-4. Overnight Wind Capital Costs in the Low Wind Cost Scenario

$/kW	2016	2020	2025	2030	2040	2050
TRG1	1663	1445	1301	1310	1304	1305
TRG2	1716	1496	1314	1297	1302	1314
TRG3	1707	1473	1291	1273	1279	1300
TRG4	1720	1487	1323	1292	1299	1320
TRG5	1733	1496	1357	1377	1384	1406
TRG6	1772	1634	1546	1544	1518	1524
TRG7	1825	1708	1640	1617	1599	1608
TRG8	1888	1856	1826	1846	1873	1885
TRG9	2011	2041	2054	2085	2134	2143
TRG10	2201	2275	2315	2344	2364	2407

Table A-5. Wind Fixed O&M Costs in the Low Wind Cost Scenario

$/kW-yr	2016	2020	2025	2030	2040	2050
TRG1	50.72	47.94	45.86	43.77	40.86	39.60
TRG2	50.72	47.94	45.86	43.77	40.86	39.60
TRG3	50.72	47.94	45.86	43.77	40.86	39.60
TRG4	50.72	47.94	45.86	43.77	40.86	39.60
TRG5	50.72	47.94	45.86	43.77	40.86	39.60
TRG6	50.72	47.94	45.86	43.77	40.86	39.60
TRG7	50.72	47.94	45.86	43.77	40.86	39.60
TRG8	50.72	47.94	45.86	43.77	40.86	39.60
TRG9	50.72	47.94	45.86	43.77	40.86	39.60
TRG10	50.72	47.94	45.86	43.77	40.86	39.60

Table A-6. Wind Net Capacity Factor in the Low Wind Cost Scenario

$/kW-yr	2016	2020	2025	2030	2040	2050
TRG1	52.23%	55.73%	58.33%	60.83%	62.04%	62.41%
TRG2	50.54%	54.04%	55.54%	57.04%	58.54%	59.29%
TRG3	49.06%	52.06%	53.43%	54.81%	56.31%	57.31%
TRG4	47.91%	50.91%	52.81%	53.81%	55.31%	56.31%
TRG5	45.53%	48.33%	50.83%	53.33%	54.83%	55.83%
TRG6	40.87%	45.66%	49.51%	51.38%	52.00%	52.50%
TRG7	34.23%	38.63%	42.43%	43.60%	44.35%	44.85%
TRG8	27.07%	31.76%	35.55%	37.30%	38.80%	39.30%
TRG9	21.04%	25.33%	28.90%	30.45%	31.95%	32.32%
TRG10	13.42%	16.43%	18.93%	19.93%	20.68%	21.18%

Figure A-1 compares annual wind additions estimated in the Reference scenario with forecasts and projections from others. Figure A-2 makes the same comparison but for the "Study Average" or the *average* wind capacity additions in each year across all 16 scenarios we modeled. Data shown in the figures for the forecasts from BNEF, MAKE, IHS, Navigant, UBS, and EIA STEO are taken directly from Wiser and Bolinger (2016). Data from the AEO 2016 Reference (EIA 2016) and *Wind Vision* study scenarios (DOE 2015) are also shown. Note that forecasts and projections were made at different times using different methods and assumptions; some of these forecasts may have since been updated.

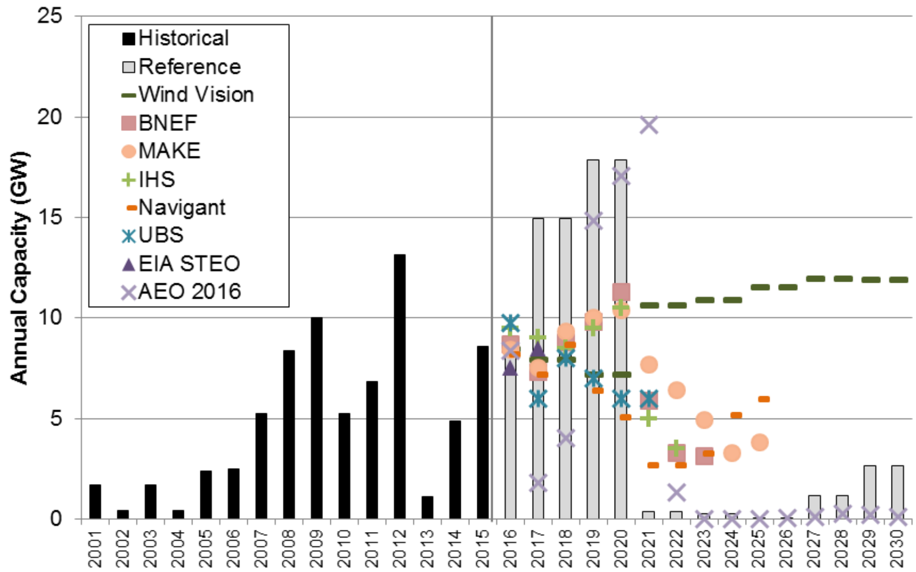

Figure A-1. Comparison of projected and forecasted wind additions with the annual additions from the Reference scenario

