Utility-Scale Solar 2014

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

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Lawrence Berkeley National Laboratory

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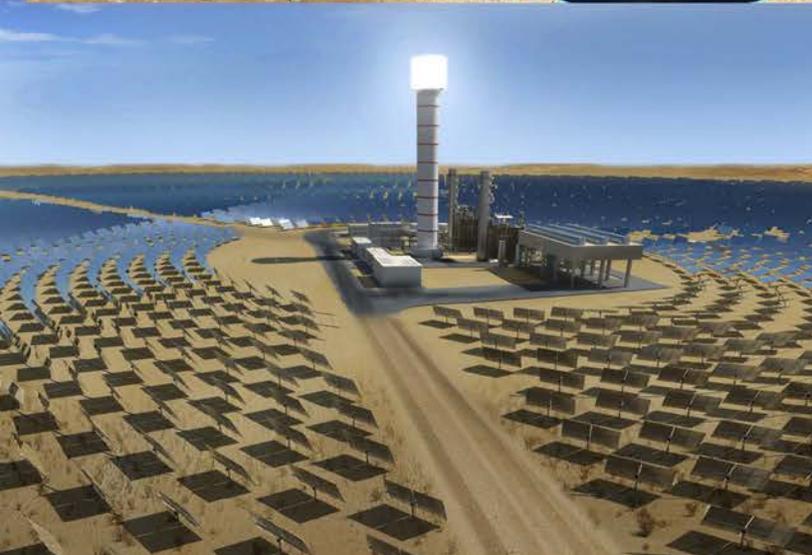
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List of Acronyms

AC……………………………………………………… Alternating Current

c-Si…………………………………………………… Crystalline Silicon

COD………………………………………………….. Commercial Operation Date

CPV………………………………………………….. Concentrated Photovoltaics

CSP…………………………………………………... Concentrated 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

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

Other than the nine Solar Energy Generation Systems ("SEGS") parabolic trough projects built in the 1980s, virtually no large-scale or "utility-scale" solar projects – defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar thermal power ("CSP") project larger than 5 MW_{AC} – existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in both 2013 and 2014 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a bit of a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including thermal storage – achieving commercial operation.

With this critical mass of new utility-scale projects now online and in some cases having operated for a number of years (generating not only electricity, but also empirical data that can be mined), the rapidly growing utility-scale sector is ripe for analysis. This report, the third edition in an ongoing annual series, meets this need through in-depth, annually updated, data-driven analysis of not just installed project costs or prices – i.e., the traditional realm of solar economics analyses – but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects in 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 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 price data analyzed later. For example, the use of tracking devices (overwhelmingly single-axis, though a few dual-axis tracking projects entered the population in 2014) continues to expand, particularly among thin-film (CdTe) projects, which had almost exclusively opted for fixed-tilt mounts prior to 2014. The quality of the solar resource in which PV projects are being built in the United States has increased on average over time, as most of the projects in the population (>90% in MW terms) are located in the Southwest where the solar resource is the strongest. That said, the market has also begun to expand outside of the Southwest, most notably in the Southeast. 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 also increased among more recent project vintages, as oversizing the array can boost revenue, particularly when time-of-delivery pricing is used. In combination, these trends should drive AC capacity factors higher among more recently built PV projects (a hypothesis confirmed by the capacity factor data analyzed in Chapter 5). Finally, 2014 also saw three new large CSP projects – i.e., two 250 MW trough projects and one 377 MW solar power tower project – achieve commercial operation; in contrast, no new CPV plants came online in 2014.

- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by more than 50% since the 2007-2009 period, from around $6.3/$W_{AC}$ to $3.1/$W_{AC}$ (or $5.7/$W_{DC}$ to $2.3/$W_{DC}$, all in 2014 dollars) for projects completed in 2014. The lowest-priced projects among our 2014 sample of 55 PV projects were ~$2/$W_{AC}$, with the lowest 20th percentile of projects having fallen considerably from $3.2/$W_{AC}$ in 2013 to $2.3/$W_{AC}$ in 2014.

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The three large CSP projects that came online in 2014 were priced considerably higher than our PV sample, ranging from $5.1/W$_{AC}$ to $6.2/W$_{AC}$.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs appear to have been in the neighborhood of $20/kW$_{AC}$-year, or $10/MWh, in 2014. CSP O&M costs are higher, at around $40-$50/kW$_{AC}$-year. These numbers 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 capacity-weighted average cumulative capacity factor across the entire PV project sample is 27.5% (median = 26.5% and simple average = 25.6%), but individual project-level capacity factors exhibit a wide range (from 14.8% to 34.9%) around these central numbers. This variation is based on a number of factors, including (in approximate decreasing order of importance): 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; and the type of modules used (e.g., c-Si versus thin film). Improvements in the first three of these factors have driven capacity-weighted average capacity factors higher by project vintage over the last three years – e.g., 29.4% among 2013-vintage projects, compared to 26.3% and 24.5% for projects built in 2012 and 2011, respectively. In contrast, two of the new CSP projects built in recent years – a trough project with storage and a power tower project – generated lower-than-expected capacity factors in 2014, reportedly due to startup and teething issues. Performance has subsequently improved at both projects during the first six months of 2015 (compared to the same period in 2014). Likewise, the two CPV projects in our sample seem to be underperforming, relative to both similarly situated PV projects and ex-ante expectations.

