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Technical Report
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NATIONAL RENEWABLE ENERGY LABORATORY

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Preface

This work responds to a request made in October 2012 by Senator Jeff Bingaman, who has since retired. At the time, Senator Bingaman was the Chairman of the Senate Committee on Energy and Natural Resources. Senator Bingaman requested that the National Renewable Energy Laboratory (NREL) estimate the level of continuing policy support necessary to avoid significant disruption to domestic wind industry manufacturing and employment. Funding for the work was provided by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy.

The production tax credit (PTC) has been the primary federal incentive for deployment of wind power in the United States since it was first enacted as part of the Energy Policy Act of 1992. The credit establishes a production incentive for qualifying projects during the first 10 years of commercial operation and has been renewed eight times since its initial passage; renewals have often occurred near to or soon after expirations. Most recently, the PTC was extended by one year through December 31, 2013. Although the PTC has now expired, this extension included an adjustment of eligibility criteria that is expected to result in the qualification of projects that began construction in 2013 and maintain construction into 2014 and 2015; under current IRS guidance, projects that maintain construction into 2016 might also qualify.

Executive Summary

The production tax credit (PTC) has been the primary federal incentive for deployment of wind power in the United States since it was first enacted as part of the Energy Policy Act of 1992. The PTC establishes a production incentive for qualifying projects during the first 10 years of commercial operation and has been renewed eight times since its initial passage; renewals have often occurred near to or soon after expirations. Most recently, the PTC was extended by one year through December 31, 2013. Although the PTC has now expired, this extension included an adjustment of eligibility criteria that is expected to result in the qualification of projects that began construction in 2013 and maintain construction into 2014 and 2015; under current IRS guidance, projects that maintain construction into 2016 might also qualify.

The PTC has been critical to the development of the wind industry and deployment of wind generation capacity in the United States over the past two decades. The presence of the PTC enables wind power project developers to reduce the price at which their electricity can be sold, effectively making their projects less costly for power purchasers and ultimately consumers.

Wind power has been a growing part of U.S. electricity supply. Through 2012, more than 60 gigawatts (GW) of land-based wind generation capacity have been installed nationally, including an average of 8.7 GW per year from 2008 through 2012. To meet recent growth in demand for wind capacity, the wind industry has invested heavily in U.S.-based manufacturing facilities. In 2012, an estimated 550 U.S.-based manufacturing facilities produced turbines, blades, towers, and their components. Of these, over 60 were dedicated suppliers to the wind industry. Due to growth in U.S. manufacturing capacity, the estimated import fraction for new plant installations has steadily declined from 75% of total turbine costs in 2006-2007 to less than 30% in 2012.

Despite recent record-setting deployment and a trend of increasing domestic content in its supply chain, the U.S. wind industry faces several challenges. Current and near-term state renewable portfolio standard (RPS) targets have largely been met and are not expected to support more than 1–3 GW per year of new wind construction through 2020. Abundant new sources of low-priced natural gas have altered the competitive landscape in the power sector, and the modest economic recovery, coupled with successful energy efficiency investments, has limited growth in demand for new electricity generation of all types.

In response to these challenges, questions have been raised concerning the effect that PTC expiration could have on installations of new wind generation capacity and, more broadly, on domestic wind industry manufacturing, economic output, and employment.

This analysis explores the potential effects of PTC expiration and various extension scenarios on future wind deployment with the Regional Energy Deployment System (ReEDS), a model of the U.S. electricity sector. ReEDS is unique among national capacity expansion models for its detailed regional structure and statistical treatment of the impact that variable wind and solar resources have on capacity planning and dispatch. The analysis considers deployment results in the context of recent wind industry installation and manufacturing trends. The analysis does not estimate the potential implications on government tax revenue associated with the PTC.

A PTC expiration scenario (Current Policy/PTC Expiration) and five conceptual designs for a PTC extension are explored. Two extension scenarios extend the PTC at its current level (taking into account adjustments for inflation over time) for different lengths into the future (Constant 2020, Constant 2030). Three scenarios ramp the credit down from its current level until it terminates in a future year. The three ramp-down designs are intended to explore scenarios in which a sufficient incentive is available such that median resource quality wind generation costs are on par with estimated electricity generation costs from new gas plants (Ramp Down Low), existing gas plants (Ramp Down High), and an intermediate case between these two (Ramp Down Mid). In the three ramp-down scenarios the PTC remains in place (with declining value) through 2020, 2022, and 2021, respectively.

Analysis results are reported in ranges to reflect uncertainty in future natural gas prices and load growth. Projected fuel prices and load growth are derived from high and low values reported in the Energy Information Administration's Annual Energy Outlook 2013. Wind technology costs across all scenarios are grounded in observed 2012 data and assume a reduction in levelized cost of energy (LCOE) of approximately 15% by 2020 and 20% by 2025. Two types of power plant retirements are simulated in the analysis: those in the near-term that have already been announced by utilities, and those over the longer-term that occur as a function of plant age and dispatch characteristics.

Figure ES-1 shows the projected average annual wind deployment from 2013–2020 for the policy scenarios analyzed. The results indicate that U.S. wind power deployment through 2020 is sensitive to both the prospective level of the PTC and market conditions over time.

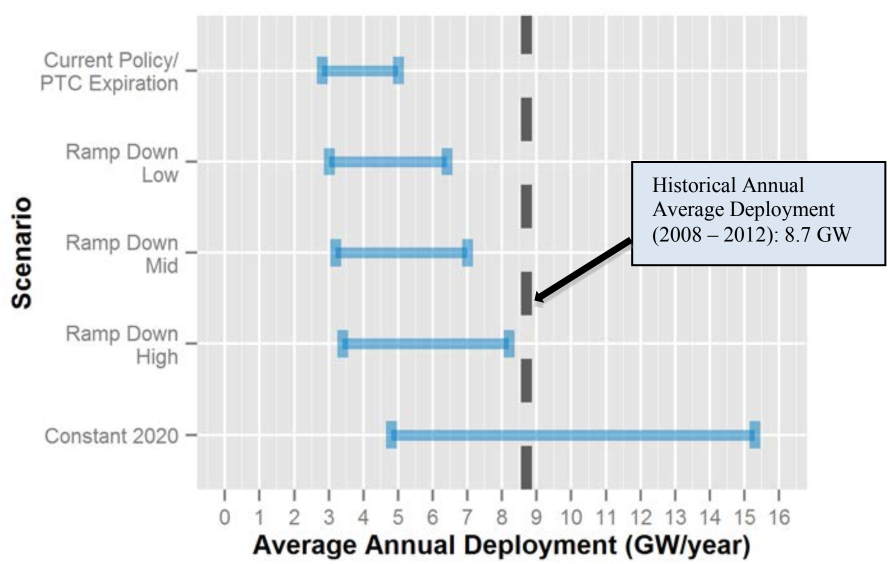

Figure ES-1. Projected average annual wind capacity deployed between 2013 and 2020 for scenarios examined

Note: Ranges shown reflect sensitivity to changes in natural gas prices and electricity demand growth. Sensitivities are coupled to provide a high and low value for the impact of a given scenario. All modeling results rely on a single set of cost and performance inputs for renewable and non-renewable power generation technologies as well as a single set of projected electric generation capacity retirements.

More specifically, key findings of the analysis include:

- Under a scenario in which the PTC is not extended (Current Policy/PTC Expiration) and all other policies remain unchanged, wind capacity additions are projected to be between 3 GW and 5 GW per year from 2013–2020.
- U.S. wind power manufacturing production generally aligns with average annual wind power capacity additions from 2008 to 2012. In the absence of U.S. domestic demand for new wind capacity, global markets are unlikely to offer many opportunities for U.S.-based manufacturers. Given the limited export market, a reduction in domestic wind power deployment is likely to have a direct and negative effect on U.S.-based wind turbine manufacturing production and employment.
- Modeled PTC extension options that ramp down and cease support by year-end 2022 (Ramp Down Low, Ramp Down Mid, Ramp Down High) appear to be generally insufficient to support deployment close to recent levels and therefore may be insufficient to sustain the current industry domestic manufacturing and supply chain through 2020.
- Of the scenarios considered, an extension of the PTC at its historical level (Constant 2020) could provide the best opportunity to support deployment consistent with recent levels across a range of market conditions; it therefore could also provide the best opportunity to sustain the existing wind installation and manufacturing base at its current level.
- In the current low-priced natural gas regime, modeling results indicate that future wind deployment will be relatively low unless additional incentives are provided that result in wind being cost competitive with *existing* gas-fired generation.
- Future uncertainty in key modeling variables, including gas prices and load growth, translates into high levels of uncertainty in the deployment outcomes of specific extension scenarios.

