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Journey to grid parity
Three converging forces
provide a tailwind for
US renewable power

Deloitte Center
for Energy Solutions



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Executive summary

In the US, the debate about when renewable energy will achieve “grid parity,” or the ability to compete on equal footing with conventional sources of generation, generally assumes the continuation of at least some state and federal subsidies for wind power and utility-scale solar photovoltaics (PV). This analysis, however, takes a different tack. Here, subsidies have been purposefully excluded from the assessment of grid parity in order to provide a different, and perhaps more relevant, perspective on the competitiveness of the renewable energy sector.

Key findings

1. Renewable power generation reaching grid parity without federal or state subsidies is not imminent, except in certain markets possessing the most robust renewable resources and having relatively high wholesale power market prices. Indeed, without dramatic cost declines and improvements in efficiency and utilization, it is unlikely that some parts of the US can reach grid parity without federal or state incentives within the next 10-15 years.
2. Onshore wind is more likely to reach grid parity before utility-scale solar PV, under a wide range of assumptions.
3. While it is widely accepted that the continuation of the federal Production Tax Credit (PTC) for wind and the federal Investment Tax Credit (ITC) for solar would allow the renewable generation sector to reach grid parity faster, the extent of the acceleration—by as much as a decade—is more pronounced than one might expect.
4. Lowering the cost of capital—by adding project-level debt at the outset of the project for instance—advances grid parity timing by around five years across most markets for onshore wind and solar PV.
5. Three trends are converging, which are collectively pushing renewable energy development forward: forecasted rising natural gas prices, wholesale power market rebalancing, and ongoing improvements in renewable technology. Whether or not these trends continue and to what degree will affect the timing of grid parity.
6. While there are many uncertainties, the pace of innovation across technology, processes, and financing is the big wild card. While it is difficult to include in an economic modeling exercise such as this, innovation should be acknowledged as a factor that could shorten the journey to grid parity to a great extent.



This analysis was performed by Deloitte MarketPoint. A detailed discussion of the methodology used in the analysis, along with sample calculations, can be found in Appendices A and B.

Introduction

At present, many states and countries provide targeted and sometimes significant incentive schemes to engender new renewable energy project development. In the US, these are chiefly in the form of the federal PTC for wind, which currently provides a 2.3 cents per kilowatt hour subsidy over the initial 10 project years to eligible technologies; the federal ITC for solar, which presently provides a 30 percent tax credit for solar generators; or tradable Renewable Energy Credits or Certificates (RECs), which provide a stream of additional income to developers as part of some state-sponsored Renewable Portfolio Standards (RPS) programs. Additionally, many states offer other programs such as job

credits, research and development incentives, and sales and use and/or property tax exemptions for renewable property.

Herein, the term “compete” means that revenue earned from regional wholesale power markets alone would cover capital investment for renewable energy projects, along with operating and financing costs, including profit on a going-forward basis. Notably, although many renewable energy projects are at least partially contracted using Power Purchase Agreements (PPAs) and do not earn revenue directly tied to wholesale power market prices, rapidly advancing project economics and changing market conditions could impact future renewable energy development and the availability and terms of PPAs.

This report examines the timing and conditions necessary for onshore wind and utility-scale solar PV to compete with conventional sources of generation on their own, or achieve “grid parity,” without federal or state subsidies.

The following analysis, which uses four different models, along with power price projections from Deloitte MarketPoint’s North American Integrated Market (NAIM) Reference Case outlook, investigates six wind and six solar US market regions—all of which have active renewable energy project development or a large installed base of generation capacity.¹ The results of this analysis provide a differentiated perspective on the grid parity debate, since potential timelines are often based on the continuation of subsidies as opposed to their absence.



The confluence of three trends

The grid parity analysis performed by Deloitte MarketPoint indicates the confluence of three trends, which taken together provide evidence that in the foreseeable future renewable energy may be able to compete on a level playing field with conventional generation sources. These trends are:

1. Forecasted rising natural gas prices
2. Wholesale power market rebalancing
3. Improvements in renewable technologies

In order to identify and better understand these trends, the analysis examined natural gas markets over a 25-year horizon. It also considered the natural gas supply in the US, including capital development costs to meet gas demand for power generation as well as demand for residential, commercial, and industrial uses. It additionally explored how the abundance of shale gas is reshaping the supply picture, including the potential impact of liquefied natural gas (LNG) exports on the natural gas supply-demand balance and market prices.

Concerning power market rebalancing, the analysis considered the current and future conditions of regional power markets. Each market has its own resource characteristics, seasonal load shape, and expectations for future demand growth. Furthermore, markets vary in terms of overall supply-demand balance with some experiencing significant oversupply conditions and others greatly depending upon imports. In addition, several high-profile regulatory developments have recently come into play, including policies to reduce carbon and other emissions, which could force further plant retirements, particularly coal, thus affecting the supply picture.



Along with the evolution of natural gas prices and power markets, the analysis further examined how renewable energy is reshaping the power market landscape as it enters the mainstream as a highly technological and efficient source of generation. Furthermore, as the sector has matured, overnight construction costs have dropped, precipitously in some instances, while technological advances have led to better operating characteristics. This combination is instrumental in bringing renewable energy closer to grid parity with conventional sources of generation.

With this background in mind, the following sections explore each of the three aforementioned trends in greater depth.

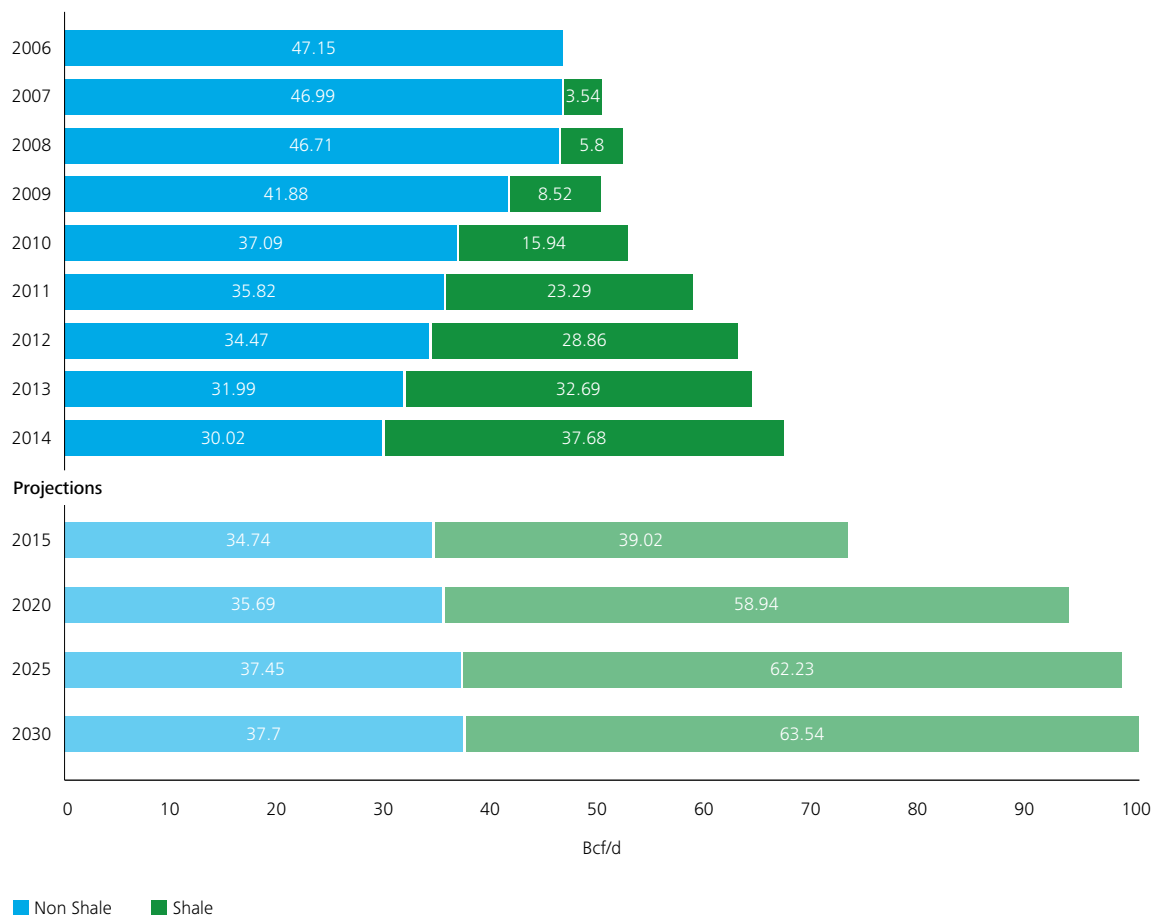
Trend #1: Rising natural gas prices

In recent years, US natural gas markets have been transformed with the advent of abundant, economic shale gas. This transformation was largely made possible by the combination of hydraulic fracturing technologies and horizontal drilling techniques.

For the natural gas markets, the “shale revolution” has advanced very rapidly, causing supply to move ahead of demand. Accordingly, this supply surge has resulted in a

relatively low gas-price environment (i.e., compared to the mid-2000s), which has now persisted for several years. At the beginning of 2014, the US Energy Information Administration (EIA) estimated total proved US conventional and shale reserves to be 354 trillion cubic feet (Tcf) and total estimated technically recoverable resources and proved reserves to be 1,400 Tcf.² Figure 1 shows the historic and projected supply of conventional natural gas compared to that of unconventional shale gas from 2006 through 2030.³

Figure 1. US gas supply by source



Source: US EIA Natural Gas Gross Withdrawals Report, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm; EIA Drilling Productivity Report, <http://www.eia.gov/petroleum/drilling/>; and Deloitte MarketPoint NAIM Reference Case (Summer 2015).