- ***PPA Prices:*** Driven by lower installed project prices, improving capacity factors, and – more recently – the rush to build projects in advance of the scheduled reversion of the 30% investment tax credit ("ITC") to 10% in 2017, levelized PPA prices for utility-scale PV have fallen dramatically over time, by a steady ~$25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples. Some of the most-recent PPAs in the Southwest have levelized PPA prices as low as (or even lower than) $40/MWh (in real 2014 dollars). At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a "fuel saver" alongside *existing* gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry through at least 2016. For example, at the end of 2014, there was at least 44.6 GW of utility-scale solar power capacity making its way through interconnection queues across the nation (though concentrated in California and the Southwest). Though not all of these projects will ultimately be built, presumably those that are built will most likely come online prior to 2017, given the scheduled reversion of the 30% ITC to 10% at the end of 2016. Even if only a modest fraction of the solar capacity in these queues meets that deadline, it will still mean an unprecedented amount of new construction in 2015 and 2016 – as well as a substantial amount of new data to collect and analyze in future editions of this report.

1. Introduction

The term "utility-scale solar" refers both to large-scale concentrating solar power ("CSP") projects that use several different technologies to produce steam used to generate electricity for sale to utilities,[1] and to large photovoltaic ("PV") and concentrating photovoltaic ("CPV") projects that typically sell wholesale electricity directly to utilities, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets). Although utility-scale CSP has a longer history than utility-scale PV (or CPV),[2] and has recently experienced a bit of a renaissance,[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 (6.4x), under construction (30.5x), or under development (12.1x) in utility-scale projects (SEIA 2015). PV's dominance follows explosive growth in recent years: utility-scale PV has been the fastest-growing sector of the PV market since 2007, and since 2012 has accounted for the largest share of the overall PV market in terms of new MW installed (with 3,934 MW_{DC} of new capacity added in 2014 alone – see Figure 1), a distinction that is projected to continue through 2016 (GTM Research and SEIA 2015).[4]
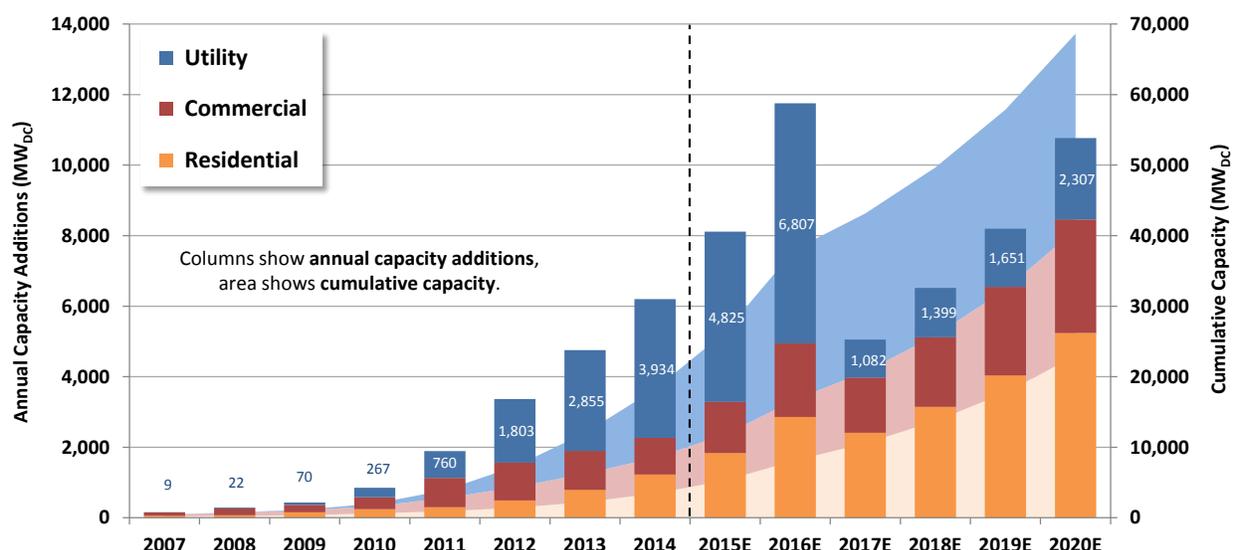
Source: GTM/SEIA (2010-2015), Tracking the Sun Database

Figure 1. Historical and Projected PV Capacity by Sector in the United States

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[1] Operating CSP projects most commonly use either parabolic trough or, more recently, power tower technology. CSP projects using other technologies, including compact linear Fresnel lenses and Stirling dish engines, have also been built in the United States, but largely on a pre-commercial prototype basis.

