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Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States –2019 Edition

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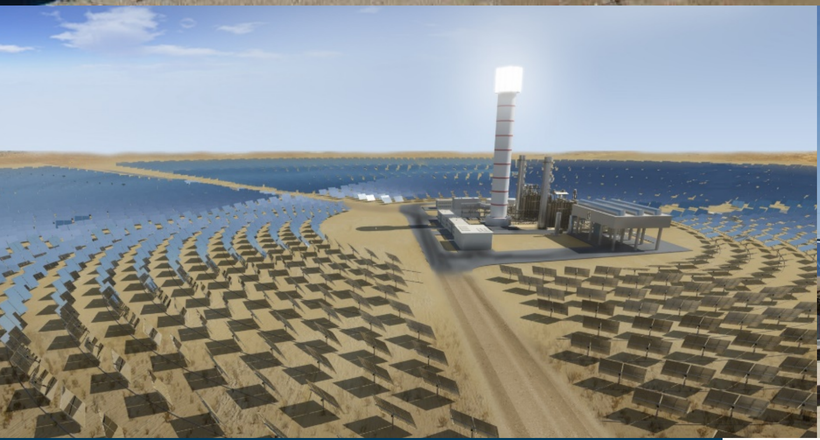

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List of Acronyms

AC	Alternating Current
c-Si	Crystalline Silicon
CAISO	California Independent System Operator
CapEx	Capital Expenditures
COD	Commercial Operation Date
CPV	Concentrating Photovoltaics
CSP	Concentrating Solar-Thermal Power
DC	Direct Current
DIF	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPC	Engineering, Procurement & Construction
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiance
FiT	Feed-in Tariff
ILR	Inverter Loading Ratio
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MISO	Midcontinent Independent System Operator
MW	MegaWatt(s)
MWh	MegaWatt-hour
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OpEx	Total Operational Expenses
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
SPP	Southwest Power Pool

Executive Summary

The utility-scale solar sector—defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar-thermal power ("CSP") project that is larger than 5 MW_{AC} in capacity—has led the overall U.S. solar market in terms of installed capacity since 2012. In 2018, the utility-scale sector accounted for nearly 60% of all new solar capacity, and is expected to maintain its market-leading position for at least another five years, driven in part by favorable Internal Revenue Service ("IRS") "safe harbor" guidance that enables projects that start construction in 2019 to qualify for the 30% federal investment tax credit ("ITC") if they achieve commercial operations prior to 2024. With four new states—Washington, Wyoming, Vermont, and Connecticut—having added their first utility-scale solar project in 2018, three quarters of all states, representing all regions of the country, are now home to one or more utility-scale solar projects. This ongoing solar boom makes it challenging—yet more important than ever—to stay abreast of the latest utility-scale market developments and trends.

This report—the seventh edition in an ongoing annual series—is intended to help meet this need, by providing in-depth, annually updated, data-driven analysis of the utility-scale solar project fleet in the United States. Drawing on empirical project-level data from a wide range of sources, this report analyzes not just installed project prices—i.e., the traditional realm of most solar economic analyses—but also technology trends, operating costs, capacity factors, power purchase agreement ("PPA") prices, levelized cost of energy ("LCOE"), curtailment, and market value from a large sample of utility-scale solar projects throughout the United States. The report also includes data and observations about completed or recently announced solar+storage projects. Given its current dominance in the market, utility-scale PV also dominates much of this report, though data from CPV and CSP projects are also presented where appropriate.

Some of the more-notable findings from this year's edition include the following:

- ***Installation and Technology Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn—i.e., 690 projects totaling 24,586 MW_{AC}—several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and PPA price data analyzed later. For example, the use of solar trackers (all single-axis, east-west tracking) dominated 2018 installations, with nearly 70% of all new capacity. Fixed-tilt projects are increasingly only built in less-sunny regions, while tracking projects continue to push into these same regions. After declining for five consecutive years—a reflection of the geographic shift in the market from the high-insolation Southwest to other less-sunny regions—the median long-term average insolation at newly built project sites stabilized in 2018. Meanwhile, the median inverter loading ratio ("ILR")—i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating—has grown steadily since 2014, to 1.33 in 2018 for both tracking and fixed-tilt projects, allowing the inverters to operate closer to (or at) full capacity for more of the day. In 2018, seven utility-scale PV+battery projects came online.
- ***Installed Prices:*** Median installed PV project prices within an overall sample of 641 projects totaling 22,886 MW_{AC} have steadily fallen by two-thirds since the 2007-2009 period, to \$1.6/W_{AC} among 60 projects completed in 2018 and totaling 2,499 MW_{AC}. The lowest 20th percentile of projects within this 2018 sample were priced at or below \$1.3/W_{AC}, with the lowest-priced projects around \$1.0/W_{AC}. Those 2018 projects that use single-axis trackers

exhibited no upfront cost premium (and even slightly lower prices) compared to fixed-tilt installations. Overall price dispersion across the entire sample has decreased steadily every year since 2013.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs were in the neighborhood of $19/kW$_{AC}$-year, or $11/MWh, in 2018. These numbers—from a limited sample of 48 projects totaling 919 MW$_{AC}$—include only those costs incurred to directly operate and maintain the generating plant, and should not be confused with total operating expenses, which would also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead.

- ***Capacity Factors:*** The cumulative net AC capacity factors of individual projects in a sample of 550 PV projects totaling 20,024 MW$_{AC}$ range widely, from 12.1% to 34.8%, with a sample median of 25.2% and a capacity-weighted average of 27.0%.[1] This project-level variation is based on a number of variables, including the strength of the solar resource at the project site, whether the array is mounted at a fixed tilt or on a tracking mechanism, the ILR, degradation, and curtailment. Changes in at least the first three of these factors drove mean capacity factors higher from 2010-vintage (at 21.7%) to 2013-vintage (at 26.7%) projects. Among more-recent project vintages, however, mean capacity factors have remained stagnant or even declined, as a build-out of lower-resource sites has offset an increase in the prevalence of tracking (while the ILR has changed little).

- ***PPA Prices and LCOE:*** Driven by lower installed project prices and, at least through 2013, improving capacity factors, levelized PPA prices for utility-scale PV have fallen dramatically over time, by $20-$30/MWh per year on average from 2006 through 2012, with a smaller price decline of ~$10/MWh per year evident in most years since 2013. Aided by the 30% ITC, most recent PPAs in our sample—including many outside of California and the Southwest—are priced below $40/MWh levelized (in real 2018 dollars), with many priced below $30/MWh and a few even priced below $20/MWh. Despite these low PPA prices, solar continues to face stiff competition from both wind and natural gas. Excluding the benefit of the 30% ITC, the median LCOE among operational PV projects in our sample stood at $53.8/MWh in 2018 (with a range from $33.8/MWh to $112.8/MWh), and has followed PPA prices lower over time, suggesting a relatively competitive market for PPAs.

- ***Solar's Wholesale Market Value:*** Falling PPA prices have been matched to some degree by a decline in the wholesale market value of solar (energy + capacity) within higher-penetration solar markets like California. Due to an abundance of solar energy pushing down mid-day wholesale power prices, solar generation in California earned just 79% of the average energy and capacity price within CAISO's wholesale market in 2018 (down from 146% back in 2012). In five of the six other ISO markets analyzed, however, solar still provides above-average value (the exception being ISO-NE, at 89% of average wholesale market value in 2018). In CAISO, falling solar PPA prices have largely kept pace with solar's declining market value over time,

[1] Capacity factor is a measure of the amount of electricity generated in a given period relative to how much electricity could have been generated if the generator was operating at full capacity for the entire period. Because solar generation varies seasonally, capacity factor calculations for solar are typically performed in full-year increments. 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].

thereby maintaining solar's competitiveness. In all other ISOs, solar offers higher value yet, in some cases, similar or even lower PPA prices than in California, which may be one reason why the market has been shifting away from California and into other regions.

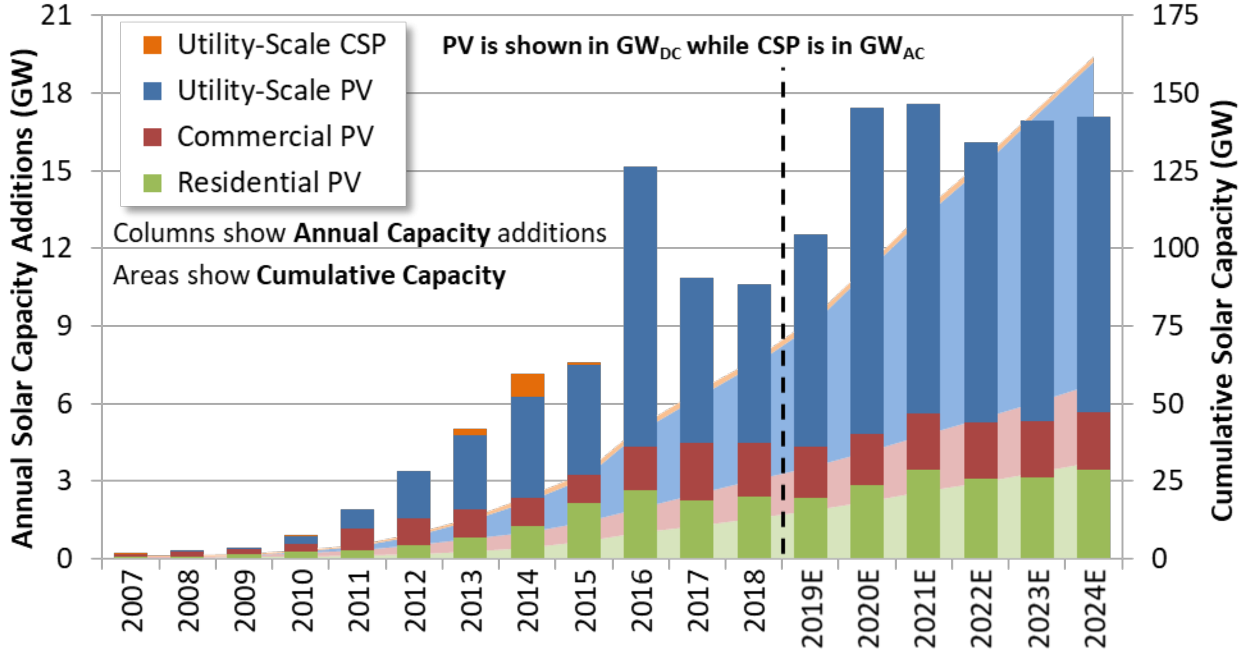
- ***Solar+Storage:*** Adding battery storage is one way to increase the value of solar, and a proliferation of PV plus storage PPAs and project announcements over the past few years has provided a critical mass of concrete data for us to begin tracking. Data from 38 completed or announced PV hybrid projects totaling 4.3 GW_{AC} of PV and 2.6 GW_{AC} of battery capacity (and with storage duration ranging from 2-5 hours, with 4 hours being by far the most common) suggests that sizing of the battery capacity relative to the PV capacity varies widely, depending on the application and specific situation. Moreover, the size of the incremental PPA price adder for 4-hour storage varies linearly with this ratio, ranging from ~$5/MWh for batteries sized at 25% of PV capacity up to $15/MWh for batteries sized at 75% of PV capacity. There are a variety of ways in which storage is compensated within these PPAs, some of which are rather creative (see the discussion following Table 3 in Section 2.5). As PV plus battery storage becomes more cost-effective, many developers are now regularly offering it as an upgrade to standalone PV.
- ***CSP:*** No new utility-scale CSP projects have come online in the United States since 2015, and no CSP plants are currently under construction or in late-stage development. As such, the only new CSP data reported in this 2019 edition relates to the capacity factors of existing CSP plants. On that front, two recent trough projects without storage have largely matched ex-ante capacity factor expectations, while two power tower projects and a third trough project with storage continue to underperform relative to projected long-term, steady-state levels. Further details are provided in Chapter 3.

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years. At the end of 2018, there were at least 284 GW of utility-scale solar power capacity within the interconnection queues across the nation, 133 GW of which first entered the queues in 2018 (with 36 GW of this 133 GW including batteries). The growth within these queues is widely distributed across all regions of the country, and is most pronounced in the up-and-coming Midwest region, which accounts for 26% of the 133 GW, followed by the Southwest (21%), Southeast and Northeast (each with 15%), California (10%), Texas (9%), and the Northwest (5%). Though not all of these projects will ultimately be built as planned, the ongoing influx and widening geographic distribution of solar projects within these queues is as clear of a sign as any that the utility-scale market is maturing and expanding outside of its traditional high-insolation comfort zones.

Finally, we've set up several data visualizations that are housed on the home page for this report: https://utilityscalesolar.lbl.gov. There you can also find an Excel workbook that features the underlying data for each of the report's figures, a slide deck, and a post-release webinar recording.

1. Introduction

"Utility-scale solar" refers to large-scale photovoltaic ("PV"), concentrating photovoltaic ("CPV"), and concentrating solar-thermal power ("CSP") projects that typically sell solar electricity directly to utilities or other buyers, rather than displacing onsite consumption (as in the commercial and residential markets).[2] Although utility-scale CSP has a much longer history than utility-scale PV (or CPV),[3] and saw substantial new deployment between 2013 and 2015, the utility-scale solar market in the United States has been dominated by PV over the past decade—resulting in twenty-one times as much utility-scale PV capacity as CSP capacity online at the end of 2018 (Figure 1). In 2018, 6.2 GW_{DC} of new utility-scale PV capacity were deployed in the United States, bringing cumulative utility-scale PV installations to 37.3 GW_{DC}. Though 43% below the record 10.8 GW_{DC} deployed in 2016, 2018's deployment was nevertheless comparable to that seen in 2017, and was significantly higher than in any year prior to 2016.



Source: Wood Mackenzie/SEIA (2010-2019), LBNL's "Tracking the Sun" and "Utility-Scale Solar" databases

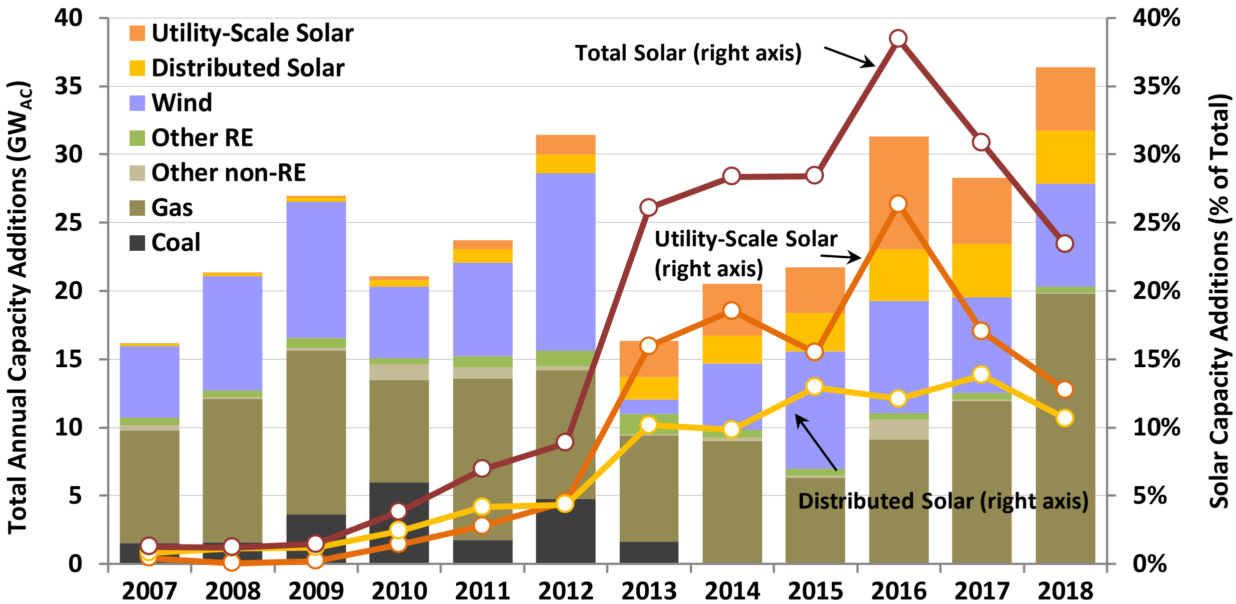
Figure 1. Historical and Projected PV and CSP Capacity by Sector in the United States[4]

[2] PV and CPV projects use silicon, cadmium-telluride, or other semi-conductor materials to directly convert sunlight into electricity through the photoelectric effect (with CPV using lenses or mirrors to concentrate the sun's energy). In contrast, CSP projects typically use either parabolic trough or, more recently, "power tower" technology to produce steam that powers a conventional steam turbine.

[3] Nine large parabolic trough projects totaling nearly 400 MW_{AC} began operating in California in the late 1980s/early 1990s, whereas it was not until 2007 that the United States saw its first PV project in excess of 5 MW_{AC}.

[4] Wood Mackenzie/SEIA's definition of "utility-scale" reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box—*Defining "Utility-Scale"*—in this chapter for a discussion of different definitions of "utility-scale"). In addition, the PV capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box—*AC vs. DC*—at the start of Chapter 2 discusses why AC capacity ratings make more sense for utility-scale PV projects). Despite these inconsistencies, the data are nevertheless useful for the purpose of providing a general sense for the size of the utility-

Led by the utility-scale sector, solar power has comprised a sizable share—more than 20%—of all generating capacity additions in the United States in each of the past six years (Figure 2). In 2018, it constituted 23% of all U.S. capacity additions (with utility-scale solar accounting for 13%), behind natural gas (55%) but ahead of wind (21%).[5]



Source: ABB, AWEA, Wood Mackenzie/SEIA, Berkeley Lab

Figure 2. Relative Contribution of Generation Types to Annual Capacity Additions

With this strong growth in new capacity, a number of states have achieved a solar penetration rate of 10% or more, while California has climbed to 19% of in-state generation. Table 1 lists the top 10 states based on actual solar generation in 2018—for all market segments as well as just utility-scale[6]—divided by total in-state electricity generation (left half of table) and in-state load (right half). When considering the entire solar market (i.e., both distributed and utility-scale), California, Nevada, and Hawaii top the list regardless of whether penetration is based on total generation or total load, while other states—most notably Vermont and Massachusetts—drop back in the rankings when penetration is calculated as a percentage of load. In 2018, eight states achieved solar penetration levels of 5% or higher, while solar penetration across the entire United States stood at 2.3-2.5%.[7] Penetration rates for just utility-scale are, of course, lower than for the market as a whole, with California and Nevada leading the pack.

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scale market and demonstrating relative trends between different market segments and technologies. Projections for 2019-2024 are based on Wood Mackenzie and SEIA 2019b.

[5] Data presented in Figure 2 are based on gross capacity additions, not considering retirements. Furthermore, they include only the 50 U.S. states, not U.S. territories, and rely on Wood Mackenzie/SEIA's definition of utility-scale solar (as described in the text box on page 9).

[6] The distinction between utility-scale solar and the rest of the market in Table 1 is based on the EIA's 1 MW_{AC} capacity threshold, which differs from the 5 MW_{AC} threshold adopted in this report. The numbers in Table 1 reflect generation from all solar power technologies: PV, CPV, and CSP.

[7] These 2018 penetration numbers do not fully capture the generation contribution of new solar power capacity added during 2018, particularly if added towards the end of the year.

Table 1. U.S. Solar Penetration Rankings in 2018: the Top 10 States

State	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	19.0%	12.8%	15.8%	10.7%
Nevada	12.7%	11.5%	13.7%	12.4%
Hawaii	11.2%	1.9%	13.3%	2.3%
Vermont	11.0%	5.7%	4.9%	2.6%
Massachusetts	10.7%	4.3%	6.1%	2.5%
Arizona	6.5%	4.5%	9.6%	6.6%
Utah	6.4%	5.4%	8.4%	7.1%
North Carolina	5.4%	5.2%	5.2%	5.1%
New Mexico	4.7%	3.9%	6.4%	5.4%
New Jersey	4.2%	1.7%	4.3%	1.7%
Rest of U.S.	*0.7%*	*0.5%*	*0.8%*	*0.5%*
TOTAL U.S.	**2.3%**	**1.6%**	**2.5%**	**1.8%**

Source: EIA's Electric Power Monthly (February 2019)

With the 30% Investment Tax Credit ("ITC") available through 2023 for those projects that start construction by the end of 2019 (see the ITC text box on the next page), the utility-scale PV market is expected to remain strong through at least 2023, averaging 10 GW_{DC} per year (Figure 1). This ongoing boom in the utility-scale market makes it increasingly challenging—yet, at the same time, more important than ever—to stay abreast of the latest developments and trends.

This report—the seventh edition in an ongoing annual series—is designed to help identify and track important trends in the market by compiling and analyzing the latest empirical data from the rapidly growing fleet of utility-scale solar projects in the United States. As in past years, this seventh edition maintains our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box at the end of this chapter describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). As in previous editions, we break out coverage of PV (including PV+battery hybrid projects) and CSP into separate chapters (Chapters 2 and 3, respectively), to simplify reporting and enable readers who are more interested in just one of these technologies to more-quickly access what they need.[8] Within each of these two chapters, we first present installation and technology-related trends (e.g., module and mounting preferences, inverter loading ratios, troughs vs. towers, etc.) among the existing fleet, before turning to empirical data on installed project prices (in $/W terms), operation and maintenance ("O&M") costs, project performance (as measured by capacity factor), power purchase agreement ("PPA") prices, and solar's levelized cost of energy ("LCOE"). New this year within the PV chapter (Chapter 2) is a section (Section 2.6) on wholesale market value, which includes data on solar curtailment. Chapter 4 concludes with a brief look ahead.

[8] Select data pertaining to the few CPV projects in our sample continue to be presented, where warranted, along with the corresponding data for PV projects in Chapter 2.

Finally, we note that this report complements several other related studies and ongoing research activities at LBNL and elsewhere. Most notably, LBNL's annual *Tracking the Sun* report series analyzes the latest trends in residential and commercial PV project pricing, while NREL's PV system cost benchmarks are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (the text box on page 24 provides more information on NREL's utility-scale cost benchmarks). In addition, Section 2.6 on solar's market value draws upon ongoing analysis conducted under LBNL's *Solar-to-Grid (S2G)* project. All of this work is funded by the U.S. Department of Energy Solar Energy Technologies Office, which aims to reduce utility-scale solar's levelized cost of electricity ("LCOE") to $30/MWh (in nominal dollars) by 2030. Most of LBNL's solar-related work can be found at emp.lbl.gov/research/renewable-energy , while information on the Solar Energy Technologies Office can be found at energy.gov/solar-office.

A Note on the Data Used in this Report

The data sources mined for this report are diverse, and vary depending on the type of data being analyzed, but in general include the Federal Energy Regulatory Commission ("FERC"), the U.S. Energy Information Administration ("EIA"), state and federal incentive programs, state and federal regulatory commissions, industry news releases, trade press articles, and communication with project owners and developers. We describe these and other sources in more detail in the *References* section at the end of the report. In most cases, data are drawn from a sample, rather than the full universe, of solar power projects installed in the United States. Sample size varies depending on the technology (PV vs. CSP) and the type of data being analyzed (e.g., cost vs. performance), and not all projects have sufficiently complete data to be included in all data sets. Furthermore, the data vary in quality, both across and within data sources. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market data, with an emphasis on 2018; with some limited exceptions (including Figure 1 and Chapter 4), the report does not discuss forecasts or seek to project future trends.

The home page for this report—utilityscalesolar.lbl.gov—houses an Excel workbook that provides all of the publicly available data for each of the report's figures, as well as a number of interactive data visualizations that enable one to explore the data in different ways.

The Federal Investment Tax Credit ("ITC")

The business energy investment tax credit, or ITC, in Section 48 of the U.S. tax code has been available to commercial solar projects for many years. Though originally a 10% credit, the *Energy Policy Act of 2005* temporarily increased the size of the credit to 30% starting in 2006. In October 2008, the *Emergency Economic Stabilization Act of 2008* extended the 30% credit through the end of 2016, and in December 2015, the *Consolidated Appropriations Act of 2016* extended it once again, through 2019. This most-recent extension brought several other changes as well. For commercial projects, the prior requirement that a project be "placed in service" (i.e., operational) by the reversion deadline was relaxed to enable projects that merely "start construction" by the deadline to also qualify. Moreover, rather than reverting from 30% directly to 10% in 2020, the credit will instead gradually phase down to 10% over several years: to 26% in 2020, 22% in 2021, and finally 10% for projects that start construction in 2022 or thereafter. Moreover, in June 2018, the IRS issued "safe harbor" guidance clarifying that any project that qualifies for the 30%, 26%, or 22% ITC by starting construction in 2019, 2020, or 2021, respectively, will have until the end of 2023 (i.e., up to 4 years for projects that start construction in 2019) to achieve commercial operations without having to demonstrate a continuous work effort. In practice, this safe harbor guidance likely means that most utility-scale solar projects deployed through 2023 will continue to benefit from the full 30% ITC. Finally, as of October 2019, there were ongoing efforts—including bills introduced in both the U.S. House and Senate—to extend the 30% ITC for another five years, before the step-down begins.

The 30% ITC has aided the utility-scale solar market over the years by enabling lower PPA prices that make solar more affordable, leading to greater deployment. One visible testament to its importance, at least historically, is 2016's record spike in deployment (see Figure 1), which was driven by the scheduled end-of-2016 reversion of the ITC to 10% (though, as noted above, that reversion was ultimately deferred by the late-December 2015 extension through 2019). Barring yet another extension, similar high deployment levels are expected over the next few years, in advance of the step down to 10% (Figure 1).

Defining "Utility-Scale"

Determining which electric power projects qualify as "utility-scale" (as opposed to commercial- or residential-scale) can be a challenge, particularly as utilities begin to focus more on distributed generation. For solar PV projects, this challenge is exacerbated by the relative homogeneity of the underlying technology. For example, unlike with wind power, where there is a clear difference between utility-scale and residential wind turbine technology, with solar, very similar PV modules to those used in a 5 kW residential rooftop system might also be deployed in a 100 MW ground-mounted utility-scale project. The question of where to draw the line is, therefore, rather subjective. Though not exhaustive, below are three different—and perhaps equally valid—perspectives on what is considered to be "utility-scale":

- Through its Form EIA-860, the Energy Information Administration ("EIA") collects and reports data on all generating plants of at least 1 MW of capacity, regardless of ownership or whether interconnected in front of or behind the meter (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Wood Mackenzie and SEIA ("Wood Mackenzie/SEIA") define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it onsite) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FiT") or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own (rather than as part of a larger portfolio of projects) to be "utility-scale" (Sternthal 2013). For PV, such financiers might consider a 40 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

Though each of these three approaches has its merits, this report adopts yet a different approach: utility-scale solar is defined herein as any ground-mounted solar project that is larger than 5 MW_{AC} (separately, ground-mounted PV projects of 5 MW_{AC} or less, along with roof-mounted systems of all sizes, are analyzed in LBNL's annual *Tracking the Sun* report series).

This definition is grounded in consideration of the four main types of data analyzed in this report: installed prices, O&M costs, capacity factors, and PPA prices. For example, setting the threshold at 5 MW_{AC} helps to avoid smaller projects that are arguably more commercial in nature, and that may make use of net metering and/or sell electricity through FiTs or other avoided cost contracts (any of which could skew the sample of PPA prices reported later). A 5 MW_{AC} limit also helps to avoid specialized (and therefore often high-cost) applications, such as carports or projects mounted on capped landfills, which can skew the installed price sample. Meanwhile, ground-mounted systems are more likely than roof-mounted systems to be optimally oriented in order to maximize annual electricity production, thereby leading to a more homogenous sample of projects from which to analyze performance, via capacity factors. Finally, data availability is often markedly better for larger projects than for smaller projects (in this regard, even our threshold of 5 MW_{AC} might be too small).

Some variation in how utility-scale solar is defined is natural, given the differing perspectives of those establishing the definitions. Nevertheless, the lack of standardization does impose some limitations. For example, Wood Mackenzie/SEIA's projections of the utility-scale market (shown in Figure 1) may be useful to readers of this report, but the definitional differences noted above (along with the fact that Wood Mackenzie/SEIA reports utility-scale capacity in DC rather than AC terms) make it harder to synchronize the data presented herein with their projections. Similarly, institutional investors may find some of the data in this report to be useful, but perhaps less so if they are only interested in projects larger than 20 MW_{AC}.

Until consensus emerges as to what makes a solar project "utility-scale," a simple best practice is to be clear about how one has defined it (and why), and to highlight any important distinctions from other commonly used definitions—hence this text box.

2. Utility-Scale Photovoltaics (PV)

At the end of 2018, 690 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) PV projects totaling 24,586 MW_{AC} were in commercial operation in the United States.[9] 16.5% of this capacity—i.e., 93 projects totaling 4,047 MW_{AC}—achieved commercial operation in 2018. The next six sections of this chapter analyze large samples of this population, focusing on installation and technology trends, installed prices, operation and maintenance costs, capacity factors, PPA prices and LCOE, and finally, market value. Sample size varies by section, and not all projects have sufficiently complete data to be included in all six samples and sections.

For reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like \$/W installed prices) are expressed in AC terms throughout this report, unless otherwise noted. In addition, all data involving currency are reported in constant or real U.S. dollars—in this edition, 2018 dollars.[10]

AC vs. DC: AC Capacity Ratings Are More Appropriate for Utility-Scale Solar

Because PV modules are rated under standardized testing conditions in direct current ("DC") terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale PV projects, however, the alternating current ("AC") capacity rating—measured by the combined AC rating of the project's inverters—is more relevant than DC, for two reasons:

1) All other conventional and renewable utility-scale generation sources (including concentrating solar-thermal power, or CSP) to which utility-scale PV is compared are described in AC terms—with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors.
2) Utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters by a median factor of 1.33 (described in more detail in later sections of this chapter, and portrayed in Figure 7). This increase in the "inverter loading ratio" boosts revenue (per unit of AC capacity) and, as a side benefit, increases AC capacity factors. In these cases, the difference between a project's DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project's output will ultimately be constrained by the inverters' AC rating, the project's AC capacity rating is the more appropriate rating to use.

