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Utility-Scale Solar 2015

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

Authors: Mark Bolinger and Joachim Seel

Lawrence Berkeley National Laboratory

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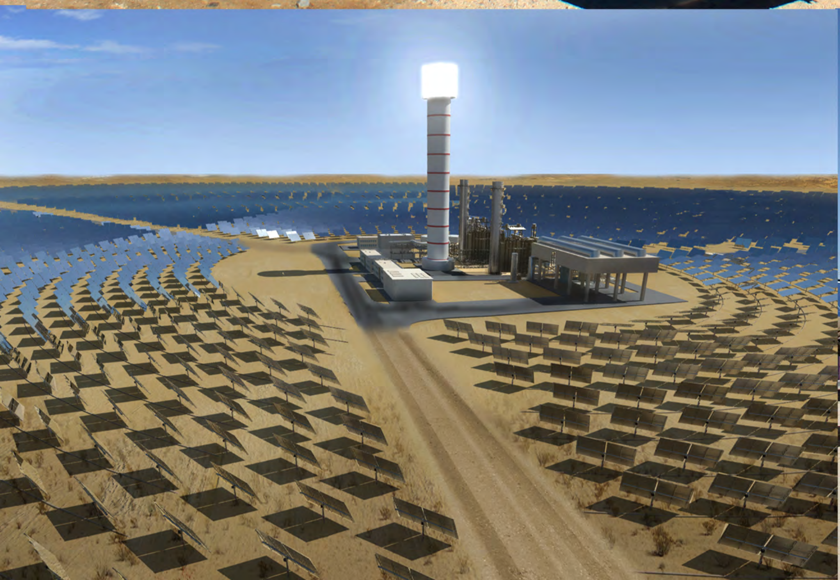

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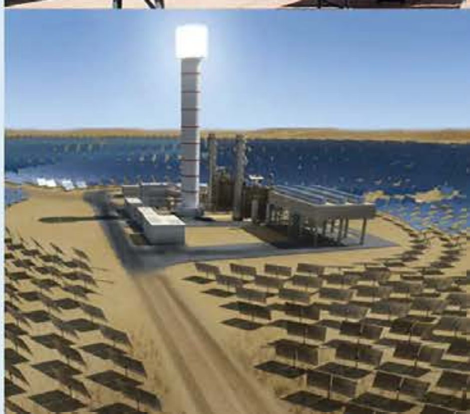

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List of Acronyms

AC……………………………………………………. Alternating Current
c-Si…………………………………………………. Crystalline Silicon
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……………………………………………………. Energy Information Agency
EPC……………………………………………………. Engineering, Procurement & Construction
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
ITC……………………………………………………… Investment Tax Credit
LBNL…………………………………………………… Lawrence Berkeley National Laboratory
LCOE…………………………………………………… Levelized Cost of Energy
MW…………………………………………………….... Megawatt(s)
NCF…………………………………………………….. Net Capacity Factor
NREL………………………………………………….. National Renewable Energy Laboratory
O&M……………………………………………………. Operation and Maintenance
PII………………………………………………………. Permitting, Interconnection & Inspection
PPA…………………………………………………….... Power Purchase Agreement
PV………………………………………………………. Photovoltaics
REC…………………………………………………….. Renewable Energy Credit
RTO…………………………………………………….. Regional Transmission Organization
SEGS…………………………………………………… Solar Energy Generation Systems
TOD…………………………………………………….. Time-Of-Delivery

Executive Summary

The utility-scale solar sector—defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar 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. It is expected to maintain its market-leading position for at least another five years, driven in part by December 2015's three-year extension of the 30% federal investment tax credit ("ITC") through 2019 (coupled with a favorable switch to a "start construction" rather than a "placed in service" eligibility requirement, and a gradual phase down of the credit to 10% by 2022). In fact, in 2016 alone, the utility-scale sector is projected to install *more than twice as much new capacity* as it ever has previously in a single year. This unprecedented boom makes it difficult, yet more important than ever, to stay abreast of the latest utility-scale market developments and trends.

This report—the fourth 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 costs or prices—i.e., the traditional realm of most solar economic analyses—but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects throughout the United States. 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 Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn, 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 tracking devices (overwhelmingly single-axis, east-west tracking—though a few dual-axis tracking projects have entered the population in recent years) continued to expand in 2015, particularly among thin-film (CdTe) projects, which had almost exclusively opted for fixed-tilt mounts prior to 2014. In a reflection of the ongoing geographic expansion of the market beyond the high-insolation Southwest, the average long-term insolation level across newly built project sites declined for the first time in 2015. Meanwhile, the average inverter loading ratio—i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating—has increased among more recent project vintages, as oversizing the array can boost generation (relative to the AC capacity), and hence revenue, particularly during the morning and evening shoulder periods. These trends should drive AC capacity factors higher among more recently built PV projects (confirmed by data for projects that were fully operational in 2015). Finally, 2015 saw one new CSP project (a 110 MW_{AC} solar tower project with 10 hours of thermal storage) and one new CPV project (an 18 MW_{AC} project with SunPower's new C7 technology) achieve commercial operation.

- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by nearly 60% since the 2007-2009 period, to \$2.7/W_{AC} (or \$2.1/W_{DC}) for projects completed in 2015. The lowest 20th percentile of projects within our 2015 sample (of 64 PV projects totaling 2,135 MW_{AC}) were priced at or below \$2.2/W_{AC}, with the lowest-priced projects around $1.7/$W_{AC}$. In comparison (though recognizing technological differences, including 10 hours of thermal storage), the single CSP power tower project that came online in 2015 was priced considerably higher than our PV sample, at $8.9/$W_{AC}$.

- ***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 $15/k$W_{AC}$-year, or $7/MWh, in 2015. These numbers—from an extremely limited sample—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.

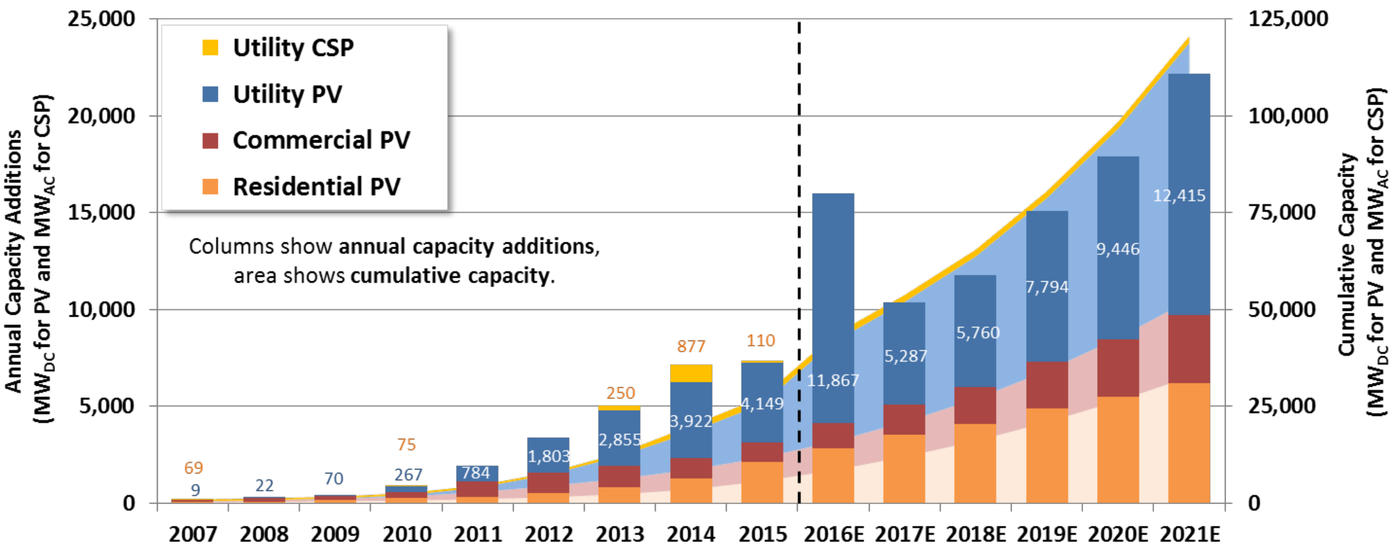
- ***Capacity Factors:*** The cumulative net AC capacity factors of individual projects in a sample of 170 PV projects totaling 5,907 MW_{AC} range widely, from 15.1% to 35.7%, with a sample mean of 25.7%, a median of 26.4%, and a capacity-weighted average of 27.6%. This project-level variation is based on a number of factors, 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 inverter loading ratio, the type of modules used (e.g., c-Si versus thin film), and likely degradation. Changes in at least the first three of these factors have driven mean capacity factors higher by project vintage over the last four years, to nearly 27% among 2014-vintage projects (whose first full operating year was in 2015). Turning to other technologies, two of the three CPV projects in our sample seem to be underperforming, relative to both similarly situated PV projects and ex-ante expectations. And the two CSP projects that had struggled to meet performance expectations in 2014 (Solana and Ivanpah) both increased their capacity factors considerably in 2015, though still not quite up to projected long-term, steady-state levels.

- ***PPA Prices:*** Driven by lower installed project prices and 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 2013, with a smaller price decline of ~$10/MWh per year evident in the 2014 and 2015 samples. Most PPAs in the 2015 sample—including many outside of California and the Southwest—are priced at or below $50/MWh levelized (in real 2015 dollars), with a few priced as aggressively as ~$30/MWh. Even at these low price levels, PV may still find it difficult to compete with *existing* gas-fired generation, given how low natural gas prices (and gas price expectations) have fallen over the past year. When stacked up against *new* gas-fired generation (i.e., including the recovery of up-front capital costs), PV looks more attractive—and in either case can also provide a hedge against possible future increases in fossil fuel costs.

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 2015 there was at least 56.8 GW of utility-scale solar power capacity making its way through interconnection queues across the nation (compared to 15.6 GW currently operational). Although most of this planned solar capacity is concentrated in California and the Southwest, the *growth* within these queues over the past two years—from 39.5 GW at the end of 2013 to 56.8 GW at the end of 2015—has come primarily from the up-and-coming Texas, Southeast, Central, and Northeast regions. Though not all of these projects will ultimately be built, the widening 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.

1. Introduction

"Utility-scale solar" refers to large-scale photovoltaic ("PV"), concentrating photovoltaic ("CPV"), and concentrating solar power ("CSP") projects that typically sell solar electricity directly to utilities or other buyers, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets).[1] Although utility-scale CSP has a much longer history than utility-scale PV (or CPV),[2] and has seen substantial new deployment over the past few years,[3] the utility-scale solar market in the United States is now largely dominated by PV: there is currently significantly more PV than CSP capacity either operating (8.5x), under construction (27.9x), or under development (27.4x) in utility-scale projects (SEIA 2016). PV's dominance follows explosive growth in recent years, culminating in a massive spike in deployment of nearly 12 GW expected in 2016 (see Figure 1[4])—the latter an artifact of what had been, up until late-December 2015, a scheduled end-of-2016 reversion of the 30% federal investment tax credit ("ITC") to 10%.



Source: GTM/SEIA (2010-2016), 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

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[1] 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 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.

[2] 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}.

[3] More than twice as much CSP capacity came online in the United States in 2013-2015 as in the previous 30 years.

[4] GTM/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 than DC for utility-scale PV projects). Despite these two inconsistencies, the data are nevertheless useful for the basic purpose of providing a general sense for the size of the utility-scale market (both historical and projected) and demonstrating relative trends between different market segments and technologies.

The December 2015 extension of the 30% ITC through 2019 brought several other changes as well. For non-residential projects (including utility-scale), 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%, 22%, and finally 10% for projects that start construction in 2020, 2021, and 2022 or thereafter, respectively.[5]

If not for this extension, projections of 2016 utility-scale PV deployment would be even higher than the nearly 12 GW_{DC} shown in Figure 1: various analysts project that ~1.8-2.5 GW_{DC} of utility-scale PV deployment will slip from 2016 into 2017 as a result of the relaxed deadline (Yozwiak 2015; Liebreich 2016; GTM Research 2015). Longer term, these same analysts project that the ITC extension will drive anywhere from 10-20 GW of incremental utility-scale PV deployment—i.e., above and beyond what had previously been expected prior to the extension—from 2017-2021. This unprecedented boom in the utility-scale market, expected to persist for at least the next five years, makes it increasingly difficult—yet, at the same time, more important than ever—to stay abreast of the latest developments and trends.

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 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. In most cases, the 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, 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 2015; with some limited exceptions (including Figure 1 and Chapter 4), the report does not discuss forecasts or seek to project future trends.

This report—the fourth 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 fourth 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 on the next page describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). In a change from previous years, this fourth edition breaks out coverage of PV 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.[6] Within each of these two chapters, we first present 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 costs or prices (in $/W terms), operation and maintenance ("O&M") costs, project performance (as measured by capacity factor), and power purchase agreement ("PPA") prices (the text box on this page—*A Note on the Data Used in this Report*—

[5] In addition, any project that qualified for a higher-than-10% ITC by starting construction prior to 2022 must also be placed in service by the end of 2023 in order to retain that higher credit; otherwise the credit drops to 10%.
[6] 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.

provides information about the sources of these data). Chapter 4 then concludes with a brief look ahead.

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, which each year analyzes the latest trends in residential and commercial PV project pricing, and NREL's PV system cost benchmarks, which are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (the text box on page 18 provides more information on NREL's utility-scale cost benchmarks). All of this work is funded by the Department of Energy's ("DOE") SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020. Most of LBNL's solar-related work can be found at emp.lbl.gov/projects/solar, while information on the SunShot Initiative can be found at energy.gov/eere/sunshot/sunshot-initiative.

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 larger than 1 MW, 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, Greentech Media and SEIA ("GTM/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 20 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 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, GTM/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 GTM/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 2015, 278 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) PV projects totaling 9,016 MW_{AC} were fully online in the United States.[7] Almost one-third of this capacity—i.e., 83 projects totaling 2,825 MW_{AC}—achieved commercial operation in 2015. The next five sections of this chapter analyze large samples of this population, focusing on technology trends, installed prices, operation and maintenance costs, capacity factors, and finally, PPA prices. Sample size varies by section, and not all projects have sufficiently complete data to be included in all five 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, 2015 dollars[8]

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 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 (described in more detail in later sections of this chapter, and portrayed in Figure 6). This increase in the "inverter loading ratio" boosts revenue 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.

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[7] 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 GTM Research and SEIA (2016)) of the amount of utility-scale PV capacity online at the end of 2015. For instance, Figure 2 shows that a lower amount of capacity was installed in 2015 than in 2014, which stands in contrast to GTM Research and SEIA (2016), 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).

[8] 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 2016* (Energy Information Administration 2016).

2.1 Technology and Installation Trends Among the PV Project Population (278 projects, 9,016 MW_{AC})

Before progressing to analysis of project-level data on installed prices, operating costs, capacity factors, and PPA prices, this section analyses trends in utility-scale PV project technology and 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, and/or PPA price data presented and discussed in later sections.

The prevalence of tracking increased in 2015

Figure 2 characterizes the population capacity by mounting and module type, by delineating between projects with arrays mounted at a fixed tilt versus on tracking devices that follow the position of the sun,[9] and between projects that use crystalline silicon ("c-Si") versus thin-film (primarily cadmium-telluride, or "CdTe") modules.

The percentage of newly built projects using tracking increased from 58% in 2014 to 65% in 2015, while in capacity terms the increase was much more significant, from 39% in 2014 to 70% in 2015. Although tracking has been the predominant mounting choice for c-Si projects for roughly five years now (as tracking costs have come down, reliability has improved, and the 30% ITC has helped defray the incremental up-front cost), the pairing of tracking with thin-film modules is a more recent phenomenon.[10] As was the case for the first time in 2014 (when 10 of the 15 new thin-film projects that came online used horizontal single-axis tracking), more new thin-film projects used tracking (11 projects) than fixed-tilt mounts (4 projects) in 2015 as well. Moreover, unlike in 2014, the *capacity* of new thin-film projects using tracking (334 MW_{AC}) also surpassed that of fixed-tilt thin-film projects (201 MW_{AC}) for the first time in 2015. As explained in footnote 10, thin-film's notably abrupt shift towards tracking has been driven in large part by significant improvements in the efficiency of CdTe modules in recent years.

Tracking aside, the prevalence of c-Si versus thin-film modules more generally has flip-flopped quite a bit in recent years, in part driven by a number of very large projects of each module type having come online in recent years, as well as the way in which we account for those projects

[9] All but seven of the 158 PV projects in the population that use tracking systems use horizontal single-axis trackers (which track the sun from east to west each day). In contrast, four recently built PV projects in Texas 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 costs (and risk of malfunction), depending on the PPA price.

[10] 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 2015, First Solar's CdTe module efficiency was roughly on par with multi-crystalline at ~16% (though both still lag *mono*-crystalline modules by several percentage points—e.g., SunPower's utility-scale modules have efficiencies above 21%).

(i.e., including them in our project population only once they are fully online). First Solar, which manufactures CdTe modules, accounts for nearly all (93%) of the new thin-film capacity added to the project population in 2015, with the remainder (35 MW_{AC}) coming from Solar Frontier, a Japanese manufacturer of "CIGS" (copper indium gallium selenide) modules. In contrast, the new c-Si capacity installed in 2015 is more broadly distributed between SunPower (33%), Trina Solar (20%), and Jinko Solar (16%), with all other c-Si module manufacturers having a market share of less than 5% each.

