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Socio-economic and Engineering Assessments of Renewable Energy Cost Reduction Potential

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Socio-economic and Engineering Assessments of Renewable Energy Cost Reduction Potential

By

Joachim Seel

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University of California, Berkeley

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Abstract

Socio-economic and Engineering Assessments of Renewable Energy Cost Reduction Potential

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Joachim Seel

Doctor of Philosophy in Energy and Resources

University of California, Berkeley

Professor Severin Borenstein, Chair

This dissertation combines three perspectives on the potential of cost reductions of renewable energy – a relevant topic, as high energy costs have traditionally been cited as major reason to vindicate developments of fossil fuel and nuclear power plants, and to justify financial support mechanisms and special incentives for renewable energy generators.

First, I highlight the role of market and policy drivers in an international comparison of upfront capital expenses of residential photovoltaic systems in Germany and the United States that result in price differences of a factor of two and suggest cost reduction opportunities. In a second article I examine engineering approaches and siting considerations of large-scale photovoltaic projects in the United States that enable substantial system performance increases and allow thus for lower energy costs on a levelized basis. Finally, I investigate future cost reduction options of wind energy, ranging from capital expenses, operating expenses, and performance over a project's lifetime to financing costs. The assessment shows both substantial further cost decline potential for mature technologies like land-based turbines, nascent technologies like fixed-bottom offshore turbines, and experimental technologies like floating offshore turbines. The following paragraphs summarize each analysis:

International upfront capital cost comparison of residential solar systems

Residential photovoltaic (PV) systems were twice as expensive in the United States as in Germany (median of \$5.29/W vs. \$2.59/W) in 2012. This price discrepancy stems primarily from differences in non-hardware or "soft" costs between the two countries, of which only 35% be explained by differences in cumulative market size and associated learning. A survey of German PV installers was deployed to collect granular data on PV soft costs in Germany, and the results are compared to those of a similar survey of U.S. PV installers. Non-module hardware costs and all analyzed soft costs are lower in Germany, especially for customer acquisition, installation labor, and profit/overhead costs, but also for expenses related to permitting, interconnection, and inspection procedures. Additional costs occur in the United States due to state and local sales taxes, smaller average system sizes, and longer project-development times. To reduce the

identified additional costs of residential PV systems, the United States could introduce policies that enable a robust and lasting market while minimizing market fragmentation. Regularly declining incentives offering a transparent and certain value proposition—combined with simple interconnection, permitting, and inspection requirements—might help accelerate PV cost reductions in the United States.

Performance analysis of large-scale solar installations in the United States

This paper presents the first known use of multi-variate regression techniques to statistically explore empirical variation in utility-scale PV project performance across the United States. Among a sample of 128 utility-scale PV projects totaling 3,201 MW_{AC}, net capacity factors in 2014 varied by more than a factor of two. Regression models developed for this analysis find that just three highly significant independent variables – the level of global horizontal irradiance (GHI), the use of single-axis tracking, and the inverter loading ratio (ILR) – can explain 92% of this project-level variation (with GHI alone able to explain 71.6%). Adding the commercial operation year as a fourth independent variable and three interactive variables (tracking x GHI, tracking x ILR, GHI x ILR) improves the model further and reveals interesting relationships (e.g., the performance benefit of tracking increases with a higher GHI but diminishes with a higher ILR). Taken together, the empirical data and statistical modeling results presented in this paper can provide a useful indication of the level of performance that solar project developers and investors can expect from various project configurations in different regions of the United States. Moreover, the tight relationship between fitted and actual capacity factors should instill confidence among investors that the utility-scale projects in this sample have largely performed as predicted by our models, with no significant outliers to date.

Holistic assessment of future cost reduction opportunities of wind energy applications

Wind energy supply has grown rapidly over the last decade. However, the long-term contribution of wind to future energy supply, and the degree to which policy support is necessary to motivate higher levels of deployment, depends—in part—on the future costs of both onshore and offshore wind. Here, I summarize the results of an expert elicitation survey of 163 of the world's foremost wind experts, aimed at better understanding future costs and technology advancement possibilities. Results suggest significant opportunities for cost reductions, but also underlying uncertainties. Under the median scenario, experts anticipate 24–30% reductions by 2030 and 35–41% reductions by 2050 across the three wind applications studied. Costs could be even lower: experts predict a 10% chance that reductions will be more than 40% by 2030 and more than 50% by 2050. The main identified drivers for near term cost reductions are rotor-related advancements and taller towers for onshore installations, fixed-bottom offshore turbines can benefit from an upscaling in generator capacity, streamlined foundation design and reduced financing costs, while floating offshore turbines require further progress in buoyant support structure design and installation process efficiencies. Insights gained through this expert elicitation complement other tools for evaluating cost-reduction potential, and help inform policy, planning, R&D, and industry strategy.

This dissertation is dedicated to my wife, Alison Michelle Seel.

While she has always been a loving and giving partner for the past seven years, she outdid herself with profound support over the course of the last year. This dissertation would have been impossible without her continuous and relentless aid.

I thank her for all her aid, her fantastic dinner cooking while I wrote this paper, her critical feedback, and her continued encouragement over the last years to finish this dissertation.

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I thank Dr. Ryan Wiser at the Electricity Markets and Policy Group at the Lawrence Berkeley National Laboratory for employing, advising, and mentoring me as a Graduate Student Researcher, Senior Research Associate and Scientific Engineering Associate throughout the duration of this dissertation. Gratitude goes as well to my other colleagues at LBNL, specifically Dr. Naim Darghouth, Dr. Andrew Mills, Galen Barbose, Mark Bolinger, Ben Hoen and Joe Rand.

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I thank my friends at the Energy and Resources Group for supporting me during this dissertation and providing very valuable feedback – gratitude goes as well to the fantastic Kay Burns.

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Specific acknowledgements for individual projects that make up this dissertation follow:

An Analysis of Residential PV System Price Differences Between the United States and Germany

I thank my coauthors Galen L. Barbose and Ryan H. Wiser at the Lawrence Berkeley National Laboratory, Berkeley, CA, 94720 USA

This work described in this paper was supported by the Solar Energy Technologies Program, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

This work would not have been possible without the assistance of many residential PV installers in the United States and Germany, data support by the firm EuPD, and collaboration and guidance by our colleagues at NREL, especially the work of surveying U.S. installers by Kristen Ardani, Ted James, and Al Goodrich. I thank the sponsors of this work at the U.S. Department of Energy's Solar Energy Technologies Office, in particular Minh Le, Christina Nichols, and Elaine Ulrich. In addition I am indebted to the helpful comments of our anonymous reviewers. Of course, any remaining errors or omissions are my own.

Maximizing MWh: A Statistical Analysis of the Performance of Utility-Scale Photovoltaic Projects in the United States

I thank my coauthors Mark Bolinger (Lawrence Berkeley National Laboratory, Berkeley, CA, 94720 USA) and Manfei Wu (Goldman School of Public Policy, University of California at Berkeley, Berkeley, CA, 94720 USA)

The work described in this paper was funded by the U.S. Department of Energy's Solar Energy Technologies Office, within the Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231.

For supporting this work, I thank Elaine Ulrich, Odette Mucha, Joshua Honeycutt and the entire DOE Solar Energy Technologies Office. I also thank Gwendalyn Bender of Vaisala for providing average 2014 irradiance data for each of the projects in our sample, and the following individuals for providing comments on earlier drafts: Ben Hoen and Ryan Wiser (Lawrence Berkeley National Laboratory), David Feldman (National Renewable Energy Laboratory), Daniel Boff (U.S. Department of Energy), Greg Wagoner (Black & Veatch), Sophie Pelland (Vaisala), and Greg Nemet (University of Wisconsin). Of course, any remaining errors or omissions are the sole responsibility of the author.

Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts

I thank my coauthors

- Ryan H. Wiser (Lawrence Berkeley National Laboratory, Berkeley, CA, 94720 USA)
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This global elicitation survey of wind energy experts would not have been possible without the assistance and support of many individuals and organizations.

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Survey Respondents: This work would not have been possible without the gracious contributions of the experts who chose to participate in the survey—I list those individuals, and their affiliated organizations, in Appendix A. For assistance in identifying possible survey respondents, I thank the members of IEA Wind Task 26 and a wide variety of others: American Wind Energy Association (Michael Goggin, Hannah Hunt), BVG Associates (Bruce Valpy), Danish Wind Industry Association (Martin Risum Bøndergaard), IEA Wind Executive Committee, Denmark Technical University (Peter Hauge Madsen, Peter Hjuler Jensen), Energy Centre of Netherlands (Bernard Bulder), European Wind Energy Association (Andrew Ho, Giorgio Corbetta), Global Wind Energy Council (Steve Sawyer), and International Renewable Energy Agency (Michael Taylor).

Project Execution: Earlier versions of the survey were reviewed by members of IEA Wind Task 26 on several occasions, as well as a select group of other wind energy experts. Additionally, for participating in an expert workshop and early pilot of the survey, and providing comments therein, I thank: Aaron Barr (MAKE), Daniel Beals (DOE), Michael Finger (EDP Renewables), Mark Higgins (DOE), Ben Quinn (Vestas), Walt Musial (NREL), Bruce Valpy (BVG), Paul Veers (NREL), Emily Williams (Altenex), and Adam Wilson (formerly NREL). Ultimately, the survey was implemented online via a platform designed by Near Zero, and I greatly appreciate Near Zero's many efforts to creatively implement aspects of our complex design: thanks especially to Steve Davis, Seth Nickell, and Karen Fries. I also thank Claudine Custodio (formerly of LBNL) for assistance with survey design and Naim Darghouth (LBNL) for assistance with the literature review of future cost reduction estimates.

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EDUCATION

University of California at Berkeley. Ph.D. in Energy and Resources. August 2017.
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Jacobs University Bremen, Germany. B.A. in International Politics and History with an Environmental Policy and European Integration emphasis. Graduated at the top 5% of the class, May 2009.

SELECTED PROFESSIONAL EXPERIENCE

LAWRENCE BERKELEY NATIONAL LABORATORY, Berkeley, CA, USA
Scientific Engineering Associate, Electricity Market and Policy Group, 2017.01 - present
Senior Research Associate, Electricity Market and Policy Group, 2015.05 -2016.12
Graduate Student Research Assistant, Electricity Markets and Policy Group, 2011- 2015.05

- Member of a diverse, nationally recognized research program on the planning, design, and evaluation of renewable energy policies; on the costs, benefits, and market potential of renewable electricity sources; on electric grid operations and infrastructure impacts; and on public acceptance.
- Analyzing the impacts of high renewable energy penetrations on wholesale power markets, electric industry participants and load-based energy programs
- Contributing to cost, performance and pricing analyses of utility-scale solar projects in the US.
- Contributed to a study under the International Energy Agency on wind cost reduction opportunities
- Contributed to an analysis of utility flexibility needs under higher renewable energy penetrations.
- Led comparative research on soft cost components of distributed solar installations between the U.S. and Germany and contributed to a comparative study between the U.S. and Japan.

FEDERAL GERMAN MINISTRY FOR ECONOMICS AND ENERGY, Berlin, Germany
Research Fellow at Referat IIIB1 Electricity Market Design 06/2011 – 08/2011

- Conducted research on electricity market design proposals for Germany that allow for high renewable penetration levels and German utility business models and infrastructure finance models

SINO-DANISH RENEWABLE ENERGY DEVELOPMENT PROGRAMME, Beijing, China
Fellow at "Center for Renewable Energy Development" (CRED) of the "China National Energy Administration" 06/2011 – 08/2011

- Consulted and published on German policies guiding the expansion of distributed photovoltaics.

PG&E, RENEWABLE ENERGY DIVISION, San Francisco, CA, USA
Consultant, 01/2011 – 05/2011

- Assessed the cost-effectiveness of tracking systems for 250MW of utility-scale photovoltaic projects.

SECOND STREET CONSULTING, INC., Walnut Creek, CA, USA
Policy Analyst and Consultant for Panasonic, 05/2010 – 08/2010

- Advised on necessary conditions for new market entrants to thrive in the U.S. solar market.
- Analyzed the federal government's role in the energy sector: Regulation, Policy and Funding.

AMERICAN WIND ENERGY ASSOCIATION, Washington D.C., USA
Policy and Data Analyst, 05/2010 – 08/2010

- Analyzed and compared renewable energy policies debated in the U.S. Senate and in 40+ countries.

EUROPEAN PARLIAMENT, Brussels, Belgium
Assistant to MEP Dr. Schmidt, Vice President of the Development Committee, 06/2008-08/2008

- Evaluated EU policies on illegal logging and fishing in West Africa, wrote policy memos and conference presentations.
- Coordinated press relations and took minutes at several committees and high-level conferences.

BREMEN PARLIAMENT, Bremen, Germany
Assistant to MBP Dr. Maike Schäfer, Speaker for development politics, 09/2007-05/2008

- Investigated options of public procurement reform respecting social and ecological sustainability criteria leading to legal reform in procurement practices of the state of Bremen.

SELECTED HONORS AND AWARDS

- SPOT Recognition Award, Lawrence Berkeley National Laboratory, 2016
- Best Student Presentation Award, 39th IEEE Photovoltaics Specialist Conference, 2013
- Graduate Studies Fellowship, German Academic Exchange Service (DAAD) 2012
- UC Regents Fellowship, University of California, Berkeley, 2011
- Goldman School of Public Policy Fellowship, University of California, Berkeley, 2010.
- Fulbright Scholarship, The Fulbright Program, 2009
- Hamburg Scholarship, German National Academic Foundation, 2009
- Scholarships for Bachelor and Master Studies, German National Academic Foundation, 2006-2012

SELECTED PRESENTATIONS AND PUBLICATIONS

5 refereed conference papers, 2 journal articles, about 10 webinars, about 25 invited presentations and industry and academic conferences, the California Public Utility Commission, the California Energy Commission, and California Governor Brown.

<u>Recent invited presentations include:</u>

- Seel. 2017. “Impacts of High Penetrations of Variable Renewable Energy on Wholesale Electricity Prices” Energy Policy Research Conference 2017, Park City, UT
- Seel. 2017. “Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States” Solar Power International 2017, Law Vegas, NV
- Seel. 2016. “Trends in Utility-Scale Solar in the US and Expert Views on Future Wind Energy Costs”, Presentation to Indonesian Energy Policy Makers Delegation, Berkeley, CA
- Seel. 2016. “Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States” Solar Power International 2016, Las Vegas, NV
- Seel. 2016. “Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States” InterSolar North America 2016, San Francisco, CA
- Seel. 2016. “Maximizing MWh: A Statistical Analysis of the Performance of Utility-Scale Photovoltatic Projects in the United States” 43rd IEEE PVSC 2016, Portland, OR
- Seel. 2016. “Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States” EUEC 2016, San Diego, CA
- Seel. 2016. “Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States” Presentation to World Bank delegation and to Chinese Energy Research Institute, Berkeley, CA

Relevant publications include:

- R. Wiser, A. Mills, J. Seel, T. Levin, A. Botterud, "Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs" - Memo to Secretary of Energy Rick Perry, Department of Energy. Lawrence Berkeley National Laboratory (LBNL), 2017.
- A. Mills, R. Wiser, J. Seel, "Power Plant Retirements: Trends and Possible Drivers" - Memo to Secretary of Energy Rick Perry, Department of Energy. Lawrence Berkeley National Laboratory (LBNL), 2017.
- A. Mills, J. Seel, G. Gallo. B. Paulos, R. Wiser, "Evaluating Impacts of High VRE Penetrations on Demand and Supply Side Resources" - Memo to the Energy Efficiency and Renewable Energy Office, Department of Energy. Lawrence Berkeley National Laboratory (LBNL), 2017.
- A. Mills, G. Barbose, J. Seel, C. Dong, T. Mai, B. Sigrin, J. Zuboy. "Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning. Lawrence Berkeley National Laboratory (LBNL), 2016.
- R. Wiser, K. Jenni, J. Seel, E. Baker, M. Hand, E. Lantz, A. Smith. 2016." Expert Elicitation Survey on Future Wind Energy Costs". *Nature Energy*, 1(10): 16135-16143. doi:10.1038/nenergy.2016.135
- R. Wiser, K. Jenni, J. Seel, E. Baker, M. Hand, E. Lantz, A. Smith." Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts". Lawrence Berkeley National Laboratory (LBNL), 2016.
- G. Barbose, J. Miller, B. Sigrin, E. Reiter, K. Cory, J. McLaren, J. Seel, A. Mills, N. Darghouth, A. Satchwell. "Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities". Lawrence Berkeley National Laboratory (LBNL), 2016.
- M. Bolinger, J. Seel. "Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States". Lawrence Berkeley National Laboratory (LBNL), 2016.
- M. Bolinger, J. Seel, M. Wu. "Maximizing MWh: A Statistical Analysis of the Performance of Utility-Scale Photovoltatic Projects in the United States". Lawrence Berkeley National Laboratory (LBNL), 2016.
- A. Mills and J. Seel. "Flexibility Inventory for Western Resource Planners". Lawrence Berkeley National Laboratory (LBNL), 2015.
- M. Bolinger and J. Seel. "Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States". Lawrence Berkeley National Laboratory (LBNL), 2015.
- D. Feldman, G. Barbose, R. Margolis, M. Bolinger, D. Chung, R. Fu, J. Seel, C. Davidson, and R. Wiser. "Photovoltaic System Pricing Trends: Historical, Recent and Near-Term Projections." National Renewable Energy Laboratory (NREL), 2015.
- J. Seel., G. Barbose, and R. Wiser. 2014. "An Analysis of Residential PV System Price Differences Between the United States and Germany." *Energy Policy*, 69(2014): 216-226.
- B. Friedman, B. Margolis, and J. Seel. "Comparing Photovoltaic (PV) Costs and Deployment Drivers in the Japanese and U.S. Residential and Commercial Markets". National Renewable Energy Laboratory (NREL), 2014.
- B. Hoen, G. Klise, J. Graff-Zivin, M. Thayer, J. Seel, and R. Wiser. "Exploring California PV Home Premiums". Lawrence Berkeley National Laboratory (LBNL), 2013.
- G. Barbose, N. Darghouth, R. Wiser, and J. Seel. "Tracking the Sun IV An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010". Lawrence Berkeley National Laboratory (LBNL), 2011.
- Contributed to: R. Wiser, and M. Bolinger."Wind Technologies Market Report 2010". Department of Energy, 2011.

Introduction to the Dissertation

Growing levels of greenhouse gases in the Earth's atmosphere threaten the stability of global social, biological, and geophysical systems (Schneider et al., 2007) and require massive mitigation efforts (Betz, Davidson, Bosch, Dave, & Meyers, 2007). Both wind and photovoltaic (PV) technologies offer significant opportunities for decarbonizing the electricity industry, due to their abundant energy potential in many parts of the world that often exceeds local electricity demand by far (IPCC, 2014).

Although the threat of human-induced climate change has been known for several decades, initial growth of wind and solar generation capacity started only at a slow pace in the early 1990s. Aside from the lack of well-rehearsed interconnection procedures and concerns about the ability to integrate these variable renewable energy resources, a chief obstacle to large-scale construction efforts was the high upfront capital cost requirements relative to the amount of generated electricity. The resulting levelized cost of electricity (LCOE) was expensive, especially in comparison to the established fossil-fueled generation alternatives in the industrialized countries (IPCC, 1996). High costs thus limited the appetite of established large-scale power producers to pivot quickly to wind and solar resources, and cautioned policy-makers to initiate large-scale investment programs or limitless incentive regimes due to the associated high public expenses.

Continued maturation of the generation technology and the underlying manufacturing infrastructure has thus been a core focus of the wind and solar industry since their early days, with the objective of reducing costs to competitive levels. Several methods have been available in the academic literature to assess both past progress and further cost reduction potentials.

<u>Learning curve analyses</u> have a long history within both the wind and solar sector (Lindman & Söderholm, 2012; Maycock & Wakefield, 1975; Neij, 1997; Nemet, 2006; Rubin, Azevedo, Jaramillo, & Yeh, 2015; van der Zwaan & Rabl, 2003; R. Wiser et al., 2011), but they have been criticized for simplifying the many causal mechanisms that lead to cost reduction (Ek & Söderholm, 2010; Ferioli, Schoots, & van der Zwaan, 2009; Junginger, Sark, & Faaji, 2010; Mukora, Winksel, Jeffrey, & Mueller, 2009; Witajewski-Baltvilks, Verdolini, & Tavoni, 2015; Yeh & Rubin, 2012). In addition, using historical data to generate learning rates that are then extrapolated into the future implicitly assumes that future trends will replicate past ones (Arrow, 1962; Ferioli et al., 2009; Nordhaus, 2014). <u>Engineering assessments</u> provide a bottom-up, technology-rich alternative to learning curve analyses (Mukora et al., 2009) and involve detailed modeling of specific possible technology advancements. They require a robust understanding of possible technology advancements. Opportunities captured by engineering studies are hence often incremental and generally realizable in the near to medium term (less than 15 years). <u>Expert knowledge</u> can be obtained through informal interviews, workshops, formalized expert elicitations (Baker, Bosetti, Anadon, Henrion, & Aleluia Reis, 2015; Gillenwater, 2013; Nemet,

Anadon, & Verdolini, 2017; Verdolini, Adadon, Baker, Bosetti, & Reis, 2016), and other approaches, and has become a mainstay of many attempts to forecast future wind and solar technology advancement and cost reduction. It can be paired with engineering assessment and learning curve tools to bolster the reliability of the overall estimates, garner a more detailed understanding of how cost reductions may be realized, and clarify the uncertainty in these estimates.

A criticism of many studies in this field is that they focus often on only one determinant of renewable energy costs, namely the upfront capital costs (Rubin et al., 2015). While the relative ease of access to such capital expense data facilitates investigatory probing, exclusive attention to this component disregards potential gains in energy capture. Larger wind rotors relative to the generator rating, oversized module arrays relative to the inverter capacity, single-axis tracking mechanisms, and higher quality components associated with lower energy losses or system downtime may well offset increases in upfront costs. Similarly, an extension in the project design life yields more hours over which capital costs can be depreciated and a reduction of perceived investment risks may lower financing costs. To assess progress in renewable energy cost reductions adequately one should thus analyze fully levelized energy cost.

Just as onshore wind and solar energy technologies have progressively lowered their energy costs over the last decades and reached (or even surpassed) cost parity with fossil-fueled and nuclear generators on a levelized basis (Lazard, 2016), increasing attention has been drawn to electricity system value considerations of non-dispatchable wind and solar assets (Joskow, 2011). At low penetration levels, solar and wind generators barely affected the price formation of wholesale electricity markets and – especially in the case of solar - often generated electricity at times of high demand and associated high prices. With increasing capacity deployment of wind and solar projects, however, their role has started to change, and concerns about value erosion at times of oversupply are beginning to arise (either due to limited technological flexibility of other generators to decrease their output, inefficient market signals or simply low demand hours) (Denholm & Margolis, 2007; Hirth, 2013; A. D. Mills & Wiser, 2013). To soften inherent system limits of economic carrying capacity for non-dispatchable but output-correlated generation technologies (Denholm, Novacheck, Jorgenson, & O'Connell, 2016), further investments in flexibility capabilities or co-located storage resources may become essential for renewable energy project developers. As consequence the pressure to reduce underlying renewable energy costs and thus to enable further economic headroom for additional flexibility means is likely to continue as renewable generators gain prominence in electricity systems.

In the context of this larger discussion, my dissertation combines three perspectives on the potential of cost reductions of renewable energy.

First, I highlight the role of market and policy drivers in an international comparison of upfront capital expenses of residential photovoltaic systems in Germany and the United States that result in price differences of a factor of two and suggest cost reduction opportunities.

In a second article I examine engineering approaches and siting considerations of large-scale photovoltaic projects in the United States that enable substantial system performance increases and thus allow for lower energy costs on a levelized basis.

Finally, I investigate future cost reduction options of wind energy, ranging from capital expenses, operating expenses, and performance over a project's lifetime to financing costs. The assessment shows both substantial further cost decline potential for mature technologies like land-based turbines, nascent technologies like fixed-bottom offshore turbines, and experimental technologies like floating offshore turbines.

A conclusion summarizes the dissertation and provides some brief updates on market developments since the writing of each preceding paper.

An Analysis of Residential PV System Price Differences Between the United States and Germany

A peer-reviewed article version of this research project has been published in the Energy Policy Journal in June 2014 (Vol 69, pp216-226) and is available online at:

http://www.sciencedirect.com/science/article/pii/S0301421514001116

http://dx.doi.org/10.1016/j.enpol.2014.02.022

A webinar briefing and further material is available at https://emp.lbl.gov/publications/why-are-residential-pv-prices-germany

1. Introduction

Growing levels of greenhouse gases in Earth's atmosphere threaten the stability of global social, biological, and geophysical systems (Schneider et al., 2007) and require massive mitigation efforts (Betz et al., 2007). Photovoltaic (PV) technologies offer significant potential for decarbonizing the electricity industry, because direct solar energy is the most abundant of all energy resources (Arvizu et al., 2011). Although PV historically has contributed little to the electricity mix owing to its high cost relative to established generation technologies, technological improvements and robust industry growth have reduced global PV prices substantially over the past decade. Numerous sources document these price reductions, including the national survey reports under Task 1 of the International Energy Agency's "Co-operative program on PV systems" and subscription-based trade publications such as those produced by Bloomberg New Energy Finance, Greentech Media (GTM), Photon Consulting, Navigant, and EuPD Research.

In the academic literature, pricing analyses of PV modules and whole systems have been discussed primarily in the learning or experience curve literature (Maycock & Wakefield, 1975; Neij, 1997; Nemet, 2006; van der Zwaan & Rabl, 2003; Watanabe, Wakabayashi, & Miyazawa, 2000). (Haas, 2004; Schaeffer et al., 2004) expanded the field by comparing pricing trends between countries and by distinguishing among prices for complete systems and costs of modules as well as hardware and "soft" (non-hardware) balance of system (BoS,) costs. Although PV system soft BoS costs were already examined 35 years ago (Rosenblum, 1978), they have received increased attention from the private and public sectors recently as their share of total system prices rose in conjunction with a decline in hardware component prices. Today, soft costs seem to be a major attribute for PV system price differences among various international mature markets.

The price difference is particularly stark for residential PV systems in Germany and the United States, averaging $14,000 for a 5-kW system in 2012. This article aims to explain the large residential system price differences between Germany and the United States to illuminate cost-reduction opportunities for U.S. PV systems. This research was conducted in the context of the U.S. Department of Energy's SunShot Initiative, which aims to make unsubsidized PV competitive with conventional generating technologies by 2020 (enabling PV system prices of $1/W for utility-scale applications and $1.50/W for residential applications) (U.S. Department of Energy, 2012).

2. Overview of the U.S. and German PV Markets

While the United States was a global leader in PV deployment in the 1980s, the German PV market was significantly larger than the U.S. market from 2000 until 2012. Annual capacity additions (including residential, commercial, and utility-scale projects) accelerated in Germany since a reform of the German Renewable Energy Sources Act (EEG) in 2004, after which annual German PV installations were three to nine times higher than U.S. installations in terms of capacity. During 2010–2012, Germany added more than 7.4 GW per year, producing a cumulative installed capacity across all customer segments about four times greater (33.2 GW vs. 8.5 GW) than in the United States by the first quarter of 2013 (Figure 1) (Bundesnetzagentur, 2013; GTM Research & SEIA, 2011, 2012, 2013, Wissing, 2006, 2011) .

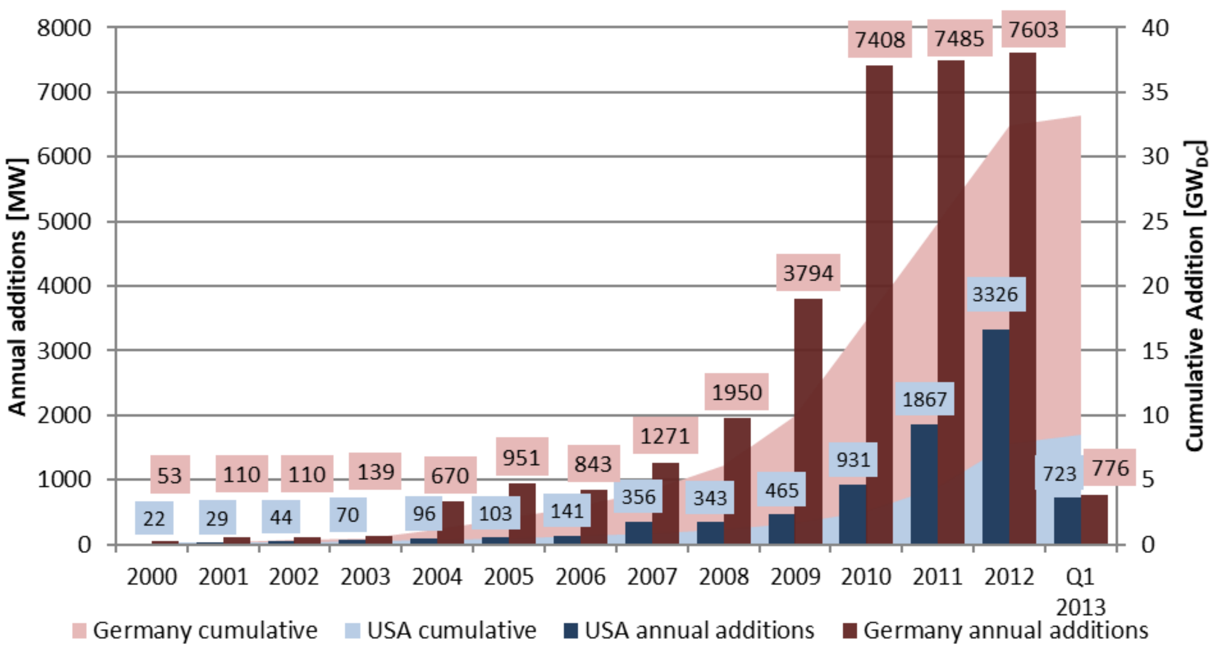


Figure 1: German and U.S. annual and cumulative PV capacity additions across all sectors

However, after the German Feed-in Tariff (FiT) was cut nearly 40% in 2012 and FiT degressions transitioned to a monthly schedule, German capacity additions slowed nearly to U.S. levels: 776 MW in Germany vs. 723 MW in the United States across all customer segments in the first quarter of 2013. Extrapolating from the first 6 months of 2013, German PV capacity additions would total about 3.6 GW in 2013, significantly lower than in previous years and close to the government target of 2.5–3.5 GW established in the 2010 EEG amendment.

A similar trend exists in the residential PV sector (defined here as any systems of 10 kW or smaller). Cumulative residential capacity in Germany was about 2.5 times greater (4,230 MW vs. 1,631 MW) than in the United States by the first quarter of 2013 (Figure 2) (Bundesnetzagentur, 2013; GTM Research & SEIA, 2011, 2012, 2013). However, German residential additions have slowed since the record year of 2011 and were for the first time smaller than U.S. residential additions in the first quarter of 2013 (136 MW vs. 164 MW). The recent residential growth in the United States has been spurred by new third-party-ownership business models, where either the system is leased to the site-host or the generation output is sold to the site-host under a power purchase agreement (quarterly market shares of third-party ownership range from 43% in Massachusetts to 91% in Arizona in Q4 2012) (GTM Research & SEIA, 2013). In contrast, third-party-ownership is uncommon in Germany.

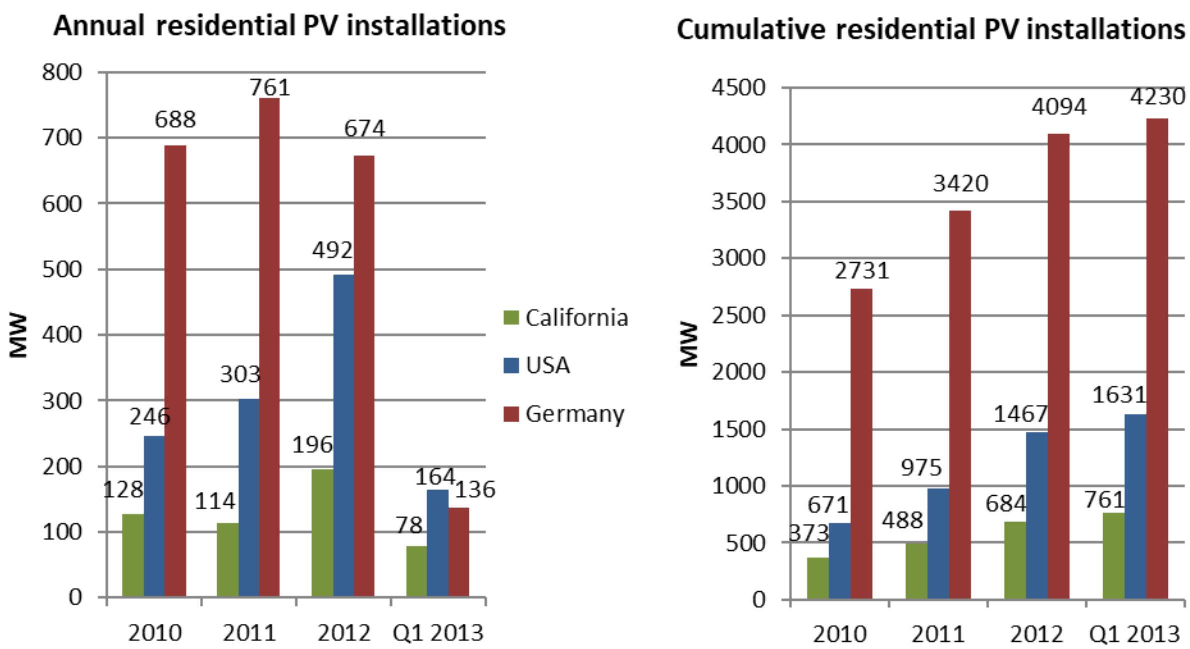


Figure 2: Residential annual and cumulative PV capacity additions: United States, Germany, California

Despite this recent trend, residential PV systems remain much more ubiquitous in Germany than in the United States, especially in relation to each country's population; cumulative per capita residential PV capacity is 5 W in the United States, 20 W in California (the largest PV market in the United States), and 53 W in Germany in Q1 2013. This sizeable difference indicates that the German residential PV market is more mature than the growing U.S. residential PV market.

3. Historical Residential PV System Pricing

3.1 Data Sources and Methodology

For this article, information for complete U.S. PV systems (but not individual soft-cost categories) and information on the country of origin of modules are derived from the database underlying the recent Lawrence Berkeley National Laboratory "Tracking the Sun VI" report, which reflects 70% of the U.S. PV capacity installed between 1998 and 2012 (G. Barbose & Darghouth, 2015). Systems larger than 10 kW and data entries with explicit information about non-residential use were excluded. It is important to note that the US data sample includes many third-party-owned projects. For systems installed by integrated companies (that both perform the installation and customer financing) the installed price data represents an appraised value, which was often significantly higher than prices of non-integrated installers between the years 2008 through 2011. The "appraised value prices" of many such systems stem from incentive applications that often utilize a "fair market value" methodology, which is based on a discounted cash flow from the project. This assessment can yield substantially higher values than the prices that would be paid under a cash-sale transaction of non-integrated installers. In order to avoid any bias that such data would otherwise introduce, projects for which reported installed prices were deemed likely to represent an appraised value – roughly 20,000 systems or 8% of the U.S. dataset – were removed from the sample to enable price comparisons with customer-owned residential systems in Germany. Unless otherwise noted, U.S. prices are reported as the statistical median from the Tracking the Sun dataset.

German system prices for 2001–2006 are arithmetic averages of data from the International Energy Agency's national PV survey reports (Wissing, 2006, 2011), the PV loan program of the German state bank Kreditanstalt für Wiederaufbau (KfW) (Oppermann, 2002, 2004), and a report comparing system prices between several European countries (Schaeffer et al., 2004). For 2007–2013, installed price averages for systems of 10 kW or smaller were obtained from quarterly surveys of 100 installers by the market research company EuPD for the German Solar Industry Association (BSW) (Tepper, 2013). In addition, 6,542 German price quotes for systems of 10 kW or smaller were analyzed for price distributions and module brand market shares (EuPD, 2013).

Annual module prices reflect average sales prices for a blend of monocrystalline and polycrystalline silicon modules at the factory gate in a mix of representative geographic locations, based on data from Navigant (Mints, 2012, 2013). Quarterly module prices from 2010 to 2012 are a blend of UBS spot market prices for Chinese and non-Chinese modules (Meymandi, Chin, Sanghavi, & Prasad, 2013), while quarterly residential inverter prices are based on the U.S. Solar Market Insights report series by Greentech Media (GTM Research & SEIA, 2011, 2012, 2013).

Throughout the analysis all prices are reported in average 2011 U.S. dollars (US\$2011). German historical data were adjusted with German inflation data to average 2011 euros (€2011) and then translated to US\$2011 by using the mean dollar-euro exchange rate for 2011 (\$1.39/€).

Focusing only on the upfront installed price of a PV system (with the metric $/W) has inherent limitations. A range of important quality characteristics are not captured, such as longevity and degradation rates of the hardware components, module capabilities (e.g., efficiency under diffuse light in cloudy Germany), inverter power-quality-management capabilities (e.g. reactive power supply), and the ability to analyze generated and self-consumed electricity data remotely. In addition, the levelized cost of solar electricity (which matters most to consumers) depends not only on installed price, but also on factors such as system uptime and, more importantly, annual insolation. Nevertheless, capacity pricing in $/W (including sales tax if applicable) is a useful metric because it enables a direct comparison of residential PV system prices between the two countries at a granular level. It is used for the remainder of the analysis, with the exception of a brief comparison of PV electricity generation costs in the results section. Operation, maintenance, and financing costs are outside the scope of this research.

3.2 Results

Average residential PV system prices have fallen significantly over the past 11 years in both countries: about 75% in Germany (starting from $11.44/W in 2001) and about 50% in the United States (starting from $10.61/W). After initial fluctuation, prices became similar in each country by 2005 (around $8.6/W). In the following years, prices increasingly diverged; during a time of nearly constant module prices from 2005 to 2008, U.S. system prices decreased only to $8.03/W in 2009, while German non-module cost reductions yielded a system price of $4.82/W in 2009 (Figure 3).

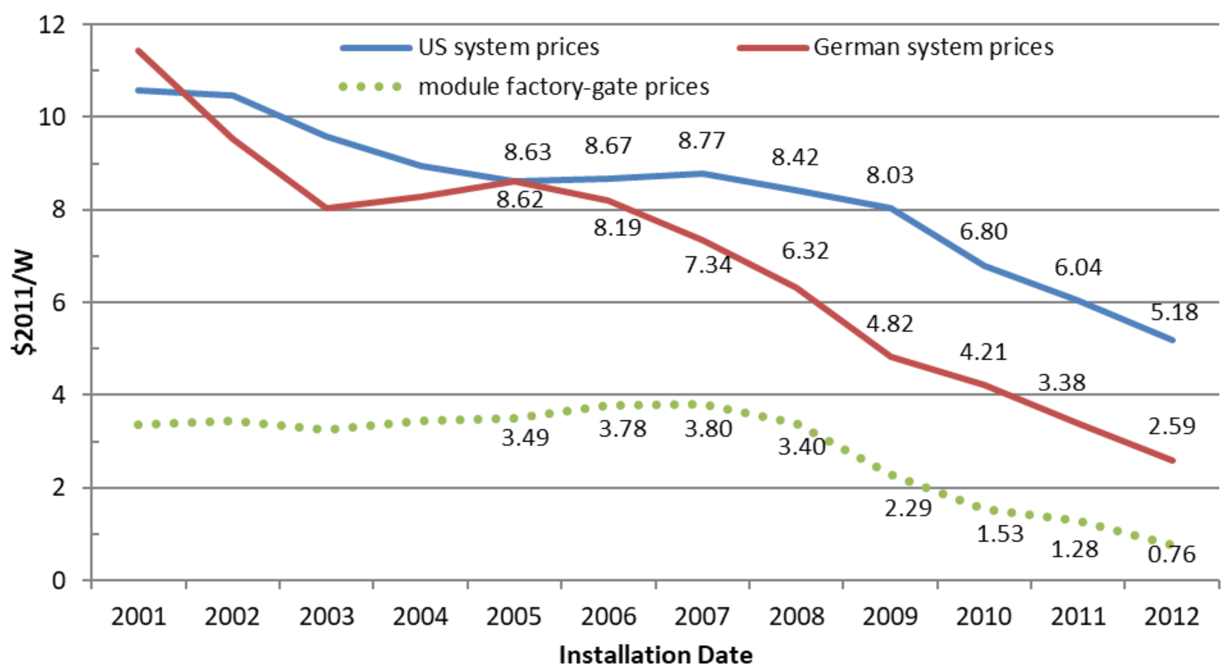


Figure 3: Median installed price of non-appraised PV systems <= 10 kW, 2001-2012

Median system prices decreased largely in parallel from 2010 through 2012, maintaining a price gap of about $2.8/W between residential systems installed in Germany and the United States. As shown in Figure 4, the price reductions in both countries were aided by a decline in module and inverter costs.

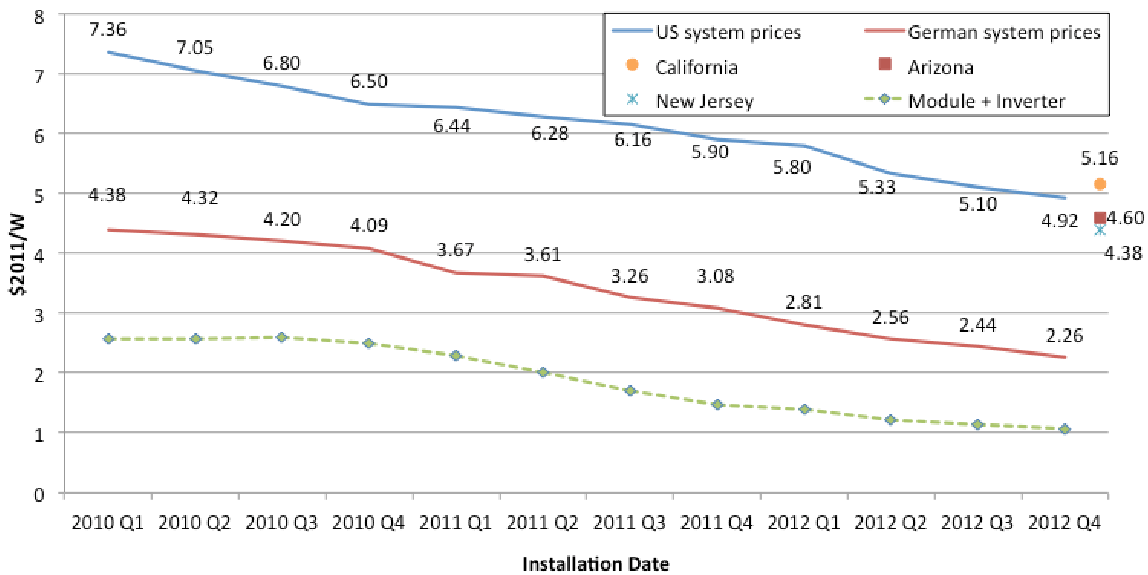


Figure 4: Median installed price of non-appraised PV systems <= 10 kW, 2010-2012

System-level prices are also much more heterogeneous in the United States than in Germany (Figure 5). For example, in 2012 the U.S. standard deviation was $1.54/W, compared with $0.45/W in Germany. Because of this wider spread of prices in the United States relative to Germany, the cheapest 15% of U.S. systems were installed at prices found among the more expensive systems in Germany.

The wider distribution can be explained in part by significant system price differences among individual U.S. states and the absence of clear price signals on the national level. For example, New Jersey (one of the lower-priced markets) had a median residential price of $4.38/W in the fourth quarter of 2012, compared with $5.16/W in California (one of the higher-priced markets and the largest U.S. PV market). This difference is partly due to varying business process costs (such as labor costs), but it also suggests the presence of value-based pricing and relatively fragmented markets across states and local jurisdictions. For example, the electricity costs avoided by net-metering agreements vary based on electricity rates and structures in different utility service territories and states, as do additional incentives.