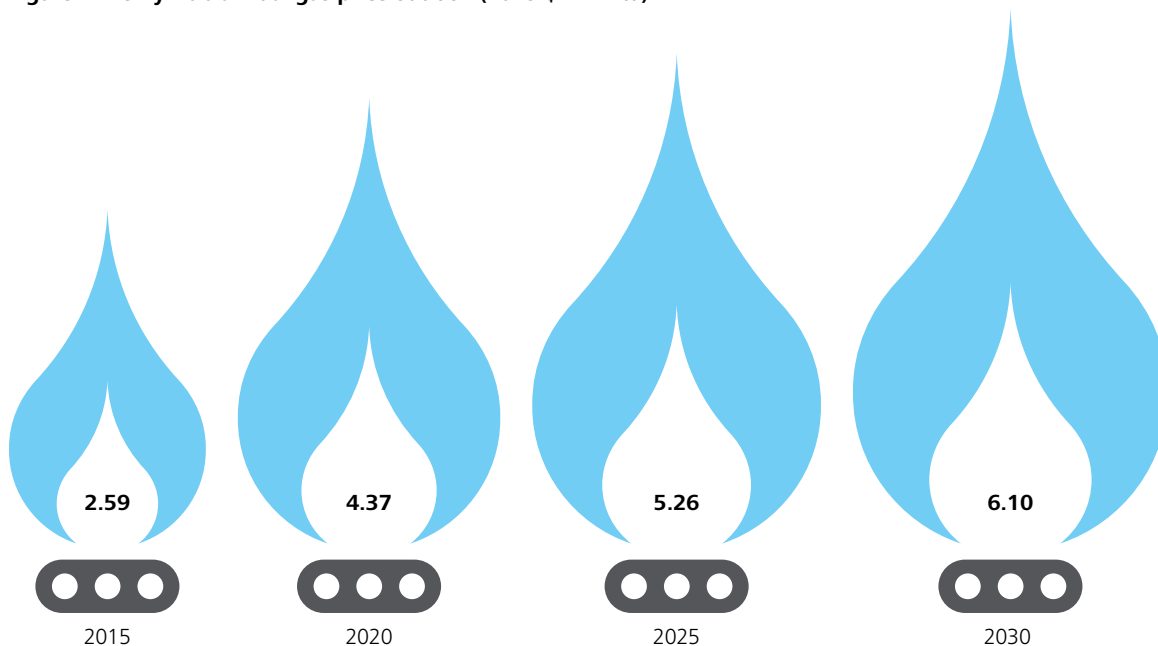
The dramatic growth in shale gas, and the resulting oversupply condition, has led to two developments that would have been virtually unthinkable a decade ago: an industrial renaissance in the US, driven by the use of natural gas as a fuel or feedstock, and the US becoming a major exporter of LNG. In its Q4 2015 World Gas Reference Case, Deloitte MarketPoint projects that by 2021, slightly less than 10 billion cubic feet per day (Bcf/d) of LNG will be exported from the lower 48 states, primarily from the Gulf Coast.

If these expectations become reality, what will be the effect on natural gas prices? In formulating its natural gas price outlook, the Deloitte MarketPoint analysis considers all sources of end-use demand in conjunction with all sources of conventional and unconventional supply. It also takes into account estimated demand growth and gas supply costs from various basins. Based on these fundamentals, the analysis projects a relatively steep rise in natural gas prices over the next decade. This rise is expected—despite expanding natural gas supplies—in order to fulfill existing demand within the residential and commercial sectors, as well as to meet new demand from LNG exports and from the industrial and power generation sectors.⁴

Figure 2 shows natural gas price projections through 2030 at the Henry Hub in Louisiana. Note, in this graph, natural gas prices have been adjusted for inflation and reflect constant 2015 dollars per million British Thermal Units (MMBtu). Importantly, natural gas prices at the Henry Hub typically resonate throughout the North American continent.

If this price strength comes to pass, it could help renewables to move toward grid parity in a number of ways. For instance, it could directly help renewables compete with gas-fired power plants. It would also put upward pressure on wholesale electricity prices, which could additionally aid renewables by providing the opportunity to earn higher margins in regional wholesale power markets, as well as by encouraging utilities and corporations to lock in PPAs as a hedge against further increases. Higher electricity prices could also encourage more consumers and businesses to pursue rooftop solar, shared solar, or other renewable offerings in an effort to save money and to gain greater control over their energy destinies. This, in turn, supports further development, potentially aiding the sector in gaining scale and continuing to drive down costs.

Figure 2. Henry Hub annual gas price outlook (2015 \$/MMBtu)



Source: US Deloitte MarketPoint NAIM Reference Case (Summer 2015).

Trend #2: Power market rebalancing

Presently, many power market regions, both regulated and deregulated, have excess generation capacity, with reserve margins extending well beyond the level required to meet reliability standards.⁵ Power generation, transmission, and distribution are all capital-intensive, with long construction lead times. Therefore, it is not uncommon for the wholesale power industry to experience boom-bust conditions. During the early days of power market restructuring, and on to the mid-2000s, the industry massively expanded, with more than 200 gigawatts (GW) of gas-fired generation capacity being built. This capacity expansion exceeded demand growth by a wide margin across many markets.

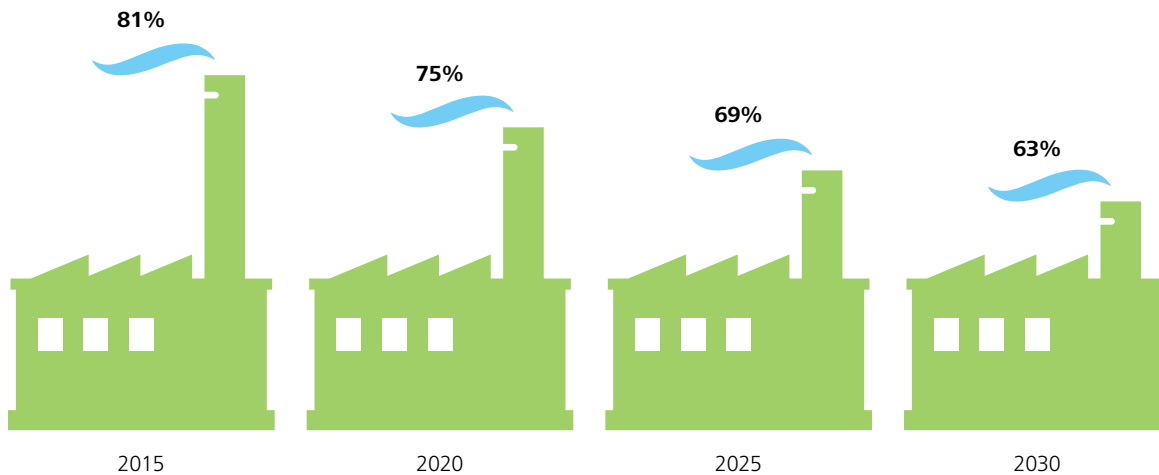
Today, as measured by the Dependable Reserve Margin (DRM), many power markets continue to experience oversupply conditions.⁶ Many point to the economic downturn as the main reason this imbalance has been

so persistent. Between 2008 and 2009, overall electricity demand across end-use sectors decreased 5.2 percent in the US. Furthermore, industrial demand alone dropped by 11 percent, a level that was unprecedented.⁷

Figure 3 shows the percentage of regional power markets [i.e., regional transmission operators (RTOs), independent system operators (ISOs), and regulated markets] that will have DRM in excess of 15 percent through 2030.⁸ This measure indicates that on average, many US power markets are over supplied, which tends to depress prices. Over the next 15 years, the Deloitte MarketPoint NAIM analysis projects a decline in that percentage to just over 60 percent. This has important power pricing implications for all types of generation, including renewables, since tighter reserve margins lead to more scarcity pricing and wider operating margins for generators.

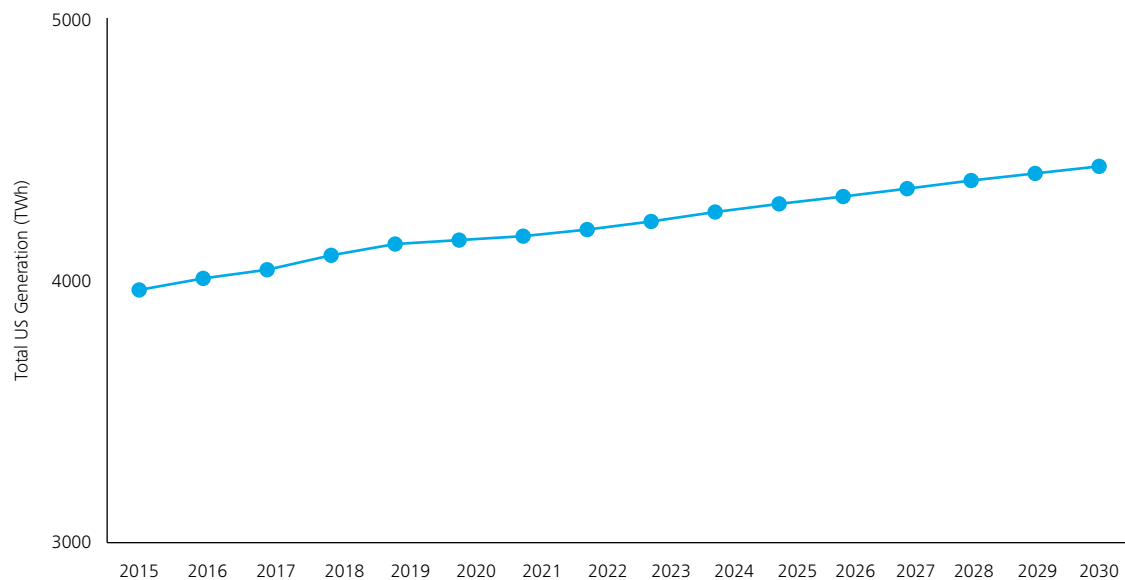
Figure 3. Power market DRM index

(Percentage of regions with peak day supply in excess of 15 percent)



Source: US Deloitte MarketPoint NAIM Reference Case (Summer 2015).