[2] Nine large parabolic trough projects totaling nearly 400 MW_{AC} have been operating in California since 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 2013/2014 as in the previous 28 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 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 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 market segments.

This rapidly growing utility-scale sector of the solar market is ripe for analysis. Historically, empirical analyses of solar economics have focused primarily on up-front installed costs or prices, and principally within the residential and commercial PV sectors (see, for example, Barbose and Darghouth 2015). But as more utility-scale projects have come online and begun to acquire an operating history, a wealth of other empirical data has begun to accumulate as well. Utility-scale solar projects can be mined for data on not only installed prices, but also project performance (i.e., capacity factor), operation and maintenance ("O&M") costs, and power purchase agreement ("PPA") prices ($/MWh) – all data that are often unavailable publicly, and are also somewhat less meaningful,[5] within the residential and commercial sectors.

This report is the third edition in an ongoing annual series that, each year, compiles and analyzes the latest empirical data from the growing fleet of utility-scale solar projects in the United States. In this third edition, we maintain our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box below describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). Within this subset of solar projects, the relative emphasis on different solar technologies within the report largely reflects the distribution of those technologies in the broader market – i.e., most of the data and analysis naturally focuses on PV given its large market share (78% of cumulative installed capacity), but CPV (<1%) and CSP (21%) projects are also included where useful data are available.

The report proceeds as follows. First, Chapter 2 describes key characteristics of the overall utility-scale solar project population from which the data samples that are analyzed in later chapters are drawn, with a goal of identifying underlying technology trends that could potentially influence trends in the data analyzed in later chapters. The remainder of the report analyzes the cost, performance, and price data samples in a logical order: up-front installed costs or prices are presented in Chapter 3, followed by ongoing operating costs and performance (i.e., capacity factor) in Chapters 4 and 5, all of which influence the PPA prices that are reported and analyzed in Chapter 6. Chapter 7 concludes with a brief look ahead.

Data sources are diverse and vary by chapter depending on the type of data being presented, but in general include the Federal Energy Regulatory Commission ("FERC"), the Energy Information Administration ("EIA"), state and federal incentive programs, state and federal

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[5] For example, even if performance data for residential systems were readily available, they might be difficult to interpret given that residential systems are often partly shaded or otherwise constrained by roof configurations that are at sub-optimal tilt or azimuth. Utility-scale projects, in contrast, are presumably less constrained by existing site conditions and better able to optimize these basic parameters, thereby generating performance data that are more normalized and easier to interpret. Similarly, even if known, the price at which third-party owners of residential PV systems sell electricity to site hosts is difficult to interpret, not only because of net metering and other state-level incentives that can affect the price, but also because residential PPAs are often priced only as low as they need to be in order to present an attractive value proposition relative to retail electricity prices (this is known as "value-based pricing"). In contrast, utility-scale solar projects must often compete (policy incentives notwithstanding) for PPAs against other generating technologies within competitive wholesale power markets, and therefore tend to offer PPA prices that reflect the minimum amount of revenue needed to recoup the project's initial cost, cover ongoing operating expenses, and provide a normal rate of return (this is known as "cost-plus" pricing). Whereas cost-plus pricing data provide useful information about the amount of revenue that solar needs in order to be economically viable in the market, value-based PPA price data are somewhat less useful in this regard, in that they often reflect the "price to beat" more than the lowest possible price that could be offered.

regulatory commissions, industry news releases, trade press articles, and communication with project owners and developers. Sample size also varies by chapter, and not all projects have sufficiently complete data to be included in all data sets. All data involving currency are reported in constant or real U.S. dollars – in this edition, 2014 dollars[6] – and all PPA price levelization uses a 7% real annual discount rate.

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, the same PV modules 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 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$_{AC}$.

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 in Chapter 6). 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.

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[6] Conversions between nominal and real dollars use the implicit 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 2015*.

Finally, we note that this report complements several other related studies and ongoing research activities, all funded as part of 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. For reference, this related work is briefly described in the text box below.

Related National Lab Research Products

Utility-Scale Solar is produced in conjunction with several related and ongoing research activities:

- *Tracking-the-Sun* is a separate annual report series produced by LBNL that focuses on residential and commercial solar and includes trends and analysis related to PV project pricing.

- *The Open PV Project* (openpv.nrel.gov) is an online data-visualization tool developed by the National Renewable Energy Laboratory (NREL) that incorporates data from *Tracking the Sun* and *Utility-Scale Solar*.

- *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections* is an annual briefing produced jointly by NREL and LBNL that provides a broad overview of PV pricing trends, based on ongoing research activities at both labs.