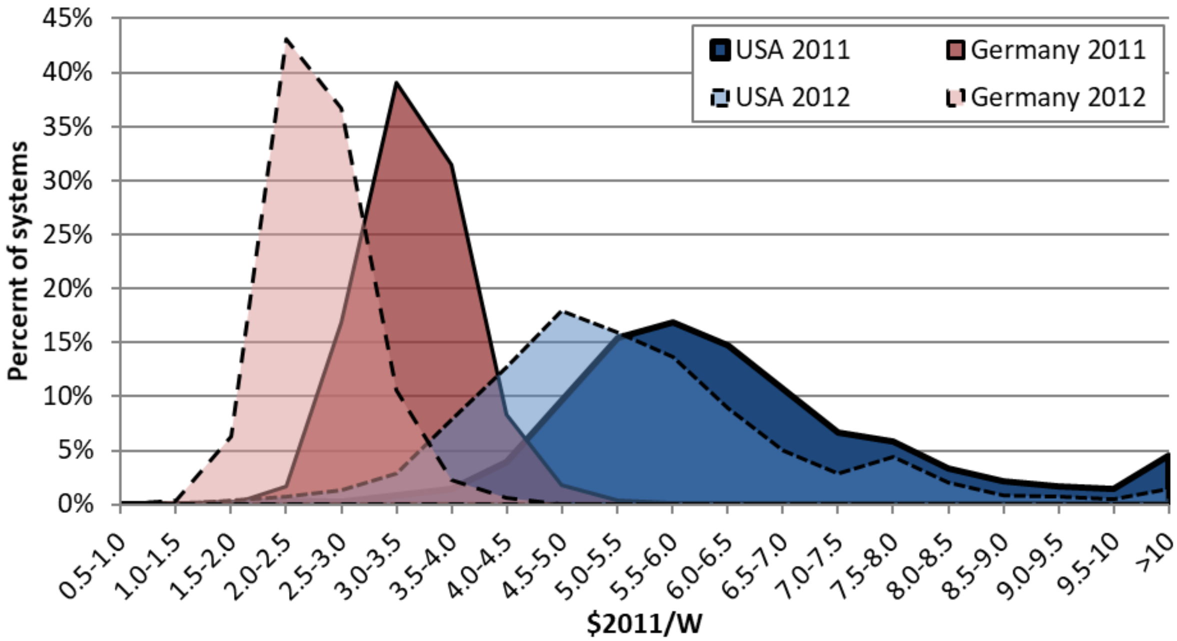


Figure 5: Price distribution of non-appraised PV systems <= 10 kW installed in the United States and Germany in 2011 and 2012

The system price differences between Germany and the United States affect the associated electricity generation costs, although they are partly offset by the different insolation resources. Germany's average insolation ranges between Alaska's and the State of Washington's, the least sunny areas of the United States (900–1,200 kWh/m^2 annual global horizontal irradiation averages). A levelized cost of electricity (LCoE) analysis based on the National Renewable Energy Laboratory's (NREL's) System Advisor Model showed that residential PV electricity generation costs at PV system prices from the fourth quarter of 2012 ($2.26/W in Germany and $4.92/W in the United States) in the cloudier parts of Germany were comparable to costs in sunny regions of the United States such as California.[1] If residential PV system prices in the United States decreased to German levels, electricity could be generated at very low costs in sunny areas in the United States. Figure 6 suggests that, with the 30% U.S. federal investment tax credit (ITC), achieving German PV system prices could reduce PV electricity generation cost to $0.06/kWh for residential installations in Los Angeles.

[1] LCoE assumptions: 25-year life span, nominal discount rate of 4.5%, O&M $100/year, one inverter replacement over the system lifetime for $1,200, derate factor of 0.77, degradation rates of 0.5%/year.

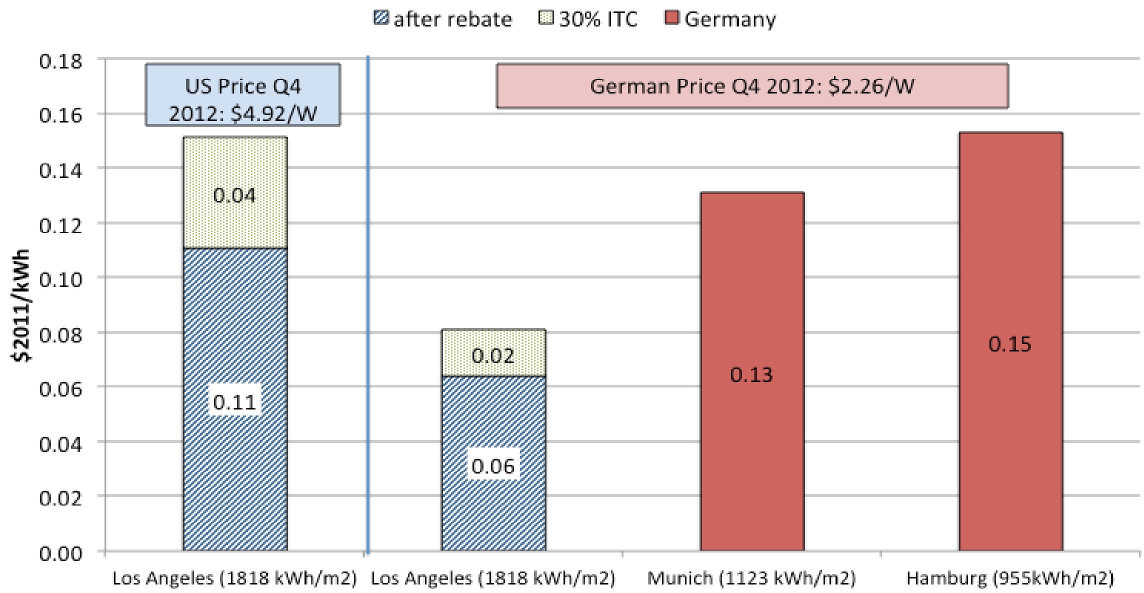


Figure 6: Levelized cost of electricity estimates for residential PV systems at varying global horizontal annual insolation rates in Q4 2012

4. Non-module Costs as primary Driver of Price Differences

With the significant growth and internationalization of PV module manufacturing, modules increasingly have become a global commodity that can be purchased at very similar prices in the large and mature PV markets around the world. Previous analyses have shown very little recent pricing discrepancy for PV modules between Germany and the United States (Goodrich, James, & Woodhouse, 2012). Further, lower-cost Chinese and Taiwanese module brands penetrated the residential markets of both countries similarly in 2012 (increasing from 23% to 39% in Germany and from 32% to 40% in the United States from 2010 to 2012), even though German brands were more popular in Germany (56% of all systems in 2010 declining to 46% in 2012 (EuPD, 2013)) than were American brands in the United States (relatively stable around 20% (G. Barbose & Darghouth, 2015))[2]. This leaves non-module costs as the primary driver of system price differences.

Non-module costs can be divided into two general categories: inverter and other BoS hardware costs and non-hardware costs, which are also called “business process costs” or “soft (BoS) costs.” Since the strong decline in module prices starting in 2008, increasing attention has been devoted to BoS costs and soft costs for further price reductions. The U.S. Department of Energy has dedicated significant consideration to these costs in the context of the SunShot Initiative (Ardani et al., 2012; U.S. Department of Energy, 2010, 2012). Other public entities on both sides

[2] Information is based on the country of the headquarter of the 25 most ubiquitous module brands in the U.S., derived from 106,472 systems installed in 20 different U.S. states between 2010 and 2012.

of the Atlantic (e.g. Bony et al., 2010; Melanie Persem et al., 2011; Sonvilla et al., 2013), private industry (e.g. GTM Research, 2011), and academic researchers have taken on this subject increasingly as well (Ringbeck & Sutterlueti, 2013; Schaeffer et al., 2004; Shrimali & Jenner, 2012). Our analysis complements that literature by providing an in-depth comparison of soft-BoS cost components in Germany and the United States, that was derived from one consistent survey instrument distributed to a larger number of respondents and resulting in more granular soft-BoS cost categories than previously available. These survey results, which are more recent then what has previously been available in the literature, are then aggregated in complete bottom-up cost models for both countries. The survey data is also contextualized with additional statistical analyses of the largest U.S. PV system database (G. Barbose & Darghouth, 2015), and a complete database of interconnected German PV systems (Bundesnetzagentur, 2013) to discern influences of system sizes and system development times on soft costs. At last we highlight best practices and associated BoS cost-reduction opportunities for both the United States and Germany.

4.1 Introduction to Soft-Cost Survey and Methodology

More detailed information on the composition of soft costs was needed to identify the sources of the significant residential PV system price gap between the United States and Germany. Building on a bottom-up benchmarking analysis of the U.S. residential PV market in 2010 (Ardani et al., 2012), we adapted a survey developed by NREL to collect granular data on soft costs for residential PV systems in Germany and to enable direct comparisons between the two countries. The survey instrument inquired about German residential systems installed in 2011. It was distributed in early 2012 to more than 300 German residential PV installers in Microsoft Excel format and as an online survey on the platform www.photovoltaikstudie.de. The survey asked either for total annual expenditures for a given business process, translated into $/W based on each installer's annual installation volume, or for labor-hour requirements per installation for individual business process tasks, which were multiplied by a survey-derived, task-specific, fully burdened wage rate to estimate $/W costs.

The German survey respondent sample consisted of 24 installers that completed 2,056 residential systems in 2011, yielding a residential capacity of 17.9 MW. This is roughly half the sample size of the corresponding U.S. survey.

Due to surprisingly low reported installation labor hours in the German survey (likely because of a misunderstanding of the term "man-hours"), a follow-up survey was fielded in October 2012 focusing solely on installation labor requirements during the preceding 12 months. Forty-one German installers participated in this second survey, collectively representing 1,842 residential systems installed over the previous year, with a capacity of 11.9 MW.

The median reported residential system size was 8 kW, which is close to the median system size of all grid-connected PV systems of 10 kW or smaller in Germany in 2011 (6.8 kW) (Bundesnetzagentur, 2013). In both German surveys, most respondents were relatively small-volume installers, completing fewer than 50 residential systems per year (median: 25 in 2011, 26 in 2012). These German firm sizes are generally comparable to the installer firm sizes of the U.S. survey (median of 30 residential installations per year), although two U.S. firms installed more than 1000 systems per year, a threshold not reached by a single German company in the survey. Survey responses were weighted by the installed residential capacity of each installer, giving a stronger emphasis to larger companies.

In contrast to the earlier reporting of median prices, capacity-weighted means are more meaningful in a bottom-up cost analysis and thus are used for the survey results. The capacity-weighted mean price for U.S. residential systems was slightly higher than the median price in 2011 ($6.19/W vs. $6.04/W).

4.2. Survey Findings

The capacity-weighted mean price for German residential systems reported in the survey for 2011 was $3.00/W, slightly lower than the BSW estimate for 2011 of $3.38/W (Tepper, 2013). Total non-hardware costs (including margin) were much lower in Germany, accounting in 2011 for only $0.62/W (21% of system price) versus $3.34/W in the United States (54%).

A comparison of fully burdened wages between the two countries reveals that installation labor was cheaper in Germany but that wages of system design engineers, sales representatives, and administrative workers were higher in Germany (Table 1).

	Electrician Installation	Non-electrician Installation	System Design Engineer	Sales Representative	Administrative Labor
United States	62	42	35	32	20
Germany	48	38	47	53	42

Table 1: Fully burdened wages at PV installation companies [$/h]

The wage data includes taxes and welfare contributions but excludes employment-related overhead costs incurred by human resources departments. Data for Germany was derived from the fielded survey, while U.S. wage data was utilized that had been previously used in U.S. soft cost analyses by the U.S. National Renewable Energy Laboratory (RSMeans, 2010). Some of the German wage data derived from the survey are higher than estimates by the German federal statistical agency (Destatis), especially for sales labor. This discrepancy can be explained by the fact that many German residential installers are small businesses and local craftsmen—where the business owner is often involved in the sales process—while the Destatis numbers are not specific to the PV industry and represent sales labor wages in larger companies.

Of the three specific soft cost categories examined, the largest difference between the United States and Germany was associated with **customer acquisition costs** (a difference of $0.62/W).

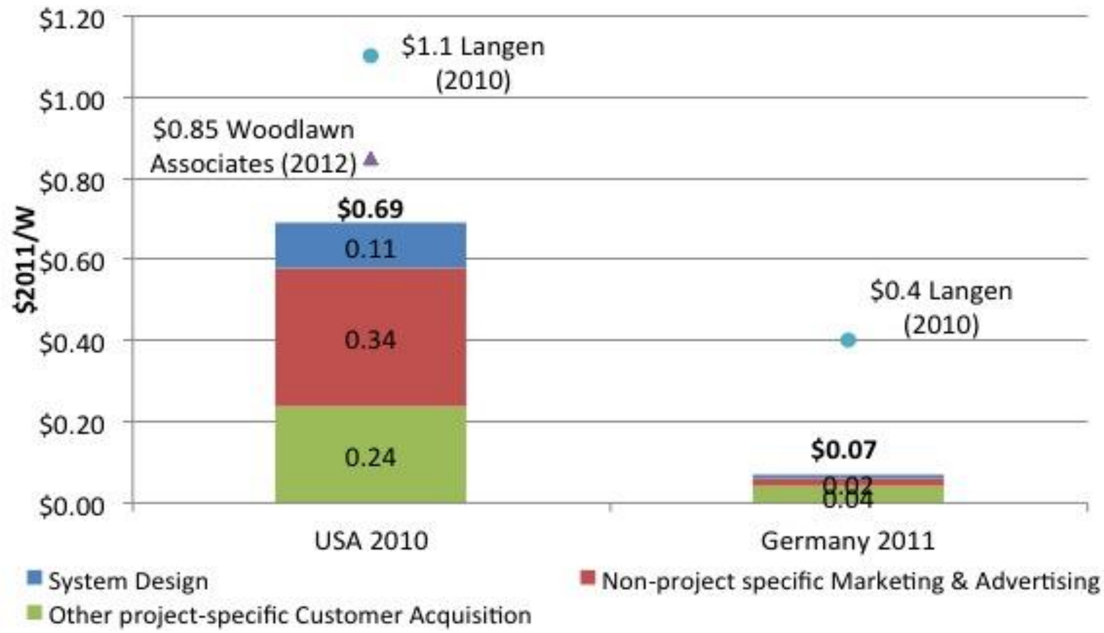


Figure 7: Average customer acquisition costs in the United States and Germany

In Figure 7, *"Non-project-specific Marketing & Advertising"* includes expenses such as online and magazine ad campaigns, while "*Other project-specific Customer Acquisition"* includes categories such as sales calls, site visits, travel time, bid preparation, and contract negotiation (averaging about $400 for a German installation). Previous analyses confirmed a similar degree of expense differences between the two countries for 2010 and similar levels of U.S. customer acquisition costs in 2012 (Woodlawn Associates, 2012). "*Non-project-specific Marketing and Advertising"* costs average about $200 for a residential installation in Germany, although one third of the respondents reported no expenses for such broad advertising activities for their businesses. "*Other project-specific Customer Acquisition"* expenses are in comparison both more substantial (averaging about $400 per installation) and more ubiquitous (only two respondents reporting no costs for this category).

Customer acquisition costs may be lower in Germany because of partnerships between installers and both equipment manufacturers and lead-aggregation websites, where potential customers are quickly linked to three to five installers in their zip code areas. German residential PV installers also have a higher bid success rate, which lowers per-customer acquisition costs: 40% of leads translate into final contracts in Germany compared to 30% in the United States.

In addition, the large German market has transformed residential PV systems from an early-adopter product into a more mainstream product, and new customers are recruited primarily by word of mouth. Peer effects in the diffusion of PV (Bollinger & Gillingham, 2012), therefore, further explain the relatively low customer acquisition costs in the more mature German market; about 1 of 32 German households owned PV systems in the first quarter of 2013 compared with 1 of 83 California households and 1 of 323 U.S. households. As explained later, the relatively straightforward value proposition of PV systems under the FiT in Germany may further facilitate the sales process and contribute to lower customer acquisition costs compared to the United States.

The second-largest soft cost difference ($0.36/W) stems from the **physical installation process** (Figure 8). According to the follow-up survey, German companies installed residential PV systems in 39 man-hours, on average, while U.S. installers required about twice as many labor hours (75 man-hours per residential system). One possible contributor to the difference in installation labor hour requirements is the prevalence of roof penetrations. Most surveyed German installers either never or only rarely install residential systems requiring rooftop penetration; this share is likely higher in the United States due to differences in roofing materials and climatic requirements.[3] Other studies have reported even shorter installation times for Germany (Bromley, 2012; PV Grid, 2012).

A recent field study by the Rocky Mountain Institute—using a time and motion methodology for residential PV installations in both countries—confirmed our findings and provided further details on differences in installation practices that highlight remaining optimization opportunities for U.S. installers (Morris, Calhoun, Goodman, & Seif, 2013). The required installation labor hours for German installations are not strongly positively correlated with the installed system size, suggesting further economies of scale for the slightly larger German residential PV systems in comparison to U.S. residential systems. The standard deviation in reported total installation labor hours is only 12h for German systems, and even the 90th percentile of German labor hours (55h) is significantly less than what their American counterparts reported for the year 2010.

In Germany, the bulk of installation labor consisted of cheaper non-electrician labor (77% of total man-hours), whereas non-electrician labor represented only 65% of total installation labor hours for U.S. residential systems. Fully burdened wages were also slightly lower in Germany than in the United States. As a result of this combination of factors (fewer total installation labor hours, greater reliance on non-electrician labor, and lower overall wage rates), installation labor costs averaged $0.23/W in Germany compared to $0.59/W in the United States (Figure 8).

[3] Additional hypotheses about faster German installations due to a lower prevalence of an extra conduit for wiring or much faster grounding practices could not be confirmed.

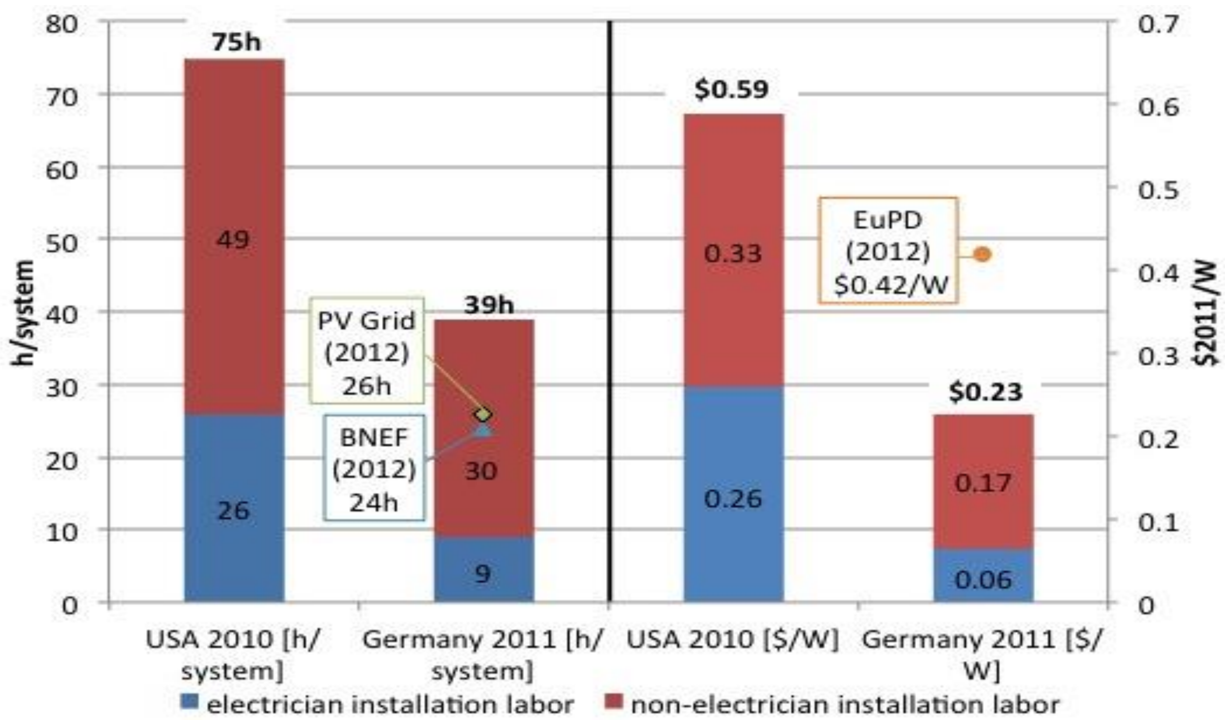


Figure 8: Installation labor hours and costs in the United States and Germany

Costs associated with **permitting, interconnection, inspection** (PII) have been discussed widely in the United States. As shown in Figure 9, our survey indicated PII costs (including incentive application processes) were $0.21/W lower in Germany than in the United States. This difference is mostly due to lower PII labor hour requirements in Germany (5.2 h vs. 22.6 h). In Germany, local permits (structural, electrical, aesthetic) and inspection by county officials are not required for the construction of residential PV systems. Incentive applications are done quickly online on one unified national platform - all respondents of the German survey reported zero labor hours for this activity, suggesting that this is done by the owner of the PV system and no facilitation of the installer is required. In addition, no permit fee is required in Germany, while residential permitting fees in the United States average $0.09/W. As result, the only sizable PII activity in Germany is the actual interconnection process to the distribution grid (the respondents are very consistent in their reports of 2h -3.5h) and an associated notification to the local utility (20% of the respondents stating that 0h are required for this activity, while 12% report time budgets of 3.5h-4h).

These survey results are very similar to other estimates of permit time requirements and total PII costs (Tong, 2012; PV Grid, 2012; Sprague, 2011; Dong & Wiser, 2013). Since the assessment of U.S. permitting time requirements in 2010 (Ardani et al., 2012), substantial efforts have been made across many U.S. jurisdictions to streamline processes and make reporting requirements more transparent. Among the initiatives are online databases such as www.solarpermit.org, the U.S. Department of Energy's "Rooftop Solar Challenge" with best practices shared in an online resource center, and state legislation limiting permit fees in Vermont, Colorado, and California.

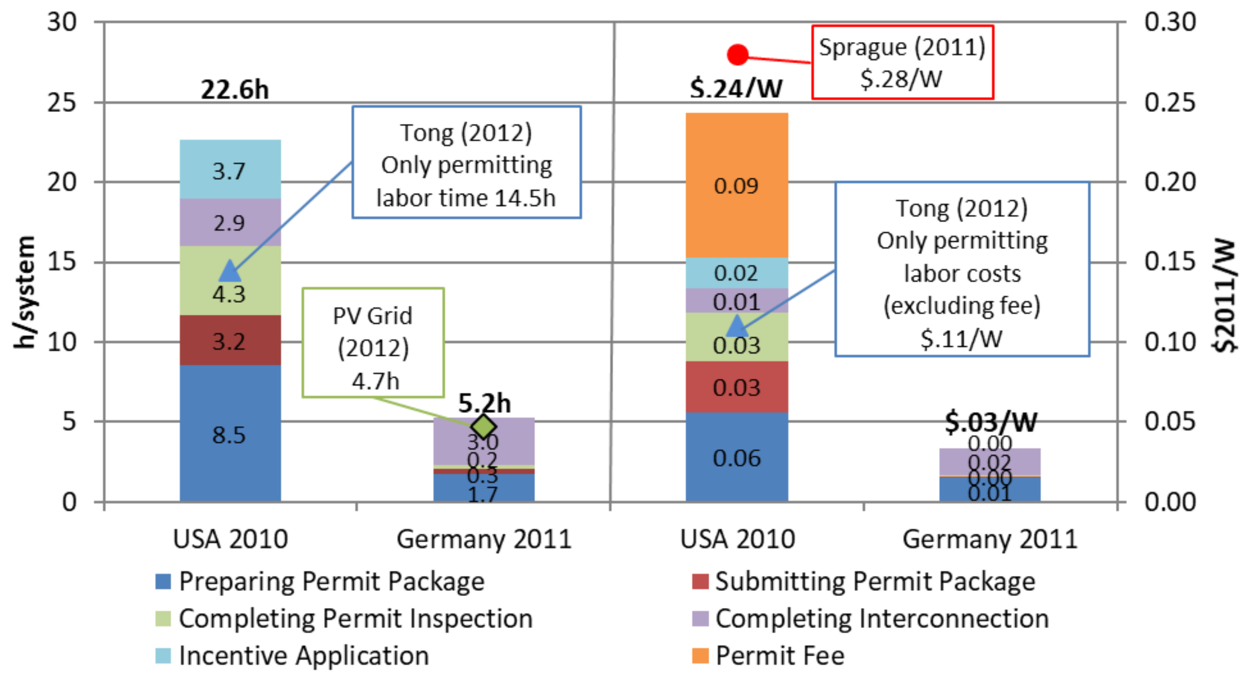


Figure 9: Permitting, interconnection, inspection, and incentive application hours and costs in the United States and Germany

In addition to the soft cost categories explored through the survey, sales taxes are another reason for the divergence between residential PV system prices in the United States and Germany. German PV systems are effectively exempt from sales and value-added taxes (usually 19%) either due to the “Kleinunternehmer” or “Vorsteuererstattungs” clause (Bundesverband Solarwirtschaft (BSW-Solar), 2012). In the United States, 23 states assess sales taxes on residential PV systems, usually ranging between 4% and 8% of the hardware costs. In addition, local sales taxes are often levied (The Tax Foundation, 2013). Given the spatial distribution of PV systems in the United States (G. Barbose & Darghouth, 2015), and accounting for PV sales tax exemptions in some states (DSIRE, 2012), state and local sales taxes added according to our analysis approximately $0.21/W to the median price of U.S. residential PV systems in 2011.

We devised a bottom-up cost model for U.S. systems using hardware cost estimates for 2011 (GTM Research & SEIA, 2012; Goodrich et al., 2012) and soft cost benchmarks for 2010 (Ardani et al., 2012). Figure 10 summarizes the identified sources for the price difference of $3.19/W between U.S. and German residential systems installed in 2011. Besides the residual costs, the largest difference in soft costs stems from customer acquisition costs, followed by installation labor costs, sales taxes, and PII costs.

To our knowledge, no detailed national data are available on additional overhead costs (e.g., property-related expenses, inventory-related costs, insurance, fees, and general administrative costs) and net profit margins of U.S. residential installers. The additional category “overhead, profit, and other residual costs” in Figure 10, therefore, accounts for the difference between the system prices (G. Barbose, Wiser, & Darghouth, 2012) and the bottom-up cost estimates. German installers reported $0.29/W for overhead costs and profits, while the U.S. residual was $1.61/W (a difference of $1.32/W). Additional research is needed to understand the source of this large difference.

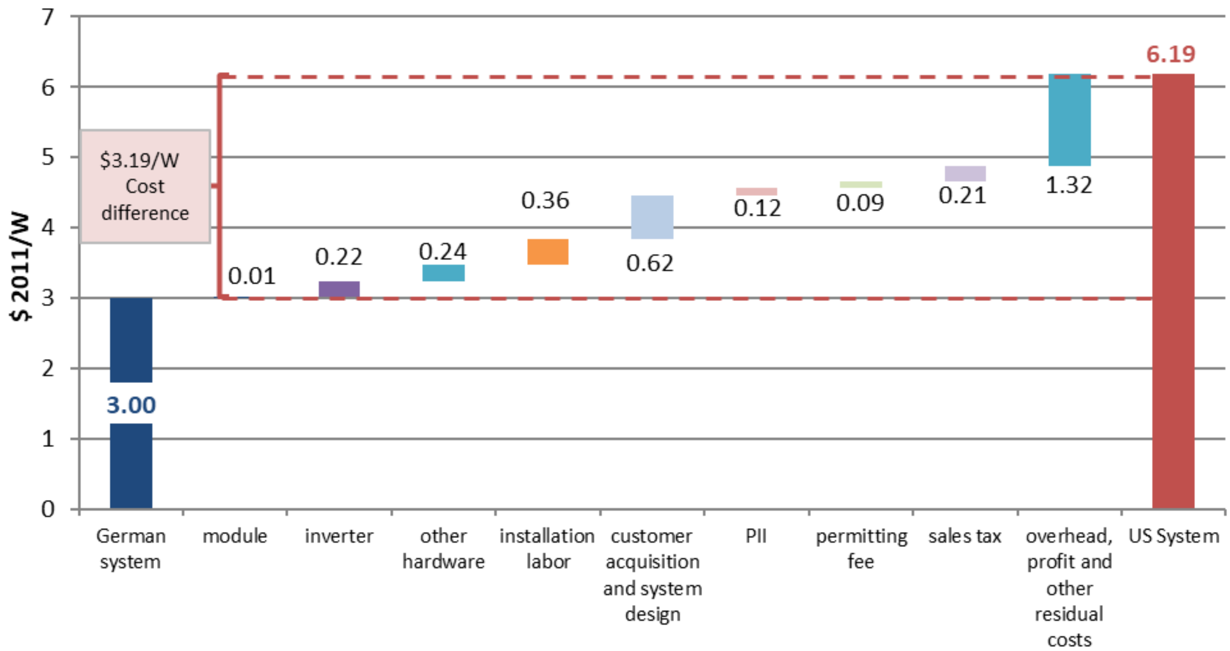


Figure 10: Cost difference between German and the U.S. residential PV systems in 2011

Two additional hypotheses may explain in part why residential PV prices are higher in the United States, even though they do not add directly to the numbers already represented in the bottom-up cost model: implications of longer development times and the effect of differences in system sizes on final system prices.

According to the survey, German residential PV installers require on average 35 days between first contact with a potential customer and the completion of the PV system installation and interconnection. System development times are substantially longer in the United States, where the average time between the first application date for a future specific PV installation and the reported system completion is 126 days. This substantially longer period of nearly 3 months impacts an installer’s financing costs for purchased materials, the volume of annual installations, and the associated relative burden of general business overhead costs per installation. It also influences the installer’s ability to pass down material price reductions to the final customer in a timely manner. For example, prices for systems completed in the fourth quarter of 2012 may have been negotiated in that quarter in Germany but in the third quarter of 2012 in the United States. The effects of these temporal misalignments vary with pricing dynamics in both countries over time. In the fourth quarter of 2012, they may explain $0.18/W of the system price difference (the price difference between the third and fourth quarters of 2012 in Germany).

An analysis of German PV interconnection data (Bundesnetzagentur, 2013) for systems of 10 kW or smaller shows that systems in Germany are also slightly larger than those in the United States, with respective medians of 6.80 kW and 4.95 kW in 2011. Although the mode is in the 5–6 kW bin in both countries, the German distribution of system sizes is positively skewed, while the U.S. distribution is negatively skewed. This difference can be explained by the fact that German residential system sizes historically have been constrained only by available roof area and the customers' willingness to pay for larger system sizes, because the FiT payments are not system-size dependent within each FiT bin (0–30 kW until April 2012, 0–10 kW since then). Because PV systems exhibit economies of scale, larger systems result in a higher rate of return, providing an incentive for larger systems. In the United States, by contrast, PV customers size their systems predominantly according to their own electricity consumption, because excess generation is not compensated favorably under most net-metering agreements (Darghouth, Barbose, & Wiser, 2011). Thus, owing to economies of scale, the larger German systems have lower average system prices than the smaller U.S. systems. Applying the German system size distribution to the U.S. system price distribution quantifies this price advantage at $0.15/W for systems installed in 2011.

5. Discussion of Findings

Our preceding empirical analysis shows that the primary sources of price differences between U.S. and German residential PV systems are non-module costs, primarily soft costs such as business process costs and "overhead costs and profit." The following discussion section contextualizes our quantitative results with a few general hypotheses that are not exclusively linked to individual business process cost categories, but that may explain differences in the broader market characteristics between the two countries. As the observed price disparities are likely of multi-causal origin, we first turn to structural market differences including market size and the degree of market fragmentation. In a second step we examine differences in the economic valuation of the generated electricity of PV systems to illuminate possible consequences on system pricing by installers and the customers' willingness to pay. We recognize however that the postulated hypotheses are by no means exhaustive and that a further analysis of market differences between both countries provides an excellent field for future research.

At first, some of the price discrepancy between the United States and Germany may be in part attributable to the smaller size of both the annual residential PV market in the United States compared with Germany as well as a significantly lower amount of cumulative installations. In general one would suppose that a larger market gives installers more experience, enabling them, for example, to streamline workflows during the physical installation process.

The transferability of the German experience to the Unites States may be limited due to a number of structural differences between the two markets that are unlikely to change: Germany has a higher population density, leading to lower transportation costs and travel times, while climatic differences such as higher wind loads and roofs not designed to withstand large snow masses may require a higher degree of scrutiny during the structural design process for PV systems in the United States.

Some of the market fragmentation in the United States—particularly fragmented permitting processes among states, utility service territories, and cities—is politically induced and originates in the substantial regulatory role that state and local governments assume. In contrast, the national Renewable Energy Sources Act and the German Energy Act primarily govern Germany's renewable energy policy, which provides the country with a national incentive structure and one unified PV market with few PII requirements. One may postulate the hypothesis that four aspects of the German PV market seem to work more effectively than in the U.S. and enable thus a quicker project flow and lower customer acquisition costs: the relative simplicity of the German regulatory framework, a large potential customer base that holds strong environmental values, bandwagon and diffusion effects among customers, and a very competitive PV market.

German PV market growth and rapidly falling prices also may have been facilitated by the regularly adjusted FiT, which has provided a simpler, more certain, and more lasting value proposition to the final customer (Haas et al., 2011; Klessmann et al., 2013; Mendonca, 2009) compared to U.S. policies consisting of a combination of tax credits, local incentives, and net-metering policies.

It is relatively easy to calculate the value of the FiT-payments revenue stream in Germany; its decline for new systems is shown in Figure 11 (blue line in $/kWh, right axis), along with its corresponding net present value (NPV) in $/W. The modeled NPV accounts for module degradation and inflation but excludes additional operation and maintenance costs—the FiT NPV should thus be higher than corresponding system prices to allow for cost recuperation and the earning of a return on the investment. Because the NPV for a given FiT level is determined primarily by local insolation, a representative system for the sunny regions in the German south (generating roughly 860 kWh/kW each year, light green dotted line, left axis) and one for the less sunny northern regions (generating roughly 730 kWh/kW each year, dark green dotted line, left axis) are modeled in Figure 11.

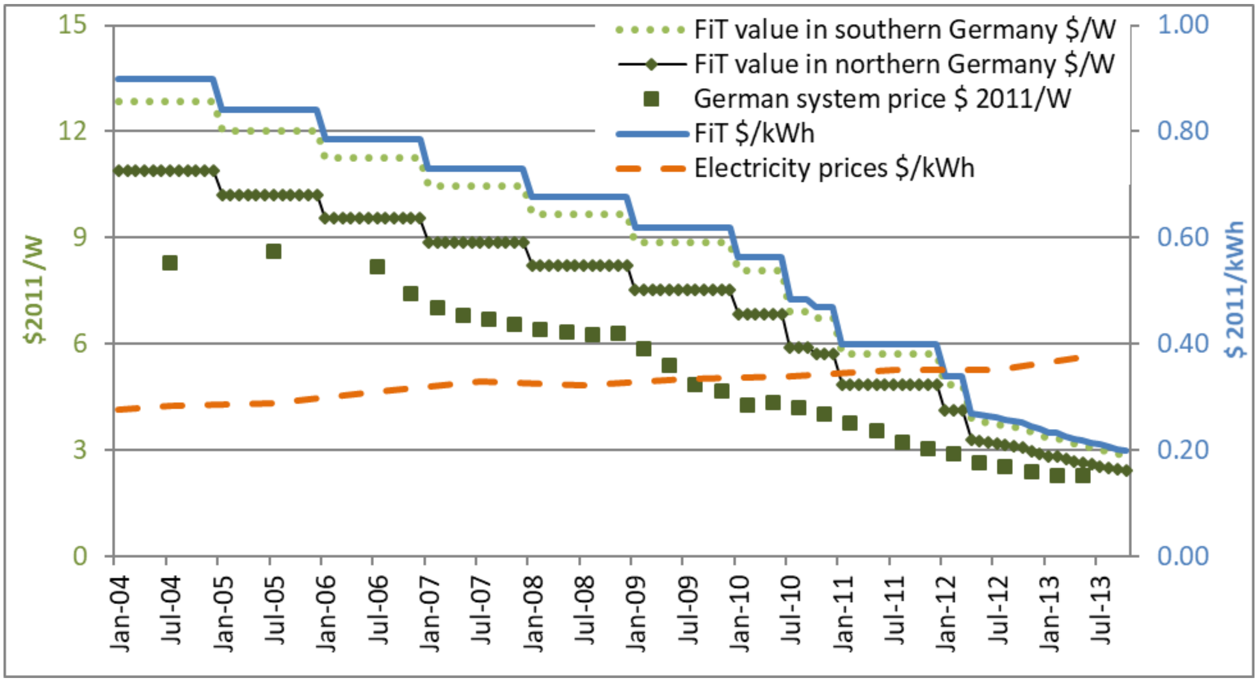


Figure 11: German residential PV system prices and the value of FiT payments in high (southern) and low (northern) irradiation regions in Germany

This policy mechanism of regular incentive reductions has forced residential installers to lower system prices (even in times of stable module prices before 2008) to offer their customers attractive rates of return. In 2012, however, the FiT for German residential PV systems reached "grid parity" as the remuneration amount was less than average residential electricity prices for the first time. Since then, the FiT has continued to decline while retail electricity prices have risen (orange dashed line, right axis in Figure 11) (Haller, Hermann, Loreck, & Matthes, 2013), leading to a difference of $0.17/kWh in July 2013. This spread has motivated new German PV customers increasingly to displace electricity purchased from the utility with self-generated electricity from the PV system. In contrast to most U.S. net-metering policies, this displacement must occur on an instantaneous basis and not on a net basis over a longer period (typically a year), which historically has limited the attractiveness of this option for German customers. However, a new federal subsidy program for batteries (30% of the battery price up to a cap of 2€ per Watt PV capacity for new residential installations) and the growing value discrepancy between the purchase price of retail electricity and the set sales price of the FiT may overcome these hurdles. The overall price-decreasing pressure of the degressing FiT could thus become less effective over the coming years should German residential PV customers rely increasingly on the higher value of the self-consumption option. That and a stagnation of module prices may explain the increase in German system prices in the second quarter of 2013, the first rise compared to the previous quarter since the second quarter of 2010. German customers have not yet responded, however, to these new value propositions by optimizing PV systems for self-consumption; size distributions between the first quarter of 2010 (pre-FiT-grid parity) and the first quarter of 2013 (post-FiT-grid parity) show no change in either shape or average values (Bundesnetzagentur, 2013).

Similar pressures to reduce system prices may not exist to the same degree in the United States. Even though state-level incentives (such as upfront rebates and performance-based incentives) have declined over time, they have done so with less consistency than the German FiT, while the largest national incentive (the federal Investment Tax Credit) has remained stable at 30% of the total system price, at least until 2016. Furthermore, significant variation in PV customer bill savings can occur in the United States due to complicated rate structures, such as changing marginal electricity prices for different consumption tiers in California (Darghouth et al., 2011; A. Mills, Wiser, Barbose, & Golove, 2008), which make the true value proposition of the PV system less transparent to the average consumer. In addition, the NPV associated with electricity cost savings from net-metering agreements does not fall regularly and may even increase with rising electricity prices over time (similar to the new reality in Germany after 2012). These facts may explain higher customer acquisition costs and the potentially more prevalent above-cost, value-based pricing of PV systems. Only a very competitive installer market and the motivation to capture a higher market share may drive installers to price their systems more aggressively.

One subject still insufficiently understood is the composition of overhead costs and margins among U.S. residential PV installers. Studies analyzing pricing decisions—such as the degree of value-based-pricing—and competition between installers would fill an important gap in the current literature and help determine whether structural differences in incentive policies can explain the sizable price gap between German and U.S. residential PV systems.

6. Conclusion

Residential PV systems in the United States were nearly twice as expensive as those in Germany in 2011 - recent price differences of about \$2.8/W continued through 2012 and then declined slightly over the first half of 2013. Most of these differences originated in high business process and overhead costs in the United States and cannot be explained by mere differences in national market size. To reduce these costs, actors in the United States could consider policy reforms that enable a larger residential PV market with a stable growth trajectory while minimizing market fragmentation. Simpler PII requirements and regularly decreasing incentives, which drive and follow price reductions and offer a transparent and certain value proposition, might help accelerate residential PV price reductions in the United States.

Maximizing MWh: A Statistical Analysis of the Performance of Utility-Scale Photovoltaic Projects in the United States

A report version of this research, a presentation, and a webinar recording is available at https://emp.lbl.gov/publications/maximizing-mwh-statistical-analysis.

1. Introduction

The installed cost of photovoltaic ("PV") projects in the United States has declined significantly in recent years, both at the distributed (Barbose et al., 2015; Barbose & Darghouth, 2015; GTM Research & SEIA, 2015) and utility-scale levels (Bolinger & Seel, 2015; Bolinger, Weaver, & Zuboy, 2015; GTM Research & SEIA, 2015). Reflecting in part this decline in costs, the prices at which utility-scale PV projects have been selling their output through long-term power purchase agreements ("PPAs") have also fallen to all-time lows, below $50/MWh on a levelized basis in some cases (Bolinger & Seel, 2015; Bolinger et al., 2015).[4]

As a result, utility-scale PV deployment has been booming (Bolinger & Seel, 2015; GTM Research & SEIA, 2015). Just five years after the first truly "utility-scale" project – defined here as any ground-mounted project with a capacity that is larger than 5 MW_{AC} – was built in the United States in 2007, the utility-scale sector became the largest segment of the overall PV market (ahead of both residential and commercial/industrial capacity) in 2012, and has held that distinction ever since. There were 9,744 MW_{DC} of utility-scale PV operating in the United States at the end of 2014, nearly double the 5,087 MW_{DC} of commercial/industrial and nearly triple the 3,486 MW_{DC} of residential PV capacity (GTM Research & SEIA, 2015). In addition, each MW of utility-scale PV tends to generate more MWh per year than each MW of commercial/industrial or residential PV (Lee & Moses, 2015; Tsuchida et al., 2015), as the latter must often contend with sub-optimal roof orientation and/or partial shading, and seldom make use of tracking devices. As a result, utility-scale PV's market-leading position is even greater in energy terms than in capacity terms (Lee & Moses, 2015). This holds true even after accounting for losses incurred by transmitting often-remote utility-scale solar generation over long distances to load. Estimates of transmission losses vary, but are generally less than 10%, and are often in the low-to-mid single digits (Energy Information Administration, 2015; Wong, 2011). For example, a recent review of utility-scale PV projects serving California load estimates transmission losses in the range of 0%-3.9%, with the upper end of the range representing projects that are located out of state (California Public Utilities Commission, 2015).

But the market is still young – e.g., 40% of the 9,744 MW_{DC} of utility-scale PV operating in the United States at the end of 2014 came online that same year (GTM Research & SEIA, 2015) – and

4 These levelized prices reflect the receipt of federal tax benefits, including the 30% federal investment tax credit and accelerated tax depreciation, as well as any state-level incentives that are available, and would be higher absent these incentives.

whether or not these utility-scale projects ultimately turn out to be profitable, particularly at such low PPA prices, depends in large part on how well they perform over time. Given that substantially all costs born by utility-scale PV projects are fixed in nature (the vast majority of which are tied to initial construction of the project), the number of MWh over which those fixed costs can be amortized is a key determinant of utility-scale PV's levelized cost of energy. Understanding how existing projects have performed and what has driven variations in performance is, therefore, paramount to understanding the likely profitability of the utility-scale PV sector. This in turn directly impacts the sector's ability to attract the large amounts of investment capital needed to fund continued deployment at levels required to progress towards national policy goals like those of the Clean Power Plan. Moreover, the importance of project performance will only increase as the federal investment tax credit (ITC) is gradually phased down from its current 30% to 26%, 22%, and ultimately 10% in future years, leaving a greater proportion of each project's overall post-tax profit dependent on revenue tied to the number of MWh generated.