Figure 4. US lower-48 power market generation



Source: US Deloitte MarketPoint NAIM Reference Case (Summer 2015) and US Department of Energy, Annual Energy Outlook 2015.

The NAIM analysis additionally anticipates some electricity demand growth, albeit slight, as shown in Figure 4. Within the continental US, the analysis projects an average 0.8 percent annual rise in electricity demand throughout the forecast horizon. This growth, along with plant retirements, particularly from coal, should lead to a more sustainable DRM level over the coming decade, although there is some

degree of variability across the regional markets. These factors, combined with the anticipated rise in natural gas prices, should help bolster margins for renewable energy developers and operators, improve their ability to secure PPAs, and generally allow renewables to compete more equitably with conventional sources of generation.

Trend #3: Improvements in renewable technologies

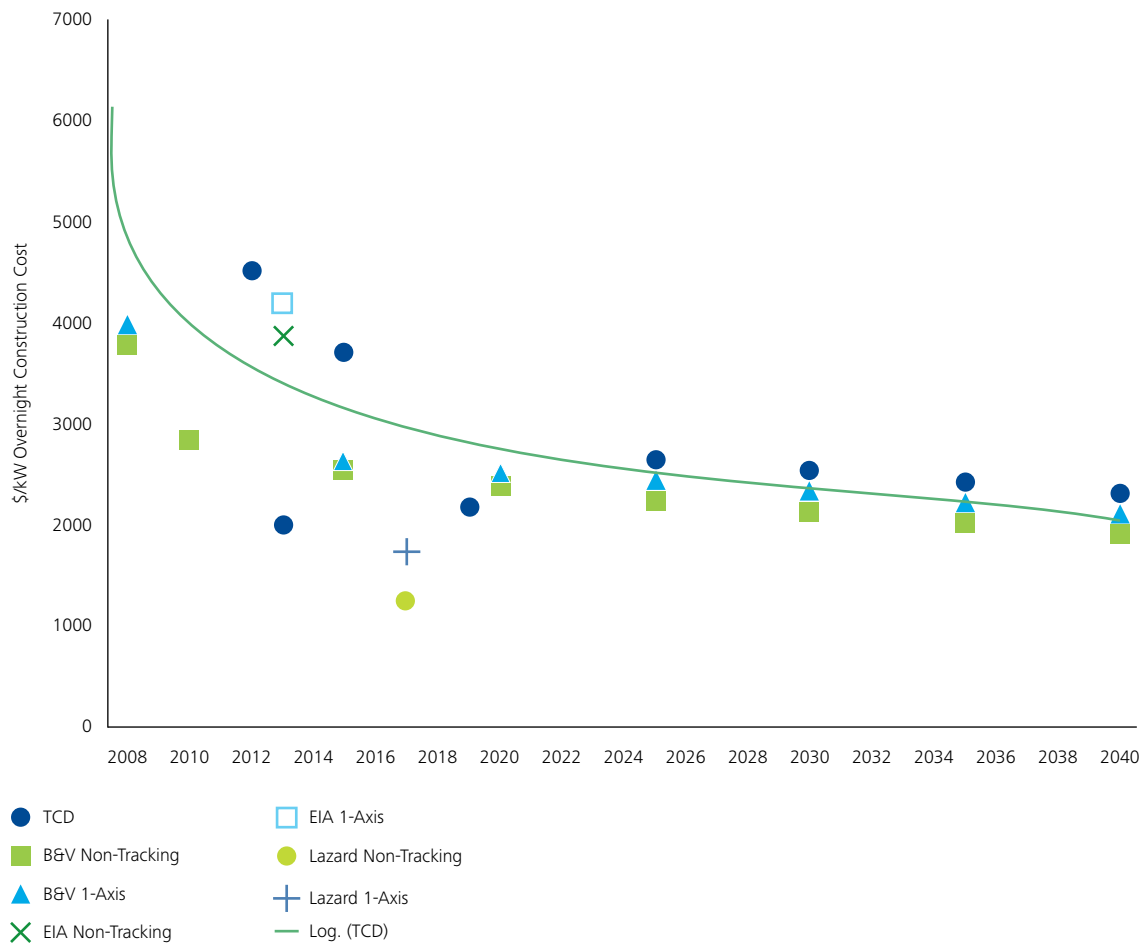
During the past decade, overnight construction costs have declined and capacity factors have improved for both onshore wind and solar PV, generally making the renewable sector more competitive. "Overnight cost" is defined as the all-in costs to build a utility-scale power generation facility, excluding financing costs and operating and maintenance costs. It is generally used to compare the economic feasibility of one type of generation technology versus another, such as natural gas combined cycle versus solar PV.

Due in part to state-sponsored RPS programs, falling overnight construction costs, and improved utilization rates, wind generation and solar generation on an energy production basis have grown by 24-fold and 34-fold respectively since 2001.⁹ The combination of higher utilization and declining costs is a critical driving force behind renewable energy's journey to grid parity.

Solar photovoltaic

Ground-mounted utility-scale solar PV installations currently range from one megawatt (MW) to more than

Figure 5. Utility-scale solar PV overnight construction costs (2008 to 2040)



Sources: NREL; Transparent Cost Database (TCD), <http://en.openei.org/apps/TCDB/>; Black & Veatch - NREL 2009 report, Table 25; EIA, Table 1, <http://www.eia.gov/forecasts/capitalcost/>; Lazard Levelized Cost of Energy (September 2014).

100 MW.¹⁰ Figure 5 shows the estimated overnight cost for constructing large solar facilities. Over the past five years, the overnight construction costs for utility-scale solar PV projects have declined by about 50 percent. Several organizations project future declines as well, but at a more gradual pace, eventually reaching a plateau around \$2000/kilowatt (kW) between 2030 and 2040; however, at least one source expects costs to fall much more aggressively to approximately \$1250/kW by 2017.¹¹ From our review of the literature and assessing the solar industry’s cost trend, we expect costs will likely continue to fall further during the forecast horizon.

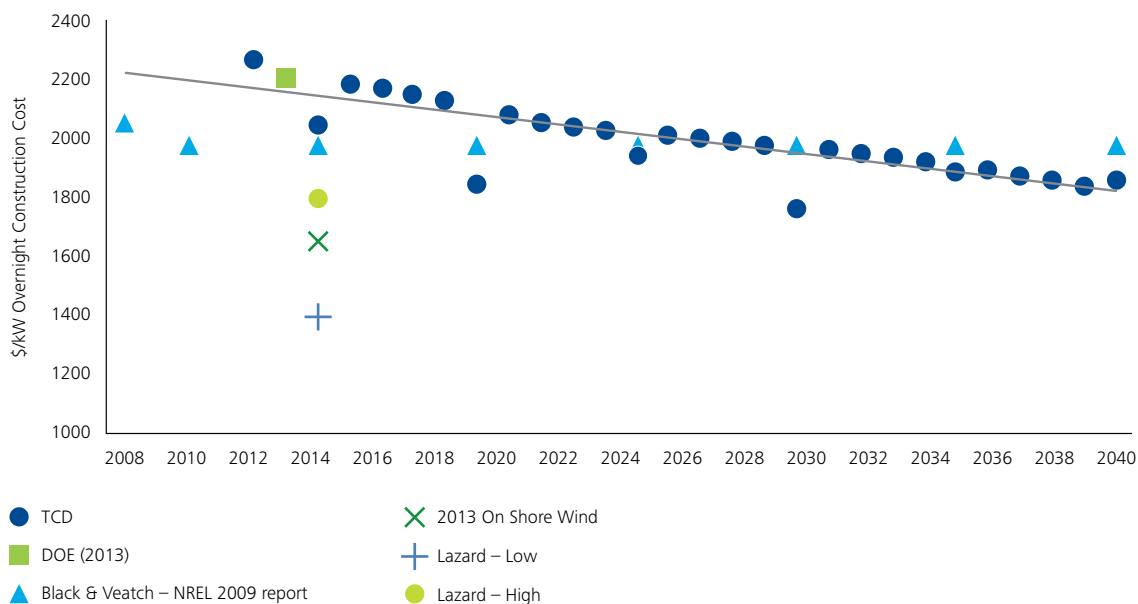
Conversion, or solar efficiency, has also improved in recent years. According to the National Renewable Energy Lab (NREL), conventional panel efficiencies have improved by 0.3 percent per year since 2000.¹² NREL tracks multiple technologies, and the efficiency levels both of thin film and crystalline silicon solar-cell technology have steadily improved since 2000 and now range in the low-to-mid 20s.¹³ This generally improves the value of solar investments since more energy can be produced from each panel or cell.

Onshore wind

Since 2000, several technical enhancements have come together to improve both the rated capacity and utilization (i.e., capacity factors) of onshore wind farms. These include variable speed turbines, taller towers and longer blades, and the selection of better wind sites, facilitated by advanced measuring techniques. These types of improvements have helped scale-up the rated capacity of wind towers/turbines from less than 1 MW to an average of 2 MW or greater today.¹⁴ For example, a 1.5–2.0 MW turbine now typically stands on a 200–250 foot tower.¹⁵ In addition, modern turbines are able to operate over a wider range of wind speeds, thus increasing their utilization, and improving their capacity factors. Indeed, new onshore wind farm capacity factors have improved markedly since 2000, reaching into the high 40s and even up to 50 percent utilization, well above the typical 30 percent range for many legacy projects.¹⁶

At the same time, overnight construction costs have declined substantially over the last few years, as illustrated in Figure 6. These declines can largely be attributed to the aforementioned technological advancements, along with manufacturing economies of scale and greater process efficiencies during construction. As with solar, future declines are generally expected.

