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Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy

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October 2019

This is a preprint version of a journal article published in *Energy Policy.*
DOI: https://doi.org/10.1016/j.enpol.2019.110994

This work was supported by the Transmission Permitting and Technical Assistance Division of the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy

Prepared for the
Office of Electricity Delivery and Energy Reliability
National Electricity Division
U.S. Department of Energy

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October 2019

This work was supported by the Transmission Permitting and Technical Assistance Division of the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Acknowledgements

This work was supported by the U.S. Department of Energy (DOE) under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. We especially thank our DOE sponsors for supporting this research, and in particular Lawrence Mansueti. We also appreciate early feedback provided by a number of external advisors on this work. Finally, we thank Rebecca Widiss, Nicholas Disanti, Will Cotton, and Kevin Porter from Exeter Associates for their help in the collection and interpretation of the interconnection study data. Jarett Zuboy provided substantial editing assistance.

Author Contributions

W.G. led the research. W.G., A.M., and R.W. designed the analysis framework. W.G. and A.M. led the literature review. W.G., A.M., and R.W. led the writing of the paper.

Competing Interests

The authors declare no competing interests.

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Abstract

Estimating the overall costs of transmission needed to integrate variable renewable energy (VRE) onto the grid is challenging. An improved understanding of these transmission costs would support electricity system planning as VRE penetrations increase. This paper brackets VRE transmission capital costs using multiple approaches based on interconnection studies, actual transmission projects, capacity-expansion simulation models, and aggregated U.S. VRE-related transmission expenditures. Each approach possesses advantages and drawbacks, and combining the approaches lends confidence to the results. The resulting range of average levelized VRE transmission costs is $1–$10/MWh, which is generally lower than earlier estimates in the literature. These transmission capital costs can increase the direct plant-level levelized cost of VRE by 3%–33%, based on levelized costs of energy of $29–$56/MWh for utility-scale wind and $36–$46/MWh for utility-scale solar. As VRE deployment continues to expand, policy makers can use this information to (1) assess the benefits of transmission avoidance and deferral when comparing distributed energy resources versus utility-scale projects, (2) evaluate the potential costs of large-scale public transmission investments, and (3) better analyze system-level costs of utility-scale VRE technologies. Future research can expand on the framework presented here by providing a review of operation and maintenance costs for transmission systems.

Keywords. Transmission investment; renewable energy; wind; utility solar; levelized cost of energy

1. Introduction

Over the last decade, variable renewable energy (VRE) technologies, such as wind and solar, have proliferated in the United States (Bolinger and Seel 2018; Wiser and Bolinger 2017). Numerous stakeholders support continued growth of cost-competitive VRE, and many researchers have studied the potential for high VRE penetrations on the electrical grid (Sørensen 2008; BNEF 2018; Elliston, Diesendorf, and MacGill 2012; Connolly et al. 2011; Mathiesen, Lund, and Karlsson 2011; Lund and Mathiesen 2009; Liu et al. 2011; Shoshanna 2011; Mai, Hand, et al. 2014) . To make VRE investment decisions, policy and electric-sector decision makers face numerous tradeoffs related to location constraints, solar/wind resource potential, supporting infrastructure requirements, and so forth (Mills, Phadke, and Wiser 2011). Analysts typically incorporate these tradeoffs into project benefit calculations (estimates of VRE energy and capacity value) and project cost calculations (estimates of VRE integration costs such as supply-demand balancing and transmission investment) (Mills and Wiser 2012). Although direct costs are relatively easy to estimate, understanding system-integration costs is more challenging (Ueckerdt et al. 2013). Still, many researchers have attempted to systematically quantify some key system-integration costs, such as supply-demand balancing, which results from the variability and uncertainty of VRE energy production (Hirth, Ueckerdt, and Edenhofer 2015; Milligan et al. 2011).

Researchers have given less attention to the transmission costs related to VRE grid integration even though the levelized transmission infrastructure costs of VRE can be significant (Wiser et al. 2017). The potential for higher costs relative to traditional generation resources is due to VRE resource quality being much more location dependent and VRE capacity factors being lower than for traditional generation. Lower capacity factors translates to lower utilization of transmission and a higher transmission cost per unit of energy generated (Mai, Mulcahy, et al. 2014; Kahn 2008; Weiss, Hagerty, and Castaner 2019). Transparent transmission costs would facilitate decisions that support cost-effective and fair VRE integration, particularly because electric ratepayers typically bear at least a portion of an electric system's transmission costs (MISO 2012; Lasher 2014). However, policy makers have limited access to clear, generalizable transmission-cost estimates. Analysts often use levelized cost of energy (LCOE) methods to compare the costs of generation resources; however, these relatively simple methods typically focus on costs up to the busbar only and ignore the complex system wide infrastructure investments needed to integrate a new resource fully (Lazard 2018); (Rhodes et al. 2017).

Estimating transmission costs for VRE integration is difficult, idiosyncratic, and dependent on geographical context for several reasons. First, it is difficult to attribute costs for system-level assets such as transmission infrastructure to individual generation resources.[3] Transmission investments generally serve multiple purposes, including reliability support and economic congestion relief, while facilitating the integration of new generators (EIA 2017). Conventional generators as well as VRE resources use expanded transmission networks. Second, immense geographic heterogeneity in system needs and costs can make it difficult to generalize costs across different projects. Finally, a project's

[3] Although this paper focuses on transmission infrastructure, a review of distribution infrastructure investment was also performed. Those results are available upon request.

incremental transmission needs have to be weighed against locations with the best VRE resources. For example, siting wind turbines in distant, windy locations that require larger transmission investments presents economic tradeoffs versus siting them closer to load where wind resources are poorer (Hoppock and Patiño-Echeverri 2010; Lamy et al. 2016; Silva Herran et al. 2016; Fischlein et al. 2013). Furthermore, liberalized electricity markets frequently present a coordination problem between investments in the regulated electrical grid (e.g., transmission network) and investments in new power generation (Wagner 2019). Project developers may prioritize utility-scale VRE development in high-resource areas to improve project economics rather than consider the combination of system-level transmission and generation costs that would minimize the overall social cost.

Some capacity-expansion models, such as the Regional Energy Deployment System (ReEDS),[4] consider generation and transmission capacity costs and aim to minimize busbar and system-level costs for electric-sector planning purposes (Eurek et al. 2016; MacDonald et al. 2016). These models can support optimal investment decisions. However, they typically simplify the transmission analysis, and actual transmission construction may differ from optimized model outcomes, especially because system planners rarely can consider transmission and generation investments jointly and holistically.

This study fills a gap in existing knowledge by exploring the magnitude of transmission costs for utility-scale wind and solar projects in the United States. It appears to be the first study that uses various sources to triangulate these costs. Electric-sector stakeholders could use the results to improve grid planning and assess tradeoffs between VRE resource potential, location, and transmission costs. Section 2 provides more background on transmission network investments and summarizes prior estimates of transmission costs. Section 3 details the study methods. Section 4 presents the results, including analysis of interconnection studies (4.1), bulk transmission projects and studies (4.2), and aggregated transmission expenditure (4.3). Section 5 discusses the results and limitations. Section 6 concludes with implications for public policy.

[4] Most other capacity-expansion models used by utilities do not jointly optimize transmission and generation capacity investments. Other examples that include co-optimization of generation and transmission investments are found in (MacDonald et al. 2016; Nelson et al. 2012; Maloney et al. 2019; Spyrou et al. 2017).

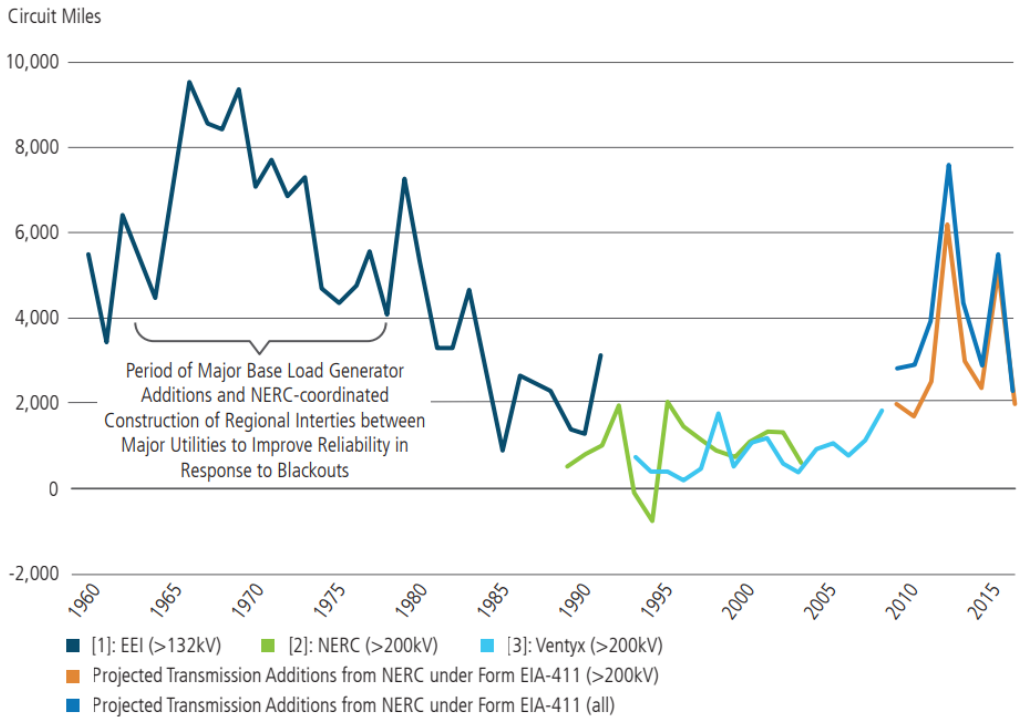
2. Background and Prior Work

The U.S. transmission network is expanded via three main channels. First, regional entities conduct transmission planning processes with the objective of meeting reliability, economic, and/or public policy goals. Second, generation project developers often trigger transmission system expansion through generation interconnection requests. Finally, merchant transmission developers propose and construct new transmission projects to connect generation projects to consumers. This paper considers costs from all these channels.

Analysts traditionally classify transmission investments into three categories: spur, point of interconnection (POI), and bulk transmission. Spur transmission investments are the short, radial transmission lines that connect generators to the bulk transmission grid. Bulk transmission investments are the networked infrastructure investments that move power from all generators to all load centers across a geographic area. POI investments are the facilities that connect spur transmission lines to bulk transmission grids (Andrade and Baldick 2017).

These distinctions relate to how electric-system users bear investment costs. For instance, generation project developers typically incur costs for spur and POI investments. Generators might also incur network-upgrade costs if an interconnection study identifies necessary bulk system expansion. However, a generation project developer typically will not incur costs from projects developed via the transmission planning process, such as the Competitive Renewable Energy Zone (CREZ) in Texas and Multi-Value Project (MVP) in Midcontinent Independent System Operator (MISO) territory.

This paper focuses on transmission costs for utility-scale wind and solar resources, although traditional generation resources historically have required large transmission investments. Figure 1, which shows historical transmission buildout peaking in the 1960s and 1970s in part to facilitate a period of baseload generator additions (Fares and King 2017), suggests that large transmission expenditures were needed to integrate new conventional generation (U.S. Department of Energy 2015). Today, economic and policy benefits are driving demand for VRE, and high future VRE penetrations likely will require large transmission investments (Cochran, Mai, and Bazilian 2014; Mai, Hand, et al. 2014).