Against this backdrop, this paper presents selected results from a multi-variable regression analysis of the drivers of utility-scale PV project performance, as measured empirically by net AC capacity factor in 2014 ("NCF"). The analysis is based on a sample of 128 utility-scale PV projects totaling 3,201 MW_{AC} that achieved commercial operation in 18 different states over the seven-year period from 2007-2013, and that were operating throughout the entirety of 2014.[5] This sample represents essentially the entire universe of utility-scale projects that were operating in the United States at the end of 2013 (note that the definition of "utility-scale" used in this paper – i.e., any ground-mounted project larger than 5 MW_{AC} – varies somewhat from how others (GTM Research & SEIA, 2015; Lee & Moses, 2015) define it). Previous related work calculated empirical project-level NCFs from this same sample and found that they varied by more than a factor of two (Bolinger & Seel, 2015), but did not statistically evaluate the drivers of this significant variability. Other earlier work analyzed some of the predictors of PV project capacity factors in the United States, but through simulation rather than examination of empirical data (Drury, Lopez, Denholm, & Margolis, 2013). In contrast, this paper presents the first known use of multi-variate regression techniques to statistically explore empirical variation in utility-scale PV project performance across the United States.

This article proceeds as follows. Section 2 defines and characterizes the dependent variable – i.e., net AC capacity factor in 2014 (i.e., NCF) – as well as a number of independent variables that potentially influence the dependent variable, within the context of the project sample. Unless otherwise noted, the project-level data behind these dependent and independent variables come from (Bolinger & Seel, 2015). Section 3 specifies the regression model and then presents and discusses results. Section 4 concludes.

[5] None of these 128 projects includes any type of storage capacity; rather, all generation net of the project's own consumption is delivered to the grid in real time.

2. Characterization of Dependent and Independent Variables

2.1 The Dependent Variable: Project-Level Capacity Factors in 2014

The purpose of our regression analysis is to examine potential drivers of the observed variation in the performance of utility-scale PV projects. In order to normalize and compare performance across all 128 projects in our sample, we rely on each project's capacity factor as the dependent variable in our regression model. The capacity factor is a measure of the actual generation from a project over the course of one or more years expressed as a percentage of the maximum possible generation from that project if it were operating at full capacity at all hours (including at night) during that same single- or multi-year period. [6] Although many projects in our sample have been operational for multiple years, thereby potentially enabling us to analyze cumulative capacity factors that are calculated over as many full operational years as are available for each project, we instead chose to focus exclusively on capacity factors in a single year, 2014, for three reasons:

1) ***The bulk of our project sample is very young.*** Although there are two projects in the sample that date back to 2007 (and hence have been operational for seven full years, from 2008-2014, over the period of study), only 10% of the total projects in the sample and 7% of the total capacity were built in the four years from 2007-2010. Conversely, 90% of all projects in the sample, and 93% of all capacity, were built in the three years from 2011-2013, with 2013 alone accounting for 37% of all projects and 52% of all capacity in the sample (Table 2). With the bulk of our sample having been built in either 2013 or 2012, it seemed more appropriate to focus on performance in one or more recent years than to include performance from as far back as 2008 in some cases, as would be the case if working with cumulative capacity factors.

COD Year	Projects in Sample	Capacity in Sample (MW_{AC})
2007	2	19
2008	1	10
2009	3	54
2010	7	144
2011	32	464
2012	36	834
2013	47	1,676
Total	128	3,201

Table 2: Project Sample by Commercial Operation Year

[6] The formula is: Net Generation (MWh_{AC}) over Single- or Multi-Year Period / [Project Capacity (MW_{AC}) * Number of Hours in that Same Single- or Multi-Year Period]. For variable, weather-dependent generation technologies like solar and wind that can exhibit strong seasonal generation profiles, capacity factors should only be measured over full-year increments.

2) ***Data availability favors a focus on 2014.*** We have access to high-quality, site-specific insolation data for 2014,[7] but not for earlier years. Even under normal atmospheric conditions, the strength of the solar resource can vary by up to 10% or more from year to year, and these inter-year variations are not necessarily consistent across sites – i.e., insolation may increase in some regions but decrease in others (Bender, 2015; Vaisala, 2015). Without knowing how insolation has varied from year-to-year at each project site, these annual deviations from the long-term norm could confound an analysis of *cumulative* capacity factors. For example, even ignoring any site-specific differences, if 2014 was generally a strong insolation year compared to 2013, then projects built in 2013 (which were operational for a full year only in 2014) would likely have higher *cumulative* capacity factors than projects built in 2012 (which were operational for all of 2013 and 2014) for this reason alone. Focusing instead on capacity factors in a single year – 2014 in this case – enables us to somewhat control for these inter-year variations in the strength of the solar resource. That said, focusing exclusively on 2014 also means that the *absolute* capacity factors discussed in this paper may not be representative over longer terms if 2014 was not a representative year in terms of the strength of the solar resource.

3) ***Focusing on 2014 allows us to isolate the potential impact of time.*** Focusing on performance in a single year – and specifically the most recent year possible – enables us to better isolate the potential impact of time (manifested here in the year in which commercial operation is achieved) within the regression model. For example, assuming we have adequately controlled for all other influences, comparing how older and newer projects performed in 2014 might help to shed light on empirical module degradation rates over time. This time variable becomes less-intuitive and less-meaningful if analyzing cumulative capacity factors measured over multiple years.

We thus focus in this paper on net capacity factors (NCF) in calendar year 2014, using the following formula:

$$NCF\ in\ 2014 = \frac{Net\ Generation\ (MWh_{AC})\ in\ 2014}{Project\ Capacity\ (MW_{AC})\ \times\ 8{,}760\ Hours\ in\ 2014}$$

[7] Vaisala – a prominent solar and wind resource consultancy (www.vaisala.com) – graciously furnished us with site-specific 2014 insolation estimates for each project in our sample. These estimates are based on project coordinates that we provided, in conjunction with Vaisala's publication of resource deviations from long-term norms in 2014 (Vaisala, 2015). Without Vaisala's data, we may have instead had to rely on publicly available government data on long-term average annual insolation over the period from 1998-2009 – a period that does not match the 2008-2014 performance period of the oldest projects in our sample, and does not overlap at all with the 2012-2014 performance period of 90% of our sample. This mismatch in measurement periods could have potentially biased the analysis due to the inter-year variation in the solar resource noted above.

Note that we express capacity factors in *net*, rather than *gross*, terms (i.e., they represent the output of each project to the grid, net of its own consumption). We use AC terms, which results in higher capacity factors than if we expressed them in DC terms (e.g. a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms if the array DC capacity were 20% greater than the inverter AC capacity). However, this allows for direct comparison with the capacity factors of other generation sources (e.g., wind energy or conventional energy), which are also calculated and expressed in AC terms.

2.2 Possible Drivers of Project-Level Capacity Factors in 2014

A utility-scale PV project's capacity factor can be influenced by a number of independent variables, as described below.

Strength of the solar resource: The amount of solar generation is, of course, directly correlated with the amount of solar energy, or insolation, reaching the PV array.[8] For PV projects, global horizontal irradiance ("GHI"), which measures both the direct and diffuse sunlight reaching the array, is the most appropriate measure of insolation.[9] Vaisala provided us with average annual GHI estimates in 2014 for each site in our sample, which range from 3.73-6.02 kWh/m^2/day with a median of 5.39 kWh/m^2/day (Table 3) and a mean of 5.08 kWh/m^2/day (Table 3). Not surprisingly, the majority of the projects in our sample are located in the southwestern United States, where the solar resource is the strongest (Table 4). For example, 83% of the capacity and 66% of the projects in our sample reside within the five states (AZ, CA, NV, CO, and NM) that have the highest mean capacity factors and 2014 GHI in Table 4. California alone accounts for 49% of the capacity and 32% of the projects in the sample.

[8] Irradiance (W/m^2) measures the *power* of the sun reaching a square meter of the earth's surface at any given time, while insolation (kWh/m^2/day) measures the amount of solar *energy* reaching that same surface over the course of a day. One can derive average insolation – the variable used in this analysis – from average irradiance by multiplying the latter by 0.024.

[9] Another measure of insolation, direct normal irradiance ("DNI"), measures only the direct radiation reaching the array. DNI is more suitable for concentrating solar projects, including concentrating photovoltaics (none of which are in our sample) and concentrating solar thermal (which is outside the scope of this PV-focused analysis), as well as perhaps PV projects that employ dual-axis tracking (none of which are in our sample).

	Project Capacity (MW_{AC})	2014 Net Capacity Factor	2014 GHI ($kWh/m^2/day$)	ILR (MW_{DC}/MW_{AC})
Minimum	5.2	14.8%	3.73	1.05
10th percentile	7.6	18.4%	3.84	1.11
25th percentile	10.0	20.7%	4.65	1.17
Median	15.0	25.7%	5.39	1.24
75th percentile	20.0	29.9%	5.61	1.28
90th percentile	38.5	31.8%	5.81	1.35
Maximum	250.0	34.9%	6.02	1.50

Table 3: Sample Descriptive Statistics

State	# of Projects	Capacity (MW_{AC})	Mean 2014 NCF	Mean 2014 GHI ($kWh/m^2/day$)	Mean ILR (MW_{DC}/MW_{AC})	% Tracking
AZ	19	594	30.4%	5.62	1.27	89.5%
CA	41	1,561	28.1%	5.52	1.26	46.3%
NV	8	284	27.9%	5.41	1.23	50.0%
CO	4	62	27.3%	5.30	1.14	100.0%
NM	13	154	26.9%	5.63	1.17	61.5%
TX	6	84	23.0%	4.85	1.18	83.3%
GA	3	54	22.5%	4.65	1.27	0.0%
TN	1	8	21.0%	4.36	1.26	0.0%
NC	3	54	20.9%	4.26	1.21	66.7%
FL	4	53	20.0%	4.88	1.12	50.0%
DE	2	22	19.9%	3.94	1.19	50.0%
IN	4	39	19.4%	3.88	1.35	0.0%
MD	3	39	19.2%	3.90	1.27	0.0%
IL	2	28	19.0%	3.77	1.18	50.0%
NY	1	32	18.5%	3.93	1.20	0.0%
OH	2	18	18.4%	3.75	1.20	50.0%
NJ	11	107	17.5%	3.85	1.20	9.1%
PA	1	10	15.9%	3.76	1.15	0.0%
Total US	**128**	**3,201**	**25.5%**	**5.08**	**1.23**	**50.8%**

Table 4: Sample Description by State (sorted in descending order by mean capacity factor)

Tracking: Single- or dual-axis tracking devices that keep the plane of the array as perpendicular as possible to the sun's rays throughout the day and/or year boost performance relative to a fixed-tilt project. Previous simulation work found that single-axis tracking can boost performance relative to a fixed-tilt array by 12-25% (i.e., in percentage, rather than absolute, terms) depending on location, while the corresponding increase for dual-axis tracking is 30-45% (Drury et al., 2013). Roughly half (50.8%) of the projects in our sample use single-axis tracking (Table 4, Figure 12), while the remaining projects have modules that are mounted at a fixed tilt and azimuth (i.e., there are no dual-axis tracking projects in our sample).[10] Single-axis tracking is more common in southwestern states with a strong solar resource (Table 4), for several reasons:

- the greater up-front cost and ongoing maintenance expense of tracking is more easily justified when tracking a stronger resource (the mean 2014 GHI among the tracking projects in our sample is 5.33 kWh/m^2/day, compared to 4.83 kWh/m^2/day among the fixed-tilt projects);
- most single-axis trackers are installed horizontally (i.e., not tilted southward), which incurs less of a production penalty in lower latitudes where, in the United States, the sun is higher in the sky and the resource is also typically stronger;
- the Southwest still has expansive and relatively inexpensive tracts of land that can accommodate the greater land-area-per-MW requirements of tracking (to avoid shading).

Figure 12 shows the distribution of capacity factors within our sample, broken out by fixed-tilt (dark/red bars) versus tracking projects (light/yellow bars), as well as in aggregate (shaded/orange bars). The distribution is somewhat bi-modal, due to the influence of tracking on capacity factor. The 63 fixed-tilt projects in our sample range in capacity factor from 14.8-30.6%, with 19% being the most common bin, while the 65 tracking projects range in capacity factor from 18.5-34.9%, with 29% being the most common bin. The project-level capacity factor data presented in Figure 12 and used in our regression analysis was originally compiled for (Bolinger & Seel, 2015) and originates from a combination of sources, including the Federal Energy Regulatory Commission's (FERC's) Electronic Quarterly Report filings, FERC Form 1 filings, the Energy Information Administration's (EIA's) Form EIA-923, and various state regulatory filings.

[10] Despite the potential incremental increase in output relative to single-axis trackers, dual-axis trackers have not yet been deployed to any great extent in the utility-scale sector in the United States. This is due to a combination of cost and performance concerns (given a greater number of moving parts) plus the fact that the largest performance boost from dual-axis tracking occurs in more-northerly latitudes (Drury, Lopez, Denholm, & Margolis, 2013), which to date have seen only limited utility-scale PV deployment in the United States. That said, several Texas projects that achieved commercial operation in 2014 do use dual-axis tracking, and it will be interesting to track their performance in the future.

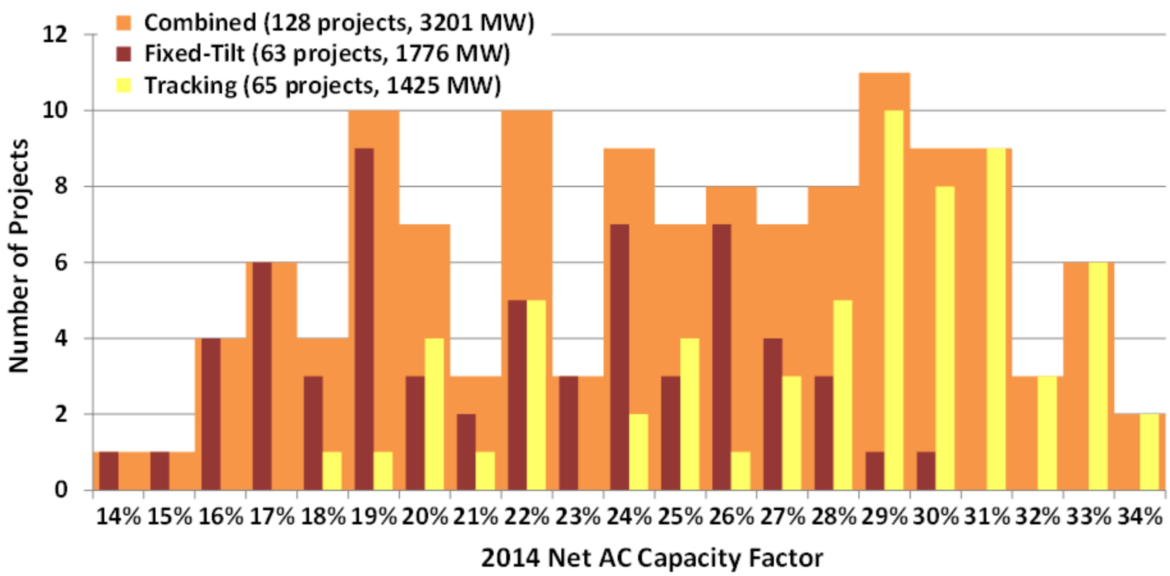


Figure 12: Histogram of 2014 Net AC Capacity Factors within the Sample

Inverter loading ratio ("ILR"): Also sometimes referred to as the DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, or DC load ratio, the ILR is simply the ratio of a project's DC capacity rating (determined by the number and rated capacity of PV modules) to its AC capacity rating (determined by the maximum AC power output of the inverters). With the cost of PV modules having dropped precipitously in recent years, and more rapidly than the cost of inverters, many developers have found it economically advantageous to increase the DC capacity rating of the array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which – like tracking – boosts the capacity factor,[11] at least in AC terms. This practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" may occur during peak production periods in high-insolation summer months. This practice, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the hydropower turbines) or feathering a wind turbine blade to allow excess wind to slip by. In the case of solar, however, clipping occurs electronically rather than physically: as the DC input to the inverter approaches maximum capacity, the inverter moves away from the maximum power point so that the array operates less efficiently, resulting in lower DC power output (Fiorelli & Zuercher-Martinson, 2013). That said, it is important to recognize that PV module capacity ratings are based on standard test conditions ("STC") of 1,000 W/m2 of irradiance at 25° C and an air mass of 1.5. Actual operating conditions in the field are often less-advantageous (e.g., cell temperatures are often greater than 25° C), which limits the actual DC output to something less than STC-rated output. This limitation, in turn, reduces the amount of power clipping that occurs.

[11] This is analogous to the boost in capacity factor achieved by a wind turbine when the size of the rotor increases relative to it's nameplate capacity rating. This decline in "specific power" (W/m^2 of rotor swept area) causes the generator to operate closer to its peak rating more often, thereby increasing capacity factor.

The ILRs in our project sample range from 1.05 to 1.50 with a median of 1.24 (Table 3) and a mean of 1.23 (Table 4). Though not shown in Table 3 and Table 4, the fixed-tilt projects in our sample have a slightly higher mean ILR (1.25) than the tracking projects (1.21), which makes sense given that tracking and a high ILR are, at least to some extent, substitutes for one another in the sense that they both flatten the diurnal generation profile by boosting production during the morning and evening "shoulder" periods.

Project vintage: Project vintage might be expected to play a role, with newer projects having higher capacity factors because the efficiency of PV modules has increased over time. As module efficiency increases, however, developers simply either use fewer modules to reach a desired amount of capacity (thereby saving on balance-of-system and land costs in addition to module costs), or they use the same number of modules to boost the amount of capacity installed on a fixed amount of land (which directly reduces at least $/W$_{DC}$ costs, if not also $/W$_{AC}$ costs). In other words, PV module efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Project vintage is, nevertheless, important to our purpose given that PV module performance tends to degrade over time, on the order of 0.2% to 1%/year (Campeau et al., 2013; Jordan & Kurtz, 2013). For this reason, we would expect older projects to have lower capacity factors than newer projects, all else equal. Conversely, one might expect newer projects – and in particular those completed in late 2013 – to possibly exhibit lower 2014 capacity factors if they spent a portion of 2014 ironing out potential "teething issues" that can sometimes hamper initial production at new projects. Such teething issues have been particularly notable among several recent concentrating solar thermal power projects (Bolinger & Seel, 2015), and are also somewhat common in the wind power industry, though PV projects are perhaps less susceptible to such problems, due to having fewer moving parts. Though not presented in this paper, we did test for potential teething issues within our sample by including a dummy variable to represent projects that achieved commercial operation in 2013; the coefficient was extremely small and highly insignificant, leading us to ignore this possible driver.

Tilt and azimuth: Especially for fixed-tilt projects, which make up 49.2% of our sample, PV module orientation will impact capacity factor. Unfortunately, we lack good data on the tilt and azimuth of the fixed-tilt projects in our sample. However, for the types of projects analyzed in this paper – i.e., ground-mounted utility-scale PV projects that can cost tens or hundreds of millions of dollars to build – we assume that these two fundamental parameters will always be optimized across projects to maximize revenue, and therefore would not add any incremental explanatory power to our models even if known and included (i.e., under this assumption of optimal orientation, the omission of tilt and azimuth should not detract from the models). This is one important reason why utility-scale projects are more amenable to this type of empirical capacity factor analysis than are residential and commercial systems, which must often contend with sub-optimal roof orientation and/or partial shading – factors that that are difficult to ascertain remotely. Another reason that we focus on the utility-scale sector is that performance data are much more readily available for utility-scale projects than for residential and commercial projects. To date, given that most PPAs either do not vary pricing based on the time of delivery or else employ time-of-delivery pricing that favors mid-day generation (Bolinger & Seel, 2015; Bolinger et al., 2015), maximizing revenue has almost universally been achieved by maximizing annual energy production (i.e., capacity factor).

Operating temperature and module power temperature coefficient: PV modules are less efficient at higher operating temperatures, though certain types or brands of modules are better able to handle the heat than others. For example, First Solar, which makes cadmium-telluride modules, claims that its modules (with a power temperature coefficient of -0.25%/°C) outperform typical crystalline silicon modules (with power temperature coefficients ranging from -0.3%/°C to -0.5%/°C) at operating temperatures in excess of 25°C (First Solar, 2015). Unfortunately, we do not have universally good information on module make and model, and hence temperature coefficient, within our project sample. Nor do we have reliable data on site-specific daytime operating temperatures. We did attempt to include a rather crude proxy for operating temperature – i.e., the long-term annual mean of maximum monthly temperatures at the approximate project location – within our regression model, but the coefficient was highly insignificant and its sign was the opposite of expectations (perhaps due to the likely correlation between temperature and GHI), prompting us to abandon this variable. Similarly, we attempted to approximate the effect of the power temperature coefficient by comparing the performance of projects using cadmium-telluride and silicon modules (given cadmium-telluride's lower power temperature coefficient), but the results were inconclusive. This may be because we are unable to account for potentially just-as-large differences in power temperature coefficient among different types or brands of silicon modules (which are used by 77% of the projects and 62% of the capacity in our sample).

2.3 Selection of Independent Variables for the Regression Analysis

Of the six potential drivers of 2014 capacity factors described above in Section 2.2, we included the first four – solar resource strength (GHI), tracking, ILR, and commercial operation year – as independent variables in the regression model and omitted the last two – tilt/azimuth and temperature – due to lack of sufficient, or sufficiently high-quality, data (and in the case of tilt/azimuth, also a presumption of little relevant differentiation among this sample).

Figure 13 presents our sample's 2014 net capacity factors broken out among three of these four independent variables (commercial operation year is excluded). The columns show the mean 2014 NCF within each bin, while the circle markers show 2014 NCFs for each individual project. In order to ensure an even distribution of projects among bins, the width of the GHI and ILR bins are based on the 33rd and 66th percentile values for each. Though several bins include only two or three projects (and one has no projects at all), in general a positive relationship between net capacity factor and ILR, tracking, and GHI is evident, particularly among the mean values (there is, naturally, more variability among the individual projects).

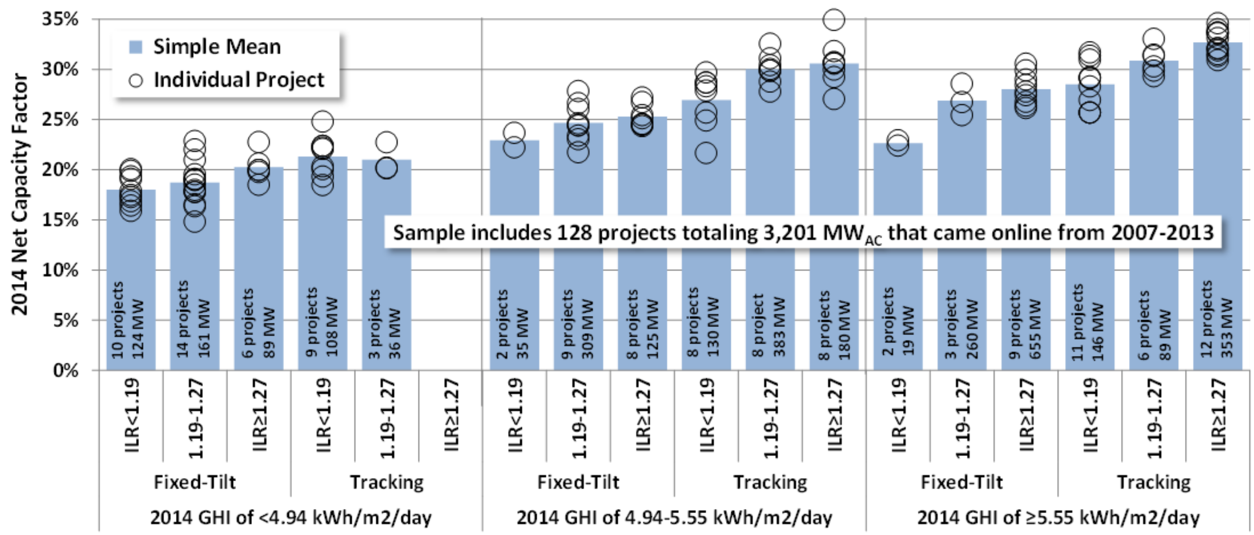


Figure 13: 2014 Net AC Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio

We also included three "interactive" variables in the regression analysis to try to capture the nuances in how GHI, tracking, and ILR influence capacity factor in relation to one another. For example, we would expect single-axis tracking to provide a greater boost to capacity factor at sites with a stronger solar resource, and so interacted tracking with GHI to try and isolate that relationship.[12] Similarly, given that tracking and a high ILR can, to some extent, be thought of as substitutes for one another, we would expect the benefit of tracking to diminish at higher ILRs, and so interacted tracking with ILR to analyze this tradeoff. Finally, as with tracking, we would also expect higher ILRs to provide a greater NCF boost at sites with a stronger solar resource, and so interacted ILR with GHI to examine this relationship.

Unlike with GHI, tracking, and ILR, there is relatively little intuition for interacting our fourth independent variable – commercial operation year – with any of the other three. Nevertheless, we did try including a variable that interacted commercial operation year with tracking, on the possibility that tracking technology may have improved sufficiently over the timeframe of our sample to have a discernible impact on capacity factor among different project vintages. The

[12] This interaction between tracking and GHI is somewhat of a simplification and approximation, as the NCF benefit of single-axis tracking is more accurately driven by the amount of direct normal irradiance or DNI (a component of GHI, along with diffuse horizontal irradiance) at any given location, along with latitude (e.g., all else equal, horizontal-mounted single-axis tracking projects will perform better at lower latitudes where the sun is higher in the sky) (Drury et al., 2013). We did try adding both a long-term (as opposed to 2014) measure of DNI and latitude to the regression model and interacting them both with tracking (in lieu of interacting tracking with GHI), but the results were counterintuitive, and adding these variables introduced heteroskedacity and multicollinearity problems (presumably due to the strong correlation between DNI and GHI). To avoid these issues, we chose to stick with the simpler model that interacts 2014 GHI with tracking (i.e., avoiding the addition of DNI and latitude), even if this specification is somewhat imperfect.

coefficient, however, was extremely small and highly insignificant, leading us to not include it in the final models.

The next section quantifies these individual and interactive relationships through multiple regression analyses.

3. Model Specification and Results

The four individual (i.e., non-interactive) independent variables included in the regression model are solar resource strength (GHI), tracking vs. fixed-tilt (a dummy variable), ILR, and commercial operation year. An examination of the two continuous independent variables – resource strength (GHI) and ILR – suggested that the ILR variable should be transformed by taking its natural logarithm. This transformation makes intuitive sense in that it reflects the diminishing marginal benefit of increasing the ILR at higher levels, due to the resulting increase in power clipping. Additionally, to ease interpretation of results and to guard against multicollinearity, we centered our independent variables (except for the tracking dummy variable) by either subtracting their means (in the case of the two continuous variables) or by subtracting 2007 (in the case of the commercial operation year variable). Because the independent variables are centered, the constant terms in Table 5 can be easily interpreted as the 2014 NCF of a fixed-tilt project (for Models 2-5 that include the Tracking dummy variable) built in 2007 (for Models 4 and 5 that include the COD Year variable) at the mean values of all other independent variables. Although our data do not appear to have heteroscedasticity problems, we nevertheless took the precaution of running "robust" regressions that correct the standard errors using Huber-White sandwich estimators.

Table 5 presents a buildup of the regression model, starting with just a single independent variable – 2014 GHI – in Model 1, and then adding each additional independent variable (as well as the three interactive variables) to progress to our preferred model specification in Model 5. The R^2 of Model 1 shows that 2014 GHI alone predicts 71.6% of the variance in the 2014 net capacity factor.[13] The constant value of 0.2546 means that at the average 2014 GHI value among our sample (from Table 4, 5.08 kWh/m^2/day), the projected capacity factor is 25.46%. The coefficient of the 2014 GHI variable means that for each 1 kWh/m^2/day increase in GHI, the model would expect capacity factor to increase by 6.04% (in absolute rather than percentage terms, so from 25.46% at the mean to 31.50% for a GHI of 6.08 kWh/m^2/day – which is slightly above the maximum 2014 GHI among our sample). Both the 2014 GHI variable and the constant term are highly statistically significant ($p<0.01$).

[13] Though not shown in Table 5, we also regressed each of the other three non-interactive independent variables individually against 2014 net capacity factor, to get a sense for their relative individual explanatory power. The resulting R^2 for each individual variable is as follows: 0.716 for 2014 GHI, 0.345 for Tracking, 0.098 for ln(ILR), and 0.065 for COD Year. When building up to Models 4 and 5 in Table 5, we added each of these variables in the descending order of their individual R^2.

Model 2 adds the Tracking dummy variable, which increases the R^2 to 0.811. The constant term finds that at the average value for 2014 GHI, the projected capacity factor for a *fixed-tilt* project is 23.75%. Adding single-axis tracking would increase capacity factor by 3.37% (to 27.12%), and a 1 kWh/m²/day increase in 2014 GHI would increase capacity factor by 5.21% (to 28.96% and 32.33% for a fixed-tilt and tracking project, respectively). Both independent variables and the constant term are highly significant ($p<0.01$).

	Model 1	Model 2	Model 3	Model 4	Model 5
2014 GHI	0.0604*** (0.00280)	0.0521*** (0.00265)	0.0478*** (0.00199)	0.0479*** (0.00202)	0.0423*** (0.00245)
Tracking		0.0337*** (0.00443)	0.0429*** (0.00296)	0.0421*** (0.00303)	0.0405*** (0.00285)
ln(ILR)			0.2391*** (0.01911)	0.2146*** (0.02206)	0.2158*** (0.03393)
COD Year				0.0033** (0.00138)	0.0023* (0.00132)
Tracking x 2014 GHI					0.0186*** (0.00501)
Tracking x ln(ILR)					-0.0015 (0.04686)
2014 GHI x ln(ILR)					0.0575* (0.02952)
Constant	0.2546*** (0.00243)	0.2375*** (0.00268)	0.2328*** (0.00198)	0.2172*** (0.00640)	0.2202*** (0.00598)
Observations	128	128	128	128	128
R^2	0.716	0.811	0.920	0.926	0.938
Root MSE	0.02746	0.02248	0.01467	0.01423	0.01316
In all five models, the dependent variable is the net AC capacity factor in 2014. Robust standard errors are in parentheses, below the coefficients. All continuous variables are centered around their means. The COD Year variable is based in the earliest possible year, 2007. ***p<0.01, **p<0.05, *p<0.1					

Table 5: Model Buildup and Robust Results

Interpretation of Models 3 and 4 becomes more involved due to the presence of multiple continuous variables, and so will be bypassed in favor of spending more time on the similar, but more-complete, Model 5. Suffice it to say that adding the natural logarithm of ILR ("ln(ILR)") in Model 3 boosts the R^2 to 0.920, while adding the commercial operation year ("COD Year") in Model 4 pushes the R^2 only slightly higher to 0.926. With the exception of "COD Year" in Model 4 (for which $p<0.05$), all other independent variables and constant terms in both Model 3 and Model 4 are highly significant ($p<0.01$).

Given the strong statistical significance of all variables and constant terms in Models 1-4, along with the relative stability in the coefficients, robust standard errors, and constant terms across models as each new independent variable is added, Model 5 introduces the three additional "interactive" variables that seek to capture the nuances in how GHI, tracking, and ILR influence capacity factor in relation to one another. Two of these three interactive variables are statistically significant (Tracking x 2014 GHI at the 1% significance level, 2014 GHI x ln(ILR) at the 10% significance level), while the third (Tracking x ln(ILR)) is not significant. However, three "partial F" tests of (1) all three variables (one individual, two interactive) that involve 2014 GHI, (2) all three variables that involve Tracking, and (3) all three variables that involve ln(ILR) find high statistical significance in all three cases. The R^2 of Model 5 increases only slightly with the addition of these three interactive variables, to 0.938, while the COD Year variable is now only significant at the 10% level (compared to significance at the 5% level in Model 4).

Figure 14 plots the fitted 2014 NCF estimates resulting from Model 5 against the actual empirical values (along with a best fit line).[14] The relationship appears to be highly linear, and the relatively small differences between estimated and actual NCFs visually support the high adjusted R^2 values reported in Table 5. In addition to using robust regression techniques and plotting and visually inspecting the residuals from Figure 14 and Model 5, we also conducted several statistical tests to ensure that our data and model specification conform to the underlying assumptions of OLS regression. The Breusch-Pagan and White tests both indicate that there is no heteroscedasticity problem in the error term, the Shapiro-Wilk test indicates normality in the residuals, the Variance Inflator Factor test suggests no multicollinearity problems, and the linktest finds good model specification.

[14] The full equation for Model 5 is as follows: 2014 NCF = .0423*(2014 GHI-mean(2014 GHI)) + 0.0405*(1 if Tracking, 0 if Fixed-Tilt) + 0.2158*(ln(ILR)-mean(ln(ILR)) + 0.0023*(COD Year-2007) + 0.0186*(1 if Tracking, 0 if Fixed-Tilt)*(2014 GHI-mean(2014 GHI)) + -0.0015*(1 if Tracking, 0 if Fixed-Tilt)*(ln(ILR)-mean(ln(ILR)) + 0.0575*(2014 GHI-mean(2014 GHI))*(ln(ILR)-mean(ln(ILR)) + 0.2202.

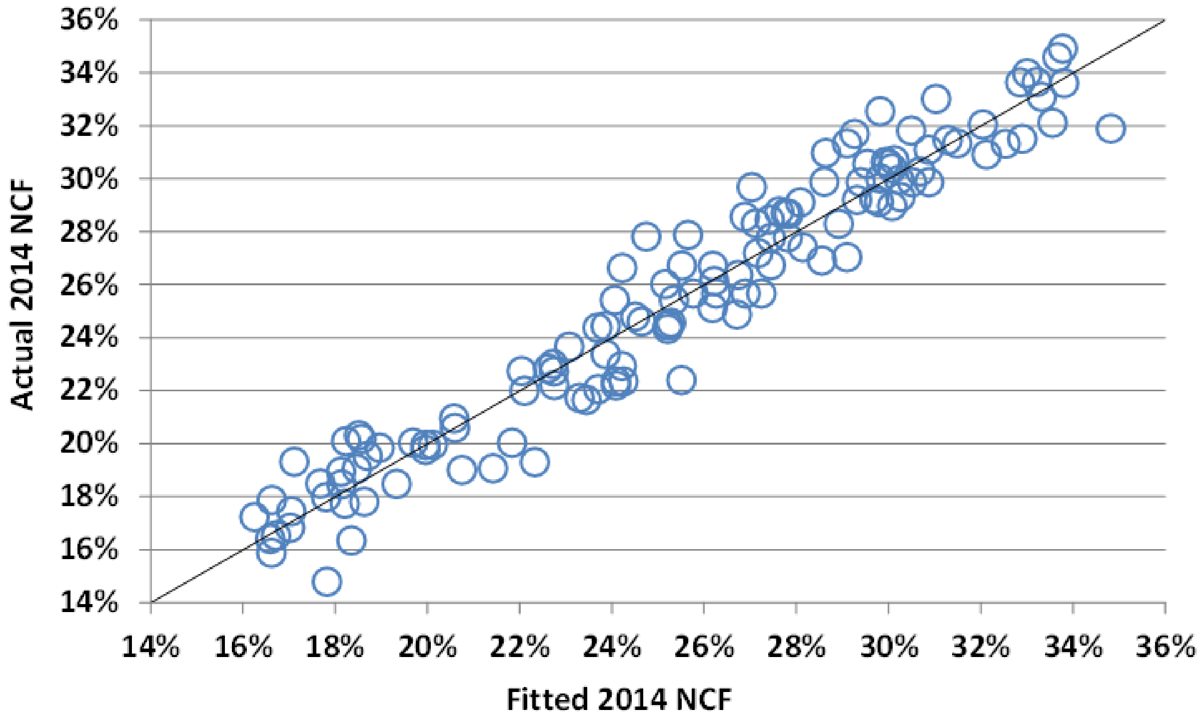


Figure 14: Scatter Plot of Model 5 Fitted versus Actual 2014 NCF

Model 5 predicts that a fixed-tilt project built in 2007 with average 2014 GHI and ILR will have a 2014 NCF of 22.02%. Single-axis tracking adds 4.05% to this same project's 2014 NCF, for 26.07% in total. This relative 18.4% empirical boost in 2014 NCF is right in the middle of the 12-25% range predicted by earlier simulations (Drury et al., 2013). Each successive COD Year adds 0.23% to both fixed-tilt and tracking projects, such that a 22.02% and 26.07% NCF for a fixed-tilt and tracking project, respectively, built in 2007 becomes 23.41% and 27.46% for projects built in 2013. Said another way, Model 5 predicts that older/earlier projects have lower 2014 capacity factors to the tune of 0.23%/year on average; one possible interpretation is that this coefficient is detecting module degradation rates. An average module degradation rate of 0.23%/year would fall towards the low end of the range of empirical degradation rates previously observed (Jordan & Kurtz, 2013). It would be even slightly below the low end of the 0.25%-1.0% range of projected degradation rates found within a sample of 29 utility-scale PV PPAs totaling 3,215 MW_{AC} (with a sample mean degradation rate of 0.6% and a median of 0.5%) (Bolinger & Seel, 2015). That said, SunPower, which has manufactured a significant percentage of the modules used in utility-scale projects in the United States, claims that its degradation rates are less than 0.25%/year (Campeau et al., 2013), and has backed up that assertion by promising degradation rates as low as 0.25% in two PPAs within the aforementioned PPA sample.

Figure 15 shows the progression of 2014 NCF by project vintage (assuming average GHI and ILR) for both fixed-tilt (solid line) and tracking (dashed line) projects, along with the benefit of tracking (shaded area), which in this case is constant at 4.05% across project vintages given that we chose not to interact Tracking with COD Year. Given our natural interest in newer rather than older projects, and the need to fix the COD Year in order to more-easily interpret the influence of other variables, the rest of the Model 5 interpretation focuses on projects that achieved commercial operation in 2013.

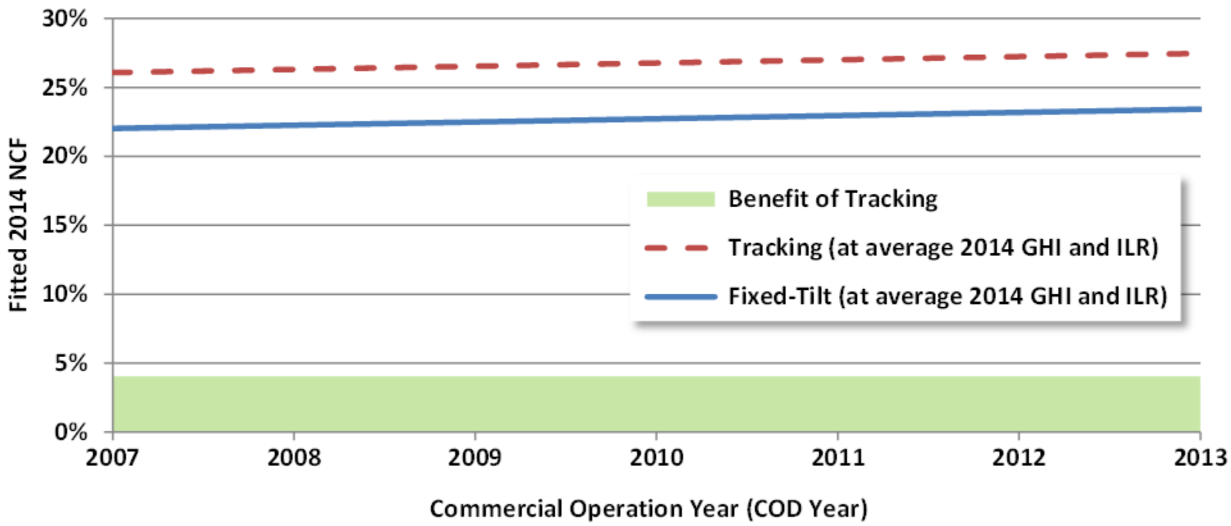


Figure 15: Impact of COD Year at Average 2014 GHI and ILR

Figure 16 shows the impact of 2014 GHI on a 2013 project with an average ILR. For each 1 kWh/m^2/day change in 2014 GHI, the model predicts a linear 4.23% absolute change in 2014 NCF for a fixed-tilt project and a 6.08% absolute change in 2014 NCF for a tracking project.[15] This means that the benefit of tracking increases at sites with a stronger solar resource, which makes intuitive sense and is consistent with the greater prevalence of tracking at high-GHI sites seen in Section 2.2. In percentage terms, the benefit of tracking is 10.8% at a 2014 GHI of 4.0 and 22.7% at a 2014 GHI of 6.0 – similar to the 12%-25% range predicted by earlier simulations (Drury et al., 2013).

[15] The effect of GHI on a fixed-tilt project is simply the *2014 GHI* coefficient of 0.0423. For a tracking project, simply add the *Tracking x 2014 GHI* coefficient of 0.0186 to reach 0.0608 in total.

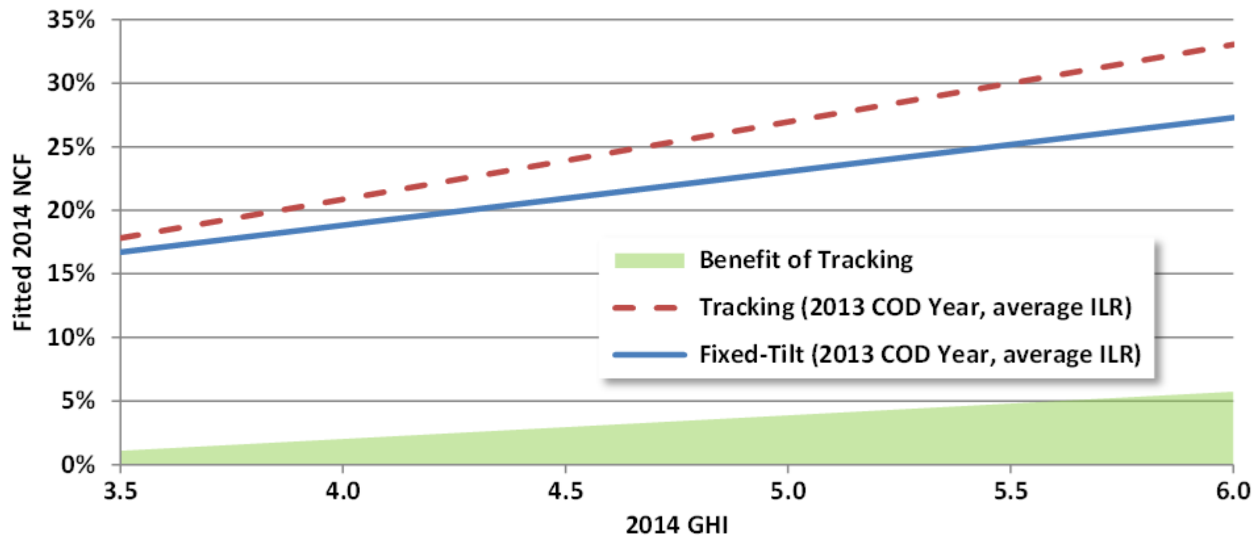


Figure 16: Impact of 2014 GHI for 2013 COD Year and Average ILR

Conversely, Figure 17 shows the impact of ILR (transformed back from the natural logarithm) on a 2013 project with an average 2014 GHI. As shown by the slight deviation from the linear dashed lines (included only for visual comparison), due to its logarithmic specification, ILR has a slightly diminishing marginal effect on 2014 NCF as it increases. For example, for both fixed-tilt and tracking projects, 2014 NCF increases by 1.00% when moving from an ILR of 1.05 to 1.10, but by only 0.73% when moving from an ILR of 1.45 to 1.50. This diminishing effect potentially reflects greater amounts of power clipping at higher ILRs. As shown earlier in Table 3, however, 90% of the projects in our sample have ILRs of 1.35 or less – levels at which significant power clipping is unlikely to occur.