Figure 6. Onshore wind overnight construction costs (2008 to 2040)



Sources: NREL, Transparent Cost Database (TCD), <http://en.openei.org/apps/TCDB/>; Black & Veatch - NREL 2009 report, Table 25; EIA <http://www.eia.gov/forecasts/capitalcost/> (table 1); and Lazard Levelized Cost of Energy (September 2014).

The analysis: Reaching grid parity without federal or state subsidies

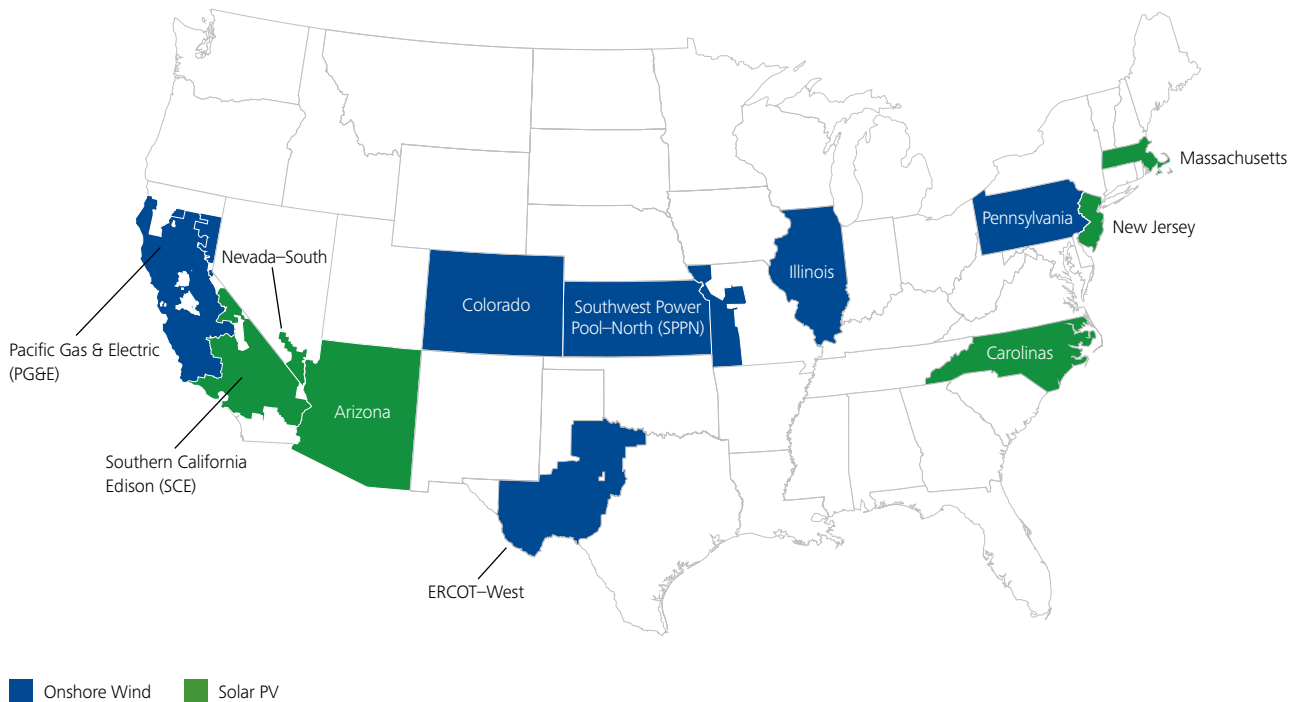
The combination of rising natural gas prices in North America, the rebalancing of wholesale power markets, and improvements in renewable technologies—in terms of overnight construction costs, total capacity, operating efficiency, and utilization—are driving factors reshaping renewable energy economics. Although there is a wide range of variability in the economics and potential of solar PV and wind across regions, the trend suggests that renewable energy projects could reach grid parity in several markets over the next 10-15 years without federal tax incentives or state RECs. This is especially true for wind. Furthermore, the following base-case forecast does not consider the implications of the Clean Power Plan (CPP) from the US Environmental Protection Agency (EPA) or state regulatory reform, such as the Renewing the Energy Vision (REV) initiative in New York, which has already stimulated similar efforts in more than a dozen states. While the impact of these impending policy changes cannot be known, they generally encourage, if not mandate, greater use of renewable technologies to curb carbon emissions and to

improve the resiliency of the electrical grid. By providing opportunities to build scale and by valuing renewables, either directly or indirectly, more than other forms of generation, they have the potential to accelerate the timeline for reaching grid parity.

To assess the timing of when renewables may reach grid parity without federal or state subsidies and incentives, Deloitte MarketPoint analyzed a total of 12 US wholesale power market zones or regions/states. They were selected from among the 76 zones in the Deloitte MarketPoint database because they represent the major US markets where wind and solar are already prevalent, or where significant future development is expected. Additionally, the selected zones span the three major interconnections: Western Electricity Coordinating Council (WECC), the Electric Reliability Council of Texas (ERCOT), and the Eastern Interconnection (EI).

Figure 7 shows the 12 market zones chosen for this analysis.

Figure 7. Wind and solar market zones analyzed



The following offers a brief rationale for why each zone was selected:

Onshore wind

- Pennsylvania: This commonwealth has experienced significant growth in wind generation, and it has relatively higher power prices than other regions within the Eastern Interconnection.
- PG&E: Covering parts of central and all of northern California, this zone represents the utility footprint of the PG&E Company. The NAIM Reference Case forecast provides SCE and San Diego Gas & Electric power prices as well. However, prices across all three California markets remain highly correlated throughout the forecast period, and choosing one region over another does not materially change the conclusions.
- Colorado: Located in the noncoastal WECC interconnection, this zone has seen wind development expand at a compound annual growth rate (CAGR) of 47 percent between 2001 and 2014.¹⁷
- ERCOT-West: This zone represents the most significant source of wind generation in Texas. As a leading wind producer, Texas accounted for 22 percent of US wind generation in 2014.¹⁸
- Illinois: This state has relatively higher wholesale power prices in the first half of the NAIM forecast, and it has experienced strong growth in wind generation (60% CAGR) between 2003 and 2013.¹⁹
- SPP-North (SPPN): This zone, which overlaps Kansas, has experienced a tremendous amount of wind development since 2001 (54% CAGR). Notably, in 2014, wind generation in Kansas reached 10,844 gigawatt hours (GWh).²⁰



Solar

Overall, the six solar zones selected represented 88 percent of total US solar generation in 2014, although these figures include solar thermal power plants as well as solar PV installations.²¹

- SCE: This zone was chosen due to the significance of solar in southern California. As of 2014, California accounted for 56 percent of total installed solar generation in the US.²²

- Arizona: This desert state accounts for 18 percent of the solar generation in the US, or approximately 10,000 GWh.²³
- Nevada-South: This zone, which encompasses Las Vegas and a large portion of the Mohave Desert, represents another hot spot in solar development.
- The remaining three zones collectively represent nine percent of the total solar generation in the US: Massachusetts (2%), the Carolinas (4%), and New Jersey (3%). These zones represent much of the regional expansion for solar across the eastern seaboard. In addition, relatively higher wholesale power prices projected for these regions push forward grid parity by as much as a decade compared to SCE, Arizona, and Nevada-South.²⁴

In assessing the timing of grid parity in each of these zones, the analysis incorporated four separate components: the Deloitte MarketPoint Summer 2015 NAIM power market price projections; a time-of-day operating factors model; regional wind and solar generation curves; and a levelized capacity cost model, which provides the annual revenue required in order for new solar PV and onshore wind generation capacity to be profitable. Notably, the levelized capacity cost model comprises both overnight construction costs and financing considerations, such as return on equity (after tax), book life, depreciation rate, and other financial assumptions.



The findings

Appendix A provides more detail on these models.

Based on the collective output of the aforementioned four models, Figure 8 highlights the projected timelines for reaching grid parity without subsidies for onshore wind across three levels of capacity factors, 30 percent, 40 percent, and 50 percent, and three levels of overnight construction costs, \$1000/kW, \$1250/kW, and \$1500/kW. These ranges generally encapsulate the uncertainty facing wind developers.

Overall, grid parity is highly region-specific. In general though, earlier grid parity is achieved with a combination of high capacity factors, lower overnight construction costs, and higher wholesale power prices. For example, in Pennsylvania, relatively higher wholesale power prices allowed it to achieve the earliest grid parity projection in the analysis—as soon as 2016. On the other hand, the combination of low capacity factors and relatively high overnight construction costs can delay grid parity to the far end of the spectrum—sometime after 2040. Meanwhile, ERCOT–West offers a good example of a middle-of-the-road scenario: it has relatively low wholesale power prices and good wind characteristics, which improve capacity factors. The analysis suggests that depending on the level of overnight construction costs, grid parity can be reached in ERCOT–West between 2020 and 2027 when a 50% capacity factor is assumed.