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1 Introduction

Wind power has been a growing part of the U.S. electricity supply. First emerging in California in the early 1980s, wind generation capacity has been installed more broadly in the United States since the late 1990s (Wiser and Bolinger 2013; Logan and Kaplan 2008). Through 2012, more than 60 GW of land-based wind generation capacity have been installed nationally, including an average of 8.7 GW per year from 2008 through 2012. U.S. wind capacity is estimated to supply approximately 4.4% of the nation's electricity demand (Wiser and Bolinger 2013).[1] Utility-scale wind capacity has been installed and is operating in 39 states; in 9 of these states wind generation exceeds 12% of in-state electricity demand, and in 3 of these states—Iowa, South Dakota, and Kansas—wind is estimated to supply more than 20% of electricity demand (Wiser and Bolinger 2013). Moreover, in 2012, wind power was the largest single source of new electric power generating capacity, constituting more than 40% of total U.S. additions (Wiser and Bolinger 2013). Installations in 2012 represented approximately $25 billion in new investment (Wiser and Bolinger 2013).

To meet this recent growth in demand for wind capacity, the wind industry has invested heavily in U.S.-based manufacturing facilities. In 2012, an estimated 550 U.S.-based manufacturing facilities produced turbines, blades, towers, and their components. Of these, more than 60 were dedicated suppliers to the wind industry (AWEA 2013). Due to growth in the U.S. manufacturing capacity, the estimated import fraction for new plant installations has steadily declined from 75% of total turbine costs in 2006–2007 to less than 30% in 2012 (Wiser and Bolinger 2013). The American Wind Energy Association (AWEA) estimates that employment from manufacturing has also grown over time. Approximately 25,500 individuals were employed in U.S.-based wind turbine component and equipment manufacturing facilities, and total U.S. wind industry employment—including manufacturing and facility installation, operation, and maintenance—was estimated at approximately 80,000 in 2012 (AWEA 2013).

Despite recent record-setting annual installations and a trend of increasing domestic content in its supply chain, the U.S. wind industry faces several challenges (Wiser and Bolinger 2013; Bloomberg NEF 2013; MAKE 2013; IHS EER 2013; EIA 2013b). Current and near-term state renewable portfolio standard (RPS) targets have largely been met and are not expected to support more than 1–3 GW per year of new wind construction through 2020. Abundant new sources of low-priced natural gas, resulting largely from advancements in production techniques for shale reservoirs, have altered the competitive landscape in the power sector. And, the modest economic recovery, coupled with successful energy efficiency investments, has limited growth in demand for new electricity generation of all types.

In conjunction with these challenges, the loss of the production tax credit (PTC), the primary federal incentive supporting the industry, has raised concerns among industry proponents, who suggest that PTC expiration could result in a reduction of new wind installations that could precipitate the loss of domestic wind industry jobs and the economic output associated with U.S. wind deployment and manufacturing. Further, some have speculated that a significant

[1] The estimate reported here assumes long-term average wind resource conditions and fleet availability. The Energy Information Administration (EIA) reports that through the first three quarters of 2013, U.S. wind generation averaged approximately 4% of total net generation and 4.4% of total retail sales (EIA 2013a).

contraction in the domestic wind market poses the risk of “offshoring” wind power manufacturing capabilities and the potential for innovation represented therein. In contrast, opponents of a PTC extension often suggest that all forms of electricity generation should compete in the marketplace on economic and environmental terms without federal financial support. For wind, in particular, some argue that incentives are no longer needed to support what is now a relatively mature industry (Brown 2012).

The analysis in this report is focused on addressing two key questions:

- What are the potential effects of PTC expiration and various PTC extension designs on future wind deployment?
- What are the implications of these deployment levels on the wind manufacturing sector?

The analysis applies NREL’s Regional Energy Deployment System (ReEDS) model (Short et al. 2011) to assess the potential impact of several PTC extension scenarios on future deployment of wind generation capacity. A range of potential PTC designs are explored, including extensions that simply maintain the PTC at its current level until some future end date, as well as designs that ramp down or reduce the level of the PTC through time. The latter are designed to provide sufficient support to maintain the cost competitiveness of wind generation with other electricity generation technologies. The analysis does not explore the potential impacts on federal government revenue or other quantitative impacts associated with the deployment outcomes for either current PTC policy or the conceptual extensions explored. The sections that immediately follow provide a brief review of the history of the PTC and its impacts on the wind industry, along with an overview of the status of wind economics and competitiveness. Section 2 describes the analysis and modeling approach used, Section 3 presents modeling results, and Sections 4 and 5 discuss their implications.

1.1 PTC Background

Since the first wind plants were commissioned in the United States more than three decades ago, state and federal policy have played a critical role in the industry (Bird et al. 2005; Chapman et al. 2012). From the 1980s to the early 1990s, wind industry growth was supported by the Public Utility Regulatory Policies Act (PURPA), state and federal investment tax credits, and accelerated depreciation provisions (Bird et al. 2005). More recently, the federal PTC, continued accelerated depreciation provisions, state RPSs, and other state support structures have been instrumental to industry expansion (Bird et al. 2005; Wiser et al. 2007; Wiser and Barbose 2008).

The PTC was first enacted as part of the Energy Policy Act of 1992 and established a production incentive of $0.015/kWh ($15/MWh) for qualifying projects during the first 10 years of commercial operation. The credit is indexed to inflation, and as a result, projects that qualified in 2013 received a tax credit of $0.023/kWh ($23/MWh). The PTC has expired or been within 5 months of expiration and subsequently renewed on six different occasions (1999, 2001, 2003, 2005, 2008, and 2012). In two additional instances (2006 and 2009) the PTC was renewed 12 and 10 months, respectively, prior to expiration. Most recently, the PTC was extended by one year through December 31, 2013. Although the PTC has now expired, the eligibility criteria in the latest extension were adjusted from project completion by that date to construction initiation. According to IRS guidance, there is no fixed deadline by which time projects beginning construction in 2013 must be placed in service; however, continuous activity must be maintained in order to qualify, and provisions exist to streamline qualification for those projects that are commissioned prior to year-end 2015 (IRS 2013). Construction times for modern wind power facilities range from 6 months to multiple years. Given this, it is likely that many projects that began construction in 2013 and maintain construction into 2014 and 2015 will qualify for the current incentive. Projects that initiated construction in 2013 and are commissioned in 2016 might also qualify.

The PTC has provided substantial assistance to the U.S. wind industry. The presence of the PTC enables wind power project developers to reduce the price at which their electricity can be sold, effectively making them less costly for power purchasers and ultimately consumers. Current estimates indicate that the PTC reduces contracted prices for wind power by approximately \$20/MWh (2012 dollars) or roughly 25%–50% (Wiser and Bolinger 2013).[2]

At the same time, the on-again, off-again historical policy environment has created substantial uncertainty and deployment volatility. Past PTC expirations have resulted in reductions in year-on-year installations between 73% and 93% (Wiser et al. 2007). The impact of such boom and bust cycles is diverse. Most notably, short-term planning timeframes associated with PTC uncertainty can discourage investments in domestic manufacturing capacity, deployment capability, component orders, and private sector research and development (R&D) (Wiser et al. 2007; Lewis and Wiser 2007).[3]

The impacts of the PTC on government revenue have not been comprehensively evaluated in the literature. However, the Joint Committee on Taxation routinely “scores” tax policy to provide a perspective on the implications of a given policy for federal government expenditures. In its most recent assessment, which includes the PTC extension through year-end 2013, the Joint Committee estimates forward-looking tax expenditures associated with credits for wind energy to be approximately \$7.7 billion cumulatively for fiscal years 2013–2017 (JCT 2013).