Except where otherwise noted, this report defaults to each project's AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices (\$/W_{AC}), operating costs (\$/kW_{AC}-year), and AC capacity factor.

[9] Because of differences in how "utility-scale" is defined (e.g., see the text box at the end of Chapter 1), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from Wood Mackenzie and SEIA 2019) of the amount of utility-scale PV capacity online at the end of 2018. For instance, Figure 4 shows that a lower amount of utility-scale PV capacity was installed in 2015 than in 2014, which stands in contrast to Wood Mackenzie and SEIA, but is the result of these definitional differences (in addition to our policy of including in each calendar year only those PV projects that have become fully operational).

[10] Conversions between nominal and real dollars use the implicit gross domestic product ("GDP") deflator. Historical conversions use the actual GDP deflator data series from the U.S. Bureau of Economic Analysis, while future conversions (e.g., for PPA prices) use the EIA's projection of the GDP deflator in *Annual Energy Outlook 2019* (EIA 2019).

2.1 Installation and Technology Trends (690 projects, 24.6 GW_{AC})

Before progressing to analysis of project-level data on installed prices, operating costs, capacity factors, PPA prices, LCOE trends, and market value, this section analyzes trends in utility-scale PV project installations and technology configurations among the *entire population* of PV projects from which later data samples are drawn. The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, PPA price, LCOE, and/or market value trends presented and discussed in later sections.

Florida was the new national leader in utility-scale solar growth

Figure 3 overlays the location of every utility-scale PV (and PV+battery) project in the LBNL population on a map of solar resource strength in the United States, as measured by global horizontal irradiance ("GHI").[11] Figure 3 also defines the regions used for regional analysis throughout this report. Individual project markers indicate mounting and module type, delineating between projects with arrays mounted at a fixed tilt versus on tracking devices that follow the position of the sun,[12] and between projects that use crystalline silicon ("c-Si") versus thin-film (primarily cadmium-telluride, or "CdTe") modules. Figure 4, meanwhile, provides a sense for how regional deployment of utility-scale solar has evolved over time.

As shown in the lower map of Figure 3, many of the cumulative projects (and much of the capacity) are located in California and the Southwest, where the solar resource is the strongest, and where state-level policies have encouraged utility-scale solar development for a long time. But starting in 2015, other regions besides California and the Southwest burst onto the scene and, in 2018, accounted for the lion's share—72%—of all new utility-scale PV capacity additions (see the top map in Figure 3, and also Figure 4). The Southeast was once again the growth leader in 2018, with nearly half of all new capacity, and for the first time the largest state market in terms of new solar capacity was not California but Florida (with slightly more than 1 GW_{AC} or 25% of all new additions, more than doubling its previous cumulative capacity). Despite its good solar resource, the "Sunshine State" added primarily fixed-tilt projects, presumably due to high wind-load considerations. The established player North Carolina continued to add many projects over 50 MW_{AC}, for a total of 472 MW_{AC}. With 16% of all new utility-scale PV capacity additions in 2018, Texas is quickly becoming a leader in utility-scale solar, just as it is in the wind sector. Finally, while California completed only 10 new utility-scale PV projects in 2018, it still added nearly 1 GW_{AC} and accounts for 40% of the cumulative installed national capacity.

[11] GHI is the total solar radiation received by a surface that is held parallel to the ground, and includes both direct normal irradiance ("DNI") and diffuse horizontal irradiance ("DIF"). DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position (i.e., the goal of dual-axis tracking devices), while DIF is the solar radiation that arrives indirectly, after having been scattered by the earth's atmosphere. The GHI data represent average irradiance from 1998-2009 (Perez 2012).

[12] All but eight of the 452 PV projects in the population that use tracking systems use single-axis trackers (which track the sun from east to west each day). In contrast, five PV projects in Texas built by OCI Solar, along with three CPV projects (and two CSP power tower projects described later in Chapter 3), use dual-axis trackers (i.e., east to west daily *and* north to south over the course of the year). For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis, which itself can increase generation by ~20%) often does not outweigh the incremental capital and O&M costs (plus risk of malfunction), depending on the PPA price.

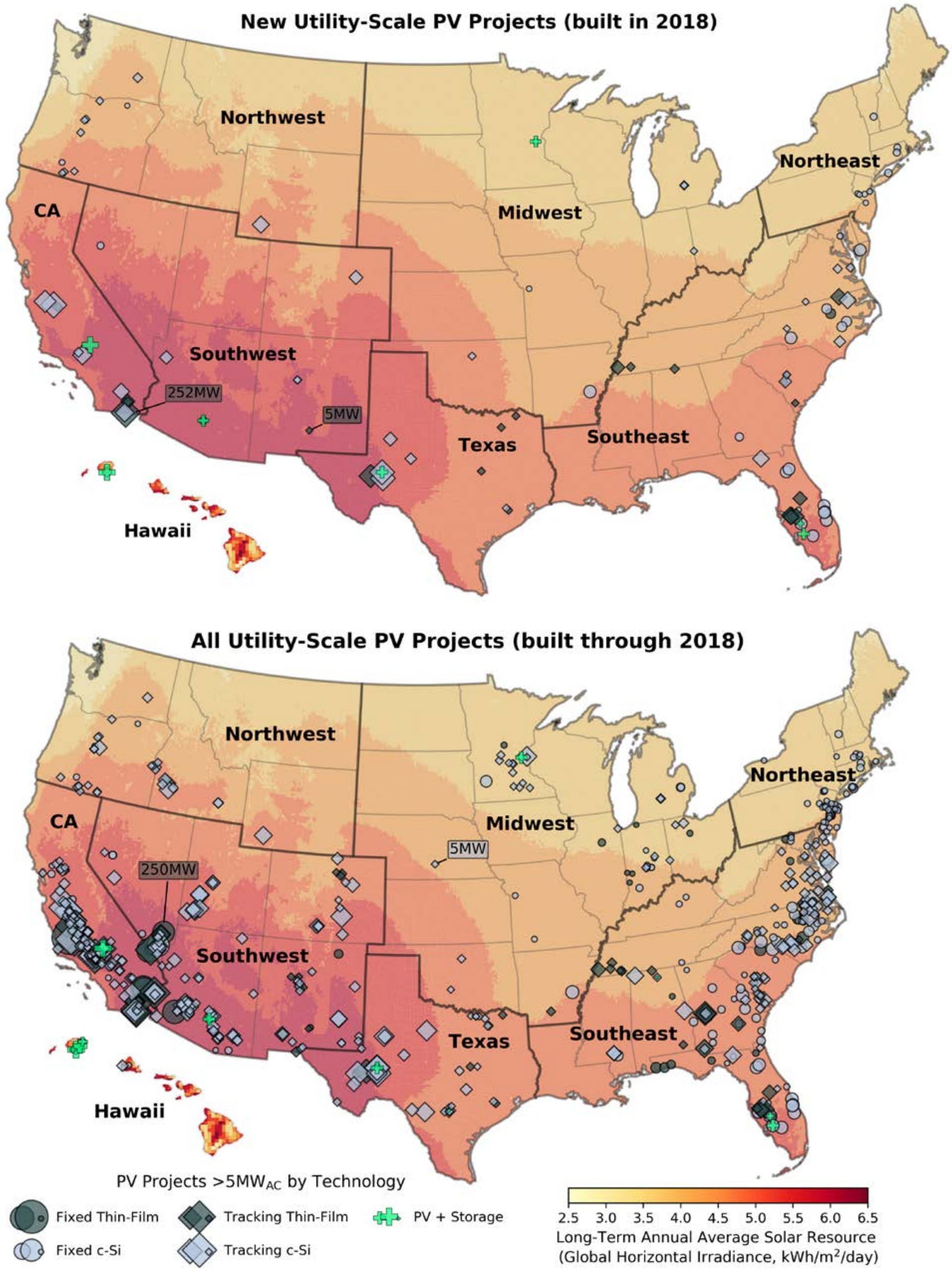

Figure 3. Maps of Global Horizontal Irradiance (GHI) and Utility-Scale PV Projects

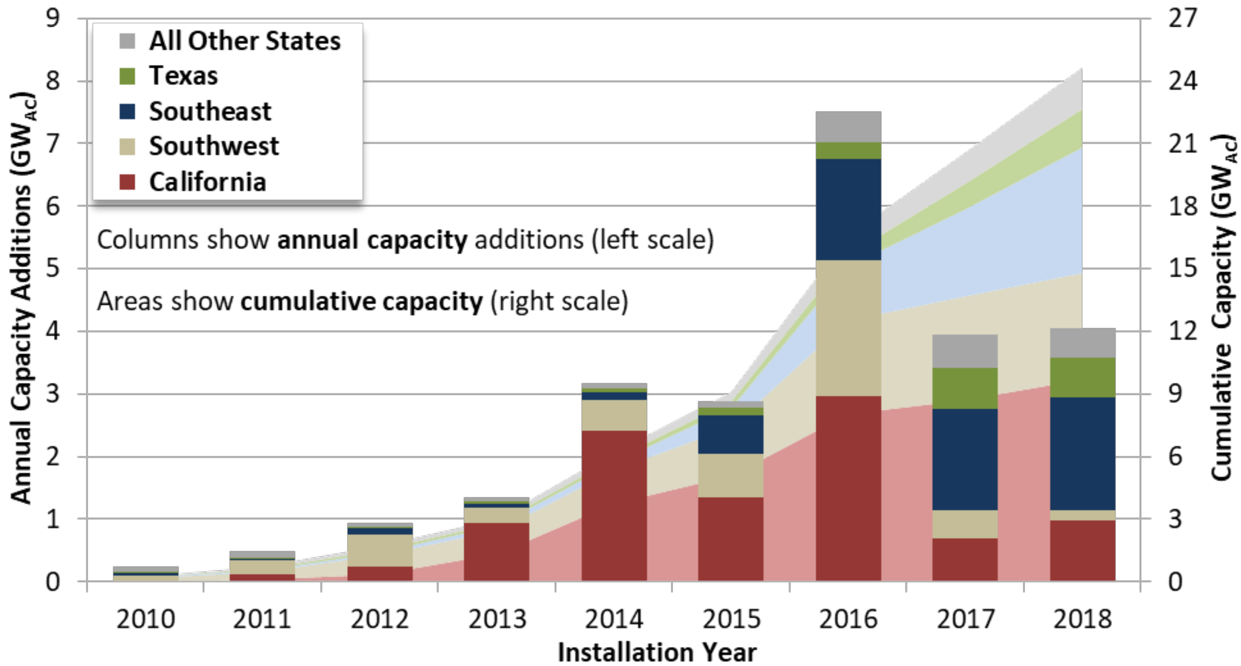

Figure 4. Annual and Cumulative Utility-Scale PV Capacity by U.S. Region

For the first time since 2010, none of the Southwestern states added more than 70 MW_{AC} in new capacity in 2018, trailing even the Northwest. Four new states—Washington, Wyoming, Vermont, and Connecticut—added their first utility-scale PV projects in 2018, bringing the total to 39 states that are now home to utility-scale solar projects larger than 5 MW_{AC}.

Tracking c-Si projects continued to dominate 2018 additions

Figure 5 shows the same data as Figure 4, but broken out by technology configuration (mounting and module type) rather than location. Following years of significant gains since 2014, the percentage of newly built projects using tracking mechanisms remained stable in 2018 at 74% (or 72% in terms of newly added capacity). Tracking has been the dominant mounting choice for c-Si projects for eight years now (as tracking costs have come down, reliability has improved, and the 30% ITC has helped defray the incremental up-front cost). Despite this, 2018 was the year with the most fixed-tilt c-Si additions ever (1.2 GW_{AC}), being particularly popular in the Northeast and Southeast. Following significant improvements in the efficiency of CdTe modules in recent years,[13] First Solar's thin-film projects were exclusively installed on trackers in 2018, marking a complete reversal from five years prior when thin-film projects were *only* mounted at a fixed-tilt.

[13] Prior to 2014, only two thin-film tracking projects had ever been built in the United States, in stark contrast to more than one hundred c-Si tracking projects. Tracking has not been as common among thin-film projects historically, largely because the lower efficiency of thin-film relative to c-Si modules in the past required more land area per nameplate MW—a disadvantage exacerbated by the use of trackers. In recent years, however, leading thin-film manufacturer First Solar has increased the efficiency of its CdTe modules at a faster pace than its multi-crystalline silicon competitors, such that at the end of 2018, First Solar's CdTe Series 4v3 module efficiency stood at 17.0% (while the Series 6 module that started production in April 2018 has an increased efficiency of 18.0%), roughly on par with multi-crystalline at ~17%-18% (though both still lag *mono*-crystalline modules—e.g., SunPower's new A series at 22.3% or the mono PERC modules of Trina, Jinko, Hanwha, and Canadian Solar at ~18-20%).

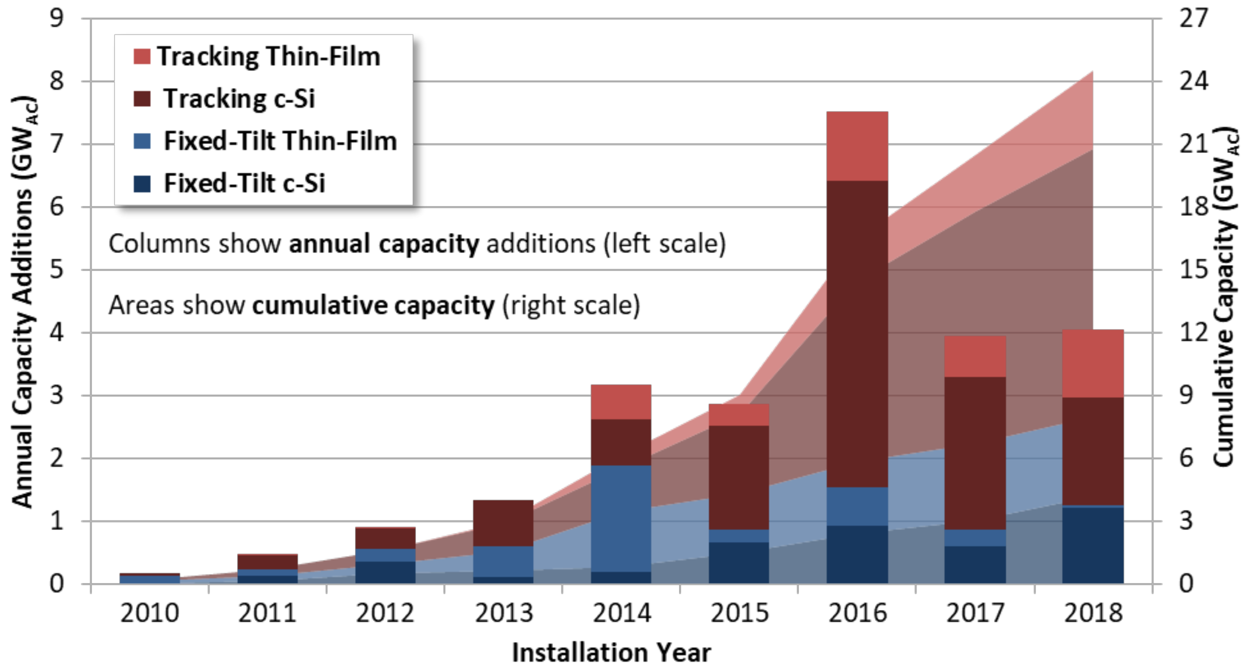

Figure 5. Annual and Cumulative Utility-Scale PV Capacity by Module and Mounting Type

c-Si modules continue to be the dominant choice for utility-scale solar additions in 2018 by a 3-1 margin, with 2.9 GW_{AC} of new capacity broadly distributed between Hanwha (29% market share), Jinko (10%), Canadian Solar (10%), and a number of other manufacturers having a market share of less than 5% each, among them newcomers like Risen (4%) and Talesun (3%).[14] In contrast, First Solar, which manufactures CdTe modules, accounts for most (84%) of the 1.1 GW_{AC} of new thin-film capacity added to the project population in 2018, with the remainder (168 MW_{AC}) coming from Solar Frontier, a Japanese manufacturer of "CIGS" (copper indium gallium selenide) modules.

Figure 5 also breaks down the composition of *cumulative* installed capacity as of the end of 2018. Tracking projects (of any module type) account for 68% of the cumulative installed utility-scale PV capacity through 2018, while c-Si modules are used in 69% of cumulative capacity. Breaking these cumulative capacity statistics out by both module *and* mounting type, the most common combination was tracking c-Si (12.8 GW_{AC} from 368 projects), followed by fixed-tilt c-Si (4.2 GW_{AC} from 182 projects), and a draw between tracking thin-film (3.75 GW_{AC} from 79 projects), and fixed-tilt thin-film (3.75 GW_{AC} from 56 projects).

More projects at lower-insolation sites, fixed-tilt mounts crowded out of sunny areas

Figure 3 and Figure 4 (earlier) provide a general sense for *where* and in what type of solar resource regime utility-scale solar projects within the population are located (Figure 3), as well as *when* these projects achieved commercial operation (Figure 4). Figure 6 further refines the picture by showing the median site-specific long-term average annual GHI (in $kWh/m^2/day$) among new utility-scale PV projects built in a given year. Knowing how the average resource quality of the

[14] We were unable to identify a module manufacturer for 33% of the c-Si capacity that came online in 2018. Thus, actual market shares likely deviate from the numbers mentioned above.

project fleet has evolved over time is useful, for example, to help explain observed trends in project-level capacity factors by project vintage (explored later in Section 2.4).

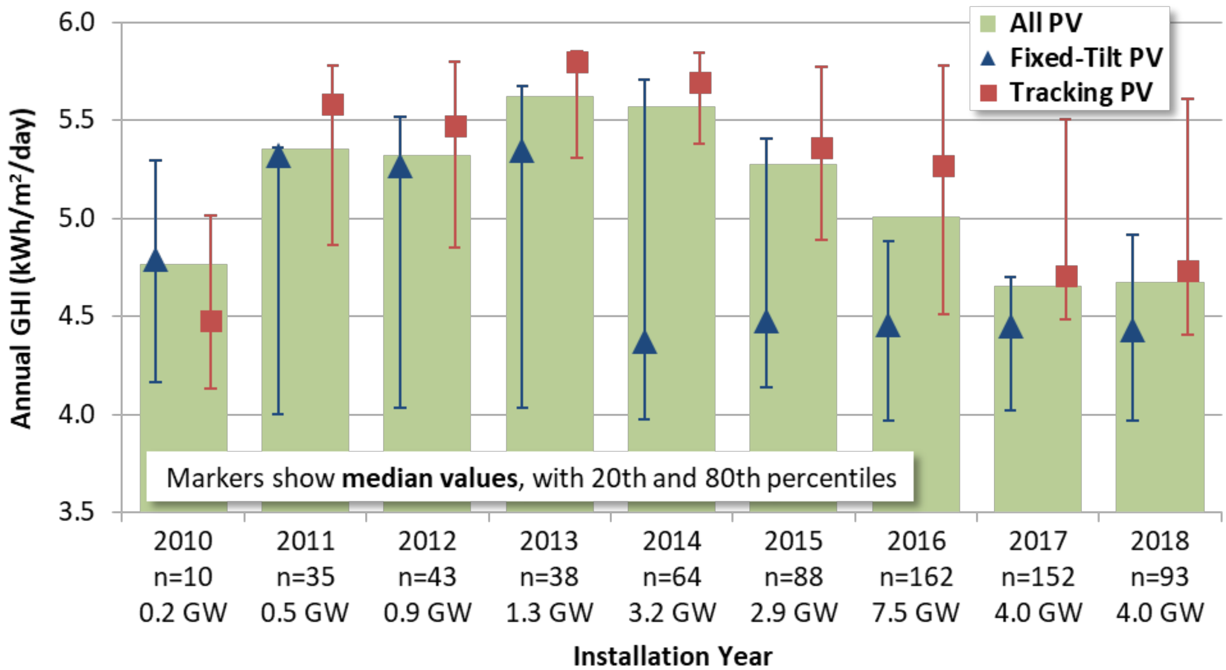

Figure 6. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

Until 2013, the median GHI among all utility-scale PV projects (shown by the green columns) had generally increased with project vintage, indicative of an ongoing concentration of projects located in solar-rich California and the Southwest. Since then, however, large-scale PV projects have been increasingly deployed in less-sunny areas as well, resulting in a strong decline in the median GHI among new projects, from a high of 5.60 kWh/m^2/day among 2013-vintage projects to only 4.68 kWh/m^2/day among projects built in 2018— a minor rebound from 2017 but still among the lowest averages in the history of the U.S. market.

Moreover, the map in Figure 3 shows a preponderance of tracking projects in California and the Southwest, compared to primarily fixed-tilt c-Si projects in the lower-irradiance Northeast. This split by insolation level can also be seen in Figure 6 via the notable differences between the 20th percentile GHI numbers for fixed-tilt and tracking projects, with the former commonly as low as 4 kWh/m^2/day across most vintages, compared to higher levels for tracking projects. With the decline in cost premiums for trackers (see Section 2.2), we have seen a continued foray of tracking projects into lower irradiance areas, in turn chasing fixed-tilt projects primarily to sites with less than 5 kWh/m^2/day—as witnessed by the steep decline in fixed-tilt's 80th percentile. Exceptions to the trend that fixed-tilt projects are mostly installed in lower insolation areas include several 2018 fixed-tilt projects in Florida, Georgia, Arkansas, and Nevada—some of which are sited along the hurricane-prone Atlantic coast, owned by regulated utilities, installed on large military bases, and/or are special projects like a geothermal-PV hybrid in Nevada.

To complement and facilitate the interpretation of the solar resource numbers in Figure 3 and Figure 6, Table 2 provides the median GHI and 20th-80th percentile range by region among our project sample.

Table 2. Typical GHI Range of PV Projects by Region

Region	Installed Projects (#)	Cumulative Capacity (MW_{AC})	Median GHI Resource ($kWh/m^2/day$)	20th-80th Percentiles (GHI)
Southwest	125	5,100	5.64	5.3 - 5.8
California	195	9,707	5.62	5.3 - 5.8
Hawaii	8	102	5.07	4.8 - 5.3
Texas	38	1,866	4.81	4.7 - 5.5
Northwest	33	598	4.58	4.5 - 4.7
Southeast	188	5,989	4.49	4.4 - 4.7
Northeast	56	564	3.99	3.9 - 4.
Midwest	47	660	3.91	3.8 - 4.1

Developers continued to favor larger array capacity relative to inverter capacity

Another project-level characteristic that can influence both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[15] With the cost of PV modules having dropped precipitously (more rapidly than the cost of inverters), many developers have found it economically advantageous to oversize the DC 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,[16] at least in AC terms (this practice may actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" may occur during peak production periods).[17] The resulting boost in generation (and revenue) during the shoulder periods of each day outweighs the occasional loss of revenue from peak-period clipping (which may be largely limited to the sunniest months).

Figure 7 shows the median ILR among projects built in each year, both for the total PV project population (green columns) and broken out by fixed-tilt versus tracking projects. Across all

[15] This ratio is referred to within the industry in a variety of ways, including: DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, inverter loading ratio, and DC load ratio (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). This report uses inverter loading ratio, or ILR.

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

[17] Power clipping, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the turbines) or feathering a wind turbine blade. 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 (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). In this sense, clipping is a bit of a misnomer, in that the inverter never really even "sees" the excess DC power—rather, it is simply not generated in the first place. Only *potential* generation is lost.

projects, the median ILR has increased over time, from around 1.2 in 2010 to 1.33 in 2018. Fixed-tilt projects commonly feature higher ILRs than tracking projects, consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, "tracking-like" daily production profile. Since 2013, however, the median ILR of tracking and fixed-tilt projects has been nearly the same, and in 2016 and 2017 tracking projects even outpaced fixed-tilt installations (1.33 vs. 1.31). 2018 projects reverted again to the traditional relationships (1.41 for fixed-tilt, 1.31 for tracking), pushed by high-ILR projects in Florida and the Northeast. The overall ILR range among all projects in 2018 remains quite large (1.14 to 1.59), pointing to continued diversity in design practices.

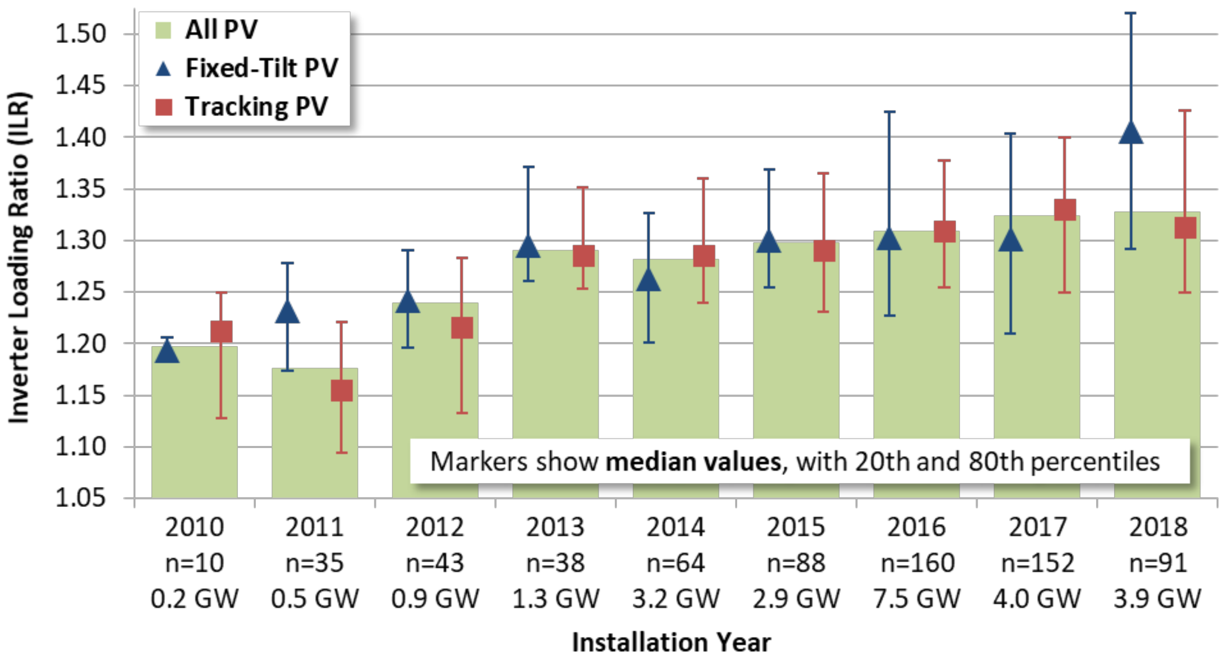

Figure 7. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

Utility-scale PV+battery projects are becoming more common

Despite an increasing number of announcements about new PV+battery projects in the pipeline (see, for example, Table 3, Figure 37, and Figure 38), relatively few projects have been built to date. In 2018, seven new projects featuring batteries connected to utility-scale PV plants came online (see Figure 3). Three of these new batteries were added to existing PV-only projects that came online in 2016 (foreshadowing the potential for a large retrofit market) while the other four were installed concurrently with new PV projects. All seven of these new storage projects use lithium-ion batteries, sized to match 5-135% of the corresponding PV capacity (in MW_{AC} terms). Most focus predominantly on the ability to shift energy for later use (up to 5 hours at full capacity), while the primary purpose of one system is the provision of grid reliability services in a region that is home to many large renewable energy projects.

2.2 Installed Project Prices (641 projects, 22.9 GW_{AC})

This section analyzes installed price data from a large sample of the overall utility-scale PV project population described in the previous section.[18] It begins with an overview of installed prices for PV projects over time, and then breaks out those prices by mounting type (fixed-tilt vs. tracking), project size, and region. A text box at the end of this section compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

Sources of installed price information include the Energy Information Administration (EIA), the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, state regulatory filings, FERC Form 1 filings, corporate financial filings, interviews with developers and project owners, and finally, the trade press. All prices are reported in real 2018 dollars.

In general, only fully operational projects for which all individual phases were in operation at the end of 2018 are included in the sample[19]—i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2019 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an Engineering, Procurement, and Construction or "EPC" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent fluctuations in component costs or other changes in market conditions. For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV, and may differ from the average installed prices reported elsewhere (Fu, Feldman, and Margolis 2018; Wood Mackenzie and SEIA 2019a). That said, the text box at the end of this section suggests fairly good agreement between our empirical installed price data and other published modeling estimates, once timing is taken into account.

Our sample of 641 PV projects totaling 22,886 MW_{AC} for which installed price estimates are available represents 93% of both the total number of PV projects and the amount of capacity in the overall PV project population described in Section 2.1. Focusing just on those PV projects that achieved commercial operation in 2018, our sample of 60 projects totaling 2,499 MW_{AC} represents 65% and 62% of the total number of 2018 projects and capacity in the population, respectively.

Median prices fell to \$1.6/W_{AC} (\$1.2/W_{DC}) in 2018

Figure 8 shows installed price trends for PV projects completed from 2010 through 2018 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly

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[18] Installed "price" is reported (as opposed to installed "cost") because, in many cases, the value reported reflects either the price at which a newly completed project was sold (e.g., through a financing transaction), or alternatively the fair market value of a given project—i.e., the price at which it would be sold through an arm's-length transaction in a competitive market.