- *In-Depth Statistical Analyses* of PV pricing data by researchers at LBNL and several academic institutions seek to further illuminate PV pricing dynamics and the underlying drivers, using more-refined statistical techniques.

These and other solar energy publications are available at: **http://emp.lbl.gov/projects/solar**

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2. Technology Trends Among the Project Population

Before diving into project-level data on installed prices, operating costs, capacity factors, and PPA prices, this chapter analyses trends in utility-scale solar project technology and configurations among the *entire population* of projects from which later data samples are drawn. This population consists of 209 ground-mounted PV, CPV and CSP projects, each larger than 5 MW$_{AC}$ and with an aggregate capacity of 7,910 MW$_{AC}$, that had achieved full commercial operation within the United States by the end of 2014.[7] The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, and/or price data presented and discussed in later chapters. As with the data samples explored in later chapters, the total project population is broken out and described here by technology type – first PV (including CPV) and then CSP. 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, unless otherwise noted.

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 this chapter, and portrayed in Figure 5). 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] With the exception of Chapter 6, which examines PPA prices for both online and planned projects, we do not include projects that have not yet achieved full commercial operation, unless multiple years lie between consecutive phases (in which case project development is more akin to the development of separate projects). One implication of this approach is that projects are attributed in their entirety to the year in which their last phase comes online, even though they may have been under construction (and even partially operating) for several years. We chose this approach because certain important project characteristics (such as project prices) are usually only reported for a project as a whole, rather than for its individual phases.

PV (194 projects, 6,236 MW$_{AC}$)

At the end of 2014, 194 PV projects totaling 6,236 MW$_{AC}$ were fully online in the United States and met the definition of utility-scale used in this report (ground-mounted and larger than 5 MW$_{AC}$).[8] These 194 projects, the first of which were installed in 2007, make up the total population of PV projects from which data samples are drawn in later chapters of this report. More than half of this capacity – i.e., 63 projects totaling 3,218 MW$_{AC}$ – achieved commercial operation in 2014.

Figure 2 breaks out this capacity by module type and project configuration – i.e., projects that use crystalline silicon ("c-Si") versus thin-film modules,[9] and projects mounted at a fixed tilt instead of on a tracking device that follows the position of the sun.[10] Though thin-film modules powered two-thirds of the new utility-scale PV capacity installed in 2010, c-Si projects dominated in 2011, 2012, and 2013, accounting for 70% of all new utility-scale PV capacity installed in those three years. This trend reversed yet again in 2014, however, when the 6 largest projects built all used thin-film modules, resulting in a 70% market share.

Among the entire project sample that came online in 2014 (including both c-Si and thin-film projects) the number of projects using solar tracking technologies increased slightly from 55% in 2013 to 58% in 2014. In capacity terms, however, tracking projects decreased to 41% of new 2014 capacity (from 56% in 2013) as the three largest 2014 projects (Topaz, Agua Caliente and Desert Sunlight) all used fixed-tilt racking.

Notably, 12 of the 16 thin-film projects that came online in 2014 use single-axis tracking – a significant departure from just 2 tracking thin-film projects built prior to 2014. This shift is largely attributable to First Solar's acquisition of RayTracker's single-axis tracking technology back in 2011; First Solar deployed this technology in all but its four largest projects in 2014.[11] Tracking has historically not been as common among thin-film projects, largely because the lower efficiency of thin-film relative to c-Si modules requires more land area per nameplate MW – an expense that is exacerbated by the use of trackers (that said, the efficiency of First Solar's CdTe modules has been increasing over time).

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[8] Because of differences in how "utility-scale" is defined (e.g., see the text box on page 3), 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 2015) of the amount of utility-scale PV capacity online at the end of 2014.

[9] Module manufacturer First Solar, which produces CdTe modules, accounts for all new thin-film capacity added to the project population in 2014.

[10] All but two of the PV projects in the population that use tracking systems use single-axis trackers (which track the sun from east to west each day). In contrast, two recently built PV projects in Texas, along with the two CPV projects and one CSP power tower project (described later), 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.