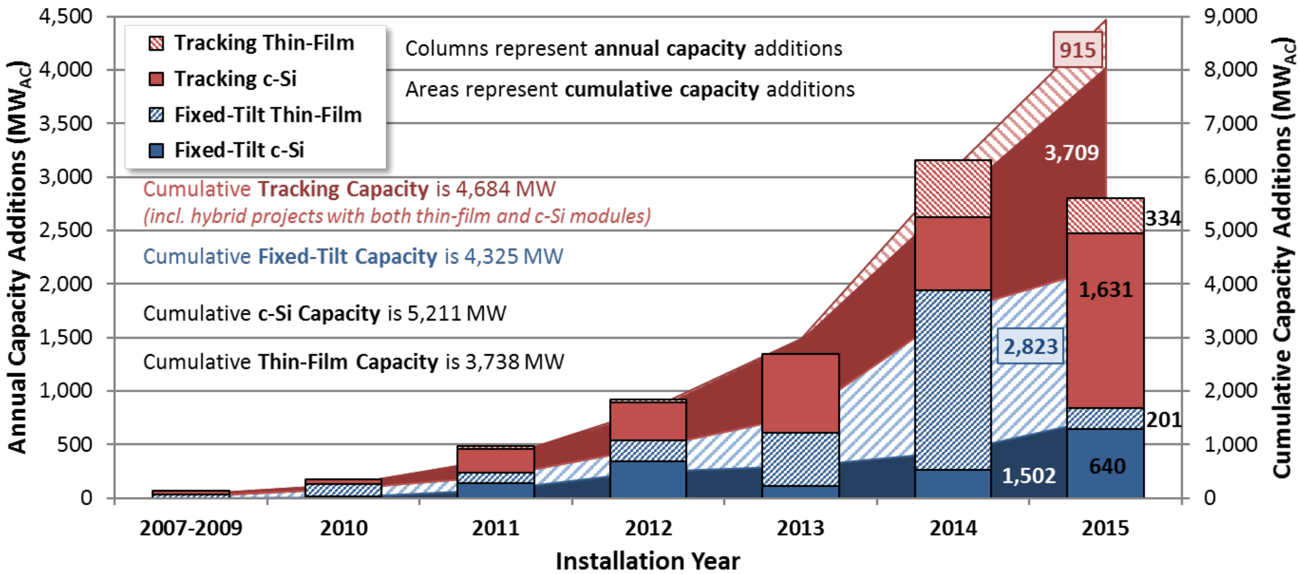

Figure 2. Capacity Shares of PV Module and Mounting Design by Installation Year

Figure 2 also breaks down the composition of *cumulative* installed capacity as of the end of 2015. For the first time since 2009, tracking projects held a slight majority at the end of 2015, with 52% of the cumulative installed capacity. In terms of module technology, due to its strong showing in 2015, c-Si regained the lead that it had lost the year before, making up 58% of the cumulative capacity installed at the end of 2015. Breaking these cumulative capacity statistics out by both module *and* mounting type, the most common combination was tracking c-Si (3,709 MW_{AC} from 129 projects), followed by fixed-tilt thin-film (2,823 MW_{AC} from 39 projects), fixed-tilt c-Si (1,502 MW_{AC} from 80 projects), and finally tracking thin-film (915 MW_{AC} from 25 projects).

Utility-scale PV continued to expand beyond California and the Southwest

Figure 3 overlays the location of every utility-scale PV project in the LBNL population (including four CPV projects) on a map of solar resource strength in the United States, as measured by global horizontal irradiance ("GHI").[11] Not surprisingly, most of the projects (and

[11] Global Horizontal Irradiance (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).

capacity) in the population are located in California and the Southwest, where the solar resource is the strongest and where state-level policies (such as renewable portfolio standards, and in some cases state-level tax credits) have encouraged utility-scale solar development. Similar state-level policies have also driven utility-scale PV deployment in various states along the east coast and in the Midwest, despite the solar resource not being as strong. Figure 3 also defines regions that will be used for regional analysis later in this report.

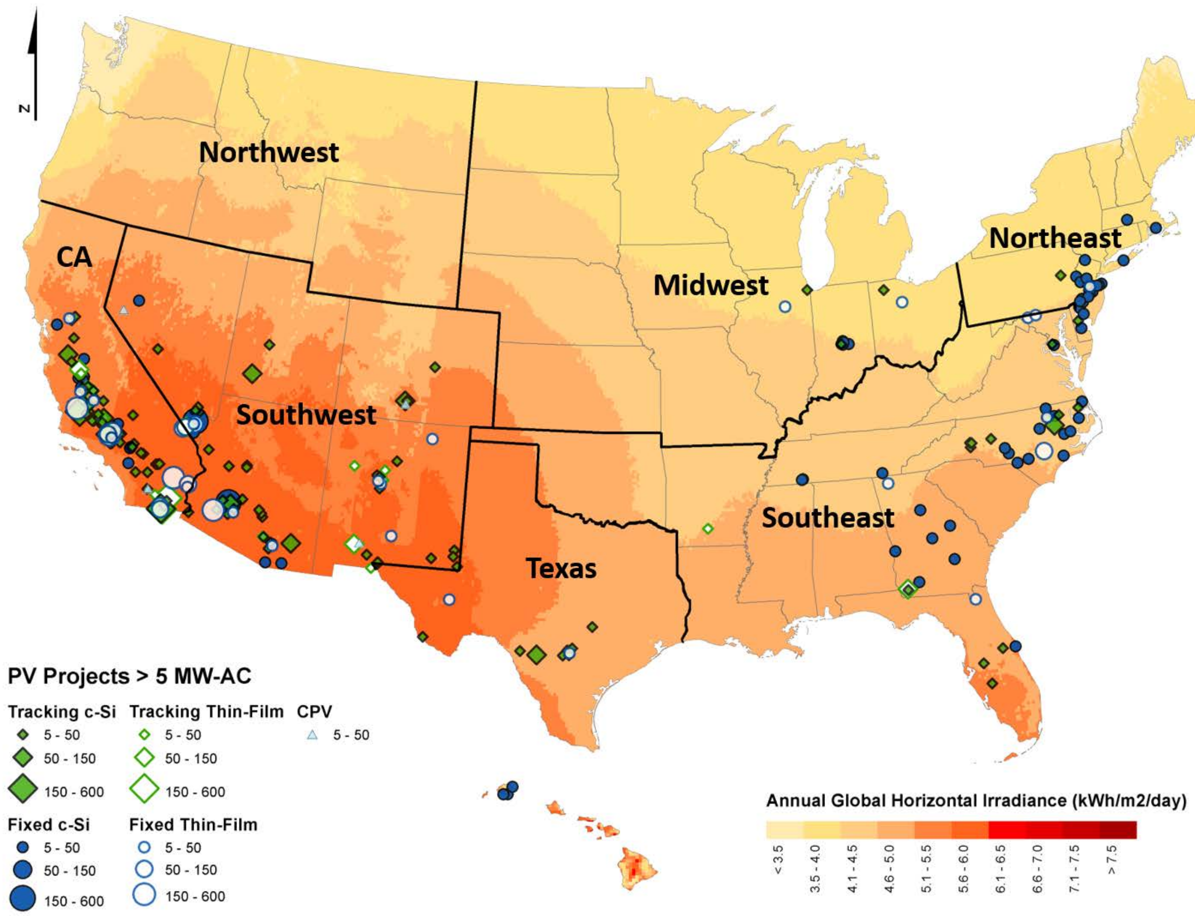

Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale PV Project Locations

2015 was a particularly strong year of growth for utility-scale PV outside of the traditional strongholds of California and the Southwest. The rest of the country contributed 28% of new utility-scale solar capacity in 2015, its highest share since 2011. Although California (56%) and the Southwest (26%) together still hold a clear lead in cumulative capacity, that lead declined from 86% in 2014 to 82% in 2015.

Notable new entrants on the map are Utah, where two larger projects totaling 130 MW_{AC} were completed in 2015 (propelling the state to tenth place in terms of cumulative installed capacity) and Arkansas, with its first utility-scale PV project of 13 MW_{AC}. Strong percentage growth occurred in North Carolina (quadrupling its previous capacity with 15 new projects, including a few that are much larger than the previous 20 MW_{AC} maximum), Georgia (nearly tripling its previous capacity with 6 new projects totaling 177 MW_{AC}), and Nevada (more than doubling its previous capacity with 4 new projects totaling 349 MW_{AC}).

Because some of these up-and-coming utility-scale PV states would barely show up if broken out on their own, Figure 4 lumps them together in demonstrating how the utility-scale market has been broadening beyond the historical capacity leaders of California and the Southwest. Specifically, 9 states outside of California and the Southwest added 28% of the newly installed capacity in 2015, an increase from the 8 such states that added only 8% of new capacity in 2014 and 5 such states that added 11% of new capacity in 2013.

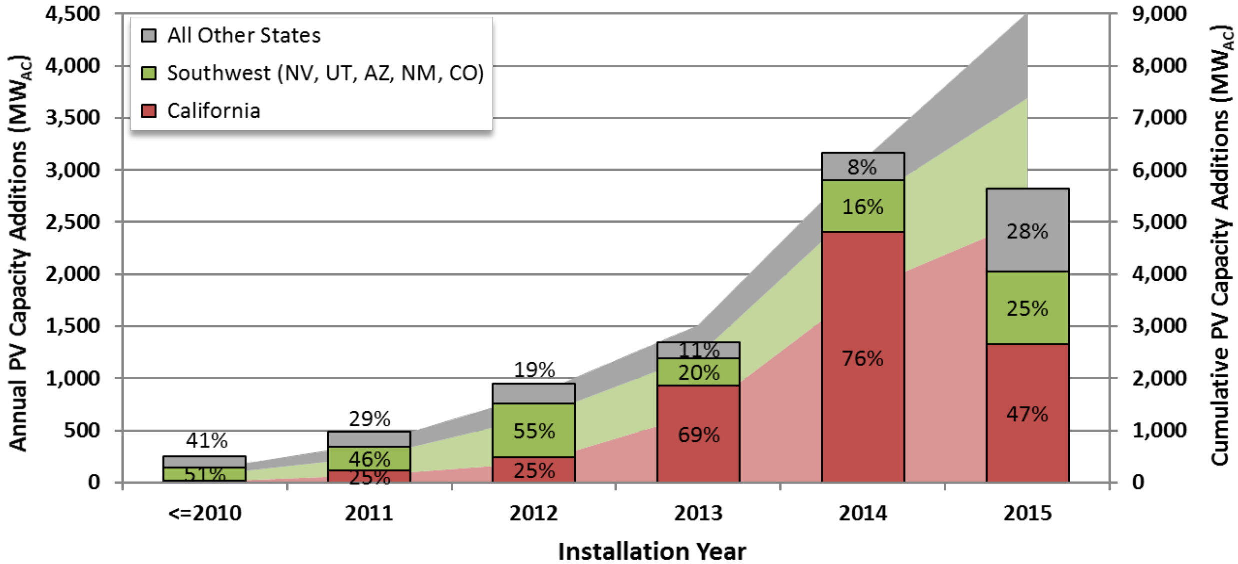

Figure 4. Annual and Cumulative Capacity Additions in California, the Southwest and Other States

The eastward expansion of utility-scale PV is reflected in the buildout of lower-insolation sites

Figure 3 above provides a static map of *where* and in what type of solar resource regime utility-scale solar projects within the population are located. But knowing *when* each of these projects was built—and hence how the average resource quality of the project fleet has evolved over time—is also useful, for example, to help explain observed trends in project-level capacity factors by project vintage (explored later in Section 2.4).

Figure 5 addresses this question by showing the capacity-weighted average GHI (in $kWh/m^2/day$) among utility-scale PV projects built in a given year, both for all projects (the solid black line with circle markers) and broken out by fixed-tilt versus tracking projects. Historically, the capacity-weighted average GHI of all utility-scale PV projects has increased steadily with project vintage, suggesting an ongoing build-out of large projects located in the solar-rich Southwest and California. As mentioned above, though, 2015 marked a deviation from this trend, resulting for the first time in a *decrease* in the capacity-weighted average solar resource among new projects. This decrease highlights the growing influence of regions outside of California and the Southwest.

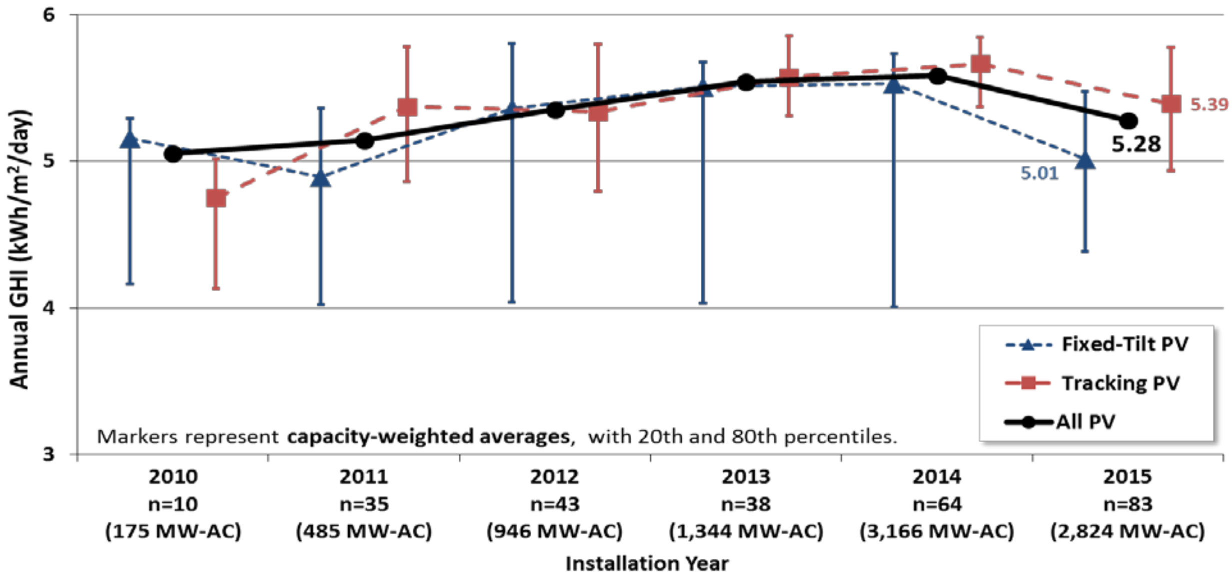

Figure 5. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

Moreover, the map in Figure 3 shows a preponderance of tracking projects (both c-Si and, more recently, thin-film) in the sunny Southwest and California, compared to primarily fixed-tilt c-Si projects in the lower-irradiance East. This dichotomy can also be seen in Figure 5 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 much higher levels for tracking projects. The wide range of insolation among fixed-tilt projects reflects the fact that most projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects (often using CdTe thin-film technology[12]) have also been built in high-GHI areas like California and the Southwest. In contrast, tracking projects have historically been concentrated in California and the Southwest, but have more recently also been deployed in other, less-sunny regions.

Developers continued to favor larger module arrays 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.[13] 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

[12] The apparent preference for thin-film (primarily CdTe) modules in Desert Southwest projects is driven primarily by CdTe’s greater tolerance for high-temperature environments (as well as relatively low land prices in the desert, which helped to mitigate CdTe’s historical efficiency deficit). In its online blog (First Solar 2015), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at high/normal operating temperatures, due to its lower power temperature coefficient of -0.25% to -0.29%/°C (compared to something more like -0.40%/°C for most c-Si modules).

[13] 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.

operate closer to (or at) full capacity for a greater percentage of the day, which—like tracking—boosts the capacity factor,[14] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production periods).[15] 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 sunny summer months).

Figure 6 shows the capacity-weighted average ILR among projects built in each year, both for the total PV project population (solid black line with circle markers) and broken out by fixed-tilt versus tracking projects. Across all projects, the average ILR has increased significantly over time, from around 1.2 in 2010 to 1.31 in 2015. The slight dip in 2014 is partly attributable to a number of very large projects that had been under construction for several years finally achieving full commercial operation in 2014; some of these projects have lower ILRs than their more-recently designed counterparts.

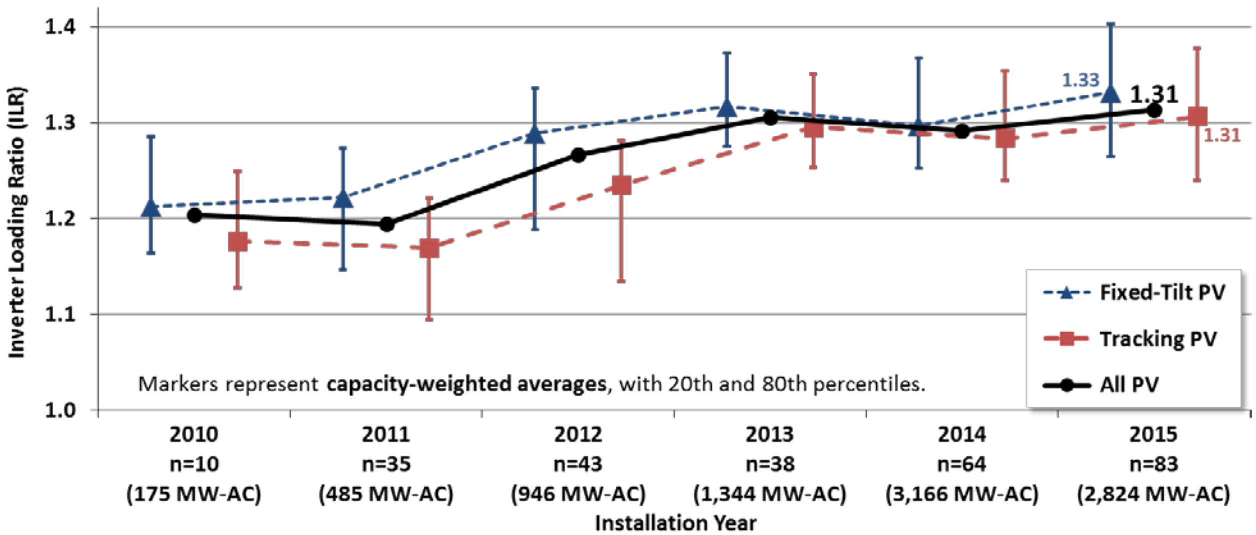

Figure 6. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

Fixed-tilt projects generally feature higher ILRs than tracking projects (statistics for 2014 were influenced by a few large fixed-tilt projects with lower ILRs). This finding is 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. One particular fixed-tilt project built in 2015 even featured a new confirmed ILR maximum among our sample of 1.67, up significantly from the previous maximum of 1.50. That said, ILRs above 1.45 are fairly rare.

[14] 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.

[15] 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.