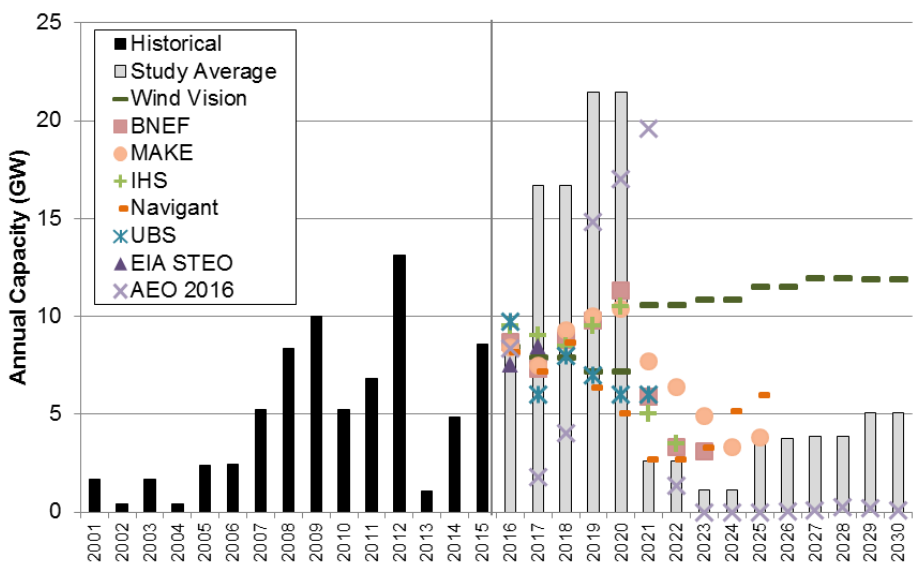

Figure A-2. Comparison of projected and forecasted wind additions with the *average* annual additions from all 16 scenarios

Figure A-3 shows cumulative installed wind capacity across all 16 modeled scenarios. Figure A-4 shows the annual capacity additions in all 16 model scenarios.

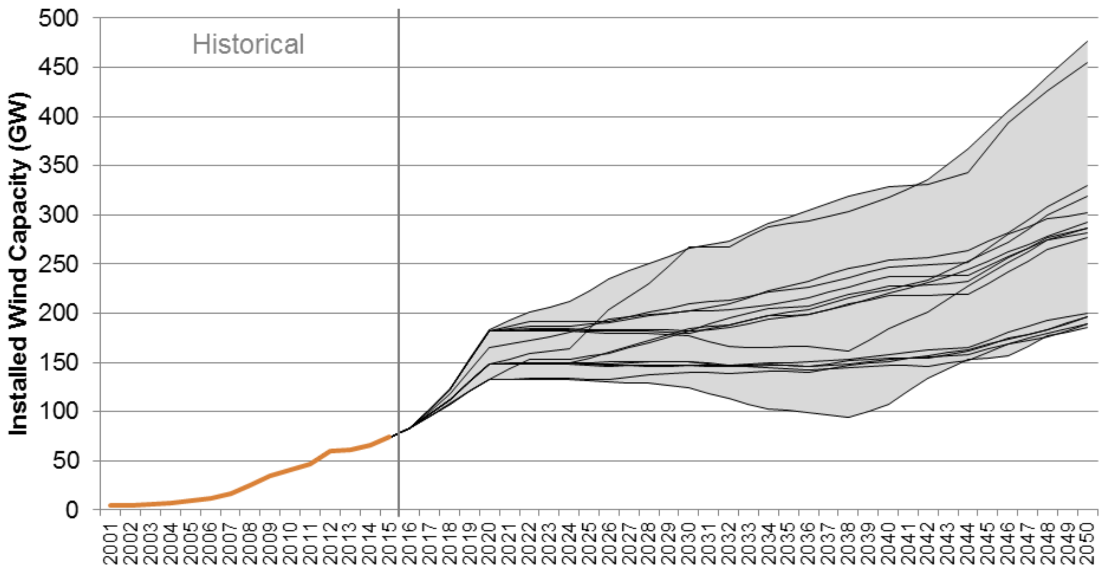

Figure A-3. Cumulative installed wind capacity projections in all modeled scenarios

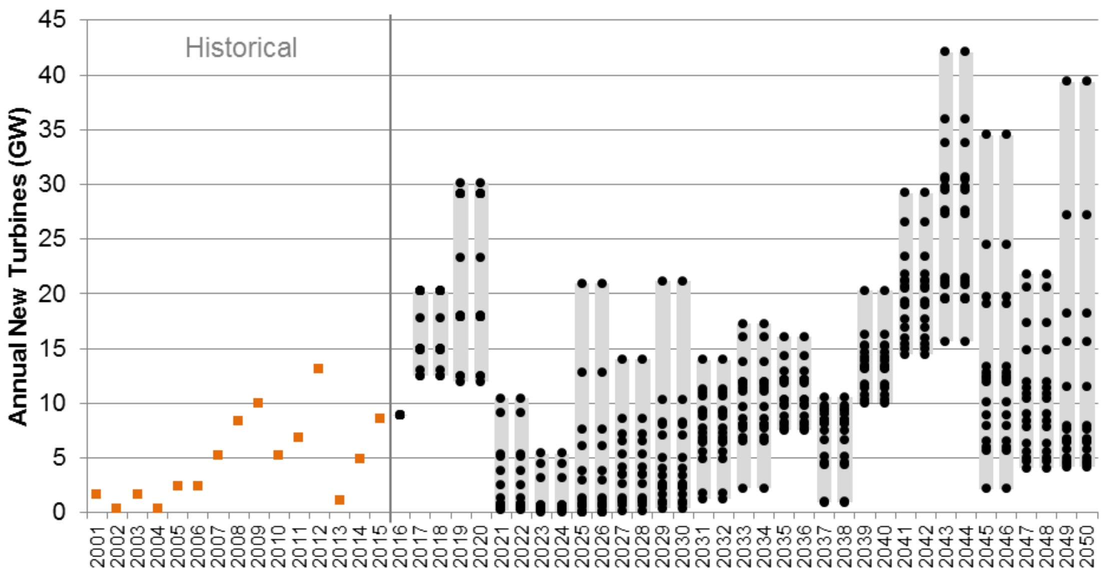

Figure A-4. Annual wind turbine capacity projected in all modeled scenarios