[11] The very large Topaz, Agua Caliente, and Desert Sunlight projects had all executed PPAs and were well under development (and perhaps even construction) prior to the acquisition of RayTracker. The large Antelope Valley project was in a similar position, but did manage to incorporate tracking in roughly 20% of the project.
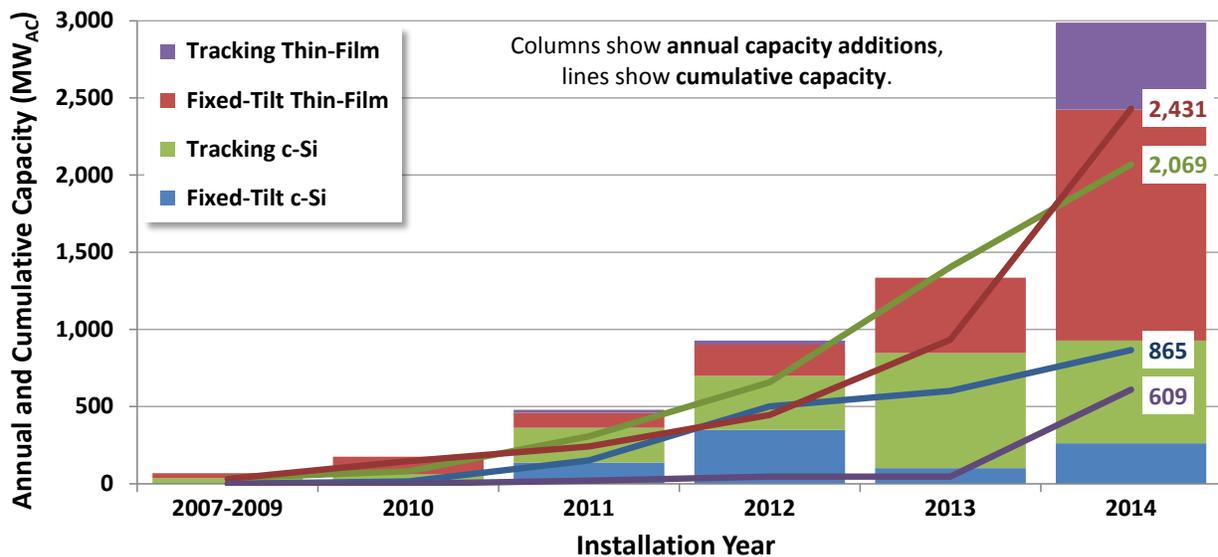
Figure 2. Capacity Shares of PV Module and Mounting Configurations by Installation Year

Figure 2 also breaks down the composition of *cumulative* installed capacity as of the end of 2014. Fixed-tilt thin-film (2,431 MW$_{AC}$) held a slight lead over tracking c-Si (2,069 MW$_{AC}$, but spread across more than twice as many projects), while fixed-tilt c-Si (865 MW$_{AC}$) and tracking thin-film (609 MW$_{AC}$) followed more distantly. Overall, the total project population as of the end of 2014 was split fairly evenly (in capacity terms) between fixed-tilt (55%) vs. tracking (45%) projects, and thin-film (53%) vs. c-Si projects (47%).

Figure 3 overlays the location of every utility-scale solar project in the LBNL population (including CPV and CSP projects) on a map of solar resource strength, as measured by global horizontal irradiance ("GHI").[12] Not surprisingly, most of the projects (and capacity) in the population are located in the southwestern United States,[13] 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) encourage utility-scale solar development. As shown, however, utility-scale solar projects have also been built in various states along the east coast and in the Midwest, where the solar resource is not as strong; these installations have largely been driven by state renewable portfolio standards. Though there are obviously some exceptions, Figure 3 also shows a preponderance of tracking projects (both c-Si and, more recently, thin-film) in the high-GHI Southwest, compared to primarily fixed-tilt c-Si in the lower-GHI East.

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[12] 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).