1.2 Economics of Wind Deployment

Growth in wind power capacity over the past decade can generally be ascribed to a combination of three principal factors:

- **Renewable Portfolio Standards**: Twenty-nine states and the District of Columbia have mandated that a certain amount or percentage of generation capacity come from renewable energy sources. Historically, state RPSs have been a critical driver for wind capacity. While it remains difficult to discern precisely how much wind capacity is a direct result of RPS policies, 83% of wind installations in 2012 occurred in states with an RPS (Wiser and Bolinger 2013).

[2] Average 2011 and 2012 wind power purchase agreement (PPA) prices are reported to be \$40/MWh (Wiser and Bolinger 2013); prices averaged approximately \$70/MWh in 2009. In 20-year levelized terms, the value of the PTC approaches the legislated 10-year incentive level of \$0.023/kWh because the incentive is in effect after-tax income. To calculate the impact of the PTC on levelized cost of energy, this after-tax income must be converted to its larger pre-tax equivalent and levelized over the full economic life of the plant.

[3] Wind power projects can have an extensive lead time prior to construction that incorporates various phases related to planning, engineering, permitting, environmental review, contract and legal documentation, and financing.

- **Economic Competitiveness**: Under certain conditions, wind power is directly competitive with other electricity generation sources and procured based on immediate or projected cost savings (Wiser and Bolinger 2013; Bloomberg NEF 2013). To date, the PTC and other federal tax incentives (e.g., accelerated depreciation) have boosted wind power's economic position relative to alternative generation sources, enabling wind to be lower cost than other generation technologies in some regions (e.g., Texas).[4] Wind is also sometimes credited as a hedge against potential natural gas price escalation (Bolinger 2013; Wiser and Bolinger 2006).
- **Discretionary Factors**: Utilities, corporations, and others can make investments in wind power to supply voluntary green pricing programs because of a preference for wind or non-emitting energy sources or for various other reasons. *This demand driver is not considered in the analytical modeling work conducted here.*

State tax and other incentives and state or regional carbon markets have also supported wind installations in the past but are generally considered to be secondary drivers.

Looking forward, some of these drivers are likely to have less impact on deployment. Existing RPS policies are expected to have only a modest impact: estimates from industry consultancies compiled over the past year project RPS wind demand at 1–3 GW/year through 2020 (Bloomberg NEF 2013; MAKE 2013; IHS EER 2013). Moreover, the emergence of low-priced natural gas has dramatically altered the competitive landscape for wind power. Figure 1 is illustrative of the gap in projected costs between new wind plants (absent the PTC) and new combined cycle gas-fired generation (left) as well as between new wind plants and existing gas-fired generation (right). This juxtaposition suggests that without policy support to enhance the cost position of wind power, purely economic deployment will also likely be modest.[5,6] The differences noted between the median wind cost reduction trajectory (dark blue line) and the range of gas-fired generation costs shown in Figure 1 are used to inform the development of ramp-down scenarios described in Section 2.2 and referred to in Section 3.1.

[4] Today, there are more than 12 GW of operating wind capacity in Texas, a level of capacity that far exceeds expected demand from Texas's RPS (ERCOT 2013).

[5] The comparison shown in Figure 1 is relative to new (left) and existing (right) gas generation as these plants are often the marginal generation unit(s) as well as a substantial source of new generation capacity (EIA 2013b). Accordingly, wind will likely be competing with existing gas units to serve current load and new gas units to serve demand for new generation resources. Existing gas-fired generation is assumed to have its capital expenditures fully recovered and therefore has a levelized cost of energy equivalent to its fuel and ongoing operations and maintenance costs.

[6] Notwithstanding these economic conditions, investments in wind power plants could continue to be made as a potential long-term hedge against future increases natural gas fuel costs (Bolinger 2013).

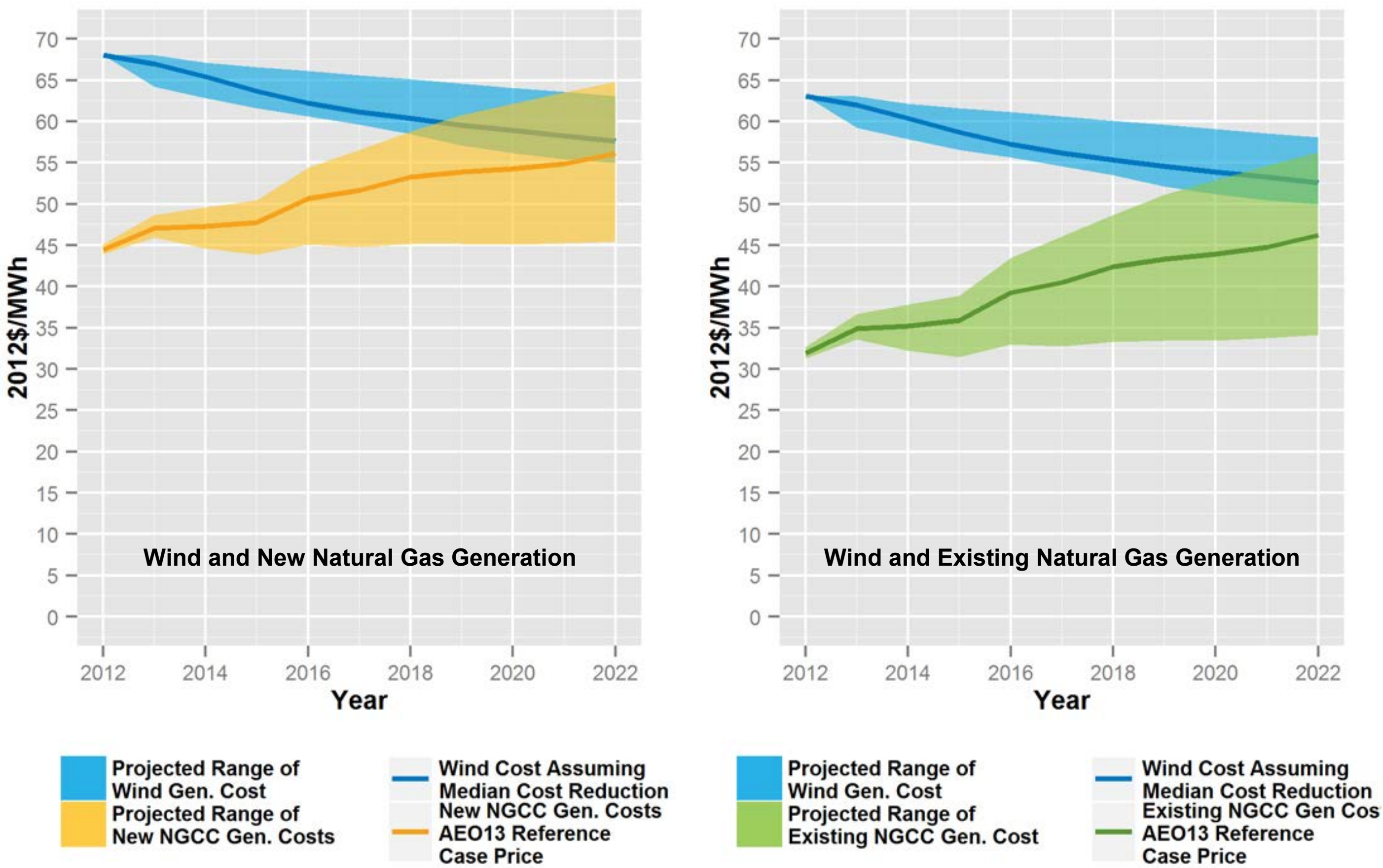

Figure 1. Relative wind and combined cycle natural gas economics

Notes: Dark yellow and green lines represent the projected cost of natural gas-fired generation based on reference case fuel prices derived from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) (EIA 2013b); for wind the dark blue line represents the generation cost associated with wind plants operating in median wind resource quality sites plus cost adders to reflect the provision of consistent capacity and energy resources to the system. More specifically, when comparing wind with new gas-fired generation (left), cost adders are included to reflect the incremental system capacity ($5/MWh as reported by EnerNex [2010], IEA [2010], Milligan and Porter [2008]) required to provide a capacity value comparable to a new combined cycle gas-fired plant and to cover incremental balancing expenditures ($2/MWh as summarized by Wiser and Bolinger [2013]) associated with the addition of variable generation into the power system. When comparing wind with existing gas-fired generation (right), as a fuel saver and assuming no need for additional capacity, only the balancing expenditures cost adder is included.[7] Wind cost reductions are based on the median, 25th, and 75th percentile literature cost reduction trajectory for wind power (Lantz et al. 2012). Bands represent uncertainty in projected costs as reported by Lantz et al. (2012) for wind and EIA (2013b) for natural gas. High and low gas prices are based on prices reported in the EIA's AEO low and high resource recovery scenarios. The gaps between the median wind cost reduction trajectory (dark blue line) and the reference case gas-fired generation cost (dark yellow and green lines) are used to inform the development of ramp-down scenarios discussed in Section 2.