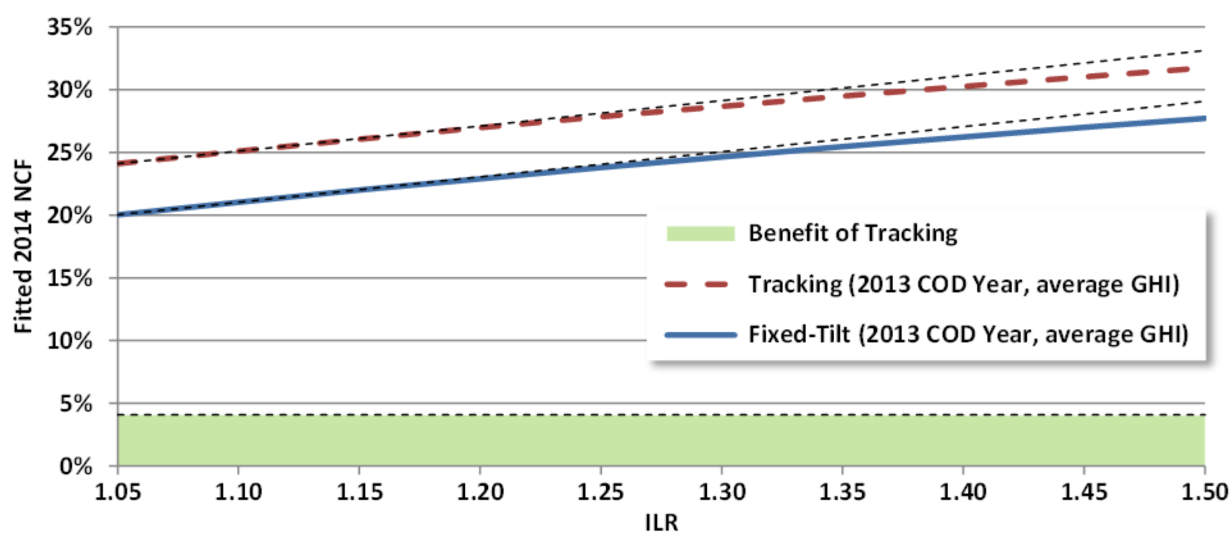


Figure 17: Impact of ILR for 2013 COD Year and Average 2014 GHI

Similarly, though hard to see in Figure 17, the positive influence of tracking also diminishes ever so slightly at higher ILRs (again, due to its logarithmic specification) – e.g., from 4.07% at an ILR of 1.05 to 4.02% at an ILR of 1.50. This deterioration makes intuitive sense (though the small magnitude is somewhat surprising, and is not statistically significant), given that boosting the ILR has a similar effect as tracking in terms of flattening the diurnal generation profile by increasing generation during the morning and evening shoulder periods. In other words, if a project's diurnal generation profile is already fairly flat due to a high ILR, then the incremental ability of tracking to increase generation during the shoulder periods should be reduced.

Lastly, Table 6 demonstrates the changing effect of ILR at different GHI levels and vice versa, for both fixed-tilt and tracking projects. The two shaded rows labeled "(A)" show the difference in fitted 2014 NCF between one project with an ILR of 1.45 and another with an ILR of 1.10 at different levels of GHI. The NCF benefit of a higher ILR increases at higher GHI levels, simply because there is more available insolation that can be captured by boosting the ILR. Moreover, for any given GHI, the benefit of a higher ILR is slightly greater for fixed-tilt than for tracking projects (e.g., 4.24% vs. 4.20% for a GHI of 4.0), which also makes intuitive sense given that tracking is somewhat redundant with a high ILR.

Similarly, the two shaded columns labeled "(B)" in Table 6 show the difference in fitted 2014 NCF between one project with an average 2014 GHI of 5.5 kWh/m^2/day and another with 4.0 kWh/m^2/day at different ILRs. The NCF benefit of a higher GHI increases with higher ILRs, as the latter is better able to capture the former. Moreover, for any given ILR, the benefit of a higher GHI is greater for tracking than for fixed-tilt projects (e.g., 8.9% vs. 6.1% for an ILR of 1.20), as tracking is able to capitalize on the stronger solar resource.

Finally, the bottom third of Table 6 confirms earlier findings from Figure 16 and Figure 17 above: for a given ILR, the benefit of tracking increases with GHI (given a greater resource to capture through tracking); conversely, for a given GHI, the benefit of tracking *decreases* slightly as ILR increases (again, given that tracking is somewhat redundant with a high ILR).

Fitted 2014 NCF of a Fixed-Tilt Project with a 2013 COD								(B)
	ILR\GHI	**3.5**	**4.0**	**4.5**	**5.0**	**5.5**	**6.0**	***5.5-4.0***
	1.05	14.8%	16.4%	18.1%	19.7%	21.4%	23.1%	*5.0%*
	1.10	15.3%	17.1%	18.9%	20.7%	22.5%	24.3%	*5.4%*
	1.15	15.9%	17.8%	19.7%	21.7%	23.6%	25.5%	*5.8%*
	1.20	16.4%	18.5%	20.5%	22.6%	24.6%	26.7%	*6.1%*
	1.25	16.9%	19.1%	21.3%	23.4%	25.6%	27.8%	*6.5%*
	1.30	17.4%	19.7%	22.0%	24.3%	26.5%	28.8%	*6.8%*
	1.35	17.9%	20.3%	22.7%	25.0%	27.4%	29.8%	*7.2%*
	1.40	18.4%	20.8%	23.3%	25.8%	28.3%	30.8%	*7.5%*
	1.45	18.8%	21.4%	24.0%	26.6%	29.1%	31.7%	*7.8%*
	1.50	19.2%	21.9%	24.6%	27.3%	30.0%	32.6%	*8.1%*
(A)	***1.45-1.10***	*3.44%*	*4.24%*	*5.03%*	*5.83%*	*6.62%*	*7.42%*	
Fitted 2014 NCF of a Tracking Project with a 2013 COD								**(B)**
	ILR\GHI	**3.5**	**4.0**	**4.5**	**5.0**	**5.5**	**6.0**	***5.5-4.0***
	1.05	15.9%	18.5%	21.1%	23.7%	26.3%	28.8%	*7.8%*
	1.10	16.5%	19.2%	21.9%	24.6%	27.4%	30.1%	*8.2%*
	1.15	17.0%	19.9%	22.7%	25.6%	28.4%	31.3%	*8.6%*
	1.20	17.5%	20.5%	23.5%	26.5%	29.4%	32.4%	*8.9%*
	1.25	18.0%	21.1%	24.2%	27.3%	30.4%	33.5%	*9.3%*
	1.30	18.5%	21.7%	24.9%	28.1%	31.3%	34.5%	*9.6%*
	1.35	19.0%	22.3%	25.6%	28.9%	32.2%	35.6%	*9.9%*
	1.40	19.4%	22.9%	26.3%	29.7%	33.1%	36.5%	*10.3%*
	1.45	19.9%	23.4%	26.9%	30.4%	33.9%	37.5%	*10.6%*
	1.50	20.3%	23.9%	27.5%	31.1%	34.8%	38.4%	*10.8%*
(A)	***1.45-1.10***	*3.40%*	*4.20%*	*4.99%*	*5.79%*	*6.58%*	*7.37%*	
Benefit of Tracking for a Project with a 2013 COD								
	ILR\GHI	**3.5**	**4.0**	**4.5**	**5.0**	**5.5**	**6.0**	
	1.05	1.13%	2.06%	2.99%	3.91%	4.84%	5.77%	
	1.10	1.12%	2.05%	2.98%	3.91%	4.84%	5.77%	
	1.15	1.11%	2.04%	2.97%	3.90%	4.83%	5.76%	
	1.20	1.11%	2.04%	2.97%	3.90%	4.82%	5.75%	
	1.25	1.10%	2.03%	2.96%	3.89%	4.82%	5.75%	
	1.30	1.10%	2.02%	2.95%	3.88%	4.81%	5.74%	
	1.35	1.09%	2.02%	2.95%	3.88%	4.81%	5.74%	
	1.40	1.08%	2.01%	2.94%	3.87%	4.80%	5.73%	
	1.45	1.08%	2.01%	2.94%	3.87%	4.80%	5.73%	
	1.50	1.07%	2.00%	2.93%	3.86%	4.79%	5.72%	

Table 6: Primary and Interactive Effects of GHI, ILR, and Tracking on Fitted 2014 NCF

As a way to graphically summarize the interpretation of Model 5, Figure 18 shows the individual and combined effects of the regressors in waterfall format. It begins at the far left with the constant term of 22.02%, which represents the predicted 2014 net capacity factor from a 2007 fixed-tilt project with average GHI (5.08 kWh/m^2/day) and ILR (1.23). It then adds the impact of each of the four non-tracking-related regressors until arriving, in the middle of the graph, at a 2013 fixed-tilt project with a GHI of 6.08 kWh/m^2/day and an ILR of 1.33, which has a predicted 2014 net capacity factor of 29.78%. The three tracking-related regressors are then added in turn to reach, on the far right of Figure 18, a predicted 2014 net capacity factor of 35.68% for a 2013 tracking project with the same GHI (6.08) and ILR (1.33) levels.

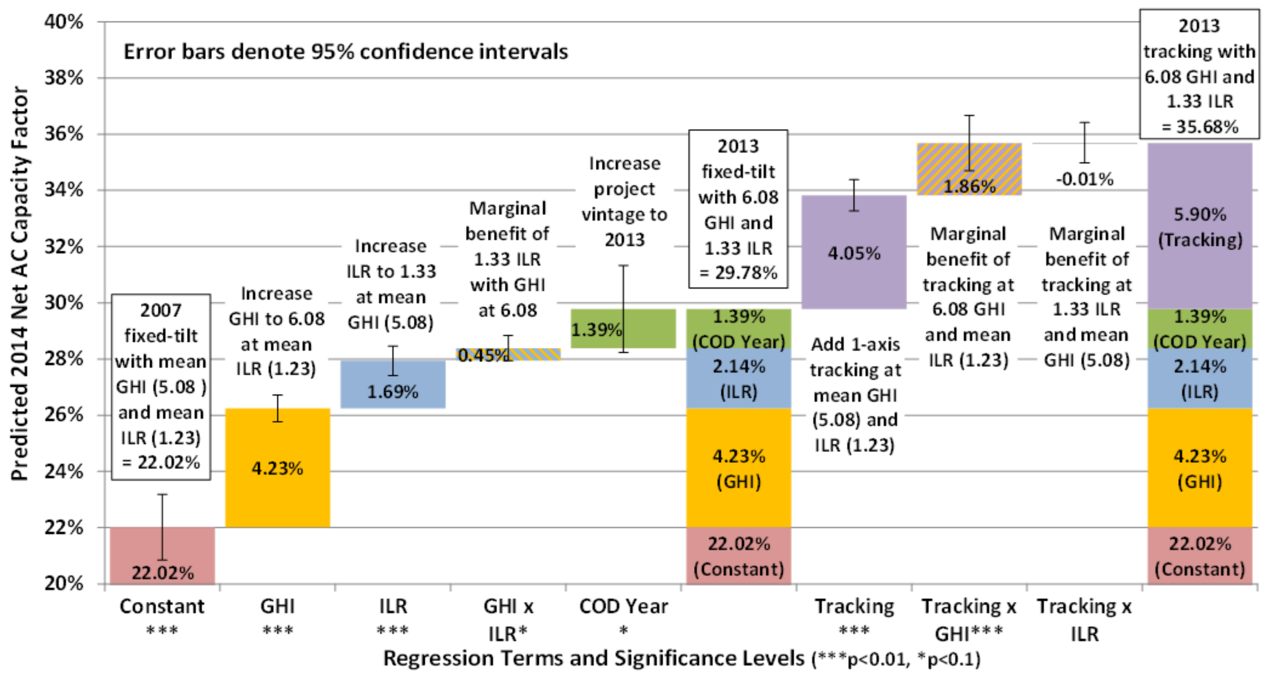


Figure 18: Individual and Combined Effects of Model 5 Regression Terms

4. Conclusion

The rapid ascendency of utility-scale PV in the United States over the last few years has resulted in a diverse fleet of operating projects that exhibit significant variation in empirical AC capacity factors, with the highest and lowest capacity factors in our sample differing by more than a factor of two. The regression models developed for this analysis find that just three highly significant independent variables – GHI, Tracking, and ILR – can explain 92% of this variation (see Model 3 in Table 5), with GHI alone able to explain 71.6% (see Model 1 in Table 5). That said, adding COD Year (in Model 4) and three interactive variables (in Model 5) improves the model further and reveals interesting relationships between these independent variables, without over-specifying the model.

Of the two additional potential drivers that were discussed in Section 2.2 but were omitted from the model due to insufficient data – i.e., the effect of module orientation (tilt and azimuth) and temperature (power temperature coefficient and module operating temperature) on performance – temperature is likely the more significant gap. Module orientation is primarily of relevance to only about half of the projects in our sample (i.e., the fixed-tilt projects), and it is highly likely that ground-mounted, fixed-tilt projects of this size and cost are almost universally oriented to maximize generation (and hence net AC capacity factor) at each site, thereby not adding much explanatory power to the model. The model would, however, presumably be improved with good data on power temperature coefficients and module operating temperatures.[16]

Taken together, the empirical data and statistical modeling results presented in this paper can provide a useful indication of the level of performance that solar project developers and investors can expect from various project configurations in different parts of the country. Moreover, although this paper has not attempted to compare ex-post to published ex-ante capacity factor projections, the tight relationship between fitted and actual capacity factors (for example, see Figure 14) should nevertheless instill confidence among investors that the projects in this sample, at least, have largely performed as expected.

Looking ahead, the analysis presented in this paper suggests that there is still room for utility-scale PV project capacity factors to progress further. For example, even within the confines of our sample and Model 5's specification, Table 6 suggest that the NCF of tracking projects at the highest limits of the GHI and ILR ranges could potentially move a little higher (e.g., as high as 38.4%) than the maximum empirical 2014 NCF in our sample of 34.9%. Moving beyond our sample and Model 5, progress towards even higher net capacity factors could come from several different directions:

First, ILRs could possibly move higher than the 1.50 maximum seen in our sample, as some inverters are designed to handle ILRs as high as 1.75 (Advanced Energy, 2013). The extent to which ILRs will continue to move higher in the future depends in large part on the relative pricing of modules and inverters (and perhaps even trackers) going forward, which – in combination with PPA terms – determines the optimal ILR from an economic perspective. Even so, our analysis finds diminishing marginal returns to higher ILRs.

Second, dual-axis tracking would boost net capacity factor beyond the levels achieved by the single-axis trackers in our sample. Although no utility-scale (i.e., >5 MW_{AC}) PV projects using dual-axis tracking had been built in the United States through 2013, several such projects came online

[16] Module operating temperature may, however, be correlated with GHI to some extent, in which case perhaps power temperature coefficient may be the more important of these two variables. We did attempt to approximate the effect of power temperature coefficient by comparing the performance of projects using cadmium-telluride and silicon modules (given cadmium-telluride's claimed advantage in this area), but the results were inconclusive.

during 2014, with 2015 being their first full year of operation. Adding these projects to the sample would be one way to refresh this analysis and perhaps improve the model.

Third, although insolation is dictated by weather patterns and natural events and cannot be directly influenced with ease, it is, of course, possible to concentrate the strength of the sun's energy to boost generation. To date, most commercial concentrating photovoltaic ("CPV") projects have focused on minimizing the size of the solar cell in order to save on materials costs, thereby tempering the benefit of concentration on capacity factor.[17] But this need not be the case going forward, particularly if the price of solar-grade silicon remains low.

Though each of the three approaches described above could boost capacity factors in the future, the extent to which any of these are implemented will depend in large part on whether it is economically advantageous to do so. At present, for example, the economics of utility-scale PV in the United States generally do not favor any of these three approaches, though this could change in the future. In fact, depending on how module and inverter prices, as well as PPA terms, play out going forward, one could even envision a future that economically favors a lower ILR than we see today, in which case capacity factors would presumably move lower as a result. Analyzing how these economic considerations interact with the empirical technical parameters reviewed herein is beyond the scope of this paper, but is fertile ground for future work.

Finally, the advent of project-level energy storage – still rare in the utility-scale PV market within the United States (and not reflected at all within our project sample) – will likely change how utility-scale PV project developers think about capacity factor and its relative importance. Maximizing generation (e.g., through tracking and/or array oversizing) to take better advantage of available transmission capacity over more of the day, or alternatively merely shifting generation from lower- to higher-priced periods, are just two possible responses. Whatever the optimal strategy (which could differ depending on a variety of factors, including PPA terms), this paradigm shift will, no doubt, complicate future analyses of comparative PV project performance.

[17] In fact, to date, the two largest CPV projects in the United States have performed at capacity factors well below what one would have expected from a similarly sited PV project using single-axis (as opposed to CPV's dual-axis) tracking (Bolinger & Seel, 2015). SunPower's new C7 technology (which concentrates the sun's energy just seven times, compared to the hundreds of times achieved by other CPV technologies) is just now starting to be deployed, and time will tell whether this low-concentration approach yields better results than earlier high-concentration technology.

Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts

A report version of this research, fact sheets, summary briefings, a webinar recording and further supplemental material is available at https://emp.lbl.gov/iea-wind-expert-survey

A peer-reviewed article version of this research project has been published in the Journal Nature Energy on September 12th 2016 (Article number 16135) and is available online at:

http://rdcu.be/khRk

http://dx.doi.org/10.1038/nenergy.2016.135

1. Introduction

Wind energy supply has grown rapidly over the last decade, supported by a myriad of national and sub-national energy policies and facilitated by technology advancements and related cost reductions (GWEC, 2015; IEA, 2013; IRENA, 2015; REN21, 2015). Though the vast majority of this expansion has occurred onshore (>97%), offshore wind power deployment has also recently increased, especially in Europe. The rising maturity of wind power technology suggests that wind energy might play a significant future role in global electricity supply, perhaps especially in the context of efforts to reduce greenhouse gas emissions (GWEC, 2014; IEA, 2015; IPCC, 2014; Luderer et al., 2014; R. Wiser et al., 2011).

The long-term contribution that wind energy makes to global energy supply, and the degree to which policy support is necessary to motivate higher levels of deployment, depends—in part—on the future costs of both onshore and offshore wind. Those costs will be affected by technology advancements, as impacted by private and public research and development (R&D), among other factors. Yet there remains sizable uncertainty about both the degree to which costs will continue to decline and the conditions that might drive greater cost reduction (DOE, 2015; Lantz, Wiser, & Hand, 2012; R. Wiser et al., 2011).

This report summarizes the results of an expert elicitation survey on future wind energy costs and technology advancement possibilities. The research relies on expert knowledge to gain insight into the possible magnitude of future wind energy cost reductions, and to identify the sources of future cost reduction and the enabling conditions needed to realize continued innovation and lower costs. An understanding of the potential for wind power costs to fall and the means by which future cost reductions could be delivered can inform policy and planning decisions affecting wind power deployment, R&D in the private and public sectors, and industry investment and strategy development. Enhanced insight into future cost-reduction opportunities also supports improved representation of wind energy technology in energy-sector modeling efforts.

Lawrence Berkeley National Laboratory and the National Renewable Energy Laboratory led the gathering of data and insights through an online elicitation survey of a large sample of the world's foremost wind energy experts, under the auspices of the International Energy Agency (IEA) Wind Implementing Agreement. The survey is global in scope—though with a focus on North America and Europe—and covers onshore (land-based), fixed-bottom offshore, and floating offshore wind technology. It emphasizes costs and associated drivers of cost changes in 2030, but with additional markers in 2020 and 2050. This report summarizes the 163 survey responses received, in what may be the largest single expert elicitation ever performed on an energy technology. Insights gained through this survey can complement other tools for evaluating cost-reduction potential, including the use of learning curves, engineering assessments, and less-formal means of synthesizing expert knowledge.

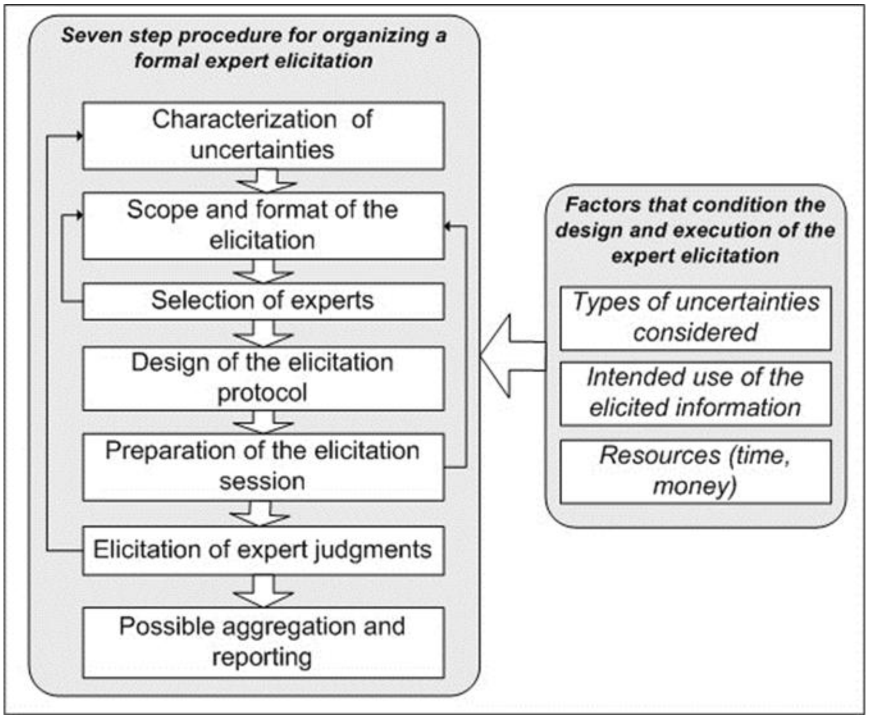
The remainder of this report is organized as follows. Chapter 2 introduces expert elicitation and discusses the scope, design, and implementation of our assessment. Chapter 3 summarizes our core results. Finally, Chapter 4 offers conclusions and discusses anticipated future work.

2. The Expert Elicitation Survey

2.1 Review of Expert Elicitation and other Methods to Assess Future Costs

Though multiple approaches have been used to assess the past and future cost of wind energy (discussed below), ours is one of the first publically available formal expert elicitation surveys with an explicit focus on future wind energy costs and related technology advancements.

Expert elicitation is a tool used to develop estimates of unknown or uncertain quantities based on careful assessment of the knowledge and beliefs of experts about those quantities (Morgan, 2014). Several options are available to a researcher who wishes to make such estimates: make projections based on past data and trends, review existing literature and adopt projections made by others, develop detailed models based on experience in related fields and apply them to create forecasts, and so on. The expert elicitation approach is to carefully assess projections of the quantities of interest from relevant subject-matter experts. It is often considered the best—or perhaps the only—way to develop credible estimates when data are sparse or lacking, or when projections are sought for future conditions that are very different from past conditions (Kotra, Lee, Eisenberg, & DeWispelare, 1996; Meyer & Booker, 2001). Several formal protocols for organizing and conducting expert elicitations have been developed; all follow a very similar set of steps to those described by (Knol, Slottje, van der Sluijs, & Lebret, 2010) and summarized in Figure 19.



Source: Knol et al., 2010

Figure 19: Steps in a Formal Expert Elicitation

Within this general protocol, a rich literature provides guidance on elicitation question design, the importance of clarity in what is being asked, how to avoid or minimize the effects of expert motivational and cognitive biases, and the importance of providing feedback to experts and providing opportunities for them to review and update their assessments (Coppersmith, Jenni, Perman, & Youngs, 2009; Hora, 2007; Morgan, 2014). Section 2.3 below describes how we applied these principles in our expert elicitation.

Expert elicitations have been widely used to support decision making in the private sector (Sharpe & Keelin, 1998) and in policy decisions (Hora & Von Winterfeldt, 1997). Their use is explicitly called for in a review of the Intergovernmental Panel on Climate Change (InterAcademy Council, 2010) and implicitly called for in a National Academies review of the U.S. Department of Energy's Applied Energy R&D programs (NRC, 2007). Within the energy community, expert elicitation is increasingly common as a tool for making estimates of the future costs of energy technologies under different possible future scenarios. (Baker et al., 2015), for example, review nearly 20 such elicitations conducted over the past decade, including studies focused on carbon capture and storage, solar, nuclear, biomass, and storage technologies. Gillenwater (2013) uses expert elicitation to explore wind investment decisions, and Kempton, McClellan, & Ozkan (2016) use elicitation to understand future offshore wind costs in one region of the United States, but formal elicitation procedures have not yet been widely applied to wind energy costs and related technology advancements. (Verdolini et al., 2016) provide a comprehensive review of energy technology expert elicitation studies.

Expert elicitation is not without weaknesses—in general and when applied to wind energy. Expert responses may be affected by the design of the data-collection instrument, by the individuals selected to submit their views, by the behavior of the interviewers (for in-person elicitation), and by features of the questionnaire or web-based instrument. Notably, it is impossible to entirely eliminate—or even to fully test for—the possibility of motivational or cognitive biases. Those individuals who are considered subject-matter experts on wind energy, for example, might have a tendency to be optimistic about the future of the sector. On the other hand, experts sometimes underestimate the possibility of technological change, as has been the case with solar energy (Verdolini et al., 2016). Regardless of the possible limitations, though, when implemented well, expert elicitation can provide valuable insights on the views of subject-matter experts, complementing other tools to assess cost-reduction potential, including learning curves, engineering assessments, and less-formal means of synthesizing expert knowledge (Lantz et al., 2012). These other methods have been used regularly—both individually and in combination—to assess potential future wind energy cost reductions:

Learning curves have a long history within the wind sector (Lindman & Söderholm, 2012; Rubin et al., 2015; R. Wiser et al., 2011), but they have been criticized for simplifying the many causal mechanisms that lead to cost reduction (Ek & Söderholm, 2010; Ferioli et al., 2009; Junginger et al., 2010; Mukora et al., 2009; Witajewski-Baltvilks et al., 2015; Yeh & Rubin, 2012). Further, few published studies focus on the most important metric of wind energy costs, the levelized cost of energy (LCOE) (BNEF, 2015b; Rubin et al., 2015; R. Wiser et al., 2011), with most research directed towards one component of LCOE: upfront capital costs (Dinica, 2011; Ferioli et al., 2009; Rubin et al., 2015). In addition, using historical data to generate learning rates that are then extrapolated into the future implicitly assumes that future trends will replicate past ones (Arrow, 1962; Ferioli et al., 2009; Nordhaus, 2014). For technologies with limited historical data, such as floating offshore wind, it is not even possible to compute technology-specific learning rates.

Engineering assessments provide a bottom-up, technology-rich alternative or complement to learning curve analyses (Mukora et al., 2009). They involve detailed modeling of specific possible technology advancements (BVG Associates, 2015; Bywaters et al., 2005; Crown Estate, 2012; Fingersh, Hand, & Laxson, 2006; Fitchner-Prognos, 2013; Malcolm & Hansen, 2002; Sieros, Chaviaropoulos, Sørensen, Bulder, & Jamieson, 2012; Valpy & English, 2014b, 2014a). Because this approach often models both cost and performance, it inherently emphasizes expected reductions in LCOE. It requires a robust understanding of possible technology advancements, thus the opportunities captured by engineering studies are often incremental and generally realizable in the near to medium term (less than 15 years). This approach also generally requires sophisticated design and cost models to capture the full array of component- and system-level interactions, and rarely provides insight into the probability of different outcomes.

Expert knowledge can be obtained through many means, not only through formal elicitation procedures. Through interviews, workshops, and other approaches, expert insight is a mainstay of many recent attempts to forecast future wind technology advancement and cost reduction. It can be paired with engineering assessment and learning curve tools to bolster the reliability of the overall estimates, garner a more detailed understanding of how cost reductions may be realized, and clarify the uncertainty in these estimates. The use of expert knowledge has proven especially valuable for emergent offshore wind technologies, for which historical data are often lacking (Crown Estate, 2012; Fitchner-Prognos, 2013; Junginger, Faaij, & Turkenburg, 2004; Navigant, 2013; TKI Wind op Zee, 2015), but expert insight has also been used to assess onshore wind (Cohen et al., 2008; Neij, 2008) and to compare onshore and offshore (Wüstemeyer, Madlener, & Bunn, 2015). As with more-formal elicitation procedures, care is needed to avoid bias and overconfidence in expert responses.

2.2 Scope of Expert Assessment: What Were We Asking?

The scope of our assessment comprises three wind power applications: utility-scale onshore wind, fixed-bottom offshore wind, and floating offshore wind. Onshore (i.e., land-based) wind is relatively mature, and it already makes a significant contribution to energy supply in many countries. Fixed-bottom offshore wind can use multiple foundation types (e.g., monopile, jacket, gravity base). It is less mature than onshore wind, but it is being deployed at scale in Europe and, to a lesser degree, outside of Europe. Floating offshore wind (e.g., spar buoy, semi-submersible platform, tension-leg platform) is not yet fully commercialized, but it has been deployed in full scale demonstration projects.

Our analysis centers on potential changes in the LCOE of projects that use each of the three wind applications, in dollars or euros per megawatt-hour ($/MWh or €/MWh). The LCOE is the levelized cost per unit of generated electricity from a specific source over its project design life that allows recovery of all project expenses and meets investor return expectations.[18] Though LCOE should not be the only metric used when comparing electric generation assets, the LCOE is regularly and appropriately used to assess the unit costs of electric-generation technologies, and minimizing LCOE is a primary goal of the wind industry and of wind energy R&D.[19]

[18] We calculate LCOE in real 2014$ or 2014€ per MWh. This LCOE estimate equates to the minimum power price a project must obtain to cover all project costs, service debt, pay expected returns to equity shareholders, and cover income tax. LCOE is calculated at the plant boundary and excludes the valuation of public benefits (e.g., Renewable Energy Credits, carbon credits, Green Certificates) as well as ratepayer, taxpayer, or other forms of project-level government support (e.g., investment and production tax credits, feed-in-tariff premiums). The formula used to calculate LCOE and more details on its use in this survey can be found at: http://rincon.lbl.gov/lcoe_v2/background.html.

[19] Though LCOE is useful for showing generation cost trends, simply comparing LCOEs among different electric-generation technologies is not sufficient to judge the relative value of those technologies. This is because electric system planners and modelers must consider not only levelized generation costs, but also system costs that include consideration of system peaking needs, transmission expenditure, and variable generation

In surveying the experts, we sought insight on the LCOE of the three wind applications at four time points: a recent-cost baseline in 2014 (for which respondents could accept a predefined baseline or create their own) and then in 2020, 2030, and 2050.[20] Note that these dates are based on the year in which a new wind project is commissioned. We did not seek a baseline estimate for floating offshore wind, given the nascent present state of that technology and lack of current commercial applications.

For the baseline year, and for our focus year of 2030, we further requested details on five core input components of LCOE: (1) total upfront capital costs to build the project (CapEx, \$ or €/kW); (2) levelized total annual operating expenditures over the project design life, including maintenance and all other ongoing costs, e.g., insurance and land payments (OpEx, \$ or €/kW-yr); (3) average annual net project-level energy output (capacity factor, %); (4) project design life considered by investors (years); and (5) costs of financing, in terms of the after-tax, nominal weighted-average cost of capital (WACC, %).[21,22] For the other two time points (2020, 2050), we solicited only estimates of the LCOE.

For the 2014 and 2030 CapEx estimates, respondents were asked to include only costs within the plant boundary, which include costs for electrical cabling within the plant but exclude costs for any needed substations, transmission lines, or grid interconnection costs. As applied to offshore wind, this means that CapEx includes costs for within-plant array cabling but excludes the costs for offshore substations, any high-voltage direct-current collector stations and associated cables, and grid connection to land (e.g., subsea export cables, onshore substations, and onshore transmission cables). As defined in the survey, OpEx excludes any costs associated with grid interconnection, substations, or transmission use; for offshore wind, transmission system use charges are also excluded.

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integration (Edenhofer et al., 2013; Hirth, 2013; Joskow, 2011; A. D. Mills & Wiser, 2013; R. Wiser et al., 2011). Differences in taxation, incentives, and societal benefits and costs are also often considered.

[20] Inclusion of a 2014 baseline allows for any changes over time to be characterized in absolute (\$ or €) and relative terms (% increase or decrease).

[21] This represents the average return required by the combination of equity and debt investors to make a project an attractive investment opportunity, where each category of capital is proportionately weighted. The WACC may be defined in after-tax or pre-tax terms. Owing to highly variable tax rules as well as the use of the tax code to incentivize wind energy in some countries, this survey relies exclusively on an after-tax WACC. Under these conditions, respective equity returns should reflect the annual average rate of return for equity positions after expenses and taxes, independent of how the rate of equity return is impacted by the applicable tax code. Similarly, debt interest rates should account for their status as a business tax deduction where applicable. In practice, after-tax WACCs may be considered either in real or nominal terms. Assuming an inflation rate of 2%, the following conversions between nominal and real apply: 4% nominal WACC = 2% real WACC; 8% nominal WACC = 5.9% real WACC; 12% nominal WACC = 9.8% real WACC.

[22] In calculating the LCOE, we use standardized taxation and inflation assumptions: standardized income tax rate (25%), depreciation schedule (20-year straight-line), and long-term inflation rate (2%); 100% of capital costs are assumed depreciable.

Our survey emphasized the "typical" LCOE of wind projects in each respondent's primary region of expertise. We defined "typical" as the median project in terms of costs (Figure 20).

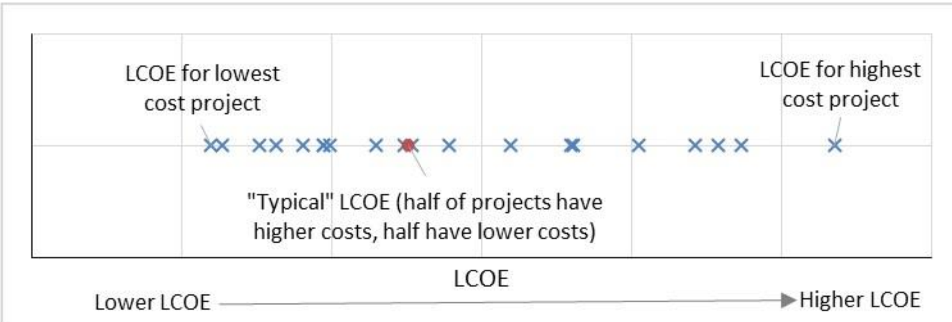

Figure 20: Definition of "Typical" LCOE in Expert Elicitation

Future wind LCOEs are uncertain. They can be affected by project-specific factors, such as the quality of the wind resource at a particular site, as well as by factors that affect the entire wind sector, such as changes in wind turbine technologies, markets, and policies. Technological changes may be induced by direct R&D or other advances. Market changes comprise, for example, systemic changes in the average wind speed of sites that remain for development as well as the amount of competition in the wind supply chain. Policy changes may directly or indirectly support or impede wind energy development and deployment.

In exploring future LCOE trends, we asked respondents to provide probabilistic estimates for three future scenarios: a low LCOE scenario (10th percentile), a high LCOE scenario (90th percentile), and a median LCOE scenario (50th percentile), considering only the broader, non-project-specific factors. We asked experts specifically to focus on changes in the typical LCOE (i.e., to ignore project-to-project variation) that might result from changes in factors that affect the industry as a whole (i.e., changes in wind energy technologies, markets, and policies). We also asked respondents to assume no changes in macroeconomic conditions (such as interest rates, inflation, and currency fluctuations), materials and commodity prices, and other factors not directly related to the wind energy business.[23]

In addition to asking about LCOE and the five core LCOE inputs, we asked about the market and technology characteristics and drivers most likely to impact LCOE trends in 2030. Specifically, we sought information on: (1) expected typical turbine characteristics for projects installed in 2030—nameplate capacity, hub height, and rotor diameter for all three wind applications; (2) the expected impact of each of a list of specific changes in wind development, technology, design, manufacturing, construction, operations, and markets on achieving reduced LCOE by 2030 for all three wind applications; and (3) broad drivers most likely to facilitate achieving "low" estimates

[23] For more detail, see: http://rincon.lbl.gov/lcoe_v2/typical_costs.html

of LCOE in 2030 as opposed to "median" estimates in that year, separately for onshore and fixed-bottom offshore wind.

2.3 Application of Expert Elicitation Principles

We applied many of the basic concepts, tools, and guidelines of a well-designed expert elicitation in order to minimize biases. Best elicitation practices include clearly defining the quantities that are being assessed, minimizing extra cognitive burden on the expert by asking questions using familiar terminology and units, and minimizing the need for "side" calculations. In addition, we sought to minimize the effects of anchoring and overconfidence biases (Kahneman, Slovic, & Tversky, 1982) by asking for low- and high-scenario estimates *before* asking for a mid-point estimate, and providing experts with feedback and the opportunity to review and modify their responses (Coppersmith et al., 2009). Our online survey format created challenges (e.g., we had a limited ability to tailor questions to respondent preferences) but also provided benefits over traditional interview-based elicitations in terms of easily accessible calculation and graphical display tools that gave experts immediate feedback and context for their assessments.

We carefully and clearly defined each of the cost-related factors for which we elicited input, and we reinforced those definitions throughout the survey. In part we took extra care here because of differences across the industry in how each factor is defined—for example, whether a project's CapEx includes or excludes transmission and grid interconnection costs, or whether nominal or real WACC is used in calculating LCOE. Because we could not ask each expert how he or she defined each term, and because we wanted to compare answers across the experts, we needed to provide detailed definitions of each quantity.

Although the experts could not challenge the definitions of the quantities being assessed, we provided some flexibility in how they provided responses, and we reduced the need for extraneous calculations. Respondents could answer cost questions in real U.S. dollars or real euros (we used the average 2014 exchange rate of €1 = US $1.33). They were also asked to indicate which of the three wind applications they were comfortable discussing, and then they were asked questions only about those applications. They were provided with an in-survey, easy-to-use LCOE calculator to translate component estimates into an LCOE estimate.[24] Additionally, respondents had the opportunity to qualify their answers with additional written comments and could skip questions they did not feel comfortable answering.

A particular challenge in online elicitations is how to provide experts with feedback and context for their responses so they can consider their own internal consistency and modify their assessments as desired. Without personal interaction, the elicitation team cannot direct an expert's attention to particular questions and responses. We addressed this issue by including graphical elements in the survey instrument and by building useful feedback into the instrument

[24] For an example, see http://rincon.lbl.gov/lcoe_v2/lcoe_calculator.html.

based on the results of pretesting that identified feedback needs. Most critical was the use of a time-trend graphical interface that (1) displayed the experts' previous assessments of a 2014 baseline LCOE and their low, median, and high scenario LCOE values for 2030, and (2) asked for low, median, and high scenario LCOE estimates for 2020 and 2050 on the same graph. This interface explicitly showed the experts all of their LCOE responses, encouraging them to think about the internal consistency of those estimates.

Though we followed expert elicitation principles and design guidelines in our assessment, three unique aspects of the present assessment deserve mention:

- Casting a Wide Net with an Online Survey: Many expert elicitations feature detailed and sometimes lengthy in-person interviews with fewer than 20 experts. In contrast, we distributed our survey online to a wide group of possible respondents. This necessitated a shorter, more focused survey than would be common in an in-person setting, with less follow-up and in-depth exploration of responses.[25] In part, this choice reflected the need for a greater number of overall respondents to address one goal of our effort: to compare responses by wind application, organizational type, location, expertise, and other respondent characteristics.[26]

- No Comprehensive Elicitation of Probability Distributions or Technical Parameters: Our assessment combined aspects of expert elicitation and an opinion survey. We focused the expert elicitation on LCOE and the five key inputs to LCOE under low, median, and high scenarios, and we limited consideration of the five key inputs to only two specific points in time. Our assessment of technical and market drivers mirrored an opinion survey—we did not seek detailed quantitative assessment of the LCOE effect of specific technical advancement possibilities. Instead we asked experts to identify which advancements they believe would be larger contributors to cost reductions.

- No Elicitation of Opinions Conditional on Specific R&D, Policy, Deployment, or Other Factors: We asked respondents to make low, high, and median scenario estimates of future LCOE, and we left it to them to define for themselves the future scenarios that might drive those cost changes. In contrast, many expert elicitations condition responses based on defined R&D expenditures and on specific market and policy scenarios, in order

[25] Some research shows that elicitations relying on self-administered, web-based surveys yield results different from those relying on in-person interviews (Nemet, Anadon, & Verdolini, 2017; Verdolini, Anadon, Lu, & Nemet, 2015), whereas other research shows less evidence of such differences (Anadón, Nemet, & Verdolini, 2013; Baker, Bosetti, Anadon, Henrion, & Aleluia Reis, 2015); where differences exist, the relative accuracy of the two methods remains unclear, though it is generally believed that in-person interviews represent the "gold standard." On the other hand, (Baker et al., 2015; Nemet et al., 2017) also suggest there is value in including diverse and relatively large groups of experts when conducting elicitations, suggesting—all else being equal, and due to the resource intensity of in-person elicitation—that there is value to online elicitations.

[26] Our interest in assessing the effect of respondent type on elicitation results follows related work conducted by Anadón et al. (2013) on nuclear energy cost expectations, Verdolini et al. (2015) on solar photovoltaics, and Nemet et al. (2017) on a range of energy technologies.

to more directly inform R&D and policy decisions. Our survey was designed to map the universe of possible future LCOEs but provides only limited information about specific contributions to lower or higher costs.

2.4 Survey Design, Testing, and Implementation

We gathered data and insights through an online elicitation survey (via the Near Zero platform[27]) of a large sample of the world's foremost wind energy experts under the auspices of IEA Wind Task 26 on the "Cost of Wind Energy."

The survey was carefully designed over a number of months, including numerous rounds of review, testing, and revision. Reviewers included the core survey design team, IEA Wind Task 26 members, and a select group of external wind energy experts. An expert workshop was held early in the process to discuss the goals of the survey and to pilot test an early draft of the survey. A PDF version of the final survey can be found online at: https://emp.lbl.gov/iea-wind-expert-survey.

The survey was launched in October 2015 and closed in December 2015. During the intervening period, various steps were taken to maximize response rate and ensure respondent comprehension of the survey. In particular, we first "pre-announced" the survey to possible respondents, and we invited participation in a webinar during which we discussed the purpose, structure, and details of the elicitation: 33 people attended the webinar, the recording was viewed 19 times, and the slides were made available for download. The online survey was distributed with personalized web links, and six separate waves of reminders were sent before the survey finally closed—including personalized and less-personalized email reminders as well as some phone and in-person exhortations. Because of the depth and length of the online survey, respondents were allowed to complete it in multiple sittings as necessary. In some cases, several individuals within an organization collaborated on a single, collective survey response.

2. 5 Selection and Response of Experts

The success of an expert elicitation depends on the expertise and commitment of the contributing experts. Given the focus of our elicitation on project-level LCOE, our ideal respondents included strategic, system-level thought leaders with wind technology, cost, and/or market expertise. Such individuals might come from the various strands of the private wind industry, public R&D institutes, academia, or a range of other organizations. We sought a relatively large number of respondents in part to ensure an adequate number of possible experts versed in each of the three wind applications. Though the survey was global in scope, we focused on experts from North America and Europe given the constitution of the members of IEA Wind Task 26.

[27] See: http://www.nearzero.org/.

We received considerable assistance in identifying possible respondents from IEA Wind Task 26 members and their affiliated institutions, and we reached out to many other wind energy experts and organizations to ensure broad coverage. We allowed our initial set of potential respondents to suggest additional names, which yielded a small number of additional respondents.

In addition to the full survey sample, we identified a smaller group of "leading experts." These individuals were selected through an iterative, deliberative process by a core group of IEA Wind Task 26 members and several leading external wind energy experts. The survey team believed this small group was uniquely qualified to complete the survey, and the group was created in part to enable comparison of survey results between the smaller leading-expert sub-sample (paralleling a more traditional elicitation) and the larger group (excluding the leading-expert sub-sample).

We successfully distributed surveys to 482 experts, including 42 in the leading-expert group. The total number of returned surveys was 163, of which 22 came from the leading-expert group and the remaining 141 fall within the larger group. This reflects a response rate of 34% across the full set and 52% among the smaller group.[28] Appendix A lists the individuals who submitted responses.