[13] As of the end of 2014, the Southwest (defined rather liberally here to include CA, NV, AZ, UT, CO, NM, and TX) accounted for 90% of the population's cumulative PV capacity, and 96% of its CSP capacity.
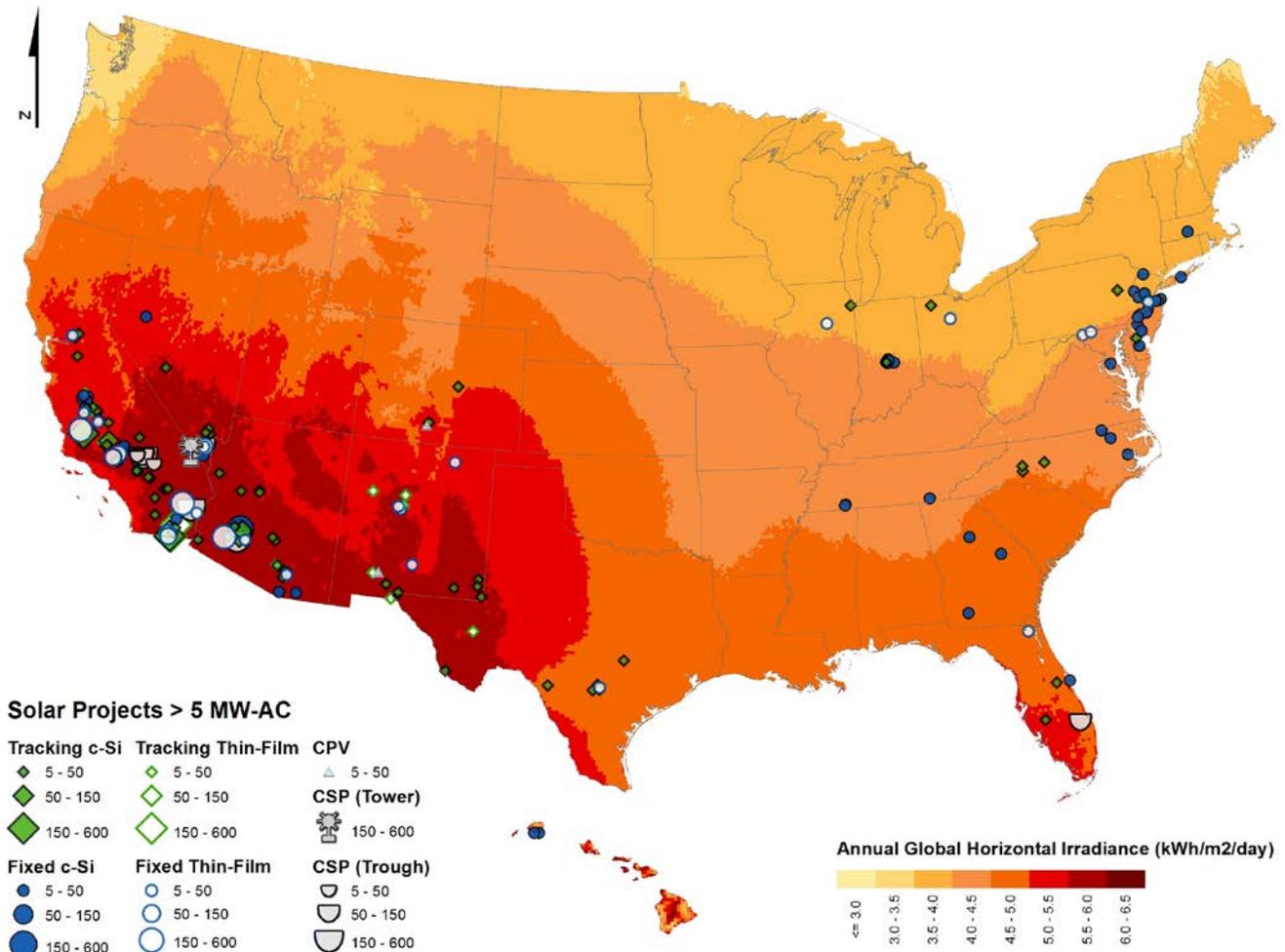
Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale Solar Project Locations

While Figure 3 provides a static view of *where* and in what type of solar resource regime utility-scale solar projects within the population are located, 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 any observed trend in project-level capacity factors by project vintage (explored later in Chapter 5).

Figure 4 addresses this question by showing the capacity-weighted average GHI (in kWh/m^2/day) among PV projects built in a given year, both for the entire PV project population (solid black line) and broken out by fixed-tilt vs. tracking projects. Across the entire population, the average GHI has increased steadily over time, suggesting a relative shift in the population towards projects located in the high-GHI Southwest. Although the capacity-weighted averages for fixed-tilt and tracking projects are not too dissimilar, the 20th percentiles are markedly different, with fixed-tilt projects stuck around 4 kWh/m2/day, in contrast to much higher (and generally increasing by vintage) 20th percentile values for tracking projects. The wide distribution of fixed-tilt projects reflects the fact that – as shown previously in Figure 3 – most

projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects are also present in the high-GHI Southwest (often using CdTe thin-film technology, perhaps due to its greater tolerance for high-temperature environments[14]). Tracking projects, meanwhile, are concentrated primarily in the Southwest.
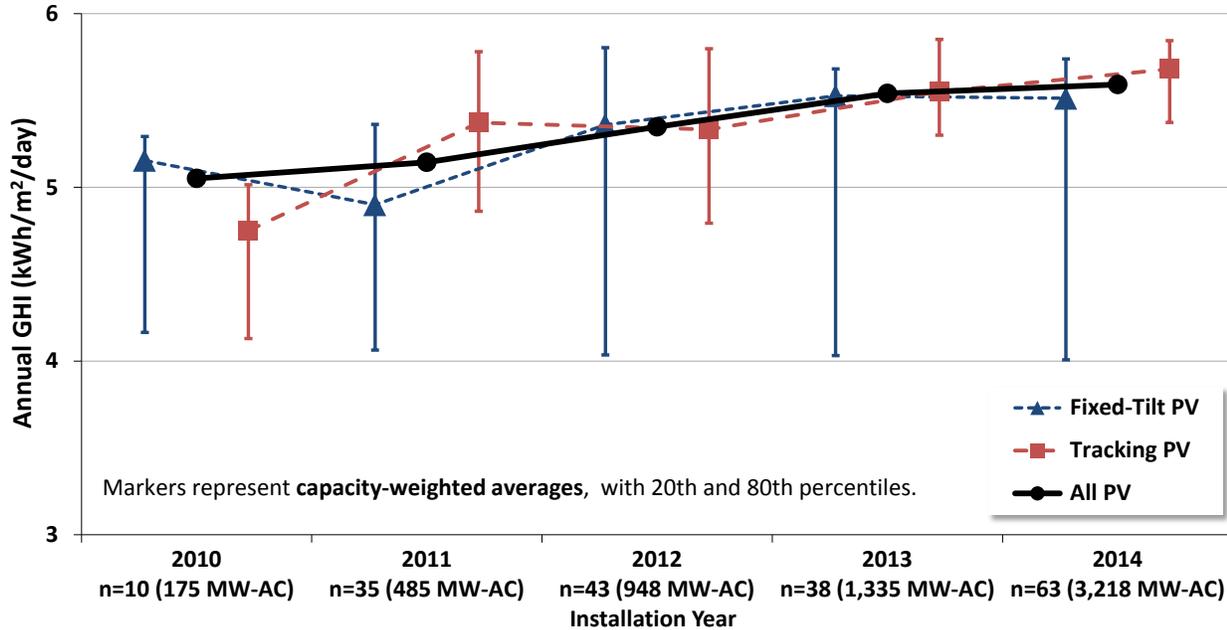