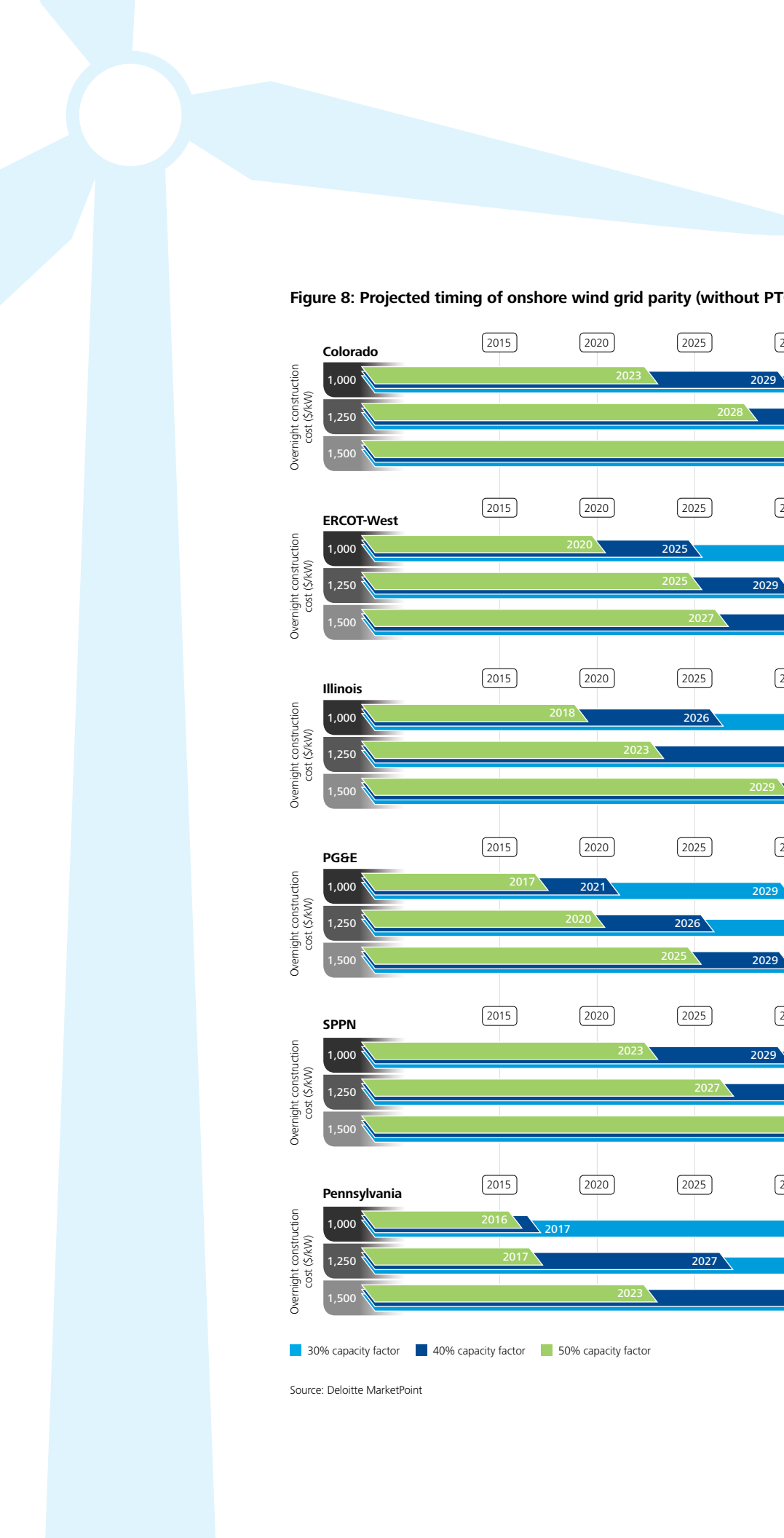
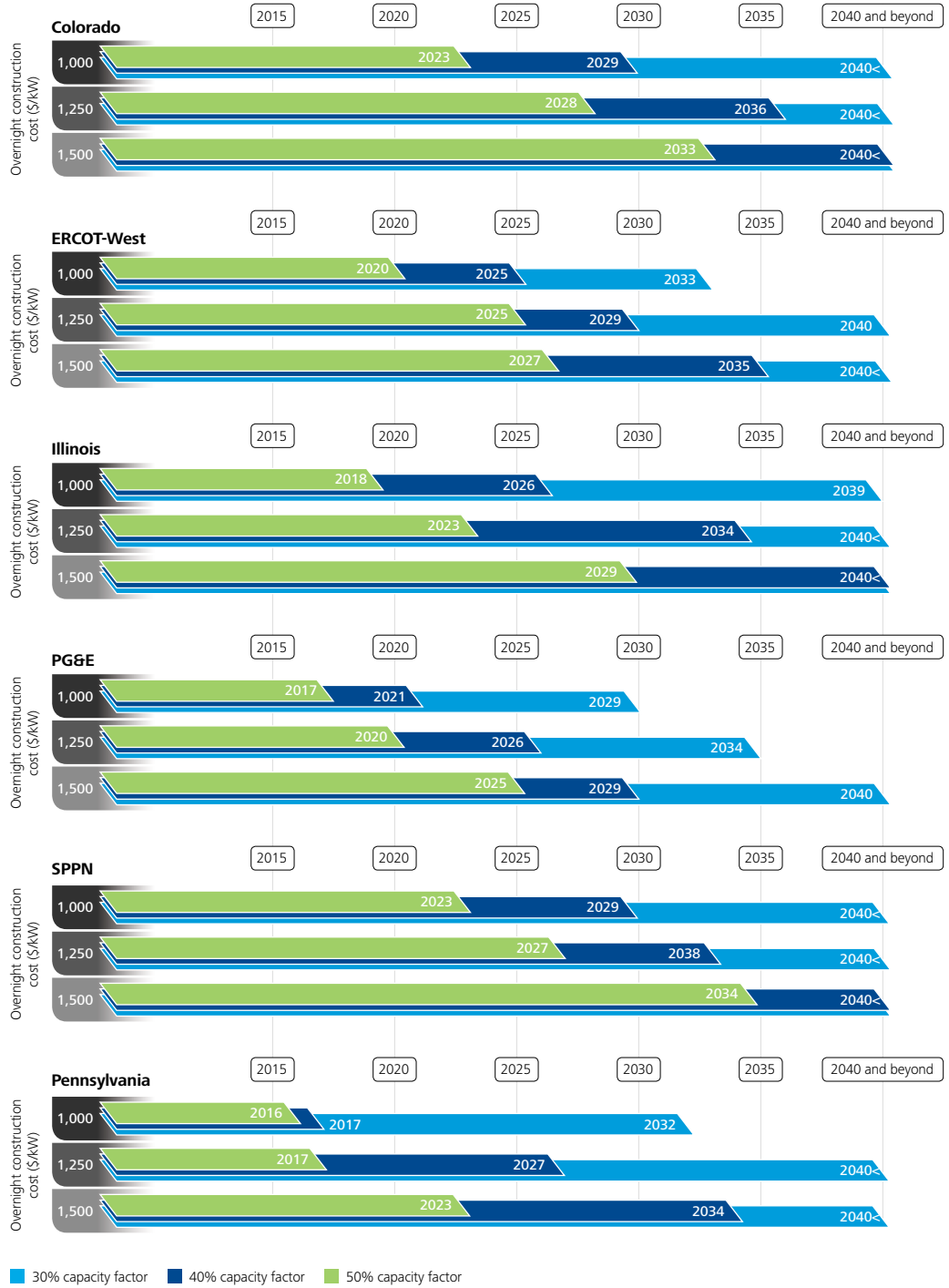


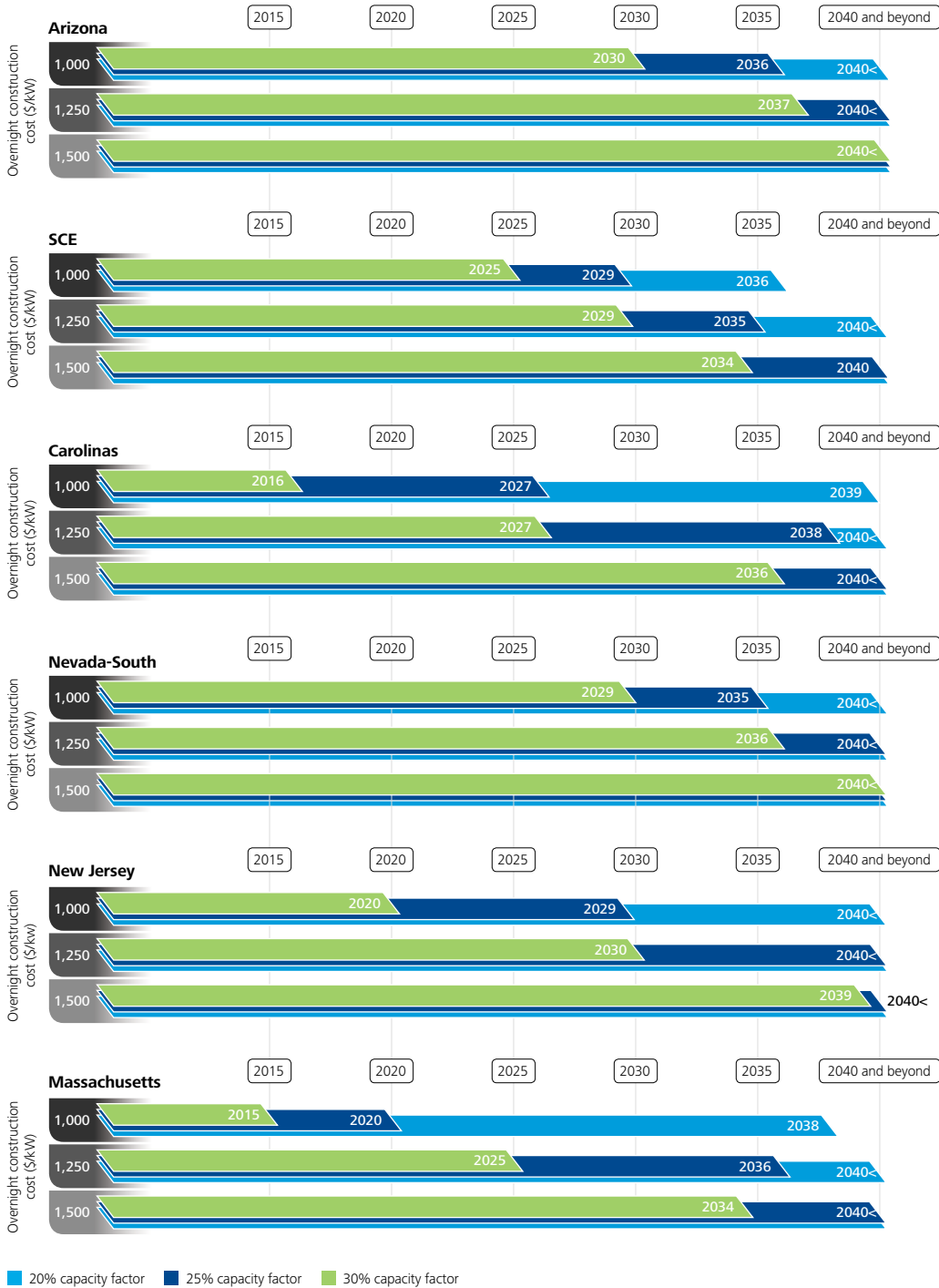
Figure 8: Projected timing of onshore wind grid parity (without PTC and REC)



Source: Deloitte MarketPoint

Figure 9 shows the same analysis but for utility-scale solar PV plants. Overall, the results suggest that utility-scale solar will take much longer to reach grid parity than wind power.