Responses came from a broad cross-section of the wind sector. Figure 21 summarizes the characteristics of the 163 respondents by wind application area addressed, region of the world with which experts are most familiar, organizational type, and type of expertise. Note that respondents were able to identify multiple wind applications, geographies, and types of expertise. The median respondent dedicated 49 minutes to completing the survey, with the 25th-to-75th percentile range from 29 to 99 minutes.

[28] In practice, there were some instances in which multiple individuals collaborated on a single survey response. Where we know of these instances, they are marked in Appendix A, and they result in a total response rate of 36% (by experts).

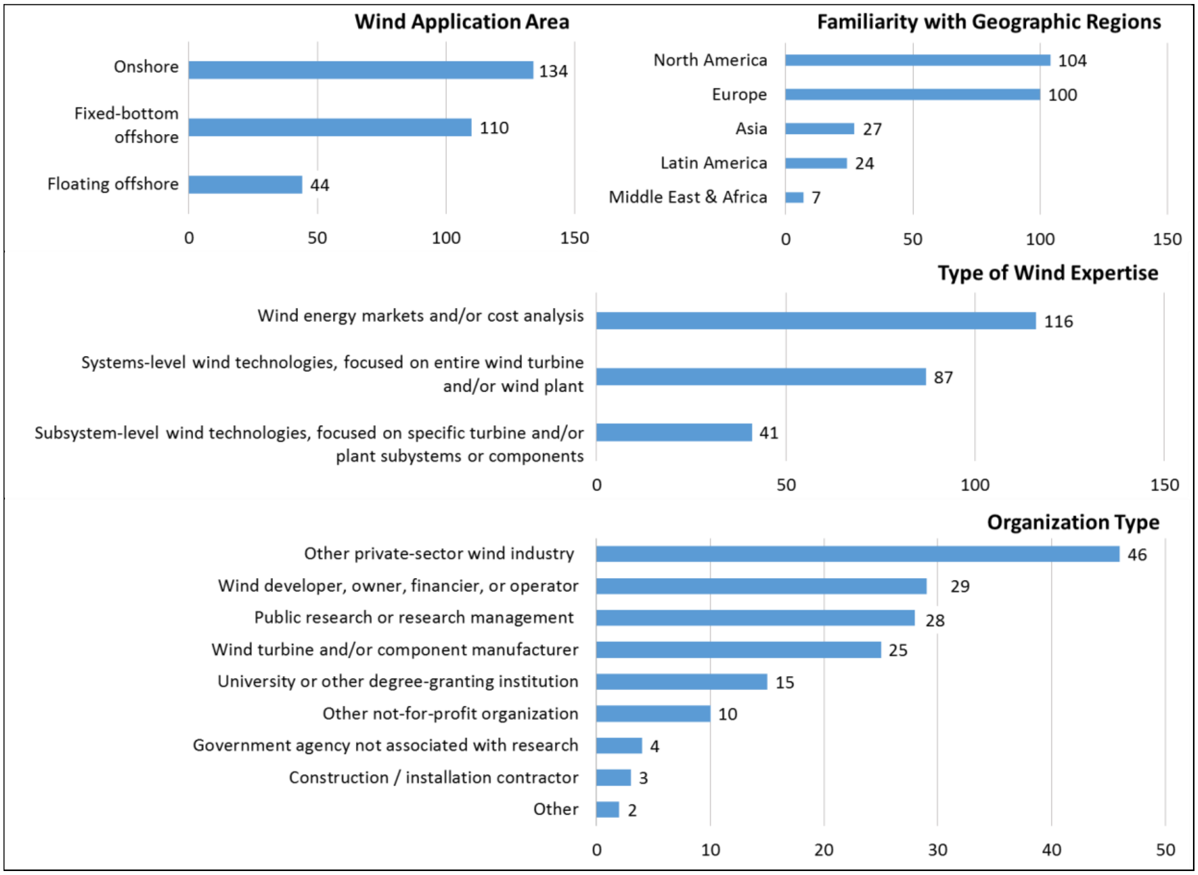

Figure 21: Characteristics of the 163 Expert Survey Respondents

3. Summary of Elicitation Results

The analysis presented in this report summarizes the full set of 163 survey responses received. Additionally, in a number of text boxes, we highlight—on a cursory basis—notable differences in responses: (1) between the smaller leading-expert group vs. the full set of responses *less* that group; (2) by organizational type[29]; (3) between respondents who provided opinions on *only* onshore or offshore wind vs. those who provided responses to *both* onshore and offshore wind; (4) by type of expertise; and (5) by familiarity with different geographic regions.[30] Such

[29] We consolidated the nine organizational type categories presented in Figure 21 into five larger categories: (1) public R&D and academic (consolidating two of the original categories, and called the "research" group for the remainder of the report); (2) wind developer/owner/financier/operator and construction/installation contractor (consolidating two of the original categories, and called the "wind deployment" group); (3) wind turbine and/or component manufacturer (called the "equipment manufacturing" group); (4) other private-sector wind industry; and (5) other (consolidating three of the original categories—government agency not associated with research, other not-for-profit, and other).

[30] Note that in many instances a single respondent may have identified multiple geographies (e.g., North America and Europe) or types of expertise (e.g., expertise on wind energy costs and on wind energy technologies). Such respondents may, therefore, fall within multiple categories when the survey responses are

comparisons are insightful in their own right, but might also help reveal underlying biases in the survey sample. Future work is planned to assess more thoroughly any systematic differences in survey responses by respondent characteristics.

3.1 Forecasts for LCOE Reduction

For each of the wind applications, experts provided a single estimate of LCOE for 2014 (the "baseline" value) and then provided low-, median-, and high-scenario estimates for the typical LCOE of wind projects in 2020, 2030, and 2050. In estimating the low-, median-, and high-scenario estimates, experts were asked to ignore project-to-project variation and instead to focus on factors that affect the industry as a whole, e.g., changes in wind energy technologies, markets, and policies. All dates are based on the year in which a new wind project is commissioned.

Figure 22 shows the resulting changes in LCOE from 2014 through 2050 in percentage terms for (a) onshore, (b) fixed-bottom offshore, and (c) floating offshore wind. Expert-specific changes in LCOE are calculated using each expert's baseline and later values. Because a 2014 baseline was not established for floating offshore, the change is shown relative to the expert-specific baseline for fixed-bottom offshore wind. The figure shows the change from the baseline values for each of the three scenarios the experts were asked to provide: low, median, and high scenarios of typical LCOE. Expert opinions on these changes vary, and the figure also shows the range of those opinions. Lines and markers show the median value of expert responses, and the shaded regions around each line show the range (25^{th} to 75^{th} percentile) of expert responses.

While the figure summarizes the full set of survey responses, Text Box 1 highlights key differences in LCOE estimates among various respondent groups. Though the differences identified in the text box are notable, it is also important that the results from most respondent groups—by organization, by region, and by expertise type—vary only to a relatively small degree. This suggests that any biases in the results that derive from our survey sample are either limited or apply similarly to many of the wind expert respondent groupings.

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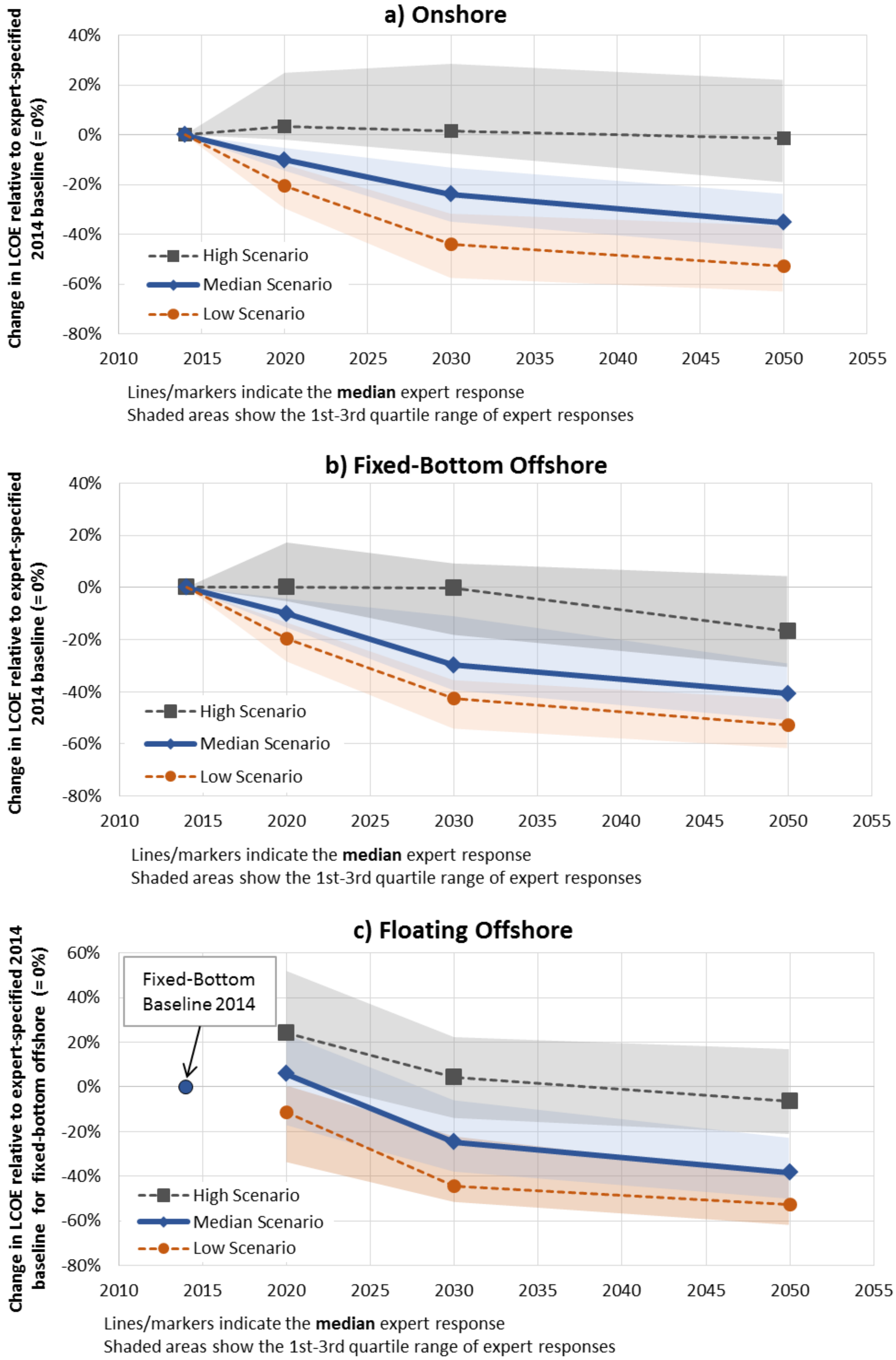
split by geography or expertise type. In these instances, careful interpretation is required. This issue is not present when culling results by organizational type; leading experts vs. larger group; or onshore, offshore, vs. both onshore and offshore—in each of the latter cases, the groupings are mutually exclusive.



Note: All dates are based on the year in which a new wind project is commissioned.

Figure 22: Estimated Change in LCOE over Time for (a) Onshore, (b) Fixed-Bottom Offshore, and (c) Floating Offshore Wind Projects

Focusing first on the median (50th percentile) scenario for typical LCOE, experts clearly predict significant continued reductions in the cost of wind energy. Though onshore wind technology is already relatively mature, experts anticipate further advancements, with the median value of expert responses (also referred to as the median-expert response) showing LCOE reductions from baseline values of 10% in 2020, 24% in 2030, and 35% in 2050. Expert views on the long-term opportunities for fixed-bottom offshore wind are even more aggressive—perhaps not surprisingly, given the earlier state of the technology—with median LCOE reductions of 10% in 2020, 30% in 2030, and 41% in 2050. Floating offshore wind comes in at a 6% LCOE premium in 2020 relative to the 2014 fixed-bottom offshore baseline (reflective of the emerging state of the technology), but then it steeply declines to 25% below and then 38% below baseline values by 2030 and 2050, respectively.

There is also clearly a sizable range of uncertainty in future LCOEs, reflected both in the median-expert response for the low-scenario and high-scenario LCOE estimates as well as the range of expert views for all three scenarios shown by the shaded regions. For onshore wind, under the high scenario, the median-expert response shows effectively no change in LCOE from 2014 to 2050. Under the low scenario, however, the LCOE declines by 44% in 2030 and 53% in 2050. For fixed-bottom offshore wind, high-scenario LCOEs similarly remain at 2014 values, but only to 2030—in contrast with the onshore wind results, the high-scenario LCOE declines for fixed-bottom offshore after 2030, with a 17% reduction by 2050 for the median-expert response. High-scenario estimates for floating offshore wind show a somewhat different pattern: 25% higher than baseline values in 2020, 5% higher in 2030, and then 6% lower in 2050. Low-scenario estimates, at least in the long term, show a similar pattern for fixed-bottom and floating offshore wind (also bearing a strong similarity to onshore wind): a 43%–45% reduction in 2030 and a 53% reduction in 2050. Overall, the range in results among the high, median, and low scenarios demonstrates a sizable "opportunity space" for R&D- and deployment-related advancements.

Though percentage changes from the baseline are the most broadly applicable approach to presenting survey findings, depicting the relative absolute value for expert-specified LCOE (in $ or €/MWh) is also relevant. Figure 23 shows the estimated LCOE values for all three wind energy applications, over time, on a single plot, focusing only on the median scenario and depicting the median value of all expert responses as well as the range of expert responses. In reviewing this chart, emphasis should be placed on the relative positioning of and changes in LCOE, not on absolute magnitudes. This is because experts could accept a given 2014 baseline, or could create their own baseline. The median baseline shown in the figure therefore does not intend to represent any specific region of the world; for any specific region, the 2014 baseline figure and therefore expected absolute future LCOEs relative to that figure would vary. Additionally, because roughly 80% of experts chose to use the default 2014 baseline values for onshore and fixed-bottom offshore, the 1st and 3rd quartile as well and the median expert response for 2014 are all equivalent to those default baseline values. Appendix B includes two similar figures focused on the low-scenario (Figure A-1) and the high-scenario (Figure A-2) LCOE estimates.

Not surprisingly, experts clearly believe that onshore wind energy will remain lower cost than offshore, at least for typical projects. That being said, offshore wind energy is anticipated to see more-significant absolute reductions in LCOE over time, and so a narrowing occurs between the LCOEs of onshore and offshore wind applications. A similar trend is apparent for fixed-bottom and floating offshore wind: while the typical floating offshore wind project is expected to remain more costly than fixed-bottom wind over the entire period, the gap narrows over time, especially because of the sizable expected LCOE reductions for floating offshore wind between 2020 and 2030. Under the median scenario, of those experts who provided both fixed-bottom and floating LCOE figures, 23% see floating as less expensive than fixed-bottom by 2030, and 40% see it as less expensive by 2050.[31] These LCOE results—and comparisons—exclude costs of transmission interconnection to shore; differential interconnection costs between fixed-bottom and floating projects could therefore shift these relative LCOE results. Finally, there is clearly much higher uncertainty for the future LCOE of offshore wind energy than for onshore wind energy, depicted by the much larger 25th-to-75th percentile range for expert responses.

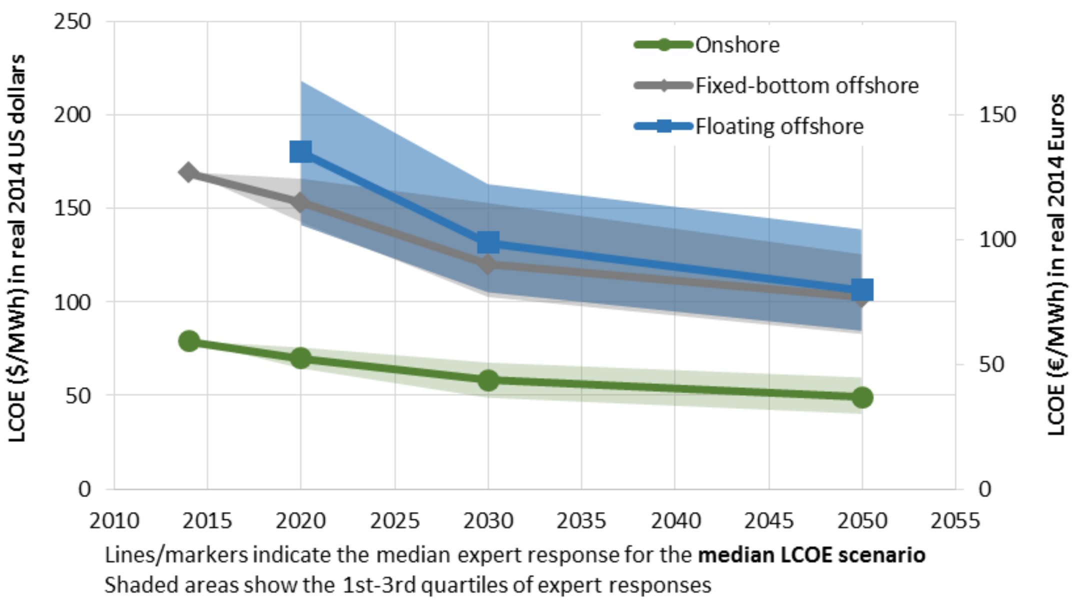


Figure 23: Expert Estimates of Median-Scenario LCOE for All Three Wind Applications

[31] In the median scenario , the median-respondent LCOE of floating offshore wind is anticipated to remain slightly higher than that of fixed-bottom offshore wind through 2050, but the gap narrows and is very small by 2050 (Figure 23). In the low scenario, the median respondent expects an earlier LCOE convergence (see Appendix B). A deeper review shows that the leading-expert group is somewhat more optimistic for this convergence than the larger group of respondents (less the leading group). In the median LCOE scenario in 2050, for example, the small number of leading experts predicts a median LCOE reduction of 51% for fixed-bottom and 50% for floating offshore wind, whereas the larger respondent group predicts a 40% reduction for fixed-bottom and 31% for floating (see Figure 24, in Text Box 1). In the low-LCOE scenario, meanwhile, the leading experts predict median LCOE reductions of 62% for fixed-bottom and 64% for floating offshore wind (lower costs for floating offshore wind than fixed-bottom), whereas the larger respondent group expects a 53% reduction for fixed-bottom and 50% for floating (Appendix B).

Respondents were given the option of providing a textual discussion of the conditions that might produce low-, median-, or high-scenario LCOE estimates; these qualitative observations complement other survey results discussed later in this report that cover similar themes. For onshore wind, the experts identify a wide variety of factors as important to achieving low-scenario LCOE and, to a lesser extent, median-scenario LCOE estimates, including technical advancements (e.g., larger rotor and taller towers as well as improved and lighter materials, component reliability, turbine life, controls, and understanding of wind flow) and other market factors (e.g., learning through deployment volume and policy stability, transmission to access high-quality sites, lower-cost financing with industry maturation, and supply-chain efficiencies). Expert comments also reveal the tradeoff between CapEx and capacity factor, with some experts anticipating continued capacity factor improvements but only with stagnating CapEx value in order to pay for those performance increases. Conditions that might lead to high-scenario LCOE estimates often include weak demand for new wind power additions and/or a depletion of higher-quality wind resource sites (and/or lack of investment in new transmission to access those sites).

Expert-provided conditions for achieving low-, median-, or high-scenario LCOE for offshore wind energy—whether fixed-bottom or floating—are easier to summarize. The dominant themes relate to deployment volumes and market stability. Simply put, many experts believe that significant deployment is an essential precondition to the technical advancements, standardization, and supply-chain efficiencies in manufacturing, installation, and operations that would be required to achieve the low-scenario or even median-scenario LCOE estimate. Larger machine ratings are also especially important, according to the experts.

Text Box 1. LCOE-Reduction Expectations: Comparing Respondent Groups

We explored whether differences in LCOE expectations existed among respondent groups, namely between the leading-expert group vs. the full set of responses *less* that group; by organizational type (see Footnote 299 for definitions of the categories used); between respondents who provided opinions on only onshore or offshore wind vs. those who provided responses to both onshore and offshore; by type of expertise; and by familiarity with different geographic regions. Many respondents indicate familiarity with multiple geographies or have several types of expertise—such respondents may fall within multiple categories when responses are split by geography or expertise type, requiring careful interpretation. Expectations for LCOE reduction do not appear to differ substantially across many of the respondent groupings, including most regions. Though full results are presented in Appendix B (Tables A-9 through A-11), some of the more notable differences include:

Leading vs. Larger Group: The leading-expert group expects greater LCOE reduction for **onshore** (27% in the median scenario in 2030 for the leading group vs. 24% for the larger group), **fixed-bottom** (35% vs. 29%), and **floating offshore** (38% vs. 15%, albeit with only six experts in the leading group). These differences persist or grow through 2050, as shown in Figure 24. Similar differences exist in the low- and high-LCOE scenarios as well.

Organization Type: For **fixed-bottom offshore**, respondents in the "wind deployment" group anticipate larger LCOE reductions (e.g., median response of 36% reduction in the median scenario in 2030), whereas those in the "equipment manufacturer" group anticipate much smaller LCOE reductions in the median scenario in 2030 (9%). As shown in Figure 24, these differences narrow by 2050; similar patterns exist for the low and high LCOE scenarios. For **onshore** wind, expected LCOE reduction is largely consistent across all organizational types and, though sample size is limited, the same appears largely true for **floating offshore** wind (note, however, that no equipment manufacturers responded to questions on floating offshore LCOE).

Applications Considered: Respondents who only expressed knowledge of offshore wind (i.e., did not answer the onshore questions) tend to be more aggressive about the LCOE reduction of offshore wind than those who expressed expertise in both onshore and offshore. For **fixed-bottom**, the median offshore-only respondent anticipates a 36% reduction in LCOE in 2030 in the median scenario, while those who also have expertise with **onshore** anticipate a 28% reduction. For **floating offshore** wind, the LCOE reductions are 25% and 20%, respectively. These differences persist to 2050 and also exist within the low and high LCOE scenarios.

Expertise Type: Those who claimed expertise on "wind energy markets and/or cost analysis" are generally more aggressive about LCOE reduction than those with "systems-level" or "subsystems-level" technology expertise; those with "subsystems-level" expertise (i.e., those focused on specific turbine or plant subsystems or components) tend to be the most cautious. These trends exist for all three applications, but the differences are small except for **floating offshore** wind (for floating, median 2030 LCOE reductions are 31% for "wind energy markets and/or cost analysis," 25% for "systems-level technology," and 17% for "subsystems-level technology").

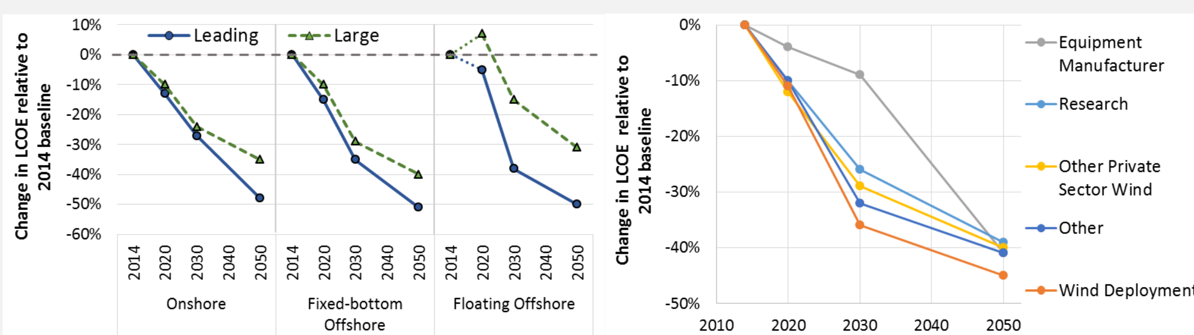


Figure 24: Impact of Leading-Expert vs. Larger Group on Median-Scenario LCOE of All Three Applications (left) and Organization Type on Median-Scenario LCOE of Fixed-Bottom Wind (right)

3.2 Baseline Values for 2014

To unpack the LCOE results presented earlier, it is first important to better understand the 2014 baseline values used by experts—not only for LCOE but also for the five key components that drive LCOE: CapEx, OpEx, capacity factor, project design life, and cost of financing. Rather than assume that all experts have the same internal “baseline” for the typical LCOE of recent projects, we offered a default option but allowed experts to provide their own estimates for onshore and fixed-bottom offshore wind; we did not provide or seek a baseline estimate for floating offshore wind, given the nascent state of that technology and lack of current commercial applications. The default baseline values offered for onshore wind were intended to reflect an average 2014 project installed in the United States or Europe, while the offshore baseline was intended to reflect European experience. Table 7 and Table 8 summarize both the default values and the range of other values provided by those experts who opted to provide their own.

The majority of experts accepted the default baseline values. For experts providing input on onshore wind projects, 103 of 134 respondents used the default baseline values shown in the tables. For experts providing input on offshore wind projects, 88 of 110 respondents used the baseline values.

Among experts modifying the 2014 baseline values for onshore wind projects, most estimated a lower LCOE, through lower CapEx and OpEx and through a longer project design life and higher capacity factor. Based on a review of open-ended responses to a question asking experts to describe their revised baseline, these revisions towards a lower LCOE came primarily from respondents who were seeking to reflect lower-cost projects in the United States, often through higher capacity factors, lower CapEx, or both. Those who revised the baseline figures to better reflect European costs did so less consistently in one direction or the other, given very different market and resource contexts from one European country to the next; a number of participants reduced the default capacity factor to better match European—and especially German—conditions, for example, while others left capacity factor at the default value but altered CapEx to better match conditions in certain windier European countries.[32]

In contrast to the onshore wind results, among those modifying the baseline values for offshore wind projects, most estimated a higher LCOE, in part through higher operating expenses. These upward revisions came from respondents seeking to better reflect European projects and, to a much lesser degree, hypothetical North American projects. In both cases, the revisions tended to result in higher 2014 baseline LCOEs; the upward revisions were particularly sizable in the few

[32] As is apparent in some of the figures in Appendix B, some experts altered the default baseline values very significantly. In some cases, these revisions were made to reflect conditions that might be considered reasonably widespread, e.g., very high capacity factors in parts of the United States. In a few cases, however, respondents developed these “outlier” values considering relatively narrow project parameters, e.g., a small project in the Northeastern United States or in a difficult site in Switzerland.

cases reflecting projects in the United States, perhaps due to the lack commercial offshore experience in that country.

	LCOE	Capital costs	Operating expenses	Capacity factor	Project design life	Cost of financing
Default baseline values (also the median response of all experts)	$79/MWh	$1,800/kW	$60/kW-yr	35%	20 years	8%
	€59/MWh	€1,353/kW	€45/kW-yr			
Mean baseline value across all experts	$77/MWh	$1,784/kW	$59/kW-yr	35%	20.7 years	7.9%
	€58/MWh	€1,341/kW	€44/kW-yr			
% of responding experts who defined their own baseline values (of 134 total respondents)	23%	21%	20%	19%	13%	14%
Median for respondents changing the baseline LCOE	$64/MWh	$1,650/kW	$55/kW-yr	36%	25 years	8%
	€48/MWh	€1,241/kW	€41/kW-yr			
% of self-defined values indicative of a lower LCOE than the default values	71%	71%	74%	52%	52%	45%

Table 7: 2014 Baseline LCOE and Associated Components for Onshore Wind

	LCOE	Capital costs	Operating expenses	Capacity factor	Project design life	Cost of financing
Default baseline values (also the median response of all experts)	$169/MWh	$4,600/kW	$110/kW-yr	45%	20 years	10%
	€127/MWh	€3,459/kW	€83/kW-yr			
Mean baseline values across all experts	$171/MWh	$4,646/kW	$115/kW-yr	45%	20.3 years	10%
	€129/MWh	€3,493/kW	€86/kW-yr			
% of responding experts who defined their own baseline values (of 110 total respondents)	20%	19%	18%	12%	7%	5%
Median for respondents changing the baseline LCOE	$189/MWh	$4,600/kW	$123/kW-yr	45%	20 years	10%
	€142/MWh	€3,459/kW	€93/kW-yr			
% of self-defined values indicative of a lower LCOE than the default values	23%	32%	14%	14%	36%	14%

Table 8: 2014 Baseline LCOE and Associated Component for Fixed-Bottom Offshore Wind

3.3 Sources of LCOE Reduction: CapEx, OpEx, Capacity Factor, Lifetime, WACC

With the baseline values now presented, the earlier LCOE results can be unpacked into five key components that impact LCOE. Due in part to the complexity of the relationships between the various LCOE components,[33] the elicitation focused on the distribution of LCOE, asking for a 10th (low scenario), 50th (median scenario), and 90th (high scenario) percentile estimate for the typical LCOE of wind projects, as presented earlier. Associated with each of these LCOE values, for 2030, the experts provided a set of LCOE component estimates that they felt would represent a project with that LCOE. With this focus, the component values themselves should not be directly interpreted as defining a specific probability range for each factor, but they do provide insight into which components experts believe are more likely to change, and by how much, as LCOE changes over time.

Appendix B provides detailed box-and-whisker charts showing the full range of expert opinions for LCOE and the five components for the 2014 baseline and for the low-, median-, and high-scenario 2030 estimates (Figures A-3 to A-5). To complement these results,

Figure 25 focuses on *relative* changes in LCOE and LCOE components. For this analysis, each expert's responses for low-, median-, and high-scenario values in 2030 are compared to their 2014 baseline values, and the median result across all experts is shown in the figure. The change between the 2014 baseline and the estimates associated with the 2030 median scenario are shown with blue bars; markers also show the relative change associated with the low- and high-LCOE scenarios for 2030. Mean baseline values for each factor are shown in the x-axis labels for reference. Though the figure uses the full set of survey responses, Text Box 2 highlights key differences among various respondent groups.

Starting with the median scenario for onshore wind (LCOE reduction of 24%), experts anticipate that CapEx (-12%) and OpEx (-9%) will decline by 2030, while capacity factor (+10%) and project life (+10%) will increase; the median respondent anticipates no change in the cost of financing.[34] Under the low LCOE scenario, these directional trends become even stronger, while cost of financing declines.

[33] For example, there is a non-linear relationship between the components and LCOE, and a logical dependency among the components: e.g., a higher CapEx may lead to higher capacity factors (and possibly, lower LCOE).

[34] That the cost of financing does not change in the median scenario is—initially—somewhat surprising. Most respondents are most-familiar with the established markets in North America and Europe, however, where advancements in the cost of financing are less-likely than in less-developed wind regions. Results based on mean survey responses (Figure A – 3) do show a reduction in the cost of finance even in the median scenario.

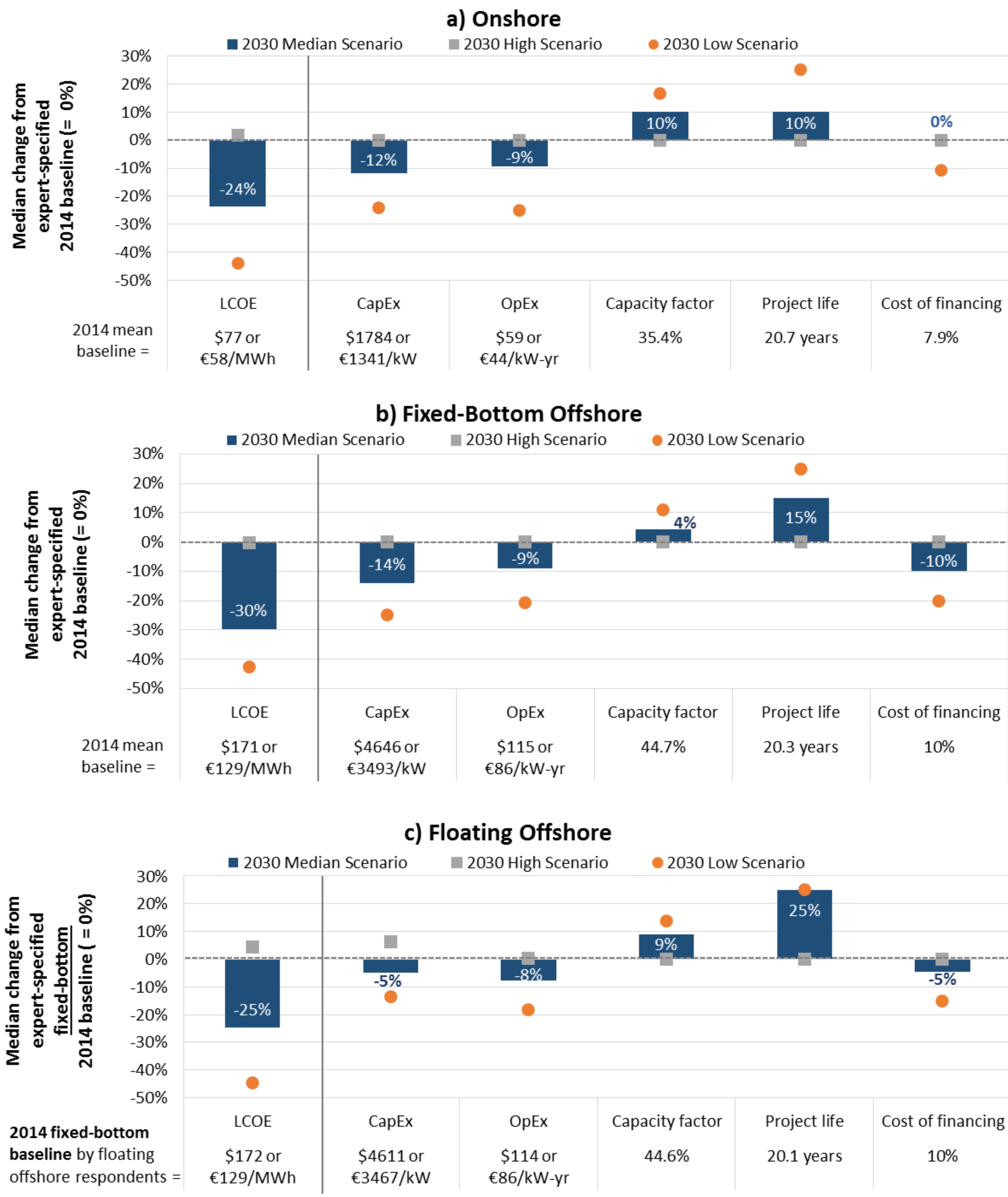


Figure 25: Relative Change in LCOE and LCOE Components from 2014 to 2030 for (a) Onshore, (b) Fixed-Bottom Offshore, and (c) Floating Offshore Wind Projects

Text Box 2. Sources of LCOE Reduction: Comparing Respondent Groups

Text Box 1 highlighted differences in LCOE reduction expectations by different respondent groups. Here we summarize some of the underlying drivers of those differences in terms of the five components that impact LCOE. See Appendix B (Tables A-12 to A-14) for data tables that underlie the text that follows.

Leading vs. Larger Group: As noted earlier, the leading-experts group is more aggressive than the larger group in terms of LCOE reduction. As shown in Figure 26, for the median LCOE scenario for **onshore** wind in 2030 (relative to the 2014 baseline), the key contributors to these differences are CapEx (-17% for leading experts vs. -11% for the larger group) and OpEx (-17% for leading experts vs. -9% for larger group).

For **fixed-bottom offshore**, major contributors are CapEx (-18% vs. -14%), capacity factor (+11% vs. +4%), and project design life (+25% vs. +15%).

For **floating offshore** wind, primary contributions come from CapEx (-10% vs. -5%), capacity factor (+20% vs. +8%), and finance cost (-15% vs. no change).

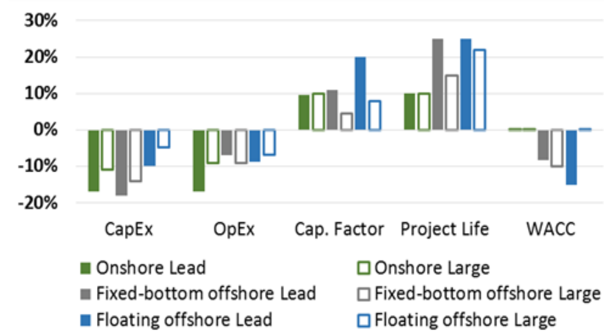


Figure 26: Sources of LCOE Reduction of Leading-Expert Group vs. Larger Group

Organization Type: As noted earlier, organization type has an impact on the LCOE of fixed-bottom offshore wind but less-obvious impacts on the other two wind applications. In reviewing the five components of median-scenario LCOEs in 2030 (relative to the 2014 baseline), however, we observe a number of notable differences across all three applications. Starting with onshore wind and again focusing on the median value for each respondent group, the larger variations include: (a) lower CapEx and OpEx reductions, as well as lower capacity factor and project life improvements, for the "equipment manufacturing" group relative to all respondents (CapEx: -3% vs. -12% for all respondents; OpEx: -4% vs. -9%; capacity factor: +8% vs. +10%; project life: +5% vs. +10%); and (b) higher OpEx reductions, capacity factor improvements, and project life for the "research" group (OpEx: -14% vs. -9% for all respondents; capacity factor: +14% vs. +10%; project life: +25% vs. +10%). For fixed-bottom offshore wind, some of the same trends are apparent for the "equipment manufacturing" group: lower CapEx improvement (-4% vs. -14%), lower OpEx reduction (-2% vs. -9%), no capacity factor improvement (0% vs. +4%), no reduction in cost of finance (0% vs. -10%), and no change in project life (0% vs. +15%). Reflecting the lower LCOEs from the "wind deployment" group, this group is more aggressive on CapEx (-18% vs. -14% for all respondents), capacity factor (+9% vs. +4%), project life (+23% vs. +15%), and cost of finance (-20% vs. -10%). For both onshore and offshore, equipment manufacturers expect lower levels of improvement across many factors. Given the small sample for floating offshore, findings are less robust and so are not reported here.

Wind Application Coverage: As noted earlier, respondents who only expressed knowledge of offshore wind tend to be more aggressive about the LCOE reduction potential of offshore wind than those who expressed expertise in both onshore and offshore applications. A review of these responses reveals that, for the median-LCOE scenario for fixed-bottom offshore in 2030 (relative to the 2014 baseline), the key contributors to LCOE differences are OpEx (-13% for offshore-only group vs. -9% for both), capacity factor (+7% vs. +4%), project design life (+20% vs. +13%), and especially cost of finance (-17% vs. -1%); CapEx reductions are actually lower for the offshore-only group (-11% vs. -16%). For floating offshore wind, key contributors are capacity factor (+11% vs. +7%) and, again, cost of finance (-15% vs. 0%). Particularly notable here is that the offshore-only group is actually less optimistic about CapEx reduction (0% vs. -8%), but offsets this with their greater optimism for other contributors to LCOE, and especially a reduced cost of finance.

Expectations for fixed-bottom offshore component trends from 2014 to 2030 differ from onshore. Under the median scenario (LCOE reduction of 30%), experts anticipate a slightly larger reduction in CapEx (-14%) than onshore, a smaller increase in capacity factors (+4%), and a sizable decline in the cost of financing (-10%). Results for OpEx (-9%) are consistent with onshore, in percentage terms, while experts are somewhat more optimistic on extended project lifetimes offshore (+15%). For floating offshore wind (LCOE reduction of 25%, relative to 2014 fixed-bottom baseline), experts anticipate a tradeoff between smaller CapEx improvements (-5%) and stronger capacity factor growth (+9%), relative to fixed-bottom wind; financing cost reductions (-5%), project life extensions (+25%), and OpEx reductions (-8%) also play a role in achieving the median-scenario LCOE estimated for 2030. Under the low LCOE scenario, these directional trends become stronger, for both fixed-bottom and floating offshore wind.

A review of the percentage change in each component, as presented above, is an imperfect proxy for the *relative* importance of those changes in driving LCOE—because some components (e.g., CapEx) play a larger absolute role in LCOE than others (e.g., OpEx). To gain insight into the relative importance of changes in each component, we use a sensitivity analysis. In particular, we use each expert's baseline and 2030 component estimates to calculate what the change in LCOE *would be* for that expert if only one of the five components changed, relative to that expert's overall estimated change in LCOE. We do this for each of the five components for each expert and then normalize these "one-off" effects to sum to the overall LCOE percentage reduction. The resulting median values of expert responses are shown in Figure 27 for both the median scenario and the low scenario, for all three wind applications.[35]

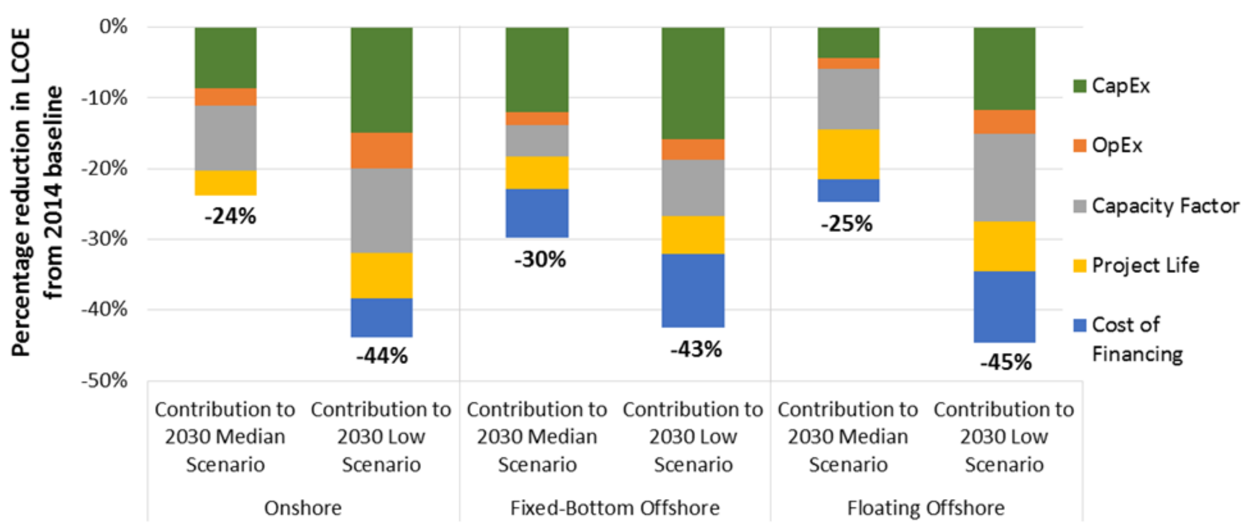


Figure 27: Relative Impact of Changes in Each Component on LCOE in 2030

[35] The high LCOE estimates for 2030 are close to the 2014 baselines, so the contribution of each component is of less interest.

For onshore wind energy, CapEx and capacity factor improvements are expected to constitute the largest drivers of LCOE reductions. Under the median scenario, 75% of the total LCOE reduction comes from these two components, with a slightly larger contribution of the capacity factor (39%) than CapEx (36%); under the low scenario, 61% of the total LCOE reduction comes from the two, with a somewhat greater impact from CapEx (34%) than capacity factor (27%). Under both the median and low scenarios, lower OpEx (~11% in both cases) and longer project life (~15% in both cases) play significant but far-smaller roles in driving LCOE changes. Lower-cost financing is not expected by experts to play a significant role for the median scenario, but it does have an impact (12%) in the low scenario.

The relative impact of the five factors differs for offshore wind. Focusing first on fixed-bottom offshore, CapEx reductions play the largest role, constituting 40% and 37% of total LCOE reduction under the median and low scenarios, respectively. Reductions in the cost of financing are also especially significant, at 23% in the median scenario and 25% in the low scenario, perhaps due to the still-early current state of commercial deployment and expectations of reduced risks over time. Capacity factor is the third most-impactful factor, at 15% and 19% for the low and median scenarios, respectively—lower in terms of contribution to LCOE reduction than for onshore wind. Closely following capacity factor improvements is project design life at 15% (median scenario) and 13% (low scenario). Improvements in OpEx are the least important driver for both the median (6%) and low (7%) scenarios.

The trends are different still for floating offshore wind, relative to the 2014 fixed-bottom baseline, with a notably more significant role for capacity factor improvements. This may reflect a belief that floating technology will tend to be deployed in windier sites as enabled by the ability to access deeper water locations. To achieve median-scenario 2030 LCOE estimates, the component rankings are: capacity factor (34%), project design life (29%), CapEx (18%), cost of financing (13%), and OpEx (6%). For low-scenario 2030 LCOE estimates, the component rankings are: capacity factor (28%), CapEx (26%), cost of financing (23%), project design life (16%), and OpEx (7%).