Figure 4. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

A second project-level characteristic that influences both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[15] With the cost of PV modules having dropped precipitously in recent years (and more rapidly than the cost of inverters), and with some utilities (particularly in California) offering time-varying PPA prices that favor generation during certain daylight hours, including late afternoon, many developers have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which – like tracking – boosts the capacity factor,[16] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production

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[14] The vast majority of thin-film capacity in the project population uses CdTe modules from First Solar. On its web site (First Solar 2015), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at module temperatures above 25° C (77° F) – i.e., conditions routinely encountered in the high-insolation Desert Southwest region.

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

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

periods[17]). Particularly under time-varying PPA prices that extend peak pricing into the morning and/or evening hours, 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 just the high-insolation summer months).

Figure 5 shows the capacity-weighted average ILR among projects built in each year, both for the total PV project population (solid black line) and broken out by fixed-tilt versus tracking projects. Across all projects, the average ILR has increased significantly over time, from around 1.2 for projects built in 2010 to 1.31 in 2013. In 2014, the capacity-weighted average declined slightly to 1.28, as a number of very large projects that had been under construction for several years finally came online; some of these projects have lower ILRs than their more-recently designed counterparts. But the 2014 median ILR (not shown) remained unchanged from 2013, at 1.29.
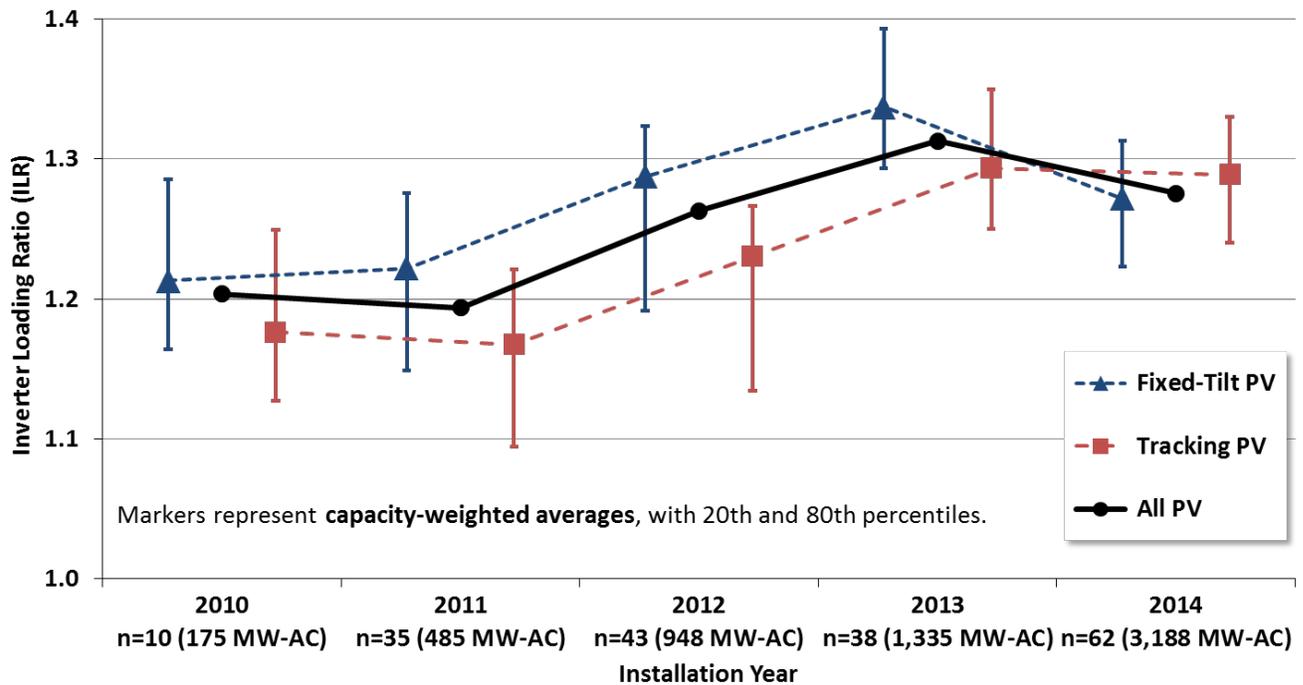
Figure 5. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