2.2 Installed Project Prices (240 projects, 8,045 MW_{AC})

This section analyzes installed price data from a large sample of the overall utility-scale PV project population described in the previous section.[16] It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by module type (c-Si vs. thin-film vs. CPV), mounting type (fixed-tilt vs. tracking), and system size. 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 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 (e.g., Greentech Media, Mercom Capital Group). All prices are reported in real 2015 dollars.

In general, only fully operational projects for which all individual phases were in operation at the end of 2015 are included in the sample[17]—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 2016 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 reductions in component costs or other changes in market conditions.[18] 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 et al. 2016; GTM Research and SEIA 2016). 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.

Our sample of 240 PV (and CPV) projects totaling 8,045 MW_{AC} for which installed price estimates are available represents 86% of the total number of PV projects and 89% of 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 2015, our sample of 64 projects totaling 2,135 MW_{AC} represents 77% and 76% of the total number of 2015 projects and capacity in the population, respectively.

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[16] 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.

[17] 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.

[18] This reasoning may partially explain why the decline in installed prices presented in this chapter has seemingly not kept pace with the decline in PPA prices reported later in Section 2.5.

Median prices fell to $2.7/W$_{AC}$ ($2.1/W$_{DC}$) in 2015

Figure 7 shows installed price trends for PV (and CPV) projects completed from 2007 through 2015 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly 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 2016; GTM Research and SEIA 2016). As noted in the text box (*AC vs. DC*) at the beginning of this chapter, however, this report analyzes utility-scale solar in AC terms. Figure 7 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 chapter, however, as well as the rest of this document, report data exclusively in AC terms, unless otherwise noted.

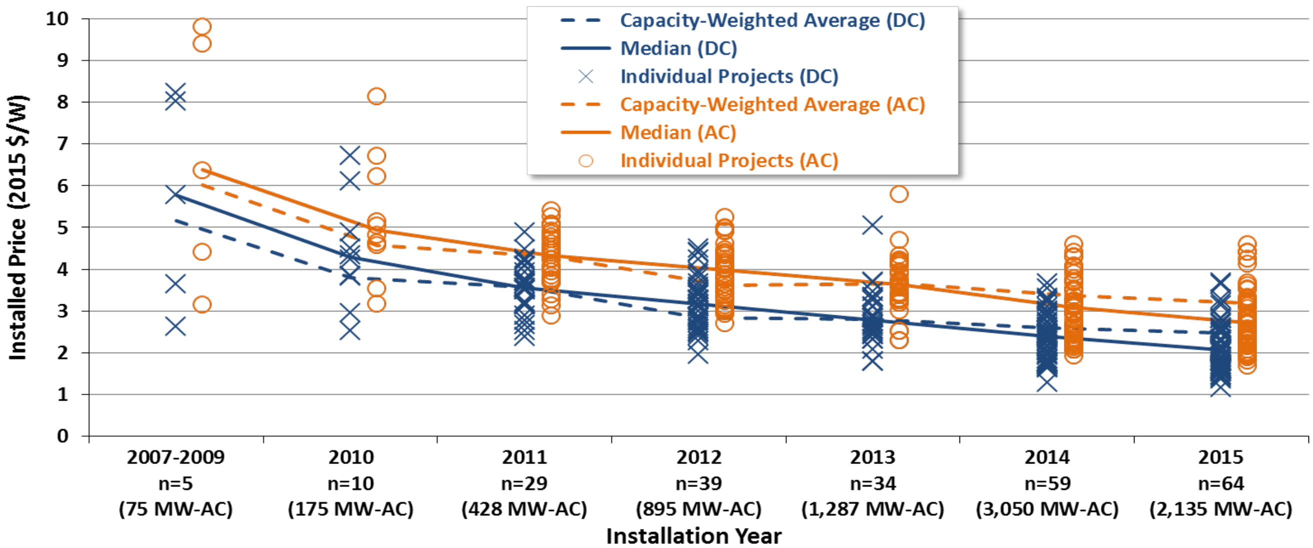


Figure 7. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

As shown, the median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to \$2.7/W$_{AC}$ (or \$2.1/W$_{DC}$) in 2015. This represents a price decline of nearly 60% since the 2007-2009 period (and 45% since 2010). The lowest-priced projects in our 2015 sample of 64 PV projects were ~\$1.7/W$_{AC}$ (~\$1.2/W$_{DC}$), with the lowest 20th percentile of projects falling from \$2.3/W$_{AC}$ in 2014 to \$2.2/W$_{AC}$ in 2015 (i.e., from \$1.8/W$_{DC}$ to \$1.6/W$_{DC}$).

In contrast, capacity-weighted average prices (dashed lines) have declined more slowly since 2012, to \$3.2/W$_{AC}$ (or \$2.5/W$_{DC}$) in 2015. That the capacity-weighted average price has been above the median price since 2013—the opposite of what one would expect for a technology like PV that should enjoy economies of scale—can be explained by a number of very large PV projects that have been under construction for several years but that only achieved final commercial operation in 2014 and 2015 (at which point they entered our installed price sample). These projects may have signed EPC contracts several years ago, perhaps at significantly higher prices than some of their smaller and more-nimble counterparts that started construction more recently.[19]

[19] For example, within our PPA price sample (described later in Section 2.5), the longest span between PPA execution date (as a proxy for EPC contract execution date) and commercial operation date for projects that came

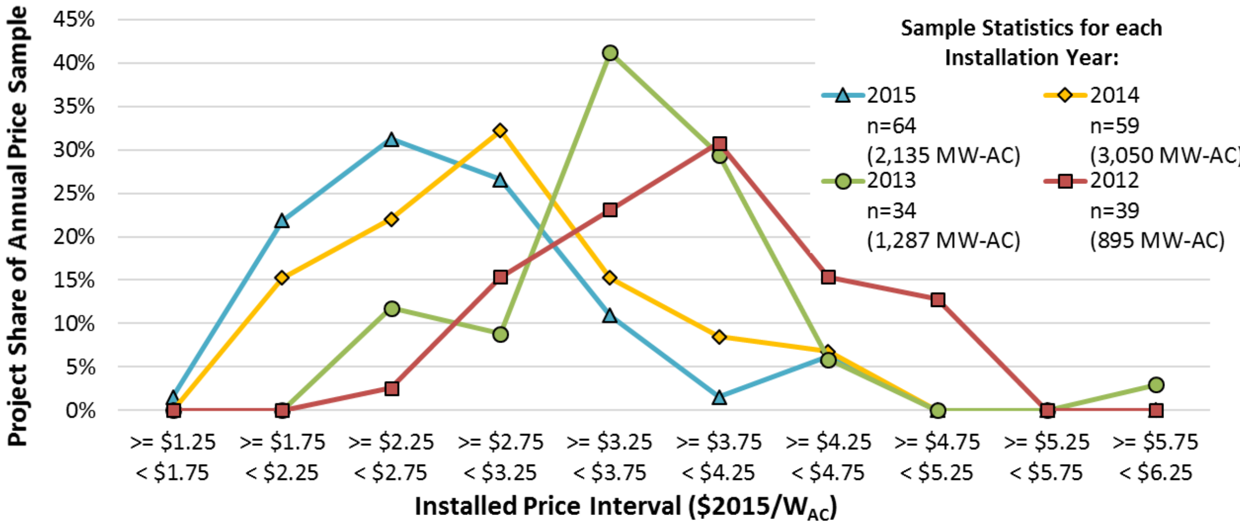


Figure 8. Distribution of Installed Prices by Installation Year

Figure 8 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 four 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 with each successive year. Additionally, the portion of the sample that falls into relatively high-priced bins (e.g., $3.75-$5.75/W$_{AC}$) decreases with each successive vintage, while the portion that falls into relatively low-priced bins (e.g., $1.25-$2.75/W$_{AC}$) increases. The "width" of the curves also narrows somewhat over time, indicating that the pricing within each successive vintage becomes less heterogeneous.

Tracking projects often command a price premium over fixed-tilt installations

While median prices in the sample have declined over time,[20] Figures 7 and 8 show that there remains a considerable spread in individual project prices within each year. The overall variation in prices may be partially attributable to differences in module and mounting type—i.e.,

online in 2015 is nearly 5 years, with the average lag for systems larger than 100 MW$_{AC}$ being 4 ½ years, compared to 2 years for systems smaller than 100 MW$_{AC}$. Because of their size, very large projects continued to dominate the capacity-weighted average price in 2015 (three projects larger than 100 MW$_{AC}$ represent 33% of the capacity additions in our price sample, but only 5% of new projects, in 2015). More detail on installed prices for these three projects is provided in Figure 11 towards the end of this section.

[20] Although in general we prefer capacity-weighted averages over medians, the rest of this section focuses on medians rather than capacity-weighted averages in order to avoid the apparent distortion seen in 2014 and 2015 of Figure 7. Whereas medians (and simple means) tell us about the typical project, capacity-weighted averages tell us more about the typical unit of capacity (e.g., the typical MW). Throughout most of this report, we are interested in analyzing the U.S. solar market in its entirety—e.g., deriving a representative installed price per unit of capacity (rather than per project), or a representative capacity factor or PPA price per MWh for the US fleet as a whole—and therefore tend to favor capacity-weighted averages over medians (or simple means). Given the apparent distortion noted above, however, as well as our increasing sample size over time (which lends itself more readily to medians), the use of medians seems more appropriate for this section—and will also align this report more closely with reported median prices for the residential and commercial PV systems in LBNL's companion *Tracking the Sun* series (see Barbose and Darghouth 2016).

whether PV projects use c-Si or thin-film modules, and whether those modules are mounted at a fixed tilt or on a tracking system.

Figure 9 breaks out installed prices over time among these four combinations (and also includes the three CPV projects in the sample—but excludes one "hybrid" project that features a mix of module and/or mounting types, and does not fit neatly into these four combinations). In 2015, the median price was $2.6/W_{AC}$ for fixed-tilt c-Si projects, $2.8/W_{AC}$ for tracking c-Si projects, $2.3/W_{AC}$ for fixed-tilt thin-film projects, and $3.1/W_{AC}$ for tracking thin-film projects.

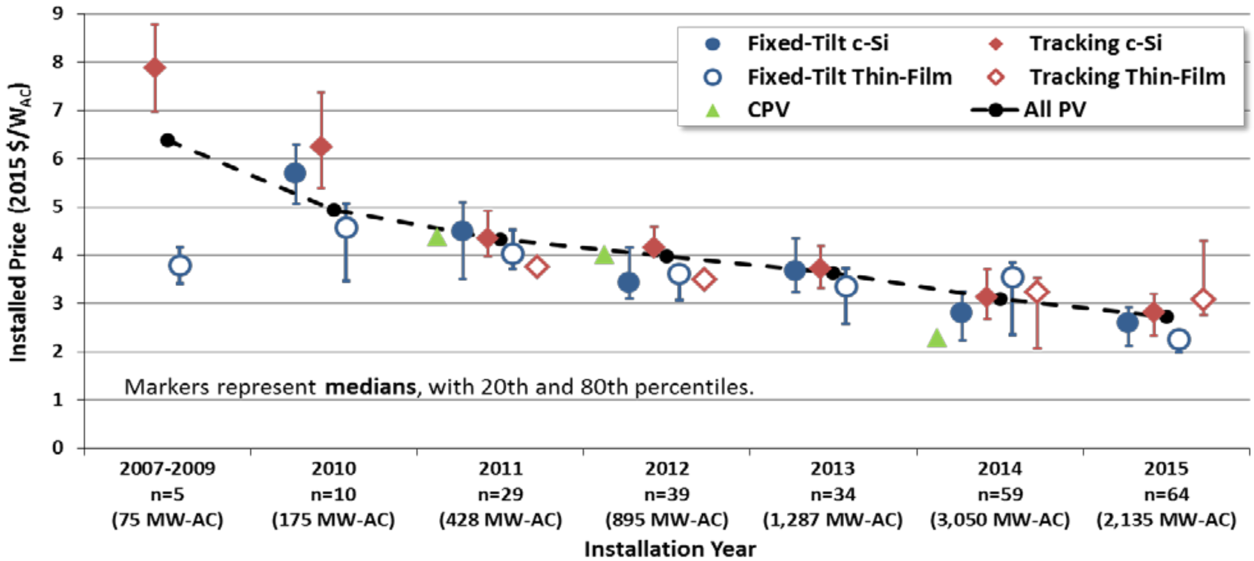


Figure 9. Installed Price of Utility-Scale PV (and CPV) Projects by Project Design and Installation Year

Although projects using c-Si modules were once significantly more expensive than projects using thin-film modules (e.g., by ~$1.1/W_{AC}$ on average among fixed-tilt projects built in 2010, according to Figure 9), the average installed price of fixed-tilt c-Si and thin-film projects has more or less converged over time, led by the falling price of c-Si modules. As c-Si and thin-film prices have converged, the predominance of c-Si projects has grown in both the installed price sample and within the broader population, as described earlier in Section 2.1.

Tracking systems achieve a slight premium over fixed-tilt systems within the sample—a difference of about $0.2/W_{AC}$ on average in 2015 among c-Si projects and as high as $0.8/W_{AC}$ for recent thin-film projects. It should be noted, however, that the thin-film sample is much less robust, with just 5 fixed-tilt projects and 10 tracking projects, compared to 17 and 29, respectively, for c-Si. As such, the thin-film sample is more susceptible to potential price outliers.

Figure 10 presents the same data, but does not differentiate between c-Si and thin-film, and instead aggregates across module types. Viewed in this way, tracking projects in 2015 come at a cost premium of $0.3/W_{AC}$ in comparison to fixed-tilt projects (similar to 2013 and 2014). This premium is supported by data recently released by the EIA, which for the first time published aggregate statistics from its new plant-level capital cost survey. Although so far the EIA has only released data for 2013, in that year the EIA's reported average installed price of tracking ($3.91/W$_{AC}$) and fixed-tilt projects ($3.55/W$_{AC}$) are similar to the LBNL medians shown in Figure 10 (Ray 2016), and show a premium of $0.37/W$_{AC}$ for tracking. Of course, as shown later in Section 2.4, this higher up-front expenditure for tracking results in greater energy production (and hence revenue), which outweighs the added cost.

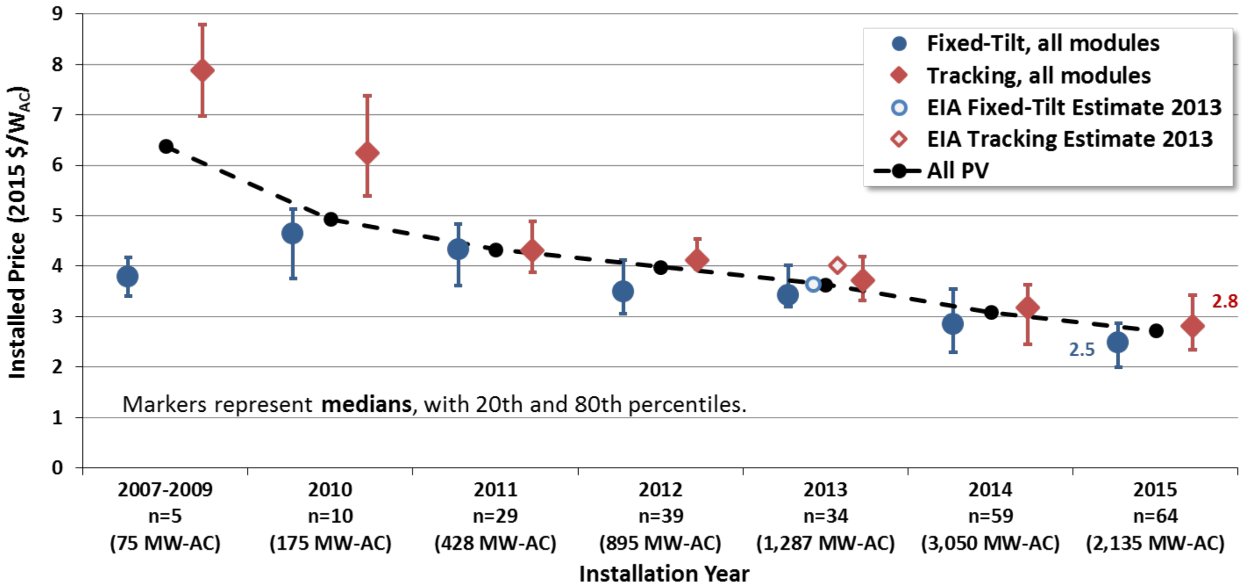


Figure 10. Installed Price of Utility-Scale PV by Mounting Type and Installation Year

Evidence of economies of scale continued to elude our sample

Differences in project size may also explain some of the variation in installed prices, as PV projects in the sample range from 5.5 MW$_{AC}$ to 315 MW$_{AC}$ (the 594 MW$_{AC}$ Solar Star project is structured as a two-part project). Figure 11 investigates price trends by project size, focusing on just those PV projects in the sample that became fully operational in 2015, in order to minimize the potentially confounding influence of price reductions over time.

As shown, no consistent evidence of economies of scale can be found among the PV systems in our pricing sample that achieved commercial operation in 2015.[21] For example, there are no clear trends—either among the various mounting/module combinations (e.g., fixed-tilt c-Si) or for all projects in aggregate—among the first three project size bins, ranging from 5 MW$_{AC}$ up to 100 MW$_{AC}$. One possible explanation for this seemingly counterintuitive finding is that economies of scale may be rather limited beyond what is already achieved by the standardized and modular "power blocks" (of up to several MW in size) that are offered by module manufacturers like SunPower and First Solar, and that are commonly used as the basis for larger

[21] These empirical findings are to some extent in conflict with recent modeling work from NREL (Fu et al. 2016) that analyzes the cost of projects in construction in Q1 2016 (that are not yet commercially operable). Excluding developer and EPC profit margins, NREL projects a $0.4/W$_{DC}$ cost advantage for a 100 MW$_{DC}$ utility-scale PV plant 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 COD (especially when significant interest for loans accrue over the development period).

projects. Alternatively, size-related cost savings may, in fact, be realized by EPC contractors, but will not necessarily show up in our installed price sample if they are not fully passed through to project owners in the form of lower prices. Or, to the extent that bulk procurement savings are realized at the developer rather than individual project level, economies of scale may be better measured by developer size than by project size. Finally, there may be some inconsistency in what costs or prices are included and reported by various projects; for example, some of the larger projects may include interconnection costs that are not present (or at least not reported) to the same degree by smaller projects.