3.4 Expectations for Wind Turbine Size

Experts were asked to provide their estimates of wind turbine characteristics in 2030 for typical projects: turbine capacity, hub height, and rotor diameter. Because these characteristics may vary by region, experts identified the specific region of the world in which their estimates applied. Figure 28 summarizes the results by presenting the median of the responses,[36] split into three regional groupings: Europe, North America, and other. To provide a recent-year benchmark, the figure also includes 2014 onshore averages for the United States and Germany as well as 2014 offshore averages for Europe as a whole. Appendix B (Tables A-15 and A-16) summarizes North American and European turbine characteristic expectations among various respondent groups,

[36] Experts did not provide specific numeric estimates, but chose a range from a list (e.g., 2.5 to 3.0 MW for capacity). For simplicity of presentation, the figures and data included in this section show the median response as the mid-point of the range of the median category selected (e.g., 3.75).

which—as shown there—are reasonably consistent with the full set of responses summarized below.

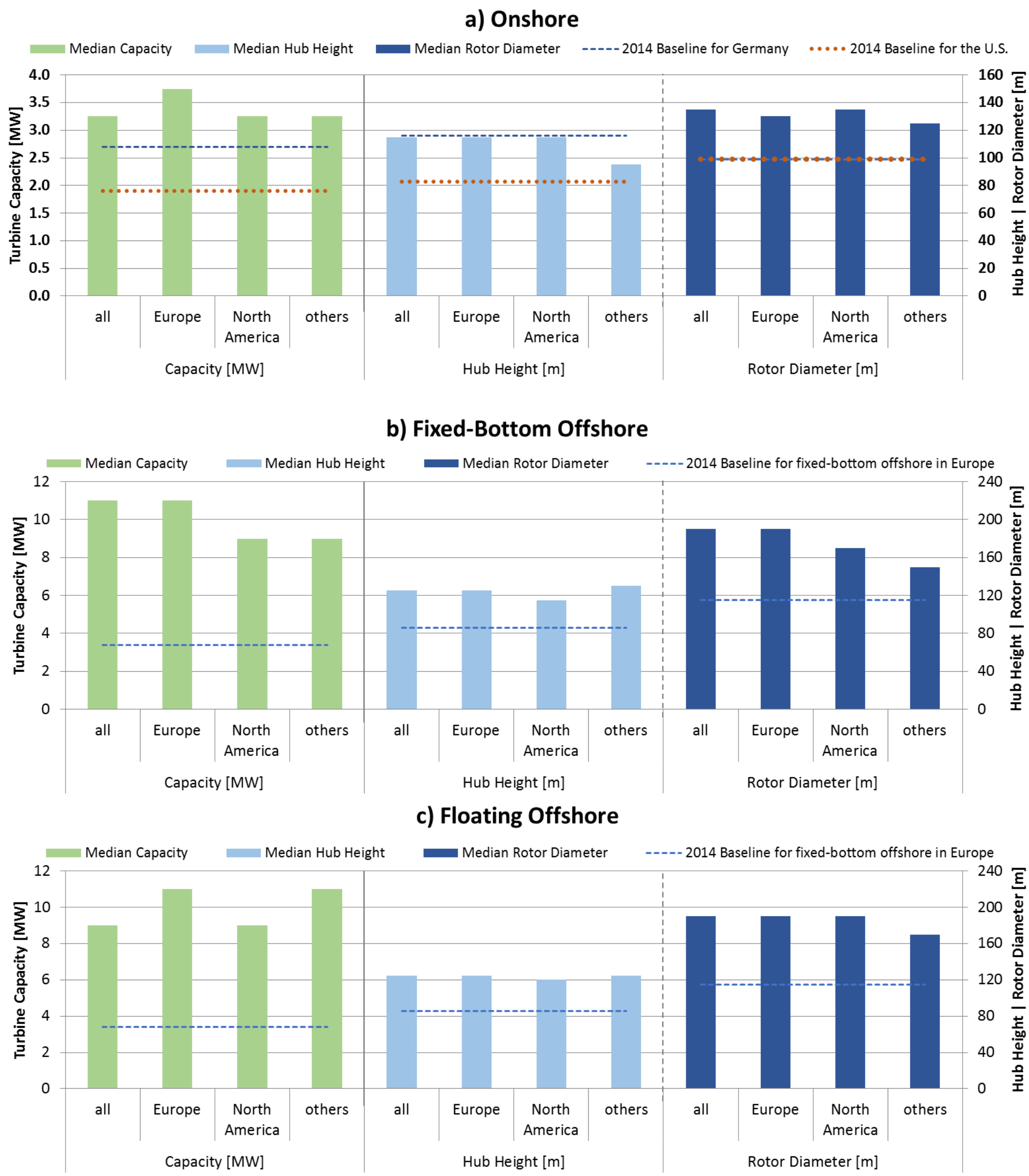


Figure 28: Wind Turbine Characteristics in 2030 for (a) Onshore, (b) Fixed-Bottom Offshore, and (c) Floating Offshore Wind Projects

It is clear that survey respondents anticipate pronounced upward scaling in wind turbine size, with some regional variations. Starting with nameplate capacity, experts believe that onshore turbines will continue to scale, with a typical size in 2030 of 3.75 MW in Europe and 3.25 MW in North America and elsewhere for the median expert response. Turbines deployed offshore are expected to grow even more dramatically, to 9 or 11 MW, depending on the region and technology. Growth in offshore wind represents another turbine design evolution beyond current commercial product development, which is generally focusing on turbines 8 MW and below.

This growth in nameplate capacity is matched by continued scaling in hub heights and rotor diameters. Hub heights onshore are expected—globally, in Europe, and in North America—to be roughly 115 m for typical wind projects, substantially higher than the 2014 benchmark average in the United States but equivalent to the 2014 average in Germany; typical hub heights are anticipated to be lower outside of Europe and North America. Increased hub heights offshore are also expected, to roughly 125 m, though with some modest regional variation. Turning to rotor diameters, onshore averages are expected to reach roughly 135 m for typical projects, with some regional variations, while median offshore estimates equal 190 m, though again with some regional differences.

Overall, for offshore wind, expectations are for somewhat smaller turbines—capacity, hub height, and rotor diameters—in North America than in Europe. While the reasons for this modest divergence are unclear, it might be hypothesized that, as the leading offshore market globally, European projects may be expected to remain on the leading edge of technology deployment. Experts may simply believe that offshore development in North America, a lagging market, will emphasize somewhat smaller turbines for which greater commercial experience exists.

All of these results reflect expectations for typical wind projects deployed in 2030; in reality, turbines used in 2030 will—of course—span a wide range, depending on site characteristics. Moreover, the results presented here represent median expert responses, but experts have divergent views on the degree of future scaling; accordingly, Appendix B shows the distribution of expert responses in histogram form (Figure A-6), and it presents median responses based on different respondent groupings (Tables A-15 and A-16).

Finally, we calculated the implied 2030 turbine specific power[37] for each expert, with

Figure 29 summarizing median responses for that metric. As shown, the median specific power estimate for onshore wind is roughly 260 W/m^2, with lower estimates for North America (250 W/m^2) and somewhat higher estimates in Europe and especially outside of Europe and North America. These specific power estimates are similar to 2014 averages from the United States, and they demonstrate that specific power is expected to decline globally by 2030, but only to the

[37] Specific power was calculated by dividing the turbine capacity by the rotor swept area, a function of rotor diameter; because turbine characteristics were presented as ranges (e.g., 4–5 MW), we used midpoints of each range for turbine capacity and for turbine rotor diameter to estimate the specific power for each expert.

current averages already seen in the United States. In North America, continued reductions in average specific power are not anticipated, through 2030.

Turning to offshore wind, estimates of typical specific power in 2030 vary regionally, but with a rough average of 375 W/m^2 for fixed-bottom offshore and 390 W/m^2 for floating offshore installations, slightly higher than the 2014 European averages of 325 W/m^2 and considerably higher than the 2030 estimates for onshore wind. The higher specific power for offshore wind—whether fixed-bottom or floating—in concert with other survey findings suggests that experts are prioritizing turbine capacity scaling (with proportional rotor scaling) and associated CapEx reductions in reducing offshore LCOE, whereas, for onshore wind, the declining global specific power reflects a more significant role for capacity factor improvements in driving LCOE trends. Appendix B offers a closer look at the distribution of the experts' implicit estimates of specific power (Figure A-7).

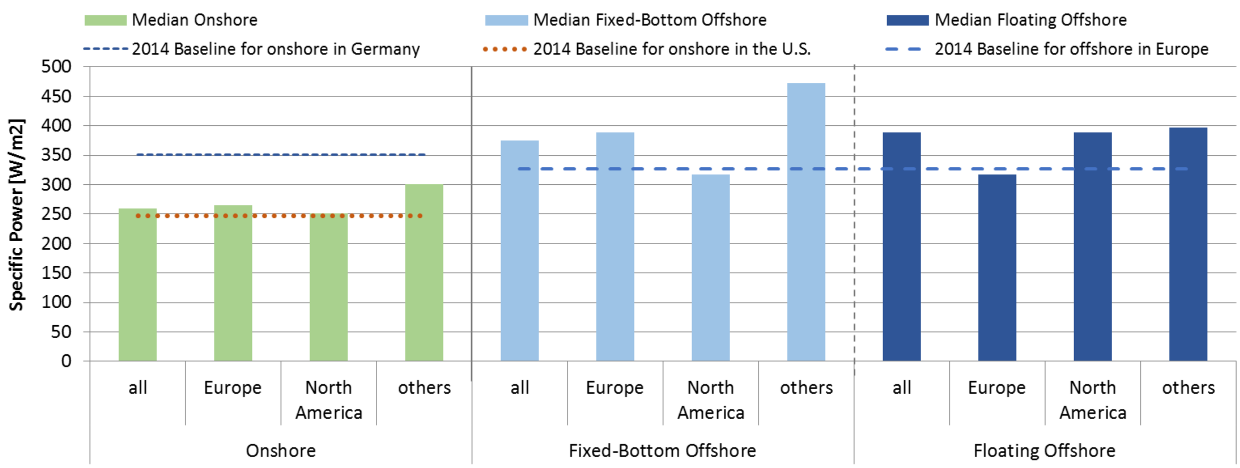


Figure 29: Wind Turbine Specific Power in 2030

3.5 Future Wind Technology, Market, and Other Changes Affecting Costs

A variety of wind development, technology, design, manufacturing, construction, operational, and market changes might contribute to reducing the LCOE for wind projects. To gauge the relative importance of the many possible drivers, we asked respondents to rate 28 different changes on a four-point scale based on their *expected* impact on *reducing* LCOE by 2030, for each of the three wind applications.[38] The 28 possible drivers were listed under seven broader categories: scaling in wind turbines; wind plant design; turbine and component design; foundation, support structure, and installation; supply-chain manufacturing; operating expenditures and performance; and competition, risk, development, and other opportunities. Respondents were allowed to add and rate "write-in" factors not otherwise specified in our list. The full set of results for all 28 listed items—across all three wind applications—is included in

[38] Respondents were also allowed to mark "no opinion," though few did so.

Appendix B (Table A-1 to A-3), while a listing of the write-in responses is also included in the appendix (Table A-4 to A-6).[39]

Figure 30 summarizes the findings at a superficial level, while Table 9 highlights the top-12 rated items for onshore, fixed-bottom offshore, and floating offshore wind. Specifically, the table summarizes the percentage of experts who said each item would have a "large expected impact" on LCOE in 2030, an "average" rating for each item based on converting the overall four-point scale to numerical scores, and the distribution of ratings (from left to right, the % of experts rating the item as having a large, medium, low, or no expected impact on LCOE). The table lists only the 12 highest-rated advancements—based on the percentage of experts who identified an item as having a "large expected impact"—for each of the three wind applications (see Appendix B for the results across all 28 items). Text Box 3 lists key differences in how the possible advancements were rated among various respondent groups.

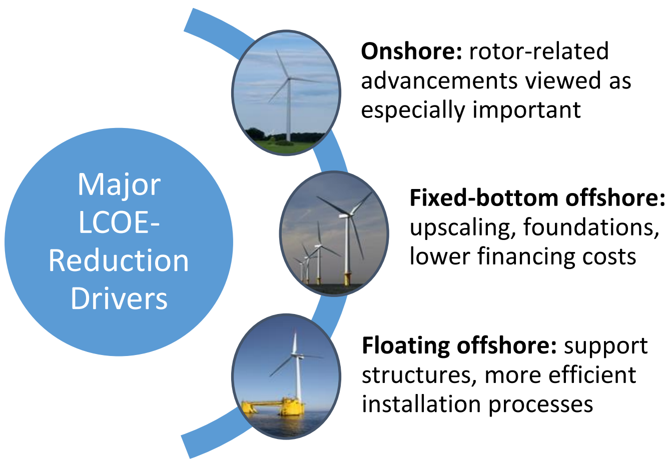


Figure 30: Top Advancement Opportunities

That the two leading drivers of LCOE reduction for onshore wind are related to rotors—increased rotor diameters and rotor design advancements—is consistent with the survey results presented earlier indicating capacity factor improvements as a major contributor to expected LCOE reduction, and with the anticipated global increase in rotor diameters (and declining specific power). Increased hub heights, coming in at number three on the ranked list, are also consistent with this theme and with previously presented results showing significant expected increases in hub height. After those three top-ranked items, a wide variety of technical and market advancements follows, from reduced financing costs and new transmission, to improved component durability and extended design lifetimes.

[39] A review of these write-in responses reveals that, in the majority of cases, experts listed: (a) detailed examples of advancements that were already captured in the 28 provided options; (b) items that might motivate an advancement but are not actually a direct advancement itself; or, in some cases, (c) options that do not obviously have a proximate impact on LCOE. Based on our review of these responses, we conclude that the 28 items originally listed do not obviously miss major advancement options.

The relative ranking of the various drivers differs for offshore wind, and many more items were given higher ratings for offshore than for onshore. Starting with fixed-bottom offshore wind, the most highly rated advancements include increased turbine capacity ratings, design advancements for foundations and support structures, and reduced financing costs and project contingencies. Each of these is fully consistent with the findings noted earlier in terms of industry expectations for growth in turbine nameplate capacity ratings, and the relatively high importance of CapEx improvements and reducing financing costs, along with the relatively lower stated importance of capacity factor and OpEx improvements. Other highly rated items are also consistent with these themes, including larger project size and installation equipment and process advancements. Finally, turning to floating offshore wind, many of the themes here are similar to those for fixed-bottom technology, except with an even greater emphasis on foundations and support structures as well as turbine installation.

Five drivers show up in the top-12 for each of the three wind applications, though with different levels of prioritization within those lists: reduced financing costs and project contingencies; improved component durability and reliability; increased turbine capacity ratings; turbine and component manufacturing standardization, efficiencies, and volume; and integrated turbine-level system design optimization. Two other drivers are found within the top-12 for onshore and one of the top-12 offshore lists: rotor design advancements and extended turbine design lifetimes. The remaining items are more exclusive to either onshore or offshore wind, but not both. For example, increased rotor diameters and tower heights, new transmission, operating efficiencies, and improved plant layout are included in the top-12 list for onshore wind, but not for offshore. Similarly, a wide variety of foundation, support structure, installation, and transportation advancements as well as increased competition and project size are embedded in the top-12 lists for offshore wind, but not for onshore wind.

Experts identify some items as having no or negligible effect on reducing LCOE by 2030. As shown in Appendix B, for onshore wind, these include: lower decommissioning costs, reduced fixed operation and maintenance costs, installation process efficiencies, altered siting and permitting procedures, foundation design and manufacturing advancements, maintenance equipment advancements, and non-conventional turbine designs. For offshore wind, some of the same themes are evident, but added to those are site-specific turbine designs, non-conventional plant layouts, and increased tower height and tower design advancements.

	Wind technology, market, or other change	Percentage of experts rating item "Large expected impact"	Mean Rating , Rating Distribution 3- large impact 2- median impact 1- small impact 0- no impact	
Onshore Wind	Increased rotor diameter such that specific power declines	58%	2.5	
	Rotor design advancements	45%	2.3	
	Increased tower height	33%	2.2	
	Reduced financing costs and project contingencies	32%	2.1	
	Improved component durability and reliability	31%	2.1	
	Increased energy production due to new transmission to higher wind speed sites	31%	2.0	
	Extended turbine design lifetime	29%	2.0	
	Operating efficiencies to increase plant performance	28%	2.0	
	Increased turbine capacity and rotor diameter (thereby maintaining specific power)	28%	1.9	
	Turbine and component manufacturing standardization, efficiencies, and volume	27%	2.0	
	Improved plant layout via understanding of complex flow and high-resolution micro-siting	27%	2.0	
	Integrated turbine-level system design optimization	23%	2.0	
Fixed-Bottom Offshore Wind	Increased turbine capacity and rotor diameter (thereby maintaining specific power)	55%	2.4	
	Foundation and support structure design advancements	53%	2.4	
	Reduced financing costs and project contingencies	49%	2.4	
	Economies of scale through increased project size	48%	2.3	
	Improved component durability and reliability	48%	2.3	
	Installation process efficiencies	46%	2.4	
	Installation and transportation equipment advancements	44%	2.3	
	Foundation/support structure manufacturing standardization, efficiencies, and volume	43%	2.2	
	Extended turbine design lifetime	36%	2.2	
	Turbine and component manufacturing standardization, efficiencies, and volume	36%	2.1	
	Increased competition among suppliers	35%	2.1	
	Integrated turbine-level system design optimization	33%	2.1	
Floating Offshore Wind	Foundation and support structure design advancements	80%	2.8	
	Installation process efficiencies	78%	2.7	
	Foundation/support structure manufacturing standardization, efficiencies, and volume	68%	2.6	
	Economies of scale through increased project size	65%	2.6	
	Installation and transportation equipment advancements	63%	2.5	
	Increased turbine capacity and rotor diameter (thereby maintaining specific power)	59%	2.4	
	Improved component durability and reliability	58%	2.5	
	Reduced financing costs and project contingencies	46%	2.3	
	Increased competition among suppliers	46%	2.2	
	Rotor design advancements	45%	2.1	
	Integrated turbine-level system design optimization	44%	2.3	
	Turbine and component manufacturing standardization, efficiencies, and volume	40%	2.3	

Table 9: Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE by 2030 for All Three Wind Applications

Text Box 3. Technology, Market, and Other Changes Affecting LCOE: Comparing Respondent Groups

As presented in tabular form in Appendix B (Table A-17 to A-19), there is a substantial consistency across respondent groups in how the technology, market, and other changes are ranked based on expected impact on LCOE. There are, however some interesting differences, some of which are summarized below. Note that we focus on the leading-expert vs. larger-group distinction and on different organization types; we emphasize only items prioritized within the top-12 of at least one of the two groups being compared, and we only highlight those items that are at least five ranks different between the two comparison groups.

Onshore Wind*:* All respondent categories agree about the importance of increased rotor diameters and related rotor design advancements, and the various respondent categories agree—in broad terms—to the full ranking of items. The leading-expert group, however, places a number of items higher on its rank-ordered list in comparison to the larger group, notable examples of which include: improved plant-level layout; increased competition among suppliers; and installation and transportation equipment advancements. The leading-expert group places lower on its list—comparatively—items such as: turbine and component manufacturing standardization, efficiencies, and volume; increased turbine capacity; and reduced financing costs and contingencies.

Fixed-Bottom Offshore Wind*:* Again, the various respondent types agree—in broad terms—to the full ranking of items. The leading-expert group, however, places a number of items higher on its list in comparison to the larger group, including: improved component durability and reliability, extended turbine design lifetime, rotor design advancements, maintenance process efficiencies, operating efficiencies to increase plant performance, and increased energy production due to new transmission. The leading-expert group places lower on its list items such as: integrated turbine-level system design optimization; turbine and component manufacturing standardization, efficiencies, and volume; foundation and support structure manufacturing standardization, efficiencies, and volume; installation process efficiencies; and reduced financing costs and contingencies.

Floating Offshore Wind*:* Notwithstanding the smaller respondent sample for floating offshore wind, many of the respondent categories again generally agree to the full ranking of items. The leading-expert group places a number of items higher on its list, including: increased turbine capacity, integrated turbine-level system design optimization, innovative non-conventional turbine designs, tower design advancements, nacelle components design advancements, operating efficiencies to increase plant performance, and improved plant-level layout. The leading-expert group places lower on its list items such as: extended turbine design lifetime; turbine and component manufacturing standardization, efficiencies, and volume; and increased competition among suppliers.

Differences by organization type match expectations. The research group, for example, tends to rank emerging areas of research as more important. For onshore wind, this means comparatively higher rankings for: improved plant-level layout, integrated turbine-level system design optimization, and innovative non-conventional plant-level layouts. For floating offshore wind, integrated turbine-level system design optimization, innovative non-conventional turbine designs, and tower design advancements all rank comparatively higher. Equipment manufacturers, on the other hand, tend to focus on issues related to component and equipment design, manufacturing, and installation. As one example, for onshore wind, this means higher rankings for: turbine and component manufacturing standardization, efficiencies, and volume; large variety of alternative turbine designs to suit site-specific conditions; and innovative non-conventional turbine designs. Finally, the wind deployment group tends to place additional emphasis on matters related to development and operations. For fixed-bottom offshore wind, as one example, this means comparatively higher rankings for: extended turbine design lifetime; increased competition among suppliers; and reduced fixed operating costs, excluding maintenance.

3.6 Broad Market, Policy, and R&D Conditions Enabling Low LCOE

Whether future LCOE trends generally follow the low-, median-, or high-scenario estimates is—in part—under the control of public and private decision makers. As such, in a final question, we asked experts to rank four broad drivers that might enable achieving *low-scenario* LCOE (as opposed to median-scenario LCOE) in 2030 for onshore and fixed-bottom offshore wind separately (we did not ask a similar question for floating offshore wind). The four drivers were defined as:

- Research and Development: Breakthrough discoveries and technological innovation resulting from public- and private-sector research and development
- Learning with Market Growth: Incremental technical, manufacturing, process, and/or workforce-efficiency improvements resulting from learning with market growth
- Increased Competition and Decreased Risk: Lower contingencies and greater competition within the supply chain resulting from market maturity and reduced technology and construction risk
- Eased Wind Project and Transmission Siting: Reduced development costs and/or increased access to higher wind resources resulting from conditions that ease wind project and transmission siting

Table 10 shows the overall expert rankings of these four drivers. In particular, the table shows the percentage of experts who ranked each item as the most important, an "average" rank for each item, and the distribution of rankings (from left to right, the % of experts ranking each driver as 1, 2, 3, 4, or lower than 4). Respondents were allowed to add and rank additional "write-in" items—a listing of those write-in responses is included in Appendix B (Table A-7 and A-8).[40] Text Box 4 highlights key differences in how these broad drivers were rated among various respondent groups.

Overall, respondents ranked "learning with market growth," followed closely by "research and development," as the two leading drivers for achieving low LCOE estimates, and they did so for both onshore and offshore wind. Experts clearly view these two items as the highest priority items for achieving low-scenario LCOE estimates. For onshore wind, "increased competition and decreased risk" and then "eased wind project and transmission siting" followed. For offshore wind, these last two items were switched in order. Somewhat surprising is the low ranking of "increased competition and decreased risk" for offshore wind energy, given the current state of the offshore wind sector.[41]

[40] A review of write-in responses reveals that most are consistent in tone and detail with the question and results discussed in Section 3.6: no obvious major "broad driver" was missed in our question formulation.

[41] Note that the question asked respondents to rank these drivers based on their expected impact in achieving the *low-scenario* LCOE estimates in 2030 as opposed to *median-scenario* estimates in 2030. Presuming that this careful wording was understood by respondents, experts might believe that "increased competition and decreased risk" is important in driving LCOE towards median-scenario values in 2030, but that there is relatively limited *incremental* opportunity for that driver to motivate even-lower LCOE.

	Wind technology, market, or other change	Percentage of experts ranking item "most important"	Mean Rating , Rating Distribution Ranking from 1- most important to 5- least important	
Onshore Wind	Learning with market growth	33%	2.2	
	Research & development	32%	2.4	
	Increased competition & decreased risk	16%	2.5	
	Eased wind project & transmission siting	14%	3.2	
Offshore Wind	Learning with market growth	33%	2.2	
	Research & development	32%	2.3	
	Eased wind project & transmission siting	25%	2.3	
	Increased competition & decreased risk	5%	3.4	

Table 10: Ranking of Broad Drivers for Lower Onshore and Fixed-Bottom Offshore LCOE in 2030

Text Box 4. Broad Market, Policy, and R&D Enablers to Low LCOE: Comparing Respondent Groups

As presented in tabular form in Appendix B (Tables A-20 and A-21), there are various differences among respondent groups in how the four broad drivers are ranked based on their ability to enable the low-scenario 2030 LCOE estimates:

For **onshore** wind, the leading-experts group places "learning with market growth" squarely at the top of the list, followed—at some distance—by "research and development." By organization type, the most notable difference is that equipment manufacturers identify "learning with market growth" as the least important driver, listing "research and development" as the leading driver. The other group, on the other hand, rates "research and development" considerably below "learning with market growth" and on par with the other two options. Interpretations for geography and expertise type are complicated by the large number of experts that fall within multiple respondent groups. Nonetheless, experts who expressed familiarity with North America—at least in comparison to those with familiarity with Europe—tend to emphasize to a greater degree "research and development" and "eased wind project siting," while respondents with familiarity with Europe place greater focus on "learning with market growth" and "increased competition and decreased risk." Respondents with expertise outside of Europe and North America tend to place a great deal of emphasis on "learning with market growth." Finally, those with systems- and subsystems-level wind technologies expertise tend to rank "research and development" above "learning with market growth," while the opposite is true for those with wind markets and/or cost analysis expertise.

For **fixed-bottom offshore** wind, the leading-experts group ranks "research and development," "eased wind project and transmission siting," and "learning with market growth" largely equivalently. By organization type, notable differences include a comparatively higher rating for "research and development" by the research group and a higher rating for "learning with market growth" by the other private-sector wind group. The other organizational group rates "eased wind project and transmission siting" comparatively higher. Respondents who expressed familiarity with Europe rate "eased wind project and transmission siting" somewhat higher than other respondents, while respondents with knowledge of markets outside of Europe and North America again tend to emphasize "learning with market growth" and, in some cases, "eased wind project and transmission siting."

3.7 Comparison of Expert-Specified LCOE Reduction to Broader Literature

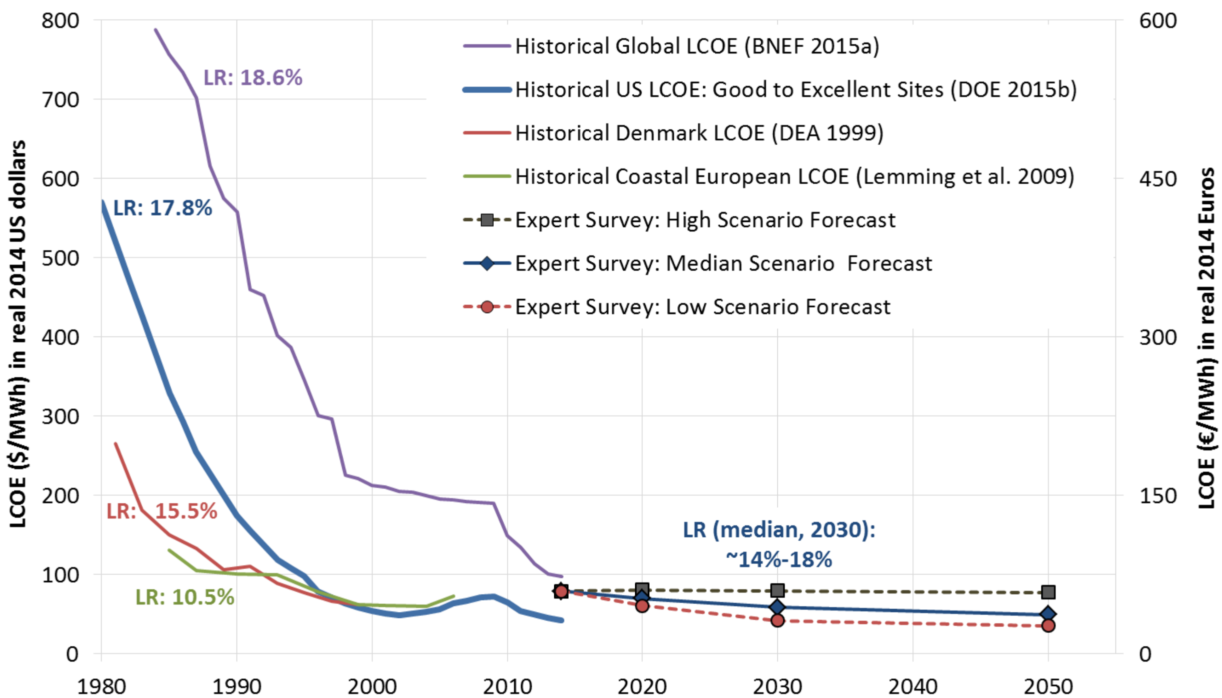
As indicated earlier, a considerable amount of literature has sought to track and understand historical wind energy cost trends and/or estimate future costs—using learning curves, engineering analysis, and/or various forms of expert knowledge. Here we compare expert survey results on LCOE expectations with: (1) past LCOE trends, and (2) other forecasts of future LCOE. Notwithstanding the sizable range in LCOE estimates reflected in the expert survey results, those results are found to be broadly consistent with historical LCOE trends—at least for onshore wind. Results are also broadly consistent with many other wind energy cost forecasts, though with some notable caveats.

3.7.1 Historical LCOE and Learning Estimates

A substantial literature has sought to estimate historical learning rates for onshore wind energy. Summaries of that literature are available in (Lindman & Söderholm, 2012; Rubin et al., 2015; R. Wiser et al., 2011). Estimated learning rates (LRs) span an enormous range, from a 33% cost decline with each doubling of cumulative production (LR = 33%) to a cost increase of 11% for each doubling (LR = -11%). The wide variation can be partly explained by differences in learning model specification (e.g., whether cumulative production is the only driver considered), assumed geographic scope of learning (e.g., whether global or country-level cumulative installations are used), and the period of the analysis (R. Wiser et al., 2011). Additionally, Rubin et al. (2015) shows that, with few exceptions, learning rates have been estimated based on turbine- or project-level CapEx, and have rarely focused on the more decision-relevant metric of LCOE. Recent CapEx learning rates have been estimated at 6-9% (BNEF, 2015b; Criqui, Mima, Menanteau, & Kitous, 2015; Ryan Wiser & Bolinger, 2015), but the use of learning rates solely based on individual factors that influence LCOE can be misleading.

To compare properly expert survey results with historical LCOE and LCOE learning rates, Figure 31 depicts four published estimates of historical onshore wind energy LCOE. Each of those estimates is derived differently, and each covers distinct geographies. Also included in the graphic are the implicit single-factor learning rates associated with the four historical LCOE trajectories, each based on historical growth in cumulative global wind capacity. The absolute values of the LCOE estimates span a considerable range—reflecting the different methods, periods, assumptions, and geographies involved—with effective onshore wind LCOE learning rates ranging from 10.5% to 18.6%.

Our expert survey did not ask respondents for their estimates of cumulative wind deployment in the low-, median-, or high-LCOE scenarios. However, a reasonable range of projections for cumulative wind capacity from (BNEF, 2015a; GWEC, 2014; IEA, 2015) can be applied to estimate an implicit onshore LCOE learning rate from the expert survey results of about 14%–18% when focused on median-scenario LCOE in 2030[42]; 2050 learning rate estimates are broadly consistent with this range. As indicated earlier, learning rates are an imperfect tool for understanding the drivers of past cost reduction or forecasting future costs. Moreover, elicitation results show that both deployment growth and R&D are expected to exert downward pressure on LCOE, implying that a two-factor learning curve would be a more appropriate specification. Nonetheless, the implicit single-factor learning rate embedded in the median-scenario LCOE forecast from our experts is highly consistent with past learning trends for onshore LCOE.



Note: For the expert survey results, emphasis should be placed on the relative positioning of and changes in LCOE, not on absolute magnitudes. Because the 2014 baselines shown in the figure are the median of expert responses, they do not represent any specific region of the world. For any specific region, the 2014 baselines and future absolute LCOE values would vary. For similar reasons, it is not appropriate to compare expert-survey results in terms of absolute LCOE magnitudes with the historical LCOE estimates shown on the chart for specific regions. Finally, learning rates are calculated based on a log-log relationship between LCOE and cumulative wind installations; as such, while historical learning rates closely match expected future learning predicted by the expert elicitation, visual inspection of the figure does not immediately convey that result.

Figure 31: Historical and Forecasted Onshore Wind LCOE and Learning Rates

[42] To best reflect median-scenario LCOE estimates from wind energy experts, we apply a range of projections for cumulative global wind capacity that includes the IEA (2015) "New Policies" scenario (1,046 GW in 2030), the BNEF (2015b) base scenario (1,300 GW in 2030), and the GWEC (2014) "moderate" scenario (1,480 GW). Forecasts that are higher or lower than this range would result in lower or higher learning rate estimates, respectively. Note also that we use total wind installations here, including both onshore and offshore, which implicitly presumes that onshore LCOE benefits from experience with both onshore and offshore wind deployment.

The expert survey results for onshore wind LCOE in the low scenario, on the other hand, are a bit of a departure from historical trends. Experts presumably based their low-scenario LCOE estimates, in part, on a strong forecast for wind energy growth. Even under the GWEC (2014) "advanced" scenario for wind deployment (1,900 GW in 2030; 4,040 GW in 2050), however, resulting implicit learning rates are 23% (2030) and 21% (2050)—higher than estimated historical rates of LCOE learning. Under the lower GWEC "moderate" scenario for future wind capacity, implicit learning rates are even higher: 27% (2030) and 25% (2050). To be sure, these implicit learning rates (as well as the ones calculated earlier) may overstate the actual rate of expected learning. Specifically, these rates do not account for the fact that aging wind turbines would need to be replaced over the duration of the forecast period to 2030 and—especially—2050. Were those replacement turbines considered in the cumulative wind capacity forecasts, estimated learning rates would be lower. As one example, if one assumes full repowering after a 20-year project life, then the GWEC (2014) "advanced" scenario would require a total wind turbine installation level of roughly 2,130 GW in 2030 and 5,980 GW in 2050, yielding implicit learning rates for onshore wind under the low-LCOE scenario of 22% (2030) and 18% (2050)—closer to historical learning rates, at least in the 2050 timeframe.

Turning to offshore wind, historical cost trends are mixed, with an initial reduction in costs for the first fixed-bottom offshore wind installations in the 1990s, following by steeply increasing costs in the 2000s and, most recently, some indication of cost reductions (IRENA, 2015; Smith, Rylander, Rogers, & Dugan, 2015; Voormolen, Junginger, & van Sark, 2016; Willow & Valpy, 2015). Given this history—and the limited amount of total deployment—there have been few attempts to fit a learning curve to offshore data. (van der Zwaan, Rivera-Tinoco, Lensink, & van den Oosterkamp, 2012) find a learning rate of 3%–5% when focused on CapEx, whereas (Dismukes & Upton, 2015) find little evidence of learning thus far. Others conclude that a simple learning curve cannot readily be used to explain historical cost developments (Voormolen et al., 2016). It is also unclear what learning specification might best be used to understand past trends or to forecast future ones. Offshore wind technology is distinct from onshore, and so cumulative offshore installed capacity might be reasonably viewed as the primary driver for LCOE reduction in a single-factor learning estimate. There is obvious overlap in onshore and offshore turbine-related learning, however, such that continued future onshore wind deployment might also contribute to future offshore LCOE reductions.

As with onshore wind, the expert survey did not ask respondents for their estimate of cumulative offshore wind deployment. However, when applying an *offshore-only* forecast of cumulative wind power capacity from BNEF (2016) of 123 GW by 2030, an implicit fixed-bottom offshore learning rate of 8% is estimated for the median-scenario 2030 LCOE estimates and 13% for low-scenario 2030 estimates.[43] These rates are considerably lower than those estimated previously

[43] We do not calculate implicit learning rates for floating offshore wind.

for onshore wind. In contrast, if one applies a range of projections for cumulative *total (onshore and offshore)* wind capacity from (BNEF, 2015a; GWEC, 2014; IEA, 2015) (which, while much greater in total capacity terms, leads to fewer total "doublings" of capacity given the higher starting point in 2014), then implicit LCOE learning rates from the expert survey range from about 16%–20% when focused on median LCOE in 2030. This learning rate range is somewhat higher than but closer to the range for onshore wind. Overall, these results for offshore wind suggest that experts either anticipate lower offshore-only learning (relative to learning for onshore wind) or expect learning spillovers from onshore to offshore.

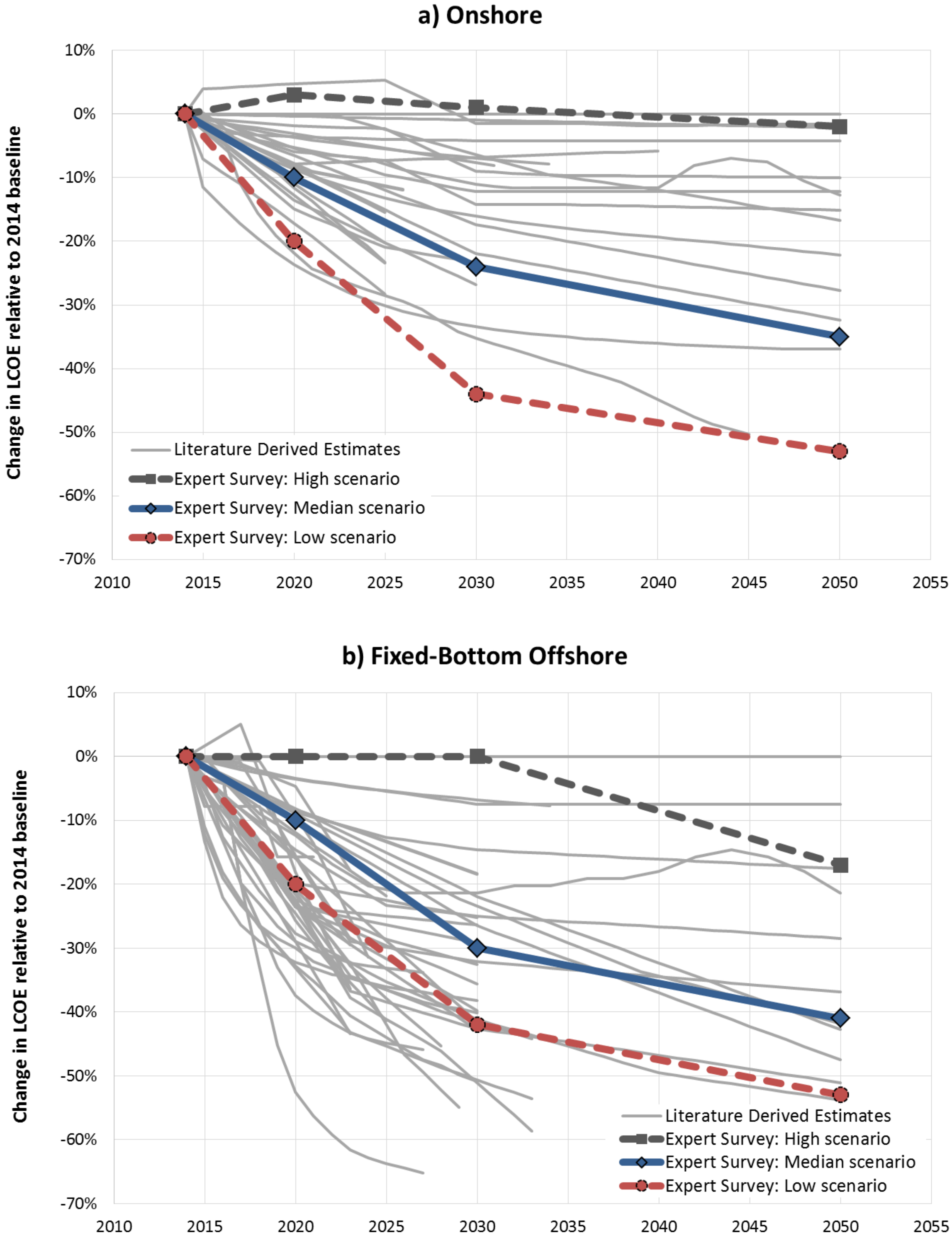
3.7.2 Forecasts for Future LCOE Reduction

It is also relevant to compare the expert elicitation results to other forecasts of LCOE change over time. Figure 32 does just that, for onshore wind and for fixed-bottom offshore wind (see Appendix C for a listing of the references from which the other forecasts were obtained).[44]

The expert survey results for onshore wind are generally within the range of other forecasts, but elicitation results tend to show greater expectations for LCOE reductions for onshore wind in the median scenario than the majority of other forecasts. The reasons for this somewhat-more aggressive set of onshore LCOE estimates from wind energy experts in the median scenario is not known. However, other forecasts are sometimes informed by published learning rates that, as noted earlier, have been primarily based on CapEx (Criqui et al., 2015). Learning rates based on CapEx alone, however, will understate LCOE-based learning given concomitant advances in capacity factor, OpEx, and other factors impacting LCOE (BNEF, 2015b). Recent estimates of CapEx-based learning (LR = 6-9%) cited earlier, for example, are well below the historical LCOE-based learning rates shown in Figure 31. As such, at least some of the broader literature might be biased low in terms of onshore wind energy LCOE forecasts due to inappropriate use of CapEx-based learning estimates (Criqui et al., 2015). Alternatively, our expert survey results could be biased in some way, or other forecasters might have tended to err on the side of conservatism for other reasons, such as a presumed decline in the learning rate over time.

The expert survey results for fixed-bottom offshore wind, meanwhile, tend to be more conservative than the broader literature, both for the median and low scenarios. Specifically, a sizable number of other forecasts anticipate steeper LCOE reductions than even the low-scenario expert survey results. As indicated earlier, offshore wind energy costs have not experienced the sizable historical reductions witnessed onshore. Those historical data points may be encouraging some conservatism among the experts, at least relative to the broader literature.

[44] We do not include a similar chart for floating offshore wind because of the limited number of unique estimates for the future cost of this technology, relative to a 2014 fixed-bottom baseline.



Note: See Appendix C for a listing of the references from which the literature-derived estimates were sourced.

Figure 32: Estimated Change in LCOE over Time for (a) Onshore and (b) Fixed-Bottom Offshore Wind Projects: Expert Survey Results vs. Other Forecasts

4. Conclusion

The wind energy industry has matured substantially since its beginnings in the 1970s, as has wind power technology. Sizable reductions in the cost of onshore wind energy have accompanied that maturation, with some experts anticipating that those reductions will also be witnessed offshore. But how much additional cost reduction is possible, both onshore and offshore? What technological and market factors are the most likely contributors to those reductions? And what broad trends might drive even greater technological advancements and cost reductions?

This study has sought to help answer these questions, leveraging the unique insights of 163 of the world's foremost wind energy experts. Specifically, we have summarized the core results of an expert elicitation survey on future wind energy costs and technology advancement possibilities, in what may be the largest single elicitation ever performed on an energy technology in terms of expert participation. Insights gained through this survey can complement other tools for evaluating cost-reduction potential, including the use of learning curves, engineering assessments, and less-formal means of synthesizing expert knowledge. Ultimately, we hope this work informs policy and planning decisions, R&D decisions, and industry investment and strategy development while improving the representation of wind energy in energy-sector planning models.

Notwithstanding the growing maturity of onshore wind and the limited evidence of historical cost reductions for offshore wind, we find that experts anticipate significant additional reductions in the levelized cost of wind energy across all three applications. As summarized in Figure 33, under the median scenario, experts anticipate 24%–30% reductions by 2030 and 35%–41% reductions by 2050. Costs could be even lower: experts predict a 10% chance that reductions will be more than 40% by 2030 and more than 50% by 2050. Though onshore wind is anticipated to remain less expensive than offshore—and fixed-bottom less expensive than floating—there are greater absolute reductions (and more uncertainty) in the long-term LCOE of offshore wind compared with onshore wind.