[19] In contrast, later sections of this chapter do present data for individual phases of projects that are online, or (in the case of Section 2.5 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

in the residential and commercial sectors), the installed cost or price of solar is often reported in $/$W_{DC}$ terms as well (Barbose and Darghouth 2019; Wood Mackenzie and SEIA 2019a). As noted in the earlier text box (*AC vs. DC*), however, this report analyzes utility-scale solar in AC terms. Figure 8 shows installed prices in both $/$W_{DC}$ and $/$W_{AC}$ terms in an attempt to provide some continuity between this report and others that present prices in DC terms. The remainder of this document, however, reports sample statistics exclusively in AC terms, unless otherwise noted.

As shown, median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to $1.6/$W_{AC}$ ($1.2/$W_{DC}$) in 2018. This represents a price decline of nearly 70% since 2010 and 22% since 2017. The lowest-priced projects in our 2018 sample of 60 PV projects were ~$1.0/$W_{AC}$ (~$0.7/$W_{DC}$), with the lowest 20th percentile of projects falling from $1.7/$W_{AC}$ in 2017 to $1.3/$W_{AC}$ in 2018 (i.e., from $1.3/$W_{DC}$ to $0.9/$W_{DC}$).

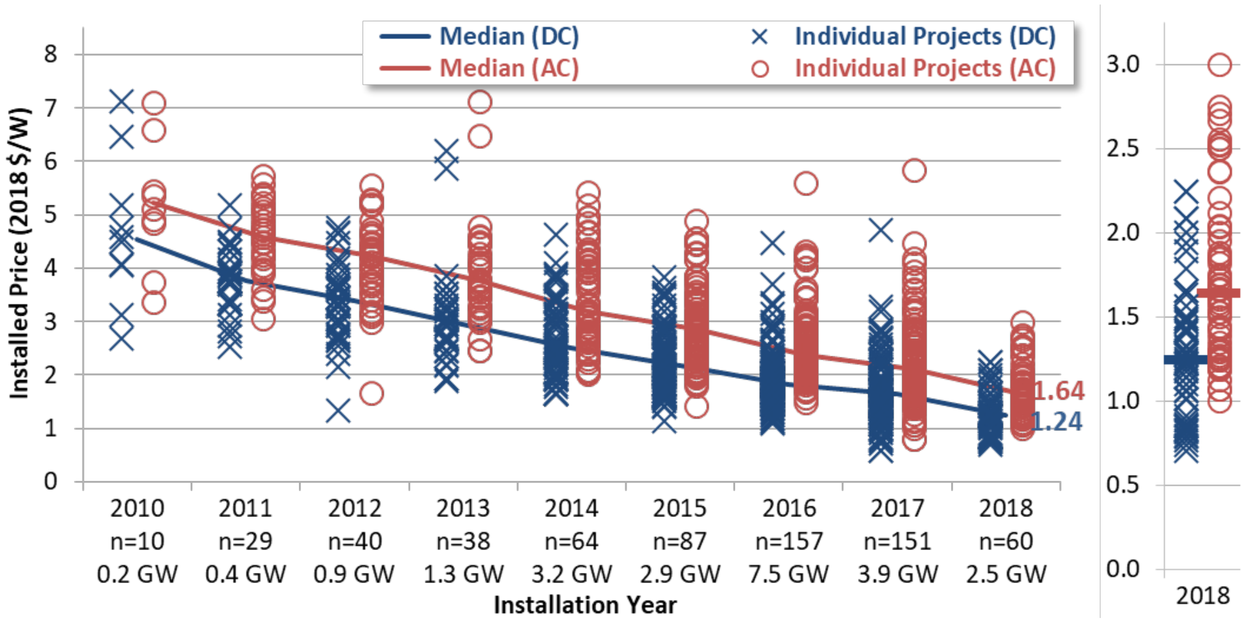

Figure 8. Installed Price of Utility-Scale PV Projects by Installation Year

Figure 9 shows histograms drawn from the same sample, with an emphasis on the changing distribution of installed prices (which are reported only in $/$W_{AC}$ terms from here on) over the last seven years. The steady decline in installed prices by project vintage is evident as the mode of the sample (i.e., the price bin with the most projects, forming the "peak" of each curve) shifts to the left from year to year. Additionally, the portion of the sample that falls into relatively high-priced bins (e.g., $1.75-$5.75/W_{AC}) decreases with each successive vintage, while the portion that falls into relatively low-priced bins (e.g., $0.75-$1.75/W_{AC}) increases. The "width" of the curves also narrows over time, indicating that the pricing within each successive vintage becomes less heterogeneous.[20] This is especially true for 2018 installations.

[20] This holds true for the individual years 2013, 2014, and 2015, even though they are combined in the graph for the sake of visual clarity. The standard deviation of installed prices declined from $0.9/$W_{AC}$ in 2013 to $0.5/$W_{AC}$ in 2018.

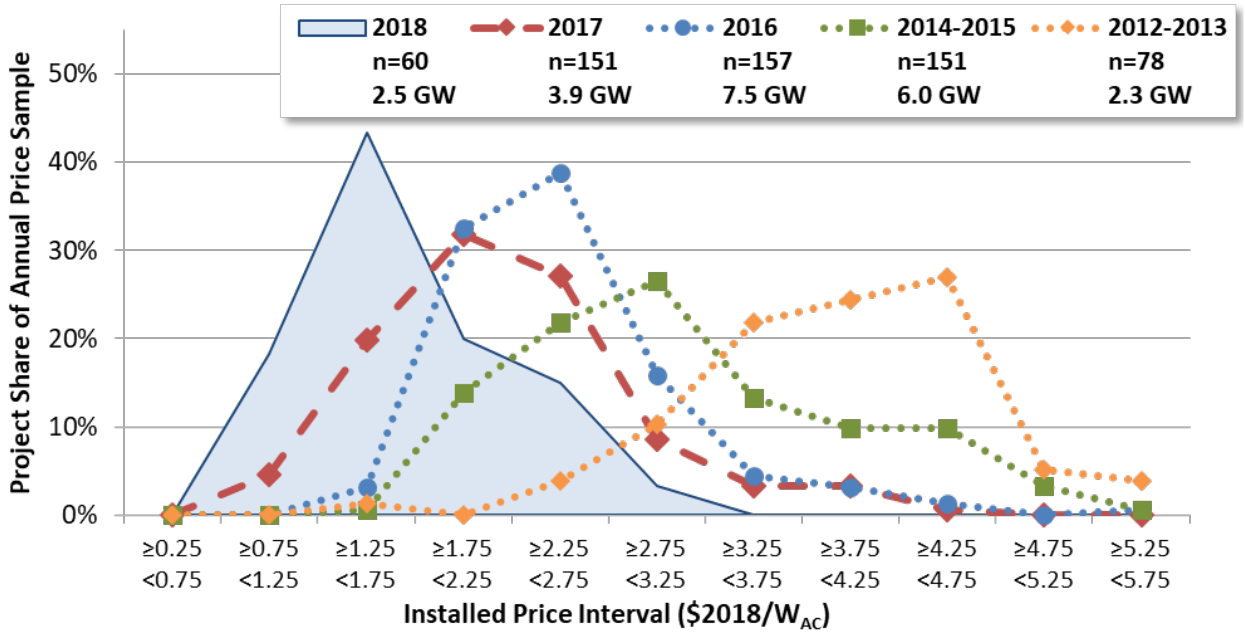

Figure 9. Distribution of Installed Prices by Installation Year

The price premium for tracking over fixed-tilt installations seemingly disappeared

While median prices and the price spread in the sample have declined over time, Figure 8 shows that there remains a considerable diversity in individual project prices within each year. One possible contributor to this price variation could be whether projects are mounted at a fixed tilt or on a tracking system. Figure 10 breaks out installed prices over time by mounting type, and finds higher costs for tracking projects than fixed-tilt installations—at least historically. Though once quite large (e.g., in 2010 and earlier), this tracker premium has been rather modest since 2011, and seemingly vanished altogether in 2017 and again in 2018. In fact, our data suggest that tracking projects actually cost slightly *less* than fixed-tilt projects, both in $/W$_{AC}$ terms ($1.6/W$_{AC}$ for tracking vs $1.7/W$_{AC}$ for fixed-tilt) and $/W$_{DC}$ terms ($1.2/W$_{DC}$ vs $1.3/W$_{DC}$ for fixed-tilt). This counter-intuitive result *does not*, however, mean that for a given project at a given site, single-axis tracking was a cheaper option than a fixed-tilt mount. Instead, it likely reflects sampling issues—e.g., a greater proportion of tracking than fixed-tilt projects in our sample, with the tracking projects located in lower-cost regions or sites while fixed-tilt projects may be built in challenging environments (high wind loads, sensitive brown-field surfaces). Nonetheless, the gradual erosion of the historical cost gap between tracking and fixed-tilt, coupled with the greater generation (and revenue) that trackers provide, help to explain the surge in tracking projects in recent years, even among the most-northerly projects in our sample (e.g., the Adam Nielson Solar project in Washington State).

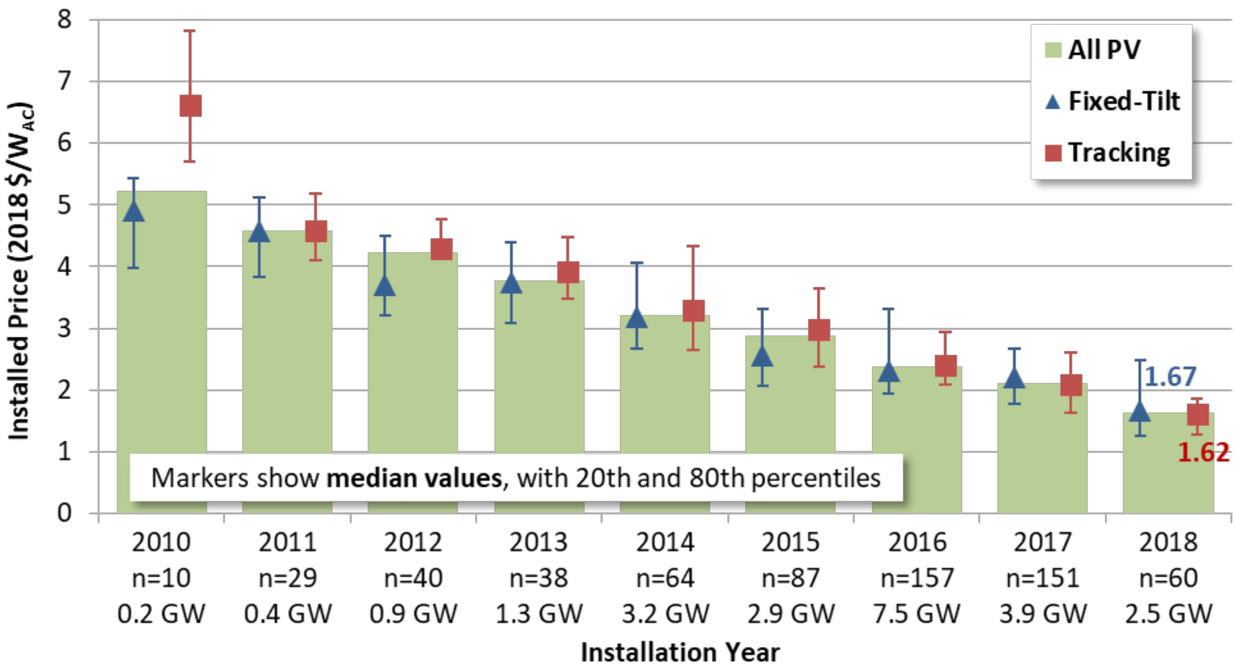

Figure 10. Installed Price of Utility-Scale PV by Mounting Type and Installation Year

Evidence of economies of scale among our 2018 sample

Differences in project size may also explain some of the variation in installed prices seen in Figure 8, as PV projects in the sample range from 5 MW_{AC} to 200 MW_{AC}. Figure 11 investigates price trends by project size, focusing on just those PV projects in the sample that became fully operational in 2018, in order to minimize the potentially confounding influence of price reductions over time.

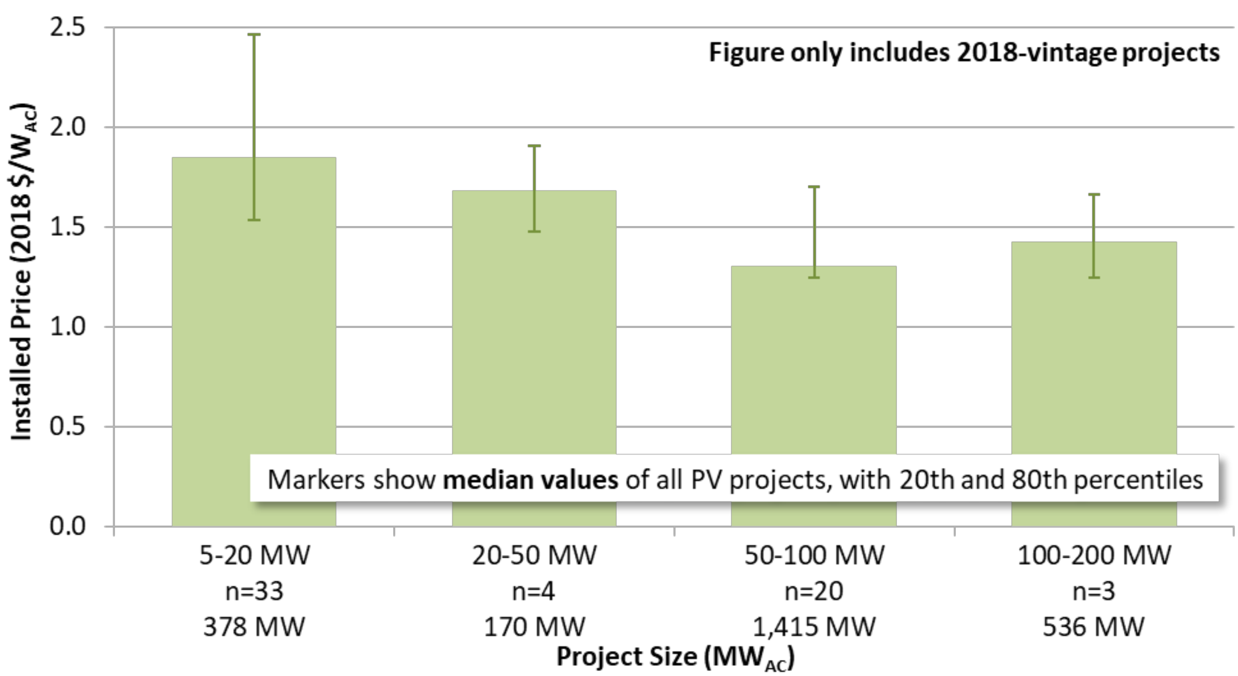

Figure 11. Installed Price of 2018 PV Projects by Size, Module Technology, and Mounting Type

We find some indications of economies of scale among our latest project sample. The median price among projects in the first size bin (5-20 MW_{AC}) is higher ($1.85/$W_{AC}$) than in the second size bin (20-50 MW_{AC}, $1.68/$W_{AC}$) and the third size bin (50-100 MW_{AC}, $1.30/$W_{AC}$), suggesting a decline in installed prices as project size increases.[21]

System prices vary by region

In addition to price variations due to technology and perhaps system size, prices also differ by geographic region. This variation may, in part, reflect the relative prevalence of different system design choices that have cost implications (e.g., the greater prevalence of tracking projects in the Southwest). In addition, regional differences in labor and land costs, soil conditions or snow load (both of which have structural, and therefore cost, implications), or simply the balance of supply and demand among solar developers or the level of competition with other electric generators, may also play a role.

As shown in Figure 12 (which uses the regional definitions shown earlier in Figure 3), installed prices among our 2018 sample were highest the Northeast, and lowest in Texas and the Southeast. With the exception of the Southeast, however, sample size within each region is limited (and numbers for Hawaii and California are not even reported due to the low number of observations), so these rankings should be viewed with some caution.

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[21] The median prices seem to *increase* to $1.43/$W_{AC}$ for the largest size bin of 100-200 MW_{AC}, though this is primarily an artifact of the small sample size of just 3 projects. In past editions of this report, we hypothesized that two other factors may contribute to apparent *dis*economies of scale for very large projects. First, it may be that these very large projects often face greater administrative, regulatory, land preparation, and interconnection costs than do smaller projects, and these costs are not fully offset by other size-driven savings like hardware procurement or a more-streamlined use of installation labor. A second explanation may be that very large projects take longer to build, and may therefore reflect higher module and EPC costs dating back further in time. Modeling work from NREL (Fu, Feldman, and Margolis 2018) estimated that a 100 MW_{DC} utility-scale PV plant enjoys a $0.3/$W_{DC}$ cost advantage over a 5 MW_{DC} project. However, the analysis does not correct for the potentially longer development times associated with the larger project, which could diminish the cost advantage when prices are indexed by commercial operation date.

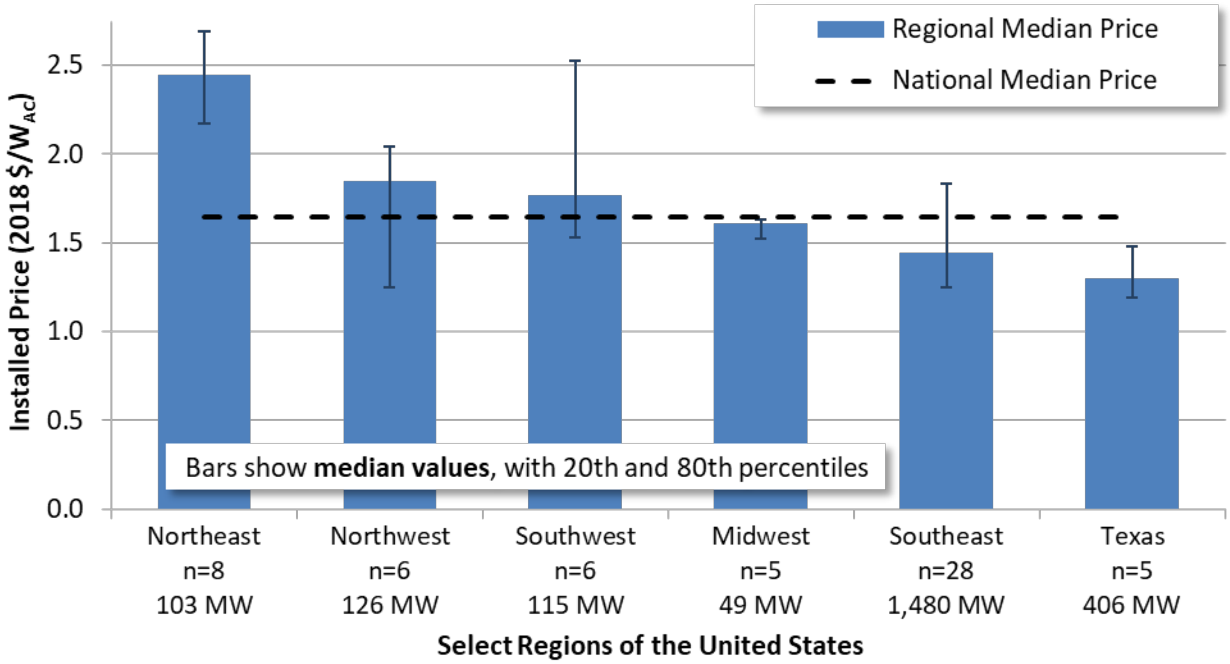


Figure 12. Median Installed PV Price by Region in 2018

Finally, the text box on the next page compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

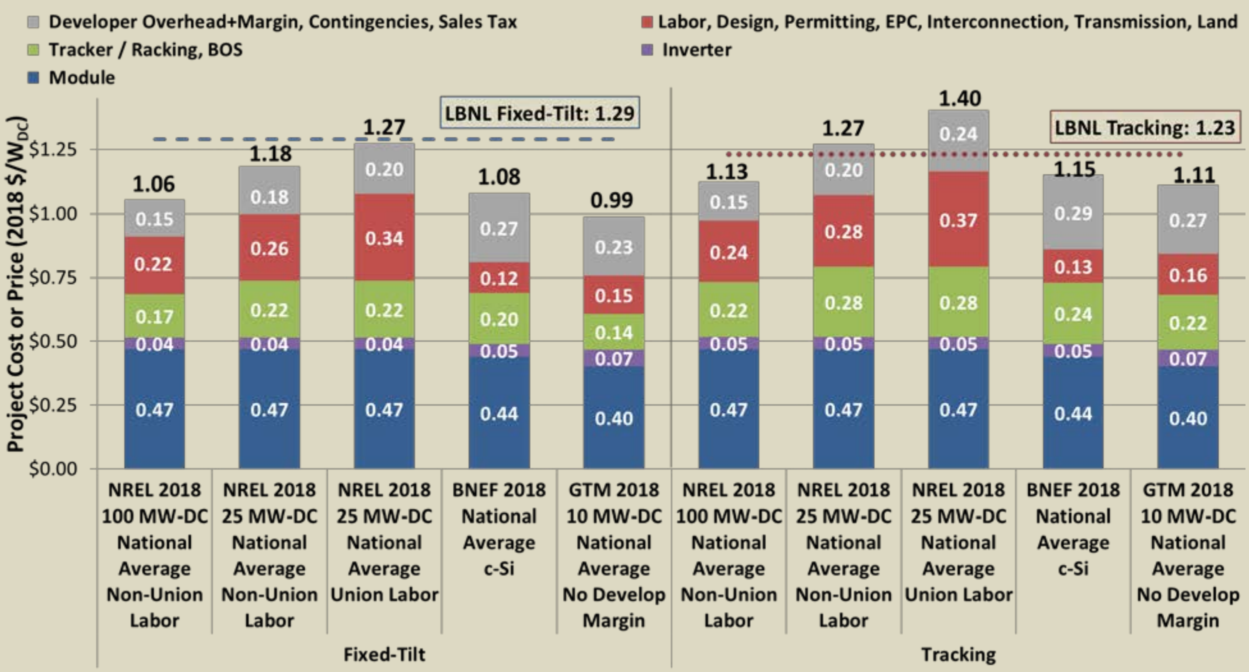
Bottom-Up versus Top-Down: Different Ways to Look at Installed Project Prices

The installed prices analyzed in this report generally represent empirical *top-down* price estimates gathered from sources (e.g., corporate financial filings, FERC filings, EIA, press releases) that typically do not provide more granular insight into component costs. In contrast, several publications by NREL (Fu, Feldman, and Margolis 2018), BNEF (Bromely, Narayanan, and Shifman 2018), and Wood Mackenzie (Wood Mackenzie and SEIA 2019a) take a different approach of modeling total installed prices via a *bottom-up* process that aggregates modeled cost estimates for various project components to arrive at a total installed cost or price. Each type of estimate has both strengths and weaknesses—e.g., top-down estimates often lack component-level detail but benefit from an empirical reality check that captures the full range of diverse projects in the market, while bottom-up estimates provide more detail and enable forecasting, but rely on modeling, typically of idealized or "best in class" projects.

A second potential source of disparity between these installed price estimates are differences in the "time stamp." LBNL reports the installed price of projects in the year in which they achieve commercial operation, while Wood Mackenzie and BNEF may instead refer to EPC contract execution dates or to projects under construction that have not yet been completed (such projects enter our sample in later years). NREL also provides more of a forward-looking estimate (in the figure below, we account for this timing mismatch by showing NREL's 1Q18, rather than current, numbers).

Notwithstanding these potential issues, the figure below compares the top-down median 2018 prices for fixed-tilt ($1.29/$W_{DC}$) and tracking ($1.23/W_{DC}) projects in the LBNL sample with various bottom-up modeled cost estimates from the three sources noted above. Each bottom-up cost estimate is broken down into a common set of cost categories, which we defined rather broadly in order to capture slight differences in how each source reports costs (note that not all sources provided estimates for all cost categories). Finally, costs are shown exclusively in $/$W_{DC}$, because that is how they are reported in these other sources.

LBNL's top-down empirical estimates reflect a mix of union and non-union labor and span a wide range of project sizes and prices ($0.7-$2.3/W_{DC})[i] . It is notable however, that the median of our price sample is higher than the other featured price estimates for fixed-tilt installations but in good alignment for tracking projects. Some of this price delta may be explained by site-specific challenges for our empirical fixed-tilt installations or differences in the defined system boundaries. For example, GTM (Wood Mackenzie) excludes interconnection and transmission costs, as well as developer profit margins. Finally, economies of scale of $0.12-$0.14/W_{DC} are reflected in NREL's bottom-up modeled cost estimates for a 100 MW_{DC} project (relative to a 25 MW_{DC} project); the median size of the LBNL sample is closer to 25 MW.



[i] For fixed-tilt projects, LBNL's median project size is 27 MW_{DC} and the price range is $0.70-$2.25/W_{DC}. For tracking projects, the comparable numbers are 26 MW_{DC} and $0.74-$1.94/W_{DC}.

2.3 Operation and Maintenance Costs (48 projects, 0.9 GW_{AC})

In addition to up-front installed project prices, utility-scale solar projects also incur ongoing operation and maintenance ("O&M") costs, which are defined here to include only those direct costs to operate and maintain the generating plant itself. In other words, the O&M costs reported here exclude payments such as property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (all of which contribute to *total operating expenses*). This section reviews and analyzes the limited data on O&M costs that are in the public domain.

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Few of the utility-scale solar projects that have been operating for more than a year are owned by regulated investor-owned utilities, which FERC requires to report (on Form 1) the O&M costs of the power plants that they own.[22] Even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful (if at all). For example, some investor-owned utilities do not report empirical O&M costs for individual solar projects, but instead report average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. A table in the appendix describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

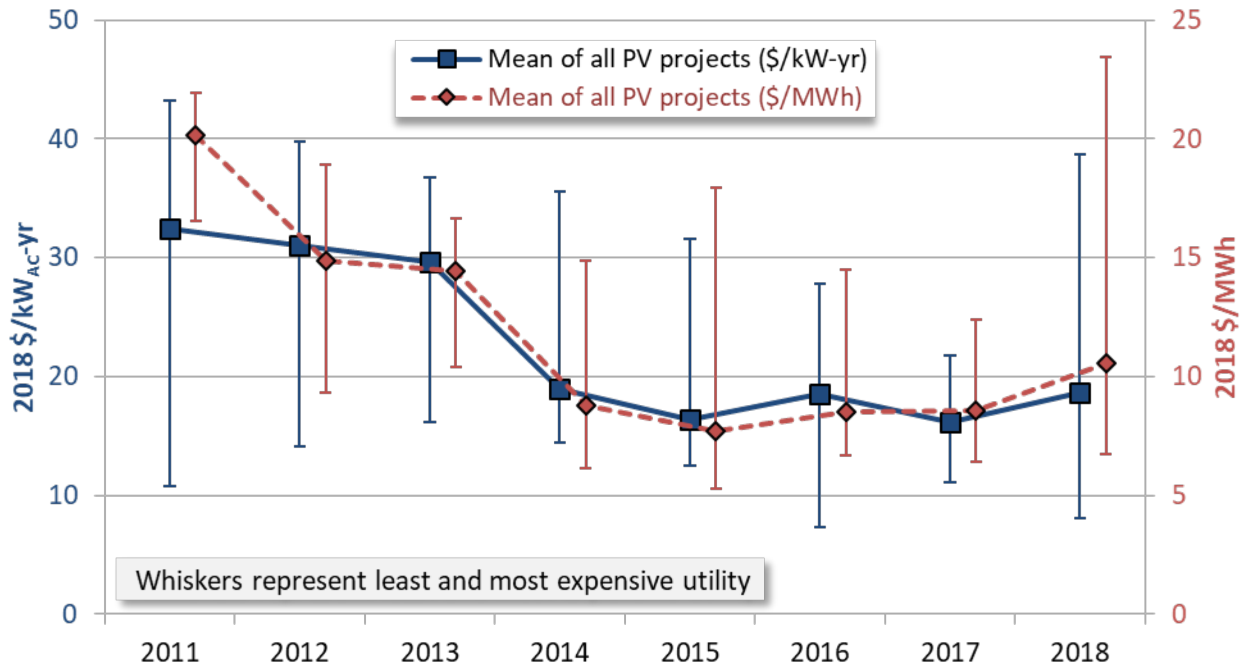


Figure 13. Empirical O&M Costs over Time for Growing Cumulative Sample of Projects

[22] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses"—namely, those operational costs of supervision and engineering, maintenance, rents, and training (and therefore excluding payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead).

Despite these limitations, Figure 13 shows average utility fleet-wide annual O&M costs for this small sample of projects in $/kW$_{AC}$-year (PV, blue solid line) and $/MWh (PV, red dashed line). The error bars represent both the lowest and the highest utility fleet-wide PV cost in each year.

Average O&M costs for the cumulative set of PV plants within this sample have declined from about $32/kW$_{AC}$-year (or $20/MWh) in 2011 to about $19/kW$_{AC}$-year ($10.6/MWh) in 2018. In comparison to 2017, the overall range of costs between the least- and most-expensive utility has increased in both capacity and energy terms (see error bars), potentially due to growth in our sample (adding Tampa Electric, Allete, DTE Electric and Virginia Electric Power). In 2018, all but seven of the 41 PV projects in the sample (i.e., in those instances where we have project-level rather than aggregate utility data) had O&M costs of less than $20/kW$_{AC}$-year (or $15/MWh).

As utility ownership of operating solar projects increases in the years ahead (and as those utilities that already own substantial solar assets but do not currently report operating cost data hopefully begin to do so, as required in FERC Form 1), the sample of projects reporting O&M costs should grow, potentially allowing for more interesting analyses in future editions of this report. For example, next year we hope to find reliable O&M cost data for solar projects owned by Alabama Power, Florida Power & Light, and Tampa Electric Company.

2.4 Capacity Factors (550 projects, 20.0 GW_{AC})

At the close of 2018, more than 550 utility-scale PV projects in the United States had been operating for at least one full year, and in some cases for as many as eleven years, thereby enabling the calculation of capacity factors.[23] Sourcing empirical net generation data from FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings, this chapter presents net AC capacity factor data for 550 PV projects totaling 20,024 MW_{AC}. This 20 GW_{AC} sample is nearly 4 GW_{AC} larger than the sample for which capacity factor data were analyzed in last year's edition of this report, reflecting new projects that began operating in 2017.