[7] The system capacity adder is not included as wind power has no effect on overall system capacity when used as a "fuel saver" to offset generation provided by an existing asset. Balancing expenditures are included as the system operator is still required to maintain adequate spinning reserve to adjust for short-term wind generation variability.

2 Analysis Methods

2.1 Model Description

This analysis applies ReEDS to explore the potential effects of PTC expiration and various extension scenarios on future deployment of wind generation capacity.[8, 9] ReEDS is a capacity expansion model that simulates the construction and operation of generation and transmission capacity to meet electricity demand. The model relies on a least-cost optimization to provide estimates of the type and location of conventional and renewable resource development; the transmission infrastructure expansion requirements of those installations; and the composition and location of generation, storage, and demand-side technologies needed to satisfy regional demand requirements and maintain grid system adequacy. The model also considers technology, resource, and policy constraints, including state RPSs. ReEDS's high spatial resolution and statistical treatment of the impact of variable wind and solar resources is specifically designed to represent the relative value of geographically and temporally constrained renewable power resources.

ReEDS does not model constraints associated with the manufacturing sector. All technologies are assumed to be available at their defined capital cost in any quantity. As well, technology cost reductions from manufacturing economies of scale and "learning-by-doing" are not endogenously modeled; rather, current and future cost reduction trajectories are defined as inputs to the model. The ReEDS model has limited market foresight and, with the exception of future fuel prices, does not make decisions based on any expectation of future market conditions. The model's least-cost optimization also does not fully represent the prospecting, permitting, and siting hurdles that are faced by project developers for either electricity generation capacity or transmission infrastructure.

2.2 PTC Extension Scenarios

Six specific PTC scenarios were explored in this analysis and are described below. These six scenarios were selected based on their ability to represent a potential range of PTC incentive levels and policy design features. One scenario represents current policy (i.e., expiration of the PTC in 2013). This case provides an estimate of future wind deployment by assuming no further extensions to the PTC. Three scenarios explore different approaches to a PTC ramp down, reflecting a multi-year policy that offers a gradual reduction in the level of the PTC. Two additional scenarios consider extensions of the PTC at its historical level (currently $23/MWh). The ramp-down scenarios are conceptually aligned with anticipated costs of combined cycle natural gas-fired units assuming reference case fuel prices (EIA 2013b); these scenarios are driven significantly by assumed projections of future natural gas prices. The range represented by the three ramp-down scenarios reflects different levels of support that enable pricing from wind (assuming a singular median cost reduction trajectory across all three scenarios) to be competitive with new units (those required to generate sufficient revenue to cover both operating costs and capital recovery), existing units (those that must only cover operating costs, including

[8] ReEDS is a widely-recognized electric sector modeling tool that has been applied across an array of past work including: DOE 2008, DOE 2012, NREL 2012, Mignone et al. 2012, among others.
[9] See Short et al. 2011 for more information about the ReEDS model. The version of the model used in this analysis is consistent with the NREL base model as of October 2013.

fuel), and the midpoint in between these two price points (Figure 1). The principal features of each scenario are summarized below (resulting PTC levels for each scenario are shown in Table 1):

- **Current Policy/PTC Expiration:** Assumes PTC expiration in accord with current law.
- **Ramp Down Low:** Provides a PTC that enables the median wind resource site to be competitive with ***new*** combined cycle gas generation. Wind projects commissioned by year-end 2014 qualify for the PTC at its current level. In 2015 the level of the PTC begins to decline. Wind projects commissioned after year-end 2020 do not qualify. Figure 1 (left) is illustrative of the generation cost gap between wind (blue wedge) and new combined cycle gas generation (orange wedge) that is bridged by this PTC scenario.
- **Ramp Down High:** Provides a PTC that enables the median wind resource site to be competitive with *existing* combined cycle gas generation. Wind projects commissioned by year-end 2014 qualify for the PTC at its current level. Beginning in 2016, the PTC declines to $6/MWh by 2022. Projects commissioned after year-end 2022 do not qualify. Figure 1 (right) is illustrative of the cost gap between wind (blue wedge) and existing combined cycle gas generation (green wedge) that is bridged by this PTC scenario.
- **Ramp Down Mid:** Provides a PTC that is designed to split the difference between the Ramp Down Low and Ramp Down High scenarios. Projects commissioned by year-end 2014 qualify for the PTC at its current level. In 2015 the level of the PTC begins to decline. Projects commissioned after year-end 2021 do not qualify.
- **Constant 2020:** Enables projects commissioned by year-end 2020 to qualify for the PTC at its historical level ($15/MWh adjusted for inflation).
- **Constant 2030:** Enables projects commissioned by year-end 2030 to qualify for the PTC at its historical level ($15/MWh adjusted for inflation).

Table 1. Applicable PTC Level in Analysis Scenarios (2012$/MWh)

Year	Current Policy/PTC Expiration	Ramp Down Low	Ramp Down High	Ramp Down Mid	Constant 2020	Constant 2030
2013	23	23	23	23	23	23
2014	23	23	23	23	23	23
2015	0	16	23	19	23	23
2016	0	12	18	15	23	23
2017	0	10	16	13	23	23
2018	0	7	13	10	23	23
2019	0	6	11	8	23	23
2020	0	5	10	7	23	23
2021	0	0	8	6	0	23
2022	0	0	6	0	0	23
2023	0	0	0	0	0	23
2024	0	0	0	0	0	23
2025	0	0	0	0	0	23
2026	0	0	0	0	0	23
2027	0	0	0	0	0	23
2028	0	0	0	0	0	23
2029	0	0	0	0	0	23
2030	0	0	0	0	0	23

Note: PTC values shown above are assumed paid in nominal dollars for a period of 10 years once the qualifying project becomes operational.

PTC policy is considered independent of other policy changes that could affect renewable power or low carbon generation technologies (statutory and regulatory policy in effect today is captured; EPA regulations that are pending or under development are not). All scenarios apply a common median wind industry anticipated cost reduction trajectory. Wind technology costs across all scenarios are grounded in observed technology cost and performance for 2012 (Wiser and Bolinger 2013; Wiser et al. 2012) and assume a reduction in levelized cost of energy (LCOE) of approximately 15% by 2020 and 20% by 2025 (Lantz et al. 2012).

2.3 Modeling Sensitivities and Other Considerations

Common high and low deployment sensitivity cases were developed and modeled for each PTC extension scenario. This approach is intended to generally bound the potential range of wind deployment that could result from each policy scenario given uncertainty in key power sector variables, specifically natural gas fuel prices and future load growth. High and low natural gas price projections were derived from the High and Low Oil and Gas Resource cases reported in the Energy Information Administration (EIA) Annual Energy Outlook (AEO) (EIA 2013b). High and low load growth estimates were also derived from the AEO, specifically the High and Low Economic Growth cases (EIA 2013b).

Assumptions for future natural gas price and load growth are presented in detail in Appendix A. Given relatively high uncertainty associated with these assumptions, this analysis focuses exclusively on bounding sensitivities and does not consider the likelihood of individual outcomes; accordingly, there is no median or reference case reported.

Approximately 60 GW of coal generation capacity was assumed to retire by 2020 in all cases. These retirements were based on data reported by Ventyx (2013) and Saha (2013) and include announced retirements only.[10]

Solar technologies, including utility-scale photovoltaics (PV), concentrated solar power (CSP), and distributed rooftop PV (DG-PV) in the residential and commercial sectors, were considered for new capacity additions in all scenarios. Solar technology cost and performance assumptions were consistent with the SunShot 62.5% cost reduction scenario documented by Eurek et al. (2013).[11]

New geothermal and hydropower generation capacity was not allowed in core modeling scenarios due to high uncertainty in both the resource potential and prospective cost of these technologies. However, sensitivity analysis allowing capacity additions for these technologies, assuming current costs and the best available resource potential estimates, showed minimal effect on scenario outcomes.