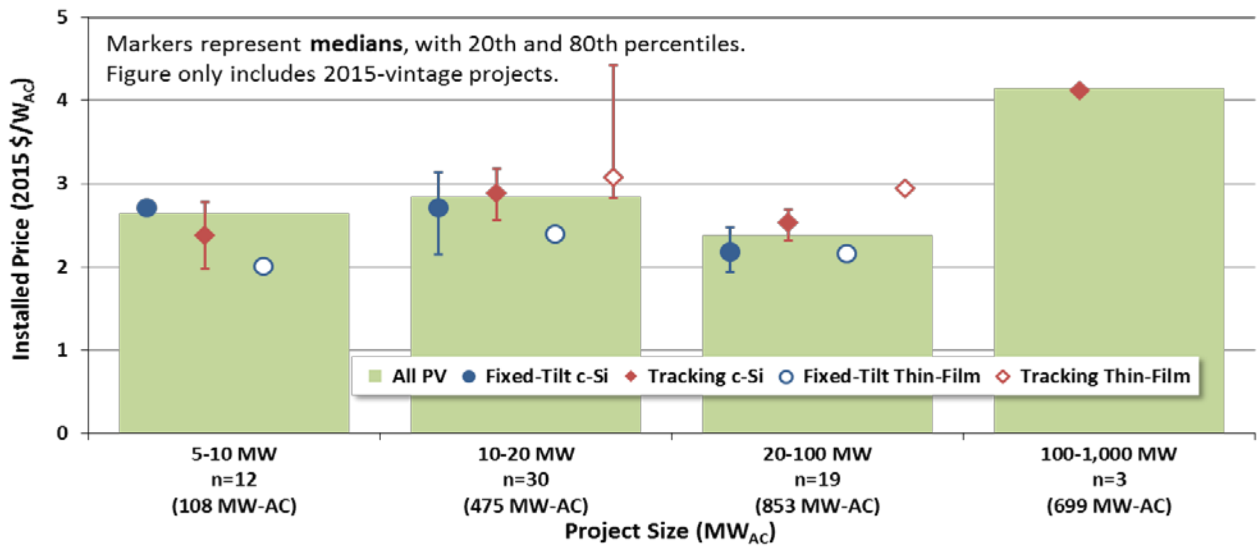


Figure 11. Installed Price of 2015 PV Projects by Size and Project Design

As was the case in last year's edition of this report (among the sample of 2014-vintage projects), the 2015 sample shown in Figure 11 once again suggests price *penalties* for projects larger than 100 MW_{AC}. Two factors may contribute to these apparent *dis*economies of scale for very large projects. First, most of these very large projects have been under construction for several years and may therefore reflect higher module and EPC costs from several years ago. For example, all projects larger than 100 MW_{AC} in our sample had a time lag between PPA execution and commercial operation date (COD) of more than 4 years, while all other projects had a time lag of less than 4 years (see also footnote 19). We find a correlation between a longer PPA-COD lag and a higher final installed project price, with an additional year of lag time resulting in a price premium of about $0.5/$W_{AC}$. A second explanation may be that these mega-scale projects—some of which involve more than 2.5 million modules and project sites of nearly 10 square miles—often face greater administrative, regulatory, 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.

System prices vary by region

In addition to price variations due to technology and—notwithstanding the previous section—perhaps system size, prices also differ by geographic region. This variation may, in part, reflect the relative prevalence of different system design choices (e.g., the greater prevalence of tracking projects in California and the Southwest) that have cost implications. In addition, regional differences in labor and land costs, soil conditions or snow load (both of which have structural implications), or simply the balance of supply and demand, may also play a role. As shown in Figure 12 (which uses the regional definitions shown earlier in Figure 3), California is one of the most-expensive states in the United States, followed by the Northeast region, while the Southwest and Southeast feature similarly low prices that are below the national median. Due to the small number of observations, projects in Hawaii, Texas, and Indiana are not reported in Figure 12.

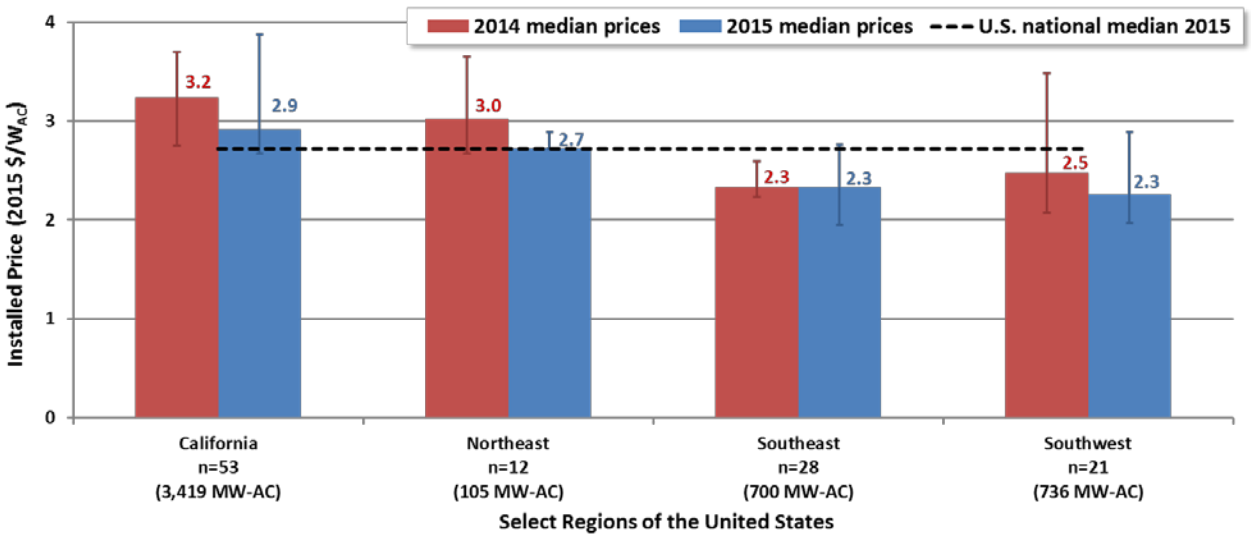


Figure 12. Median Installed PV Price by Region in 2015 and 2014

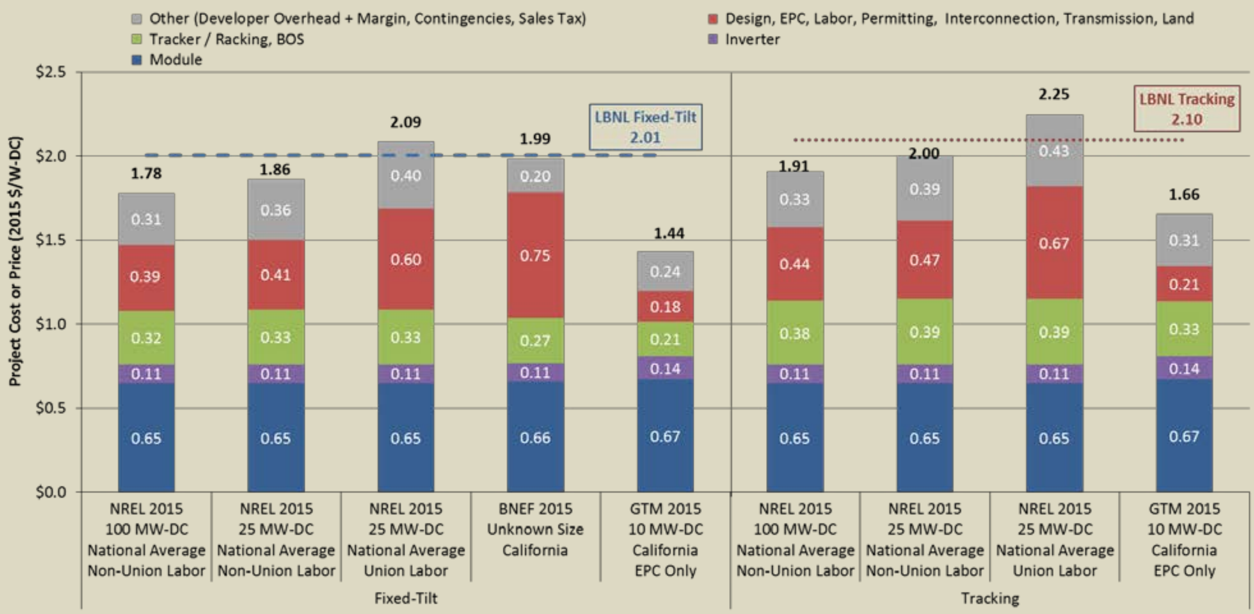
Finally, the text box on the next page compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

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, the Treasury's Section 1603 grant database) that typically do not provide more granular insight into component costs. In contrast, several publications by NREL (Fu et al. 2015), BNEF (Bloomberg New Energy Finance 2015), and Greentech Media (GTM Research and SEIA 2016) 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 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 but rely on modeling, typically of idealized or "best in class" projects.

The figure below compares the top-down median 2015 prices for fixed-tilt ($2.01/W$_{DC}$) and tracking ($2.10/W$_{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}$, which is how they are reported in these other sources.

Although GTM's relatively low cost estimates stand out as potential outliers, they represent only turnkey EPC costs—i.e., they exclude permitting, interconnection, and transmission costs, as well as developer overhead, fees, and profit margins—which perhaps explains the difference. LBNL's median fixed-tilt estimate of $2.01/W$_{DC}$ is quite close to BNEF's $1.99/W$_{DC}$, and for both fixed-tilt and tracking projects, LBNL's top-down empirical estimates fall in between NREL's bottom-up modeled estimates for a 25 MW$_{DC}$ project built with either union or non-union labor. This relative positioning makes sense, given that LBNL's sample (which, incidentally, has a median project size of roughly 25 MW$_{DC}$ for both fixed-tilt and tracking projects) reflects a mix of union and non-union labor, and has a fairly wide distribution of installed prices that encompasses the NREL single-point estimates. Finally, though not evident in the LBNL sample (as discussed earlier), modest economies of scale of less than $0.10/W$_{DC}$ are reflected in NREL's bottom-up modeled cost estimates for a 100 MW$_{DC}$ project.



2.3 Operation and Maintenance Costs (30 projects, 546 MW_{AC})

In addition to up-front installed project costs or 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, O&M costs—at least as 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. Very 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). It also appears that, at least historically, some investor-owned utilities have not reported empirical O&M costs for individual solar projects, but instead have reported 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. Table 1 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Year	PG&E		PNM		APS[23]		FP&L	
	MW_{AC}	Projects	MW_{AC}	Projects	MW_{AC}	Projects	MW_{AC}	Projects
2011	#N/A	#N/A	#N/A	#N/A	51	3	110	3
2012	50	3	8	2	96	4	110	3
2013	100	6	30	4	136	6	110	3
2014	150	7	55	7	168	7	110	3
2015	150	7	95	11	191	9	110	3
Predominant Technology	fixed-tilt c-Si		4 fixed-tilt and 3 tracking thin-film, 4 tracking c-Si		primarily tracking c-Si		mix of c-Si and CSP	

Table 1. Operation and Maintenance Cost Sample (cumulative over time)

[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).

[23] APS reports O&M costs in FERC Form 1 only in an aggregated manner across customer classes (residential, commercial, and utility-scale). For lack of better data, we use their 191 MW_{AC} of total PV capacity (including residential and commercial) as a proxy for the 9 utility-scale solar plants with a combined capacity of 181 MW_{AC}.

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 bars represent both the lowest and the highest utility fleet-wide PV cost in each year. The yellow dotted line, meanwhile, shows the annual O&M costs of FP&L's 75 MW CSP plant (in $/kW-year terms only, because this project provides steam to a co-located combined cycle gas plant). Although this chapter focuses on PV projects, we've included this lone CSP plant here largely for the sake of expediency, given that it is the only CSP project for which we have O&M cost data. Not surprisingly, its O&M costs—which may not even be fully representative if they represent just the solar collector field and not the power block of the gas-fired combined cycle plant—are well above those of the PV projects shown.

Average O&M costs for the cumulative set of PV plants within this sample have steadily declined from about $31/kW$_{AC}$-year (or $19/MWh) in 2011 to about $16/kW$_{AC}$-year ($7/MWh) in 2015. This decline could potentially indicate that utilities are capturing economies of scale as their PV project fleets grow over time, although the significant drop from 2013 to 2014 may simply be a result of missing PG&E's costs for 2014 (PG&E's reported costs to the CPUC for 2012 and 2013 were above average, while costs reported to FERC for 2015 have come down to levels seen at other utilities). In 2015, all but five 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 $11/MWh), which is lower than medium-term projections by bond rating agencies (see the O&M cost section of Bolinger and Weaver (2014)).

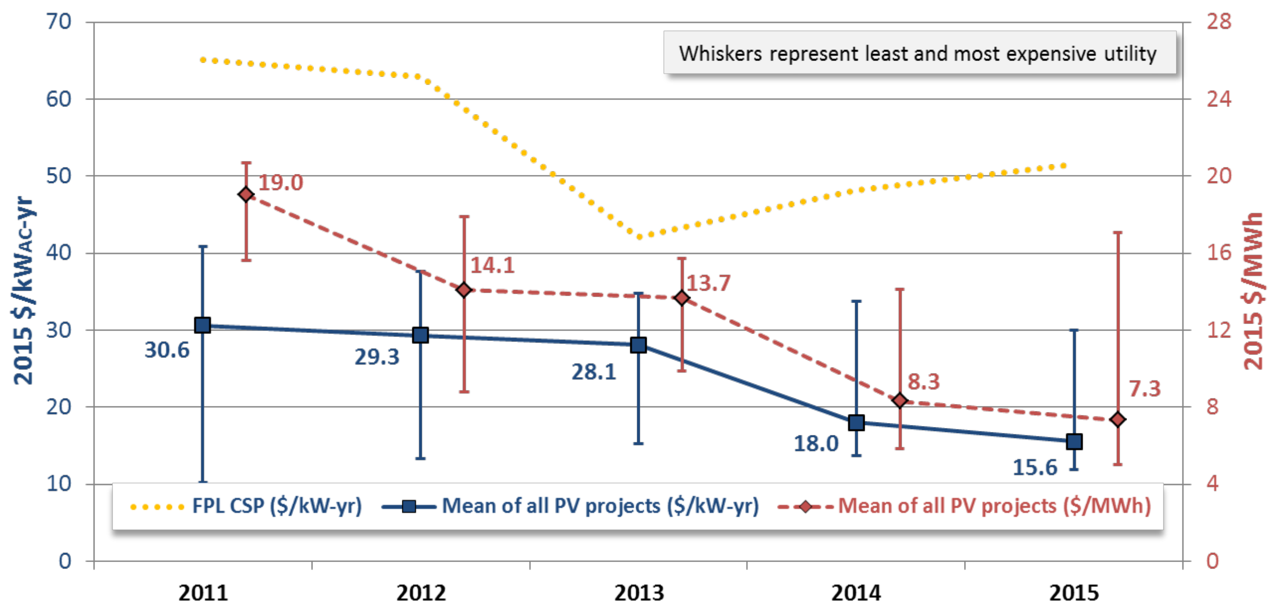


Figure 13. Empirical O&M Costs Over Time for Growing Cumulative Sample of Projects

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.

2.4 Capacity Factors (170 projects, 5,907 MW_{AC})

At the close of 2015, at least 170 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 eight years, thereby enabling the calculation of capacity factors.[24] Sourcing empirical net generation data from FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings, this chapter presents net AC capacity factor data for 170 PV projects totaling 5,907 MW_{AC}. This 5.9 GW_{AC} sample represents a substantial increase from the 3.2 GW_{AC} sample for which capacity factor data were analyzed in last year's edition of this report, driven in large part by new projects that began operating in 2014.

The capacity factors of individual projects in this sample range widely, from 15.1% to 35.7%, with a sample mean of 25.7%, a median of 26.4%, and a capacity-weighted average of 27.6%. 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 eight years, from 2008 to 2015, in this case), rather than for just a single year (though for projects completed in 2014, only a single year of data—2015—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. Finally, they are calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[25] yielding higher capacity factors than if reported in DC terms,[26] but allowing for direct comparison with the capacity factors of other generation sources (e.g., wind energy or conventional energy), 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 recent statistical analysis (Bolinger et al. 2016) found to explain more than 90% of the variation in utility-scale PV project capacity factors: 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).[27] The blue-shaded columns show the mean cumulative capacity factor within each individual bin.

[24] Because solar generation is seasonal (greater in the summer than in the winter), capacity factor calculations are performed in full-year increments.

[25] 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].

[26] 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.