The capacity factors of individual projects in this 20 GW_{AC} sample range widely, from 12.1% to 34.8%, with a sample mean of 25.0%, a median of 25.2%, and a capacity-weighted average of 27.0%. Notably, these are *cumulative* capacity factors—i.e., calculated over as many years of data as are available for each individual project (up to a maximum of eleven years, from 2008 to 2018), rather than for just a single year (though for projects completed in 2017, only a single full calendar year of data—2018—exists at present). Furthermore, they are also expressed in *net*, rather than *gross*, terms—i.e., they represent the output of the project net of its own consumption, as well as net of any curtailment that may have occurred. Finally, they are calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating), yielding higher capacity factors than if reported in DC terms,[24] but allowing for direct comparison with the capacity factors of other generation sources (e.g., wind energy or thermal energy sources), which are also calculated in AC terms.

Wide range in capacity factors reflects differences in insolation, tracking, and ILR

Figure 14 presents the cumulative net AC capacity factors of each project in the sample (see the circle markers) broken out by three key project characteristics that a recent statistical analysis (Bolinger, Seel, and Wu 2016) found to explain more than 90% of the variation in utility-scale PV project capacity factors. These characteristics include the estimated strength of the long-term solar resource at each site (measured in GHI with units kWh/m^2/day), whether the array is mounted at a fixed tilt or on a tracking mechanism, and the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or ILR).[25] The blue-shaded columns show the median cumulative capacity factor within each individual bin.

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[23] Capacity factor is a measure of the amount of electricity generated in a given period relative to how much electricity could have been generated if the generator was operating at full capacity for the entire period. Because solar generation varies seasonally, capacity factor calculations for solar are typically performed in full-year increments. 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].

[24] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

[25] Instead of using capacity factors to gauge project performance, some analysts prefer to use the "performance ratio"— defined as "the ratio of the electricity generated to the electricity that would have been generated if the plant consistently converted sunlight to electricity at the level expected from the DC nameplate rating" (Dierauf et al. 2013). Because the performance ratio takes into account many of the variables explored in this section—e.g., fixed-tilt vs. tracking mounts, variations in insolation, DC capacity ratings, etc.—it can provide a more precise measure of how a project is performing *in light of its specific circumstances*. In this report, however, we are specifically interested in exploring the full range of empirical project performance experienced in the market, as well as the specific circumstances that drive it, and therefore prefer to focus on capacity factors, which do not filter out this information. In addition, some of the information required to calculate performance ratios—e.g., site-specific insolation during the period of interest—is not readily accessible, making capacity factors a more expedient choice for this report.

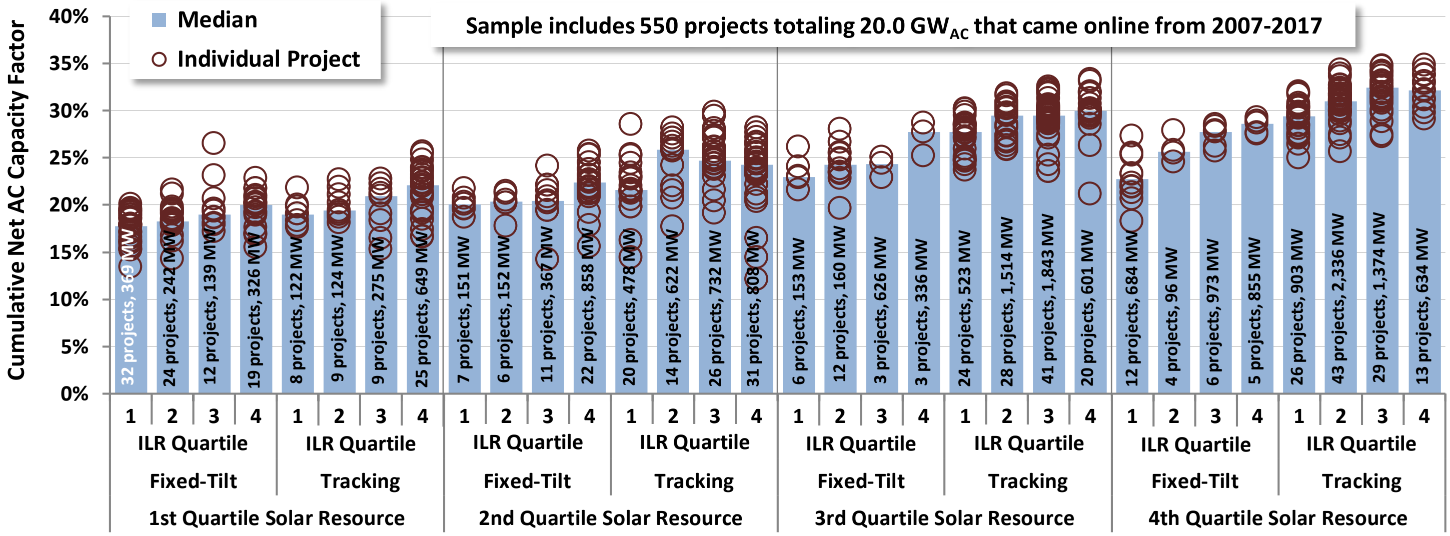

Figure 14. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio[26]

Each of the three drivers of capacity factor explored in Figure 14 is discussed in turn below.

- **Solar Resource:** Based on its geographic coordinates, each project in the sample is associated with a long-term average global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Figure 14 then parses the sample into solar resource quartiles that have the following thresholds: <4.46, 4.46-5.18, 5.18-5.64, and ≥5.64 kWh/m^2/day GHI. Roughly 137 projects fall into each resource quartile, though capacity is concentrated in the third (29%) and fourth (39%) quartiles, with just 11% of capacity in the first resource quartile. Not surprisingly, projects sited in stronger solar resource areas tend to have higher capacity factors, all else equal. The difference can be substantial: the median capacity factors in the highest resource bin, for example, average 9 percentage points higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending from 5 to 12 percentage points depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** 184 projects in the sample (totaling 6,487 MW$_{AC}$) are mounted at a fixed-tilt, while the remaining 366 (totaling 13,537 MW$_{AC}$) utilize tracking (overwhelmingly horizontal single-axis east-west tracking, with the exception of five dual-axis tracking projects located in Texas). In other words, there are now roughly twice as

[26] Figure 14 (as well as the rest of this section) excludes four CPV projects: the 5.04 MW$_{AC}$ Hatch project (online since late-2011), the 30 MW$_{AC}$ Cogentrix Alamosa project (online since early 2012), the 6.3 MW$_{AC}$ Desert Green project (online since late-2014), and the 18 MW$_{AC}$ Fort Churchill project (online since 2015). If plotted in Figure 14, these four projects would fall into the 29th, 21st, 32nd, and 21st bins, respectively, where their cumulative capacity factors of 20.3%, 23.5%, 25.6%, and 23.6% would fall below the respective PV bin medians of 29.3%, 27.7%, 32.1%, and 27.7% (despite the CPV projects' use of dual-axis tracking, which should provide an advantage over the overwhelmingly single-axis PV sample). Based on this comparison to similarly situated PV projects, Hatch in particular seems to be underperforming (at just 20.3%, compared to the PV median of 29.3%—though Hatch's capacity factor has improved into the mid-20% in 2017 and 2018). Earlier editions of this report provide additional details about the specifications and performance of the Hatch and Cogentrix Alamosa PV projects.

many tracking projects (and capacity) in the sample as there are fixed-tilt projects, reflecting the strong inroads that tracking has made in recent years. Tracking boosts the median capacity factor by 2-5 percentage points on average (in absolute terms), depending on the resource quartile (i.e., 2 percentage points within the 1st resource quartile, 3 percentage points in the 2nd quartile, 4 percentage in the 3rd quartile, and 5 percentage points in the 4th), and by 3 percentage points on average across all four resource quartiles. This finding—that the impact of tracking on capacity factor increases at higher insolation levels—is consistent with results from Bolinger et al. (2016), and also explains why there are more fixed-tilt (87) than tracking (51) projects in the lowest insolation quartile and many more tracking (111) than fixed-tilt (27) projects in the highest insolation quartile of Figure 14.

- **Inverter Loading Ratio (ILR):** Figure 14 breaks the sample down further into ILR quartiles: <1.24, 1.24-1.29, 1.29-1.36, and ≥1.36. Again, each quartile houses roughly 137 projects, but capacity is concentrated in the second (26%), third (32%) and fourth (25%) quartiles. The effect of a higher ILR on median capacity factor is noticeable: across all four resource quartiles and fixed/tracking bins, the absolute percentage point difference in capacity factor between the fourth and first inverter loading ratio quartiles is as high as 6 percentage points (with an average of 3 percentage points across all bins). Although the data do, in general, suggest diminishing returns when moving from the third to the fourth ILR quartile in particular, the increasing deployment of DC-coupled battery storage may continue to push ILRs higher in the future.

Beyond the three drivers depicted in Figure 14, additional explanatory factors, such as array tilt and azimuth, will also play an obvious role in influencing capacity factors, particularly for fixed-tilt projects. Given that we focus only on ground-mounted utility-scale projects, however, our operating assumption is that these two fundamental parameters will tend to be equally optimized across all projects to maximize energy production. An examination of the data reveals that, though not universally true, this assumption seems to be reasonable. For example, among our sample, azimuth ranges from 159 to 220 degrees, but the vast majority of the sample—including the 10th and 90th percentiles—has an azimuth of 180 degrees. Among the 184 fixed-tilt projects in our sample, the tilt ranges from 7.5 to 30 degrees, and generally increases with latitude; 80 of these projects have a 20-degree tilt, while another 63 have a 25-degree tilt (and the latter have a higher average latitude than the former). Among the 366 tracking projects in our sample, 5 use dual-axis tracking (the rest are single-axis), and 6 of the single-axis tracking projects are mounted at a tilt ranging from 20 to 38 degrees—all the rest have no tilt (i.e., are horizontal single-axis).

Finally, Figure 15 presents similar information as in Figure 14, but in a slightly different way. Instead of accounting for the strength of the solar resource via insolation quartiles (as in Figure 14), Figure 15 breaks out cumulative capacity factors for both fixed-tilt and tracking projects on a regional basis (with regions as defined earlier in Figure 3)—for those readers who prefer to think geographically rather than in terms of insolation. For the sake of simplicity, Figure 15 also ignores ILR differences. Given what we know about insolation levels regionally (see Figure 3 and Table 2), the results are not surprising: capacity factors are lowest in the Northeast and Midwest and highest in California and the Southwest. Although sample size is small in some regions, the greater benefit of tracking in the high-insolation regions is evident, as are the greater number of tracking projects in those regions (whereas the relatively low-insolation Northeast sample includes many more fixed-tilt than tracking projects).

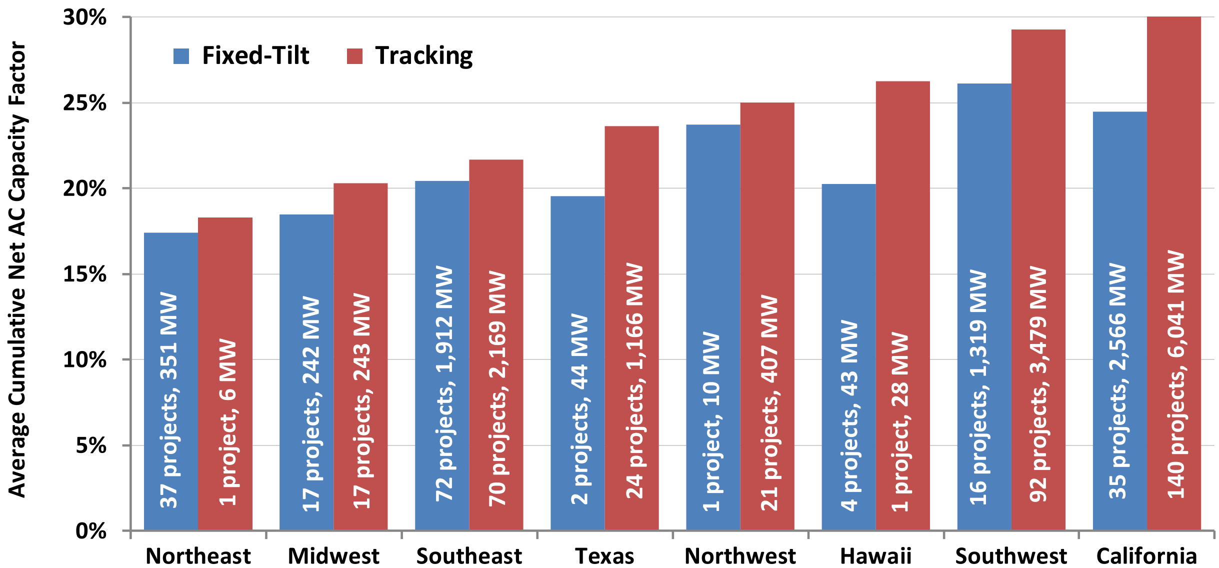

Figure 15. Cumulative Capacity Factor by Region and Fixed-Tilt vs. Tracking

Since 2013, competing drivers have reduced average capacity factors by project vintage

Although one might initially expect improvements in PV module efficiency over time to boost the capacity factors of more recent project vintages, this is a misunderstanding. As module efficiency increases, developers either use fewer modules to reach a fixed amount of capacity (thereby saving on balance-of-system and land costs as well) or, alternatively, use the same number of modules to boost the amount of capacity installed on a fixed amount of land (directly reducing at least $/W$_{DC}$ costs, if not also $/W$_{AC}$ costs). As a result, for PV more than for other technologies like wind power, efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Any increase in capacity factor by project vintage is, therefore, most likely attributable to a time trend in one of the other variables examined above—e.g., towards higher inverter loading ratios or greater use of tracking, or a buildout of higher insolation sites. Additional factors that could influence capacity factors include performance degradation, inter-annual resource variability, changes to availability stemming from improved asset management and/or equipment quality, and—in the future—the use of bifacial modules.[27]

Figure 16 tests some of these hypotheses by breaking out the average net capacity factor (both cumulative and in 2018) by project vintage across the sample of projects built from 2010 through 2017 (and by noting the relevant average project design parameters within each vintage). Capacity factors improved gradually and steadily with each new project vintage from 2010 through 2013, driven by commensurate increases in each of the three design parameters shown: ILR, percentage of projects using tracking, and GHI (changes to GHI are portrayed both numerically and through

[27] To date, our capacity factor sample does not include any projects using bifacial modules. Going forward, bifacial projects will become more common, though the impact of bifaciality on capacity factor remains to be seen, and will depend in part on how the capacity of such modules is defined (e.g., whether it will take into account just the front-side, or instead both the front- and back-side, capacity).

the varying intensity of the blue and orange shading). Since 2013, however, there has been no improvement in average capacity factors among more-recent project vintages, as a decline in site quality has offset the increase in the percentage of projects using tracking, while the average ILR has remained more or less constant. In fact, 2017 projects even show a roughly 2 percentage point *decline* in average capacity factor (relative to 2013-2016 vintages), as both the average ILR and percentage of projects using tracking held steady while the long-term GHI continued its multi-year decline (indicative of the ongoing market expansion into less-sunny regions).

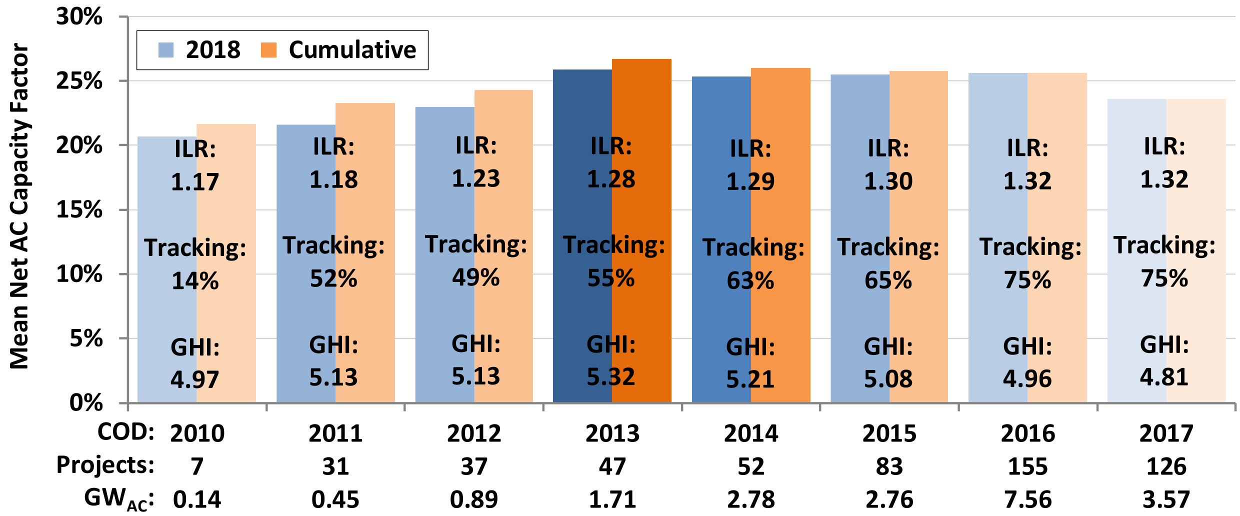

Figure 16. Cumulative and 2018 Capacity Factor by Project Vintage: 2010-2017 Projects

Two other factors could plausibly contribute to the changes in average capacity factor by vintage seen in Figure 16: inter-year variation in the strength of the solar resource and performance degradation over time (as more recent project vintages have had less time to degrade). The former could play a role if insolation at these project sites were significantly stronger in more recent years (e.g., 2014-2018) than in earlier years (e.g., 2011-2013). If this were the case, then 2013-vintage projects might be expected to exhibit higher cumulative capacity factors than older projects. However, the fact that the blue columns in Figure 16 measure capacity factors across vintages during the same single year—2018—yet show essentially the same trend as the orange columns that measure cumulative capacity factors, suggests that inter-year resource variation is *not* a significant factor, and instead that ILR, GHI, and tracking (and perhaps also degradation—addressed in the next section) are the true drivers.

Performance degradation is evident, but is difficult to assess and attribute at the project level

Finally, the possibility of performance degradation has been mentioned several times in the preceding text as a potential driver of project-level capacity factors. Unfortunately, degradation is difficult to assess, and even more difficult to attribute, at the project-level, in part because its impact over limited time frames is likely to be rather modest and swamped by other factors. For example, over an 11-year period (i.e., the maximum number of full calendar years that any project in our sample has been operating to date), a representative degradation rate of 0.75%/year would reduce an initial net AC capacity factor of 30.0% to 27.8% in the eleventh year (all else equal). This 220 basis point reduction in capacity factor over eleven years is rather trivial in comparison to, and could easily be overwhelmed by, the impact of other factors, such as curtailment or inter-year variation in the strength of the solar resource.

Nevertheless, some amount of degradation is widely expected (e.g., module manufacturers commonly build degradation into their performance guarantees, and many power purchase agreements for utility-scale PV projects also account for degradation when projecting output over time[28]), and so should not be ignored as a possible driver of cumulative capacity factors. To that end, Figure 17 graphs both the median (with 20th and 80th percentile bars) and capacity-weighted average "irradiance-normalized" (i.e., to correct for inter-annual variability in the strength of the solar resource) capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values).

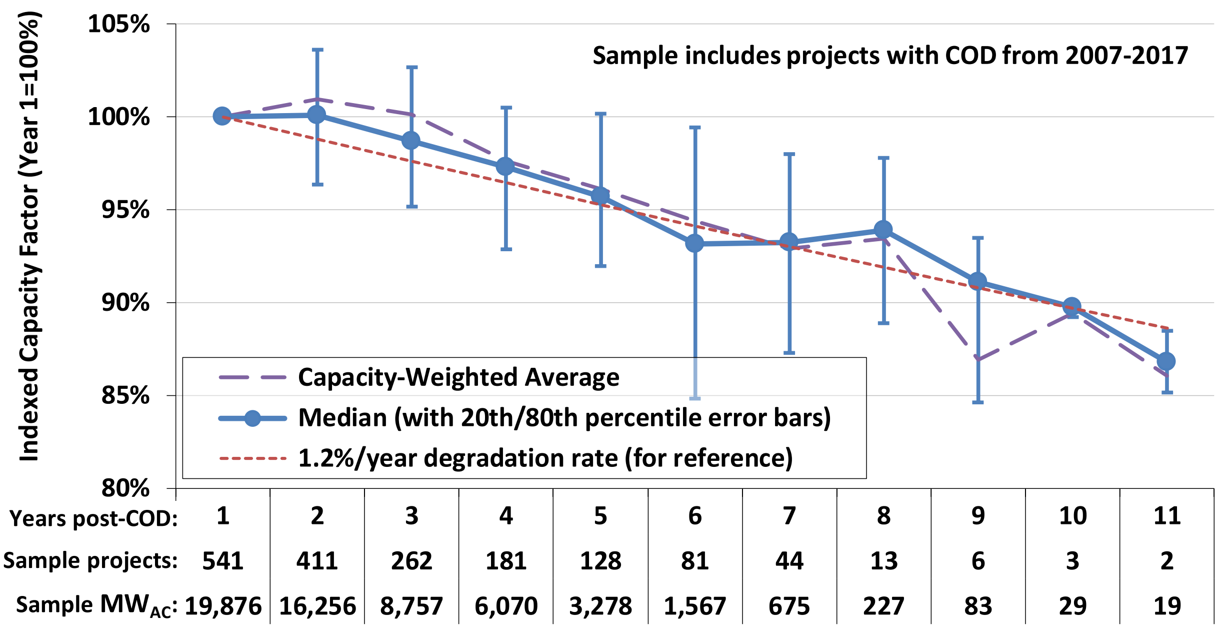

Figure 17. Changes in Capacity Factors Over Time Suggest Performance Degradation

At first glance, Figure 17 suggests that performance degradation has been considerably worse than is commonly assumed—e.g., the dashed red line, which approximates the slope of both the median and capacity-weighted average, depicts a straight-line degradation rate of 1.2%/year.[29] However, several caveats are in order.

[28] For example, within a sub-sample of 40 utility-scale PV PPAs totaling 3,943 MW$_{AC}$ that were collected for the next section of this report, contractual not-to-exceed degradation rates range from 0.25%-1.0% per year, with a sample mean of 0.6%/year and a median of 0.5%/year.

[29] The fact that year two shows no degradation on average could partly reflect the initial production ramp-up period that is sometimes experienced by solar projects as they work through and resolve initial "teething" issues during their first year of operations.

First, curtailment has increasingly affected the output of some solar projects in higher penetration markets, and could be influencing the trends seen in Figure 17. As discussed later in Section 2.6 on market value, if not for curtailment, the average 2018 capacity factor among our California sample would have increased from 28.5% to 29.0%, while the average 2018 capacity factor among our Texas sample would have increased from 22.3% to 24.9%. These curtailment-induced reductions in capacity factor are similar to the effect of three and fifteen years, respectively, of performance degradation at a rate of 0.75%/year, and could certainly explain some of the apparent degradation seen in Figure 17.[30]

Second, the project sample is not the same in each year shown along the x-axis of Figure 17, and shrinks rapidly as the number of post-COD years increases, reflecting the relative youth of the utility-scale PV market. This sampling heterogeneity could be complicating interpretation.

In short, though Figure 17 undoubtedly does reflect some amount of degradation among the modules and balance-of-station components of the existing solar fleet, other factors such as curtailment also likely play a role. Teasing apart these various influences is beyond the scope of this high-level exploration (but will be the focus of separate, more-in-depth work forthcoming from Berkeley Lab).

[30] As discussed later in Section 2.6, the bulk of solar curtailment in Texas is concentrated among just a few plants that are on the wrong side of a transmission constraint. One of these plants came online in 2018 and so is not included in Figure 17, while the other two affect only year 2 (for one plant) and years 2 and 3 (for the other) of Figure 17—and do not have any bearing on the degradation curve over longer terms.

2.5 Power Purchase Agreement Prices (290 contracts, 18.6 GW_{AC}) and LCOE (640 projects, 22.9 GW_{AC})

The cost of installing, operating, and maintaining a utility-scale PV project, along with its capacity factor—i.e., all of the factors that have been explored so far in this report—are key determinants of a project's levelized cost of energy ("LCOE") as well as the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electric Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale PV projects in the U.S. (some of which include battery storage), including 290 contracts in 32 states, totaling 18,615 MW_{AC}. In addition, the final sub-section explores the LCOE of utility-scale PV in the United States, drawing on a sample of 640 projects totaling 22,876 MW_{AC}, and compares it to these empirical PPA prices.

The population from which this PPA price sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that benefit from net metering or customer bill savings, are therefore not included in the sample. We also exclude those projects that unbundle and sell RECs separately from the underlying electricity, because in those instances the PPA price alone does not reflect the project's total revenue requirements (on a post-incentive basis). PPAs resulting from Feed-in Tariff ("FiT") programs are excluded for similar reasons—i.e., the information content of the pre-established FiT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). The same holds true for "avoided cost" contracts with non-negotiated or "standard offer" pricing (also known as "PURPA" or "QF" contracts),[31] which are FiT-like in nature and, in some states, also involve unbundling RECs. In short, the goal of this section is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[32] As such, the PPA price sample comes entirely from utility-scale projects that sell bundled energy, capacity, and RECs to utilities (both investor-owned and publicly-owned utilities) or other offtakers through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[33] All that said, projects that do not meet these requirements and so are excluded from

[31] The Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978 and requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects smaller than 80 MW) at prices that represent their "avoided cost"—i.e., what they would pay for the same amount of electricity generated by a non-qualifying facility. In recent years, PURPA has come under fire in some states that are experiencing a large influx of wind and solar projects seeking avoided cost contracts (for more information, see the text box—*Trend to Watch: The Rise (and Fall?) of "Avoided Cost" Markets*—in the 2014 edition of this report (Bolinger and Seel 2015)).

[32] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs. In general, the project sponsor and investors bear these risks (to varying degrees, depending on the specifics of their contractual arrangements).

[33] Because all of the PPAs in the sample include RECs (i.e., transfer them to the power purchaser), we need not worry too much about REC price trends in the unbundled REC market. It is, however, worth noting that some states have implemented REC "multipliers" for solar projects (whereby each solar REC is counted as more than one REC for renewable portfolio standard ("RPS") compliance purposes), while others have implemented solar "set-asides" or "carve-outs" (requiring a specific portion of the RPS to be met by solar) as a way to encourage solar power development specifically. In these instances, it is possible that utilities might be willing to pay a bit more for solar

the PPA price sample can still contribute to an understanding of utility-scale PV's LCOE, and as such are still included in the LCOE calculations described in the last sub-section.

For each of the contracts in the sample,[34] we have collected the contractually locked-in PPA price data over the full term of the PPA,[35] and have accounted for any escalation rates and/or time-of-delivery pricing factors employed.[36] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum amount of revenue required by[37]) these projects over the life of the contract—at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal tax incentives (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation)[38] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[39] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized LCOE; the final sub-section (starting on page 46) calculates the latter and compares it to the former, and finds that PPA prices are consistently lower than LCOE estimates, as expected.

Finally, not all of the projects behind the PPAs in our sample are yet online, though there is currently no compelling reason to think that they will not be built. Unlike other chapters of this report, which focus exclusively on operating projects (determined by commercial operation date),

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through a bundled PPA than they otherwise would be, either because they need to in order to comply with a solar set-aside, or because they know that each bundled solar REC has added value (in the case of a multiplier). So even though REC prices do not directly affect the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases—presumably to the upside.

[34] In general, each PPA corresponds to a different project, though in some cases a single project sells power to more than one utility under separate PPAs, in which case two or more PPAs may be tied to a single project.

[35] The minimum PPA term in the sample is 3 years, though this contract (along with several other short-term contracts like it) covers just the first few years of a project that has a longer-term PPA with a different counterparty starting in 2019 or 2020. The maximum PPA term is 34 years, the mean is 22.4 years, the median is 20 years, and the capacity-weighted average is 22.9 years.

[36] In cases where PPA price escalation rates are tied to inflation, EIA's projection of the U.S. GDP deflator from *Annual Energy Outlook 2019* (EIA 2019) is used to determine expected escalation rates. For contracts that use time-of-delivery pricing and have at least one year of operating history, each project's average historical generation profile is assumed to be replicated into the future. For those projects with less than a full year of operating history, the generation profiles of similar (and ideally nearby) projects are used as a proxy until sufficient operating experience is available.

[37] In a competitive "cost-plus" pricing environment—where the PPA price is just sufficient to recoup initial capital costs, cover ongoing operating costs, and provide a normal rate of return—PPA prices will represent the minimum amount of revenue required by a project. In contrast, "value-based" pricing occurs when the project developer or owner is able to negotiate a higher-than-necessary PPA price that nevertheless still provides value to the buyer.

[38] In addition to the other federal incentives listed, eleven projects within the sample also received U.S. Department of Energy loan guarantees through the Section 1705 program. In all eleven cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee did not affect the PPA price.