Dispatch and deployment of fossil and nuclear technologies across all scenarios was based on cost and performance assumptions informed by the AEO 2013 Reference Case.

Deployment projections assume sufficient tax appetite on the part of project sponsors to utilize all accelerated depreciation deductions and PTCs in the years in which they are generated. In practice however, PTC monetization results in lower project debt levels and frequently requires third-party tax equity, with an associated incremental cost. As a result, scenario results may overestimate the impact that a given PTC incentive level could have on future deployment. At the same time, the lack of explicit consideration of discretionary deployment (e.g., voluntary Green Power Pricing Programs) suggests that the model results may underestimate this aspect of future deployment.

This analysis does not consider the potential federal government revenue impacts associated with the PTC scenarios modeled here. A net revenue impacts assessment would estimate tax expenditures and tax receipts associated with wind generation capacity investment in relation to other investments that might be pursued in the absence of the PTC. A more simplistic approach to estimate federal revenue impacts might consider only the present value of the tax credits to be paid to wind project owners; however, this is only one of several components of the overall revenue impact.

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[10] More speculative estimated retirements could not be modeled due to a lack of data, specifically the location and the timing of affected plants. However, the opportunity for new capacity additions resulting from additional coal plant retirements beyond the approximately 60 GW reflected here is at least in part captured by the load growth assumptions included in high deployment sensitivity cases.

[11] For utility-scale PV, this trajectory reduces installation costs from \$4.0/W_{DC} in 2010 to \$1.5/W_{DC} by 2020. DG-PV capacity additions are modeled outside of ReEDS and are consistent with the SunShot 62.5% cost reduction trajectory.

Scenarios analyzed (including those presented above) are not intended to be forecasts or predictions; rather, the model employed provides a consistent framework for assessing the impact of different technology, market, and policy conditions reflected in the scenarios analyzed.

2.4 Analysis Assumptions in Context

Figure 2 summarizes the range of values applied in this study for key model inputs, including energy demand, technology cost and performance, fuel prices, and policy/regulatory support. The figure also places the explicit values modeled within a range of potential inputs for these variables. Values used in recent studies are shown for reference. This standardized contextual framework informs the design of specific scenarios explored in the analysis and provides a visual means for conveying these values in the context of a range of study assumptions employed for future technology, market, and policy conditions.

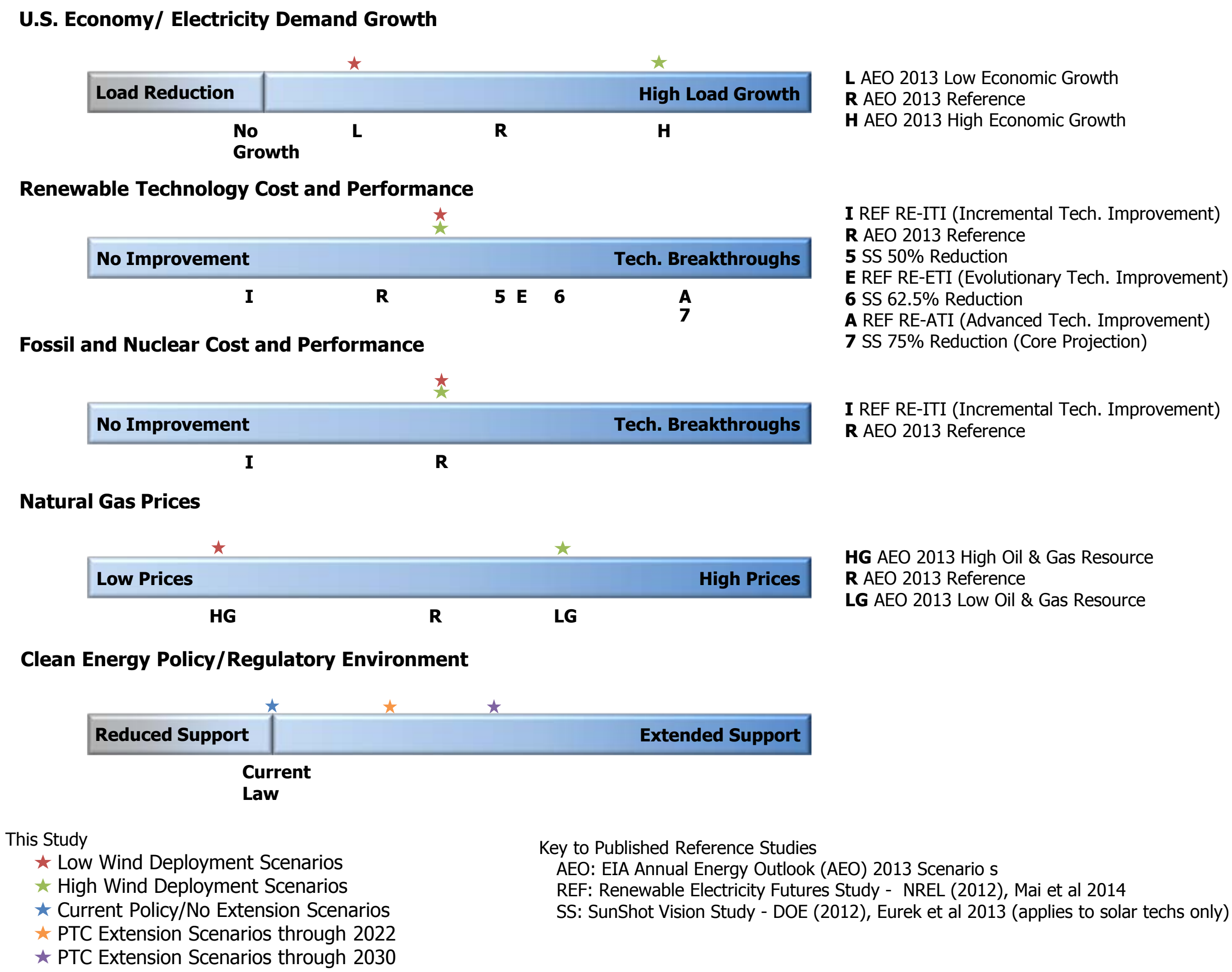

Figure 2. Analysis assumptions in context of standard framework

Notes: Scenarios assessed in this analysis are shown as stars, distinguished by color, positioned above each bar relative to the qualitative end points identified for the input variable (e.g., low prices, high price for natural gas). Corresponding input assumptions for other recent studies are identified below each bar and referred to specifically to the right.

3 Results

The presentation of results is focused on near-term implications of a PTC extension. Results through 2020 are discussed in detail in Section 3.1. Results through 2030 are discussed more generally in Section 3.2.

3.1 Results Through 2020

Analysis results indicate that U.S. wind power deployment through 2020 is sensitive to both the prospective PTC level and market conditions over time (Figure 3). Detailed discussions of the results for each individual scenario follow below. Implications from these results are considered in Sections 4–6.

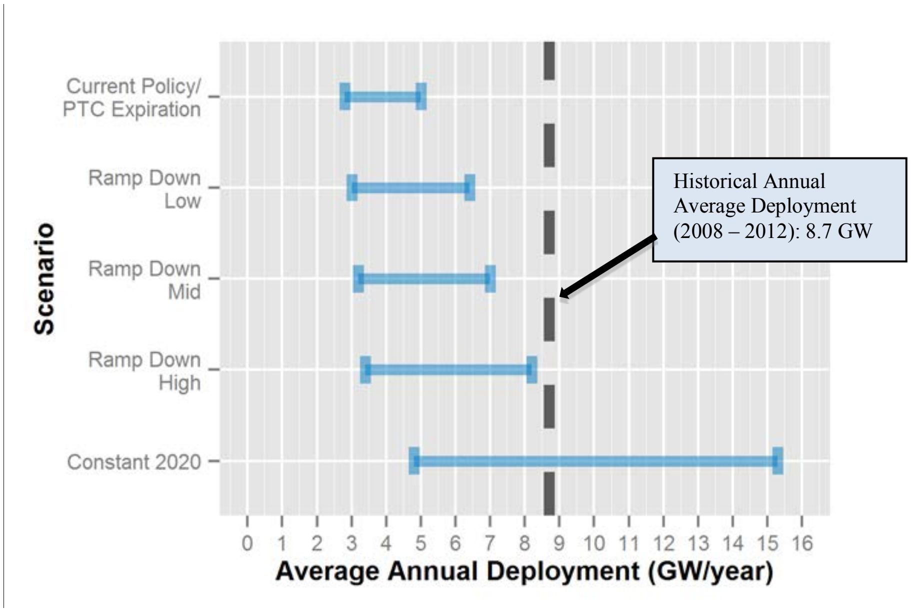

Figure 3. Projected average annual wind capacity deployed between 2013 and 2020 for PTC extension scenarios

Note: High and low ends of the projected ranges are based on the ranges of assumed future natural gas prices (high and low, respectively) and electricity demand growth (high and low, respectively). While an average projected annual addition through 2020 is depicted, wind capacity additions may not be distributed uniformly across the period.