For onshore wind, CapEx and capacity factor improvements are expected to constitute the largest drivers of LCOE reduction. The importance of higher capacity factors is consistent with expert views on turbine characteristics, with scaling expected not only in turbine capacity ratings but also rotor diameters and hub heights. For fixed-bottom offshore wind, on the other hand, CapEx reductions and improvements in financing costs are the largest expected contributors to LCOE reduction. The relatively higher importance of CapEx and lower importance of capacity factor is consistent with expert opinions on future offshore turbine size: expected turbine capacity ratings (and hub heights) grow significantly in order to minimize CapEx, but specific power is expected to remain roughly at recent levels. Capacity factor improvements play a larger role for floating offshore wind (relative to the 2014 baseline for fixed-bottom), perhaps reflecting a belief that floating technology will tend to be deployed in windier sites as enabled by the ability to access deeper water locations. Some of the specific technology, market, and other changes expected to drive down LCOE are listed in Figure 33 and detailed earlier.

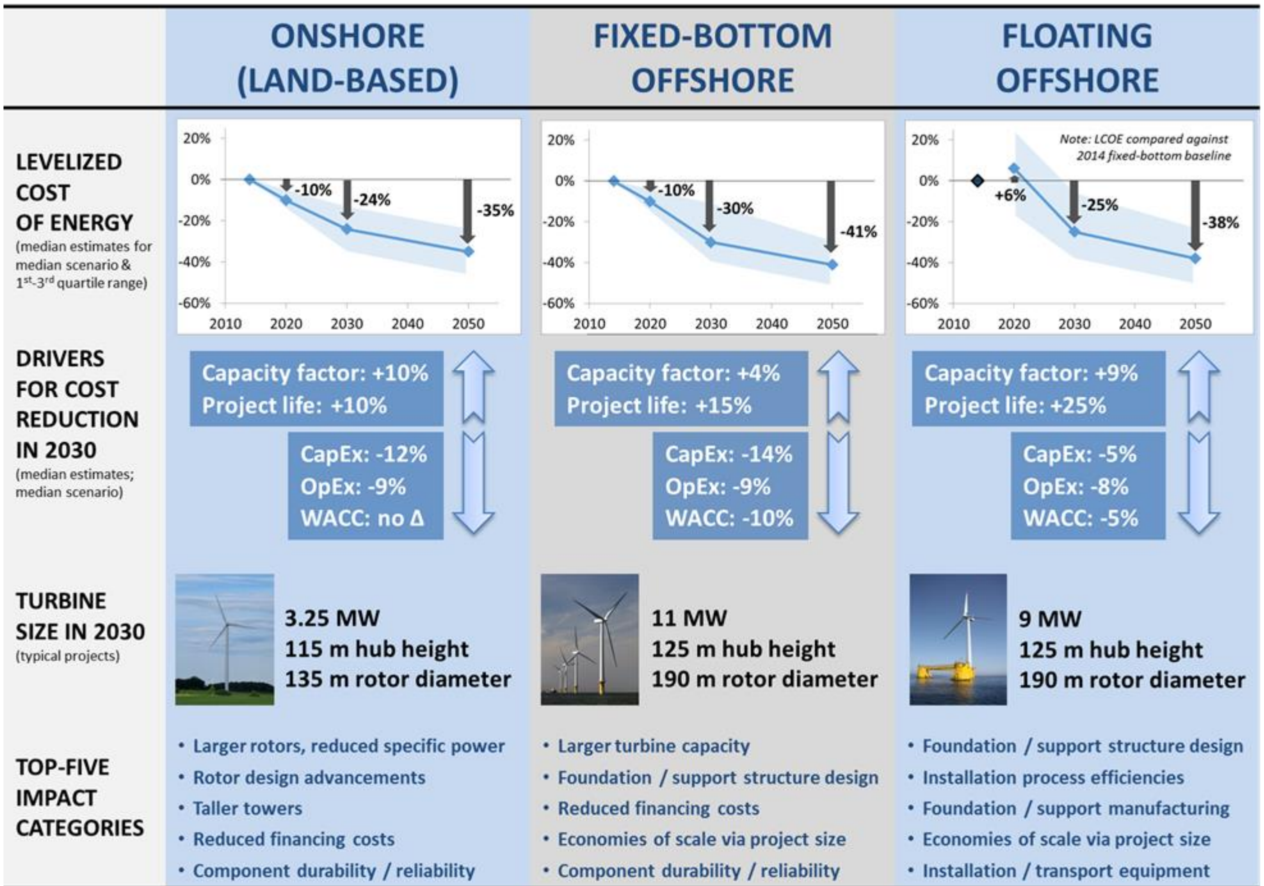


Figure 33: Summary of Expert Survey Findings

Elicitation results for onshore wind are consistent with historical LCOE learning, suggesting that properly constructed learning rates may be reasonably used to forecast future costs in more mature applications. However, the majority of the literature assessing historical learning rates for wind have emphasized only upfront capital costs, and some energy-sector and integrated-assessment models rely on those learning estimates when forecasting future costs (Criqui et al., 2015). Expert elicitation findings demonstrate that capital-cost improvements are only one means of achieving LCOE reductions, and not always the dominant one. Extrapolation of past capital-cost-based learning models therefore likely understates the opportunities for future LCOE reduction by ignoring major drivers for that reduction. This is illustrated by the fact that the elicitation-based forward-looking LCOE learning rates are twice as high as recently estimated CapEx-based learning rates for onshore wind of 6-9%, and may explain why onshore cost reduction estimates from wind experts are more aggressive than many past forecasts.

Expert survey results further illustrate the considerable uncertainty that exists across all of these variables and factors. This uncertainty is, in part, reflected in the range among expert-specified low-, median-, and high-scenario LCOE estimates. And, to some degree, managing this uncertainty is within the control of public and private decision makers: learning with market growth along with R&D, for example, are the two most significant factors in enabling the low-

LCOE scenario. Differences are also found when reviewing the range in expert-specific responses (rather than median responses). Some of the variation in expert-specific responses, meanwhile, can be explained by segmenting respondents into various categories. As presented in various text boxes earlier, for example, we find that the smaller "leading-expert" group generally expects greater wind energy cost reductions than the larger set of other respondents, whereas equipment manufacturers are sometimes more cautious about nearer-term advancement possibilities. Future work is planned to assess more thoroughly these differences in survey responses by respondent characteristics.

Conclusion of the Dissertation

Working on renewable energy cost developments has been a rewarding field for me and the continued progress in the wind and especially solar industry over the past years has been exciting to follow. The downside of working on market developments is that individual values are often already outdated as soon they are published and the next quarter commences with new statistics.

Since 2013 the German and U.S. solar sector have developed with differing dynamics: In the United States installed solar capacity has soared thanks to continued project price declines (G. Barbose & Darghouth, 2017; Bolinger & Seel, 2017), an extension of the investment tax credit until 2023, and overall very favorable solar resource conditions, to nearly $15GW_{DC}$ of new annual installations at the end of 2016. In Germany the pace of new solar installations has slowed in contrast since the heights of 2009-2012, largely due to strongly reduced remuneration levels and the introduction of annual capacity limits, to a mere tenth of U.S. annual installations. As a result, both markets are now on par with about $40GW_{DC}$ of cumulative solar capacity at the end of 2016. Even though significant progress has been made towards achieving the ambitious cost reduction targets of U.S. SunShot initiative for 2020 (leading to a second set of targets for 2030 that aim at further energy cost reductions of 50%), a cursory look seems to indicate that upfront capital costs of U.S. residential systems in 2016 continue to be nearly twice as high as their German counterparts.

It is instead utility-scale solar systems that have led the capacity explosion in the United States over the last years, and project cost declines enabled many new state markets outside of the traditional Southwest in less sunny regions. At the same time, falling prices for single-axis trackers have since promoted the increasing ubiquity of tracking capabilities, even among the northern-most installations in Minnesota. As result of these opposing trends, national average net capacity factors have stabilized around 28% over the past three years. While some U.S. developers have started to incorporate electric storage solutions into their utility-scale PV system designs, I have not yet seen a widespread deployment outside of Hawaii. Increasingly the focus among project developers seems to shift from maximizing overall net generation (and thus reducing the average LCOE) to increasing the project’s value proposition (for example via a more western orientation to deliver electricity in high-demand evening hours).

Since polling our experts on future wind energy cost reductions in late 2015, there have been frequent media reports on record-low PPA announcements for fixed-bottom offshore wind projects in Europe. While it is difficult to place these new low-cost projects exactly within our methodological framework of “typical projects” (several of them are built on the continental shelf in favorable low-depths and it is unclear whether all costs that we included in our “plant-boundary” definition are captured in the reported estimates, or whether additional incentives may have lowered the strike prices), it seems that fixed-bottom offshore LCOE are tumbling far faster in Europe than what our survey respondents predicted.

While individual statistics are prone to become quickly stale and outdated in the very dynamic environment of renewable energy costs, I have demonstrated repeatable methods in this dissertation that are hopefully of lasting value and that can be re-applied as desired.

Whereas system components for wind and solar projects have increasingly been standardized globally (although some pricing and technical differences may persist due to import tariffs or local content requirements), project design choices continue to be potentially quite distinct to capture the highest value based on local electricity demand and supply patterns, different regulatory approaches and policy incentive design. Cross-market analyses in particular can discover innovative project design approaches and business practices that may have not yet fully permeated to other markets, but that could offer significant benefits. This will hold especially true as system design becomes increasingly differentiated to capture a larger variety of value streams (e.g. ancillary service and capacity value in addition to energy value alone) and to arbitrage across high and low value hours (either via demand response or energy storage in increasingly sophisticated energy management systems).

This dissertation focused on examples of renewable energy cost reduction potentials, but equally important are complementary analyses that investigate opportunities to increase the value that can be captured by variable renewable energy projects that harness wind and solar energy. While continued cost reductions are essential given the staggering task of broad renewable energy capacity deployment to slow destructive climate change, an exclusive focus on such measures may be misleading. In an extreme scenario, non-dispatchable solar and wind resources would be caught in a vicious spiral of self-inflicted value destruction and further forced excessive cost-cutting measures in a race to the bottom as they gain larger shares in an electricity system – potentially negating benefits such as widespread employment opportunities with livable wages across a range of worker skills and vitalized communities.

Utilizing the aforementioned cross-market analyses to identify and learn from promising engineering approaches, successful business strategies, insightful market designs, or broader policy and community-based initiatives will thus become increasingly important to facilitate a continued cost- and value-effective build-out of low-carbon, renewable energy systems – even at higher penetration levels.

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Appendices

Appendix A. Survey Respondents

Respondents to the survey are listed below. If it is known that multiple individuals within an organization collaborated on a single survey response, that is noted by listing multiple names in one row of the table. Prior to survey release, a select group of “top experts” were identified. Survey participants among that group are identified with an asterisk (*) after their name.

Name(s)	Organization
John Dalsgaard Sørensen	Aalborg University
Scott Baron	Acciona
Thomas Donoghue	Acciona
Michaela O'Donohoe	Adwen
Alberto Ceña	AEE
Wallace Ebner	AIG
David Blittersdorf	All Earth Renewables
Michael Goggin	American Wind Energy Association
Bruce Bailey	AWS Truepower
Ryan Pletka	Black and Veatch
John Reilly	Bord na Mona
Sandy Butterfield	Boulder Wind Consulting
Mike Blanch, Charlie Nordstrom, Alun Roberts, Bruce Valpy*	BVG Associates
Nancy Rader	California Wind Energy Association
Denja Lekou	Center for Renewable Energy Sources
Rashid Abdul	CG Holdings
Ignacio Cruz	CIEMAT
Michael Skelly	Clean Line Energy Partners
Matt McCabe	Clear Wind
Andy Paliszewski	Consultant
Bernard Chabot	Consultant
David Milborrow	Consultant
Eize de Vries	Consultant
John Brereton	Consultant
Paul Gipe	Consultant
Edgar DeMeo	Consultant
Per Vøland	COWI
Flemming Rasmussen	Denmark Technical University
Kenneth Thomsen	Denmark Technical University
Klaus Skytte	Denmark Technical University
Lena Kitzing	Denmark Technical University
Peter Hjuler Jensen	Denmark Technical University
Poul Erik Morthorst*	Denmark Technical University
Thomas Buhl*	Denmark Technical University
Carl Sixtensson	DNV GL
Carlos Albero Fuyola	DNV GL
Clint Johnson	DNV GL

Name(s)	Organization
Johan Sandberg	DNV GL
Karen Conover	DNV GL
Peter Frohbose	DNV GL
Robert Poore*	DNV GL
Mats Vikholm*	DONG energy
Sune Strom	DONG energy
Aidan Duffy	Dublin Institute of Technology
Aisma Vitina	EA Energy Analyses
Robert Brueckmann	Eclareon
Sander Lensink	ECN
Bob Prinsen	Ecofys
David de Jager	Ecofys
James Walker*	EDF
Jeffery Ghilardi	EDF
Francisco Galván González	EDPR
Mike Finger	EDPR
Christopher Namovicz	Energy Information Agency
Andrew Scott	Energy Technologies Institute
Jasper Voormolen	Energyprofs
Kevin Standish	Envision Energy
Roberto Lacal Arantegui	European Commission Joint Research Centre
Andrew Ho	European Wind Energy Association
Joe Phillips	Everoze Partners
Mark Jonkhof	EWT
Randall Swisher	formerly American Wind Energy Association
Jorgen Lemming	formerly Denmark Technical University
Birger Madsen	formerly Navigant
Per Krogsgaard	formerly Navigant
Henrik Stiesdal*	formerly Siemens
Volker Berkhout	Fraunhofer IWES
Jochen Giebhardt	Fraunhofer IWES
Aris Karcanis	FTI
Feng Zhao	FTI
Juan Diego Diaz Vega	Gamesa
Henk-Jan Kooijman	General Electric
Seth Dunn	General Electric
Thomas Fischetti*	General Electric
Steve Sawyer	Global Wind Energy Council
Weiping Pan	Goldwind
Fort Felker	Google
Jérôme Guillet*	Green Giraffe Energy Bankers
Carlos Casco	Iberdrola
Richard Glick, Scott Haynes, Wayne Mays, Kevin Walker, Scott Winneguth	Iberdrola
Thomas Choisnet	Ideol
Matt Daprato	IHS
Maxwell Cohen	IHS

Name(s)	Organization
Philip Heptonstall*	Imperial College
Heymi Bahar, Cedric Philibert	International Energy Agency
Christian Kjaer	International Renewable Energy Agency
Michael Taylor	International Renewable Energy Agency
Gadi Hareli	Israeli Wind Energy Association
Carsten Ploug Jensen	K2 Management
Albert Jochems	Laidlaw Capital Management
Mark Bolinger	Lawrence Berkeley National Lab
Lorry Wagner	LEEDCo
Lena Neij	Lund University
Jeffrey Kehne	Magellanwind
Jim Lanard	Magellanwind
Aaron Barr	MAKE
Dan Shreve*	MAKE
Aaron Zubaty	MAP
Sam Enfield*	MAP
Jorg Kubitza	MHI Vestas
Brian Smith	National Renewable Energy Lab
Christopher Mone	National Renewable Energy Lab
Daniel Laird	National Renewable Energy Lab
Paul Veers	National Renewable Energy Lab
Rick Damiani	National Renewable Energy Lab
Robert Thresher*	National Renewable Energy Lab
Senu Sirnivas	National Renewable Energy Lab
Walt Musial	National Renewable Energy Lab
Bruce Hamilton	Navigant
Dan Brake	NextEra
Mike O'Sullivan*	NextEra
Leif Husabo	Norwegian Water Resources and Energy Directorate
Jim Lyons	NOVUS Energy Partners
Gavin Smart	Offshore Renewable Energy Catapult
Ignacio Marti Perez	Offshore Renewable Energy Catapult
Andreas Wagner	Offshore Wind Energy Foundation
John Calaway	Pattern
Joshua Weinstein	Principal Power Inc
Brian Healer	RES
Rob Morgan	RES
Brian Naughton	Sandia National Lab
Steve Dayney	Senvion
Henning Kruse	Siemens
Jason Folsom	Siemens
John Amos*	Siemens
Lanny Kirkpatrick	Siemens
Liz Salerno	Siemens
Morten Rasmussen	Siemens
Peder Nickelsen	Siemens

Name(s)	Organization
Iver Bakken Sperstad	SINTEF Energy Research
Jan Schelling	Statkraft
Eirik Byklum	Statoil
Finn Gunnar Nielsen	Statoil
Jan-Fredrik Stadaas*	Statoil
Duncan Koerbel*	Suzlon
Reto Rigassi	Swiss Wind Energy Association
Jim O'sullivan	Technip
Andy Swift	Texas Tech University
Jurgen Weiss	The Brattle Group
Alastair Dutton*	The Crown Estate
Craig Christenson	Turbine Technology Partners
Doug Pfeister	TUV-SUD PMSS
Daniel Beals	U.S. Department of Energy
Greg Matzat	U.S. Department of Energy
Jim Ahlgrimm	U.S. Department of Energy
Mike Derby	U.S. Department of Energy
Mike Robinson*	U.S. Department of Energy
Nick Johnson	U.S. Department of Energy
Patrick Gilman	U.S. Department of Energy
Rich Tusing	U.S. Department of Energy
Case Van Dam	UC Davis
Steve Clemmer	Union of Concerned Scientists
Jimmy Murphy	University College Cork
Stephanie McClellan	University of Delaware
Barry Butler	University of Iowa
Robert de Bruin, Dolf Elsevier van Griethuysen	Van Oord
Johannes Kammer*	Vattenfall
Anurag Gupta	Vestas
Chris Brown	Vestas
Jorge Magalhaes	Vestas
Margaret Montanez*	Vestas
Mark Ahlstrom*	WindLogics
Bob Gates	Windstream Properties

Appendix B. Additional Survey Results

This appendix includes a number of additional figures and tables based on the survey results:

- **Absolute LCOE, 2014-2050:** The main report includes a figure (Figure 23) depicting estimated absolute LCOE values for all three wind energy applications, over time, on a single plot, focusing only on median-scenario LCOE estimates, and showing the median and range of expert responses. This appendix includes two similar figures, one focused on the low-scenario LCOE and the other one on the high-scenario LCOE.

- **LCOE and LCOE Components, 2014 and 2030:** This appendix includes three detailed figures for LCOE and the five components of LCOE for the baseline year of 2014 and 2030, one for each of the wind applications. These figures show the mean, median, and range of expert estimates in box-and-whiskers plots. In these plots, shaded grey boxes show the 1st to 3rd quartile values, and the "whiskers" generally show the minimum to maximum assessed values, except where there are outlier values, which appears as small circles. Outliers are defined as values that are less than the 1st quartile or greater than the 3rd quartile by more than 1.5 times the inter-quartile difference. Most experts endorsed the default 2014 baseline values—as a result, the median values for 2014 as well as the 25th and 75th percentiles are all equal to the default baseline values, and all cases where experts defined baseline values different from the default values appear as outliers.

- **Turbine Characteristics, 2030:** This appendix includes histograms of respondent assessments of turbine nameplate capacity, hub height, and rotor diameter, for all three wind energy applications. Implied specific power is also presented, in the form of a box-and-whiskers plot; unlike in (2), above, however, outlier values are not presented in this chart, and so the whiskers do not necessarily represent absolute maximum or minimum respondent values.

- **Wind Technology, Market, and Other Changes:** This appendix provides survey results for all 28 wind technology, market, and other changes that might impact LCOE by 2030, for each of the three wind applications. It also lists the expert-provided "write-in" responses to the question, separately for onshore, fixed-bottom offshore, and floating offshore wind.

- **Broad Drivers for Lower LCOE:** This appendix lists the expert-provided "write-in" responses to the question about broad drivers for achieving low LCOE estimates in 2030, for onshore and fixed-bottom offshore wind projects.

- **Differences among Respondent Groups:** This appendix includes a series of color coded tables that provide additional detail on the results found in text boxes and elsewhere throughout the main body of the report, summarizing key differences in expert responses based on various respondent groupings.

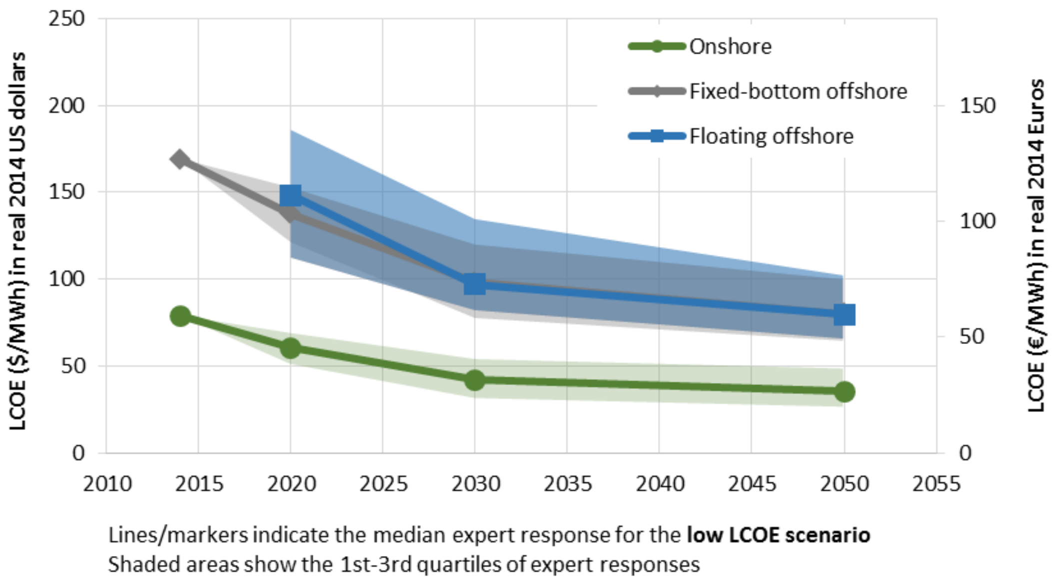

Figure A –1. Expert Estimates of Low-Scenario LCOE for All Three Wind Applications

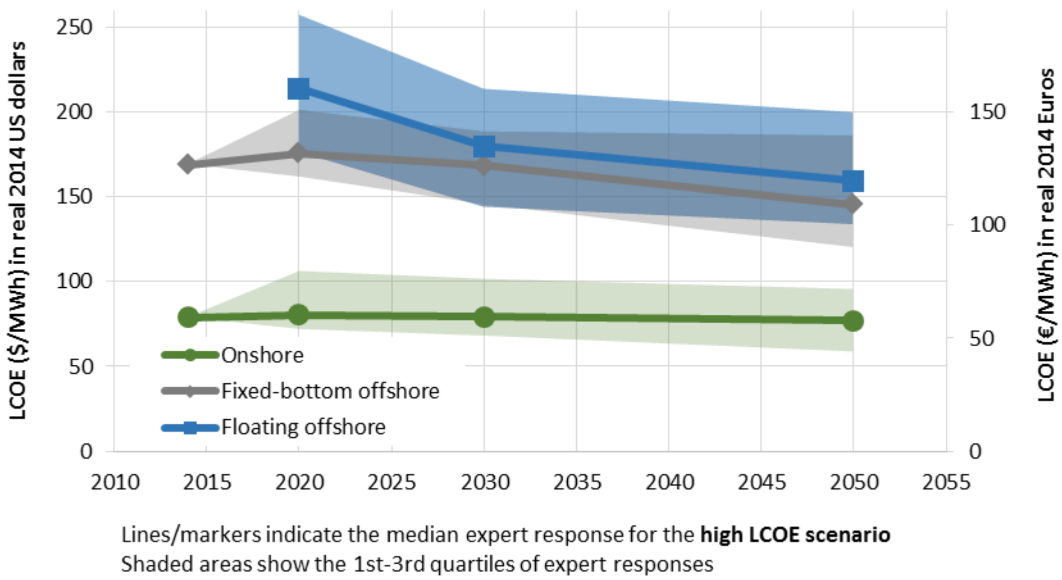

Figure A – 2. Expert Estimates of High-Scenario LCOE for All Three Wind Applications

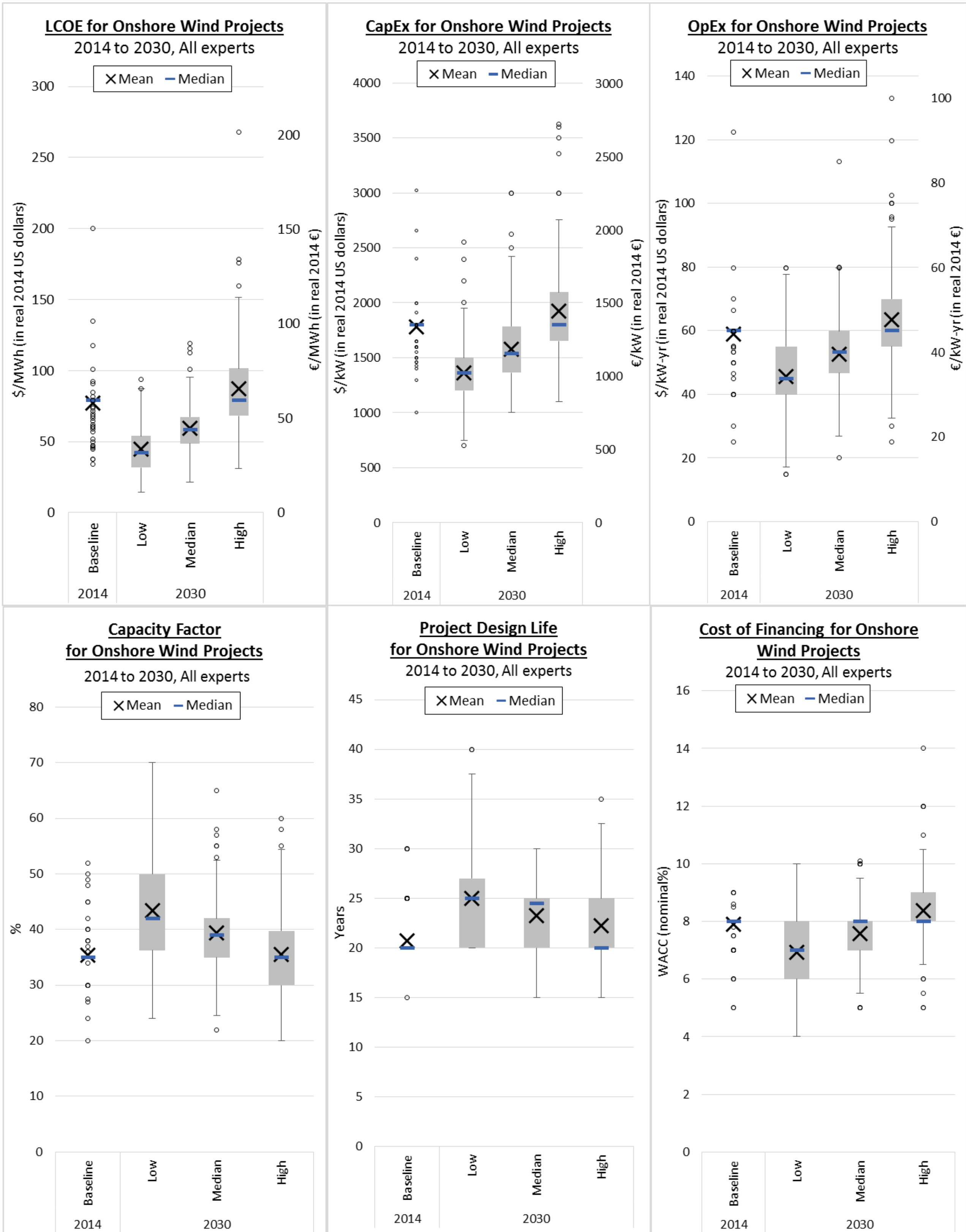

Figure A – 3. Expert Estimates of LCOE and LCOE Components for Onshore Wind in 2014 and 2030

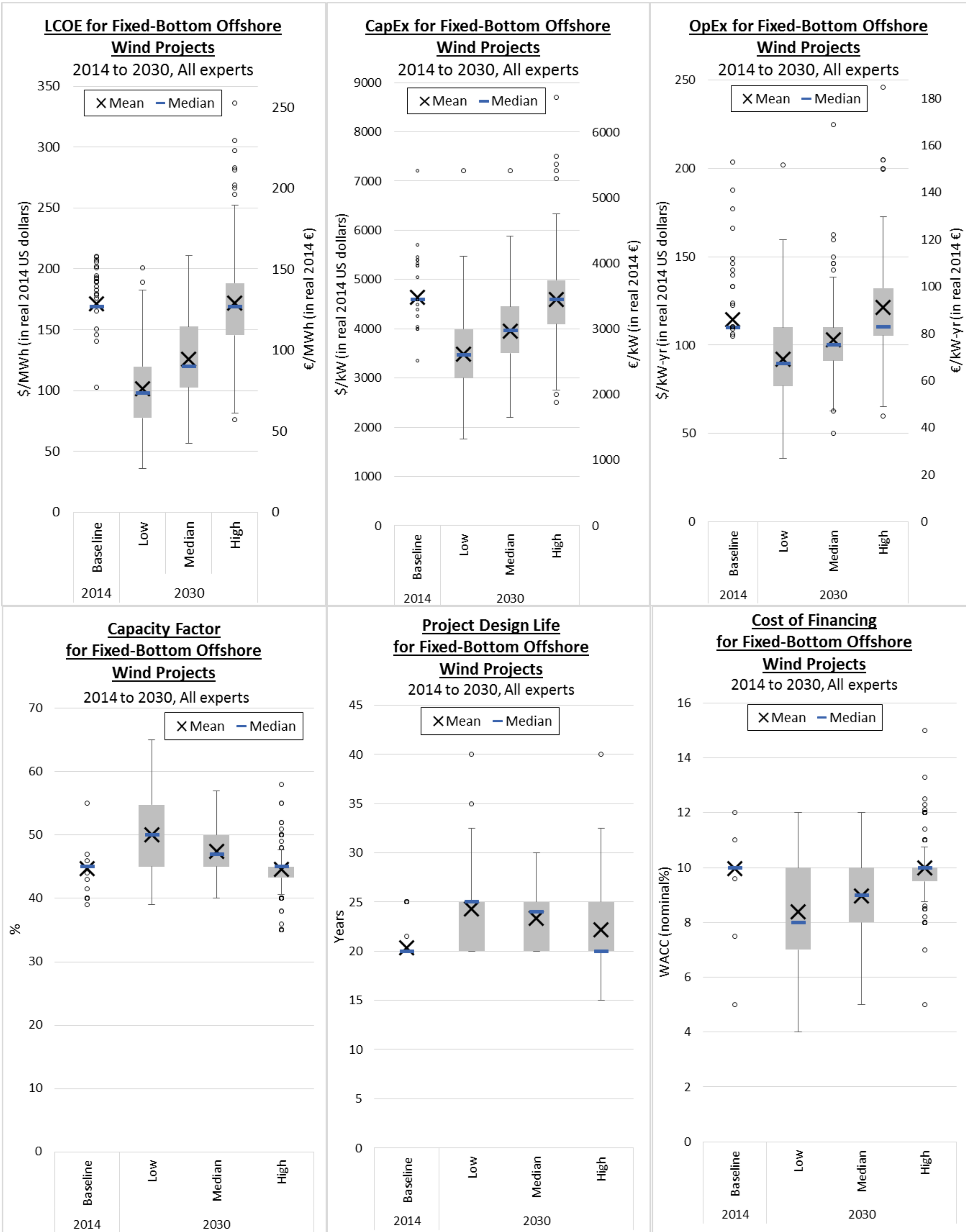

Figure A – 4. Expert Estimates of LCOE and LCOE Components for Fixed-Bottom Offshore Wind in 2014 and 2030

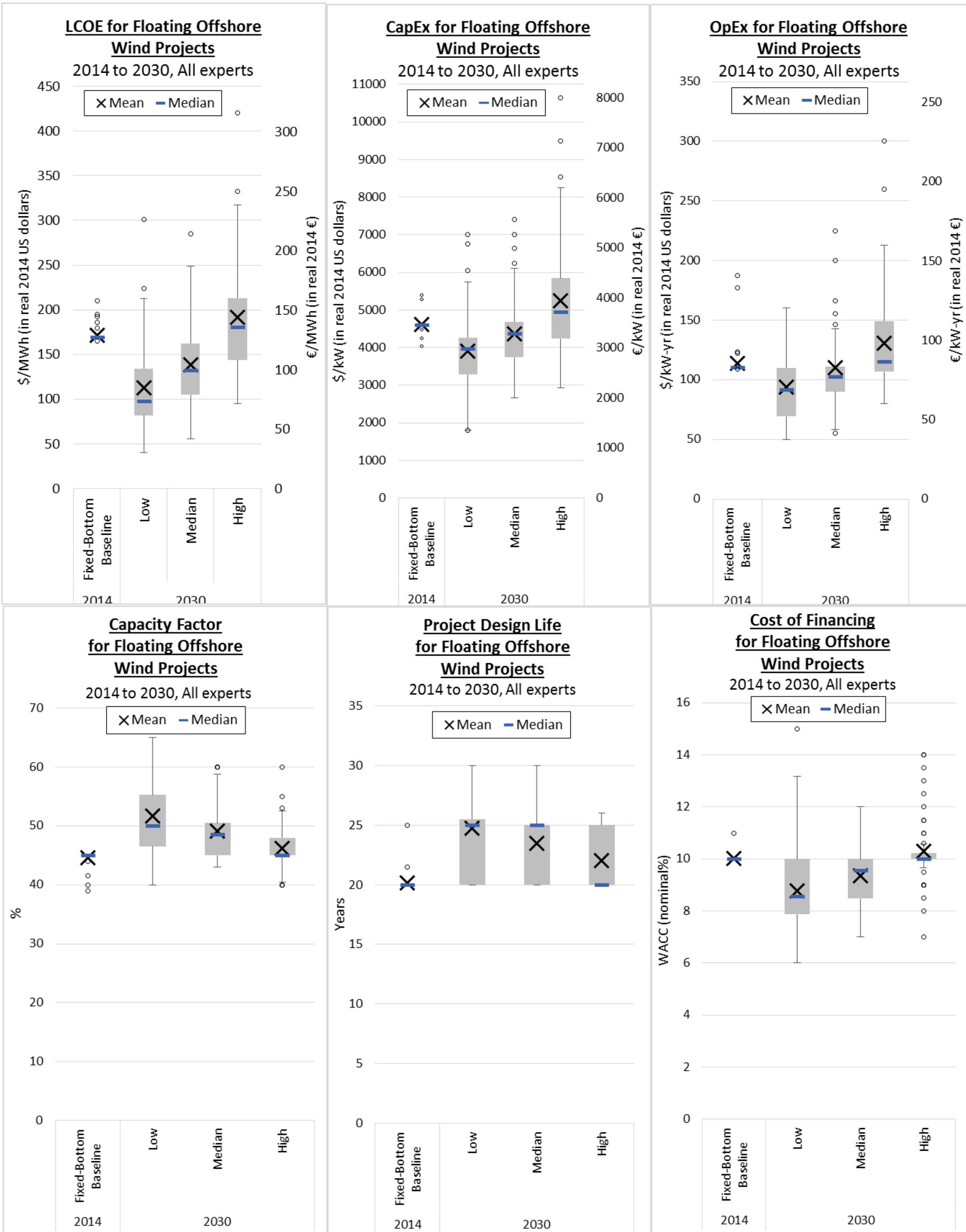

Figure A – 5. Expert Estimates of LCOE and LCOE Components for Floating Offshore Wind in 2030, Compared to Fixed-Bottom 2014 Baseline

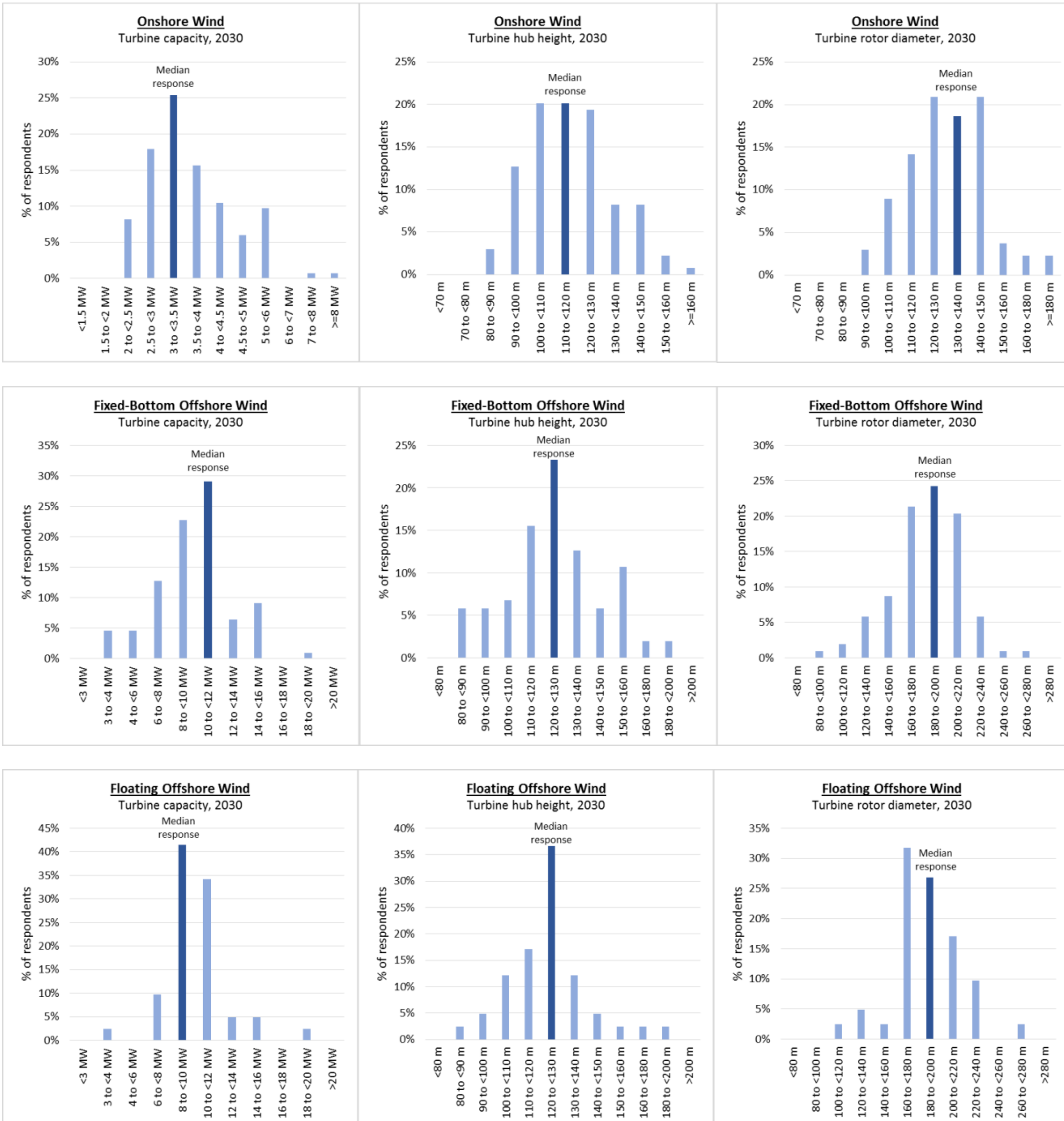

Figure A – 6. Wind Turbine Characteristics in 2030 for Onshore, Fixed-Bottom Offshore, and Floating Offshore Wind Projects

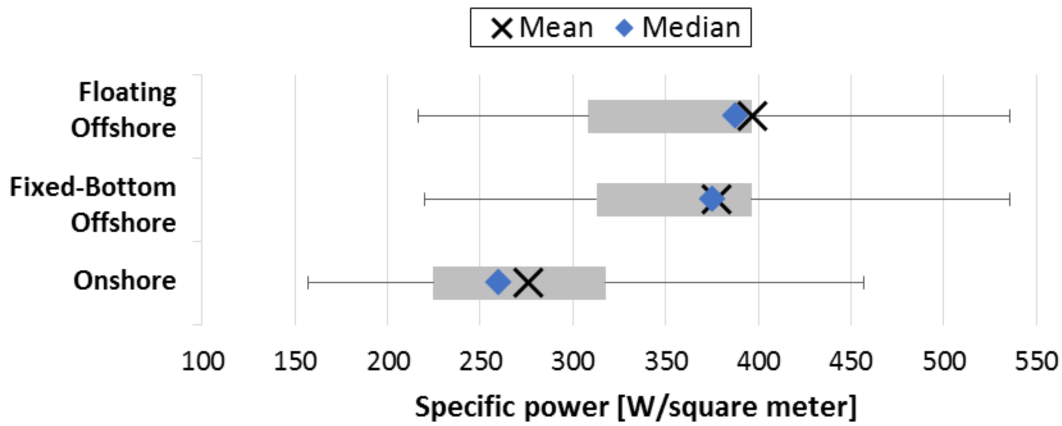

Figure A – 7. Wind Turbine Specific Power in 2030 for Onshore, Fixed-Bottom Offshore, and Floating Offshore Wind Projects

Table A – 1. Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE of Onshore Wind Projects by 2030

Wind technology, market, or other change	Percentage of experts rating item "Large expected impact"	Mean Rating, Rating Distribution 3- large impact 2- median impact 1- small impact 0- no impact	
Increased rotor diameter such that specific power declines	58%	2.5	
Rotor design advancements	45%	2.3	
Increased tower height	33%	2.2	
Reduced financing costs and project contingencies due to lower risk profile, greater accuracy in energy production estimates, improved risk management, and increased industry experience and standardization	32%	2.1	
Improved component durability and reliability	31%	2.1	
Increased energy production due to new transmission to higher wind speed sites	31%	2.0	
Extended turbine design lifetime	29%	2.0	
Operating efficiencies to increase plant performance	28%	2.0	
Increased turbine capacity and rotor diameter (thereby maintaining specific power)	28%	1.9	
Turbine and component manufacturing standardization, efficiencies, and volume	27%	2.0	
Improved plant-level layout through understanding of complex flow and high-resolution micro-siting	27%	2.0	
Integrated turbine-level system design optimization	23%	2.0	
Increased competition among suppliers of components, turbines, Balance of Plant services, installation, and operations and maintenance	21%	1.8	
Large variety of alternative turbine designs to suit site-specific conditions	17%	1.7	
Innovative non-conventional plant-level layouts that could involve mixed turbine ratings, hub heights and rotor diameters	17%	1.6	
Maintenance process efficiencies	17%	1.8	
Tower design advancements	14%	1.8	
Economies of scale through increased project size	12%	1.6	
Installation and transportation equipment advancements	12%	1.7	
Nacelle components design advancements	12%	1.6	
Innovative non-conventional turbine designs	12%	1.2	
Maintenance equipment advancements	10%	1.6	
Foundation and support structure manufacturing standardization, efficiencies, and volume	10%	1.5	
Foundation and support structure design advancements	10%	1.3	
Reduced total development costs and risks from greater transparency and certainty around siting and permitting approval timelines and procedures	9%	1.5	
Installation process efficiencies	9%	1.4	
Reduced fixed operating costs, excluding maintenance	5%	1.3	
Lower decommissioning costs	1%	0.8	

Table A – 2. Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE of Fixed-Bottom Offshore Wind Projects by 2030