[39] For example, taking a simplistic view (i.e., not considering financing effects), the average PPA price could be as much as 50% higher (i.e., 30%/(1 minus the federal tax rate)) if there were no federal ITC. Without the ITC, however, the resulting increase in PPA prices would be mitigated by the fact that sponsors with tax appetite could then leverage up their projects more heavily with cheap debt, while sponsors without tax appetite would be able to forego expensive third-party tax equity in favor of cheaper forms of capital, like debt. Because of these financing shifts, the PPA price would not increase by 50%, but rather more like 35-40% in the case of a sponsor with tax appetite, and by roughly 20% in the case of a sponsor without tax appetite that currently relies on third-party tax equity to monetize the ITC (Bolinger 2014).

this chapter tracks PPA prices by contract execution date—which means including projects that are still in development—in order to provide a better picture of where the market is (or was) at any given point in time. As of August 2019, 86% of all projects and 74% of all capacity within the PPA sample were either partially or fully operating, with the remainder representing more-recently signed contracts for projects that are still under development or construction. While it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown in the figures below, the sample does not include any PPAs that have already been terminated.[40]

PPA prices have fallen dramatically, in all regions of the country

Figure 18 shows trends in the levelized (using a 7% real discount rate) PPA prices from the full PV contract sample over time. Each bubble in Figure 18 represents a single PPA, with the color of the bubble representing the region in which the underlying project is located,[41] the area of the bubble corresponding to the size of the contract in MW_{AC}, and the placement of the bubble reflecting both the levelized PPA price (along the vertical y-axis) and the date on the which the PPA was executed (along the horizontal x-axis).[42]

Figure 19, meanwhile, is essentially the same as Figure 18, except that it focuses only on those PPAs that were signed since the start of 2015. The purpose of Figure 19 is to provide greater resolution on the most-recent time period, which otherwise appears a bit crowded in Figure 18.

[40] There is a history of solar project and PPA cancellations in California and elsewhere, though in many cases these have involved projects using less-mature technologies (e.g., Stirling dish engines, compact linear Fresnel reflectors, and power towers). For PV projects, downward price revisions are perhaps a more likely risk than outright termination; several such downward price revisions have recently been announced in the wake of PG&E's most-recent bankruptcy.

[41] In order to limit the maximum y-axis value to \$250/MWh, Figure 18 excludes one northeastern PPA—a 32 MW_{AC} project on Long Island that was signed in June 2010 and that has a real levelized price of ~\$299/MWh (in 2018 dollars). The apparent above-market pricing of this contract should not be considered representative of utility-scale PV pricing in the Northeast more broadly, given that Long Island is widely recognized as a high-priced, transmission-constrained load pocket. There are eight other Northeast contracts in the sample—the highest-priced of which is also on Long Island—and most of these contracts are priced closer to (but still a bit above) the broader market.

[42] Because PPA prices reflect market expectations at the time a PPA is executed—which could be two years or more in advance of when the project achieves commercial operation—the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices.

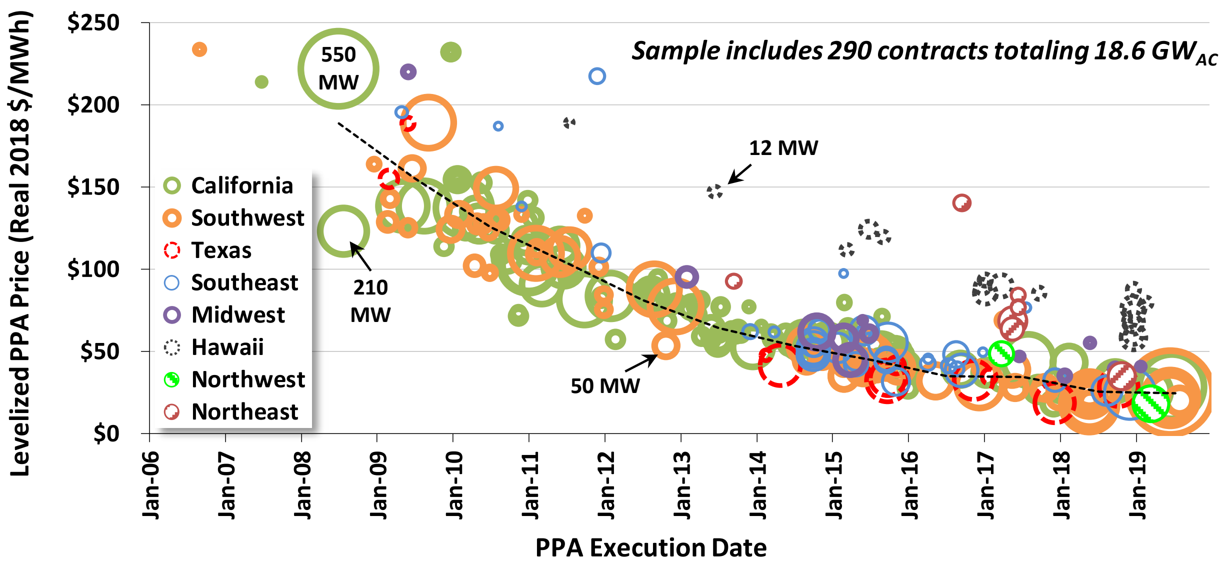

Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

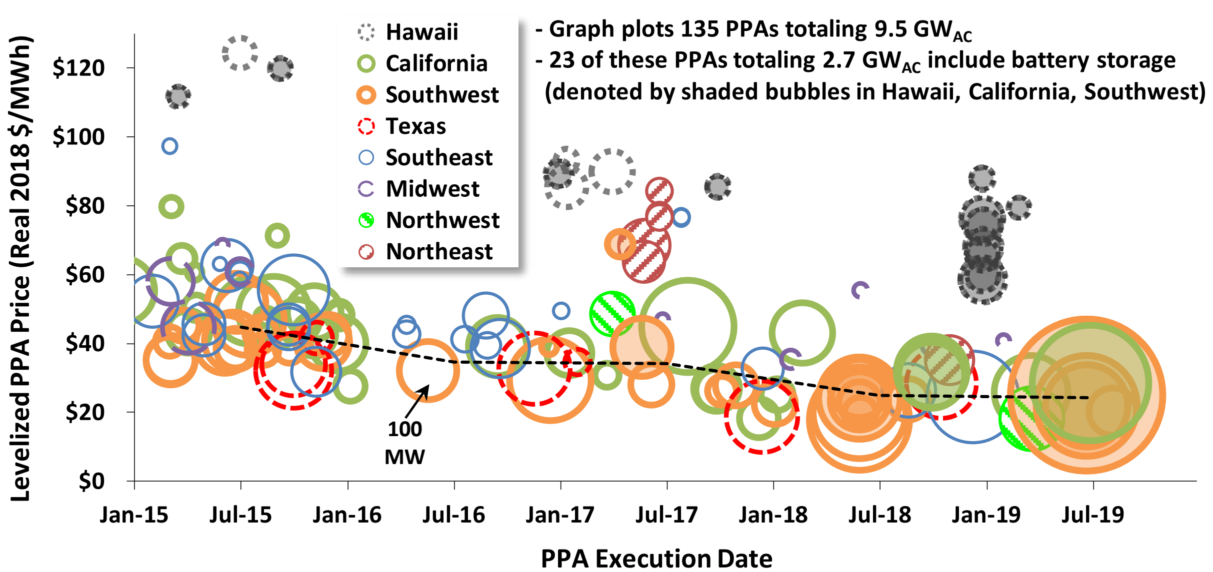

Figure 19. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: 2015-2019 (YTD) Contracts Only

Figure 18 and Figure 19 show that PPA pricing has declined steadily and significantly over time. As recently as 2011, solar PPA prices in excess of $100/MWh were quite common. Since the beginning of 2015, however, levelized PPA prices above $50/MWh have been more the exception than the rule, generally limited to projects in high-priced areas like Hawaii and the Northeast, and/or to projects that also incorporate significant amounts of medium-duration (e.g., 2-5 hours) battery storage. More recently, 27 of the 38 post-2017 contracts in our sample are priced below $40/MWh (levelized, in real 2018 dollars), with 21 of those below $30/MWh and four even dipping below $20/MWh. Many of these lower-priced contracts are from larger projects, but

Figure 19 shows that, in some cases, smaller projects (e.g., in the 20-50 MW range) can also boast PPA prices that are seemingly just as competitive as larger projects.[43]

Though California and the Southwest still dominate the sample, the market has expanded to other regions in recent years. Among the sub-sample of PPAs executed *after* 2014 (as shown in Figure 19), 53% of the contracts representing 68% of the capacity are for projects located in either California or the Southwest, down significantly from 83% of the contracts representing 88% of the capacity within the sub-sample of PPAs executed *prior to* 2015. Expanding markets include primarily the Southeast (14% of post-2014 capacity in the sample), Texas (8%) and Hawaii (5%).[44] With the exception of Hawaii, all other regions shown in Figure 18 and Figure 19 feature at least one PPA that is priced below $40/MWh.

Figure 20 portrays the data from Figure 18 in a slightly different way, to more clearly illustrate the strong downward time trend in average pricing. The individual markers (green triangles for Hawaiian projects, orange X's for Northeastern projects, and gray circles for all other projects) show the levelized PPA price of each individual contract grouped by the year in which the contract was signed, while the blue columns show the generation-weighted average of those individual levelized contract prices. Levelized PPA prices for utility-scale PV projects within the sample consistently fell by $20-$30/MWh per year on average from 2006 through 2012, with smaller price declines averaging ~$10/MWh from 2013 through 2016.[45] After a pause in 2017, due in part to a number of relatively high-priced Hawaiian and Northeastern contracts, average prices declined another ~$10/MWh in 2018 (to $31.1/MWh), and have continued to move lower so far in 2019 (to $28.2/MWh).

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[43] Very large projects may face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as greater interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from economies of scale in terms of the effect on the PPA price.

[44] Given the incomplete nature of our PPA price sample, Figure 4 and Figure 38 potentially provide a truer sense of expanding markets by reviewing the location of historical capacity additions over time (Figure 4) and by compiling data on projects making their way through various interconnection queues across the country (Figure 38).

[45] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength, tracking versus fixed-tilt, inverter loading ratio, and module type. To try and control for the influence of time, one could potentially analyze these variables within a single PPA vintage, but doing so might divide the sample to the point where sample size is too small to reliably discern any differences. Furthermore, it is not clear that some of these variables should even have much of an effect on PPA prices. For example, several of the PPAs in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing.

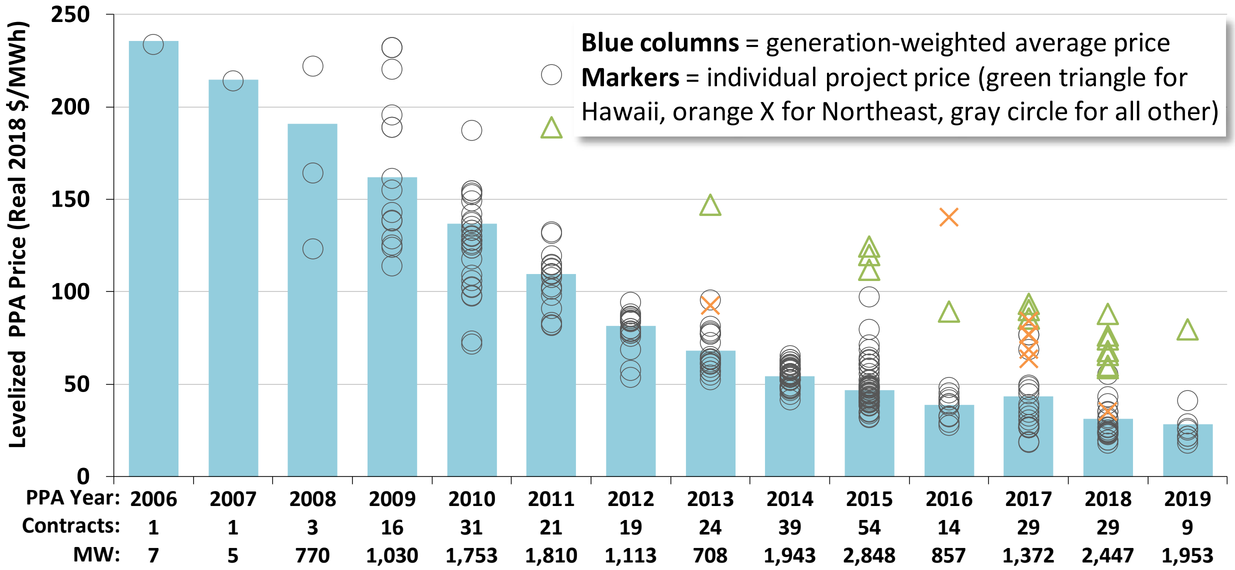

Figure 20. Levelized PV PPA Prices by Contract Vintage[46]

Though this price decline is impressive in terms of both scale and pace, it is also worth noting that in some markets with high solar penetration, the *wholesale market value* of solar energy has also declined over time as solar penetration has increased. Section 2.6 (starting on page 49) explores the *value* of solar in organized markets across the United States.

An increasing number of PPAs (and projects in general) are including battery storage

As the cost to add medium-duration (i.e., 2-5 hour) battery storage to utility-scale PV projects continues to fall, interest has grown both among utility offtakers (many of which now encourage all PV proposals to include a storage option) and developers (a number of which have made it standard practice to always provide a storage option when responding to a solicitation). As a result, the number of online or announced utility-scale PV plus battery storage projects has more than doubled from the sixteen projects that we highlighted here last year, and many more such projects are still in the early development phase or making their way through solicitations (e.g., Figure 38, later, shows more than 55 GW of PV hybrid projects within interconnection queues across the country as of the end of 2018).

Table 3 presents the key characteristics of 38 PV hybrid projects in 11 states totaling 4.3 GW_{AC} of PV and 2.6 GW_{AC} of battery capacity (with 2-5 hours of storage). The projects are sorted in alphabetical order by state, and within each state are listed in chronological order by the battery's actual or expected COD. Fewer than ten of these projects are yet online, while the rest have merely been announced (often at the time of PPA execution).

[46] Figure 20 excludes the two CPV projects in our sample. If included, they would both fall within the 2010 bin, at levelized prices of $113/MWh and $131/MWh—i.e., within the range of PV projects shown.

Table 3. Metadata for Online and Announced PV Hybrid Projects*

State	Project: Name	Project: Sponsor	Project: Offtaker	Actual or Expected COD (PV/Wind/Battery)	Capacity (MW-AC): PV	Capacity (MW-AC): Wind	Capacity (MW-AC): Battery	Battery Storage: Hours	Battery Storage: MWh	Battery:PV Capacity Ratio	Levelized PPA Price (2018 $/MWh)
AL	Redstone Arsenal	SunPower	Redstone Arsenal	Dec-17	10	0	1	2.0	2	10%	?
AR	Searcy	NextEra	Entergy (owner)	Dec-21	100	0	30	?	?	30%	#N/A
AZ	Pinal Central	NextEra	SRP	Apr-18	20	0	10	4.0	40	50%	68.9
AZ	Wilmot	NextEra	TEP	Dec-19	100	0	30	4.0	120	30%	40.7
AZ	Redhawk(?)	First Solar	APS	Jun-21	65	0	50	2.7	135	77%	?
CA	Desert Harvest II	EDF-RE	SCPPA	Dec-20	70	0	35	4.0	140	50%	LMP plus $15.25
CA	RE Slate 2	ReCurrent	MBCP and SVCE	Jun-21	150	0	45	4.0	180	30%	≤31.8
CA	BigBeau	EDF-RE	MBCP and SVCE	Dec-21	128	0	40	4.0	160	31%	≤30.9
CA	?	NextEra	Kaiser Permanente	Dec-20/Dec-21/Dec-21	131	50	110	?	?	84%	?
CA	Sonrisa	EDPR	SJCE & EBCE	Dec-22	200	0	40	4.0	160	20%	?
CA	Raceway	sPower	EBCE	Dec-22	125	0	80	2.0	160	64%	?
CA	Eland	8minute Solar	LADWP/Glendale	Dec-23	400	0	300	4.0	1200	75%	28.5
FL	Babcock	NextEra	FPL (owner)	Dec-16/NA/Mar-18	74.5	0	10	4.0	40	13%	#N/A
FL	Citrus	NextEra	FPL (owner)	Dec-16/NA/Mar-18	74.5	0	4	4.0	16	5%	#N/A
FL	Manatee	NextEra/FPL	FPL (owner)	Dec-16/NA/Dec-21	74.5	0	409	2.2	900	549%	#N/A
HI	Kapaia	Tesla	KIUC	Apr-17	13	0	13	4.0	52	100%	119.8
HI	Lawai	AES	KIUC	Oct-18	20	0	20	5.0	100	100%	89.4
HI	Kekaha	AES	KIUC	Sep-19	14	0	14	5.0	70	100%	85.5
HI	West Loch	HECO	HECO (owner)	Oct-19	20	0	20	4.0	80	100%	#N/A
HI	Waikoloa Solar	AES	Hawaiin Electric	Jul-21	30	0	30	4.0	120	100%	59.8
HI	Kuihelani Solar	AES	Hawaiin Electric	Jul-21	60	0	60	4.0	240	100%	58.5
HI	West Oahu	AES	Hawaiin Electric	Sep-21	12.5	0	12.5	4.0	50	100%	79.5
HI	Hoohana Solar 1	174 Power Global	Hawaiin Electric	Dec-21	52	0	52	4.0	208	100%	76.3
HI	Mililani I Solar	Clearway	Hawaiin Electric	Dec-21	39	0	39	4.0	156	100%	68.0
HI	Waiawa Solar	Clearway	Hawaiin Electric	Dec-21	36	0	36	4.0	144	100%	74.0
HI	Hale Kuawehi	Innergex	Hawaiin Electric	Jun-22	30	0	30	4.0	120	100%	65.8
HI	Paeahu	Innergex	Hawaiin Electric	Jun-22	15	0	15	4.0	60	100%	87.9
MN	Ramsey/Athens	Engie/NextEra	Connexus	Dec-18	10	0	15	2.0	30	150%	?
NV	Battle Mountain	Cypress Creek	NV Energy	Jun-21	101	0	25	4.0	100	25%	22.3
NV	Dodge Flat	NextEra	NV Energy	Dec-21	200	0	50	4.0	200	25%	23.1
NV	Fish Springs Ranch	NextEra	NV Energy	Dec-21	100	0	25	4.0	100	25%	25.9
NV	Townsite	Capital Dynamics	Munis/Co-op	Dec-21	180	0	90	4.0	360	50%	?
NV	Arrow Canyon	EDF-RE	NV Energy	Dec-22	200	0	75	5.0	375	38%	21.8
NV	Southern Bighorn	8minute Solar	NV Energy	Sep-23	300	0	135	4.0	540	45%	21.9
NV	Gemini	Quinbrook/Arevia	NV Energy	Dec-23	690	0	380	3.8	1460	55%	25.1
OK	Skeleton Creek	NextEra	WFEC	Dec-23/Dec-19/Dec-23	250	250	200	4.0	800	80%	?
OR	Wheatridge	NextEra	PGE	Dec-21/Dec-20/Dec-21	50	300	30	4.0	120	60%	?
TX	Castle Gap	Luminant	Luminant (owner)	Jun-18/NA/Dec-18	180	0	10	4.2	42	6%	#N/A

**Only projects that include batteries with at least 2 hours of storage, and for which sufficient details are public, are included in Table 3. In the final column, "?" indicates an unknown PPA price while "#N/A" indicates that there is no PPA because the offtaker is also the owner.*

A number of notable elements among these 38 projects are worth highlighting:

- The ratio of battery capacity to PV capacity varies widely, reflecting specific circumstances. All twelve Hawaiian projects—interconnected to isolated island grids with significant solar penetration—are at parity (1:1 or 100%) in order to capture and shift most or all mid-day generation into peak evening or nighttime hours. Also towards the upper end of the range is a First Solar project from which Arizona Public Service will only buy energy during the hours of 3-8 PM—which explains both the relatively high battery-to-PV capacity ratio (77%) and also the relatively short storage duration of 2.7 hours (as stored energy need not be available beyond 8 PM). In contrast, one of the few DC-coupled battery systems, Citrus, is at the low end of the range (5%), reflecting its primary purpose to capture what would otherwise be “clipped” mid-day solar energy (given Citrus’ very high inverter loading ratio of 1.65). Finally, two projects—Ramsey/Athens in Minnesota (150%) and Manatee in Florida (549%)—exceed 100%, though Manatee’s high percentage is misleading given that it is based solely on the existing 74.5 MW Manatee PV project, despite the fact that Florida Power & Light (FPL) plans to build another PV project nearby, and also seems to be thinking of the Manatee battery as a system-wide rather than project-specific resource.

- Among the 36 projects in Table 3 for which storage duration has been announced, duration ranges from 2 hours (our somewhat arbitrary minimum cutoff for inclusion in the table) to 5 hours, with a mean of 3.8 hours, a median of 4.0 hours, and a $10^{th}/90^{th}$ percentile range of 2.5 to 4.1 hours. A clear majority—26 of the 36 projects—have 4.0 hours of storage.

- Though most of the projects in Table 3 are greenfield projects, battery retrofits have become more common since the IRS provided guidance (via Private Letter Ruling 201809003) that such retrofits will qualify for the ITC. FPL retrofitted both Babcock and Citrus with batteries roughly a year after the two PV projects came online, and more recently announced an upcoming retrofit at the Manatee project site. In June 2018, Arizona Public Service released a solicitation for up to 106 MW of battery storage to be retroactively installed at a handful of its existing utility-scale PV projects, but expanded the program to 200 MW (of three-hour storage) across eight sites after receiving favorable bids; these projects (not yet listed in Table 3, due to incomplete information) should be online by 2020.

- Storage is being compensated in a variety of ways within these PPAs, some of which are interesting. Five of the earliest hybrid PPAs (in Hawaii and Arizona) simply bundle the storage cost into the overall (in these cases, time-invariant) energy price, with the PPAs further specifying how the storage is to be utilized. More recently, three PPAs in Nevada (Arrow Canyon, Southern Bighorn, and Gemini) similarly subsume the storage cost within the energy price, but in all three of these cases the energy price spikes to 6.5x its normal level during five peak hours (4-9 PM) each day in the summer months of June-August, which is presumably when the batteries earn their keep. Desert Harvest II provides no direct compensation for storage within the PPA, but given that the PPA is priced at the prevailing local nodal price (plus $15.25/MWh for RECs), the sponsor has an incentive to store energy during the lowest-priced hours (typically mid-day) and deliver stored energy during the highest-priced hours (typically in the late-afternoon). In contrast, seven other PPAs (in California and Nevada) compensate the storage component through a separate fixed capacity payment (expressed in either $/kW-month or $/MWh terms). Meanwhile, the eight most-recent Hawaii projects are all using the new “Renewable Dispatchable Generation” PPA, through which the PV+battery projects are paid a lump sum (rather than a volumetric $/MWh rate) for being available to be dispatched by the offtaker.[47] Finally, though we do not (yet) have pricing for either of these PPAs, a First Solar project with Arizona Public Service will only be compensated for energy delivered from 3-8 PM (as noted earlier), and

[47] For these eight projects, we report the levelized “unit price,” which is simply the lump sum payment divided by the MWh of “net energy potential” as specified in the contract. These Renewable Dispatchable Generation contracts are based on some earlier consulting work conducted by the Smart Electric Power Alliance and ScottMadden (Sterling et al. 2017).

the Townsite PPA in Nevada has been described as the first PV project to use batteries to shape and firm a fixed-volume delivery PPA (Capital Dynamics 2019).

- Finally, three of the proposed hybrid projects include wind power. All three are sponsored by NextEra, which, as the largest owner of wind power in the United States, sees benefits to expanding the hybrid model beyond just PV and battery hybrids.

The incremental PPA price adder for storage depends on the size of the battery

Figure 19 (above) includes 23 PPAs (denoted by the bubbles that are shaded) signed since the start of 2015 whose price covers *both* PV *and* battery storage (all 4-5 hours in duration, but with varying battery:PV capacity ratios). Compared to other contemporary projects located within the same regions but lacking storage, the PV+battery PPAs shown in Figure 19 do not seem to be priced at much of a premium—but the figure is noisy, which complicates a solely visual determination. To isolate and enhance the visibility of these PV+battery projects, Figure 21 shows *only* these 23 contracts, 12 of which are in Hawaii (not surprising, given its isolated island grids and high solar penetration), with the rest spread among Nevada, California, and Arizona—all of which are also relatively high-penetration solar markets, per Table 1 (earlier).

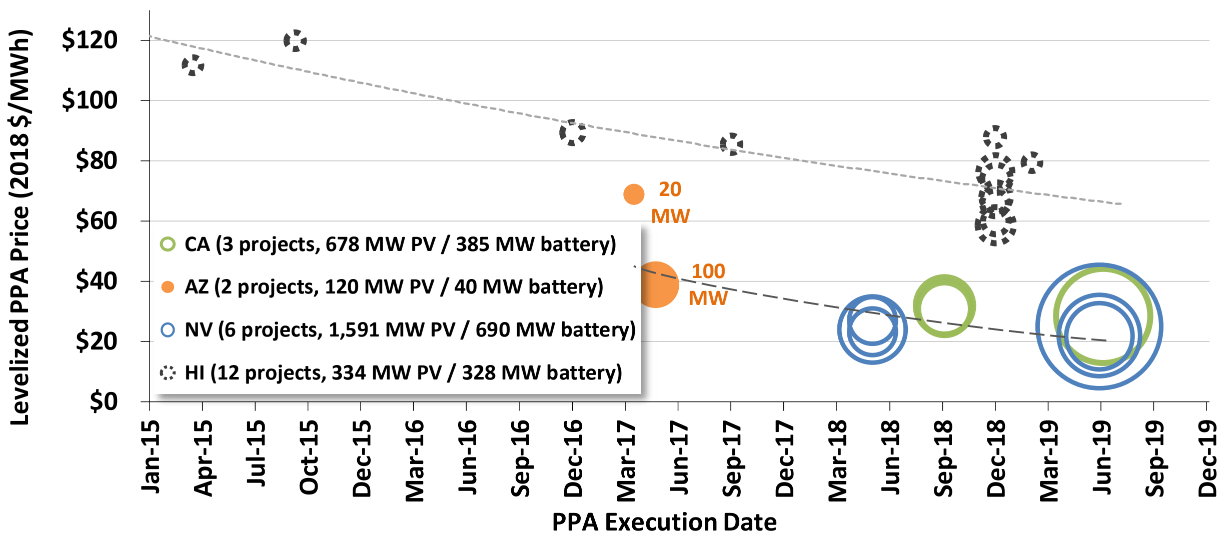

Figure 21. Levelized Price of PV+Battery PPAs in the LBNL Sample

Hawaiian PV hybrid projects are priced at a significant premium over those in California and the Southwest. Some of this premium could be attributable to the high battery:PV capacity ratios in Hawaii, where 1:1 is common (see Table 3, earlier). That said, Figure 22 shows little difference between standalone and hybrid PV PPA prices in Hawaii, suggesting that the Hawaii premium may be more general in nature—e.g., due to its remote location (which drives up costs) and weaker solar resource (at least relative to California and the Southwest). Another possibility, based on the ~$40/MWh magnitude of the premium,[48] is that some degree of value-based (as opposed to cost-

[48] Fu et al. (2015) modeled the LCOE of utility-scale PV projects throughout the United States (including Hawaii), based on differences in labor rates, installation costs, insolation, and other factors, and estimated that in 2015, a project in Kona, Hawaii would have had an LCOE that was $14-$15/MWh higher than an identical project in California's Imperial Valley, and only $7-$8/MWh higher than an identical project in Bakersfield, California. These estimates are significantly below the ~$40/MWh premium derived from the empirical data.

based, or cost-plus) pricing may be occurring in Hawaii, with developers bidding to some extent against the high cost of oil-fired generation. Value-based pricing would help explain why, in Figure 22, storage seems to command little or no premium in Hawaii, despite high battery:PV capacity ratios. Still another contributor could be the relatively small size of utility-scale PV projects in Hawaii, where limited developable land and rugged terrain make larger projects that can capture greater economies of scale unlikely.

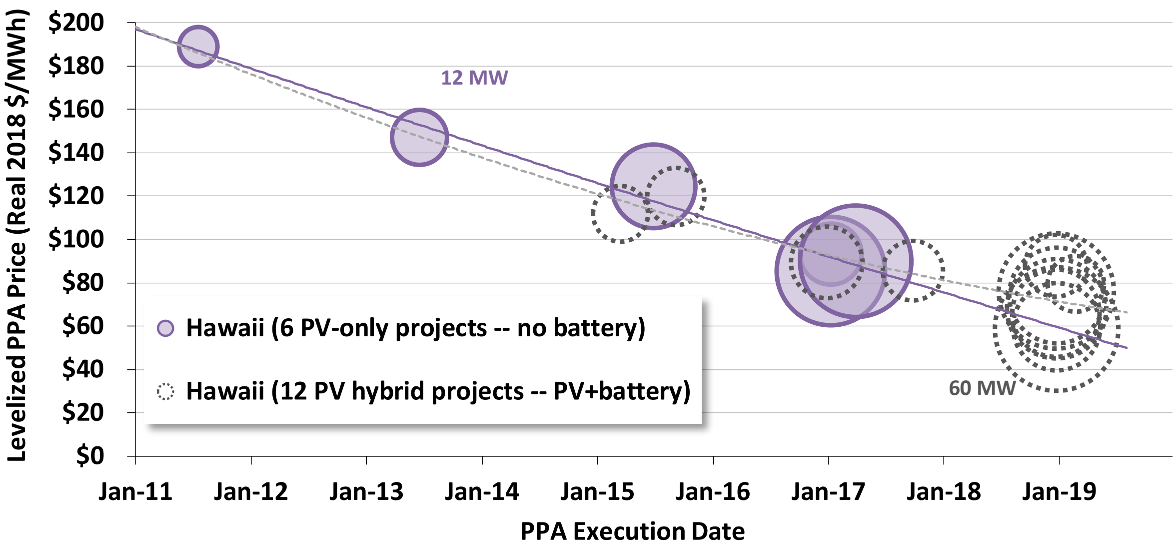

Figure 22. Prices from Standalone PV versus PV+Battery PPAs in Hawaii

While visually inferring storage adders to PPA prices is difficult, a handful of these 23 PV+battery PPAs provide enough information (e.g., through separate capacity payments for the storage component) to enable the direct calculation of a storage adder. All PPAs shown in Figure 23 include 4 hours of battery storage, while the battery:PV capacity ratio varies along the x-axis. Based on this limited sample, a 4-hour battery that is sized at roughly 25% of the PV capacity adds about $4/MWh to the overall PPA price.[49] But as the battery capacity increases to 50% and 75% of the PV capacity, the levelized storage adder increases linearly to ~$10/MWh and ~$15/MWh, respectively.