3.1.1 Current Policy/PTC Expiration

Modeling results indicate an average of approximately 3–5 GW per year of wind installations from 2013 to 2020 for the Current Policy/PTC Expiration scenario. Installations in this scenario are driven in part by remaining unfilled existing state RPS requirements and are comparable to other short-term industry estimates (also based on the absence of a new PTC extension) (Bloomberg NEF 2013; MAKE 2013; Navigant 2013; IHS EER 2013). The relatively narrow band projected under this scenario indicates a general lack of sensitivity to changes in natural gas prices and load growth in the absence of policy support. Discretionary factors (e.g., bilateral corporate contracts or utility green power pricing programs) could supplement this level of deployment; however, in the absence of new policy support, annual additions are projected to remain well below the 8.7 GW per year achieved from 2008 to 2012.

3.1.2 Ramp-Down Scenarios

The near-term deployment implications of PTC ramp-down scenarios depend on the PTC level trajectory over time. Modeling results indicate that the three ramp-down scenarios considered here (Ramp Down Low, Ramp Down Mid, Ramp Down High) could support average annual wind installations through 2020 of 3–4 GW under low gas price/low load growth conditions and 6–8 GW under high gas price/high load growth conditions.

Notably, only the Ramp Down High case appears capable of supporting average annual installations close to the 2008–2012 annual average of 8.7 GW; the Ramp Down Low scenario appears to provide only a small amount of incremental deployment beyond the PTC Expiration scenario.

3.1.3 Constant 2020 Scenario

Modeling results indicate that extending the PTC at its current level through 2020 (Constant 2020) could result in additions within the range of recent builds. The full range of projected average annual installations is 5–15 GW. At this level of support, even low gas prices and low load growth conditions could result in a 65% increase in installations beyond the Current Policy/PTC Expiration scenario.

Given widespread historical reliance on third-party tax equity and the subsequent reduction in effective PTC value to project sponsors noted above, an additional Constant 2020 sensitivity was conducted assuming a one-third lower value for the PTC (i.e., modeling the PTC at an effective value of approximately $15/MWh as opposed to the $23/MWh full value achieved if a project sponsor were to have sufficient internal tax appetite to monetize the credit or if the credit were made refundable).[12] Under these conditions the Constant 2020 range of projected average annual installations is reduced to 3–9 GW.

3.2 Analysis Results Through 2030

The policy pathways described in Section 2 were modeled through the year 2030 to assess potential mid-term (2020 to 2030) deployment implications of the PTC extension scenarios considered here. As numerous market dynamics are at play, not all of which are represented in the modeling, and key model inputs—notably gas prices, load growth, and retirements—become increasingly uncertain over time, these results should be viewed as indicative only.

Near-term PTC policy scenarios (those expiring by the end of 2022) have only modest impacts on mid-term cumulative wind deployment (Figure 4); cumulative deployment of wind power in the electric sector through 2030 is projected to be comparable for these extension scenarios (roughly 90 GW or 7% of total generation for low sensitivity cases; 180 GW or 14% of generation for high sensitivity cases) and virtually the same as the Current Policy/PTC Expiration case. The provision of near-term policy support appears to effectively shift

[12] The actual impact of third-party tax equity on the effective value of the PTC is uncertain and varies depending on the explicit project financial structure. However, a one-third reduction has been suggested as a gross approximation. For additional detail, see Bloomberg NEF (2013) and Chadbourne & Park (2013).

deployment earlier in time.[13] However, this conclusion assumes that global innovation and wind industry cost reductions proceed with or without U.S. deployment. If U.S. deployment is material to global wind industry innovation and a key driver of future cost reductions, policy scenarios that result in lower near-term deployment may not achieve the mid-term deployment levels presented below. In contrast to the near-term policy scenarios, the Constant 2030 scenario, where the historical support structure is maintained throughout the analysis period, results in greater deployment under both low and high sensitivity cases.

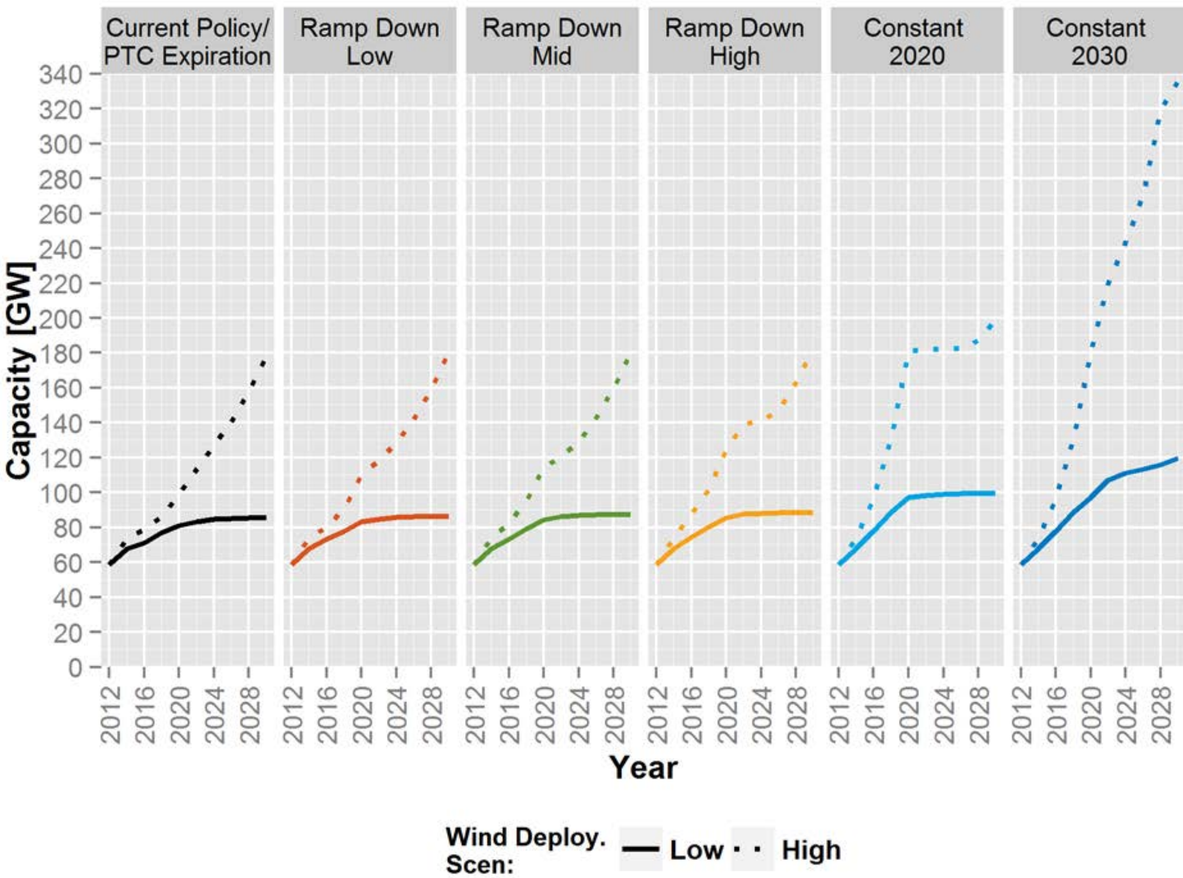

Figure 4. Range of projected cumulative wind capacity deployed through 2030 for PTC extension scenarios

[13] Under the conditions assumed in this analysis, policy results in a temporary shift in wind supply making more wind power potential cost competitive. Following policy termination, a period of little deployment is observed due to an effective step-change in the cost of the next wind plant.