[27] 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

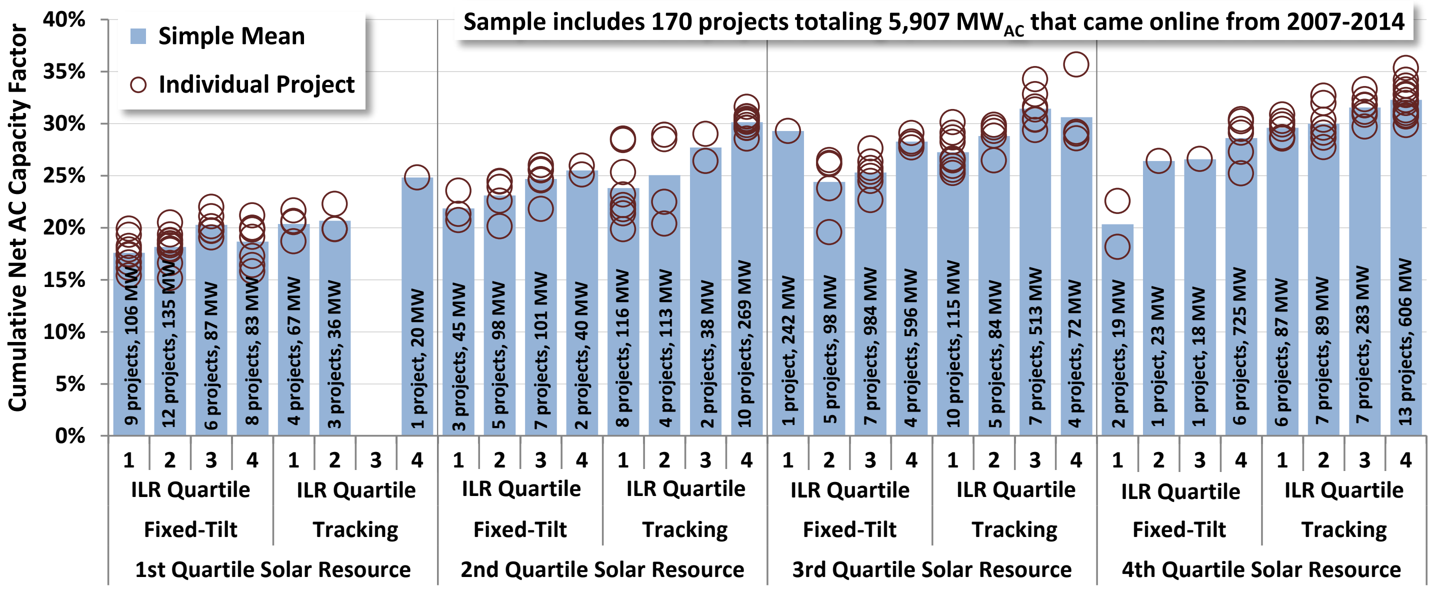


Figure 14. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio[28]

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: <4.74, 4.74-5.39, 5.39-5.79, and ≥5.79 kWh/m^2/day GHI. Roughly 43 projects fall into each resource quartile, though capacity is concentrated in the third (46%) and fourth (31%) quartiles. Not surprisingly, projects sited in stronger solar resource areas tend to have higher capacity factors, all else equal. The difference can be substantial: the mean capacity factors in the highest resource bin, for example, average 8 percentage points higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending from 3 to 10 percentage points depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** Seventy-nine projects in the sample (totaling 3,398 MW$_{AC}$) are mounted at a fixed-tilt, while the remaining ninety-one (totaling 2,509 MW$_{AC}$) utilize

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insolation during the period of interest—is not readily accessible, making capacity factors a more expedient choice for this report.

[28] Figure 14 (as well as the rest of this section) excludes three CPV projects: the 5.04 MW$_{AC}$ Hatch project (online since late-2011), the 30 MW$_{AC}$ Cogentrix Alamosa project (online since early 2012), and the 6.3 MW$_{AC}$ Desert Green project (online since late-2014). If plotted in Figure 14, these three projects would fall into the 29th, 10th, and 32nd bins, respectively, where their cumulative capacity factors of 18.4%, 23.9%, and 28.0% would—with the exception of Cogentrix Alamosa—fall below the respective PV bin means of 29.6%, 23.1%, and 32.3% (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 18.4%, compared to the PV average of 29.6%). Earlier editions of this report provide additional details about the specifications and performance of the Hatch and Cogentrix Alamosa PV projects.

tracking (overwhelmingly single-axis east-west tracking, with the exception of two recent dual-axis tracking projects located in Texas). Tracking boosts average capacity factor by 2-5 percentage points on average (in absolute terms), depending on the resource quartile (i.e., 2% within the 2nd resource quartile, 5% in the 4th resource quartile), and 4% on average across all four resource quartiles. This finding that the benefit of tracking increases at higher insolation levels is consistent with results from Bolinger et al. (2016), and also explains why there are many more fixed-tilt (35) than tracking (8) projects in the lowest insolation quartile and many more tracking (33) than fixed-tilt (10) projects in the highest insolation quartile of Figure 14.

- **Inverter Loading Ratio (ILR):** Figure 14 breaks the sample down further into ILR quartiles: <1.19, 1.19-1.25, 1.25-1.30, and ≥1.30. Again, each quartile houses roughly 430 projects, but capacity is concentrated in the third (34%) and fourth (41%) quartiles. The effect of a higher ILR on average 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 8% (with an average of 4% across all bins).

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 be equally optimized across all projects to maximize energy production. Although this assumption may become increasingly tenuous as PV's grid penetration increases,[29] the fact that we lack solid data on project-level tilt and azimuth prevents further analysis of these two fundamental variables at present.

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), 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 and Midwest samples include more fixed-tilt than tracking projects).

[29] For example, at higher penetration levels, time-of-day pricing factors may shift to more-heavily favor the late afternoon hours, which could encourage developers of fixed-tilt projects to orient them in a more westerly direction.

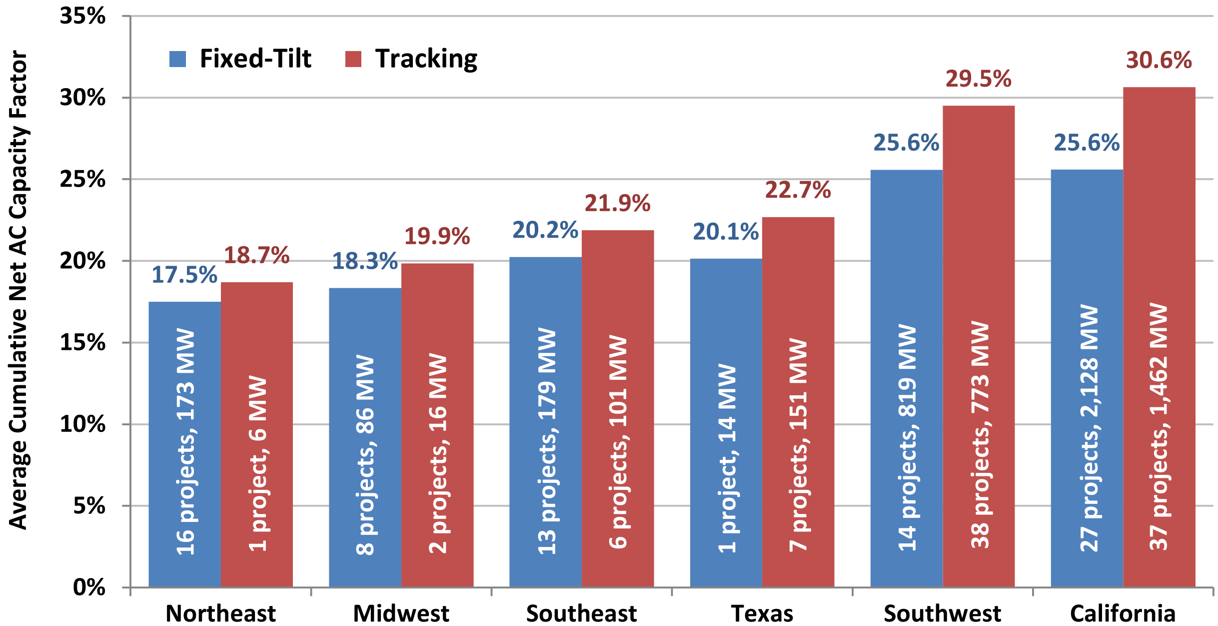

Figure 15. Cumulative Capacity Factor by Region and Fixed-Tilt vs. Tracking

More recent project vintages exhibit higher capacity factors

Although one might initially expect project vintage to be positively correlated with capacity factor because the efficiency of PV modules has improved over time, this is a red herring. 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.

Figure 16 tests this hypothesis by breaking out the average net capacity factor (both cumulative and in 2015) by project vintage across the sample of projects built from 2010 through 2014 (and by noting the relevant average project design parameters within each vintage). Following a notable step up from 2010- to 2011-vintage projects, driven by an increase in both tracking and mean GHI, the average cumulative capacity factor increases only slightly among 2012-vintage projects, given little movement in any of the three design parameters shown. A more-significant increase in average capacity factor is seen among 2013-vintage projects, corresponding to positive trends in all three design parameters, while 2014-vintage projects show essentially no change in average capacity factor, once again due to little movement in the underlying design parameters.

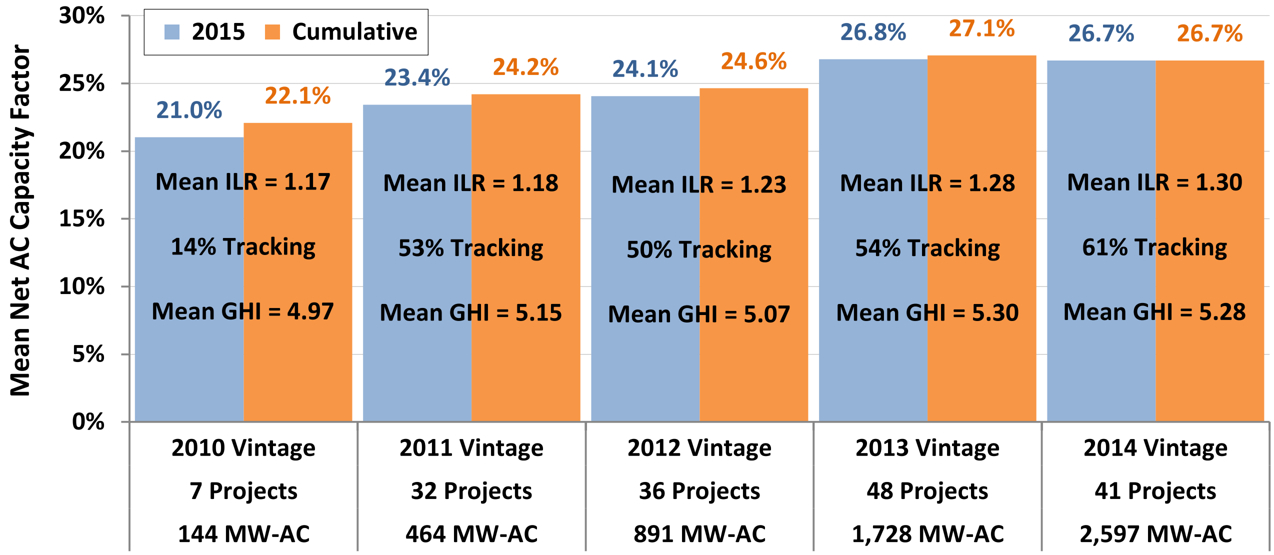

Figure 16. Cumulative and 2015 Capacity Factor by Project Vintage: 2010-2014 Projects

Two other factors could plausibly contribute to the general increase 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., 2014-2015) than in earlier years (e.g., 2011-2013). If this were the case, then 2014-vintage projects, for example, might be expected to exhibit higher cumulative capacity factors than older projects, given that 2015 is the only applicable performance year for a 2014-vintage project.

Two findings, however, suggest that inter-year resource variation is *not* contributing to the upward trend seen in Figure 16. First, ex-post annual solar resource data (3Tier 2013; Vaisala 2014; Vaisala 2015, Vaisala 2016) finds that 2013-2015 were generally *below-normal* insolation years in California and the Southwest, where most utility-scale PV projects are located. Second, the blue columns in Figure 16 measure capacity factors across vintages during the same single year—2015—yet show essentially the same upward trend as the orange columns that measure cumulative capacity factors, suggesting that ILR, GHI, and tracking (and perhaps degradation—addressed in the next section) are the true drivers.

Degradation hard to measure at project level, but is seemingly within expectations

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 at the project-level, in large part because its impact over limited time frames is likely to be rather modest and swamped by other factors. For example, over an 8-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 0.5%/year would reduce an initial net AC capacity factor of 30.0% to 29.0% in the eighth year. This single percentage point reduction in capacity factor over an eight-year period is rather trivial in relation to, and could easily be overwhelmed by, the impact of inter-year variations 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[30]), and so should not be ignored as a possible driver of cumulative capacity factor.

To that end, Figure 17 shows a time series of capacity factors by calendar year for the thirteen projects in our sample (denoted by the eight different states in which they are located) that have been operating for at least five years, and for as long as eight years. No attempt has been made to correct the data for inter-year variations in the solar resource; as such, interpretation of the trends is difficult. A general decline in capacity factor over time is evident, particularly during 2013-2015. But as mentioned earlier, 2013-15 reportedly featured below-normal insolation throughout much of the West and Southwest (where eight of these projects are located), particularly during the crucial summer months when solar generation peaks (3Tier 2013; Vaisala 2014; Vaisala 2015; Vaisala 2016). Meanwhile, the three eastern states in Figure 17—Ohio, Illinois, and Florida—were not hit quite as hard in 2015 (Vaisala 2016), which is reflected in their relatively stable capacity factors in that year. In summary, though Figure 17 presumably reflects some amount of degradation, the more prominent driver of lower capacity factors in recent years is likely to be the relatively poor insolation experienced throughout much of the country from 2013-15.

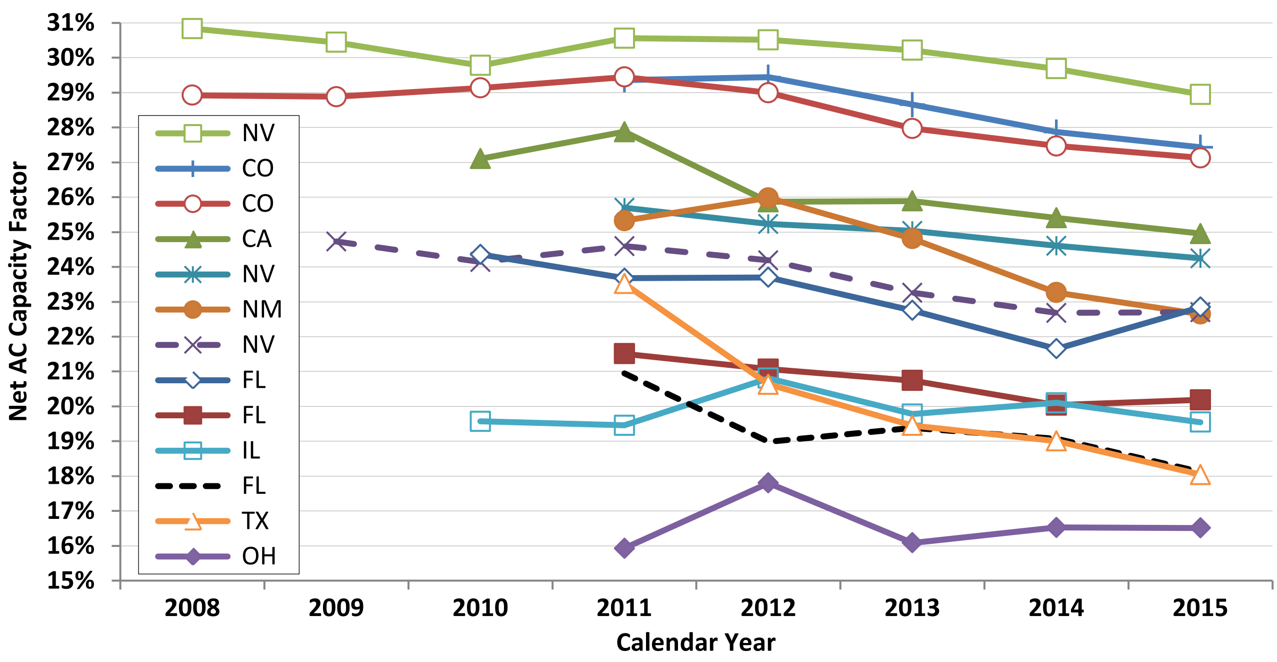

Figure 17. Capacity Factors by Calendar Year for 13 Projects with at least 5 Years of Performance History

[30] For example, within a sub-sample of 29 utility-scale PV PPAs totaling 3,215 MW_{AC} that were collected for the next section of this report, 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.

2.5 Power Purchase Agreement (PPA) Prices (136 contracts, 9,097 MW_{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 the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electronic 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., including 136 contracts totaling 9,097 MW_{AC}.

The population from which this 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 (at least 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 chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[32] As such, the PPA 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]

[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 last year's 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 (e.g., Colorado) have implemented REC "multipliers" for solar projects (whereby each solar REC is counted as more than one REC for 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 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

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 ("TOD") 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.[39,40] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized levelized cost of energy ("LCOE").

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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. The maximum PPA term is 34 years, the mean is 22.6 years, the median is 23.1 years, and the capacity-weighted average is 22.9 years.

[36] In cases where PPA price escalation rates are tied to inflation, the EIA's projection of the U.S. GDP deflator from *Annual Energy Outlook 2016* 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 DOE 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 investment tax credit ("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).

[40] Though there is too much variety in state-level incentives to systematically quantify their effect on PPA prices here, one example is New Mexico's refundable Production Tax Credit, which provides a credit of varying amounts per MWh (averaging $27/MWh) of solar electricity produced over a project's first ten years. One PPA for a utility-scale PV project in New Mexico allows for two different PPA prices—one that is $43.50/MWh higher than the other, and that goes into effect only if the project does not qualify for the New Mexico PTC. Based on New Mexico's top corporate tax rate of 7.6%, a $43.50/MWh price increase due to loss of New Mexico's PTC seems excessive (a more appropriate 20-year adjustment would seemingly have been roughly half that amount), but nevertheless, this is one tangible example of how state incentives can reduce PPA prices.

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, 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 exactly the same as Figure 18, except that it focuses only on those PPAs that were signed in 2014 or 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.