Source: DOE QER: Energy Transmission, Storage, and Distribution Infrastructure (2015)

Figure 1. Historical transmission construction

Previous studies have provided some information on VRE-related transmission costs. A review of U.S. transmission planning studies found median wind transmission costs of $15/MWh or $300/kW, roughly 15%–20% of a wind project's cost at the time (Mills, Wiser, and Porter 2012). Two Intergovernmental Panel on Climate Change reports estimated wind transmission costs of $0–$30/MWh for Organization for Economic Co-operation and Development (OECD) countries (Intergovernmental Panel on Climate Change 2011; 2014). A European study found transmission costs of $7.5–$30/MWh at 30% VRE penetration (Heptonstall, Steiner, and Gross 2017). A study of the MISO service area found wind-related transmission costs of $0.4-$9.7/MWh or $33–$762/kW using interconnection studies (Lamy et al. 2016). However, basing costs on interconnection reports tends to neglect the costs of region-wide transmission investments. A study of the western United States found transmission costs of $9/MWh or $314/kW when considering the integration of wind, solar, geothermal, biomass, and hydro resources (Mills, Phadke, and Wiser 2011). Finally, a study of utility-scale wind and solar transmission costs found costs of $0.83–$75/MWh for proposed western U.S. projects, with wind transmission costs often at least $20/MWh (Kahn 2010; 2008).

The present study builds on this existing literature. It benefits from the availability of more VRE-related transmission data, because utility-scale wind and solar energy deployment has grown rapidly in the last 10 years (EIA 2019). In previous studies, many project costs were based on budget estimates or modeling rather than the actual project costs this paper can take advantage of. The present study also takes a more comprehensive approach to all transmission needed for utility-scale wind and solar energy buildout, drawing on interconnection studies, actual transmission projects, simulation/optimization

models, and aggregated U.S. utility-scale wind and solar transmission expenditures. This multifaceted approach enables realistic system-level cost estimates. Finally, this study's integration of utility-scale wind and solar transmission costs enables comparison of transmission requirements between the two resource types, whereas most previous studies focused on only one of these types.

3. Methods

This section describes the study's approaches to transmission-cost estimation and its levelized transmission cost calculations.

3.1 Approaches

This study combines four complementary approaches to provide robust estimates of VRE transmission costs (Table 1). The interconnection study approach draws on studies from two regional transmission operators—PJM in the East and MISO in the Midwest—as well as the U.S. Energy Information Administration (EIA) Form 860 interconnection costs from 2005–2012 (EIA 2018c). These sources cover many planned and built generation projects over the past 10 years. In general, they include POI and bulk system costs required for transmission interconnection that are assigned to particular generators. They do not include spur transmission line costs. In addition to facilitating transmission cost attribution, this is the only approach of the four that enables comparison of costs related to VRE and non-VRE resources. However, interconnection studies do not always include bulk transmission investments associated with delivering significant amounts of electricity across long distances.

Table 1. Four approaches to estimating VRE transmission costs

Attribute	Interconnection Studies	Simulation Studies	Aggregation Method	Actual Projects
Geography considered	MISO, PJM, and EIA	Select regions within U.S.	Entire U.S.	
Project scopes	Generation project	Transmission system		Transmission project
Cost Responsibility	Developer	Developer (spur line) and socialized (bulk)		Socialized
Costs considered	Actual/study costs (POI and bulk system)	Modeled costs (bulk system and spur)	Actual costs (bulk system)	
VRE amount	Small penetration	Large penetration		Both small and large penetrations
Generation types	All types	Utility-scale wind and solar only		
Key challenges	Limited bulk costs	Unrealistic optimizations	Coarse analysis Ambiguous cost responsibility	Selection bias Ambiguous cost responsibility

The other three approaches address these large bulk transmission costs. The actual project approach benefits from using cost data for built or proposed large-scale transmission projects that have corresponding estimates of VRE capacity integration. However, compared with the interconnection study approach, this approach provides less information about cost attribution to particular generation resources versus other transmission investment drivers such as reliability and economic congestion relief. Furthermore, although project capital costs are generally transparent and concrete, the amount of VRE integrated owing to the transmission investment can be ambiguous and difficult to determine.

The simulation study approach draws on regional grid-modeling studies that estimate directly the transmission investments needed to integrate VRE. In contrast with the actual project approach—which entails selection bias because only VRE projects requiring long-distance transmission are included—the simulation study approach accounts for VRE that does and does not need new transmission for successful integration. However, the simulation study approach relies on equipment cost assumptions that may be imprecise[5], and it typically uses optimization to estimate the lowest-cost (but often unrealized in practice) solution.

The aggregation approach uses the actual transmission costs needed to integrate VRE in California and nationwide. The California costs are estimated using California Energy Commission (CEC) data on transmission investments related to renewable portfolio standard (RPS) compliance (CEC 2018), California's cumulative VRE deployment, California Public Utilities Commission records, budgets of completed projects, and Edison Electric Institute (EEI) reports. Compared with the other approaches, this approach provides more certainty that transmission costs are primarily related to VRE integration because CEC states that listed transmission projects were required for RPS compliance. In addition, this approach enables estimation of the total regional transmission costs associated with integrating all VRE and thus avoids the selection bias that occurs when estimates are based on individual projects.

Finally, aggregated national cost estimates draw on data from EIA Form 411, EEI, and EIA's electric power monthly dataset. EIA Form 411, which is compiled by the North American Electric Reliability Corporation (NERC), contains data on proposed high-voltage transmission projects back to the early 2000s and reports reasons for transmission buildout (e.g., reliability, VRE integration, economics, non-renewable integration) starting in 2008 (EIA 2017). The historical capital cost of transmission for VRE is calculated based on the amount of proposed VRE-driven transmission and EEI's estimate of historical transmission investment. Then, EIA's data on total amount of U.S. VRE generation installed are used to calculate a levelized capital cost of the transmission infrastructure.

3.2 Levelization Calculation

This study calculates the levelized capital cost of transmission (LCOT) mainly by dividing the annualized capital cost of a transmission project or aggregation of projects (left term of equation 1) by the amount of annual VRE estimated to flow across the system (right term of equation 1).

$$LCOT = \left[\frac{C*r}{[1-(1+r)^{-n}]}\right] \div [K * CF * 8760] \qquad \text{Eq. 1}$$

Where
C = capital cost of transmission investment
r = discount rate
n = transmission asset lifetime (in years)

[5] Simulation studies often rely on average costs of transmission across a given region or territory and thus oftentimes cannot take into account detailed geographic constraints which might influence actual transmission costs.

K = incremental capacity (in MW) of VRE integrated by transmission infrastructure
CF = capacity factor of VRE resource

If a capacity factor is not reported in the primary source document, the calculation uses recent region-specific values from Lawrence Berkeley National Laboratory analysis (Bolinger and Seel 2018; Wiser and Bolinger 2017); see Appendix C for the specific values. The assumed real discount rate is 4.4%, and the assumed transmission asset life is 60 years (Larsen 2016).[6] The discount rate, which has a significant effect on the results, is based on the cost of capital faced by the electric utility industry. Currently, utilities are earning close to an 11.25% return on equity and can access debt with an interest rate of 3.6% for transmission projects. Using a 55/45 debt-to-equity structure, this results in a 4.4% real weighted average cost of capital (WACC; adjusted for inflation).[7] This discount rate is lower than rates used in prior studies and represents the market opportunity cost of capital, effectively the value that affects customer rates. Prior studies use discount rates as high as 10%, which almost doubles levelized transmission costs (Mills, Wiser, and Porter 2009).

Because public policy analysis often uses societal costs of capital rather than investor costs of capital, this study includes a sensitivity calculation on the discount rate. Borenstein suggested a real social discount rate of 1%–3% (Borenstein 2008). This study's sensitivity analysis uses 2%; see Appendix A and B. Finally, the study reports levelized cost estimates in 2018 dollars, adjusting capital costs for years before 2018 based on historical gross domestic product (GDP) implicit price deflators (BEA 2018) and those for years after 2018 based on a GDP chain-type price index (EIA 2018a).

Although the study applies the method above to the vast majority of its calculations, it uses an adjusted method when estimating VRE-related transmission costs over time based on aggregate U.S. data and the National Renewable Energy Laboratory's (NREL's) standard scenarios data; see Equation 2 (Borenstein 2012). The equation calculates the net present value (NPV) of a time series of transmission costs while discounting the incremental VRE growth over the same period.

$$LCOT = \frac{\sum_{n=0}^{N} \frac{C_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{q_n}{(1+r)^n}} \qquad \text{Eq. 2}$$

Where
C = real expenditures in period n
r = discount rate
N = total discount period (in years)

[6] Changing the assumed lifetime from 60 to 30 years would increase estimates of VRE-related transmission costs by roughly 25%.
[7] The debt cost is a U.S. power industry average (Damodaran 2018). The return on equity includes a base utility return on equity of 9.75% plus a 150 basis point adder for Federal Energy Regulatory Commission (FERC) transmission incentives (EEI 2018; Strunk and Sullivan 2013). The debt-to-equity ratio is from EEI, while the marginal tax rate is based on the 2018 tax law and Tax Foundation analysis (Pomerleau 2018). The Fischer equation is applied to convert from nominal to real after-tax WACC.

q = renewable energy output (in MWh) in period n

The study only analyzes transmission capital costs owing to the difficulty of obtaining consistent operation and maintenance (O&M) costs. Section 5 discusses the implications of this limitation.

4. Results

This section presents results by cost-estimation approach: interconnection study (4.1), actual project and simulation study (4.2), and aggregated costs (4.3).

4.1 Interconnection Costs

This subsection presents the interconnection cost results by individual data source—MISO (4.1.1), PJM (4.1.2), and EIA (4.1.3)—followed by a combined analysis (4.1.4).

4.1.1 MISO

MISO's public record of generator interconnection applications includes 2,209 generation projects (MISO 2018). The present analysis drops the 1,255 projects that were withdrawn by generators and, of the remaining 954 projects, uses 303 that include public reports of interconnection costs. These 303 projects amount to 49 GW of generation resources.

Table 2 shows the generator types analyzed, their interconnection costs, and their levelized costs of transmission (LCOTs). Utility-scale wind projects total 23 GW at an average LCOT of $2.5/MWh. Utility-scale solar projects total 3.3 GW at an average LCOT of $1.6/MWh. These VRE LCOTs are at least an order of magnitude larger than the LCOTs of other generation resources, largely because of differences in assumed transmission utilization. For instance, the average solar unit cost ($/kW) is only 50% higher than the average natural gas unit cost, but the average solar LCOT is 350% higher, because capacity factors are lower for solar than for natural gas. For comparison, the nationwide utility-scale generation LCOEs reported by Lazard are $41–$206/MWh for natural gas, $29–$56/MWh for wind, and $36–$46/MWh for solar (Lazard 2018).

Table 2. MISO interconnection costs for selected utility-scale projects

				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	Projects	Costs ($2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	55	$0.55	14,642	$38	$31	$55	$0.34	$0.28	$0.50
Wind	161	$4.51	23,232	$194	$66	$317	$2.48	$0.85	$4.05
Solar	33	$0.18	3,277	$56	$70	$53	$1.56	$1.95	$1.48
Coal	19	$0.01	2,991	$4	$4	NA	$0.03	$0.03	NA
Hydro	13	$0.06	4,234	$13	$13	NA	$0.18	$0.18	NA

Note: Biomass, energy storage, oil, and nuclear are excluded from this table owing to limited observations in the dataset. Overall, projects based on these four technologies have a weighted-average unit cost of $57/kW.