[49] On a levelized basis, these adders are roughly consistent with NextEra Energy's latest investor presentation, which pegs the historical PPA price adder for 4 hours of storage sized at 25% of PV capacity at $19-$29/MWh in 2016 and $9-$16/MWh in 2018, falling to an expected $8-$14/MWh in 2020 and $4-9/MWh in 2022 (NextEra Energy 2019).

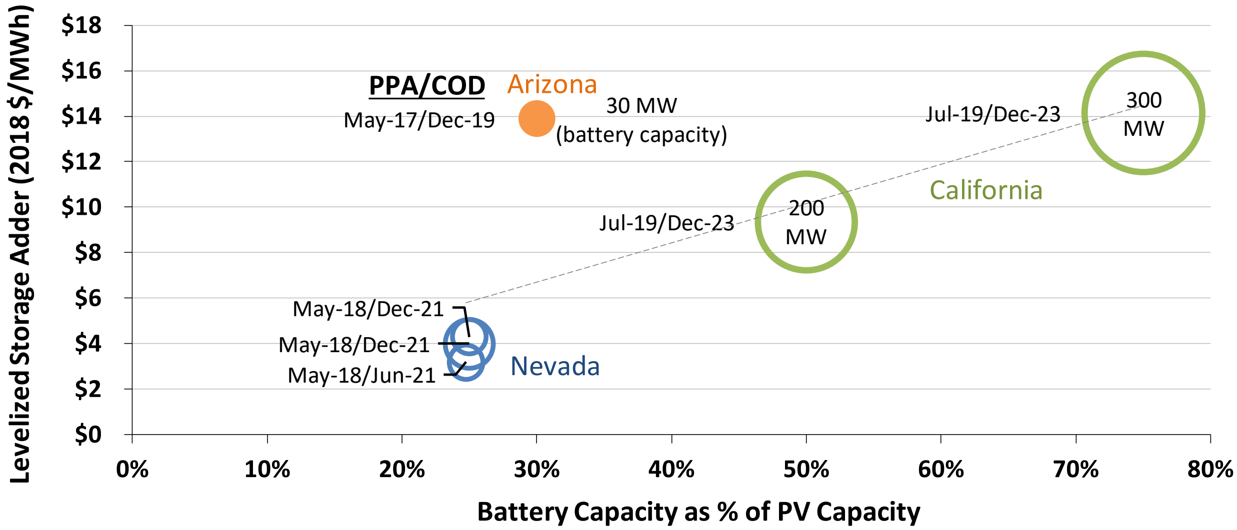

Figure 23. Levelized Storage Adder as a Function of Battery:PV Capacity

Given that these storage price adders have fallen over time (NextEra Energy 2019), the single Arizona PPA in Figure 23—one of first PV hybrid projects announced in the continental United States—might be considered somewhat of an outlier, in light of its earlier dates for both PPA execution and expected COD.

Despite record-low PPA prices, solar faces stiff competition from both wind and natural gas

Figure 24 plots utility-scale PV (gold) and wind (blue) PPA prices on a levelized basis since 2008 (the dashed gold and blue lines show the generation-weighted average PV and wind PPA prices in each year, respectively). Although the gap between solar and wind PPA prices was quite wide a decade ago, that gap has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices.[50]

Figure 24 also shows that both solar and wind PPA prices are now competitive with the projected fuel costs of gas-fired combined cycle generators. Specifically, the black dash markers show the 20-year levelized fuel costs (converted from natural gas to power terms at an assumed heat rate of 7.5 MMBtu/MWh) from then-current EIA projections of natural gas prices delivered to electricity generators.[51] Supported by federal tax incentives, the generation-weighted average levelized wind and solar PPA prices within our contract sample have, for several years now, been below the projected levelized cost of burning natural gas in existing gas-fired combined cycle units.

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[50] The wind PPA prices are sourced from the U.S. Department of Energy's *2018 Wind Technologies Market Report*, which is also prepared by Berkeley Lab (windreport.lbl.gov).

[51] For example, the black dash marker in 2008 shows the 20-year levelized gas price projection from *Annual Energy Outlook 2008*, while the black dash in 2019 shows the same from *Annual Energy Outlook 2019* (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh). The assumed heat rate is intended to reflect an average among the existing fleet of combined cycle generators, rather than the current best-in-class, which might be closer to 6.0-6.5 MMBtu/MWh. Price expectations reflected in NYMEX natural gas futures contracts might differ from the EIA projections used here, but the NYMEX futures strip extends only 12-13 years, compared to the 20-year term used in the figure.

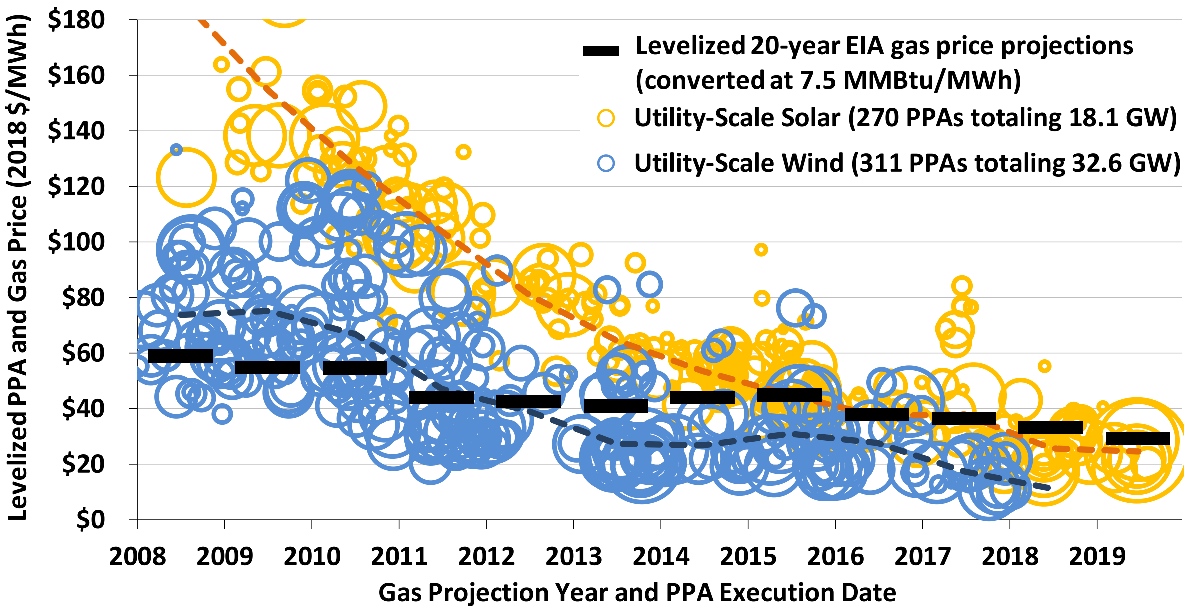
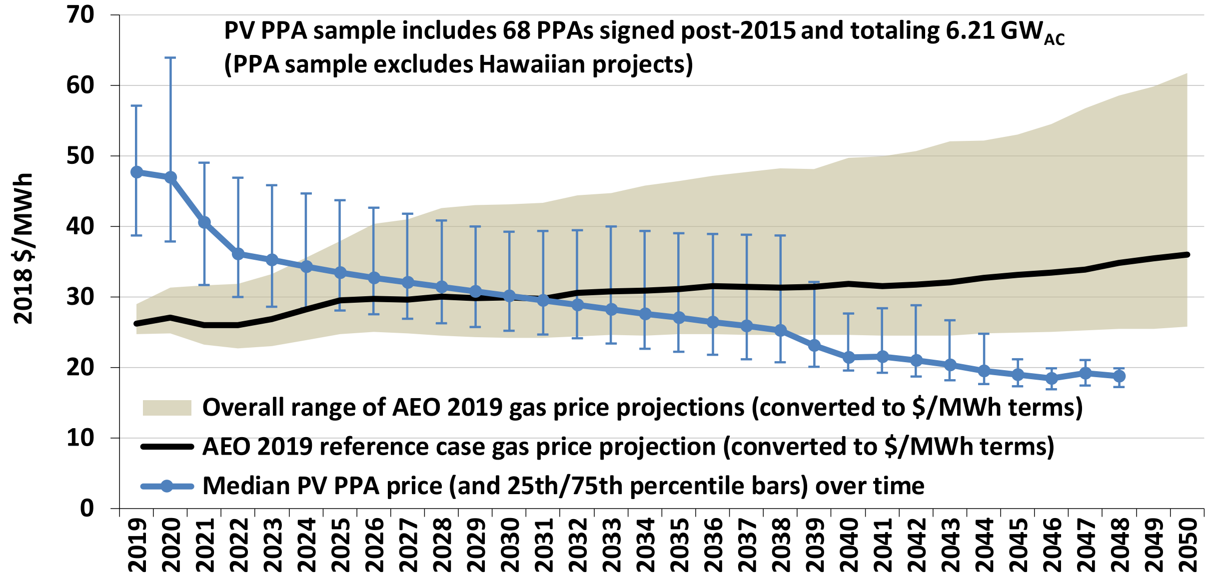


Figure 24. Levelized PV and Wind PPA Prices and Levelized Gas Price Projections

Rather than levelizing the solar PPA prices and gas price projections (as in Figure 24), Figure 25 plots the *future annual stream* of median PV PPA prices from 68 contracts executed post-2015 against a range of EIA projections of *just the fuel costs* of natural gas-fired generation.[52] In this way, Figure 25 essentially compares the annual cost of *new* PV projects to the cost of *existing* gas-fired generation over time. This comparison is not perfect, however, given that existing gas-fired generators will also incur some small amount of non-fuel variable operating costs that are not accounted for, and may also still need to recover some portion of their initial capital costs to build the project. Nor do natural gas and solar projects have equivalent output profiles or environmental characteristics.

Nonetheless, as shown, the median PPA prices start out well above the range of fuel cost projections in 2019 and 2020, but then decline (in real 2018 $/MWh terms) over time, entering the fuel cost range in 2024 and eventually reaching, and then falling below, the reference case fuel cost projection by the early-2030s. On a levelized basis (in real 2018 dollars) from 2019 through 2048, the median PV PPA price comes to $32.7/MWh, compared to $29.2/MWh for the reference case fuel cost projection, suggesting that sustained low gas prices (and low gas price expectations) has made it difficult for PV to compete with *existing* gas-fired generation. That said, the PV PPA prices shown in Figure 25 have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain—actual fuel costs could end up being either lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases (Bolinger 2013; 2017).

[52] The national average fuel cost projections come from the EIA's *Annual Energy Outlook 2019* publication, and increase from around $3.27/MMBtu in 2019 to $5.34/MMBtu (both in 2018 dollars) in 2050 in the reference case. The upper and lower bounds of the fuel cost range reflect the low and high, respectively, oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using the average heat rates implied by the modeling output, which start at roughly 8.0 MMBtu/MWh in 2019 and gradually decline to roughly 6.7 MMBtu/MWh by 2050.



Note: The 25th/75th percentile range narrows considerably in later years as the PPA sample dwindles

Figure 25. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

Moreover, as noted above, the comparison laid out in Figure 25 is not entirely apples-to-apples, as it does not include the recovery of fixed capital costs that would be incurred by *new* gas-fired generators (or other non-fuel operating costs that would be incurred by both new and existing gas-fired generators), whereas the PV PPA prices are set at a level intended to be sufficient (in concert with federal incentives) to recover *all* costs (i.e., both initial capital costs and ongoing operating costs). By one estimate, capital and non-fuel O&M costs can add $21-$50/MWh to the levelized cost of energy from a combined-cycle gas plant (Lazard 2018). In addition, as PV plus battery storage becomes more cost-effective, perhaps a more-appropriate comparison would be to gas-fired peaking plants, which typically have much higher (i.e., less-efficient) heat rates than those embedded within Figure 25.

On the other hand, Figure 25 also makes no attempt to account for the operational and environmental differences between these two generation sources, or the differences in federal and state subsidies received. In particular, it is well known that the market value (and capacity credit) of solar declines with increased solar penetration, as a result of grid integration challenges and other characteristics related to its temporal generation profile (Mills and Wiser 2013); these factors are explored later in Section 2.6 on market value.

Levelized PPA prices track the LCOE of utility-scale PV reasonably well

In a competitive, cost-based market, bundled long-term solar PPA prices should track the levelized cost of solar energy or LCOE (after properly accounting for the levelized value of any state or federal incentives received). Here we use the project-level empirical data presented earlier in this report—e.g., CapEx, OpEx, and capacity factor—coupled with assumptions about financing, taxes, and other items enumerated below, to estimate the LCOE of utility-scale PV by project and on average over time. Calculating LCOE in this way enables us to analyze the cost of solar across a larger sample of projects than those for which we have PPA prices, and to evaluate the efficiency and competitiveness of the PPA market by analyzing the degree to which PPA prices track LCOE.

While LCOE is typically calculated and expressed excluding the beneficial impact of federal tax credits, here we calculate it both with and without the 30% ITC, in order to be able to compare the former to the empirical PPA prices analyzed earlier in this section.

Our LCOE calculations make liberal use of the empirical project-level data presented earlier, starting with the >22.8 GW_{AC} of projects for which we have compiled CapEx estimates (as presented in Section 2.2). For projects that have been operating for at least a full year and for which we have capacity factor data (as presented in Section 2.4), we rely on those empirical data. For projects where we do not yet have capacity factor data, we estimate capacity factors based on underlying project characteristics (e.g., the average long-term irradiance at the project site, whether or not tracking is used, the ILR) in conjunction with the regression formula laid out in Bolinger, Seel, and Wu (2016). In all cases, we then handicap the project-level capacity factor data to reflect a projected annual degradation rate of 0.75%/year before plugging it into the LCOE equation (which is the same equation used in Cole et al. (2019)). Total OpEx is assumed to be $30/kW-year for all projects; this assumption is higher than the average utility O&M cost numbers shown in Figure 13, but those numbers are derived from FERC Form 1 and do not reflect total OpEx (see footnote 22).

Financing assumptions reflect a variety of industry benchmarks and anecdotal data points. The cost of equity is assumed to be 10% (after-tax, levered) for all projects, while the cost of debt varies daily (but is averaged across each calendar year) based on the 30-year fixed-for-floating swap rate benchmark (ICE 2019) plus an estimate of the debt spread in the commercial bank market over time (BNEF 2017; Norton Rose Fulbright 2019). The nominal after-tax weighted average cost of capital, or WACC, reflects a 60%/40% debt/equity ratio in all cases, applied to the average cost of debt and equity *in the year prior to* when each project achieves commercial operation (in an attempt to reflect the time lag between when a project is financed and built). For reference, the nominal after-tax WACC ranges from a high of 6.5% in 2009 (for projects with a 2010 COD) to a low of 5.4% in 2016 (for projects with a 2017 COD).

Other assumptions include a 30-year project life; an inflation rate of 2.0%/year; a combined federal and state tax rate of 40% for all projects built prior to 2018's reduction in the corporate federal tax rate, and 27% thereafter; and a 5-year MACRS depreciation schedule. Finally, the "capital recovery factor" and "project finance factor" are calculated (from various data and assumptions already noted above) per the formulas in Cole et al. (2019).

Figure 26 shows the results of this exercise, with both project-level and median LCOEs plotted alongside median levelized PPA prices (from a smaller sample than indicated for LCOE, and in this case levelized over 30 years to match the LCOE term and then plotted by COD, rather than execution, year). The median LCOE *without* the 30% ITC (orange dash markers) has declined by 68% since 2011, to $53.8/MWh in 2018. The median LCOE that *includes* the 30% ITC (green dash markers) provides a closer comparison to PPA prices, and has declined by 65% since 2011, to $39.1/MWh in 2018. In general, the median LCOE estimates that *include* the ITC closely track the declining PPA price trend seen here (and elsewhere in this section), suggesting a relatively competitive market for PPAs. Looking ahead, the median levelized PPA price among a small sample of 11 projects totaling 787 MW that are likely to achieve commercial operations in 2019 suggests a further slight decline in LCOE.

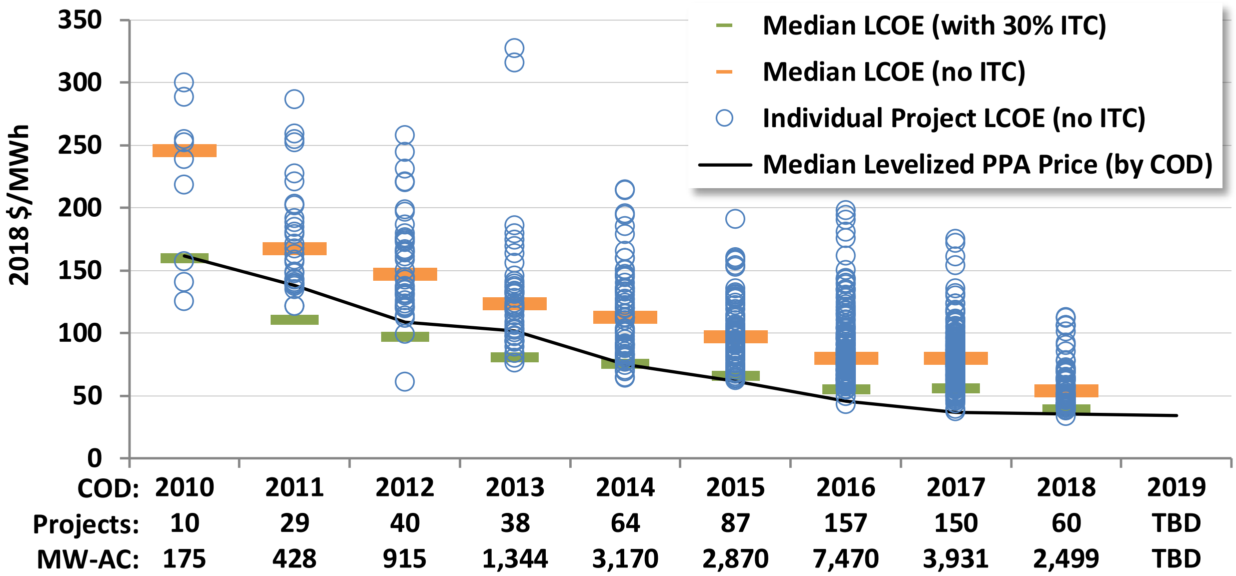


Figure 26. PPA Prices versus LCOE

2.6 Wholesale Market Value

In describing the economic competitiveness of utility-scale solar, the PPA prices and LCOE presented in the previous section tell only half of the story—i.e., what solar energy *costs*. Equally important is solar's market value—i.e., what solar energy is *worth* in wholesale power markets. Like PPA prices and LCOE, solar's wholesale market value is expressed in $/MWh, but in this case reflects the revenue that a solar project could earn in wholesale power markets from the sale of energy and/or capacity (and potentially other items as well, like ancillary services and RECs) divided by the total MWh generated over the time period of interest. That revenue depends not only on market prices, but also on the generation profile of solar in each market.

In this section, we use historical wholesale energy and capacity market prices, in conjunction with hourly solar generation profiles, to assess solar's wholesale energy and capacity value in organized markets run by independent system operators (ISOs) across the United States.[53] Because market value is negatively affected by curtailment, we begin by presenting data on solar curtailment from the two ISOs that so far report such data: the California Independent System Operator ("CAISO") and the Electric Reliability Council of Texas ("ERCOT"). These curtailment data are inputs to the market value calculations presented thereafter. Finally, we compare solar's wholesale market value to a subset of the PPA prices presented in the previous section, to provide a general sense for how solar's value compares to its cost.

Solar curtailment is a function of market penetration and transmission constraints

A curtailed MWh is a MWh that *could have* displaced other generation and earned revenue from the sale of energy and/or capacity (and/or other services) if not for curtailment.[54] This lost opportunity negatively affects market value. Hence, a proper assessment of solar's wholesale market value should include both un-curtailed *and* curtailed generation in the denominator of the $/MWh market value metric, so that all potential generation—whether or not curtailed—is accounted for.

Solar curtailment in the United States is not widely tracked: only two of the seven ISOs that oversee competitive wholesale power markets across the United States—CAISO and ERCOT—currently track and report solar curtailment.[55] Figure 27 shows the percentage of total potential solar generation that was curtailed in each of these ISOs, on a monthly basis, while Figure 28 shows similar data on an annual basis (with quarterly allocations denoted by shading gradients).

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[53] The solar generation profiles used in this section reflect *all* market sectors—residential, non-residential, and utility-scale—which means that we are technically calculating the wholesale market value of solar in general, rather than of utility-scale solar specifically. That said, differences in wholesale market value across sectors are minimal, if considering only energy and capacity value. Inclusion of the residential and non-residential sectors also means that our reported market penetration rates are larger than for just utility-scale, while reported curtailment rates will be lower than for just utility-scale.

[54] Some power purchase agreements do compensate the seller in the event of certain curtailments, but from a system-wide perspective, this contractual arrangement is not particularly relevant.

[55] The fact that all seven ISOs do track and report wind power curtailment perhaps suggests that solar curtailment is simply not much of an issue yet in the five non-reporting ISOs, given modest solar penetration. That said, we do know that curtailment is an issue in other non-ISO markets, such as Arizona and Hawaii—but because these markets are not part of ISOs, they are difficult to track, and we ignore them here.

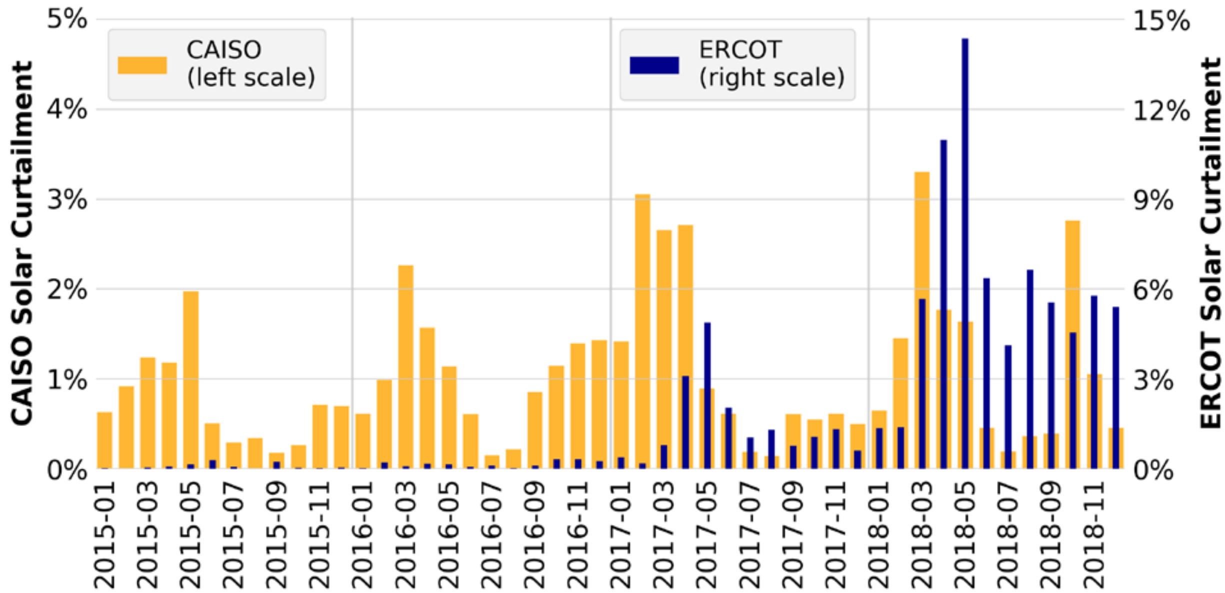

Figure 27. Monthly Solar Curtailment in CAISO and ERCOT

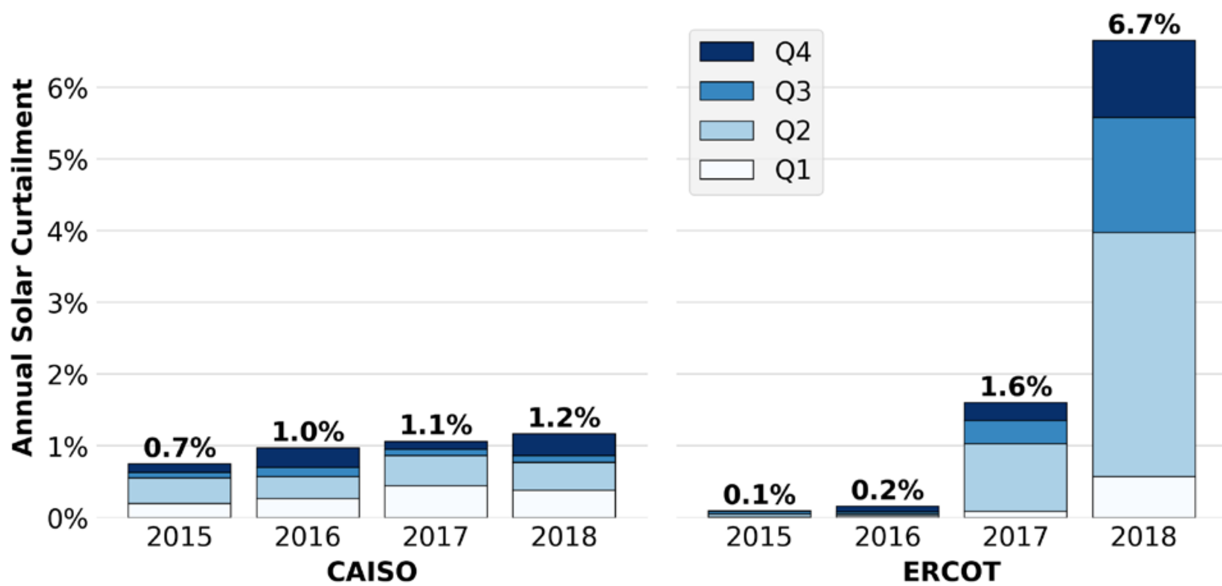

Figure 28. Annual and Quarterly Solar Curtailment in CAISO and ERCOT

Figure 27 shows a clear seasonal pattern to curtailment, particularly in California, where solar curtailment tends to be concentrated in the non-summer months, typically peaking in late winter and early spring—i.e., the "shoulder" months when irradiance starts to increase, load is still modest, and hydropower generation is often strong due to melting snowpack and spring runoff. Yet Figure 28 shows that the annual solar curtailment rate in CAISO is still relatively modest, at just 1.2% in 2018.[56] Moreover, solar curtailment in CAISO has increased only gradually over this four-year period, despite solar's market penetration having doubled over this same period, from

[56] Though not shown in Figure 27 or Figure 28, CAISO solar curtailment has risen sharply in the first seven months of 2019, to 671 GWh—more than double the 290 GWh curtailed during the same months of 2018.

7.9% to 16.3% (market penetration is shown in Figure 30, below). The creation and expansion of the Western Energy Imbalance Market, which enables real-time bulk power trading throughout the West, has been credited with avoiding greater amounts of solar (and wind) curtailment within the CAISO market (CAISO 2019).

In ERCOT, where solar is still a relatively new resource and solar penetration is only around 1% (much lower than in CAISO, see Figure 30), there was almost no solar curtailment prior to 2017. But in 2017, ERCOT curtailed 1.6% of total solar generation, and in 2018, that number shot up to 6.7%—a rate that far exceeds anything yet seen in CAISO (despite its higher solar penetration), and also well above ERCOT's 2018 wind curtailment rate of 2.5% (despite ERCOT having a much higher wind than solar penetration). Closer examination reveals that the bulk of this solar curtailment—i.e., 81% of curtailed MWh in 2018—was concentrated among just three solar projects, which came online in 2014 (22 MW_{AC}), 2016 (158 MW_{AC}), and 2018 (150 MW_{AC}). These projects—which reportedly had 20%-36% of their annual output curtailed in 2018—are all located in West Texas near Fort Stockton, an area specifically noted by ERCOT's independent market monitor to have experienced severe congestion in 2018 (Potomac Economics 2019). Thus, the sharp rise in ERCOT's solar curtailment—which seems out of proportion to the level of solar penetration in Texas—has seemingly thus far been driven by local congestion severely impacting just a few projects, rather than by broader system-wide conditions.[57]

To place the 432 GWh of solar energy that was curtailed in CAISO in 2018 in perspective, it is roughly equivalent to the annual output of a hypothetical 173 MW_{AC} PV project operating at an average California capacity factor of 28.5%. Absent this curtailment, the average 2018 capacity factor among our California sample would have been half a percentage point higher than it was, increasing from 28.5% to 29.0%. In ERCOT, the 278 GWh of solar energy curtailed in 2018 roughly matches the annual output of a hypothetical 142 MW_{AC} project operating at an average Texas capacity factor of 22.3%. Absent this curtailment, the average 2018 capacity factor among our Texas sample would have been 2.6 percentage points higher, increasing from 22.3% to 24.9%.

More to the point of this section, if not for the curtailment reported in this sub-section, solar's market value in 2018 (as reported in the next sub-section) would have increased by $0.2/MWh in CAISO and by $2.4/MWh in ERCOT.