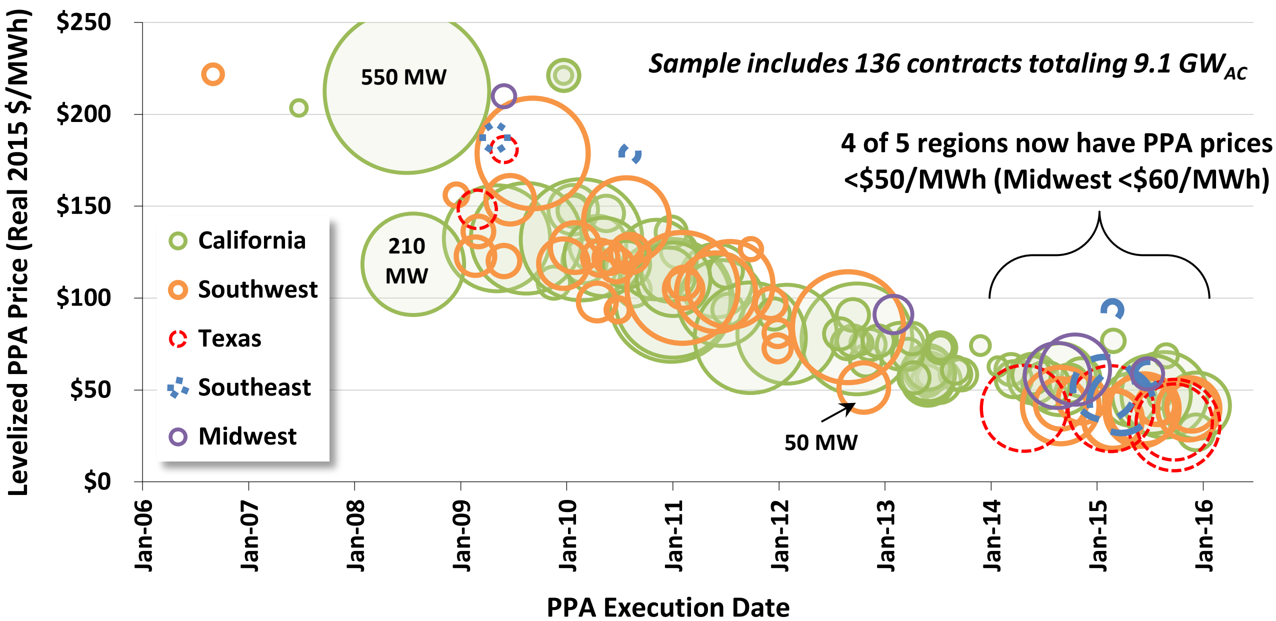

Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

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[41] Figure 18 excludes the single northeastern PPA in our sample: a 32 MW$_{AC}$ project on Long Island that was signed in June 2010 and that has a real levelized price of ~$286/MWh.

[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. For those interested in viewing average PPA prices by commercial operation date, however, Figure 21 breaks it out both ways.

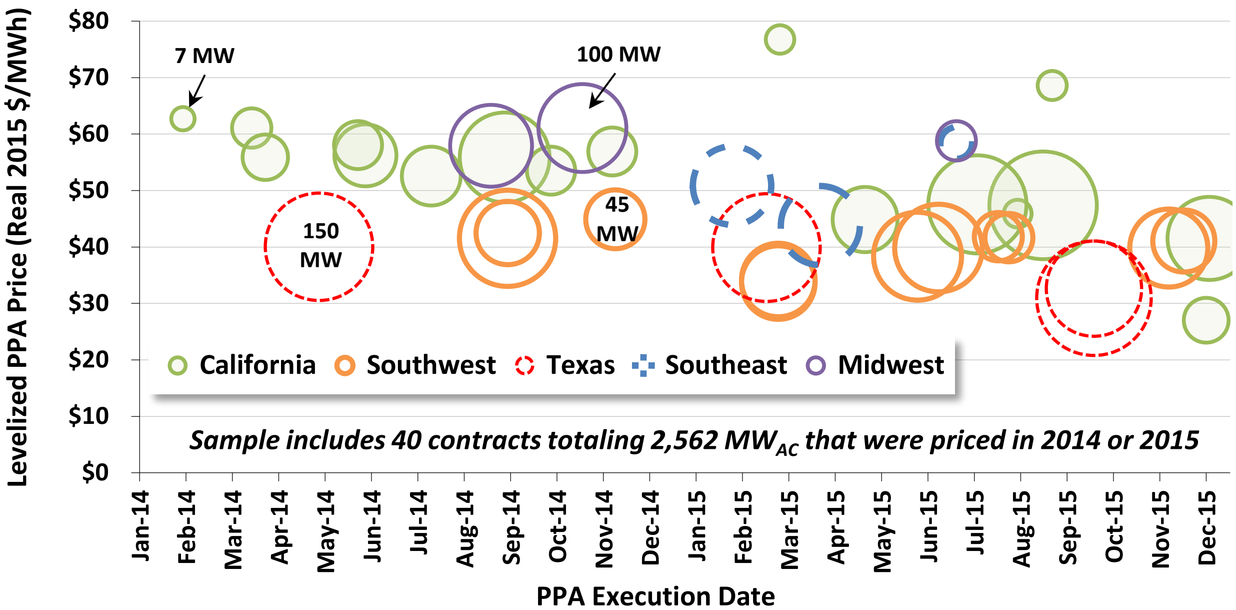

Figure 19. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: 2014 and 2015 Contracts Only

A number of aspects of Figures 18 and 19 are worth highlighting:

- ***PPA pricing has declined steadily and significantly over time.*** As recently as 2011, solar PPA prices in excess of $100/MWh were quite common. Barely five years later, most PPAs in the 2015 sample are priced at or below $50/MWh levelized (in real, 2015 dollars), with a few priced as aggressively as ~$30/MWh.

- ***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* 2013, 73% of the contracts representing 62% of the capacity are for projects located in either California or the Southwest, down significantly from 93% of the contracts representing 98% of the capacity within the sub-sample of PPAs executed *prior to* 2014. New markets include Texas (23% of post-2013 capacity in the sample), the Southeast (7%), and even the sun-challenged Midwest (8%).

- ***All five regions now feature relatively low PPA prices.*** Four of the five regions shown in Figures 18 and 19 are now home to PV projects with levelized PPA prices that are below $50/MWh, and three of these regions—California, the Southwest, and Texas—have contracts below $35/MWh levelized. Somewhat surprising, given the relative weakness of its solar resource, the Midwest is not too far behind, with several projects priced under $60/MWh—a price that only a year or two ago would have been considered aggressive even in much sunnier regions.

- ***PV is increasingly competitive with other renewable power options.*** In California and the Southwest in particular, pricing this low is, in some cases, competitive with in-region wind power.[43] This is especially the case when considering solar's on-peak generation profile, which can provide ~$25/MWh of TOD value relative to wind, at least at low levels of solar penetration in the electric grid.[44] Although the number of utility-scale PV and (especially) wind projects in the Southeast is still comparatively sparse, wind is likely to find it hard to compete with PV in this up-and-coming region as well.

- ***Smaller projects are equally competitive.*** Though there have recently been a number of large, low-priced contracts announced (particularly in Texas), smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are, in some cases, seemingly just as competitive as larger projects. In many states, very large projects often 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.

- ***Not all of these projects are online.*** Unlike other chapters of this report, which focus exclusively on operating projects (determined by commercial operation date), 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 June 2016, at least three quarters of all projects and capacity within the PPA sample were either partially or fully operating, with the remainder representing more-recently signed contracts for projects that had, prior to the ITC extension, been targeting a December 2016 commercial operation date. With the ITC extension having now eased the pressure somewhat, a number of these projects will likely lapse into 2017.

- ***There is no compelling reason to believe that projects still in development will not be built.*** Given that many of the lowest-priced contracts in the sample are from projects that are still in development, it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown in Figure 19.[45] That said, the sample does not include any PPAs that have been terminated, and a recent spin-off modeling analysis (Bolinger, Weaver, and Zuboy 2015) finds that today's aggressive PPA prices can indeed pencil out using modeling assumptions that are based on best-in-class PV data presented in other sections of this report. Moreover, as described in a text box within last year's edition of this report (see *Solicitation Responses Reveal Deep Market at Low Prices* in

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[43] See, for example, the text box in Bolinger and Weaver (2013) that compares the economics of the co-located Macho Springs wind and solar projects.

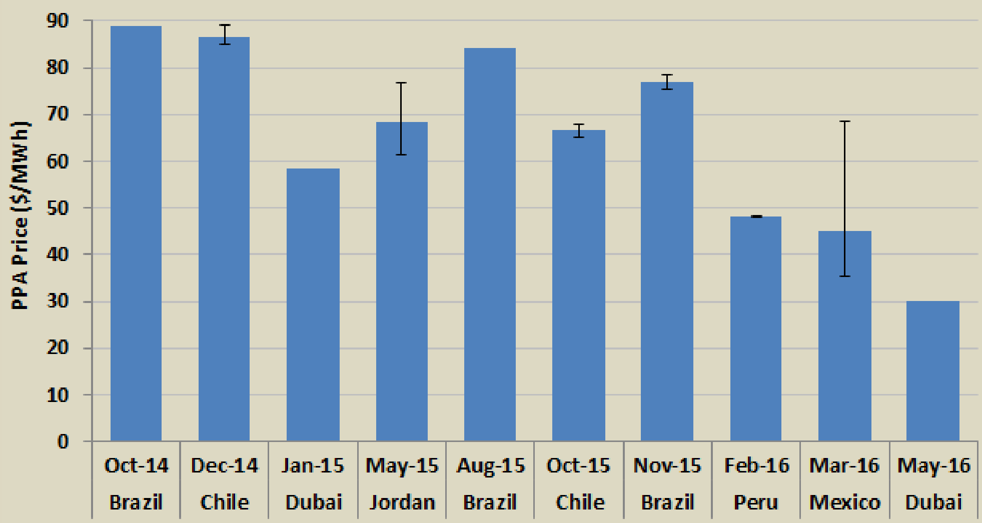
[44] For further explanation, see the text box titled *Estimating PV's TOD Value* in the 2013 edition of this report (Bolinger and Weaver 2014). Also note that the levelized PPA prices shown in Figures 18 and 19 (and throughout this chapter) already incorporate all applicable TOD factors. Not all PPAs, however, use explicit TOD factors, though in those instances where they are not used, PV's on-peak generation profile still presumably provides higher *implicit* value (compared to wind) to the buyer.

[45] 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, price revisions are perhaps a more likely risk than outright termination.

Bolinger and Seel (2015)), these low prices do not appear to be one-off anomalies, as evidenced by the deep field of projects bidding into various solicitations at these low prices. Finally, as described in the text box on this page, recent experience in international markets suggests that the U.S. is not alone in enjoying record-low solar PPA prices; in fact, compared to some recently announced PPA prices in other countries, the U.S. market looks comparatively expensive.

Low International PPA Prices Reveal Expanding Global Market

Low PPA prices for utility-scale PV projects are not, of course, confined to the United States. The past two years have witnessed several successive announcements of low-priced solar PPAs in different parts of the world, each newly proclaiming to represent the world's cheapest solar power. The graph below summarizes many of these PPA prices, which have primarily resulted from competitive auctions in countries located in the sun-rich Middle East and North Africa (MENA) region or Latin America. The blue columns represent the average PPA price, and the error bars (if any) show the range of successful bids (no error bars either means that the auction cleared at a single price, like in Dubai, or else we could not find enough data to determine the proper range of prices, like in the first two Brazil auctions).



While these global PPA prices appear comparable to those in the U.S. (as described elsewhere in this chapter), an important distinction is that U.S. PPA prices reflect federal tax and other subsidies, while the global PPA prices presented in the graph are often presented as being "unsubsidized." That said, some of these PPAs do reflect various "soft" subsidies, such as low-cost financing or guarantees from development banks and/or sovereign wealth funds, or PPAs denominated in U.S. dollars to mitigate currency risk, for example. Without these soft subsidies, pricing would likely be higher than shown.

Although the presence of varying types and levels of both explicit and soft subsidies complicates an apples-to-apples comparison between international PPA prices, one potentially useful data point to inform the discussion is what the 30% ITC and accelerated tax depreciation equate to in PPA price terms. Results from a basic financial pro forma model suggest that a U.S. PV project that requires a levelized PPA price of $35.5/MWh (in real 2015 dollars, or $42.2/MWh levelized in nominal dollar terms) with the 30% ITC and 5-year accelerated depreciation in place would need to increase its levelized PPA price by ~$18/MWh (in real 2015 dollars, or by ~$21.3/MWh in nominal dollar terms) if the ITC were eliminated and the depreciation schedule was lengthened to 12-year straight line (the schedule allowable for natural gas power plants). In other words, without federal tax subsidies, this representative (at least in some parts of the U.S.) $35.50/MWh levelized PPA price would be more like $53.50/MWh. In this light, some of the more-recent "unsubsidized" PPA prices shown in the graph above—e.g., the sub-$30/MWh price out of Dubai or the $35.5/MWh winning bid in Mexico—look truly astounding indeed.

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 circle markers show the levelized PPA price of each individual contract grouped by the year in which the contract was signed (each circle in Figure 20 corresponds to a bubble in Figure 18), while the blue-shaded columns show the generation-weighted average of those individual levelized contract prices. Levelized PPA prices for utility-scale PV projects consistently fell by $20-$30/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples.[46] With levelized PPA prices now below $50/MWh on average (the 2015 sample has a generation-weighted average of $41/MWh, a simple mean of $47/MWh, and a median of $42/MWh), future average price declines are likely to be much smaller than in the past.

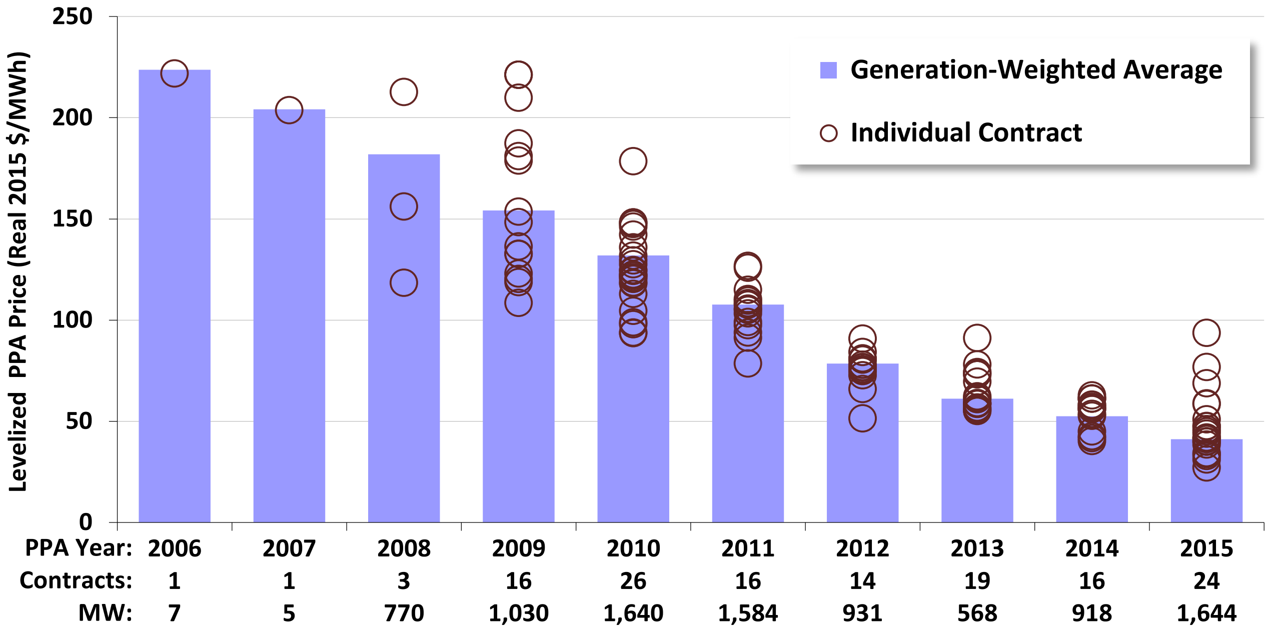


Figure 20. Levelized PV PPA Prices by Contract Vintage[47]

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[46] 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. This makes sense when one considers that tracking systems, for example, add up-front costs to the project (see Section 2.2) that are recouped over time through greater energy yield (see Section 2.4), thereby potentially leaving the net effect on PPA prices largely a wash. In support of this theory, the Public Service Company of New Mexico estimated (based on a review of 216 solar responses to its 2012 Renewable RFP) that—at least at that time—the average PPA price benefit of single-axis tracking was just $3/MWh, or less than 4% of a levelized PPA price in the mid-$70/MWh range (O'Connell 2013).

[47] Figure 20 excludes the two CPV projects in our sample. If included, they would both fall within the 2010 bin, at levelized prices of $109.3/MWh and $126.6/MWh—i.e., within the range of PV projects shown.

As noted earlier, some projects in our PPA price sample have not yet been built, and for those that have been built often a year or more can pass between when a PPA is signed and when the underlying project ultimately achieves commercial operation. As a result, the decline in PPA prices over time looks more erratic when viewed by commercial operation date (rather than by PPA execution date). The blue columns in Figure 21 are based on PPA execution date (and thus match those shown in Figure 20), while the orange columns show the generation-weighted average PPA price in the years in which each project achieved full commercial operation. Virtually all of the projects that had not come online by the end of 2015 had been targeting 2016 completion dates in order to capture the 30% ITC, but some construction schedules may have since lapsed in light of the December 2015 ITC extension, which—in addition to the fact that 2016 is still in progress—is why 2016 is labeled as provisional in the graph. Though the average levelized price of PPAs signed in 2015 is ~$40/MWh, the average levelized PPA price among projects that came online in 2015 is significantly higher at ~$85/MWh; this difference was even starker in 2014.