Figure 9. Solar grid parity (without ITC and REC)



Source: Deloitte MarketPoint



As with wind, wholesale power prices play a big role in the timing of solar grid parity. Ironically, markets with above-average wholesale power prices tend to have weaker solar and wind potential, while those with strong wind and solar potential tend to have below-average wholesale power prices. This paradox delays grid parity in some of the most promising regions for renewable development. For instance, markets such as Arizona and Nevada–South have among the best solar radiation potential in the US, but due to relatively low wholesale power prices, the analysis suggests that grid parity will not be attained for more than 20 years in either. Even using a much lower overnight construction cost (\$800/kW), which is projected by a few analysts, and a capacity factor at the top of what is presently considered to be a feasible range

for solar in these markets (30%), the Deloitte MarketPoint model still indicates grid parity would not be reached until 2025 in Nevada and by 2026 in Arizona.

In relatively high-priced wholesale power markets, the model suggests grid parity could be attained somewhat faster, but lower solar radiation potential reduces the likelihood that the projected timeline would be met. For instance in Massachusetts, which has generally higher wholesale power prices, grid parity would be reached in 2025, with an overnight construction cost of \$1250/kW and a 30 percent capacity factor; however, such a high capacity factor is unlikely to be achieved in New England without significant advances in technology. The findings for New Jersey and the Carolinas tell a similar story.

While the projected dates for reaching grid parity without subsidies appear to be much farther out than many predictions being featured in the media today, this report does not consider the future pace of innovation and its effect on grid parity timing. As discussed in the recent Deloitte report, [“US Solar Power Growth through 2040: Exponential or inconsequential?”](#) this innovation could come in the form of technological advancements leading to lower overnight construction costs, greater operating efficiencies and higher capacity factors, and/or in the form of financing or process improvements leading to lower cost of capital and decreased “soft costs,” such as permitting, interconnections, marketing, professional fees, and other intangible expenses associated with development. Many other analyses attempt to predict the pace of innovation using history as an analog; however, in this case the Deloitte MarketPoint team has chosen to pursue a more conservative route, since in its view, this area is too difficult to envisage with any reasonable degree of certainty.

Project economics with the PTC, ITC, and lower cost of capital

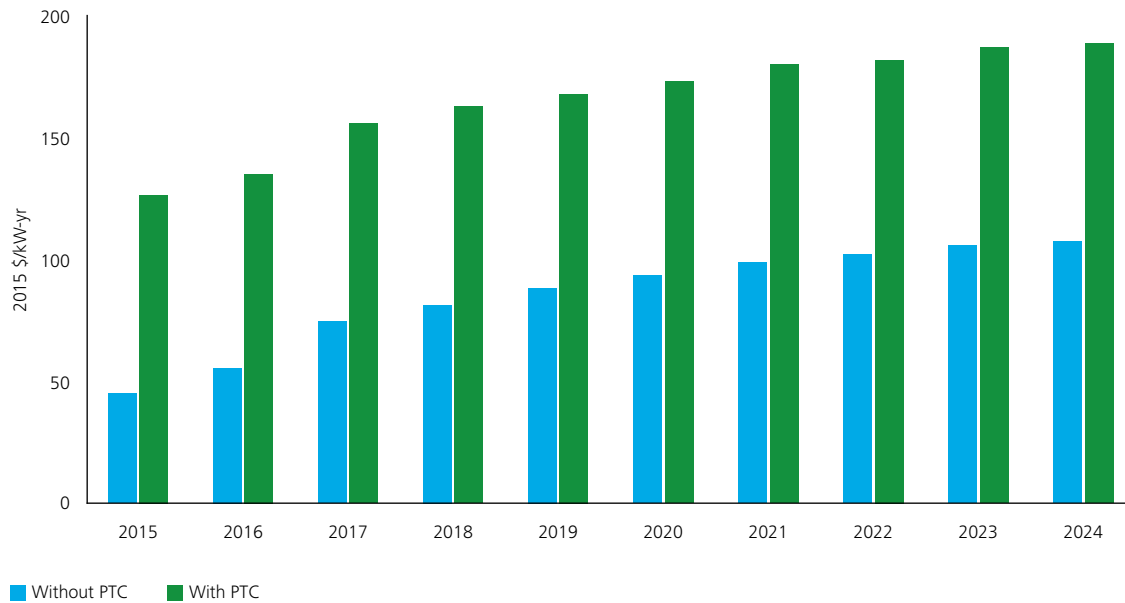
It is widely acknowledged that the existing federal tax incentives improve project economics substantially, thus accelerating the grid parity timeline, but by how much? To underscore the importance of the PTC on wind project economics, Figure 10 compares the first 10 years of a wind farm in the SPP-North zone with and without the PTC, assuming a 40 percent annual capacity factor.

In the SPP-North zone, the relatively low wholesale power market prices mean that the gross margin that can be earned is projected to be only \$46/kW-yr without the PTC in 2015. Adding in the PTC, which flows directly to the project’s bottom line, boosts the gross margin by 176

percent to approximately \$127/kW-yr in 2015. Inclusion of the PTC makes the project immediately economic at an overnight construction cost in the range of \$1050/kW. In contrast, exclusion of the PTC means the project may not reach grid parity until 2027.

The analysis for the solar ITC shows a similar acceleration to grid parity. Figure 11 compares the economics of a utility-scale solar facility in Arizona, with the current 30 percent ITC, the lower 10 percent ITC, and no ITC. All cases assumed a \$1000/kW overnight construction cost. On average, the 30 percent ITC pushed grid parity forward by seven to nine years. Utilization is also critical: with lower capacity factors, 20 percent to 22.5 percent in this analysis, grid parity is not reached within the next 25 years without ITC support.

Figure 10. SPP – North wind gross margin (\$/kW-yr)



Source: Deloitte MarketPoint

Changing the financing assumptions of the analysis to reflect a lower cost of capital also impacts grid parity timing. In the analysis, the Deloitte MarketPoint team chose to use an after-tax return on equity (ROE) of eight percent and assumed no project-level debt. This is one approach renewable developers use when assessing project economics. With this approach, developers would have the option at a later point in time to add low-cost debt to lever up their generation portfolios to achieve higher returns for their holding companies.

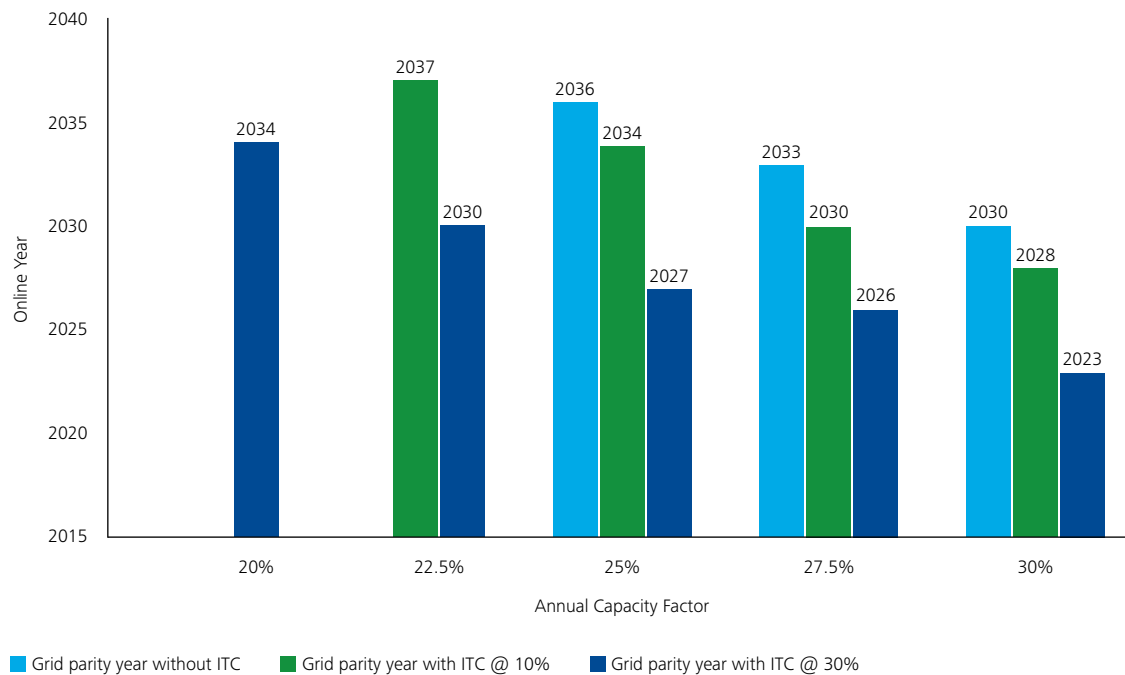
Our team believes the relatively high hurdle rate and the assumption of no project-level debt used in the base case are reasonable over the long term for three reasons:

1. Current historically low interest rates may not be indicative of future rates available during the forecast horizon.
2. Not every developer can access low-cost debt or will get the best interest rate.