4 Implications for Domestic Manufacturing

U.S. wind power manufacturing production varies by component type. Among major turbine components in 2012, an estimated 7.4 GW of towers, 8.1 GW of blades, and 13.0 GW of nacelles were produced or assembled domestically (James and Goodrich 2013). In aggregate, these production levels generally align with annual average wind power capacity additions in the United States from 2008 to 2012.

In the absence of U.S. domestic demand for new wind capacity, global markets are unlikely to offer many opportunities for U.S.-based manufacturers. Trade flows of wind products are generally limited in the global industry due to relatively high shipping costs for major turbine components. As a result, foreign direct investment in regions with strong demand for wind products is common as the cost structure of the industry favors regional manufacturing hubs (Kirkegaard et al. 2009). In the United States, the factory gate prices for components like blades, which are labor-intensive to produce, also tend to be higher than the prices of the same goods manufactured in many other regions, further limiting export opportunities from U.S.-based facilities (James and Goodrich 2013).

Given the limited export market, a reduction in domestic wind power deployment is likely to have a direct and negative effect on U.S.-based wind turbine manufacturing production and employment. This is notable as the manufacturing sector has been observed to represent a substantial share of wind industry jobs (Bloomberg NEF 2012; Lantz and Tegen 2008). In addition, reductions in demand can be expected to translate relatively rapidly into factory closures and job losses. The effects of reduced demand for 2013 equipment deliveries became evident as early as 2012 as year-over-year employment in wind manufacturing fell by nearly 5,000 workers, and 12 facilities exited the U.S. wind market (Wiser and Bolinger 2013).

Under some extension scenarios analyzed in this report, negative effects on U.S.-based wind manufacturers may be muted. The Constant extension scenarios could offer an opportunity to achieve deployment levels for a range of potential market conditions that align with both recent installation trends and domestic manufacturing production. Under relatively high gas prices and load growth, the Ramp Down High scenario can also enable current production levels to remain relatively constant through 2020. Projected deployment in the other PTC extension scenarios is likely to be insufficient to maintain domestic manufacturing at recent historical levels.

5 Other Policy-Relevant Considerations

Results presented above suggest that when considering PTC extensions, an extension of current policy can provide an opportunity to maintain a rate of wind installations consistent with deployment observed from 2008 to 2012 for a range of potential market conditions. However, under nearly all conditions analyzed, a PTC that expires or ramps down prior to 2022 is unlikely to generate levels of wind deployment consistent with the 2008–2012 5-year average.

At the same time, stable wind deployment is only one of many objectives that might be served by a PTC extension. Other factors, although not explored in this study, could also be considered as objectives and include:

- Greater certainty for foreign and domestic investment in U.S. industry
- Sustained conditions for continued technology innovation
- Reduced electric sector greenhouse gas emissions, air pollution, and water use
- Greater diversity of electric generation sources
- Reduced electric sector demand for natural gas, potentially enabling reduced pipeline congestion in critical regions, lower gas prices, or increased exports
- Maintained or improved global competitiveness of U.S.-based manufacturing
- Maintained or reduced cost of generation as a key economic input to U.S. economic competitiveness.

The contribution of a PTC extension to the achievement of the above objectives could also be assessed.

In addition, the complexity associated with the use of a tax credit as the primary incentive for wind technology has some associated challenges. Chiefly, the PTC, in its current form, is widely recognized as costly to monetize due to lack of financial market fungibility and constraints to tax equity supply (Mendelsohn and Harper 2012; Bloomberg NEF 2013; Chadbourne & Park 2013). In contrast, a refundable form of the credit would obviate the need for project sponsors lacking tax appetite to rely on third-party tax equity, with its associated transaction costs. As such, this refundable form could result in a higher level of wind deployment for the same cost to the federal government. Alternative policies, such as opening public capital vehicles (e.g., master limited partnerships) to wind power technologies or federal carbon standards, also offer the opportunity to support wind deployment and provide associated manufacturing and installation-related employment support at potentially lower total cost.

Finally, given the uncertainty associated with key variables (e.g., fossil fuel prices, load growth) in this analysis, if the policy objective is to maintain a minimum level of wind power deployment or to limit contraction of the existing wind industry, policymakers could also consider alternative policies that might provide greater certainty in future deployment levels.

6 Conclusions

The high-level findings from this analysis are summarized as follows:

- Under a scenario in which the PTC is not extended and all other policies remain unchanged, wind capacity additions are projected to be between 3 GW and 5 GW per year from 2013–2020.
- U.S. wind power manufacturing production generally aligns with average annual wind power capacity additions from 2008 to 2012. In the absence of U.S. domestic demand for new wind capacity, global markets are unlikely to offer many opportunities for U.S.-based manufacturers. Given the limited export market, a reduction in domestic wind power deployment is likely to have a direct and negative effect on U.S.-based wind turbine manufacturing production and employment.
- Modeled PTC extension options that ramp down and cease support by year-end 2022 appear to be generally insufficient to support deployment close to recent levels and therefore may be insufficient to sustain the current industry domestic manufacturing and supply chain through 2020.
- Of the scenarios considered, an extension of the PTC at its historical level could provide the best opportunity to support deployment consistent with recent levels across a range of market conditions; it therefore could also provide the best opportunity to sustain the existing wind installation and manufacturing base at its current level.
- In the current low-priced natural gas regime, modeling results indicate that future wind deployment will be relatively low unless additional incentives are provided that result in wind being cost competitive with *existing* gas-fired generation.
- Future uncertainty in key modeling variables, including gas prices and load growth, translates into high levels of uncertainty in the deployment outcomes of specific extension scenarios.

This work provides insight into wind deployment under current policy and various PTC extension scenarios. One possible next step would be to estimate the federal government revenue impacts associated with these scenarios. This might entail evaluation of tax expenditures but could also look more comprehensively at net revenue impacts also accounting for changes in tax receipts. Future work could also consider how other policy mechanisms affect U.S. wind deployment or further consider how changes in deployment could affect domestic wind industry manufacturing. Exploring the role of U.S. wind deployment in driving global wind technology and manufacturing innovations, along with associated future cost reductions, can also provide critical insights into the interaction of policy and future U.S. wind deployment.

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Appendix A: Additional Information on Model Inputs and Assumptions

Wind Costs

Supply curves for wind technology, which reflect wind cost as a function of available resource, are developed from current and projected wind technology cost and performance. This analysis assumes a 2012 LCOE (excluding the PTC) of approximately $61/MWh for projects sited in median resource conditions (based on 2011 and 2012 installations). The overall range in 2012 LCOE varies from approximately $55/MWh to $91/MWh, depending on resource quality.

Cost projections apply the median case cost reduction trajectory shown in Figure A-1 and are based on a literature review reported by Lantz et al. (2012). The median cost reduction trajectory results in a 15% reduction in LCOE by 2020 and achieves an approximately 20% reduction by 2025.

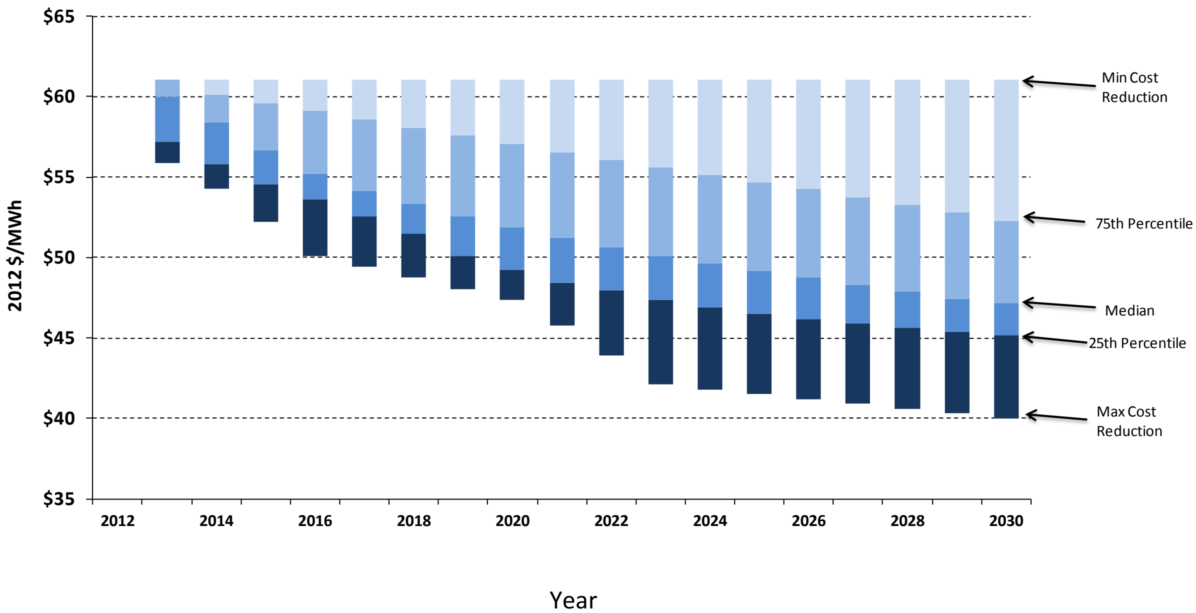

Figure A-1. Projected wind levelized cost per industry literature review

Source: Lantz et al. (2012)