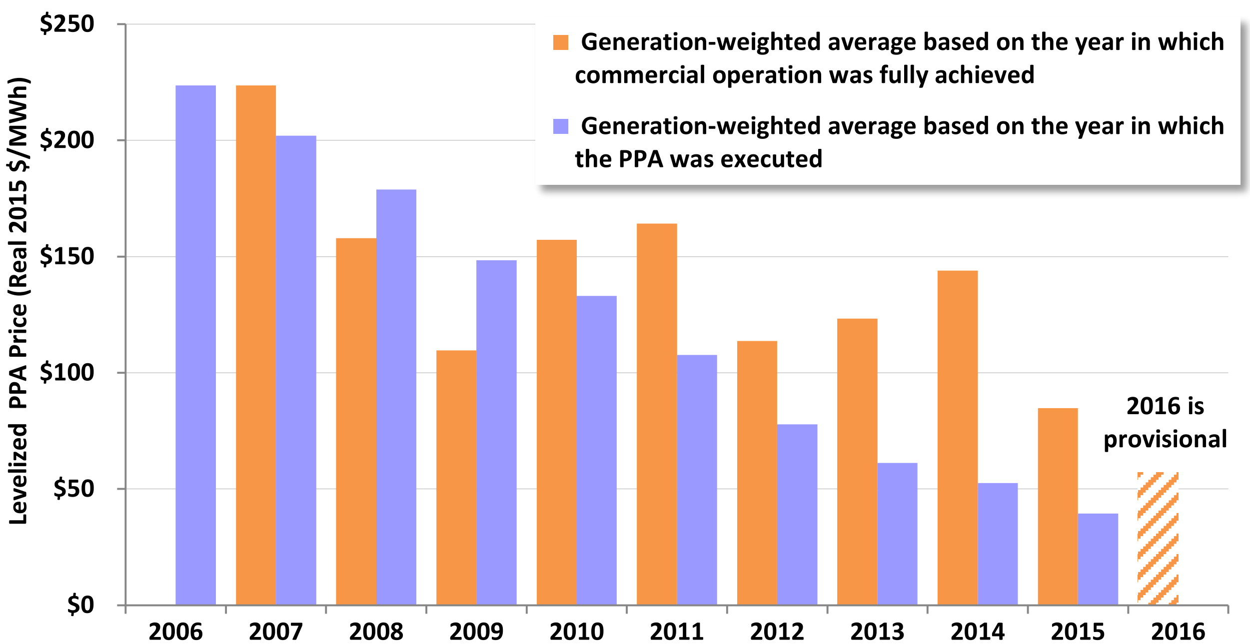


Figure 21. Average Levelized PV PPA Prices by Contract and COD Vintage

Solar's largely non-escalating and stable pricing can provide hedge value

Nearly 70% of the contracts (and MW) in the PPA sample feature pricing that does *not* escalate in nominal dollars over the life of the contract—which means that pricing actually *declines* over time in real dollar terms. Figure 22 illustrates this decline by plotting over time, in real 2015 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts). In other words, for each contract vintage, Figure 22 shows the stream of generation-weighted average PPA prices over time (these are the future PPA price streams that were levelized to yield the blue-shaded columns in Figures 20 and 21).

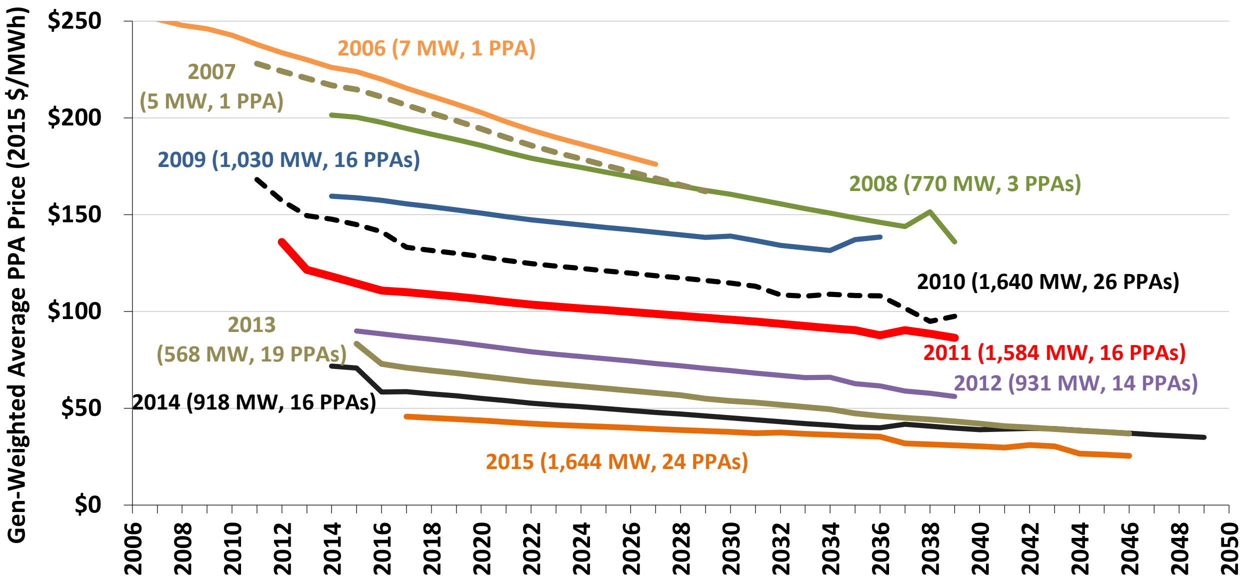


Figure 22. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

By offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013). Figure 23 illustrates this potential by plotting the future stream of average and median PV PPA prices from the 24 contracts in the sample that were executed in 2015 against a range of projections of *just the fuel costs* of natural gas-fired generation.[48] In this way, Figure 23 essentially compares the cost of *new* PV projects to the cost of *existing* gas-fired generation. This comparison is not perfect, however, given that existing gas-fired generators will also incur some small amount of non-fuel 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.

As shown, both the generation-weighted average and median PPA prices start out well above the range of fuel cost projections in 2017, but decline (in real 2015 $/MWh terms) over time, entering the fuel cost range in 2020 and 2021, respectively, and eventually reaching the reference case fuel cost projection by the end of that decade (by which time the 80th percentile PPA price has also entered the fuel cost range) and largely tracking it thereafter.

[48] The national average fuel cost projections come from the EIA's *Annual Energy Outlook 2016* publication, and increase from around $3.89/MMBtu in 2017 to $5.36/MMBtu (both in 2015 dollars) in 2040 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 a flat heat rate of 7 MMBtu/MWh, which is aggressive compared to the heat rates implied by the reference case modeling output (which start at roughly 7.9 MMBtu/MWh in 2017 and gradually decline to just above 7 MMBtu/MWh by 2040).

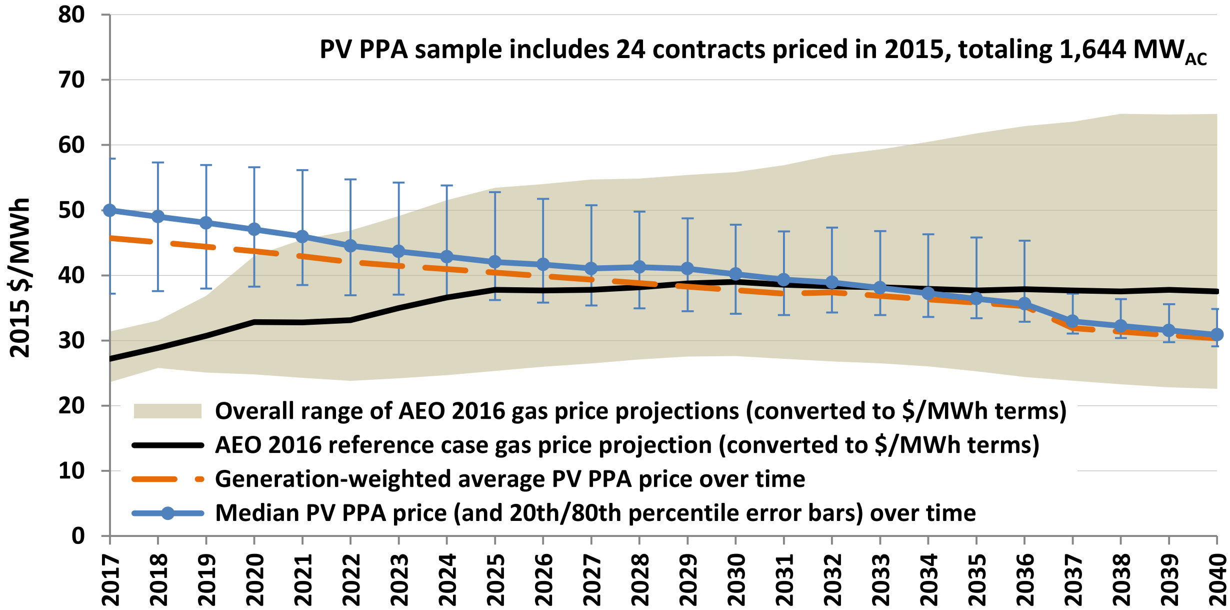


Figure 23. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

On a levelized basis (in real 2015 dollars) from 2017 through 2040, the PV PPA prices come to $42.9/MWh (median) and $40.4/MWh (generation-weighted average), compared to $34.8/MWh for the reference case fuel cost projection, suggesting that the drop in long-term gas price expectations over the past year has made it more difficult for PV to compete with *existing* gas-fired generation. That said, it is important to recognize that the PV PPA prices shown in Figure 23 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.

Moreover, as noted above, the comparison laid out in Figure 23 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 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 $29-$54/MWh to the levelized cost of energy from a combined-cycle gas plant (Lazard 2015).

On the other hand, Figure 23 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 widely known that the market value 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 not considered here.

3. Utility-Scale Concentrating Solar Power (CSP)

This chapter largely follows the same format as the previous chapter, but focuses on CSP rather than PV projects.[49] Isolating these two different technologies in this way is new to this fourth edition of the report, and the split has been undertaken in an effort to simplify reporting and enable 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, as they have been in previous editions, we have endeavored to include reference data points from our PV sample in many of the CSP-focused graphs in this chapter.

3.1 Technology and Installation Trends Among the CSP Project Population (16 projects, 1,781 MW_{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 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 in the past three years, there are currently no other major CSP projects moving towards construction in the United States. Moreover, two of the oldest CSP plants in the United States—SEGS I and II, which came online in the mid-1980s—have been decommissioned over the past year, following 30 years of service, and their owner has applied for permits to replace these two plants with PV. The remaining SEGS plants (III-IX) are owned by a different entity and continue to operate.

Figure 24 overlays the location of every utility-scale CSP project in the LBNL population 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.[50] With the exception of the 2010 project in Florida (75 MW_{AC}), all other CSP projects in the United

[49] One notable exception is that this chapter does not include a section on O&M prices. As noted in Section 2.3, we only have empirical O&M cost data for a single CSP project (the 75 MW_{AC} Martin trough project in Florida), and so opted to present those data along with the PV O&M cost data in Figure 13.

[50] 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).

States have been deployed in California (1,237 MW_{AC}) and the Southwest (250 MW_{AC} in Arizona and 179 MW_{AC} in Nevada).

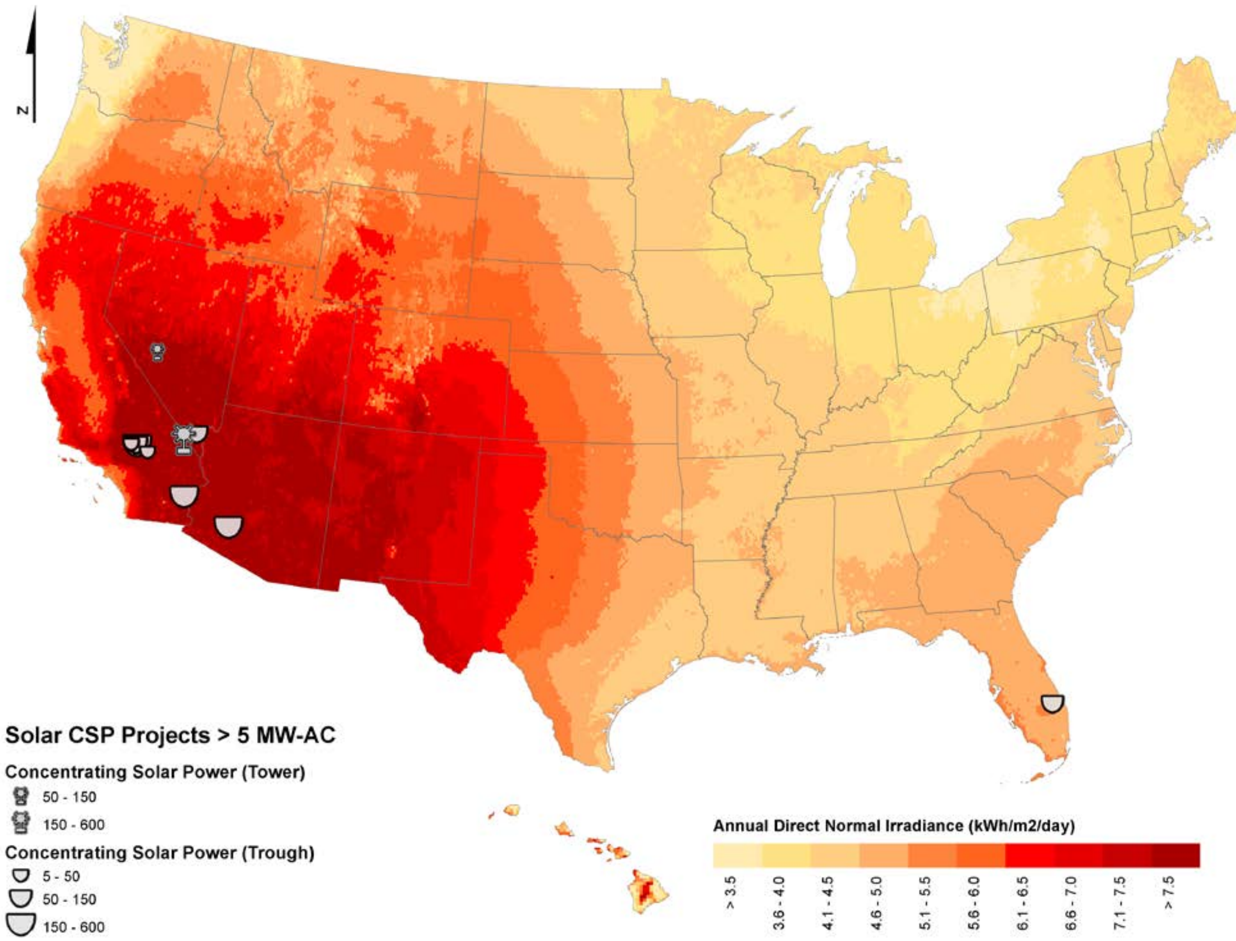


Figure 24. Map of Direct Normal Irradiance (DNI) and Utility-Scale CSP Project Locations

3.2 Installed Project Prices (7 projects, 1,381 MW_{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 2015 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 towers without long-term storage, the other just featuring one tower but with 10 hours of molten salt storage).

Figure 25 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2015),[51] and also compares their installed prices to the median installed price of PV (from Figure 7) in each year from 2010 through 2015. 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 ($5.17/W$_{AC}$ vs. $6.22/W$_{AC}$). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $6.84/W$_{AC}$), 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 that features 10 hours of molten salt storage is the highest yet in our sample, at $8.86/W$_{AC}$.

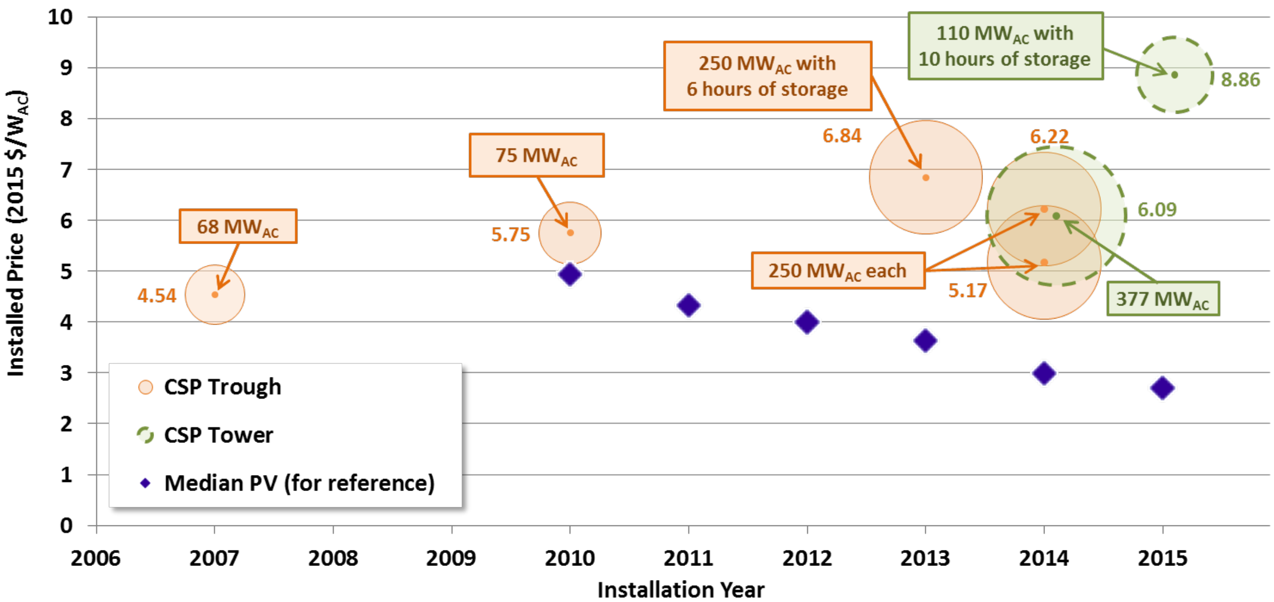


Figure 25. Installed Price of CSP Projects by Technology and Installation Year

In other words, CSP prices 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.

[51] The installed CSP prices shown in Figure 25 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

3.3 Capacity Factors (14 projects, 1,588 MW_{AC})

Figure 26 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 26[52]) 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.