3. Eliminating PTCs or ITCs for a project increases its volatility. For instance, PTCs reduce the federal income taxes of qualified tax-paying owners of a project based on the megawatts of power produced for a 10-year period. ITCs, on the other hand, provide immediate benefits to qualified tax-paying owners since they are earned when projects are placed into service. One could argue that without the economic certainty these mechanisms provide, either upfront or over the long run, developers will seek higher returns for the increased risk they are taking.

However, developers with good credit might choose to make their final investment decisions by including project-level debt at the outset. Doing so lowers the project's developer cost of capital. For instance, using 50 percent debt for project financing with a five percent rate lowers the cost of capital to 5.5 percent. This improves project economics, as well as increases the likelihood of reaching grid parity much sooner than projected in the base-case analysis. For instance, the

Figure 11. Arizona solar grid parity year with and without ITC (Overnight construction cost: \$1000/kW)



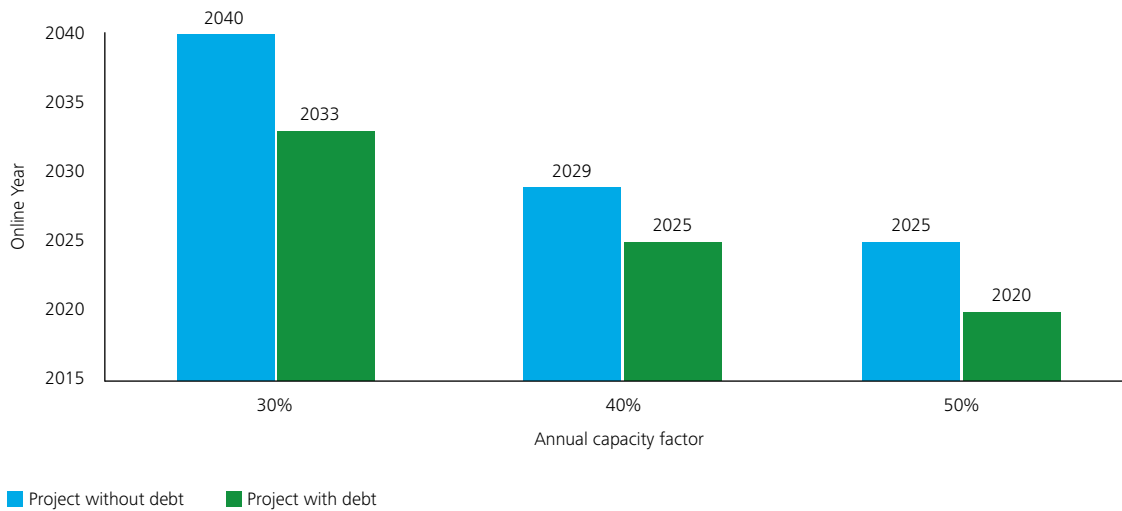
Source: Deloitte MarketPoint

addition of 50 percent project-level debt for a wind farm in ERCOT-West advances the grid parity year from 2029 to 2025, assuming a 40 percent capacity factor and no PTC or other REC payments. Utility-scale solar PV in Arizona shows a similar result. Adding project-level debt advances grid parity by between four to six years, depending on the capacity factor assumption, using a \$1000/kW overnight construction cost. Figures 12 and

13 show the impact of these changes on the timing of reaching grid parity.

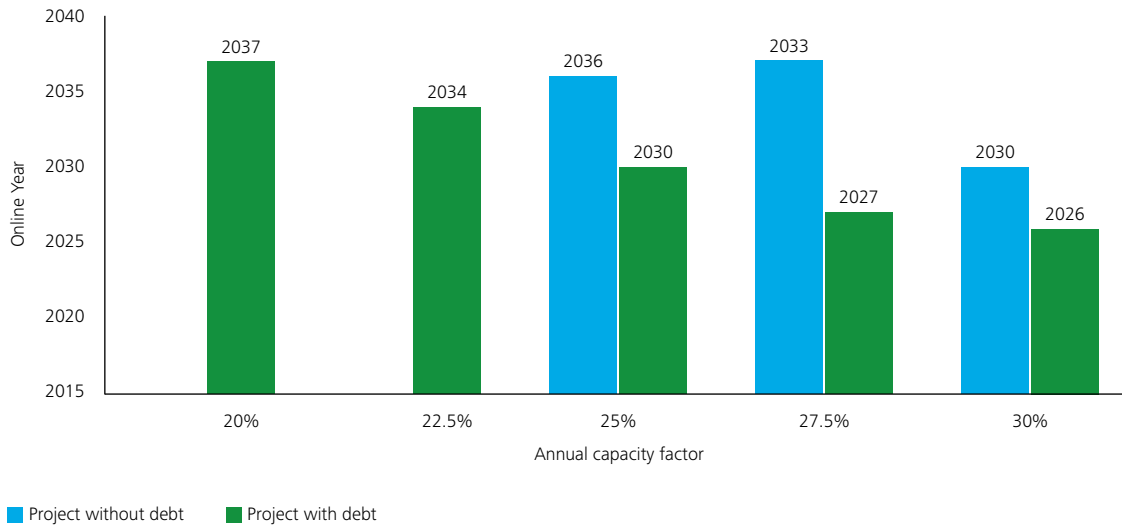
Overall, adding project debt advances grid parity by around five years across most markets and for each technology. This conclusion was not sensitive to higher or lower overnight construction cost assumptions for either wind or solar.

Figure 12. ERCOT-West wind grid parity financing sensitivity



Source: Deloitte MarketPoint

Figure 13. Arizona solar PV grid parity financing sensitivity



Source: Deloitte MarketPoint

Implications for stakeholders

The permanent abatement of the PTC for wind and/or the ITC for solar in the foreseeable horizon is one possible scenario facing the renewable energy sector. Reduction or elimination of such federal tax incentives will impact the wind and/or solar value chains as well as policy on a state and/or regional basis. Indeed, some wind developers have grown accustomed to proceeding as if the PTC is not available, since Congress often renews it retroactively for the previous year. Should the PTC and/or the ITC be allowed to permanently expire, some believe that the states will increase their RPS requirements and expand incentive regimes, such as RECs, in order to pick up the slack. Regardless of what eventually happens at the state level, the discontinuation of the PTC and/or the ITC would, at a minimum, have the following implications for the following stakeholders:

Developers

The fact that PTC/ITC support has become uncertain means developers need to remain cost-focused to ensure they can compete without most or all federal support mechanisms as the market transitions. Given the current absence of the PTC for 2015 (although it may be renewed retroactively), wind developers have already become quite sophisticated at driving costs out of their value chains. Solar developers are also in the process of re-optimizing their value chains in anticipation of the scheduled step-down of the ITC to 10 percent at the beginning of 2016. Here, in addition to technology costs, many solar developers are seeking reductions in financing, sales and marketing, and administrative costs, which collectively comprise a large portion of their expenses. In addition, access to lower cost debt and leveraging the project balance sheet can improve project economics and advance reaching grid parity.

Suppliers and manufacturers

Global suppliers will need to rationalize their operations and focus on the markets with the most robust support mechanisms. In the absence of US federal tax incentives, how to participate profitably in the US market may now become a question, but the availability of state tax incentives and exclusions could make a difference. As in many other industries, driving down costs and continuing to increase efficiencies will likely be the best overall strategy. Those suppliers that have flexibility stand to gain market share.

Electric utilities

Electric utilities and load-serving entities will be monitoring the PTC, the ITC, and state-sponsored support mechanisms closely. Should federal tax incentives permanently end, renewable energy developers will naturally reflect their new cost structures in their PPA negotiations; indeed, wind developers are already doing this for projects placed into service after 2016 since the PTC has effectively ceased beyond that point. Load-serving entities that must meet RPS requirements will need to be careful not to overpay, given improving wholesale market conditions and declining renewable project costs.

Regulators and policymakers

Both regulators and policymakers will need to understand the changing economics for renewable developers in terms of their cost structures and the wholesale power market environment. Providing just enough support through incentives, but not too much, should be the goal.

Conclusion

Grid parity is not imminent but may be reached sooner rather than later

The purpose of this report was to examine the timing of reaching grid parity without state RECs and without federal tax incentives, such as the PTC for onshore wind and the ITC for utility-scale solar PV.

The research indicated that reaching grid parity is not imminent, except in certain markets possessing the most robust renewable resources and having relatively higher wholesale power market prices. Overall, the results show that onshore wind is more likely to reach grid parity before utility-scale solar PV, under a wide range of assumptions. Indeed, without dramatic cost declines and/or improvements in efficiency and utilization, it is unlikely that some parts of the country will reach grid parity without federal or state incentives within the next 10-15 years. While it is widely accepted that the continuation of PTCs and ITCs would allow the renewable energy sector to reach grid parity faster, the extent of the acceleration—by as much as a decade—is more pronounced than one might expect.

In addition to regional wind and solar resource characteristics, the research identified three converging factors that will affect the timing of grid parity. These are rising natural gas prices, wholesale power market rebalancing, and improvements in renewable technology. Together, these converging forces will likely provide a tailwind for renewable energy development, pushing it to become competitive with fossil fuels, without subsidies, over the 25-year forecast horizon across many regional power markets.