Figure 2 shows the range of interconnection costs by generator type for constructed/under construction projects (dark blue lines) and proposed projects (teal lines). Wind's estimated costs are

notably higher for proposed projects ($4/MWh) than for constructed projects ($0.85/MWh). Higher costs for proposed projects might occur because projects requiring less transmission are built before those requiring more, or because many proposed projects will not be built (as suggested by the number of projects withdrawn from interconnection queues), and those that ultimately withdraw might have higher estimated transmission costs.

Figure 2 also disaggregates POI and bulk transmission costs, showing that POI costs constitute a smaller proportion of total transmission costs for all generators except solar. The interconnection studies used for this analysis do not include spur transmission line costs.

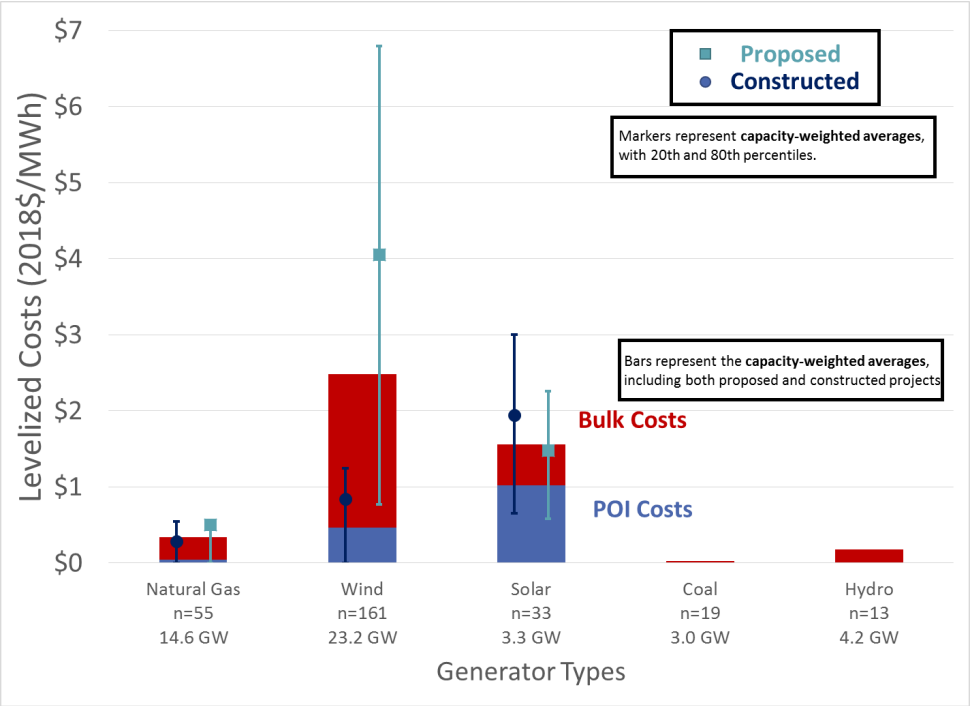


Figure 2. Range of levelized costs for selected utility-scale projects in MISO

4.1.2 PJM

Of 4,152 generation projects in PJM's public record of interconnection applications, generators withdrew 2,467 (PJM 2019), and 338 of the remaining projects have reliable public reports on their interconnection costs—amounting to 64 GW of generation resources.[8] Table 3 shows the

[8] Of the 1,685 non-withdrawn projects, 460 do not have a public report online, and the analysis omits 267 others owing to their small size (< 10 MW). The analysis omits an additional 560 projects that represent incremental, rather than new-build, generation projects owing to challenges in confirming the capacities integrated as a result of the interconnections. A sensitivity analysis shows that including these projects with estimates for their incremental capacity yields little change in the capacity-weighted average cost. For this reason, there is no reason to believe that the costs of the 398 analyzed new-build projects are fundamentally different from the costs of the incremental projects. Finally, 60 projects were aggregated due to them being identified as being located on the same interconnection site.

interconnection cost results for PJM. Wind projects total 11 GW at an LCOT of $0.3/MWh. Solar projects total 10 GW at an average LCOT of $3.2/MWh.

Figure 3 shows the PJM range of costs by generator type. Proposed projects are more expensive than constructed ones, and bulk transmission costs constitute most of the total transmission costs. Wind interconnection costs are significantly lower in PJM than in MISO, whereas solar costs are higher.

Table 3. PJM interconnection costs for selected utility-scale projects

				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	**Projects**	**Costs ($2018 B)**	**MW**	**Overall**	**Constructed Projects**	**Proposed Projects**	**Overall**	**Constructed Projects**	**Proposed Projects**
Natural Gas	98	$1.43	38,733	$36.92	$18.40	$76.63	$0.34	$0.17	$0.70
Wind	72	$0.25	10,859	$22.73	$19.07	$54.10	$0.30	$0.25	$0.69
Solar	134	$1.17	10,057	$116.17	$61.83	$131.90	$3.22	$1.72	$3.66
Coal	4	$0.05	1,303	$36.26	$36.26	NA	$0.25	$0.25	NA
Nuclear	2	$0.03	1,674	$19.63	$19.63	NA	$0.12	$0.12	NA

Note: Hydro, biomass, energy storage, and oil are excluded from this table owing to limited observations in the dataset. Overall, projects based on these four technologies have a weighted-average unit cost of $33/kW.

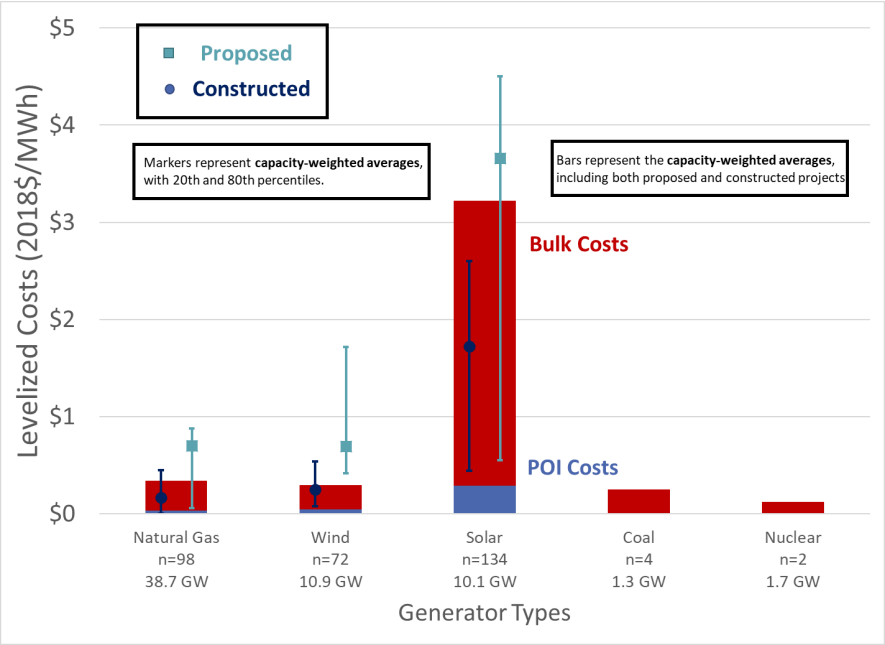


Figure 3. Range of levelized costs for selected utility-scale projects in PJM

4.1.3 EIA

The EIA dataset includes 3,281 constructed generation projects (no proposed projects). The analysis drops 327 projects that are duplicated across years or have data-quality issues, and another 555 that are smaller than 1 MW. The 2,399 projects that remain total 148 GW of generation resources. Table 4 shows the generator types analyzed and their interconnection costs. Wind projects total 50 GW at an average LCOT of $1.0/MWh. Solar projects total 2.2 GW at an average LCOT of $2.2/MWh.

Figure 4 shows the EIA range of costs by generator types. Wind interconnection costs in the EIA dataset are lower than in MISO and higher than in PJM, whereas EIA solar costs are higher than in MISO and lower than in PJM.

Table 4. EIA interconnection costs for selected utility-scale projects

Generator Type	Projects	Costs ($2018 B)	MW	Unit Cost ($/kW)	Levelized ($/MWh)
Natural Gas	675	$3.13	71,006	$44.04	$0.40
Wind	610	$3.45	49,526	$69.61	$0.97
Solar	304	$0.22	2,187	$102.73	$2.21
Coal	42	$1.28	19,671	$65.01	$0.44
Hydro	42	$0.03	639	$50.44	$0.69
Biomass	365	$0.16	1,609	$99.73	$1.09
Oil	303	$0.14	2,397	$58.11	$1.59
Geothermal	39	$0.07	554	$128.24	$1.75

Note: Nuclear and energy storage are excluded owing to few observations in the dataset.

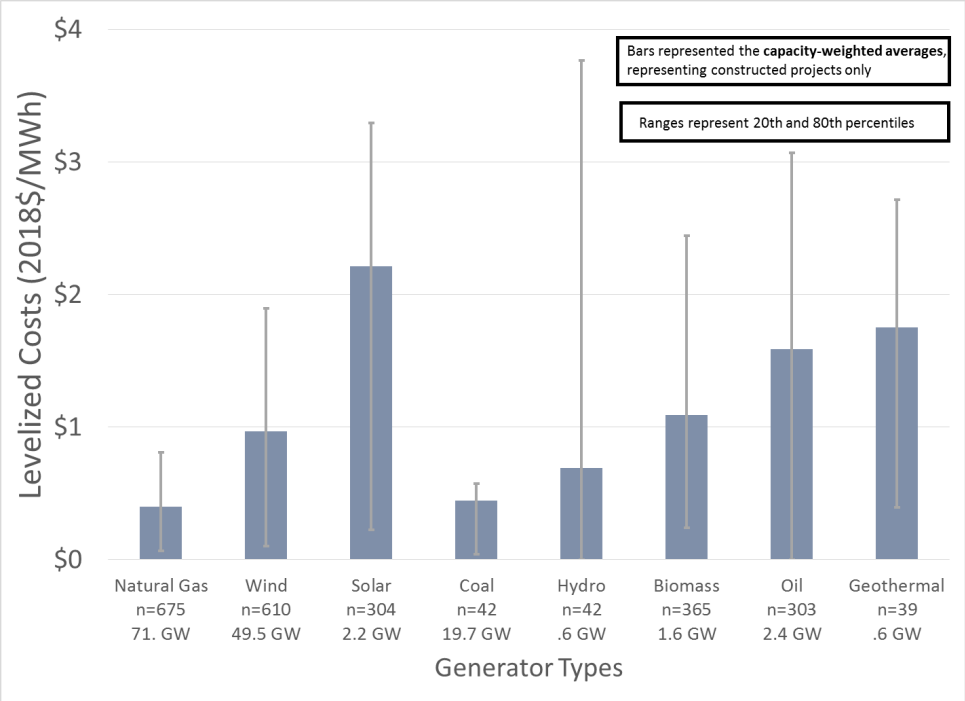
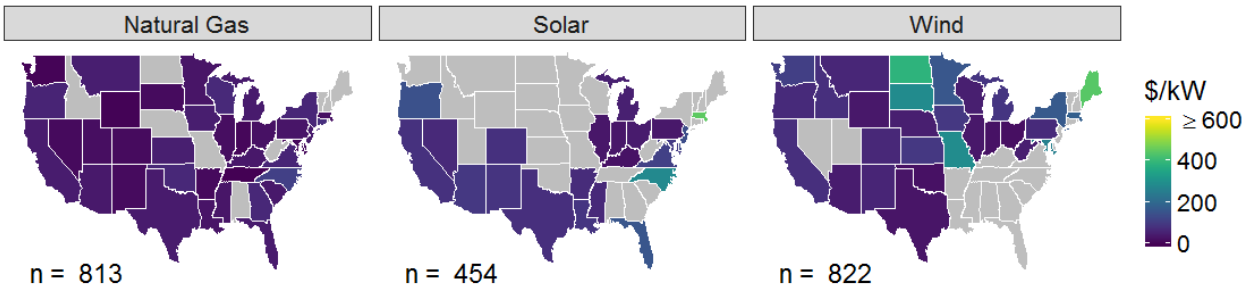


Figure 4. Range of levelized costs for selected utility-scale projects in EIA dataset

4.1.4 Combined Analysis

These results combine the MISO, PJM, and EIA data to assess how location and queue date correlate with transmission costs. Figure 5 highlights differences in project-related transmission costs by resource type and state. For wind, North and South Dakota, Maine, and Missouri have projects with the most expensive transmission needs, perhaps reflecting the limited preexisting transmission infrastructure and electrical load in these states. Figure 6 shows unit costs by the date each constructed project entered the interconnection queue. There is little evidence of significant cost trends over time, although solar costs may have declined.