In most regions of the United States, solar provides above-average market value

In many regions of the country, utility-scale solar projects participate in organized wholesale electricity markets for energy and, where available, capacity. In a few cases, so-called "merchant" solar projects directly bid into those markets, and earn the prevailing market price. In most other cases—e.g., when a PPA is in place—the buyer will schedule the solar energy into the market, paying the solar project owner the pre-negotiated PPA price but earning revenue from the prevailing wholesale market price. In either instance, the revenue earned (or that could have been

[57] ERCOT's 2018 "Constraints and Needs" report indicates a plan to alleviate this congestion by upgrading the Barilla Junction-Fort Stockton 69 kV Line before the end of 2020 (ERCOT 2018).

earned) from the sale of solar into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system.[58]

In the case of merchant solar projects (of which there are so far only a few), the link between wholesale market prices and value is direct, in that the former directly affects the latter through earned revenue. In the much more common case of solar projects with PPAs, on the other hand, the pre-negotiated PPA price establishes plant revenue and, depending of the specifics of the PPA, pricing may or may not be linked to wholesale market prices. In this latter case, however, the revenue earned (or that could have been earned) by the sale of solar into the wholesale market still reflects the underlying market value of that solar—but in this case, in the form of an avoided cost to the buyer. This is because the buyer could, in theory, have purchased power from the wholesale market instead of from the solar project. Hence, the solar project's estimated revenue were it selling into the wholesale market therefore reflects costs avoided by the buyer under the solar PPA. This (potential) revenue—or value—can be broken out into energy value and, where capacity markets or requirements exist, capacity value.

In this sub-section, we present the energy and capacity value of solar on an annual basis from 2012-2018, across the seven ISOs in the United States.[59] In aggregate, these seven ISOs—CAISO, ERCOT, Southwest Power Pool ("SPP"), Midcontinent Independent System Operator ("MISO"), PJM, the New York Independent System Operator ("NYISO"), and ISO New England ("ISO-NE")—are home to roughly two-thirds of the solar capacity in our overall PV project universe.[60] We focus exclusively on energy and capacity value, and ignore the possibility of additional value derived from the sale of RECs (e.g., to a buyer seeking to satisfy RPS obligations) and/or ancillary services.

Energy value is simply the product of hourly solar generation and hourly wholesale energy prices. Where available, we start with ISO-reported aggregate hourly solar generation (which is typically comprised mostly of utility-scale solar), and supplement that with modeled hourly solar generation from residential, non-residential, and any remaining utility-scale plants that are not already included within the ISO-reported generation data. For hourly wholesale energy prices, we use historical prices from representative trading hubs within each ISO.[61]

Capacity value relies on the same reported and constructed generation profiles as does energy value to assess the "capacity credit" of solar according to each ISO's rules in place at the time. We then multiply the resulting capacity credit by historical capacity prices or costs to arrive at

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[58] Though this grid-system perspective on value is important, it does not take into account other considerations, such as a need to comply with state-level RPS policies, which may ultimately drive some investment decisions in the case of solar.
[59] Much of the analysis reported in this section was conducted under LBNL's *Solar-to-Grid* (S2G) project, and is explained more fully and in greater detail within a forthcoming S2G report (Mills et al. 2019).
[60] The remainder are located in non-ISO regions of the continental United States, or Hawaii.
[61] In other words, we are computing *historical* market value, which may differ markedly from *future* market value, as fuel prices change and the penetration of variable renewable generation sources like wind and solar continues to increase, potentially causing significant shifts in wholesale price patterns in the years ahead. Since this report focuses on empirical data, however, we limit this analysis to historical market value based on actual, rather than projected, energy and capacity prices.

capacity value.[62] Total market value is simply the sum of energy and capacity value (except in ERCOT, which does not have a capacity requirement—there, total market value simply equals the energy value).

Figure 29 shows energy and capacity value over time across all seven ISOs. In 2018, solar market value was lowest in CAISO (at $34.0/MWh) and highest in PJM ($56.3/MWh). Energy value accounted for the bulk of total market value, but capacity value was still an important contributor in some markets (e.g., capacity value contributed $16.2/MWh of PJM's total $56.3/MWh market value in 2018). Fluctuations in market value over time are primarily a function of changing wholesale energy and capacity prices—i.e., largely dependent on factors like the prevailing cost of natural gas or other fuels used to generate electricity, and largely independent of anything having to do with solar. But, in some high-penetration markets (e.g., CAISO), the visible decline in market value over time is also partly a function of increasing solar penetration driving prices lower during solar generation hours.

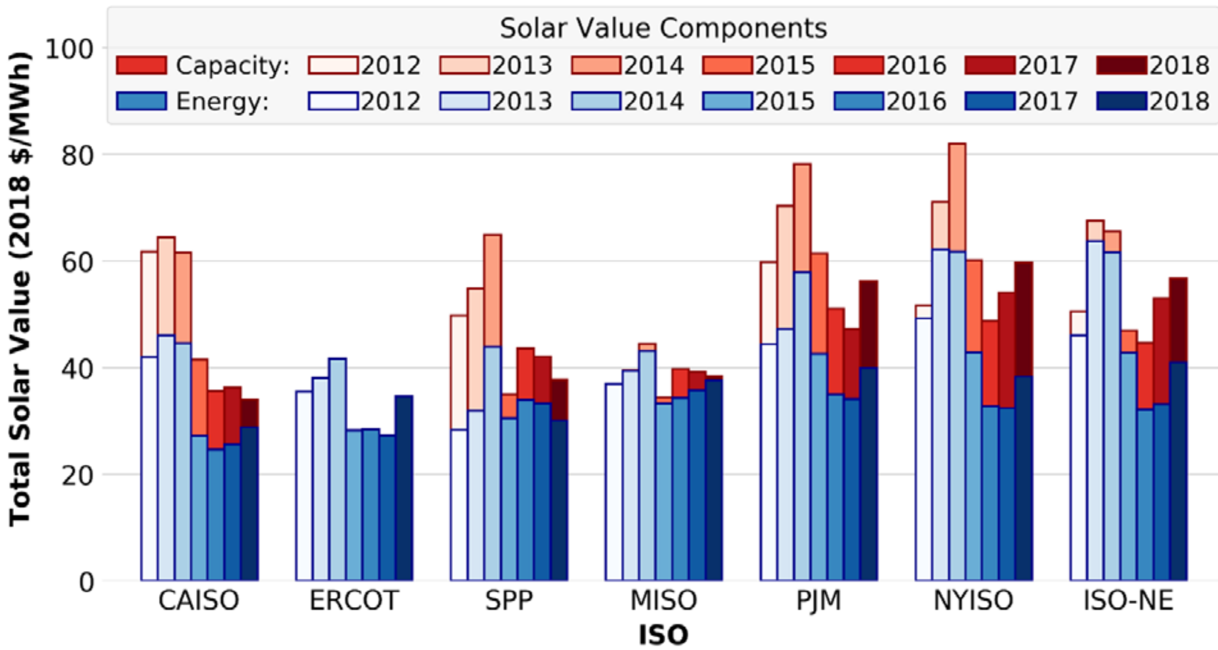

Figure 29. Wholesale Energy and Capacity Market Value by ISO

In order to tease out the relative impact of these two influences—i.e., general price levels in wholesale power markets versus solar penetration rates and generation profiles—Figure 30 presents solar's "Value Factor" in all seven ISOs. The Value Factor is computed as the ratio of solar's market value (both energy and capacity, together) to the market value of a "flat block" (i.e., a 24x7 block) of generation, and simply indicates whether the total potential merchant revenue captured by solar is higher (Value Factor>100%) or lower (Value Factor<100%) than the average revenue available to a generator with constant, round-the-clock output. In other words, the Value Factor controls for fluctuations in energy and capacity prices across different years, and focuses instead on the effect of solar's generation profile (and penetration) on its value.

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[62] For more details on how we derived the various components of energy and capacity value in each ISO, see LBNL's forthcoming *Solar-to-Grid* (S2G) report (Mills et al. 2019).

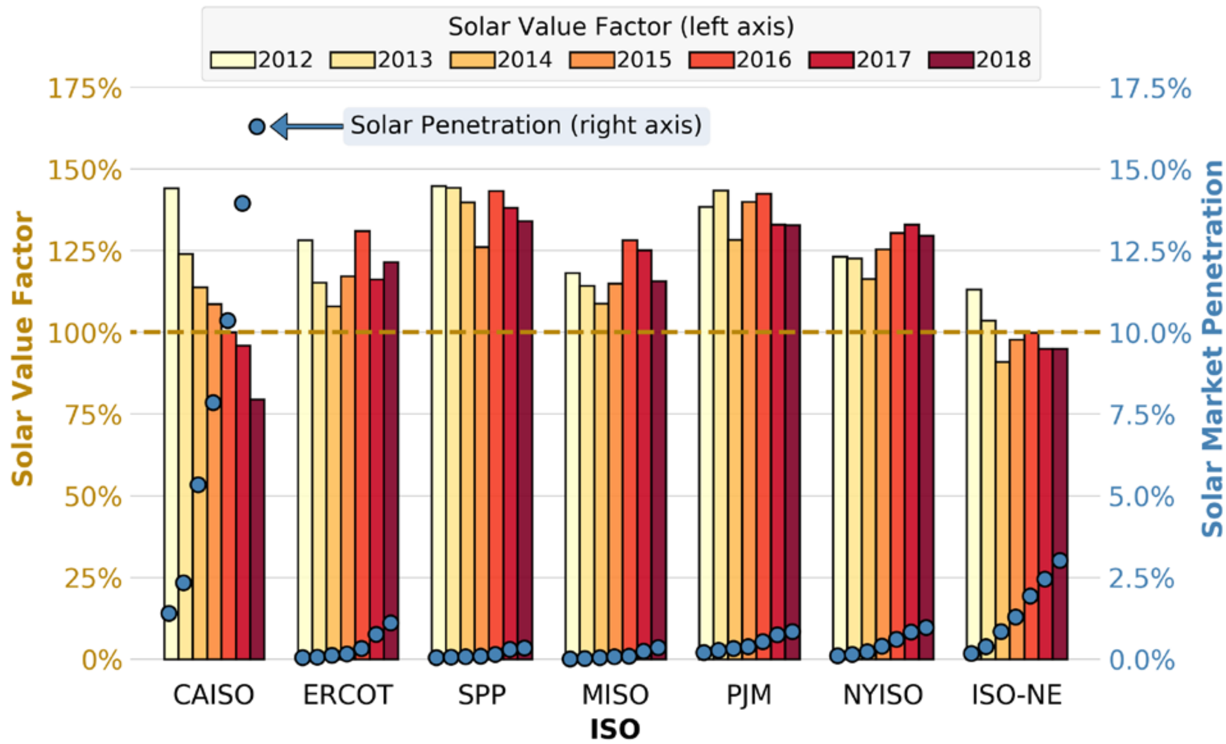

Figure 30. Solar "Value Factor" by ISO

Figure 30 shows that in five of the seven ISOs, solar has consistently provided above-average market value since 2012 (i.e., Value Factor>100%). But in CAISO and ISO-NE—i.e., the two markets with the highest solar penetration rates—solar's Value Factor has dipped below 100% in recent years (and down to 80% in CAISO in 2018).[63] Particularly within CAISO, this decline in the Value Factor as penetration increases is symptomatic of the much-discussed "duck curve" problem in California, where a large influx of mid-day solar generation depresses wholesale power prices (reducing solar's energy value) and shifts peak net loads into the early evening (reducing solar's capacity credit).

Reduced by the ITC, solar PPA prices are generally comparable to solar's market value

To provide a general sense for how the cost and value of solar have compared over time, Figure 31 plots PPA prices against market value within California—i.e., the largest solar market in the United States. The blue and red columns represent solar's energy and capacity value, respectively, and match the CAISO values shown above in Figure 29. The blue-shaded area represents the 10th-90th percentile range in CAISO wholesale energy prices across all hours of the year, and is included simply to demonstrate how solar's energy value is affected by, and fluctuates with, general wholesale price levels over time. Solar's capacity value (the red portion of each column) has gradually diminished over the years, as solar market penetration within California has increased.

[63] While ISO-NE solar had one of the highest market values of any ISO in 2018 (Figure 29), it had the second-lowest (after CAISO) Value Factor (Figure 30). Again, the former is a function of general wholesale price levels (which are high in New England), while the latter is a function of solar penetration in conjunction with hourly solar generation and wholesale price profiles.

The green circles show the average levelized solar PPA price within CAISO among contracts signed in each year. The comparison between these levelized PPA prices and total market value is imperfect, primarily because the PPA prices are forward-looking and levelized over many future years, while the market value estimates are historical and for a single year.[64] Yet, to the extent that PPA counterparties use solar's current market value as a starting point to inform whether solar PPA pricing will likely be in or out of the money over time, the comparison is still relevant (even if imperfect).[65] Figure 31 shows that while solar's market value within CAISO has declined over time, falling PPA prices have largely kept pace since 2013, more or less maintaining solar's competitiveness.

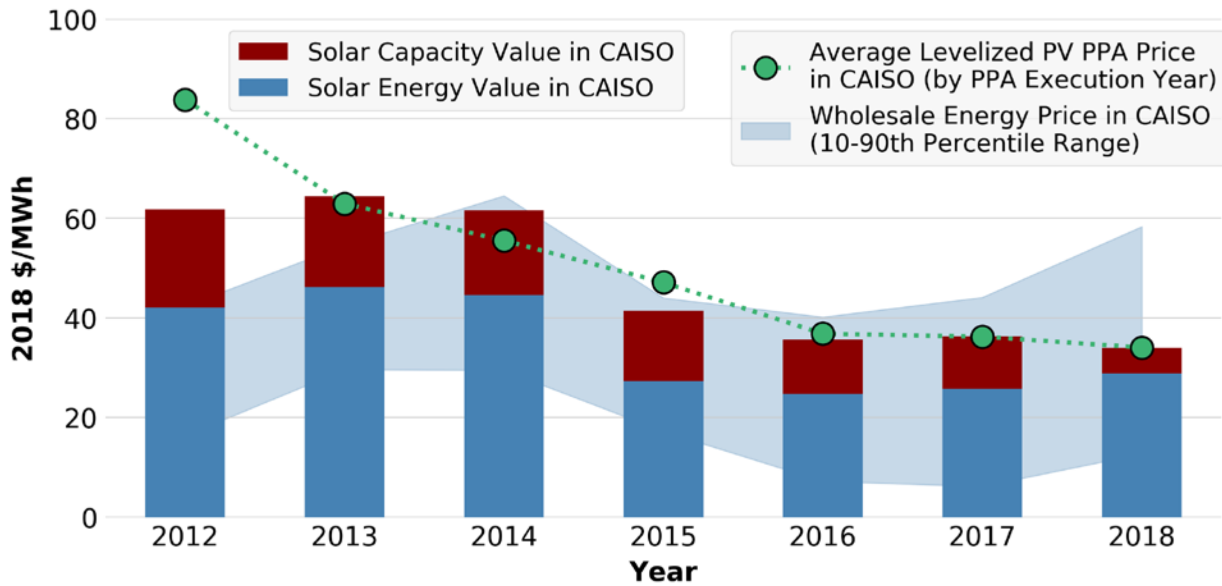

Figure 31. Solar Market Value versus PPA Prices in CAISO over Time

Although our PPA price sample within ISOs outside of California is not sufficiently robust to replicate Figure 31 for each ISO going back in time, Figure 32 shows a similar comparison across four ISOs in just 2018. The blue and red columns once again represent energy and capacity value, respectively, across each ISO (ERCOT does not have a capacity requirement), while the green circle markers show the average levelized solar PPA price within each ISO among contracts signed in 2018 (i.e., all just as in Figure 31, but in this case only for 2018). The golden diamond markers, meanwhile, offer a slightly different comparison point—namely, the average first-year PPA price among projects that achieved commercial operations within each ISO in 2017 or 2018. By focusing on newly operating projects rather than newly-signed PPAs,

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[64] In addition, the PPA prices in Figure 31 represent the price that will be paid to *new* solar projects, while solar's market value in each year is a function of *all* solar projects—both older and newer—that were operating in the market during that year. That said, solar's market value is also *marginal* in nature—i.e., representing the value that can be captured by the next marginal unit of solar to enter the market—and in this light is compatible with and can be rightly compared to PPA prices among new solar projects.

[65] In practice, PPA counterparties will rely on projections of future value, rather than current value, to make this determination. While many considerations will feed into projections of future value—most notably, wholesale price forecasts, which themselves are perhaps partly informed by projections of solar's market penetration—solar's current market value is, nevertheless, likely to serve as an empirical starting point for any such projections.

the golden diamond markers provide a comparison that is arguably more-temporally aligned with the 2018 market value estimates. In all four ISOs, the golden diamond markers exceed the green circle markers for two reasons: PPA prices have fallen over time, and real-dollar levelization will tend to depress prices, particularly when PPA prices do not escalate (i.e., are flat) over time.

Figure 32 shows that while CAISO offers PPA prices that are commensurate with current market value, the three other ISOs generally offer higher solar market value, yet with similar or even lower PPA prices, resulting in a superior cost/value tradeoff. This may be one reason why, for the first time ever, California was deposed as the largest solar market in the United States in 2018, as the market continues to expand to other regions.

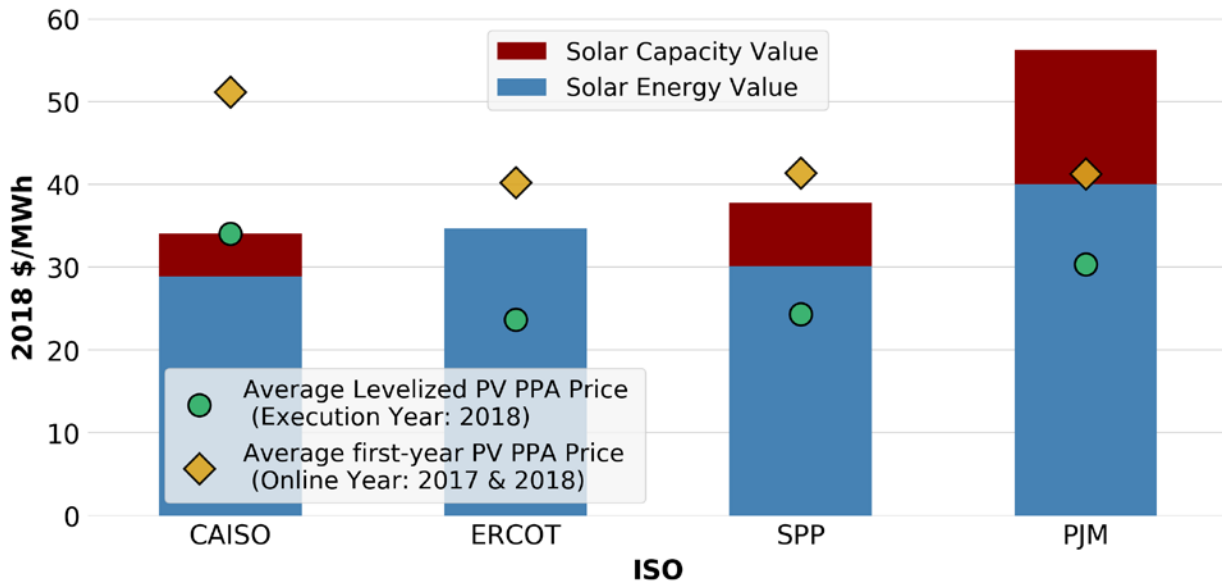

Figure 32. Solar Market Value versus PPA Prices by ISO in 2018

Finally, we reiterate that our assessment of market value includes *only* energy and capacity value, and does *not* include potential revenue from the sale of RECs (e.g., into RPS compliance markets or voluntary green power markets) or from providing ancillary services. It also excludes other less-tangible and harder-to-quantify sources of value that solar may provide, such as price certainty, resilience, and other environmental or social benefits that are not already internalized in REC prices or wholesale energy and capacity markets (e.g. via permit prices for pollution allowances). If included, these additional sources of revenue or value would boost the value of solar shown throughout this section.

3. Utility-Scale Concentrating Solar-Thermal Power (CSP)

This chapter largely follows the same format as the previous chapter, but focuses on CSP rather than PV projects.[66] Isolating these two different technologies in this way simplifies reporting and enables readers who are more interested in just one of these technologies to more-quickly access what they need. So as not to lose the value of being able to easily compare the two technologies when presented side by side, however, we have endeavored to include reference data points from our PV sample in many of the CSP-focused graphs in this chapter.

Because no new CSP plants were built (or were under construction, or even officially announced) in the United States in 2018, only the capacity factor section (Section 3.3) contains new data—i.e., capacity factors in 2018—compared to last year's edition of this report. That said, all other sections have been updated (e.g., by adjusting dollar years, by adding or revising relevant commentary) as appropriate.

3.1 Technology and Installation Trends Among the CSP Project Population (16 projects, 1.8 GW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough buildout in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed a few years later by the 75 MW_{AC} Martin project in 2010 (also a trough project, feeding steam to a co-located combined cycle gas plant in Florida).

A more-concentrated burst of CSP deployment occurred in the three-year period from 2013 to 2015. In 2013, the 250 MW_{AC} Solana trough project, which includes 6 hours of molten salt storage capacity, came online in Arizona. In 2014, three additional CSP projects came fully online in California: two more trough projects (Genesis and Mojave, each 250 MW_{AC}) and the first large-scale "solar power tower" project in the United States (Ivanpah at 377 MW_{AC}); none of these three projects includes thermal storage. A second 110 MW_{AC} solar power tower project with 10 hours of built-in thermal storage—Crescent Dunes in Nevada—finished major construction activities in 2014 and became commercially operational in 2015.

In the wake of this buildout—totaling 1,237 MW_{AC}—of new CSP capacity from 2013-2015, no other utility-scale CSP projects have been built in the United States, nor are any projects moving towards construction. Moreover, two of the oldest CSP plants in the United States—SEGS I and II, which came online in the mid-1980s—were decommissioned in 2015, following 30 years of service. The remaining SEGS plants (III-IX) are owned by a different entity and continue to operate.

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[66] Notable exceptions are that this chapter does not include sections on O&M costs, LCOE, or market value. We have just a single record of O&M costs for CSP projects—FP&L's 75 MW gas-coupled trough project from 2010. Not surprisingly, its O&M costs—which may not even be fully representative if they reflect just the solar collector field and not the power block of the coupled gas-fired combined cycle plant—are well above those of the PV projects discussed in Section 2.3, ranging from $45-$70/kW-year over time ($59/kW-year in 2018).

Figure 33 overlays the location of each utility-scale CSP project on a map of solar resource strength in the United States, as measured by direct normal irradiance ("DNI"), which is a more appropriate measure of insolation than GHI for CSP projects.[67] With the exception of the 2010 project in Florida (75 MW_{AC}), all other CSP projects in the United States have been deployed in California (1,237 MW_{AC}) and the Southwest (250 MW_{AC} in Arizona and 179 MW_{AC} in Nevada), where the DNI resource is strongest.

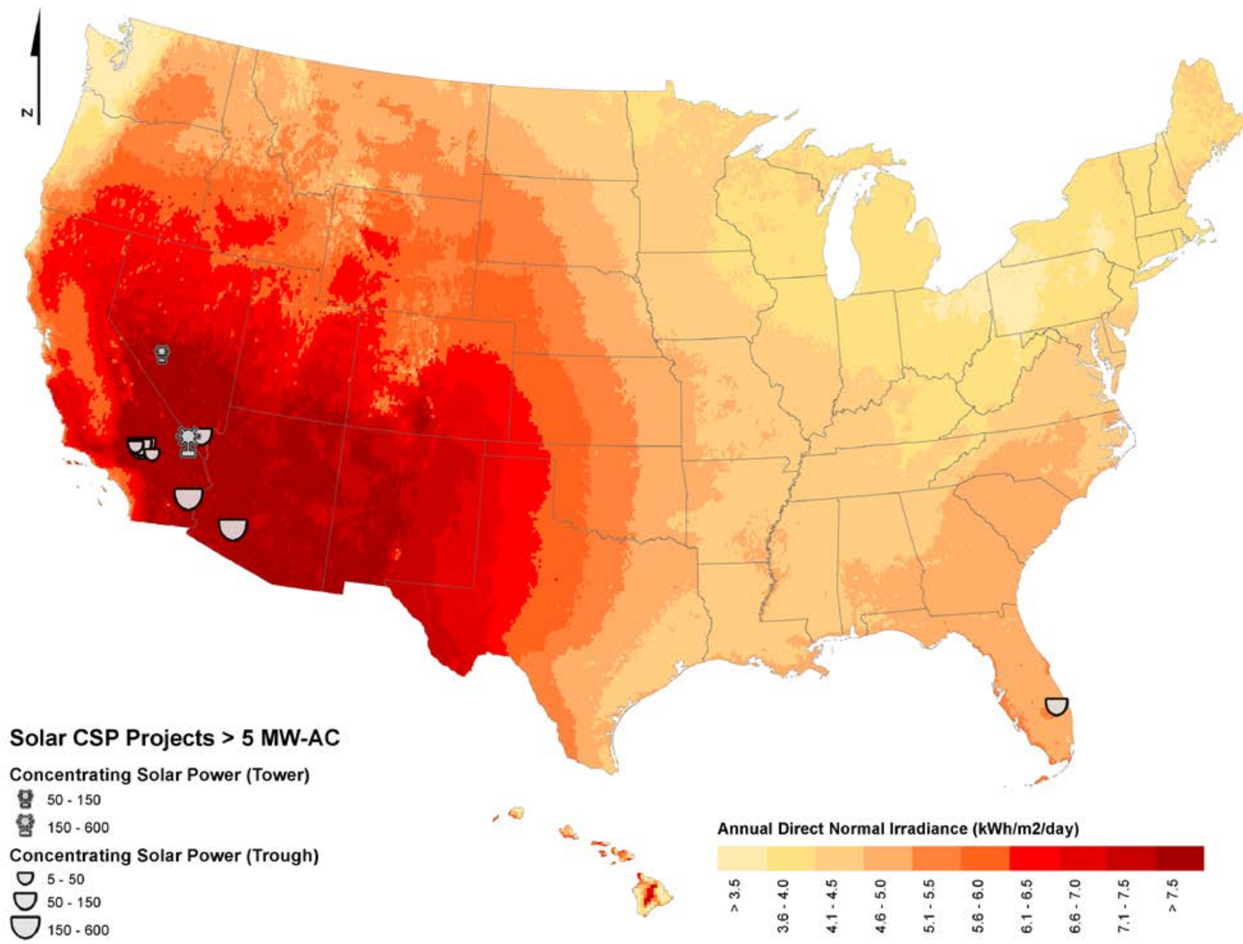

Figure 33. Map of Direct Normal Irradiance (DNI) and Utility-Scale CSP Project Locations

3.2 Installed Project Prices (7 projects, 1.4 GW_{AC})

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other CSP projects, totaling 1,381 MW_{AC}, that were commercially operational at the end of 2018 and larger than 5 MW_{AC}. Five of these seven projects feature parabolic trough technology (one of which has 6 hours of molten salt thermal storage capabilities), while the two most recently built projects use power tower technology (one project consisting of a total of 3 solar

[67] DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position in the sky. The DNI data represent average irradiance from 1998-2009 (Perez 2012).

towers without long-term storage, the other featuring just one tower but with 10 hours of molten salt storage).

Figure 34 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2015),[68] and also compares their installed prices to the median installed price of PV (from Figure 8) in each year from 2010 through 2018. The small sample size makes it difficult to discern any trends. In 2014, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($5.48/WAC vs. $6.56/WAC). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $7.23/WAC), while the 2014 power tower project was priced at the higher end of the range of the two trough projects built that same year. The most recent addition to our sample is the Crescent Dunes project, which faced a prolonged testing and commissioning phase that delayed commercial operation by roughly a year. The estimated cost of this project, which features 10 hours of molten salt storage, is the highest in our sample, at $9.34/WAC (all prices are expressed in 2018 dollars).

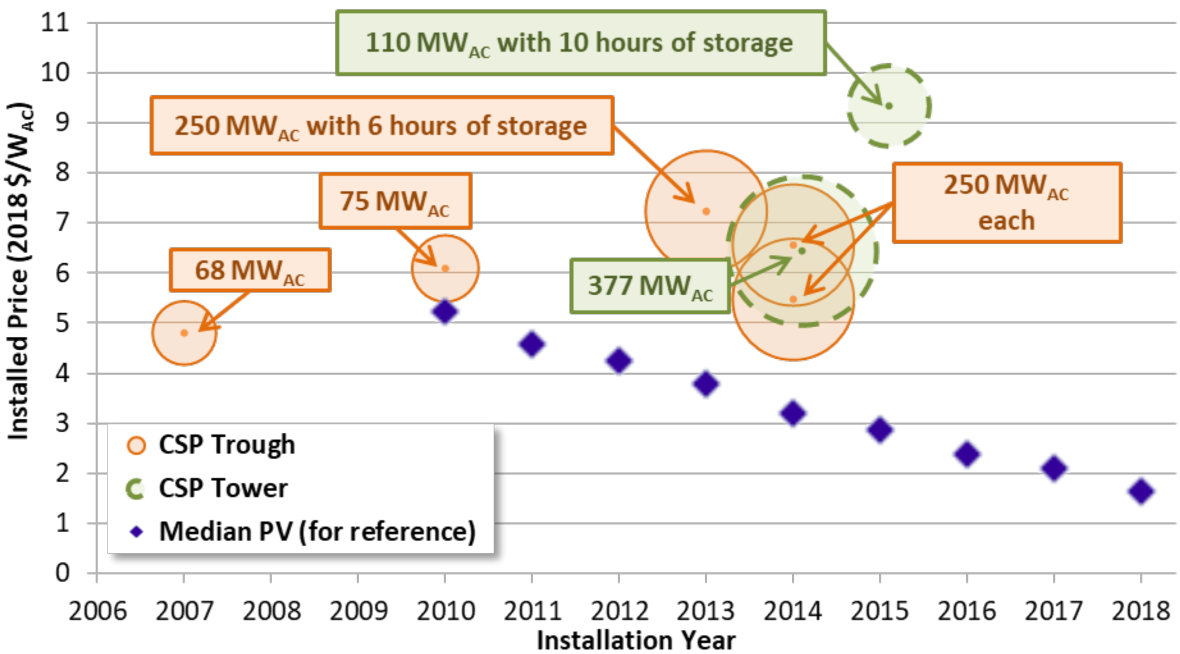

Figure 34. Installed Price of CSP Projects by Technology and Installation Year

Installed prices for CSP projects installed in the United States from 2007 to 2015 do not seem to have declined over time, which stands in stark contrast to the median PV prices included in the figure. Of course, the CSP sample is small, and features several different technologies and storage capabilities, which complicates comparisons. Installed prices have reportedly declined among newer projects in other parts of the world, to $3.2-$7.3/WAC among both tower and trough projects with 4 to 8+ hours of storage—(IRENA 2019).