In summarizing the findings of the analysis, it should be noted that the future pace of innovation cannot be predicted based on market fundamentals or historical data; therefore, it was not included in this analysis. Nonetheless, it could accelerate or delay the timing of grid parity to a great degree. For instance, an improvement in wind technology that facilitates a 500 basis point increase in operating capacity factor (e.g., 40% to 45%) could advance grid parity timing by about five years in most regions.

Open questions include: construction costs have declined substantially, can this continue or will the pace of reductions slow? The literature suggests solar-plant costs might decline further and faster than for wind based on recent evidence, but this is not a given. Also, overnight construction cost estimates vary widely, due in part to the use of different equipment and regional variations in labor and material costs, as well as when the plants were commissioned. The difference between the low and the high ends of the range can impact grid parity timing greatly—by as much as 10 or more years in some instances. Will these cost estimates drop and will their range narrow as the renewable energy sector expands and matures across regions? The answer, again, is unknown, but yet material to the grid parity discussion.

Finally, financing also deserved mention. A lower cost of capital, attained by accessing lower cost debt and leveraging project balance sheets, can advance grid parity timing considerably, by as much as five years in the scenarios examined. Over the past couple of years, financing innovations, such as YieldCos, green banks, and securitization, have generally made capital more accessible and affordable for developers. Ongoing access to such funding may likely help to spur renewable development and expedite the journey to grid parity. It would also make solar and wind projects less reliant on traditional tax equity financing, which is dependent upon the continuation of federal tax incentives.

Although the results clearly show that solar PV and onshore wind are not immediately economic without federal tax incentives or state RECs, they do indicate that under the right conditions grid parity could occur within the next decade in some regions for wind and somewhat later for solar. If utilization and/or operational efficiencies increase or construction costs decrease further, as has been witnessed over the past decade, the timeline could be shortened considerably. The results also acknowledge that the door is open for other factors not directly included in the analysis, such as the Clean Power Plan, state regulatory reform, or declines in financing costs, to provide an additional boost for the renewable energy sector on its journey to grid parity.

Appendix A

To calculate the timing for reaching grid parity without federal or state subsidies, four separate models were used:

- The NAIM model provides the long-term (to 2040) regional wholesale power and gas market prices used for the analysis. For each region, it provides highly granular price projections for power and natural gas markets, based on an assessment of future supply and demand conditions. More specifically, these projections are based on fuel prices, load growth, new plant capacity, and plant retirements across technologies, along with marginal cost analysis and regulatory drivers impacting the economics of electricity generation. The projections also consider availability of imported power from neighboring zones, since power can be imported from one market to another if it is economic to do so and there is available transmission capacity. The scenario used in this study was the summer 2015 Reference Case.²⁵ The NAIM database also includes observed hourly wind and solar profiles. These contain the average generation profiles for each source observed over the past several years.²⁶ In general, these values aggregate several generations of older plants with lower operational capacity factors than what the current and future renewable energy technologies will deliver. As a result, current and future renewable capacity factors were adjusted upwards as described next to account for efficiency improvements.
- Wind and solar operating factors and shapes were derived from historical data and are used to produce monthly on-peak and off-peak generation by source. A time-of-day operating factors model is used to calculate these. This model used the original NAIM renewable energy solar and wind capacity factor shapes. These come from a variety of sources, including: various ISOs, the EIA, and the NREL solar PV calculator, which was employed by our team to drive seasonality shapes for solar.
- In the process, the analysis team maintained the original wind and solar regional/monthly/time-period generation shape. It then scaled up the original generation shape to meet the three reported annual capacity factor levels to account for current and expected future technology improvements for wind and solar plants. Overnight construction costs were also sensitized to account for future uncertainty.

- A levelized capacity cost model was used to provide the annual revenue required for new solar PV and onshore wind generation capacity. The key inputs used were overnight construction cost, return on equity (after tax), book life, depreciation rate, and other financial assumptions. The final output is a \$/kW-year requirement that new plants will need to earn to reach grid parity—or in economic terms, to enter the market profitably—in a particular year (see Table A).

Table A. Wind and solar overnight construction cost and equivalent levelized revenue target

Overnight construction cost	Levelized revenue target
(\$/kW)	(\$/kW-yr)
800	95
850	101
900	107
950	113
1000	119
1050	125
1100	131
1150	138
1200	143
1250	150
1300	155
1350	161
1400	167
1450	173
1500	179
1550	185
1600	191
1650	197
1700	203
1750	209

Source: Deloitte MarketPoint

Appendix B

The following example calculation illustrates the models employed and the processes used to arrive at the grid parity projections.

Calculated levelized revenue requirements

If the overnight construction cost for onshore wind is assumed to be \$1250/kW, then the levelized revenue target requirement per year is equal to \$150/kW-yr.²⁷ A higher construction cost, ROE, or fixed operating and maintenance cost—or a longer construction period—generally raise the target amount proportionately.

Energy margin

The energy margin available is then calculated by combining the monthly on-peak and off-peak prices with the calculated wind capacity profile for each month and time period. Assuming a 40 percent annual capacity factor profile, a \$40/kW-yr fixed operating and maintenance cost, and ERCOT–West zonal power prices in 2025 results in a \$128/kW-yr gross margin for the facility. The result will vary by region based on the generation mix, natural gas prices, and level of reserve margin.

Grid parity projection (i.e., first-year economic entry)

To determine whether the ERCOT–West wind plant has reached grid parity where it can enter the market profitably, the gross margin earned must be equal to or higher than the levelized revenue requirement for the assumed overnight construction cost. In this example, the wind plant cannot economically enter in 2025 since the revenue target is higher than the gross margin that can be earned; or simply put, it doesn't reach grid parity.

Revenue target (\$150) > Energy gross margin in 2025 (\$128)

However, if the overnight construction cost was \$1050/kW, the revenue target would drop to \$125/kW-yr, which signals profitable entry in the example. Likewise, assuming a higher capacity factor profile, such as 45 percent, would raise the gross margin to \$149/kW-yr, just below the level required.

Endnotes

1. Forecast prices as of summer 2015. The Deloitte MarketPoint Reference Case is a long-term fundamental analysis of 76 North American power regions and 65 natural gas demand regions. The analysis uses Deloitte MarketPoint's proprietary MarketBuilder economic forecasting model. The tool is a generalized equilibrium model that projects market quantities and prices while ensuring that economic actors maximize their profitability or minimize their costs.
2. US EIA Liquid Fuels and Natural Gas in the Americas, Figure 11, http://www.eia.gov/beta/international/analysis_includes/special_topics/Liquid_Fuels_Natural_Gas_Americas/pdf/americas.pdf.
3. US EIA Natural Gas Gross Withdrawals Report, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm; EIA Drilling Productivity Report, <http://www.eia.gov/petroleum/drilling/>; and Deloitte MarketPoint NAIM Reference Case (Summer 2015).
4. In an earlier study performed by Deloitte MarketPoint and the Deloitte Center for Energy Solutions, "Exporting the American Renaissance, Global impact of LNG exports from the United States," we considered a more muted case of only 6 Bcf/d of exports over a shorter 2016-2030 timeframe. In that case, Henry Hub prices rose by \$0.15 from what they would have otherwise been. In the present analysis, we consider nearly double the LNG and over a longer time frame (to 2040). In addition, this analysis utilizes a fully integrated gas and power model, which considers the impact more abundant gas supplies have on other gas end-use sectors, and the impact upon natural gas demand from the power sector, which is additionally driven by other factors such as environmental or regulatory policies.
5. Reserve margin is a measure of supply-demand balance in the electric utility industry. A value higher than 15 percent often, but not always, indicates excess supply over the level required for reliability.
6. Dependable Reserve Margin is the net dependable capacity after derating divided by the peak hourly load. Derating is applied to renewable generators whose total capacity is not fully available during peak load conditions.
7. US EIA, Table 7.6 Electricity End Use, June 2015 Monthly Energy Review, released June 25, 2015. In the comparison, the trailing 12-month moving average of retail sales was compared (i.e., July 2008 compared to December 2009).
8. The 15 percent DRM measure is rule of thumb indicating equilibrium conditions. Markets with a high proportion of hydro and those that are large exporters will report naturally larger values.
9. US EIA Electricity Data Browser, <http://www.eia.gov/electricity/data/browser/>.
10. For the purpose of this report, we consider utility-scale solar photovoltaic and onshore wind generation only.
11. Lazard, Levelized Cost of Energy Analysis, Version 8.0, September 2014.
12. Peter Kelly-Detwiler, "As Solar Panel Efficiencies Keep Improving, It's Time To Adopt Some New Metrics," Forbes.com, July 16, 2013, <http://www.forbes.com/sites/peterdetwiler/2013/07/16/as-solar-panel-efficiencies-keep-improving-its-time-to-adopt-some-new-metrics/>
13. NREL, Research Cell Efficiency Records, <http://www.nrel.gov/ncpv/>.
14. Deloitte MarketPoint analysis of SNL Financial data.
15. Iowa Energy Center, "How Tall Are Wind Turbines," <http://www.iowaenergycenter.org/renewable-energy/wind/how-tall-are-wind-turbines/>.
16. Deloitte MarketPoint.
17. US EIA, "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)," <http://www.eia.gov/electricity/data/state/>.
18. Ibid.
19. Ibid.
20. Ibid.
21. Ibid.
22. Ibid.
23. Ibid.
24. Ibid.
25. Deloitte MarketPoint North American Power and Gas Reference Case, Summer 2015.
26. Wind data profiles 2012-2014 for PJM and CAISO; 2010-2014 for NYISO and MISO; 2008-2014 for SPP. In addition, the solar profiles used were from 2012-2014.
27. The main assumptions used to derive this value are: construction years (one year), book life (25 years), ROE after tax (8%), and fixed operating and maintenance (\$40/kW-yr).

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