Note: Gray states represent states not present (containing less than three observations) in the datasets.

Figure 5. Average unit transmission cost by state and utility-scale resource type

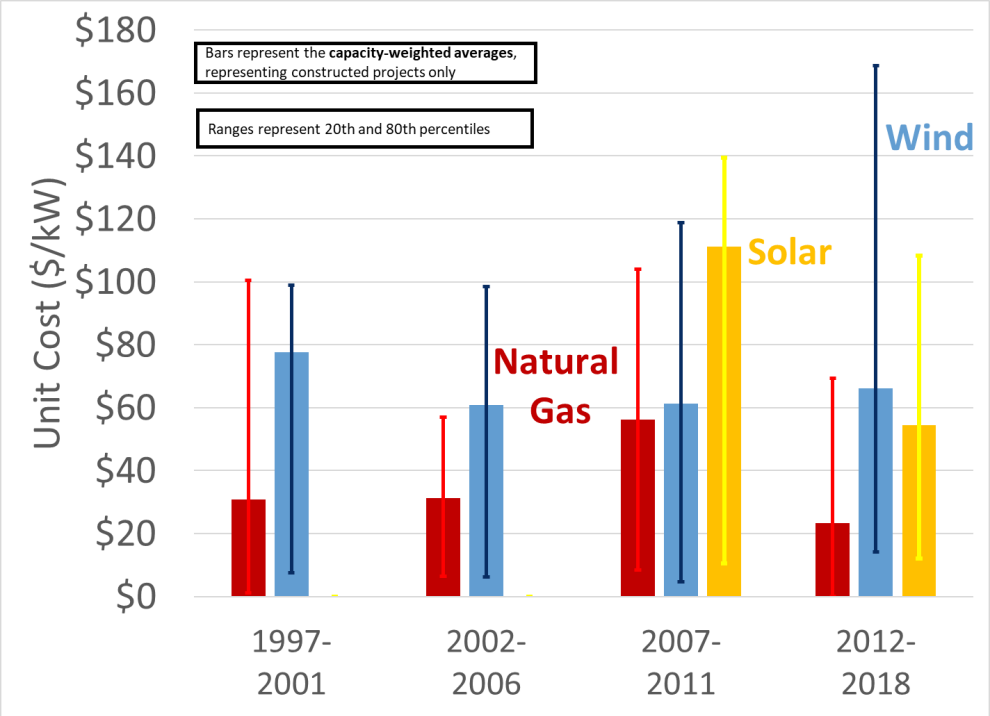


Figure 6. Average unit cost by queue entry year for constructed utility-scale projects

4.2 Bulk System Costs from Actual Projects and Simulation Studies

This subsection presents results from actual projects and simulation studies for utility-scale wind (4.2.1) and solar (4.2.2).

4.2.1 Wind

Figure 8 compares the levelized capital cost of transmission buildout for wind-related constructed transmission projects, proposed transmission projects, and simulation studies (see Appendix A for the specific projects and studies included in this review). All analyses assign full capital cost responsibility to the incremental wind resource being integrated into the transmission system; this is a highly conservative assumption, because transmission investments often serve multiple needs and provide benefits beyond VRE integration. Overall, these sources demonstrate a wide range of transmission costs, from $0–$38/MWh.[9]

Of the 40 actual constructed or proposed transmission projects associated with wind integration, Figure 8 displays the 26 projects that integrate greater than 500 MW of wind and are closer to or finished with construction. The constructed projects have a weighted-average wind LCOT of $5.4/MWh (10%–18% of Lazard's onshore wind LCOE), ranging from $0.9–$11.2/MWh. The proposed projects—which are in early-stage construction or have progressed in the regulatory process but have not secured all

[9] See supplemental information for unit cost ($/kW) data

approvals necessary for completion—are more expensive than the constructed projects, with a weighted-average LCOT of $11.5/MWh (21%–40% of Lazard's onshore wind LCOE).

Transmission costs from the simulation studies are generally lower than those from the actual projects, with a weighted-average LCOT of $3.3/MWh (6%–11% of Lazard's onshore wind LCOE). Of the simulation studies shown, NREL's Standard Scenarios Study ("NREL SS") includes particularly detailed data and is the most recent study to assess transmission investments (Eurek et al. 2016). Using a set of cost assumptions, NREL simulates 26 scenarios and tracks the spur line and bulk system transmission investments needed for the optimal generation mix, resulting in LCOTs of $2.6–$4.6/MWh and a weighted average of $3.1/MWh. However, these estimates assign all transmission costs to wind without netting out costs that are required regardless of wind capacity. Comparing transmission costs in NREL's low wind cost scenario (which builds 366 GW of wind) with those in the low natural gas price scenario (which builds 99 GW of wind) results in an incremental wind transmission cost of $2.2/MWh.[10] Figure 7 reports this value.

[10] This calculation subtracts the NPV of the total transmission capital cost in the low natural gas price scenario from the cost in the low wind cost scenario ($42.9 billion – $21.4 billion = $21.5 billion). Then, the total levelized incremental wind generation in the low natural gas price scenario is netted out from the generation in the low wind cost scenario (16,706 TWh – 7,074 TWh = 9,632 TWh). Finally, $21.5 billion divided by 9,632 TWh results in $2.2/MWh.

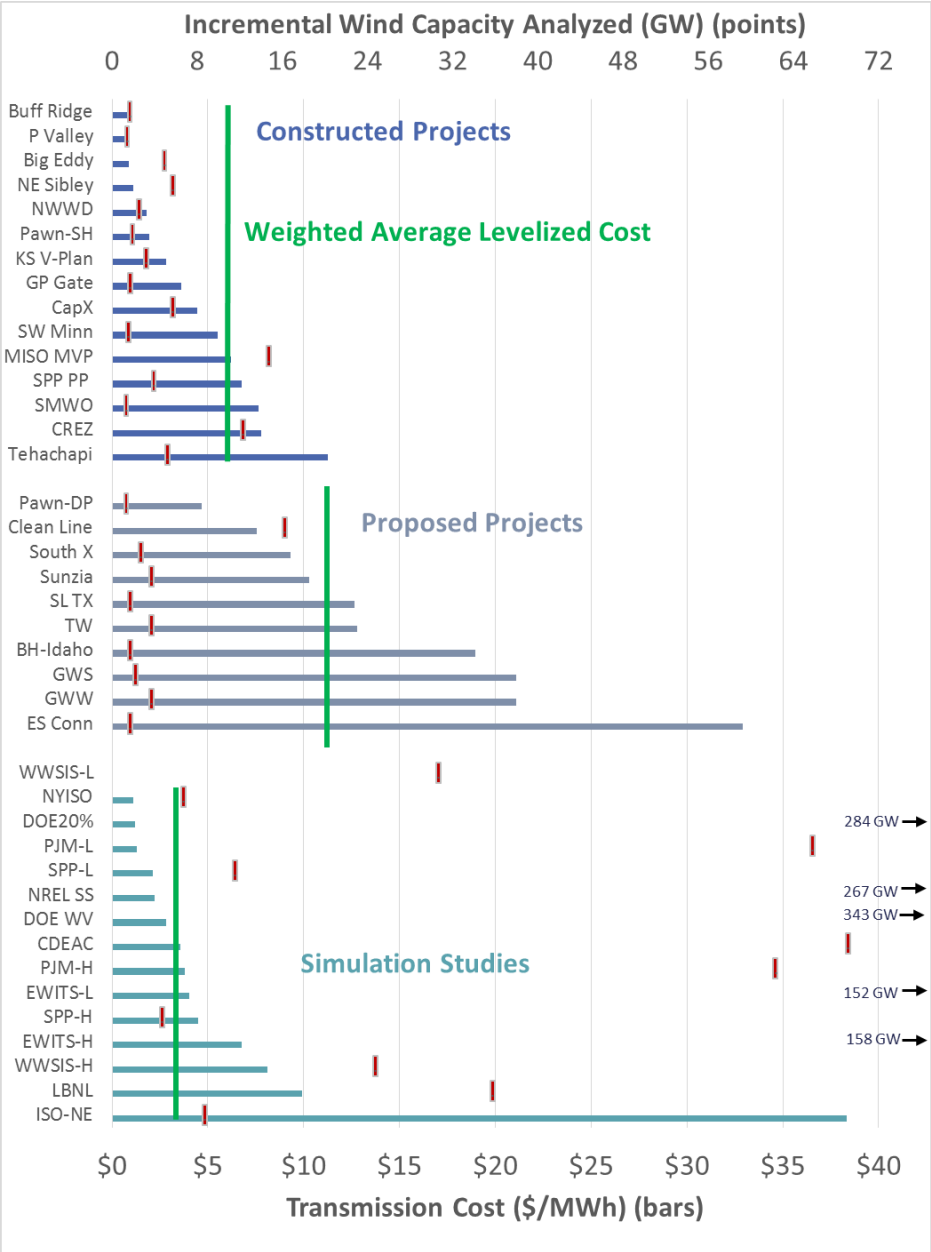


Figure 7. Wind LCOT from constructed and proposed projects and simulation studies

4.2.2 Solar

Figure 8 shows the solar transmission cost results. See Appendix B for a bibliography of studies and reports used. As with wind, the solar transmission cost range is large, from $0–$40/MWh.[11] However, the solar sample is significantly smaller, with only four major studies and four transmission projects with enough certainty to report. Utility-scale solar development has only recently started to expand. In 2010, 40 GW of utility-scale wind had been installed but only 1 GW of utility-scale solar. By 2017, 88

[11] See supplemental information for unit cost ($/kW) data

GW of utility-scale wind had been installed compared to 25 GW of utility-scale solar (EIA 2018b). Combined with the fact that utility-scale solar is not as locationally constrained as wind—and thus many utility-scale solar projects may not require significant transmission[12]—this disparity in capacity deployed might partially explain the disparity between the number of solar and wind projects and studies available. The lack of data hinders analysis of solar transmission costs, particularly with regard to selection bias: focusing on solar projects that require transmission infrastructure will yield transmission cost estimates that are biased high.