[68] The installed CSP prices shown in Figure 34 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

3.3 Capacity Factors (13 projects, 1.7 GW_{AC})

Figure 35 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with natural gas or fuel oil is included in Figure 35[69]) of our CSP project sample. The nine SEGS projects are grouped within the green and red shaded areas as indicated, rather than broken out individually. For comparison purposes, the average capacity factor in each calendar year from our sample of PV projects located in California, Nevada, and Arizona—i.e., the three states in which the CSP projects in our sample reside—are also shown.

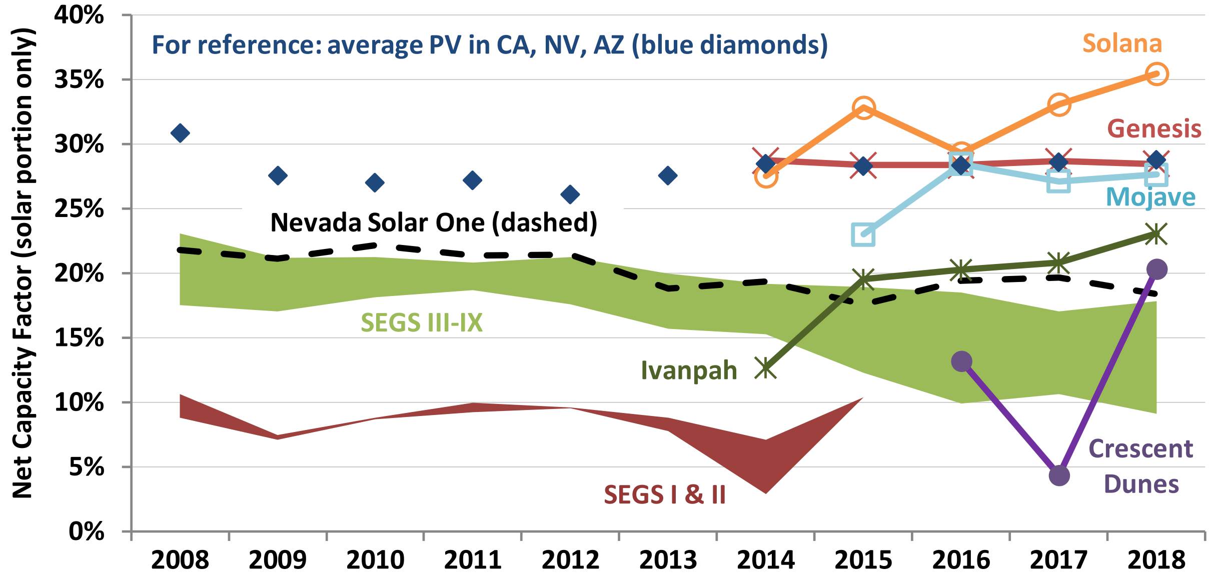

Figure 35. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

A few points are worth highlighting:

- In 2018, the two "power tower" projects—Ivanpah and Crescent Dunes—turned in higher capacity factors than in 2017 or 2016, but continued to perform below long-term expectations of ~27% and ~50%, respectively. With a 2018 capacity factor of just 20%—by far its best performance over its 3-year operating history—Crescent Dunes in particular has been performing significantly below long-term expectations, in part due to significant downtime (primarily in 2017) related to a leak in one of the molten salt tanks used for thermal storage. As a result of this ongoing underperformance, NVEnergy cancelled its PPA with Crescent Dunes in early October 2019.

[69] Many of these projects also use gas-fired turbines to supplement their output (e.g., during shoulder months, into the evening, or during cloudy weather). In the case of Nevada Solar One, for example, gas-fired generation has boosted historical capacity factors by twenty to forty basis points depending on the year (e.g., from 18.4% solar-only to 18.8% gas-included in 2018), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 190-380 basis points in 2018, depending on the project. The Ivanpah power tower project also burns gas, primarily to keep its steam turbines sufficiently warm overnight and to generate the morning's first steam, both of which significantly shorten each day's ramp-up period; the amount of total generation attributable to burning gas at Ivanpah is limited to 5%, and has reportedly been under that threshold to date (Kraemer 2016). For example, in 2018, gas-fired generation accounted for 4.3% of total generation from the Ivanpah project as a whole.

- Solana—i.e., the 250 MW solar trough project with 6 hours of thermal storage—also had its best year yet (at 35.4%) in 2018, but still operated below long-term expectations of >40%.
- Genesis (250 MW_{AC} trough with no storage) maintained its capacity factor and matched expectations for the fifth year running, while the slightly newer but otherwise very similar Mojave project (also a 250 MW_{AC} trough with no storage) had a similar capacity factor as Genesis for the third year in a row.
- Both of these newer trough projects without storage (Genesis and Mojave) performed significantly better in 2018 than the existing fleet of eight older trough projects (also without storage) in the sample, including the seven SEGS plants (SEGS III-IX, totaling 349 MW_{AC}) that have been operating in California for at least twenty-five years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[70]
- In recent years, the Solana, Genesis, and Mojave projects have been able to exceed or match the average capacity factor among utility-scale PV projects across California, Nevada, and Arizona. All other CSP projects shown in Figure 26 have exhibited capacity factors that fall below the PV-only average in those three states.

Looking ahead, we'll continue to watch for further improvements from Ivanpah, Crescent Dunes, and Solana as they attempt to dial up performance to match pre-construction estimates.

3.4 Power Purchase Agreement (PPA) Prices (6 projects, 1.3 GW_{AC})

The PPA price sample for CSP projects includes six of the seven projects built since the turn of the century (the 75 MW_{AC} Martin trough project in Florida, which was built in 2010, is owned by a utility, and so does not have a PPA). Contract terms range from 20 to 30 years, with both a median and mean term of 25 years.

PPA prices from five of these six projects are shown in Figure 36 (along with the de-emphasized PV PPA price sample from utility-scale PV projects located in California, Nevada, and Arizona, for reference). The sixth, Nevada Solar One, is excluded in order to make the figure more readable, given that its PPA was executed in late-2002 (and later amended in 2005). Nevada Solar One's levelized PPA price of ~$200/MWh (in real 2018 dollars) is the highest in our sample, though not by much.

Most of these CSP contracts appear to have been competitive with utility-scale PV projects in their home states at the time they were executed. Since then, however, PPA prices from utility-scale PV projects have declined significantly, and CSP has not been able to keep pace. As a result, there have been no new CSP PPAs executed in the United States since 2011, and a number of previously-executed CSP contracts have been either canceled (prior to construction) or converted to PV technology. And in October 2019, NVEnergy cancelled its PPA with the 110 MW Crescent Dunes power tower, following several years of underperformance (see Section 3.3).

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[70] One additional parabolic trough project—the 75 MW_{AC} Martin project in Florida—is excluded from the analysis due to data complications. Specifically, since 2011, the Martin project has been feeding steam to a co-located combined cycle gas plant, and a breakdown of the amount of generation attributable to solar versus gas is not readily available.

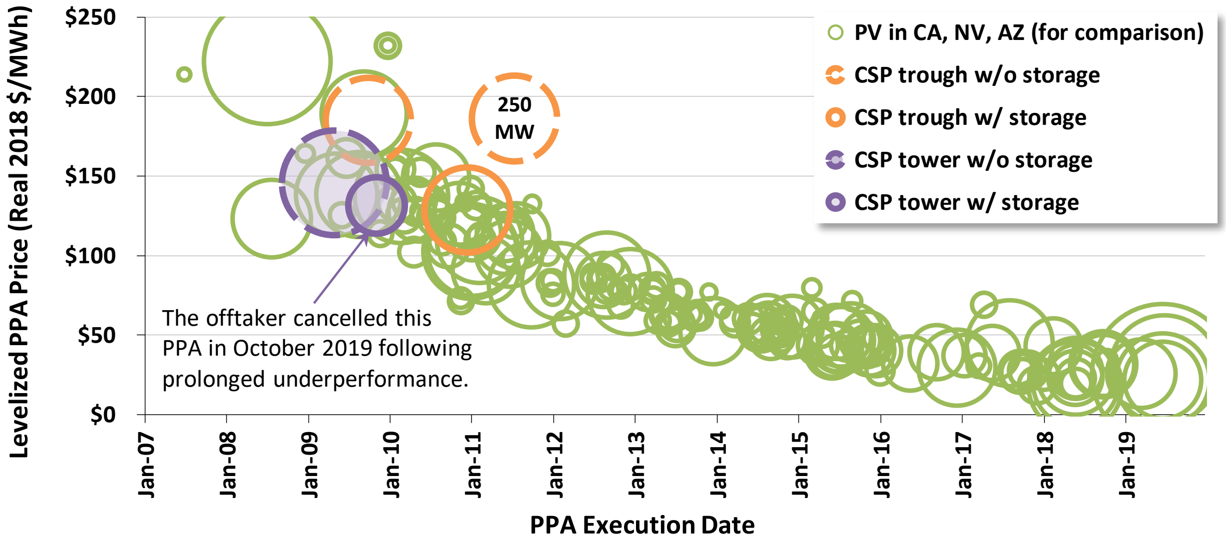


Figure 36. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

4. Conclusions and Future Outlook

This seventh edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly over the past decade, enabling record-low PPA prices of under $20/MWh (levelized, in real 2018 dollars) in a few cases and under $30/MWh on average—even in areas outside of the traditional strongholds of California and the Southwest. Meanwhile, the other principal utility-scale solar technology, CSP, has also made strides in the last decade—e.g., deploying several large projects featuring new trough and power tower technologies and demonstrating thermal storage capabilities—but has struggled to meet performance expectations in some cases, and is otherwise finding it difficult to compete in the United States with increasingly low-cost PV. As a result, there were no new CSP projects either online or under construction in 2018, and one existing project had its PPA cancelled due to underperformance.

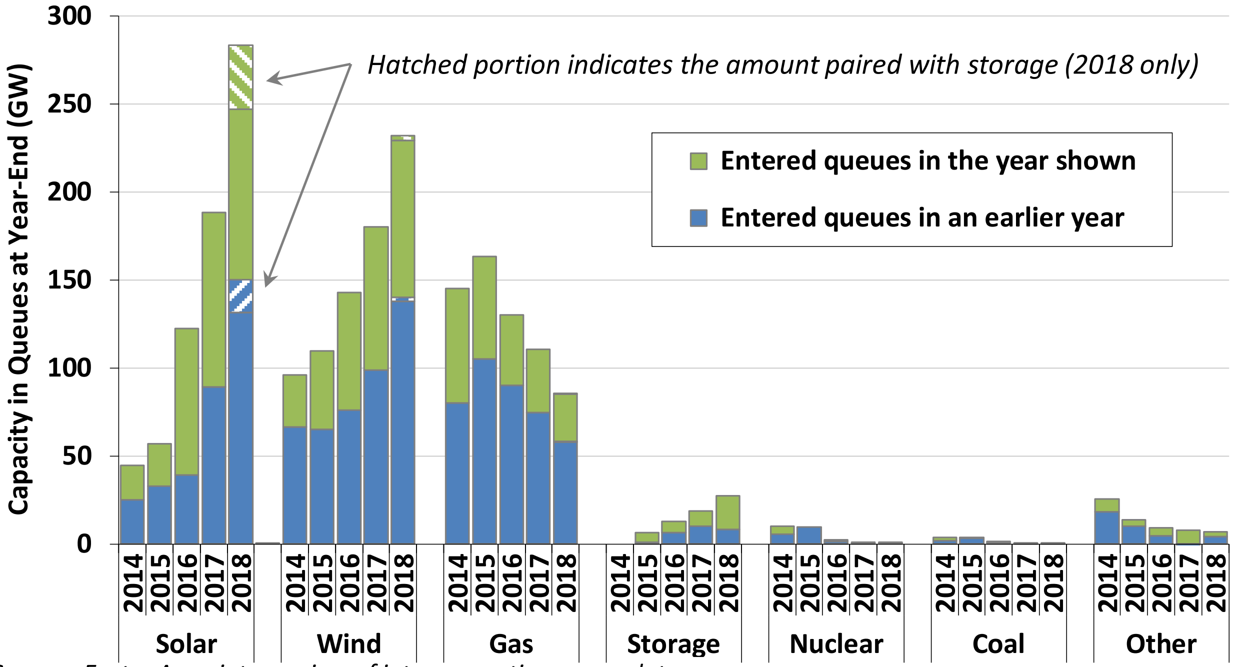
Looking ahead, analyst projections, as well as data on the amount of utility-scale solar capacity in the development pipeline, suggest a significant expansion of the industry in the coming years—in terms of both volume and geographic distribution. For example, Figure 37 and Figure 38 show the amount of solar power (and, in Figure 37, other resources) working its way through 37 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2018.[71] Although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built[72]—as a result, these data should be interpreted with caution. That said, efforts have been made by the FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have, in previous years, clogged these queues, and despite its inherent imperfections, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development.

At the end of 2018, there were 284 GW of solar power capacity (of any type—e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report***—more than ten times the installed utility-scale solar power capacity in our entire project population at that time.*** These

[71] The queues surveyed include the seven ISOs (CAISO, ERCOT, PJM, SPP, MISO, NYISO, ISO-NE), Southern Company, Duke/Progress Energy, PacifiCorp, Public Service Company of Colorado, Florida Power & Light, Los Angeles Department of Water and Power, Arizona Public Service, Tennessee Valley Authority, Bonneville Power Administration, Public Service Company of New Mexico, Western Area Power Administration, Santee Cooper, NV Energy, Salt River Project, Associated Electric Cooperative, Imperial Irrigation District, Tampa Electric, Tucson Electric, Tri-State G&T, Portland General Electric, Avista, and nine other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of ~80% of the U.S. total. Figure 37 and Figure 38 only include projects that were active in the queues at the end of 2018 but that had not yet been built; suspended projects are not included.

[72] It is also worth noting that while most of the solar projects in these queues are probably utility-scale in nature, the data are not uniformly (or even commonly) consistent with the definition of "utility-scale" adopted in this report. For example, some queues are posted only to comply with the Large Generator Interconnection Procedures in FERC Order 2003 that apply to projects larger than 20 MW, and so presumably miss smaller projects in the 5-20 MW range. Other queues include solar projects of less than 5 MW (or even less than 1 MW) that may be more commercial than utility-scale in nature. It is difficult to estimate how these two opposing influences net out.

284 GW—133 GW of which first entered the queues in 2018—represented 44% of all generating capacity within these selected queues, opening up solar's lead on both wind power at 36% and natural gas at 13% (see Figure 37). The end-of-2018 solar total is also 95 GW higher than the 189 GW of solar that were in the queues at the end of 2017, demonstrating that the solar pipeline was more than replenished in 2018, despite the 4 GW_{AC} of new solar capacity that came online (and therefore exited these queues) in 2018. Finally, this year we've also tallied the amount of solar (and other resources) in the queues that is paired with battery storage as a hybrid project; as indicated by the hatched area in Figure 37, solar leads the pack with 55 GW of PV hybrid capacity (compared to just 5 GW of wind hybrid capacity).[73] Standalone storage capacity has also continued to grow in the queues, to 28 GW at the end of 2018.

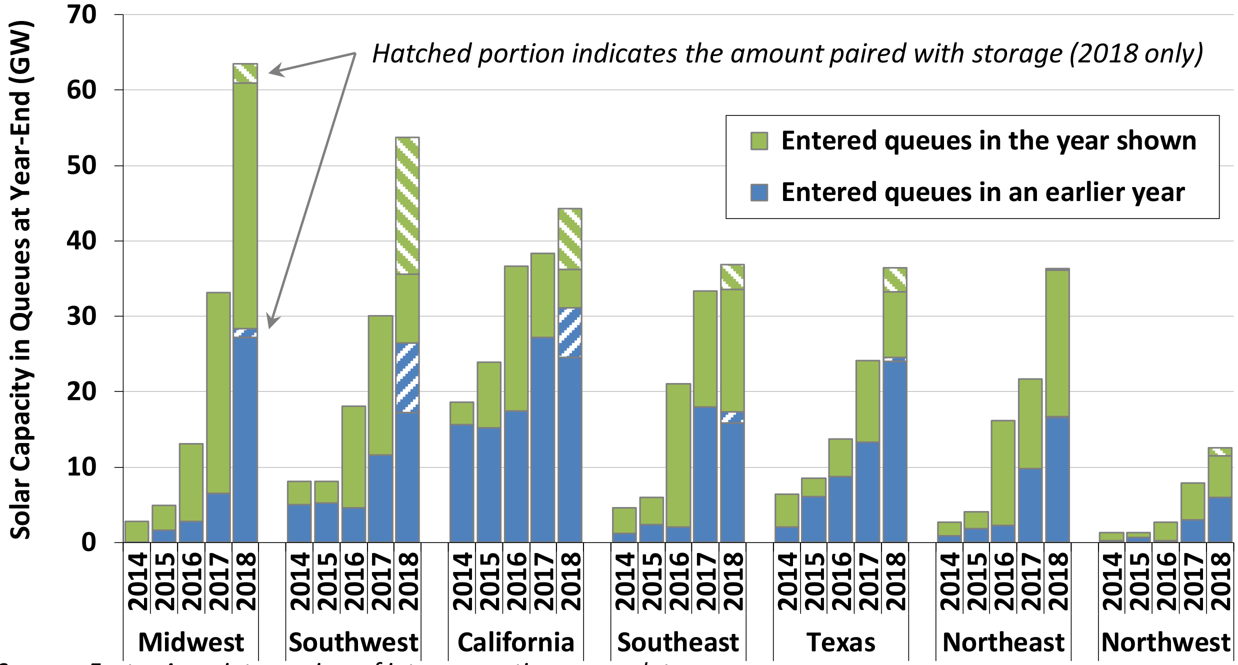


Source: Exeter Associates review of interconnection queue data

Figure 37. Solar and Other Resource Capacity in 37 Selected Interconnection Queues

Figure 38 breaks out the solar (and PV hybrid) capacity by state or region, to provide a sense of where in the United States this pipeline resides (as well as how that composition has changed going back to 2014). As shown, solar capacity in the queues is now much more evenly distributed across the country than it was just three years ago. For example, at the end of 2015, 42% of all solar capacity in the queues was located in California, compared to just 16% at the end of 2018. Moreover, 2018 was the first year in which California (with 44 GW) did *not* lead the country in terms of solar capacity in the queues, having been supplanted by the meteoric rise of the Midwest (64 GW), while also falling behind the Southwest (54 GW). Meanwhile, the Southeast, Texas, and the Northeast were all essentially tied at ~36 GW. This notable expansion of utility-scale solar development to regions beyond California and the Southwest is indicative of a maturing market that is capitalizing on solar's increasing competitiveness across the country.

[73] This disparity between wind and solar likely has to do with batteries qualifying for the ITC when paired with solar, but not the production tax credit ("PTC") when paired with wind. In addition, solar's predictable diurnal generation profile generally provides a better fit with, and also benefits more from, batteries than is the case with wind.



Source: Exeter Associates review of interconnection queue data

Figure 38. Solar Capacity by Region in 37 Selected Interconnection Queues

As with Figure 37, the hatched portion of each column in Figure 38 shows the amount of solar capacity that is paired with a storage as a hybrid project. More than 75% of the 55 GW of PV hybrid capacity in the queues at the end of 2018 is in the Southwest (49%) and California (26%)—two high-penetration regions that are grappling with "duck curve" issues that can be at least partly alleviated by storage.[74]

Though not all of these 284 GW of planned solar and PV hybrid projects represented in Figure 37 and Figure 38 will ultimately be built, Figure 1 at the start of this report showed that analysts do expect historically strong deployment of roughly 11 GW per year of utility-scale solar through at least 2024, driven in part by ongoing access to the 30% ITC through 2023 (as a result of favorable "safe harbor" guidance from the IRS), coupled with utility-scale PV's declining costs. Of course, accompanying all of this new solar capacity will be substantial amounts of new cost, price, and performance data, which we plan to collect and analyze in future editions of this report.

[74] The 55 GW of PV hybrid capacity noted above refers to the PV capacity, as only 8 of the 37 queues surveyed provide corresponding data on the battery capacity. These 8 queues account for ~30 GW of the 55 GW of PV hybrid capacity in the queues at the end of 2018, which is paired with ~18 GW of battery capacity, for an average battery-to-PV capacity ratio of 60%. Among the 8 queues, this battery-to-PV capacity ratio is highest in CAISO (75%) and LADWP (64%), which—once again—makes sense in light of the "duck curve" issues that California is facing.

References

Data Sources

Much of the analysis in this report is based on primary data, the sources of which are listed below (along with some general secondary sources) by data set. We collect data from a variety of unaffiliated and incongruous sources, often resulting in data of varying quality that must be synthesized and cleaned in multiple steps before becoming useful for analytic purposes. In some cases, we essentially create new and useful data by piecing together various snippets of information that are of little consequence on their own.

Technology Trends: Project-level metadata are sourced from a combination of Form EIA-860, FERC Form 556, state regulatory filings, interviews with project developers and owners, and trade press articles. We independently verify much of the metadata—such as project location, fixed-tilt vs. tracking, azimuth, module type—via satellite imagery. Other metadata are indirectly confirmed (or flagged, as the case may be) by examining project performance—e.g., if a project's capacity factor appears to be an outlier given what we think we know about its characteristics, then we dig deeper to revisit the veracity of the metadata.

Installed Prices: Project-level CapEx estimates are sourced from a combination of Form EIA-860, Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL. CapEx estimates for projects built from 2013-2017 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement (and we expect to receive similar data for 2018 projects and successive years going forward). The close agreement between the confidential EIA data and our other sources in most cases provides comfort that our normal data collection process (i.e., the process that we go through prior to receiving the confidential EIA data with a one-year lag) does, in fact, yield reputable CapEx estimates. That said, we do caution readers to focus more on the overall trends rather than on individual project-level data points.

O&M Costs: O&M cost estimates are sourced from FERC Form 1 and state regulatory filings. FERC Form 1 data are limited to utility-owned solar projects, which severely limits our sample size (given that most utility-scale solar projects are owned by independent power producers). Moreover, different utilities respond to FERC Form 1 in different ways, and it is not always clear what costs utility project owners are or are not including in their reported O&M cost numbers. As such, O&M costs are likely our least-reliable data set.

Capacity Factors: We calculate project-level capacity factors using net generation data sourced from a combination of FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings. Because many projects file data with several of these sources, we are often able to cross-reference (and correct, if needed) odd-looking data across several sources, thereby providing higher confidence in the veracity of the data.

PPA Prices: We gather PPA price data from a combination of FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, and trade press articles. We only include a PPA within our sample if we have high confidence in all of the key variables such as execution date, starting date, starting price, escalation rate (if any), time-of-day factor (if any), and term. By this process of exclusion, there is very little chance for erroneous PPA price data to enter our sample. Instead, this winnowing process results in our PPA price sample being somewhat smaller than it might otherwise be—though we are typically able to add back in any "incomplete" PPAs in subsequent years, once more data have become available with the passage of time.

LCOE: Our project-level LCOE calculations draw upon the empirical project-level data presented throughout this report, including installed prices, O&M costs, and capacity factors, and are supplemented with assumptions about financing and other items, as described in detail in the LCOE sub-section of Section 2.5.

Market Value: Energy value is simply the product of hourly solar generation and hourly wholesale energy prices. Where available, we start with ISO-reported aggregate hourly solar generation, and supplement that with modeled hourly solar generation (using NREL's *System Advisor Model* and site- and year-specific insolation data from NREL's *National Solar Radiation Database*) from residential, non-residential, and any remaining utility-scale plants that are not already included within the ISO-reported generation data. For the two ISOs that do *not* report aggregate hourly solar generation—MISO and NYISO—we rely exclusively on modeled generation. For hourly wholesale energy prices, we use historical prices from representative trading hubs within each ISO.

Capacity value relies on the same reported and constructed generation profiles as does energy value to assess the "capacity credit" of solar according to each ISO's rules in place at the time. We then multiply the resulting capacity credit by historical capacity prices to arrive at capacity value. Total market value is simply the sum of energy and capacity value (except in ERCOT, which does not have a capacity market—there, total market value simply equals the energy value). For further detail on solar's market value and how to calculate it, see LBNL's forthcoming *Solar-to-Grid* (S2G) report (Mills et al. 2019).

In addition, the individual reference documents listed below provided additional data and/or helped to inform the analysis.

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Appendix

Total Operational PV Population

State	Size Range (MW_{AC})	Year Range	2018 Sample		Total Population	
			No. of Projects	Total MW_{AC}	No. of Projects	Total MW_{AC}
AL	7 - 79	2016 - 2018	1	16	6	198
AZ	5 - 290	2011 - 2018	2	66	42	1,648
AR	13 - 81	2015 - 2018	1	81	2	94
CA	5 - 586	2009 - 2018	10	981	195	9,707
CO	5 - 120	2007 - 2018	1	50	15	434
CT	20 - 20	2018 - 2018	2	40	2	40
DE	10 - 12	2011 - 2012	-	-	2	22
FL	5 - 75	2009 - 2018	15	1,010	31	1,473
GA	6 - 146	2013 - 2018	1	31	24	988
HI	5 - 28	2012 - 2018	1	20	8	102
ID	20 - 80	2016 - 2017	-	-	8	240
IL	8 - 20	2010 - 2012	-	-	2	28
IN	5 - 17	2013 - 2018	1	8	16	129
KY	9 - 10	2016 - 2017	-	-	2	19
MD	6 - 75	2012 - 2018	2	87	11	190
MA	6 - 15	2014 - 2017	-	-	6	59
MI	8 - 29	2017 - 2018	2	24	4	72
MN	6 - 100	2016 - 2018	1	7	15	262
MS	51 - 52	2017 - 2017	-	-	3	155
MO	8 - 8	2017 - 2018	1	8	2	16
NE	6 - 6	2017 - 2017	-	-	1	6
NV	10 - 255	2007 - 2018	1	20	26	1,705
NJ	5 - 18	2010 - 2018	5	44	41	355
NM	5 - 70	2010 - 2018	3	25	30	502
NY	6 - 32	2011 - 2018	1	25	5	81
NC	5 - 81	2010 - 2018	9	472	63	2,045
OH	8 - 20	2010 - 2017	-	-	3	38
OK	5 - 10	2017 - 2018	1	10	2	15
OR	6 - 56	2016 - 2018	9	82	23	259
PA	10 - 10	2012 - 2012	-	-	1	10
SC	5 - 71	2016 - 2018	5	71	21	310
TN	8 - 53	2012 - 2018	2	68	8	147
TX	5 - 182	2010 - 2018	10	646	38	1,866
UT	20 - 80	2015 - 2016	-	-	12	810
VT	20 - 20	2018 - 2018	1	20	1	20
VA	6 - 100	2016 - 2018	3	38	17	442
WA	19 - 19	2018 - 2018	1	19	1	19
WY	80 - 80	2018 - 2018	1	80	1	80
Total	5 - 586	2007 - 2018	93	4,047	690	24,586

Total Operational CSP Population

State	Size Range (MW_{AC})	Year Range	2018 Sample		Total Population	
			# of Projects	Total MW_{AC}	# of Projects	Total MW_{AC}
AZ	250	2013	0	0	1	250
CA	34 - 377	1986 - 2014	0	0	10	1,234
FL	75	2010	0	0	1	75
NV	69 - 110	2007 - 2015	0	0	2	179
Total	**34 - 377**	**1986 - 2015**	**0**	**0**	**14**	**1,737**

O&M Cost Sample (Cumulative Over Time)

Year		2011	2012	2013	2014	2015	2016	2017	2018	predominant technology
Pacific Gas & Electric	MW_{AC}		50	100		150	150	150	150	Fixed-Tilt c-Si
	project #		3	6		9	9	9	9	
Public Service New Mexico	MW_{AC}		8	30	55	95	95	95	95	4 Fixed-Tilt, 7 Tracking
	project #		2	4	7	11	11	11	11	
Nevada Power	MW_{AC}						16		16	Tracking c-Si
	project #						1		1	
Georgia Power	MW_{AC}						36	126	126	Fixed-Tilt c-Si
	project #						2	5	5	
Kentucky Utilities	MW_{AC}							10	10	Fixed-Tilt c-Si
	project #							1	1	
Arizona Public Service*	MW_{AC}	51	96	136	168	191	237	237	238	Tracking c-Si
	project #	3	4	6	7	9	10	10	10	
Public Service Enterprise Group *	MW_{AC}						44	79	79	Fixed-Tilt and Tracking c-Si
	project #									
Allete	MW_{AC}								10	Fixed-Tilt Thin-Film
	project #								1	
DTE Electric	MW_{AC}								48	Fixed-Tilt c-Si
	project #								2	
Virginia Electric and Power	MW_{AC}								114	2 Fixed-Tilt, 4 Tracking
	project #								6	
Florida Power and Light	MW_{AC}	110	110	110	110	110	110	110	110	mix of c-Si and CSP
	project #	3	3	3	3	3	3	3	3	

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Utility-Scale Solar project page with data files and interactive visualizations:

https://utilityscalesolar.lbl.gov

All EMP renewable energy publications:

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