Natural Gas Prices

Supply curves for gas-fired technologies in the ReEDS model are developed using natural gas price trajectories from the High and Low Oil and Gas Resource cases reported in the AEO (EIA 2013b). Input gas prices from both cases are shown in the Table A-1. These natural gas price trajectories are the inputs to the Low and High Wind Deployment sets of scenarios, respectively.

Table A-1. Input Electric-Sector Delivered Natural Gas Prices (2013$/MMBtu)

Year	AEO 2013 High Oil & Gas Resource	AEO 2013 Low Oil & Gas Resource
2013	$3.68	$4.10
2014	$3.49	$4.25
2015	$3.38	$4.40
2016	$3.59	$5.02
2017	$3.56	$5.37
2018	$3.63	$5.73
2019	$3.65	$6.06
2020	$3.66	$6.29
2021	$3.70	$6.53
2022	$3.75	$6.76
2023	$3.80	$6.92
2024	$3.86	$7.06
2025	$3.93	$7.22
2026	$3.95	$7.48
2027	$3.99	$7.61
2028	$4.01	$7.78
2029	$4.03	$7.86
2030	$4.15	$7.87

Source: EIA (2013b)

Gas prices driving dispatch of the existing fleet and factoring into new build decisions are subsequently calculated endogenously in the model and are responsive to changes in modeled electric sector demand for natural gas. Calculated natural gas prices applied in the ReEDS modeling completed in this analysis are shown in Tables A-2 and A-3.

Table A-2. Model-Calculated Electric-Sector Delivered Natural Gas Prices (2013$/MMBtu)—Low Wind Deployment Set of Scenarios

	Low Wind Deployment					
Year	Current Policy/ PTC Expiration	Ramp Down Low	Ramp Down High	Ramp Down Mid	Constant 2020	Constant 2030
2012	$3.71	$3.71	$3.71	$3.71	$3.71	$3.71
2014	$3.51	$3.48	$3.51	$3.51	$3.51	$3.51
2016	$3.28	$3.21	$3.28	$3.28	$3.27	$3.27
2018	$3.18	$3.14	$3.18	$3.18	$3.18	$3.18
2020	$3.10	$3.06	$3.10	$3.10	$3.10	$3.10
2022	$3.21	$3.17	$3.19	$3.20	$3.11	$3.06
2024	$3.21	$3.17	$3.19	$3.20	$3.15	$3.11
2026	$3.26	$3.23	$3.26	$3.26	$3.21	$3.17
2028	$3.24	$3.19	$3.23	$3.24	$3.22	$3.17
2030	$3.27	$3.23	$3.26	$3.27	$3.25	$3.20

Source: EIA (2013b) and NREL

Table A-3. Model-Calculated Electric-Sector Delivered Natural Gas Prices (2013$/MMBtu)—High Wind Deployment Set of Scenarios

	High Wind Deployment					
Year	**Current Policy/ PTC Expiration**	**Ramp Down Low**	**Ramp Down High**	**Ramp Down Mid**	**Constant 2020**	**Constant 2030**
2012	$3.71	$3.71	$3.71	$3.71	$3.71	$3.71
2014	$4.20	$4.20	$4.20	$4.20	$4.20	$4.18
2016	$4.77	$4.77	$4.76	$4.77	$4.68	$4.64
2018	$5.69	$5.65	$5.56	$5.63	$5.36	$5.33
2020	$6.37	$6.28	$6.17	$6.24	$5.74	$5.71
2022	$6.85	$6.83	$6.66	$6.82	$6.34	$6.09
2024	$7.14	$7.15	$7.07	$7.15	$6.77	$6.35
2026	$7.51	$7.52	$7.51	$7.52	$7.26	$6.72
2028	$7.78	$7.79	$7.78	$7.78	$7.63	$6.99
2030	$7.98	$7.95	$7.97	$7.96	$7.87	$7.32

Source: EIA (2013b) and NREL

In general, scenarios resulting in higher levels of wind deployment result in lower natural gas consumption in the electric sector; this reduction in the overall demand for gas contributes to lower relative gas prices.

Load Growth

High and low electricity load growth estimates are derived from the AEO High and Low Economic Growth cases (EIA 2013b). Detailed information on those cases is shown in Table A-4 and Figure A-2.

Table A-4. AEO 2013 Electricity Load Growth—Low and High Economic Growth Cases

	Average Annual Load Growth		
	2013 - 2020	**2021-2030**	**2013-2030**
AEO 2013 Low Economic Growth	0.4%	0.5%	0.5%
AEO 2013 High Economic Growth	1.2%	1.0%	1.1%

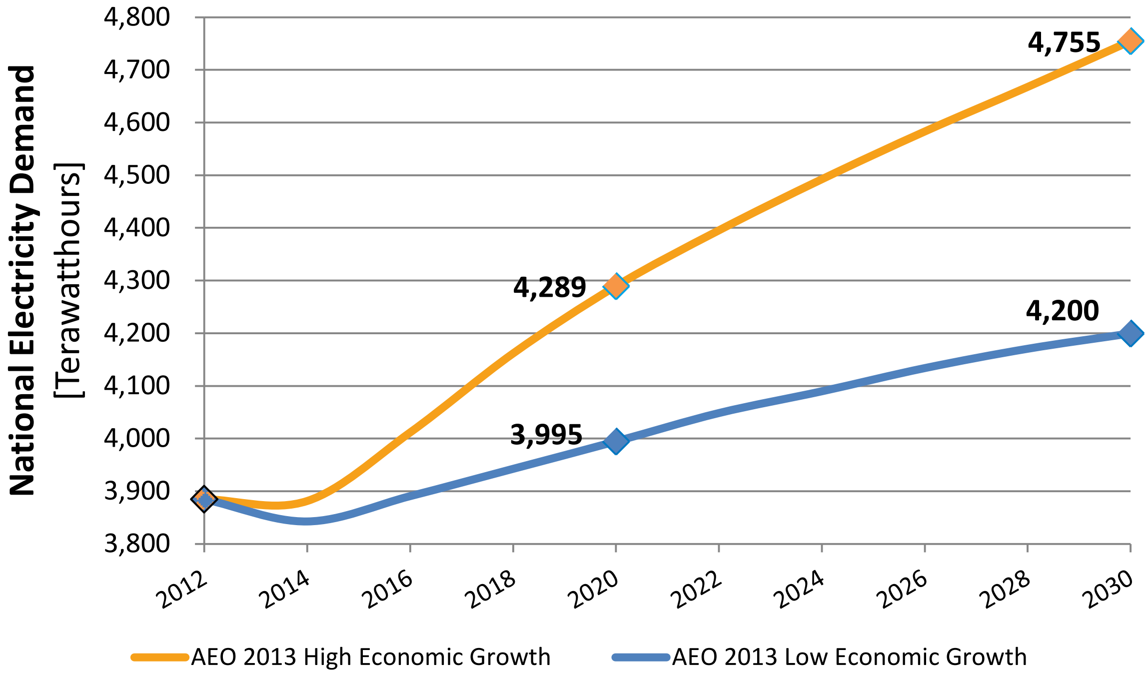

Figure A-2. Projected electricity load growth from AEO 2013 assumed in this analysis

Source: EIA (2013b)

Note: Demand axis (y-axis) does not begin at zero.