These caveats notwithstanding, the four reviewed transmission projects have a weighted-average cost of $15/MWh (33%–42% of Lazard's utility-scale solar LCOE). The large expense associated with the Sunrise Powerlink project in California pushes this average up owing to sensitive national land and difficult terrain that required expensive underground lines—conditions that likely will not apply to most utility-scale solar projects (Akin and Holland 2012; Kahn 2008). Overall, because of the small number of projects and the associated selection bias, these utility-scale solar transmission cost estimates are not highly reliable.

The simulation study solar transmission costs are much lower, with a simple average of $5.3/MWh (12%–15% of Lazard's LCOE) and a range of $0–$15/MWh.[13] Some of these studies noted that the transmission projects analyzed also would improve key reliability issues while providing access to other generation resources such as geothermal and wind; assigning full cost responsibility to solar therefore overstates solar's contribution to transmission costs. The Nevada study and the NREL study identified the amount of utility-scale solar, wind, and other resources that would be facilitated by transmission expansion. In these cases, the present study's solar transmission cost contribution is based on the proportion of solar capacity served by the transmission expansion.

As discussed for wind in Section 4.2.1, NREL's Standard Scenarios Study is particularly useful for analyzing utility-scale solar transmission costs. The study shows LCOTs of $3.1–$7.4/MWh and a weighted average of $4.9/MWh. However, these estimates assign all transmission costs to utility-scale solar without netting out costs that are required regardless of utility-scale solar capacity. Comparing transmission costs in NREL's low photovoltaic (PV) cost scenario (which builds 668 GW of utility-scale solar) with those in the high renewable cost scenario (which builds 118 GW of utility-scale solar)[14] results in an incremental utility-scale solar transmission cost of $1.8/MWh.[15] Figure 8 reports this value.

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[12] Distributed solar is more likely to avoid than to impose transmission costs.

[13] A simple average removes the heavy weighting the U.S. Department of Energy's SunShot Vision Study otherwise would have had. That study suggested that a high-solar future would have the same transmission costs as a low-solar future, but—for the present study—this result was not deemed sufficient to justify pushing the average estimate toward $0/MWh.

[14] Comparing these two scenarios also helps ensure that the incremental transmission difference is likely not driven by wind transmission expansion, because the wind capacity built in each scenario is about the same (165–187 GW).

[15] This calculation subtracts the NPV of the total transmission capital cost in the high renewable cost scenario from the cost in the low PV cost scenario ($36.5 billion – $21.1 billion = $15.4 billion). Then, the total levelized incremental solar generation in the high renewable cost scenario is netted out from the generation in the low PV cost scenario (12,000 TWh – 3,330 TWh = 8,670 TWh). Finally, $15.4 billion divided by 8,670 TWh results in $1.8/MWh.

Figure 8. Solar LCOT from constructed projects and simulation studies

4.3 Aggregated Transmission Costs for Renewables

This subsection presents the aggregated VRE transmission cost results for California (4.3.1) and nationwide (4.3.2).

4.3.1 California RPS Transmission Cost Aggregation

Table 5 summarizes the projects with transmission investments required to meet California's 33% RPS target (CEC 2018).[16] Spending for these projects totals $7.3 billion (in $2018; annualized to $347 million), while about 42,000 GWh of California-sourced utility-scale wind and solar generation are

[16] The present analysis focuses on the 33% RPS target, because California's 50% RPS target is further in the future, and less certainty exists about whether more transmission expenditures might be needed to meet the higher target. In any case, the target allows for inclusion of small hydropower, geothermal, and biomass facilities. Although some of the analyzed transmission lines may facilitate integration of those resources, most upgrades apparently are for utility-scale wind and solar projects.

required to meet the 33% target (CEC 2017).[17] Based on these two values, the total LCOT to meet the utility-scale wind and solar targets is $8.3/MWh.[18]

Table 5. California transmission projects to meet RPS

Transmission Project	California ISO Status	In-Service Date	RPS target	Cost Source	Cost Million ($2018)
Sunrise Powerlink 500 kV line	Approved	2012	33%	Sempra	$2,023
Sycamore Canyon-Peñasquitos 230 kV Line	Approved Policy with Reliability Benefits	2018	33%	CPUC	$271
Tehachapi 500 kV line	Approved	2016	33%	EEI	$3,270
Colorado River-Valley 500 kV line	Approved	2013	33%	EEI	$852
Eldorado-Ivanpah 230 kV line	LGIA	2013	33%	EEI	$373
South of Contra Costa 230 kV Reconductoring	LGIA	2012	33%	Estimated	$50
Carrizo-Midway 230 kV Reconductoring	LGIA	2013	33%	Estimated	$53
Path 42 230 kV Reconductoring	Approved Policy	2016	33%	EEI	$32
IID: Path 42 230 kV Reconductoring and additional upgrades	N/A	N/A	33%	LBNL	$41
LADWP: Barren Ridge 230 kV line	N/A	2016	33%	LADWP	$312

ISO = Independent System Operator, LADWP = Los Angeles Department of Water and Power, LGIA = Large Generator Interconnection Agreement.

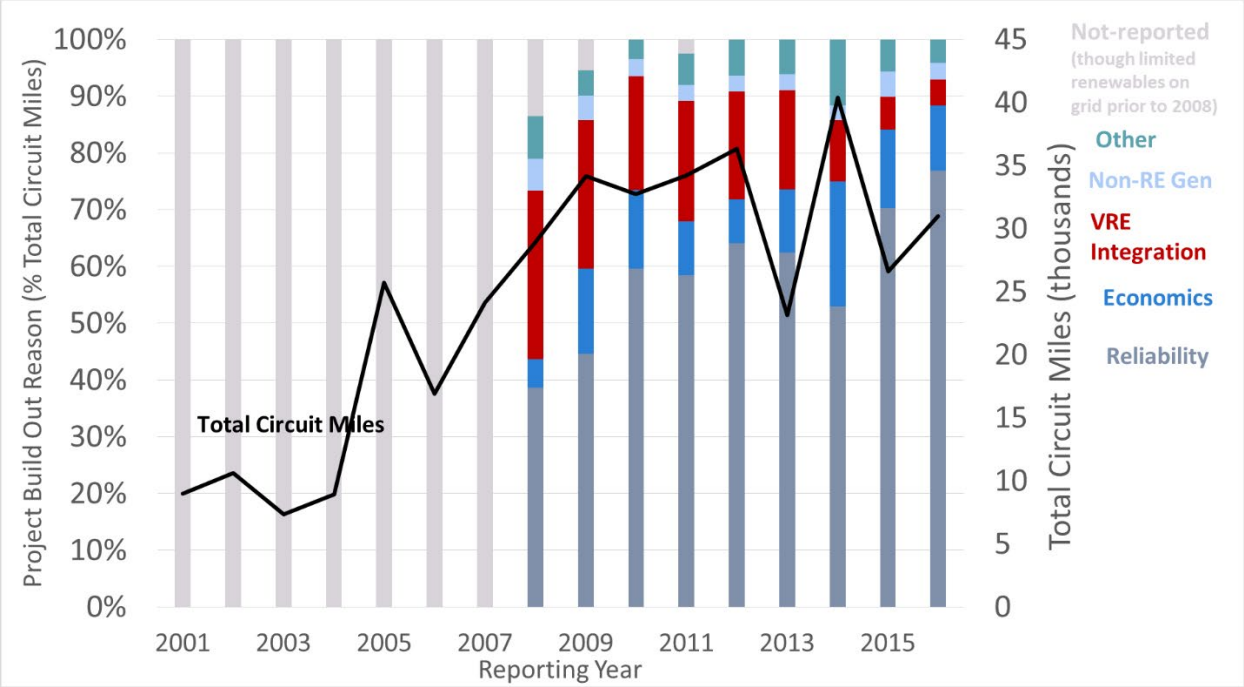
Two lines constitute $5.3 billion of California's $7.2 billion transmission investment: Sunrise Powerlink for utility-scale solar and Tehachapi for wind. The Sunrise project was particularly expensive owing to construction constraints (see Section 4.2.2); it represents 28% of the costs but only accounts for 6% of the energy. Thus, although the aggregate calculation spreads more high transmission costs over a larger amount of VRE generation, a few large investments can significantly affect the average cost of transmission.

4.3.2 U.S.-Wide Transmission Cost Aggregation

From 2001–2016, the total circuit miles of proposed U.S. transmission projects increased, shown as the black line in Figure 9, which covers the next 10-year window within each reporting year (e.g., the 2003 point includes proposed projects from 2004–2013). The colored bars in Figure 9 show the reasons for transmission line investments back to 2008 in percentage of total circuit miles proposed; reliability increased as a reason while VRE integration decreased over the 2008–2016 period (EIA 2017). Before 2008, EIA did not report the major reason for transmission investment.

[17] More than 50,000 GWh of utility-scale wind and solar are contributing to California's RPS, but a portion of this energy is sourced from outside of the state. This analysis includes only California generation and transmission (as listed in Table 5).

[18] Prior to 2008, 5,500 MWh of wind already on the system might have required transmission buildout not included in CEC's report. Excluding this resource increases the LCOT to $9.5/MWh. However, the original estimate of $8.3/MWh only includes generation from California resources, whereas some of this transmission expenditure likely was made to facilitate importation of out-of-state resources. The LCOT estimate decreases to $7/MWh if out-of-state generation is used.



Note: Data compiled by NERC into EIA Form 411

Figure 9. Total U.S. transmission 10-year proposed buildout

Combining the data from Figure 9 with FERC form 1 estimates of nationwide transmission expenditure from 2008–2016 enables estimation of annual transmission expenditures for VRE integration (FERC 2018). Figure 10 shows transmission expenditure by investor-owned utilities (IOUs), grossed up to account for co-ops and public power utilities, from 1996–2016, along with estimates of the proportion of expenditure associated with VRE integration from 2008–2016.[19] Although total transmission expenditure increased during this timeframe, the percentage of transmission proposals affiliated with VRE dropped from 30% to 5% (Figure 9), which makes the VRE transmission expenditure drop (green line in Figure 10). These data suggest a VRE LCOT of $6.2/MWh.

[19] This expenditure is grossed up to account for investment from co-ops, public utilities, and merchant investors, as described below.