Wind technology, market, or other change	Percentage of experts rating item "Large expected impact"	Mean Rating, Rating Distribution 3- large impact 2- median impact 1- small impact 0- no impact	
Increased turbine capacity and rotor diameter (thereby maintaining specific power)	55%	2.4	
Foundation and support structure design advancements	53%	2.4	
Reduced financing costs and project contingencies due to lower risk profile, greater accuracy in energy production estimates, improved risk management, and increased industry experience and standardization	49%	2.4	
Economies of scale through increased project size	48%	2.3	
Improved component durability and reliability	48%	2.3	
Installation process efficiencies	46%	2.4	
Installation and transportation equipment advancements	44%	2.3	
Foundation and support structure manufacturing standardization, efficiencies, and volume	43%	2.2	
Extended turbine design lifetime	36%	2.2	
Turbine and component manufacturing standardization, efficiencies, and volume	36%	2.1	
Increased competition among suppliers of components, turbines, Balance of Plant services, installation, and operations and maintenance	35%	2.1	
Integrated turbine-level system design optimization	33%	2.1	
Rotor design advancements	32%	2.1	
Maintenance process efficiencies	32%	2.2	
Maintenance equipment advancements	30%	2.0	
Operating efficiencies to increase plant performance	29%	2.1	
Increased rotor diameter such that specific power declines	27%	2.0	
Reduced total development costs and risks from greater transparency and certainty around siting and permitting approval timelines and procedures	25%	1.9	
Increased energy production due to new transmission to higher wind speed sites	21%	1.7	
Improved plant-level layout through understanding of complex flow and high-resolution micro-siting	21%	1.8	
Nacelle components design advancements	19%	1.9	
Innovative non-conventional turbine designs	17%	1.5	
Tower design advancements	12%	1.5	
Reduced fixed operating costs, excluding maintenance	10%	1.5	
Increased tower height	6%	1.3	
Innovative non-conventional plant-level layouts that could involve mixed turbine ratings, hub heights and rotor diameters	5%	1.1	
Large variety of alternative turbine designs to suit site-specific conditions	5%	1.2	
Lower decommissioning costs	2%	0.9	

Table A – 3. Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE of Floating Offshore Wind Projects by 2030

Wind technology, market, or other change	Percentage of experts rating item "Large expected impact"	Mean Rating , Rating Distribution 3- large impact 2- median impact 1- small impact 0- no impact	
Foundation and support structure design advancements	80%	2.8	
Installation process efficiencies	78%	2.7	
Foundation and support structure manufacturing standardization, efficiencies, and volume	68%	2.6	
Economies of scale through increased project size	65%	2.6	
Installation and transportation equipment advancements	63%	2.5	
Increased turbine capacity and rotor diameter (thereby maintaining specific power)	59%	2.4	
Improved component durability and reliability	58%	2.5	
Reduced financing costs and project contingencies due to lower risk profile, greater accuracy in energy production estimates, improved risk management, and increased industry experience and standardization	46%	2.3	
Increased competition among suppliers of components, turbines, Balance of Plant services, installation, and operations and maintenance	46%	2.2	
Rotor design advancements	45%	2.1	
Integrated turbine-level system design optimization	44%	2.3	
Turbine and component manufacturing standardization, efficiencies, and volume	40%	2.3	
Extended turbine design lifetime	39%	2.2	
Maintenance process efficiencies	35%	2.2	
Innovative non-conventional turbine designs	34%	1.9	
Increased rotor diameter such that specific power declines	32%	2.1	
Increased energy production due to new transmission to higher wind speed sites	29%	1.7	
Tower design advancements	28%	1.9	
Nacelle components design advancements	28%	1.8	
Maintenance equipment advancements	25%	2.0	
Reduced total development costs and risks from greater transparency and certainty around siting and permitting approval timelines and procedures	20%	1.9	
Operating efficiencies to increase plant performance	18%	2.0	
Improved plant-level layout through understanding of complex flow and high-resolution micro-siting	15%	1.8	
Increased tower height	15%	1.4	
Large variety of alternative turbine designs to suit site-specific conditions	12%	1.2	
Innovative non-conventional plant-level layouts that could involve mixed turbine ratings, hub heights and rotor diameters	12%	1.2	
Reduced fixed operating costs, excluding maintenance	8%	1.4	
Lower decommissioning costs	3%	0.8	

Table A – 4. Expert-Added Wind Technology, Market, and Other Changes that Are Expected to Reduce LCOE of Onshore Wind Projects by 2030

Access to high wind class due to taller towers and larger rotors	Hybrid projects, mainly PV, better use of electrical infrastructure
Advanced controls with smart rotors	Improved control strategy
Advanced feed-in tariffs adapted to the quality of sites and giving incentives to use wind turbines with high specific area Su (m2/kW) values	Improved operational forecasts
Advanced storage systems	Increased lifetime of wind turbine generators
Advanced wind plant control	Lighter structures, less material
Better wind feedback from i.e. lidar measuring in front of the turbine	Lower financing costs
Carbon blades	Modularity in electric generators and power electronics
Carbon tax	Modularization
Continuing increase in specific area Su ratio (m2/kW)	New climate change agreement
Cross border infrastructure	New electricity demand
Cross-country alignment of regulations	Optimization of blade design
Dispersed energy solutions and comprehensive wind farm controls balancing annual energy productions, grid quality, loads, and noise	Plant control systems
Disruptive new airborne wind energy systems	Reduced energy storage costs
Electrical system efficiency improvements	Reduced tax credits , lower cost of capital
Energy storage technologies combined with wind power to provide more stability to the grid	Regulation
Enhanced power-system flexibility that reduces curtailment	Regulatory stability
Farm control strategies	Segmented blades to reduce transportation cost
Full transparency, public access, and good data based on actual projects' performances and costs	Smarter modularized tower designs to ease transport logistics
Global energy market reform	Tailored gearbox designs for wind turbines
Hardware reliability improvements	High altitude kite turbine technology
Wind plant control to enable new plant layout options and efficiencies	Wind plant control to optimize production and minimize losses

Table A – 5. Expert-Added Wind Technology, Market, and Other Changes that Are Expected to Reduce LCOE of Fixed-Bottom Offshore Wind Projects by 2030

Advanced wind plant control	Improvements in electrical collection systems
Carbon rotors at low cost	Inland Sea developments
Coastal State energy policies	Integrated Logistics
Cross-border alignment of regulation for greater development flexibility	Large vessel strategy
Departure from onshore technology with emphasis on reducing offshore installation and maintenance	Less complex sites
Design of turbines for offshore installation	Market introduction of floating systems
Development of foundations for rocky seabeds	Nearshore, shallow, good wind, good geology sites
Development of interest rates	New business models
Disruptive new airborne wind energy systems	New custom design procedures for wind turbine gearboxes
Electricity demand	Smarter foundation design i.e. jackets with suction-buckets
Far-shore site development	Stable energy policy framework in support of offshore wind
Higher transmission voltage	Tailored installation vessels

Table A – 6. Expert-Added Wind Technology, Market, and Other Changes that Are Expected to Reduce LCOE of Floating Offshore Wind Projects by 2030

Advanced wind plant control with dynamic turbine positioning	Float out installation
Aggressive GHG reduction policies	Integration with fishing industry
Aggressive GHG reduction policies in Pacific Rim jurisdictions opening new markets for large-scale development	Integration with Oil & Gas industry (e.g. the WIn WIn project)
Carbon rotors at low cost	Large scale energy storage technology providing grid stability
Coastal State energy policies	Mooring components qualification
Creating public support through information campaigns and demonstrating that floating wind can be built beyond the horizon	Nearshore, good wind sites
Departure from onshore and fixed offshore technologies to take advantage of unique system opportunities available to pre-fabricated floating units	New customized design procedures for wind turbine gearboxes
Dry dock fabrication	Rational federal tax policy
Electricity demand	

Table A – 7. Expert-Added Broad Drivers to Move from Median to Low LCOE Scenario for Onshore Wind in 2030

A carbon fiber cost reduction breakthrough will enable lighter weight and very large rotor turbines	Larger rotors compared to generator
Availability of IEC3 and IEC2 wind turbines with increasing high and very high specific area ratios Su (m2/kW), delivering high and very high capacity factors on IEC3 and IEC2 sites (or from 55 to 85 m/s average at hub height)	Low natural gas prices and possible withdrawal of subsidies force turbine vendors and purchasers to lower installed costs
Cheaper financing: stable regulatory frameworks and increasing familiarity with risks allow for cheaper types of capital, with longer term horizon	Lower cost of financing as offshore wind becomes more like other utility projects
Common components and systems and modules	R&D incremental improvements leading to efficiency in O&M
Cost reduction of longer blades and taller towers	Reduced hurdle rates
Increased economic life of projects	Robust, stable policy driving markets for wind
Increased net capacity factor through technology and manufacturing innovation	Standardization and modularization
Integrated design of wind farms with holistic approach and system optimization, and continuous improvement of wind detection and capture as well as improved reliability of wind farm plants	

Table A – 8. Expert-Added Broad Drivers to Move from Median to Low LCOE Scenario for Fixed-Bottom Offshore Wind in 2030

A carbon fiber cost reduction breakthrough will enable lighter weight and very large rotor turbines	Increased turbine rating (yield)
Cheaper financing: stable regulatory frameworks and increasing familiarity with risks allow for cheaper types of capital, with longer term horizon	Lower costs of capital as per previous
Gigawatts of development	Realistic project pipeline with appropriate support at the state and federal level
Increase of project design life over 30 years	Site selection: nearshore, shallow, good wind, good geology

Table A – 9. Estimated Change in LCOE over Time for Onshore Wind Projects, by Respondent Group

Onshore wind (LCOE relative to expert-specific 2014 baseline)											
Respondent Group		Number of respondents	Median scenario for typical LCOE (median expert response)			Low scenario for typical LCOE (median expert response)			High scenario for typical LCOE (median expert response)		
			2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
All		134	**-10%**	**-24%**	**-35%**	**-20%**	**-44%**	**-53%**	**3%**	**1%**	**-2%**
By Lead / Larger group	Leading	17	-13%	-27%	-48%	-26%	-57%	-66%	0%	0%	-7%
	Larger	117	-10%	-24%	-35%	-19%	-44%	-52%	3%	2%	-1%
By type of organization	Research	38	-9%	-25%	-31%	-21%	-44%	-50%	7%	10%	1%
	Wind deployment	22	-10%	-22%	-34%	-21%	-43%	-50%	0%	1%	-1%
	Equipment manufacturer	22	-12%	-23%	-36%	-21%	-40%	-53%	-3%	0%	-10%
	Other private sector	39	-10%	-26%	-37%	-18%	-48%	-54%	5%	7%	0%
	Other	13	-10%	-24%	-34%	-20%	-42%	-47%	0%	0%	-2%
By applications evaluated	Onshore only	52	-9%	-24%	-36%	-19%	-43%	-52%	4%	2%	3%
	Both onshore and offshore	82	-11%	-24%	-35%	-21%	-44%	-54%	3%	1%	-5%
By type of expertise	Wind energy markets	94	-10%	-27%	-38%	-21%	-46%	-54%	1%	0%	-2%
	Systems level	74	-11%	-26%	-38%	-21%	-44%	-53%	1%	0%	-6%
	Subsystem level	36	-8%	-24%	-34%	-21%	-44%	-53%	5%	0%	-4%
By familiarity with region	North American	93	-10%	-25%	-38%	-22%	-46%	-55%	2%	0%	-2%
	Europe	77	-10%	-23%	-32%	-21%	-44%	-53%	5%	5%	-2%
	Asia	22	-12%	-27%	-40%	-27%	-49%	-55%	33%	4%	9%
	Latin America	24	-8%	-19%	-34%	-22%	-37%	-54%	1%	0%	0%
	Middle East and Africa	6	-11%	-24%	-30%	-24%	-54%	-50%	17%	-5%	-6%

Note: Colors refer to whether and the degree to which the LCOE estimate is lower (green) or higher (red) than for "all" respondents

Table A – 10. Estimated Change in LCOE over Time for Fixed-Bottom Offshore Wind Projects, by Respondent Group

Fixed-Bottom Offshore wind (LCOE relative to expert-specific 2014 baseline)											
Respondent Group		Number of respondents	Median scenario for typical LCOE (median expert response)			Low scenario for typical LCOE (median expert response)			High scenario for typical LCOE (median expert response)		
			2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
All		110	**-10%**	**-30%**	**-41%**	**-20%**	**-43%**	**-53%**	**0%**	**0%**	**-17%**
By Lead / Larger group	Leading	15	-15%	-35%	-51%	-29%	-53%	-62%	8%	-3%	-21%
	Larger	95	-10%	-29%	-40%	-19%	-42%	-53%	0%	0%	-15%
By type of organization	Research	38	-10%	-26%	-39%	-20%	-43%	-51%	6%	0%	-12%
	Wind deployment	16	-11%	-36%	-45%	-23%	-53%	-58%	-4%	-12%	-25%
	Equipment manufacturer	12	-4%	-9%	-41%	-7%	-32%	-51%	3%	0%	-11%
	Other private sector	32	-12%	-29%	-40%	-20%	-43%	-55%	0%	0%	-16%
	Other	12	-10%	-32%	-41%	-17%	-43%	-54%	-3%	-4%	-22%
By applications evaluated	Offshore only	28	-11%	-36%	-44%	-24%	-49%	-56%	-2%	-12%	-22%
	Both onshore and offshore	82	-10%	-28%	-39%	-18%	-42%	-53%	2%	0%	-14%
By type of expertise	Wind energy markets	77	-12%	-31%	-41%	-21%	-45%	-55%	-1%	0%	-19%
	Systems level	59	-10%	-31%	-41%	-19%	-43%	-54%	0%	0%	-17%
	Subsystem level	30	-10%	-29%	-39%	-18%	-43%	-53%	2%	1%	-13%
By familiarity with region	North American	65	-8%	-27%	-39%	-18%	-42%	-53%	0%	0%	-15%
	Europe	79	-11%	-32%	-42%	-20%	-43%	-53%	1%	0%	-16%
	Asia	21	-14%	-29%	-44%	-26%	-47%	-56%	-1%	-4%	-23%
	Latin America	11	-11%	-28%	-39%	-15%	-42%	-52%	-1%	0%	-28%
	Middle East and Africa	6	-6%	-25%	-38%	-10%	-37%	-53%	-1%	-3%	-17%

Note: Colors refer to whether and the degree to which the LCOE estimate is lower (green) or higher (red) than for "all" respondents

Table A – 11. Estimated Change in LCOE over Time for Floating Offshore Wind Projects, by Respondent Group

Floating Offshore wind (LCOE relative to expert-specific 2014 baseline)											
Respondent Group		Number of respondents	Median scenario for typical LCOE (median expert response)			Low scenario for typical LCOE (median expert response)			High scenario for typical LCOE (median expert response)		
			2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
All		44	**6%**	**-25%**	**-38%**	**-11%**	**-45%**	**-53%**	**25%**	**5%**	**-6%**
By Lead / Larger group	Leading	6	-5%	-38%	-50%	-23%	-54%	-64%	28%	2%	-13%
	Larger	38	7%	-15%	-31%	-11%	-40%	-50%	23%	5%	-5%
By type of organization	Research	17	7%	-26%	-31%	-11%	-45%	-48%	18%	8%	-4%
	Wind deployment	7	5%	-25%	-38%	-13%	-47%	-55%	28%	5%	-9%
	Equipment manufacturer	0	NA	NA	NA	NA	NA	NA	NA	NA	NA
	Other private sector	15	5%	-20%	-39%	-14%	-44%	-53%	19%	0%	-5%
	Other	5	13%	-15%	-44%	-9%	-39%	-55%	29%	9%	-6%
By applications evaluated	Offshore only	13	8%	-25%	-39%	-11%	-45%	-56%	25%	5%	-9%
	Both onshore and offshore	31	5%	-20%	-31%	-11%	-44%	-52%	24%	4%	-5%
By type of expertise	Wind energy markets	29	5%	-31%	-42%	-20%	-45%	-53%	19%	0%	-12%
	Systems level	31	6%	-25%	-38%	-10%	-45%	-53%	26%	5%	-6%
	Subsystem level	16	0%	-17%	-31%	-11%	-43%	-48%	13%	4%	-4%
By familiarity with region	North American	27	5%	-20%	-31%	-11%	-45%	-53%	22%	4%	-5%
	Europe	31	8%	-15%	-38%	-11%	-40%	-53%	28%	13%	-5%
	Asia	9	7%	-15%	-31%	-12%	-34%	-44%	27%	13%	-1%
	Latin America	4	13%	-4%	-23%	-8%	-4%	-36%	26%	13%	2%
	Middle East and Africa	2	-4%	-22%	-31%	-23%	-34%	-42%	13%	-3%	-9%

Note: Colors refer to whether and the degree to which the LCOE estimate is lower (green) or higher (red) than for "all" respondents

Table A – 12. Relative Change in LCOE and LCOE Components from 2014 to 2030 for Onshore Wind Projects, by Respondent Group

Onshore wind (LCOE component values in 2030 relative to expert-specific 2014 baseline)								
Respondent Group		Number of respondents	Median scenario for typical LCOE					
			LCOE	**CapEx**	**OpEx**	**Capacity Factor**	**Project Life**	**WACC**
All		134	**-24%**	**-12%**	**-9%**	**10%**	**10%**	**0%**
By Lead / Larger group	Leading	17	-27%	-17%	-17%	10%	10%	0%
	Larger	117	-24%	-11%	-9%	10%	10%	0%
By type of organization	Research	38	-25%	-11%	-14%	14%	25%	0%
	Wind deployment	22	-22%	-11%	-8%	11%	0%	-1%
	Equipment manufacturer	22	-23%	-3%	-4%	8%	5%	0%
	Other private sector	39	-26%	-15%	-11%	11%	10%	0%
	Other	13	-24%	-15%	-8%	10%	0%	0%
By applications evaluated	Onshore only	52	-24%	-11%	-8%	10%	0%	0%
	Both onshore and offshore	82	-24%	-14%	-12%	11%	15%	0%
By type of expertise	Wind energy markets	94	-27%	-14%	-11%	11%	10%	0%
	Systems level	74	-26%	-15%	-11%	9%	10%	0%
	Subsystem level	36	-24%	-15%	-8%	11%	13%	0%
By familiarity with region	North American	93	-25%	-11%	-8%	14%	10%	0%
	Europe	77	-23%	-15%	-10%	9%	15%	0%
	Asia	22	-27%	-17%	-12%	4%	13%	0%
	Latin America	24	-19%	-9%	0%	8%	0%	0%
	Middle East and Africa	6	-24%	-11%	-13%	9%	13%	0%

Note: Colors refer to whether and the degree to which the factor change will result in LCOE estimates that are lower (green) or higher (red) than for "all" respondents

Table A – 13. Relative Change in LCOE and LCOE Components from 2014 to 2030 for Fixed-Bottom Offshore Wind Projects, by Respondent Group

Fixed-Bottom Offshore wind (LCOE component values in 2030 relative to expert-specific 2014 baseline)								
Respondent Group		Number of respondents	Median scenario for typical LCOE					
			LCOE	**CapEx**	**OpEx**	**Capacity Factor**	**Project Life**	**WACC**
All		110	**-30%**	**-14%**	**-9%**	**4%**	**15%**	**-10%**
By Lead / Larger group	Leading	15	-35%	-18%	-7%	11%	25%	-8%
	Larger	95	-29%	-14%	-9%	4%	15%	-10%
By type of organization	Research	38	-26%	-17%	-9%	7%	0%	-5%
	Wind deployment	16	-36%	-18%	-8%	9%	23%	-20%
	Equipment manufacturer	12	-9%	-4%	-2%	0%	0%	0%
	Other private sector	32	-29%	-15%	-13%	4%	20%	-10%
	Other	12	-32%	-10%	-4%	4%	13%	-20%
By applications evaluated	Offshore only	28	-36%	-11%	-13%	7%	20%	-17%
	Both onshore and offshore	82	-28%	-16%	-9%	4%	13%	-1%
By type of expertise	Wind energy markets	77	-31%	-14%	-9%	7%	20%	-10%
	Systems level	59	-31%	-17%	-9%	7%	15%	-9%
	Subsystem level	30	-29%	-17%	-13%	3%	25%	0%
By familiarity with region	North American	65	-27%	-13%	-9%	4%	10%	-5%
	Europe	79	-32%	-17%	-12%	7%	20%	-10%
	Asia	21	-29%	-18%	-13%	4%	20%	-10%
	Latin America	11	-28%	-11%	-9%	4%	20%	0%
	Middle East and Africa	6	-25%	-10%	0%	4%	23%	-13%

Note: Colors refer to whether and the degree to which the factor change will result in LCOE estimates that are lower (green) or higher (red) than for "all" respondents

Table A – 14. Relative Change in LCOE and LCOE Components from 2014 to 2030 for Floating Offshore Wind Projects, by Respondent Group

Floating Offshore wind (LCOE component values in 2030 relative to expert-specific 2014 baseline)								
Respondent Group		Number of respondents	Median scenario for typical LCOE					
			LCOE	**CapEx**	**OpEx**	**Capacity Factor**	**Project Life**	**WACC**
All		44	**-25%**	**-5%**	**-8%**	**9%**	**25%**	**-5%**
By Lead / Larger group	Leading	6	-38%	-10%	-9%	20%	25%	-15%
	Larger	38	-15%	-5%	-7%	8%	23%	0%
By type of organization	Research	17	-26%	-7%	-9%	9%	25%	0%
	Wind deployment	7	-25%	-3%	5%	2%	25%	-20%
	Equipment manufacturer	0	NA	NA	NA	NA	NA	NA
	Other private sector	15	-20%	-8%	-7%	7%	16%	-3%
	Other	5	-15%	0%	-7%	11%	0%	-5%
By applications evaluated	Offshore only	13	-25%	0%	-9%	11%	25%	-15%
	Both onshore and offshore	31	-20%	-8%	-7%	7%	25%	0%
By type of expertise	Wind energy markets	29	-31%	-12%	-9%	9%	25%	-5%
	Systems level	31	-25%	-3%	-7%	11%	25%	-4%
	Subsystem level	16	-17%	-4%	-8%	4%	25%	0%
By familiarity with region	North American	27	-20%	-2%	-9%	7%	25%	-7%
	Europe	31	-15%	0%	-5%	9%	25%	-3%
	Asia	9	-15%	-7%	0%	10%	25%	0%
	Latin America	4	-4%	-6%	0%	3%	0%	10%
	Middle East and Africa	2	-22%	-10%	-6%	22%	8%	8%

Note: Colors refer to whether and the degree to which the factor change will result in LCOE estimates that are lower (green) or higher (red) than for “all” respondents

Table A – 15. Wind Turbine Characteristics in 2030 for North American Wind Projects, by Respondent Group

			North America											
			Onshore				Fixed-Bottom Offshore				Floating Offshore			
Number of all respondents	Respondent Group		n	Turbine capacity (MW)	Hub height (m)	Rotor diameter (m)	n	Turbine capacity (MW)	Hub height (m)	Rotor diameter (m)	n	Turbine capacity (MW)	Hub height (m)	Rotor diameter (m)
77	**All North America**		71	3.25	115	135	37	9	115	170	18	9	120	190
69	By Lead / Larger group	Larger	63	3.25	115	135	31	9	125	170	16	9	115	180
8		Leading	8	3.5	115	125	6	8	115	190	2	10	125	210
52	By type of expertise	Wind energy markets	47	3.25	115	125	24	9	125	190	11	11	125	190
46		Systems level	44	3.25	115	135	22	9	115	170	4	9	120	180
23		Subsystem level	23	3.25	115	135	12	9	120	190	8	9	120	190
35	By applications evaluated	Onshore only	34	3.25	115	135		NA	NA	NA		NA	NA	NA
5		Offshore only		NA	NA	NA	4	11	125	200	3	11	125	210
37		Both onshore and offshore	37	3.25	115	125	33	9	115	170	15	9	115	170
22	By type of organization	Research	20	3.25	115	125	17	9	115	190	11	9	125	190
16		Wind deployment	14	3.5	130	140	2	12	130	210	2	12	130	210
14		Equipment manufacturer	14	3.25	125	145	4	12	155	200	0	NA	NA	NA
21		Other private sector	19	2.75	105	125	13	7	100	170	4	9	95	170
4		Other	4	3	115	115	1	7	155	150	1	9	170	170

Note: Colors refer to whether turbine size is larger (green) or smaller (red) than for "all" respondents

Table A – 16. Wind Turbine Characteristics in 2030 for European Wind Projects, by Respondent Group

			Europe											
			Onshore				Fixed-Bottom Offshore				Floating Offshore			
Number of all respondents	Respondent Group		n	Turbine capacity (MW)	Hub height (m)	Rotor diameter (m)	n	Turbine capacity (MW)	Hub height (m)	Rotor diameter (m)	n	Turbine capacity (MW)	Hub height (m)	Rotor diameter (m)
73	**All Europe**		49	3.75	115	130	58	11	125	190	20	11	125	190
61	By Lead / Larger group	Larger	41	3.75	120	135	50	11	125	190	18	10	125	190
12		Leading	8	3.25	115	110	8	10	130	150	2	11	125	200
53	By type of expertise	Wind energy markets	34	3.5	115	125	42	11	125	190	14	10	125	190
34		Systems level	23	4.25	115	135	9	11	125	190	13	11	125	190
13		Subsystem level	9	3.25	125	130	13	11	125	190	5	9	115	170
12	By applications evaluated	Onshore only	10	3.75	115	115		NA	NA	NA		NA	NA	NA
22		Offshore only		NA	NA	NA	20	11	125	190	8	11	125	190
39		Both onshore and offshore	39	3.75	125	135	38	11	135	190	12	9	125	180
20	By type of organization	Research	17	3.75	115	135	17	11	125	170	4	10	125	190
14		Wind deployment	7	4.75	125	135	12	11	125	210	5	9	115	190
9		Equipment manufacturer	6	3.75	130	145	7	11	135	190	0	NA	NA	NA
20		Other private sector	12	3.5	115	125	15	11	125	190	8	11	125	190
10		Other	7	3.25	115	125	7	11	135	190	3	11	135	190

Note: Colors refer to whether turbine size is larger (green) or smaller (red) than for "all" respondents

Table A – 17. Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE for Onshore Wind Projects by 2030, by Respondent Group

Onshore																	
Percent of experts rating item "Large expected impact"		By Lead / Larger group		By type of organization					By familiarity with region					By type of expertise		
Wind technology, market, or other change	All Respondents	Large	Leading	Research	Wind deployment	Equipment manufacturer	Other private sector	Other	North America	Europe	Asia	Latin America	Middle East & Africa	Wind energy markets	Systems level	Subsystems level
Number of respondents	129	112	17	37	22	22	36	12	89	75	21	24	6	90	74	35
Increased rotor diameter such that specific power declines	58%	62%	39%	68%	68%	60%	51%	33%	60%	56%	50%	52%	50%	58%	61%	62%
Rotor design advancements	45%	46%	38%	47%	45%	64%	35%	33%	43%	49%	48%	54%	60%	40%	52%	46%
Increased tower height	33%	33%	33%	31%	32%	45%	30%	33%	36%	28%	33%	54%	17%	36%	28%	36%
Reduced financing costs and project contingencies due to lower risk profile, greater accuracy in energy production estimates, improved risk management, and increased industry experience and standardization	32%	35%	17%	47%	24%	27%	21%	46%	29%	39%	36%	21%	33%	31%	32%	35%
Improved component durability and reliability	31%	31%	31%	39%	19%	23%	31%	42%	26%	39%	48%	29%	60%	31%	32%	28%
Increased energy production due to new transmission to higher wind speed sites	31%	32%	22%	22%	38%	33%	31%	38%	36%	25%	32%	35%	33%	35%	31%	35%
Extended turbine design lifetime	29%	29%	25%	31%	27%	32%	24%	33%	24%	40%	38%	25%	20%	28%	29%	31%
Operating efficiencies to increase plant performance	28%	29%	24%	31%	14%	27%	32%	33%	24%	32%	43%	21%	67%	30%	26%	25%
Increased turbine capacity and rotor diameter (thereby maintaining specific power)	28%	30%	12%	19%	45%	36%	28%	8%	31%	24%	24%	46%	0%	31%	34%	26%
Turbine and component manufacturing standardization, efficiencies, and volume	27%	30%	12%	21%	14%	48%	32%	17%	20%	36%	43%	29%	60%	24%	34%	29%
Improved plant-level layout through understanding of complex flow and high-resolution micro-siting	27%	27%	29%	32%	18%	32%	24%	27%	29%	28%	33%	38%	17%	26%	34%	31%
Integrated turbine-level system design optimization	23%	23%	21%	36%	10%	32%	15%	10%	20%	28%	20%	17%	0%	20%	30%	26%
Increased competition among suppliers of components, turbines, Balance of Plant services, installation, and operations and maintenance	21%	20%	24%	17%	14%	14%	26%	38%	16%	32%	32%	29%	50%	23%	20%	23%
Large variety of alternative turbine designs to suit site-specific conditions	17%	18%	12%	19%	10%	33%	8%	25%	16%	15%	24%	13%	17%	18%	15%	20%
Innovative non-conventional plant-level layouts that could involve mixed turbine ratings, hub heights and rotor diameters	17%	19%	0%	22%	14%	27%	8%	11%	16%	17%	24%	25%	0%	16%	19%	17%
Maintenance process efficiencies	17%	16%	18%	22%	10%	9%	14%	36%	10%	22%	14%	8%	0%	18%	12%	11%
Tower design advancements	14%	16%	6%	12%	19%	14%	14%	17%	15%	13%	5%	22%	20%	14%	17%	18%
Economies of scale through increased project size	12%	12%	17%	5%	14%	14%	19%	8%	8%	15%	15%	13%	0%	13%	18%	17%
Nacelle components design advancements	12%	12%	14%	12%	14%	9%	15%	8%	10%	12%	15%	13%	0%	11%	17%	15%
Installation and transportation equipment advancements	12%	11%	19%	18%	5%	14%	11%	8%	14%	9%	10%	21%	20%	13%	16%	26%
Innovative non-conventional turbine designs	12%	13%	0%	12%	14%	22%	8%	0%	14%	13%	21%	10%	0%	11%	16%	20%
Maintenance equipment advancements	10%	10%	12%	9%	10%	5%	11%	30%	8%	13%	14%	8%	0%	12%	8%	9%
Foundation and support structure manufacturing standardization, efficiencies, and volume	10%	11%	0%	18%	5%	15%	6%	0%	6%	14%	10%	13%	0%	6%	15%	12%
Foundation and support structure design advancements	10%	11%	0%	18%	10%	0%	8%	9%	6%	11%	5%	4%	0%	8%	11%	11%
Reduced total development costs and risks from greater transparency and certainty around siting and permitting approval timelines and procedures	9%	9%	11%	14%	5%	5%	5%	23%	7%	14%	9%	8%	17%	10%	13%	12%
Installation process efficiencies	9%	9%	6%	15%	10%	0%	11%	0%	6%	11%	10%	13%	20%	8%	14%	11%
Reduced fixed operating costs, excluding maintenance	5%	4%	12%	3%	0%	5%	5%	17%	1%	6%	5%	0%	0%	3%	1%	3%
Lower decommissioning costs	1%	1%	0%	0%	5%	0%	0%	0%	1%	1%	0%	4%	0%	1%	0%	0%

Note: Colors refer to the relative rating of each advancement possibility within each respondent category (i.e., colors are coded based on each column, with green designating a higher-rated advancement and red a lower-rated advancement)

Table A – 18. Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE for Fixed-Bottom Offshore Wind Projects by 2030, by Respondent Group

Fixed-Bottom Offshore																	
Percent of experts rating item "Large expected impact"		By Lead / Larger group		By type of organization					By familiarity with region					By type of expertise		
Wind technology, market, or other change	All Respondents	Large	Leading	Research	Wind deployment	Equipment manufacturer	Other private sector	Other	North America	Europe	Asia	Latin America	Middle East & Africa	Wind energy markets	Systems level	Subsystems level
Number of respondents	98	83	15	33	15	9	30	11	56	74	20	11	6	70	6	29
Increased turbine capacity and rotor diameter (thereby maintaining specific power)	55%	57%	47%	55%	67%	44%	50%	64%	50%	58%	45%	73%	50%	61%	54%	52%
Foundation and support structure design advancements	53%	55%	36%	44%	60%	67%	47%	73%	53%	51%	50%	73%	80%	53%	51%	45%
Reduced financing costs and project contingencies due to lower risk profile, greater accuracy in energy production estimates, improved risk management, and increased industry experience and standardization	49%	51%	33%	46%	56%	44%	42%	67%	44%	49%	45%	55%	33%	53%	47%	38%
Economies of scale through increased project size	48%	49%	40%	46%	50%	44%	57%	30%	46%	47%	40%	64%	60%	51%	44%	38%
Improved component durability and reliability	48%	48%	50%	56%	53%	33%	41%	45%	46%	49%	50%	73%	40%	45%	56%	52%
Installation process efficiencies	46%	49%	29%	41%	56%	22%	47%	70%	47%	45%	50%	73%	50%	46%	46%	55%
Installation and transportation equipment advancements	44%	46%	36%	39%	44%	44%	50%	45%	46%	45%	55%	64%	20%	43%	43%	48%
Foundation and support structure manufacturing standardization, efficiencies, and volume	43%	48%	8%	42%	38%	44%	45%	45%	39%	45%	42%	55%	20%	46%	42%	43%
Extended turbine design lifetime	36%	35%	43%	24%	56%	33%	33%	55%	26%	42%	45%	55%	40%	41%	37%	34%
Turbine and component manufacturing standardization, efficiencies, and volume	36%	40%	8%	30%	50%	22%	38%	40%	30%	37%	26%	45%	20%	36%	35%	32%
Increased competition among suppliers of components, turbines, Balance of Plant services, installation, and operations and maintenance	35%	38%	20%	31%	56%	22%	32%	33%	31%	38%	25%	36%	17%	39%	30%	24%
Integrated turbine-level system design optimization	33%	37%	7%	39%	23%	38%	33%	20%	30%	40%	33%	40%	25%	32%	38%	36%
Rotor design advancements	32%	32%	36%	33%	27%	33%	36%	27%	33%	35%	42%	55%	20%	26%	38%	39%
Maintenance process efficiencies	32%	32%	33%	28%	27%	33%	33%	45%	25%	34%	30%	36%	17%	32%	32%	34%
Maintenance equipment advancements	30%	30%	27%	31%	40%	11%	27%	36%	19%	32%	25%	36%	17%	31%	26%	34%
Operating efficiencies to increase plant performance	29%	28%	33%	31%	27%	33%	24%	36%	23%	32%	25%	45%	17%	26%	25%	24%
Increased rotor diameter such that specific power declines	27%	29%	14%	28%	27%	33%	28%	13%	26%	30%	35%	45%	0%	26%	33%	32%
Reduced total development costs and risks from greater transparency and certainty around siting and permitting approval timelines and procedures	25%	28%	7%	20%	20%	44%	29%	17%	24%	30%	37%	45%	17%	22%	23%	34%
Increased energy production due to new transmission to higher wind speed sites	21%	20%	27%	21%	20%	33%	19%	20%	21%	22%	20%	36%	40%	22%	20%	11%
Improved plant-level layout through understanding of complex flow and high-resolution micro-siting	21%	23%	7%	24%	15%	33%	17%	18%	27%	21%	26%	45%	20%	14%	24%	24%
Nacelle components design advancements	19%	20%	14%	16%	21%	13%	28%	9%	26%	16%	26%	40%	20%	19%	20%	31%
Innovative non-conventional turbine designs	17%	20%	0%	16%	14%	33%	17%	10%	20%	17%	26%	10%	25%	15%	21%	24%
Tower design advancements	12%	11%	14%	16%	7%	11%	10%	9%	9%	13%	10%	9%	20%	9%	13%	10%
Reduced fixed operating costs, excluding maintenance	10%	10%	7%	3%	29%	11%	7%	10%	7%	12%	11%	18%	0%	10%	9%	17%
Increased tower height	6%	6%	7%	6%	0%	11%	7%	9%	11%	5%	10%	18%	0%	8%	9%	14%
Innovative non-conventional plant-level layouts that could involve mixed turbine ratings, hub heights and rotor diameters	5%	6%	0%	9%	0%	0%	7%	0%	5%	6%	5%	0%	25%	1%	9%	10%
Large variety of alternative turbine designs to suit site-specific conditions	5%	6%	0%	3%	6%	0%	0%	30%	7%	5%	10%	18%	50%	6%	4%	3%
Lower decommissioning costs	2%	3%	0%	0%	14%	0%	0%	0%	2%	1%	0%	0%	0%	3%	2%	4%

Note: Colors refer to the relative rating of each advancement possibility within each respondent category (i.e., colors are coded based on each column, with green designating a higher-rated advancement and red a lower-rated advancement)

Table A – 19. Expected Impact of Wind Technology, Market, and Other Changes on Reducing LCOE for Floating Offshore Wind Projects by 2030, by Respondent Group

Floating Offshore																
Percent of experts rating item "Large expected impact"		By Lead / Larger group		By type of organization					By familiarity with region					By type of expertise		
Wind technology, market, or other change	All Respondents	Large	Leading	Research	Wind deployment	Equipment manufacturer	Other private sector	Other	North America	Europe	Asia	Latin America	Middle East & Africa	Wind energy markets	Systems level	Subsystems level
Number of respondents	41	37	4	15	7	0	14	5	26	29	8	3	2	28	29	14
Foundation and support structure design advancements	80%	78%	100%	80%	86%	NA	79%	80%	77%	76%	63%	33%	0%	79%	83%	79%
Installation process efficiencies	78%	76%	100%	80%	57%	NA	86%	80%	88%	69%	75%	100%	50%	79%	72%	79%
Foundation and support structure manufacturing standardization, efficiencies, and volume	68%	69%	50%	43%	86%	NA	79%	80%	54%	75%	75%	67%	0%	70%	57%	43%
Economies of scale through increased project size	65%	64%	75%	71%	71%	NA	64%	40%	72%	61%	75%	100%	50%	61%	64%	69%
Installation and transportation equipment advancements	63%	65%	50%	60%	43%	NA	79%	60%	77%	59%	75%	100%	50%	64%	62%	71%
Increased turbine capacity and rotor diameter (thereby maintaining specific power)	59%	54%	100%	47%	71%	NA	57%	80%	62%	55%	63%	100%	50%	61%	59%	57%
Improved component durability and reliability	58%	56%	75%	50%	86%	NA	50%	60%	54%	57%	75%	67%	100%	67%	64%	71%
Increased competition among suppliers of components, turbines, Balance of Plant services, installation, and operations and maintenance	46%	49%	25%	33%	57%	NA	43%	80%	42%	48%	50%	100%	50%	57%	41%	21%
Reduced financing costs and project contingencies due to lower risk profile, greater accuracy in energy production estimates, improved risk management, and increased industry experience and standardization	46%	46%	50%	40%	43%	NA	50%	60%	42%	45%	50%	67%	50%	46%	38%	36%
Rotor design advancements	45%	44%	50%	53%	57%	NA	31%	40%	52%	43%	63%	67%	50%	39%	50%	64%
Integrated turbine-level system design optimization	44%	41%	75%	60%	14%	NA	43%	40%	42%	48%	50%	67%	50%	43%	45%	57%
Turbine and component manufacturing standardization, efficiencies, and volume	40%	44%	0%	21%	57%	NA	43%	60%	38%	43%	38%	100%	50%	44%	36%	21%
Extended turbine design lifetime	39%	41%	25%	33%	57%	NA	36%	40%	38%	38%	50%	67%	50%	43%	41%	50%
Maintenance process efficiencies	35%	36%	25%	29%	14%	NA	50%	40%	38%	36%	63%	67%	100%	41%	32%	50%
Innovative non-conventional turbine designs	34%	32%	50%	47%	0%	NA	43%	20%	38%	31%	50%	33%	100%	32%	41%	57%
Increased rotor diameter such that specific power declines	32%	31%	33%	36%	14%	NA	38%	25%	29%	38%	38%	33%	0%	27%	41%	46%
Increased energy production due to new transmission to higher wind speed sites	29%	30%	25%	27%	57%	NA	14%	40%	35%	24%	38%	67%	50%	32%	28%	21%
Tower design advancements	28%	25%	50%	40%	14%	NA	31%	0%	28%	29%	50%	33%	0%	18%	32%	50%
Nacelle components design advancements	28%	25%	50%	27%	29%	NA	31%	20%	40%	18%	38%	33%	0%	29%	29%	50%
Maintenance equipment advancements	25%	25%	25%	7%	14%	NA	36%	60%	23%	29%	38%	67%	100%	30%	21%	14%
Reduced total development costs and risks from greater transparency and certainty around siting and permitting approval timelines and procedures	20%	22%	0%	20%	0%	NA	29%	20%	23%	25%	57%	67%	50%	21%	14%	29%
Operating efficiencies to increase plant performance	18%	14%	50%	7%	0%	NA	23%	60%	16%	22%	38%	67%	50%	22%	15%	21%
Improved plant-level layout through understanding of complex flow and high-resolution micro-siting	15%	11%	50%	20%	0%	NA	8%	40%	12%	11%	0%	0%	0%	18%	15%	14%
Increased tower height	15%	14%	25%	13%	0%	NA	15%	40%	16%	14%	13%	33%	0%	21%	18%	21%
Large variety of alternative turbine designs to suit site-specific conditions	12%	14%	0%	13%	0%	NA	7%	40%	8%	14%	13%	33%	50%	11%	7%	0%
Innovative non-conventional plant-level layouts that could involve mixed turbine ratings, hub heights and rotor diameters	12%	14%	0%	20%	0%	NA	7%	20%	8%	17%	13%	33%	50%	7%	10%	7%
Reduced fixed operating costs, excluding maintenance	8%	9%	0%	0%	0%	NA	15%	20%	4%	12%	14%	0%	0%	7%	8%	7%
Lower decommissioning costs	3%	3%	0%	0%	0%	NA	7%	0%	0%	4%	14%	0%	50%	4%	4%	8%

Note for Table A-19: Colors refer to the relative rating of each advancement possibility within each respondent category (i.e., colors are coded based on each column, with green designating a higher-rated advancement and red a lower-rated advancement)

Table A – 20. Ranking of Broad Drivers for Lower Onshore LCOE in 2030, by Respondent Group

Ranking of Broad Drivers for Lower Onshore LCOE in 2030																
Percent of experts rating item "Large expected impact"		By Lead / Larger group		By type of organization					By familiarity with region					By type of expertise		
Driver	All Respondents	Large	Leading	Research	Wind deployment	Equipment manufacturer	Other private sector	Other	North America	Europe	Asia	Latin America	Middle East & Africa	Wind energy markets	Systems level	Subsystems level
Learning with market growth	33%	30%	47%	39%	30%	10%	32%	54%	31%	35%	48%	32%	67%	34%	24%	25%
Research and development	32%	32%	25%	32%	33%	48%	26%	17%	38%	24%	19%	26%	0%	28%	36%	42%
Increased competion and decreased risk	16%	16%	19%	16%	15%	14%	19%	17%	9%	24%	14%	22%	17%	16%	21%	17%
Eased wind project and transmisison siting	14%	15%	7%	11%	14%	14%	16%	17%	15%	11%	10%	13%	17%	15%	14%	17%

Note: Colors refer to the relative rating of each broad driver within each respondent category (i.e., colors are coded based on each column, with green designating a higher-rated driver and red a lower-rated driver)

Table A – 21. Ranking of Broad Drivers for Lower Fixed-Bottom Offshore LCOE in 2030, by Respondent Group

Ranking of Broad Drivers for Lower Offshore LCOE in 2030																
Percent of experts rating item "Large expected impact"		By Lead / Larger group		By type of organization					By familiarity with region					By type of expertise		
Driver	All Respondents	Large	Leading	Research	Wind deployment	Equipment manufacturer	Other private sector	Other	North America	Europe	Asia	Latin America	Middle East & Africa	Wind energy markets	Systems level	Subsystems level
Learning with market growth	33%	34%	27%	27%	31%	33%	42%	33%	32%	35%	52%	36%	50%	30%	33%	27%
Research and development	32%	33%	29%	41%	31%	36%	23%	27%	31%	26%	15%	18%	33%	32%	31%	37%
Eased wind project and transmisison siting	25%	25%	29%	19%	25%	27%	29%	36%	24%	29%	33%	45%	0%	30%	25%	30%
Increased competion and decreased risk	5%	3%	14%	8%	6%	0%	3%	0%	7%	4%	0%	0%	17%	4%	7%	7%

Note: Colors refer to the relative rating of each broad driver within each respondent category (i.e., colors are coded based on each column, with green designating a higher-rated driver and red a lower-rated driver)

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