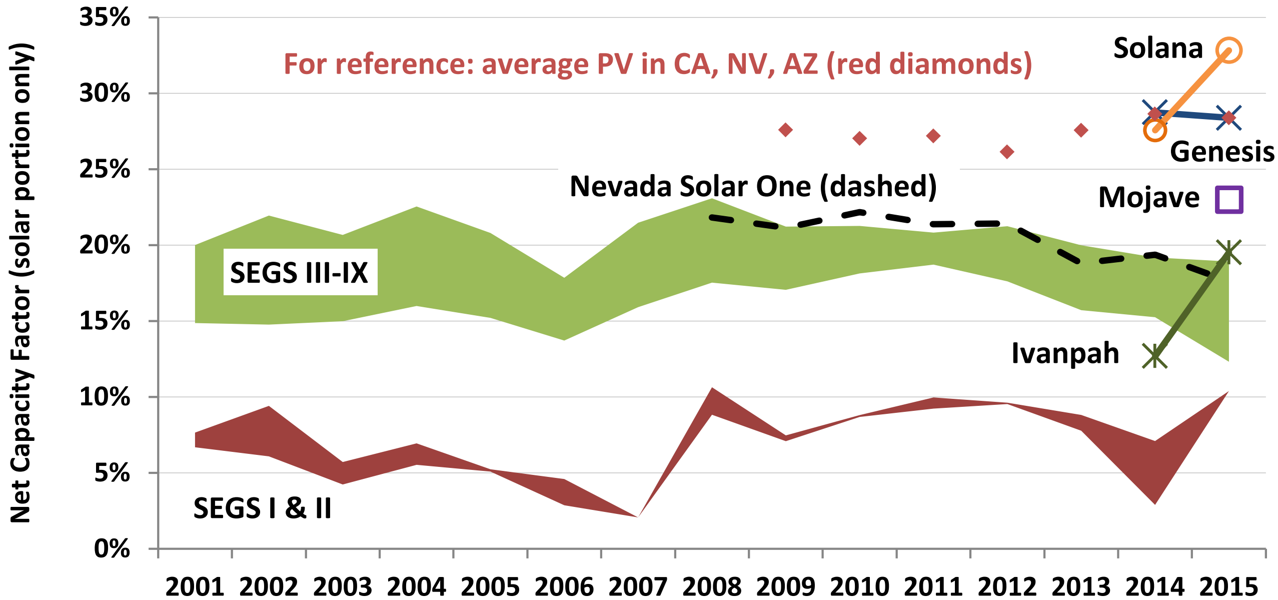


Figure 26. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

A few points are worth highlighting:

- Capacity factors at both Solana (trough with storage) and Ivanpah (power tower with no storage) improved significantly in 2015, to 32.8% and 19.5%, respectively. However, these second-year numbers are still below long-term expectations of 41% and 27%, respectively, and are expected to continue to improve in future years as these projects overcome typical start-up challenges and are fine-tuned for optimal performance (Danko 2015; Stern 2015).[53]

[52] 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 17.6% solar-only to 18.0% gas-included in 2015), 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 200-300 basis points in 2015, 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).

[53] Ivanpah documentation suggests that this initial ramp-up could last as long as four years (Danko 2015). Throughout this section, long-term, steady-state capacity factor expectations are drawn from either the sources cited, or in some cases from documentation surrounding DOE loan guarantees that were provided to several CSP projects.

That said, on May 19, 2016, misaligned heliostats caused a portion of Ivanpah's Unit 3 tower to catch on fire, requiring roughly one-third of the plant's capacity to come offline. Although repairs were not expected to take long (a matter of weeks rather than months), Unit 3 had not yet returned to service at the time of writing. However brief it may be, this unplanned outage will make it more difficult for Ivanpah to comply with the terms of forbearance agreements that one of the plant's offtakers, Pacific Gas & Electric, provided in early 2016; these agreements gave Ivanpah up to an additional year to reach minimum performance levels required in the PPAs.

- Genesis (250 MW_{AC} trough with no storage) essentially maintained its 2014 capacity factor into 2015 (at 28.4%, right on expectations), while the slightly newer but otherwise very similar Mojave project (also a 250 MW_{AC} trough with no storage) posted a 2015 capacity factor of 23.0% (below expectations of 28%).
- Both of these newer trough projects, however, performed significantly better in 2015 than the existing fleet of nine older trough projects in the sample, including the eight SEGS plants (totaling 362 MW_{AC}, excluding the 30 MW_{AC} SEGS II project that was decommissioned in 2014) that have been operating in California for more than twenty years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[54] Nearly all of these projects have experienced lower solar-only capacity factors since 2012 (i.e., from 2013-2015). This decline is potentially attributable in part to inter-year variations in the solar resource, which was reportedly below average in California and the Southwest (where these projects are located) during the past three summers (3Tier 2013; Vaisala 2014; Vaisala 2015; Vaisala 2016).
- With the exception of the Solana and Genesis projects, all other CSP projects have had capacity factors that fall below that of the average PV project across California, Nevada, and Arizona. Genesis essentially matched the average PV capacity factor in both 2014 and 2015, while Solana—which has 6 hours of storage capability—exceeded the PV average by more than 4 percentage points in 2015.

Looking ahead, the 110 MW Crescent Dunes project in Nevada (with 10 hours of storage) was placed in service in late 2015 after a prolonged commissioning process, and so will enter our sample in next year's edition of this report. Additionally, several of the newer projects that have been gradually ironing out teething issues under a long-term ramp-up schedule should continue to mature over the next few years (Ivanpah's May 2016 fire notwithstanding).

[54] 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.

3.4 Power Purchase Agreement (PPA) Prices (6 projects, 1,301 MW_{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 27 (along with the de-emphasized PV PPA price sample, for reference). The sixth, Nevada Solar One, is excluded because its PPA was executed in late-2002 (and later amended in 2005), which is off the scale of the x-axis; its levelized PPA price of ~$190/MWh (in real 2015 dollars) is the highest in our sample, though not by much.

Although most of these CSP contracts appear to have been competitive with PV at the time they were executed, PPA prices from utility-scale PV projects have since 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 or converted to PV technology.

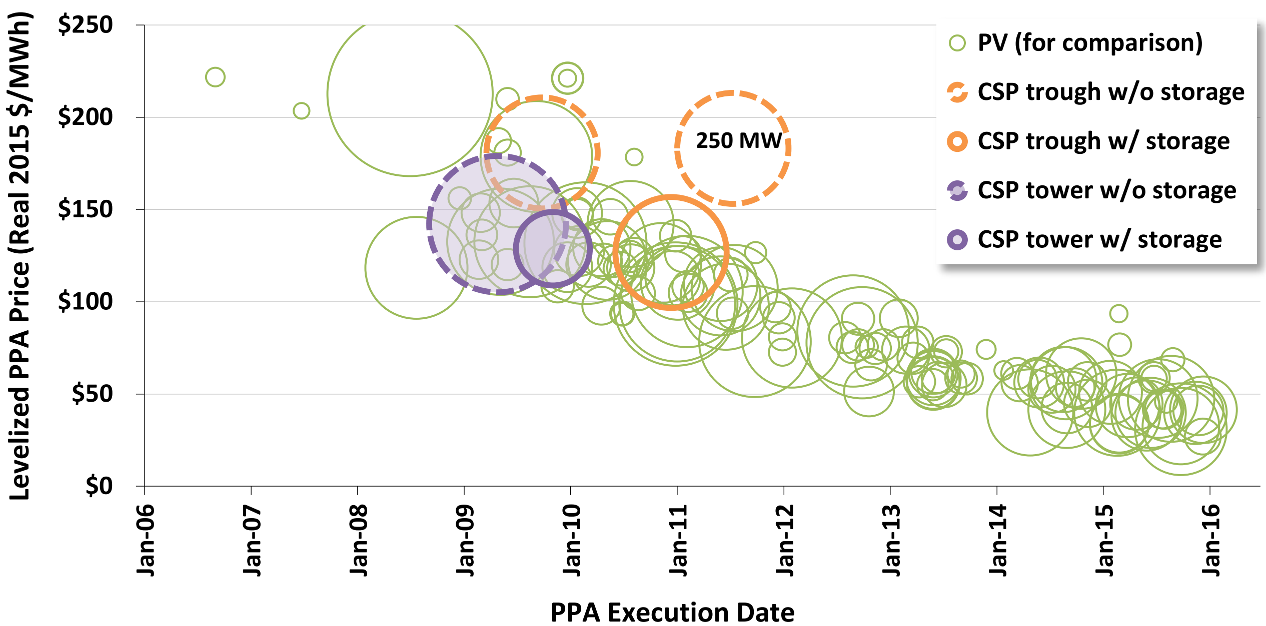


Figure 27. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

4. Conclusions and Future Outlook

This fourth 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 since 2007-2009, relatively modest O&M costs, solid performance with improving capacity factors, and record-low PPA prices of around \$30/MWh (levelized, in real 2015 dollars) in a few cases and under \$50/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 recent years—e.g., deploying several large projects featuring new trough and power tower technologies and demonstrating thermal storage capabilities—but is finding it difficult to compete in the United States with increasingly low-cost PV.[55]

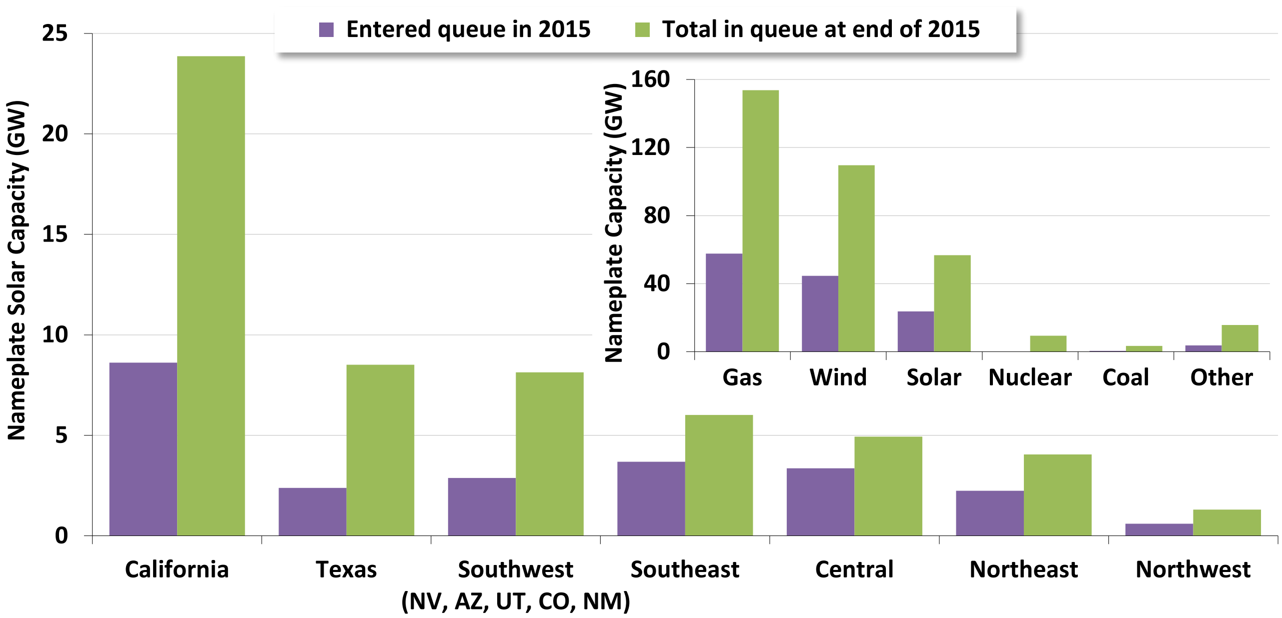
Looking ahead, December 2015's long-term extension of the 30% ITC through 2019 (along with the switch to a "start construction" rather than "placed in service" deadline), with a gradual phase down to 10% thereafter, should ensure continued momentum for the foreseeable future. Data on the amount of utility-scale solar capacity in the development pipeline support this view, and also suggest a significant expansion of the industry—both in terms of volume and geographic distribution—in the coming years. For example, Figure 28 shows the amount of solar power (and, in the inset, other resources) working its way through 35 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2015.[56] 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[57]—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.

[55] Avian mortality has also emerged as an unexpected potential challenge to power tower technology in particular, but also to large PV projects that, from a distance, can reportedly resemble bodies of water and attract migrating waterfowl that are injured or killed while attempting to land in the solar field.

[56] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas (ERCOT), Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Southern Company, NV Energy, PacifiCorp, Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Duke/Progress Energy, Public Service Company of Colorado, Public Service Company of New Mexico, and 20 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 about 86% of the U.S. total. Figure 28 only includes projects that were active in the queue at the end of 2015 but that had not yet been built; suspended projects are not included.

[57] 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.

At the end of 2015, there were 56.8 GW of solar power capacity (of any type—e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report—***more than five times the installed utility-scale solar power capacity in our entire project population at that time.*** These 56.8 GW (23.8 GW of which first entered the queues in 2015) represented 16% of all generating capacity within these selected queues at the time, in third place behind natural gas at 44% and wind at 31% (see Figure 28 inset). The end-of-2015 solar total is also more than 12 GW higher than the 44.6 GW of solar that were in the queues at the end of 2014, suggesting that the solar pipeline has been more than replenished over the past year, despite the record amount of new solar capacity that came online (and therefore exited these queues) in 2015.



Source: Exeter Associates review of interconnection queue data

Figure 28. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 28 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides. Perhaps not surprisingly (given the map of solar resource and PV project location shown in Figure 3 earlier), 56% of the total solar capacity in the queues at the end of 2015 is within California (42%) and the Southwest region (14%). This combined 56% is down from 60% at the end of 2014 (and 80% at the end of 2013), however, and is yet another indication that the utility-scale solar market is spreading to new states and regions beyond California and the Southwest.

For example, Figure 29 shows how the amount of solar in these queues has changed overall and by region over the last three years, from 2013-2015. With the queues in California and the Southwest rather stagnant over this period, the strong growth in the aggregate amount of solar within all queues—from 39.5 GW at the end of 2013 to 56.8 GW at the end of 2015—has come primarily from the up-and-coming Texas, Southeast, Central, and Northeast regions.

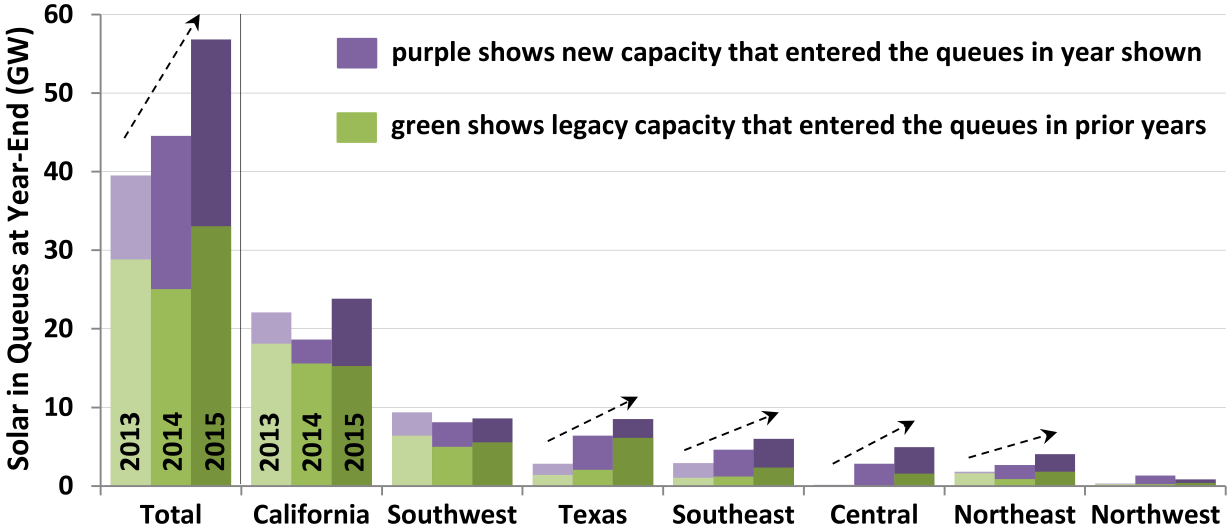


Figure 29. Solar Capacity in 35 Selected Interconnection Queues over Time

Though not all of the 56.8 GW of planned solar projects represented in Figure 29 will ultimately be built, as shown earlier in Figure 1, analysts expect nearly 12 GW to come online in 2016 alone, with many additional years of strong growth thereafter, driven in part by the long-term extension of the 30% ITC, 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 hope to collect and analyze in future editions of this report.

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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), broken out by data set:

Technology Trends: Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), interviews with project developers and owners, trade press articles

Installed Prices: 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

O&M Costs: FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors: FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices: FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

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Appendix

Total PV Population

State	Size Range (MW_{AC})	Year Range	2015 Sample		Total Population	
			No. of Projects	Total MW_{AC}	No. of Projects	Total MW_{AC}
AZ	5 - 290	2011 - 2015	4	122	30	1,110
AR	13 - 13	2015 - 2015	1	13	1	13
CA	6 - 586	2009 - 2015	35	1,332	107	5,047
CO	5 - 52	2007 - 2015	1	52	6	144
DE	10 - 12	2011 - 2012	-	-	2	22
FL	6 - 25	2009 - 2015	1	6	5	59
GA	6 - 81	2013 - 2015	6	177	9	230
HI	6 - 12	2012 - 2015	1	12	3	30
IL	8 - 20	2010 - 2012	-	-	2	28
IN	8 - 10	2013 - 2015	1	10	7	66
MD	6 - 20	2012 - 2015	1	9	4	48
MA	6 - 14	2014 - 2014	-	-	2	20
NV	10 - 255	2007 - 2015	4	349	14	673
NJ	5 - 18	2010 - 2015	4	41	21	189
NM	5 - 52	2010 - 2015	4	40	22	274
NY	32 - 32	2011 - 2011	-	-	1	32
NC	12 - 81	2010 - 2015	15	401	22	530
OH	8 - 10	2010 - 2011	-	-	2	18
PA	10 - 10	2012 - 2012	-	-	1	10
TN	8 - 16	2012 - 2014	-	-	3	39
TX	6 - 95	2010 - 2015	3	130	12	305
UT	50 - 80	2015 - 2015	2	130	2	130
Total	5 - 586	2007 - 2015	83	2,824	278	9,016

Total CSP Population

State	Size Range (MW_{AC})	Year Range	2015 Sample		Total Population	
			No. of Projects	Total MW_{AC}	No. of Projects	Total MW_{AC}
AZ	250	2013	-	-	1	250
CA	34 - 377	1986 - 2014	-	-	10	1,234
FL	75	2010	-	-	1	75
NV	69 - 110	2007 - 2015	1	110	2	179
Total	34 - 377	1986 - 2015	1	110	14	1,737

Key Report Contacts

Lawrence Berkeley National Laboratory:

Mark Bolinger
603-795-4937; MABolinger@lbl.gov

Joachim Seel
510-486-5087; JSeel@lbl.gov

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