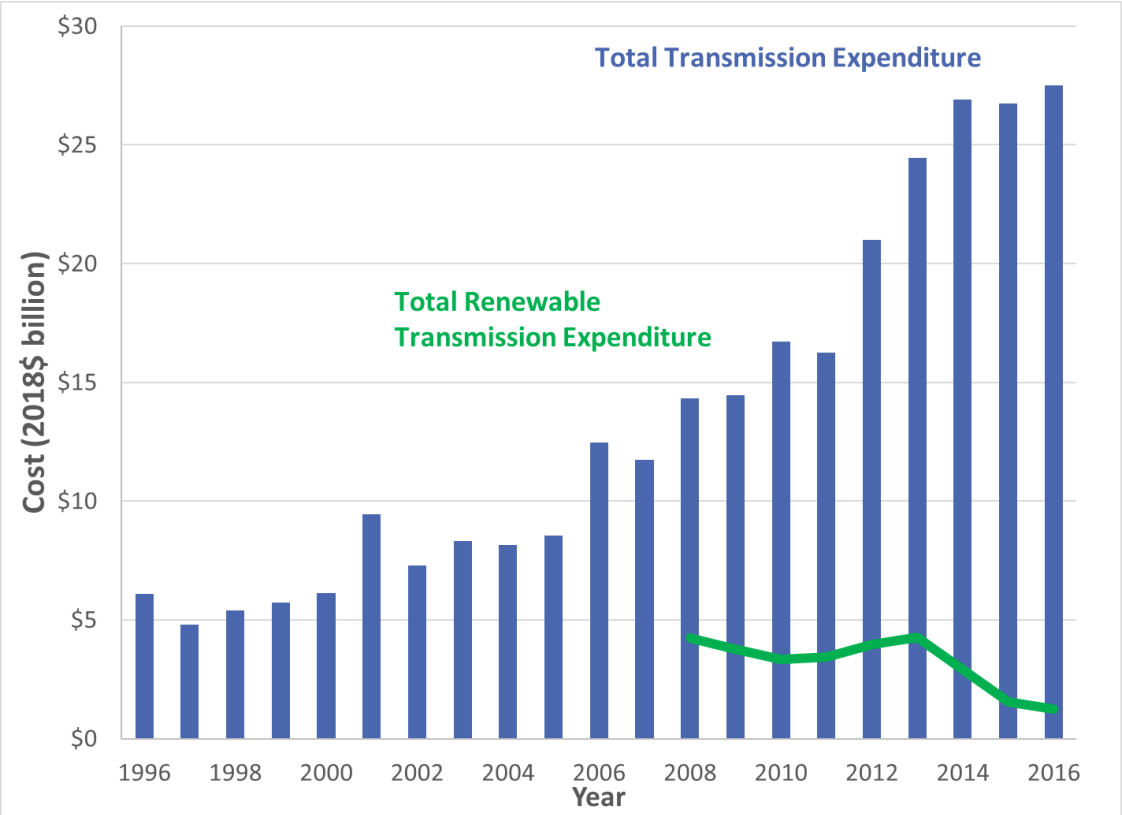


Figure 10. Estimated U.S. transmission expenditure 1996–2016

This analysis hinges on two assumptions: (1) the drivers for proposed transmission lines are highly correlated with the drivers of historical actual transmission line investments, and (2) total U.S. transmission expenditure can be estimated by linearly extrapolating IOU expenditure based on total load served. An analysis of privately available data from the company C Three—tracking U.S. transmission expenditure and including data for co-ops and public utilities as well as IOUs—explores the validity of these assumptions (North American Electric Transmission Projects Database 2018).[20] C Three attributes 19% of $98.4 billion in total investment over the 2008–2016 period to VRE, compared with 15% of $188 billion shown in Figure 10. The similar proportions of transmission expenditure attributed to VRE impart confidence in the Figure 10 estimates. In addition, the C Three data attribute 80% of the $98.4 billion in total investment to IOUs; Figure 10 uses this value to gross up FERC-derived IOU transmission expenditures to account for expenditures by co-ops, public utilities, and merchant developers.

[20] These data are not used in this study's final analysis, because they have many missing expenditures for various transmission projects and thus likely would understate absolute costs. However, the relative costs from these data used to validate the final analysis generally appear to be valid.

5. Discussion

Figure 11 summarizes the utility-scale VRE LCOT results derived from the four estimation approaches. Based on these results, the *average capital cost* of transmission investments is $1–$10/MWh, with individual projects ranging from $0–$40/MWh. However, it is important to understand why the different approaches produce different results and to understand the key challenges to interpreting the results.

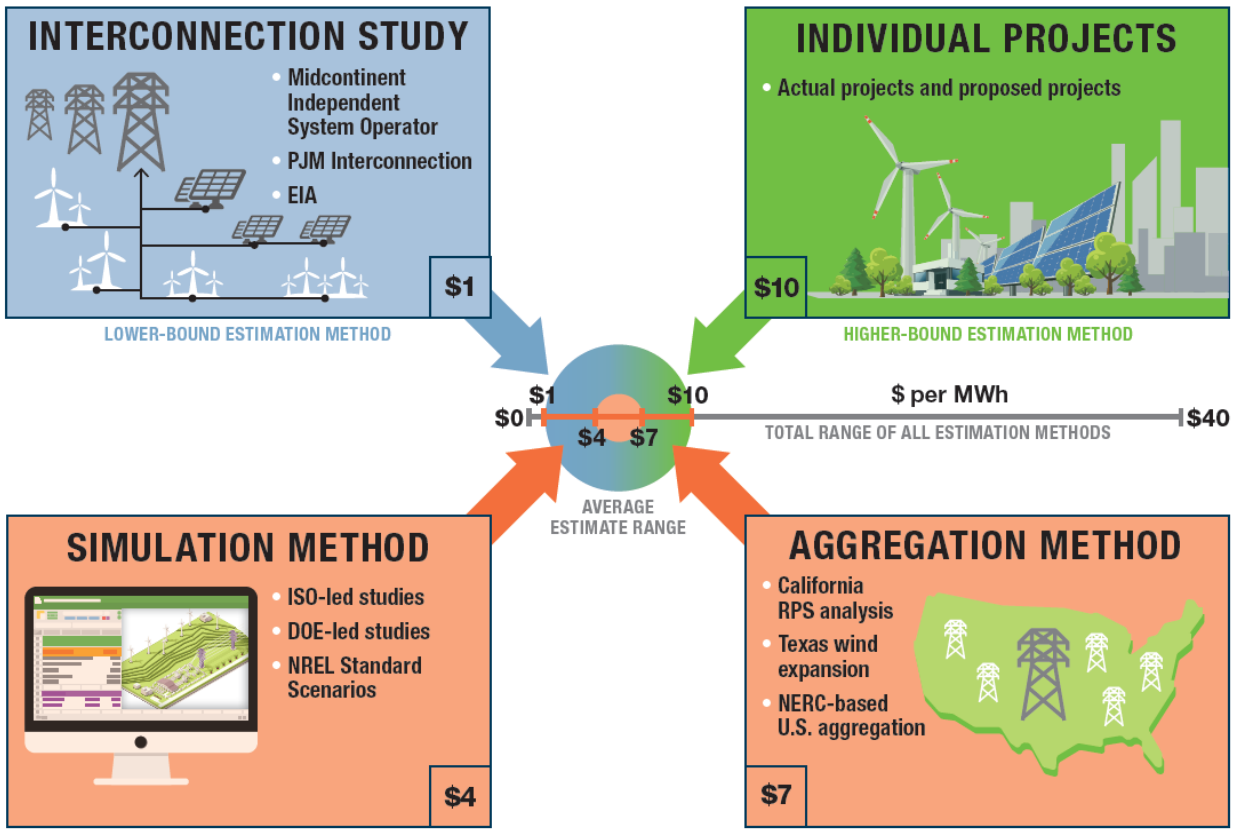


Figure 11. Summary of LCOT for utility-scale wind and solar integration

Two main issues might result in overestimation of VRE transmission costs when the analytical approach focuses on individual actual or proposed transmission projects. First, determining the appropriate cost responsibility for VRE transmission is difficult owing to the multiple purposes and benefits of transmission, which include increasing reliability and reducing congestion. This study assumes all transmission project costs are attributable to VRE and ignores other reasons for building transmission. The resulting overestimate of VRE transmission costs is amplified by VRE's relatively low capacity factors, which yield a lower overall utilization of transmission projects fully assigned to VRE integration. Second, there is a selection bias when focusing on VRE projects that require transmission upgrades rather than all VRE projects, some of which might not need new transmission. Clearly some VRE can be developed without significant transmission investment. Before the CREZ projects in Texas, for instance,

4,500 MW of wind had already been integrated into the Texas system (EIA 2018c).[21] Yet the CREZ projects represent the single major transmission expenditure to integrate wind in the region; if this transmission cost is levelized by all the wind on the Electric Reliability Council of Texas (ERCOT) system, the LCOT decreases from $7.8/MWh to $4.1/MWh (American Wind Energy Association 2017). VRE resources can also exploit transmission lines connected to retiring thermal generators. For instance, LADWP has suggested creating a renewable power hub in Utah owing to the imminent retirement of 1.9 GW of coal capacity (Reyes 2018). In cases like these, VRE projects result in little to no incremental transmission capital investments.

Furthermore, this study mostly analyzes bulk transmission construction in the Plains and Midwest. Although other regions have made a few transmission investments, wind in regions such as the Pacific Northwest has required little transmission investment thus far (NPCC 2013). If the wind built in Oregon and Washington is levelized by the region's single large wind transmission project (Big Eddy), the total cost for wind-based transmission is only $0.6/MWh (EIA 2018c). New England appears to have integrated close to 1,300 MW of wind without large transmission investments, but is now experiencing transmission barriers that will likely require large transmission projects to increase wind penetration further (ISO-NE 2017).

For these reasons, the actual project approach provides an upper bound of estimated transmission costs, although long-term transmission needed to integrate more remote resources might increasingly require these types of transmission projects. The project-level approach may particularly overstate the transmission needed for utility-scale solar, because this study considers only a few solar transmission projects, and solar has less locational dependence than wind does. For example, North Carolina—the state with the second-largest utility-scale solar capacity—appears not to have any significant transmission projects built to integrate these resources.[22]

The simulation study approach overcomes some drawbacks of the actual project approach, but its tendency to underestimate VRE transmission costs make it most suitable for estimating lower bounds to these costs. Simulation studies tend to represent idealized regional or national systems with co-optimized transmission and generation expansion. Because multiple regional entities oversee real-world transmission investments with complex regulatory models and permitting processes, simulation and optimization approaches likely yield lower-bound cost estimates. Furthermore, although NREL ReEDS model studies include spur and bulk transmission investments, many other studies do not specify which costs are incorporated in their estimates. Not incorporating spur and POI costs could further underestimate overall cost estimates.

Interconnection studies also do not account comprehensively for all transmission costs, and thus they likely underestimate total transmission costs. These studies tend to include POI and bulk transmission

[21] This value is a sum of Texas' wind capacity as of 2007.

[22] However, much of North Carolina's utility-scale solar is made up of plants smaller than 5 MW, which might have triggered distribution upgrades rather than transmission lines.

costs associated with different generation types, but they do not include spur costs. Furthermore, the costs reported for interconnection tend not to include all the required bulk transmission investment needed to integrate generation resources. Costs from large transmission projects that result from systemwide regional planning are typically spread over an entire load area (e.g., MISO's MVP and ERCOT's CREZ). Interconnection reports do not include these costs, because the costs are not typically the responsibility of a specific generation resource, and the transmission typically provides systemwide benefits beyond VRE integration.

Finally, the coarse aggregation approach might underestimate or overestimate VRE transmission costs. This study's U.S.-wide aggregation, for example, relies on the assumption that all line miles have the same cost, ignoring the fact that the capacity/voltage of the transmission investment also impacts the total cost. In general, higher-voltage lines are more expensive per mile than their lower-voltage counterparts (SPP 2016). According to EIA's Form 411 data, transmission proposed for VRE integration uses a higher percentage of higher-voltage lines compared with transmission proposed for other reasons—as might be expected owing to the need to transmit large amounts of VRE from remote areas to load centers. This issue suggests that the U.S.-wide aggregation might underestimate the cost of VRE transmission projects. Conversely, the U.S.-wide aggregation approach might overestimate VRE transmission costs because it does not account for future VRE deployment facilitated by U.S. transmission investments. The analysis includes transmission cost estimates through 2016 but freezes the amount of VRE integrated by those investments at 2016 levels. However, a lag likely exists between transmission investment and VRE integration, so conservatively freezing the VRE level likely omits LCOT reductions due to further VRE integration.

These caveats suggest that using any one approach to generalize VRE transmission costs is inadequate. However, using multiple approaches bounds average VRE transmission costs, producing a cost range with a relatively high level of confidence. The key caveats to our high-end estimates tend to suggest that those estimates are too high (e.g. selection bias and strict cost responsibility on our actual project estimates) while the key caveats to our low-end estimates tend to suggest that those estimates are likely too low (e.g. simulations being unrealistically optimized and interconnection studies not including large bulk investment costs).

Furthermore, these costs are relevant for understanding potential future transmission investment costs. While the approaches rely on costs from current and historical transmission buildout, which could theoretically differ from future transmission costs at increasing VRE penetrations,[23] this study does not identify strong and widespread evidence to suggest time trends in transmission investment costs. This study also does not consider how the declining cost of energy storage could change the competitive landscape for transmission development. Onsite energy storage could be both a

[23] At lower VRE penetration levels developers might be able to exploit resource locations that have lower transmission costs and once those cheaper locations have been exhausted, costs might rise to integrate resources located in transmission constrained regions.

complement or substitute for transmission projects and future research might aim to better understand this tradeoff for VRE integration (Khastieva et al. 2019).

Lastly, this paper only considers transmission capital costs to integrate VRE and does not include transmission O&M costs. Some sources estimate average annual U.S. transmission O&M costs at 5%–10% of a project's original capital cost (Larsen 2016); (FERC n.d.). Adding this average annual O&M cost to the annualized financial calculations would approximately double the LCOT presented above. However, applying the average O&M cost to incremental transmission costs likely would overestimate LCOT, because O&M costs do not easily map onto individual projects and likely do not increase linearly with transmission investment. Furthermore, the interconnection studies reviewed for this analysis do not mention assigning lifetime O&M costs to individual generators, suggesting transmission operators do not consider these costs to be the responsibility of generation projects. Nevertheless, because of the potential large share of costs due to O&M, future work should consider adding transmission O&M cost estimates to the capital cost estimates.

6. Conclusions and Policy Implications

The average VRE LCOT range estimated in this study, $1–$10/MWh, represents a substantial expense in relation to the LCOEs of utility-scale wind ($29–$56/MWh) and solar ($36–$46/MWh). Transmission can increase direct plant-level LCOE by 3%–33%.

This study's levelized capital cost estimates for VRE-related transmission are generally lower than prior estimates. At the same time, the study's unit costs ($/kW) are generally in line with prior estimates,[24] highlighting the sensitivity of the levelized results to assumptions regarding project lifetime, discount rate, and capacity factor. This study assumes long lives for transmission assets, discount rates based on the cost of capital for U.S. utilities, and regionally specific capacity factors based on empirical observations.

The results show no large, consistent disparity in the capital cost of transmission between utility-scale solar and wind resources. The smaller number of solar observations could suggest that solar integration is less transmission constrained than wind integration. Future research that benefits from more development of utility-scale solar projects should track the development of solar-related transmission expenses.

The multiple analytical approaches used in this study lend confidence to the resulting range of average VRE transmission capital costs. However, this generalized information is not applicable to individual investment decisions. Rather, it is useful for informing high-level decisions and directions. First, the results might be used in studies assessing the benefits of transmission avoidance and deferral. This information is often important in public policy debates comparing distributed energy resources to utility-scale projects (Kahn 2008). Second, the results might be used when evaluating the potential costs of large-scale public transmission investments (e.g., CREZ in Texas and MVP in the Midwest). Increasingly, region-wide coordination in transmission investment likely will be needed, and these results can inform policy makers about the magnitude of transmission costs compared with potential resource costs. Finally, the results provide insight into a system-level cost component that is not always adequately assessed in studies of high-VRE futures.

[24] See supplemental information for detailed unit cost ($/kW) data

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Appendix A. Details of wind studies/costs reviewed

Table A-1. Source information for wind studies and projects

Transmission Project Name	Acronym in Figure 7	Source name (for MW)	Author	Year	Source Name (for cost)	Author	Year
ISO-NE Wind Integration Study	ISO-NE	New England Wind Integration Study	ISO-NE/GE/Enernex	2010	ibid	ibid	ibid
Analysis of Western Renewable Energy Zones	LBNL	Exploration of resource and transmission expansion decisions in the Western Renewable Energy Zone initiative (table 4)	Mills et. al.	2011	ibid	ibid	ibid
Western Wind and Solar Integration Study	WWSIS-H	Western Wind and Solar Integration Study (Table 3)	GE	2010	ibid	ibid	ibid
Eastern Wind Integration and Transmission Study	EWITS-H	Eastern Wind Integration and Transmission Study (Table 2)	Enernex	2011	ibid	ibid	ibid
SPP Wind Integration study	SPP-H	2016 Wind Integration Study	SPP	2016	ibid	ibid	ibid
Eastern Wind Integration and Transmission Study	EWITS-L	Eastern Wind Integration and Transmission Study (Table 2)	Enernex	2024	ibid	ibid	ibid
PJM Renewable Integration Study	PJM-H	PJM Renewable Integration Study Task 3A Part C Transmission Analysis	GE	2014	ibid	ibid	ibid
CDEAC Study	CDEAC	20% Wind Energy by 2030 (pg. 95 cites CDEAC)	DOE	2008	ibid	ibid	ibid
DOE Wind vision 2015	DOE WV	WindVision: A New Era for Wind Power in the United States (pg. 3)	DOE	2015	ibid	ibid	ibid
NREL Standard Scenarios (w/ ReEDs)	NREL SS	2018 Standard Scenarios Report: A U.S. Electricity Sector Outlook	NREL	2018	ibid	ibid	ibid
SPP Wind Integration study	SPP-L	2016 Wind Integration Study	SPP	2016	ibid	ibid	ibid
PJM Renewable Integration Study	PJM-L	PJM Renewable Integration Study Task 3A Part C Transmission Analysis	GE	2014	ibid	ibid	ibid
20% Wind Energy by 2030 Study	DOE20%	20% Wind Energy by 2030 (pg. 143)	DOE	2006	ibid	ibid	ibid
NYISO Wind Integration Study	NYISO	NYISO Wind Generation Study (Final Draft)	NYISO	2010	ibid	ibid	ibid
Western Wind and Solar Integration Study	WWSIS-L	Western Wind and Solar Integration Study (Table 3)	GE	2010	ibid	ibid	ibid
Tehachapi	Tehachapi	Wind Tech Market Report 2015	LBNL	2016	Transmission Project at a Glance: 2016	EEI	2017
CREZ	CREZ	Estimation of Transmission Costs for New Generation	UT Austin Energy Institute	ibid	ibid	ibid	ibid
Southwest Minnesota wind outlet	SMWO	Transmission Projects Supporting Renewable Resources	EEI	2009	ibid	ibid	ibid
SPP Priority Projects	SPP PP	Wind Tech Market Report 2013	LBNL	2014	Third Quarterly Project Tracking Report 2017	SPP	2017
MISO Multi-Value Projects	MISO MVP	Wind Tech Market Report 2016	LBNL	2017	Regionally Cost Allocated Project Reporting Analysis: MVP Project Status March 2018	MISO MTEP17	2018
SW Minnesota Wind Expansion Project	SW Minn	Transmission Project at a Glance: 2007	EEI	2007	ibid	ibid	ibid
CapX	CapX	Wind Tech Market Report 2013	LBNL	2014	Transmission Project at a Glance: 2016	EEI	2017
Grand Prairie Gateway	GP Gate	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017
Kansas V-Plan	KS V-Plan	Transmission Project at a Glance: 2009	EEI	2009	ibid	ibid	ibid
Pawnee - smoky hill	Pawn-SH	Transmission Project at a Glance: 2012	EEI	2013	ibid	ibid	ibid
Northwest-woodward District	NWWD	Transmission Project at a Glance: 2009	EEI	2009	ibid	ibid	ibid
Nebraska Sibley Line and latan - Nashua Line	NE Sibley	Transmission Project at a Glance: 2013	EEI	2014	ibid	ibid	ibid
Big Eddy – Knight and Central Ferry – Lower Monumental	Big Eddy	Wind Tech Market Report 2014	LBNL	2015	BPA energizes 500-kV Big Eddy–Knight line, halts Montana-to-Washington project	Transmission Hub	2015
Pleasant Valley Transmission	P Valley	Transmission Project at a Glance: 2009	EEI	2009	ibid	ibid	ibid
Buffalo Ridge incremental Generation Outlet	Buff Ridge	Xcel Energy completes major transmission projects	TEI Times	2010	ibid	ibid	ibid
Empire State Connector	ES Conn	Wind Tech Market Report 2016	LBNL	2017	Empire State Connector "HVDC" Transmission Project to Deliver Zero Carbon Energy from Upstate New York Directly to NYC	Cision PR Newswire	2016
Gateway West	GWW	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017
Gateway South	GWS	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017
Boardman-Hemingway	BH-Idaho	Wind Tech Market Report 2016	LBNL	2017	Project Fact Sheet: Boardman to Hemingway Transmission Line Project	Idaho Power	2017
Transwest Express	TW	Wind Tech Market Report 2016	LBNL	2017	http://www.transwestexpress.net/about/index.shtml	Web	2018
Southline Transmission Project	SL TX	Wind Tech Market Report 2016	LBNL	2017	Southline Transmission Project Frequently Asked Questions	Developer	2017
Sunzia	Sunzia	Wind Tech Market Report 2016	LBNL	2017	SunZia Transmission seeks approval of 500-kV project in New Mexico	Transmission Hub	2018
Southern Cross	South X	Wind Tech Market Report 2016	LBNL	2017	Report on the Economic and Fiscal Impacts of the Southern Cross Transmission Project, Louisiana	Moss Adams	2016
Clean Line Projects	Clean Line	Wind Tech Market Report 2016	LBNL	2017	Assortment of project websites	Energy Partners	2018
Pawnee—Daniels Park	Pawn-DP	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017

Table A-2. Levelized capital cost of transmission for wind (actual transmission projects)

Transmission Project / Study Name	Region	Estimated Potential Wind Capacity (MW)	Cost Source	Source Year	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Tehachapi	California	4,500	EEI	2017	$726.67	$11.24
CREZ	Texas	11,553	UT Austin	2017	$610.32	$7.80
Southwest Minnesota wind outlet	Midwest	600	EEI	2009	$598.83	$7.65
SPP Priority Projects	Southwest	3,200	SPP	2017	$437.49	$6.77
MISO Multi-Value Projects	Midwest	14,000	MISO MTEP17	2017	$485.39	$6.20
SW Minnesota Wind Expansion Project	Midwest	800	EEI	2007	$431.64	$5.52
CapX	Midwest	5,000	EEI	2017	$347.44	$4.44
Grand Prairie Gateway	Midwest	1,000	EEI	2017	$283.06	$3.62
Kansas V-Plan	Plains	2,500	EEI	2009	$220.68	$2.82
Pawnee - smoky hill	West	1,200	EEI	2013	$126.48	$1.96
Northwest-woodward District	Plains	1,800	EEI	2009	$140.37	$1.79
Nebraska Sibley Line and Iatan - Nashua Line	Midwest	5,000	EEI	2014	$85.20	$1.09
Big Eddy – Knight and Central Ferry – Lower Monumental	West	4,200	News	2015	$58.20	$0.90
Pleasant Valley Transmission	Midwest	700	EEI	2009	$67.89	$0.87
Buffalo Ridge incremental Generation Outlet	Midwest	940	News	2010	$67.00	$0.86

Table A-3. Levelized capital cost of transmission for wind (proposed transmission projects)

Transmission Project / Study Name	Region	Estimated Potential Wind Capacity (MW)	Cost Source	Source Year	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Empire State Connector	Northeast	1,000	Web	2016	$1,560.41	$32.89
Gateway West	West	3,000	EEI	2017	$1,362.51	$21.07
Gateway South	West	1,500	EEI	2017	$1,362.51	$21.07
Boardman-Hemingway	West	1,000	Idaho Power	2017	$1,226.26	$18.96
Transwest Express	Plains	3,000	Web	2018	$1,000.00	$12.78
Southline Transmission Project	West	1,000	Project FAQ	2017	$817.51	$12.64
Sunzia	West	3,000	Web	2018	$666.67	$10.31
Southern Cross	Texas	2,000	Moss Adams	2016	$728.19	$9.31
Clean Line Projects	Plains	16,000	Web	2018	$590.63	$7.55
Pawnee—Daniels Park	West	600	EEI	2017	$303.16	$4.69

Table A-4. Levelized capital cost of transmission for wind (studies)

Transmission Project / Study Name	Region	Estimated Potential Wind Capacity (MW)	Cost Source	Source Year	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
ISO-NE Wind Integration Study	Northeast	8,000	ISO-NE	2009	$2,593.33	$38.35
Analysis of Western Renewable Energy Zones	West US	35,000	LBNL	2011	$641.08	$9.91
Western Wind and Solar Integration Study	West US	24,030	GE / NREL	2010	$524.16	$8.11
Eastern Wind Integration and Transmission Study	East US	151,938	EnerNex / NREL	2024	$511.61	$6.77
SPP Wind Integration study	Plains	3,963	SPP	2016	$353.32	$4.52
Eastern Wind Integration and Transmission Study	East US	158,628	EnerNex / NREL	2024	$276.74	$4.03
PJM Renewable Integration Study	East US	61,590	PJM	2011	$249.55	$3.80
CDEAC Study	All US	68,400	DOE 20% Wind pg 95	2006	$271.65	$3.55
DOE Wind vision 2015	All US	343,000	DOE	2015	$215.01	$2.81
NREL Standard Scenarios (w/ ReEDs)	All US	267,592	NREL	2018	$80.14	$2.23
SPP Wind Integration study	Plains	10,797	SPP	2016	$166.88	$2.13
PJM Renewable Integration Study	East US	65,045	PJM	2011	$86.24	$1.31
20% Wind Energy by 2030 Study	All US	284,000	DOE	2006	$90.39	$1.18
NYISO Wind Integration Study	East US	6,000	NYISO	2010	$71.57	$1.09
Western Wind and Solar Integration Study	West US	29,940	GE / NREL	2010	$0.00	$0.00

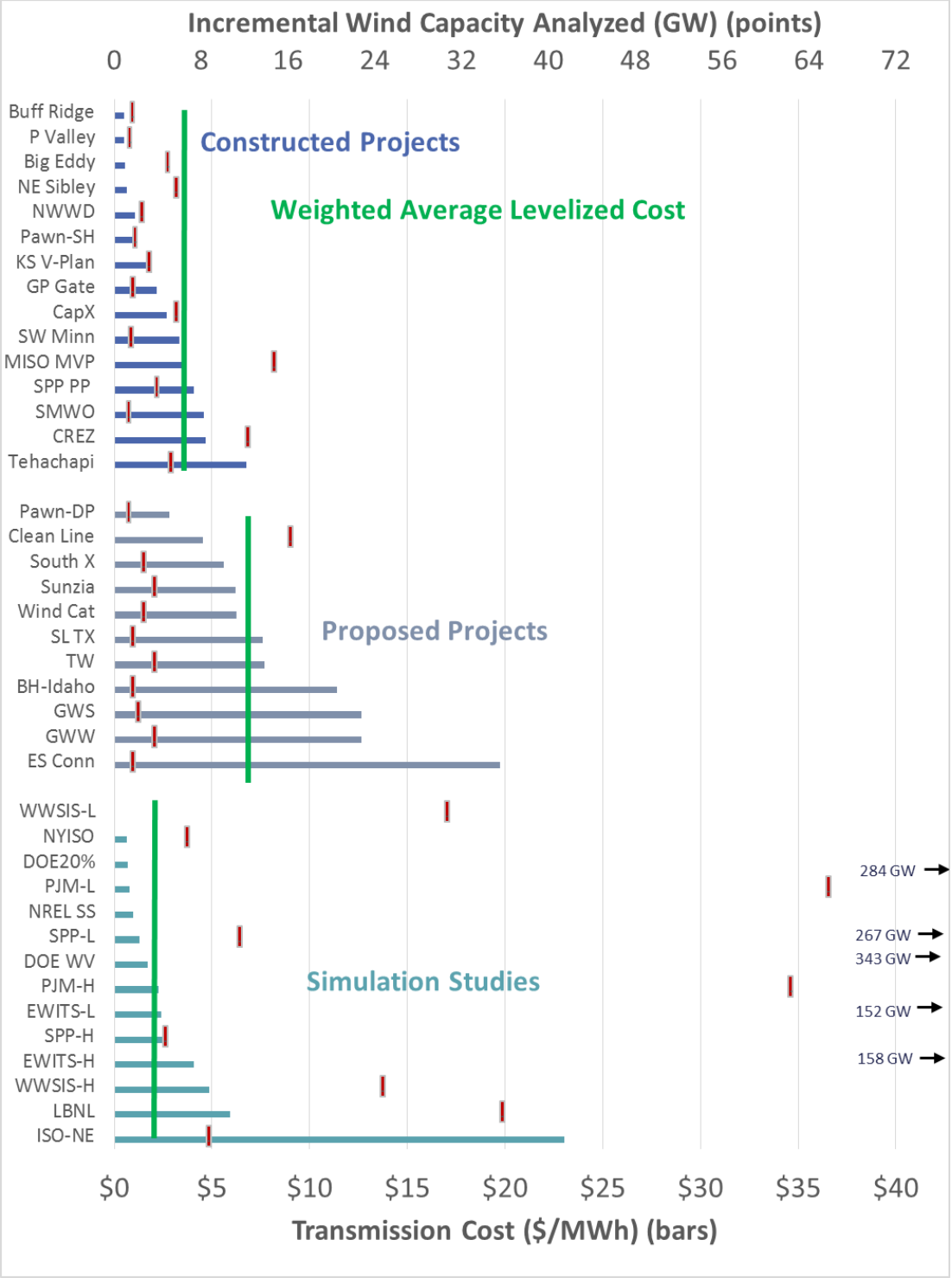

Figure A-1. Utility-scale wind chart (at 2% discount rate)

Appendix B. Details of solar studies/costs reviewed

Table B-1. Source information for utility-scale solar transmission projects and studies

Transmission Project Name	Acronym in Figure 8	Source name (for MW)	Author	Year	Source Name (for cost)	Author	Year
Sacramento River / Lassen / Round Mountain	RETI_3	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
Solano TAFA	RETI_5	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
Riverside and Victorville/Barstow TAFA	RETI_2	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
Imprerial Valley TAFA	RETI_1	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
San Joaquin Valley TAFA	RETI_4	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
South Project	NV_4	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
El Dorado and Clayton extension	NV_1	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
Harry Allen Transformer	NV_3	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
Nevada Study: Harry Allen to Mead	NV_2	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
NREL Standard Scenarios (w/ ReEDs)	NREL SS	2018 Standard Scenarios Report: A U.S. Electricity Sector Outlook	NREL	2018	ibid	ibid	ibid
DOE Sunshot Vision Study	DOE SS	SunShot Vision Study	DOE	2012	ibid	ibid	ibid
Sunrise Powerlink	Sun PL	Sunrise Powerlink Inspires Innovation	T&D World Magazine	2014	ibid	ibid	ibid
Devers - Valley No. 2 Transmission Project DPV2	DPV2	Decision 16-08-017 August 18, 2016 application for west of denvers upgrade project	CPUC	2016	Transmission Project at a Glance: 2014	EEI	2014
Palo Verde Substation - Pinnacle Peak Substation	PV to PP	Transmission Project at a Glance: 2016	EEI	2017	ibid	ibid	ibid
Eldorado-Ivanpah	Eld-Ivan	Website: https://www.sce.com/about-us/reliability/upgrading-transmission/eldorado	SCE	NA	Transmission Project at a Glance: 2014	EEI	2014

Table B-2. Levelized capital cost of transmission for utility-scale solar (studies)

Transmission Project / Study Name	Region	Estimated Potential Solar Capacity (MW)	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Sacramento River / Lassen / Round Mountain	California	5,500	$756.56	$14.93
South Project	West	600	$741.69	$14.64
Imprerial Valley TAFA	California	2,200	$567.42	$11.20
El Dorado and Clayton extension	West	1,300	$415.10	$8.19
San Joaquin Valley TAFA	California	3,200	$143.04	$2.82
Harry Allen Transformer	West	380	$111.84	$2.21
NREL Standard Scenarios (w/ ReEDs)	All US	549,756	$28.03	$1.79
Harry Allen to Mead	West	800	$68.29	$1.35
Solano TAFA	California	1,200	$43.34	$0.86
Riverside and Victorville/Barstow TAFA	California	2,000	$17.68	$0.35
DOE Sunshot Vision Study	All US	530,000	$0.00	$0.00

Table B-3. Levelized capital cost of transmission for utility-scale solar (actual projects)

Transmission Project / Study Name	Region	Estimated Potential Solar Capacity (MW)	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Sunrise Powerlink	California	1,000	$2,023.44	$39.94
Devers - Valley No. 2 Transmission Project DPV2	California	1,250	$681.58	$13.45
Palo Verde Substation - Pinnacle Peak Substation	Southwest	1,000	$306.56	$6.08
Eldorado-Ivanpah	California	1,400	$266.24	$5.26

Figure B 1. Utility-scale solar chart (at 2% discount rate)

Appendix C. Additional Information

Table C-1. Capacity Factors Used for Levelization

Region	Wind	Utility Solar	Natural Gas	Coal	Hydro	Nuclear
Northeast	26%	18%	60.0%	80.0%	40.0%	90.0%
California	35%	28%	60.0%	80.0%	40.0%	90.0%
West	35%	28%	60.0%	80.0%	40.0%	90.0%
Southwest	35%	28%	60.0%	80.0%	40.0%	90.0%
Texas	43%	23%	60.0%	80.0%	40.0%	90.0%
Midwest	43%	20%	60.0%	80.0%	40.0%	90.0%
West US	35%	28%	60.0%	80.0%	40.0%	90.0%
East US	36%	20%	60.0%	80.0%	40.0%	90.0%
All US	42%	26%	60.0%	80.0%	40.0%	90.0%
Plains	43%	20%	60.0%	80.0%	40.0%	90.0%