With the exception of 2014 (again, influenced by these few large fixed-tilt projects with lower ILRs), fixed-tilt projects generally feature higher ILRs than tracking projects. 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.

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[17] Power clipping, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the turbines) or feathering a wind turbine blade. In the case of solar, however, clipping occurs electronically rather than physically: as the DC input to the inverter approaches maximum capacity, the inverter moves away from the maximum power point so that the array operates less efficiently (Advanced Energy 2014, Fiorelli and Zuercher-Martinson 2013). In this sense, clipping is a bit of a misnomer, in that the inverter never really even "sees" the excess DC power – rather, it is simply not generated in the first place. Only *potential* generation is lost.

All else equal, Figure 4 and Figure 5 suggest that project-level capacity factors should increase among more recently built PV projects. This hypothesis is explored further (and confirmed) in Chapter 5.

CSP (15 projects, 1,673 MW$_{AC}$)

After the nearly 400 MW$_{AC}$ SEGS I-IX parabolic trough build-out 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 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), and the 250 MW$_{AC}$ Solana trough project in Arizona in 2013 (which also includes 6 hours of molten salt storage capacity).

In 2014, three additional CSP projects came online in California: two more trough projects without storage (Genesis and Mojave, each 250 MW$_{AC}$) and the first large-scale "solar tower" project in the United States (Ivanpah at 377 MW$_{AC}$). A second 110 MW$_{AC}$ solar tower project with 10 hours of built-in thermal storage – Crescent Dunes in Nevada – has finished major construction activities but, at the time of writing, was still in the commissioning phase and not yet commercially online, and is thus excluded from this report. In the wake of this unprecedented buildout – totaling 1,127 MW$_{AC}$ – of new CSP capacity in the past two years, there are currently no other major CSP projects moving towards construction in the United States.

3. Installed Prices

This chapter analyzes installed price data from a large sample of the overall utility-scale solar project population described in the previous chapter.[18] Specifically, LBNL has gathered installed price data for 176 utility-scale (i.e., ground-mounted and larger than 5 MW$_{AC}$) solar projects totaling 7,145 MW$_{AC}$ and built between 2007 and 2014. The price sample is dominated by 170 PV projects (including 2 CPV projects) that total 5,874 MW$_{AC}$ (i.e., PV accounts for 97% of all projects and 82% of all capacity in the installed price sample). It also includes 6 CSP projects totaling 1,270 MW$_{AC}$, consisting of the more recently built projects described in the previous chapter (rather than the older SEGS projects).

In general, only fully operational projects for which all individual phases were in operation at the end of 2014 are included in the sample[19] – i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2015 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.[20] For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV (Feldman et al. 2015), and may differ from the average installed prices reported elsewhere (Bloomberg New Energy Finance 2015; Fu et al. 2015; GTM Research and SEIA 2015). A text box later in this chapter (see *Bottom-Up vs. Top-Down*) explores this issue in more detail.

This chapter analyzes installed price trends among the sample of utility-scale projects described above. 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. The chapter then provides an overview of installed prices for the six CSP projects in the sample. 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, trade press articles, and data previously gathered by the National Renewable Energy Laboratory (NREL). All prices are reported in real 2014 dollars.

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

[19] In contrast, later chapters of this report do present data for individual phases of projects that are online, or (in the case of Chapter 6 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

[20] 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 Chapter 6.

PV (170 projects, 5,874 MW$_{AC}$, including 2 CPV projects totaling 35 MW$_{AC}$)

LBNL's sample of 170 PV (and CPV) projects totaling 5,874 MW$_{AC}$ for which installed price estimates are available represents 87% of the total number of PV projects and 94% of the amount of capacity in the overall PV project population described in Chapter 2. Focusing just on those PV projects that achieved commercial operation in 2014, LBNL's sample of 55 projects totaling 3,052 MW$_{AC}$ represents 87% and 95% of the total number of 2014 projects and capacity in the population, respectively.

Figure 6 shows installed price trends for PV (and CPV) projects completed from 2007 through 2014 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 2015; GTM Research and SEIA 2015). As noted in the text box (*AC vs. DC*) at the beginning of Chapter 2, however, this report analyzes utility-scale solar in AC terms. Figure 6 shows installed prices both ways (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.
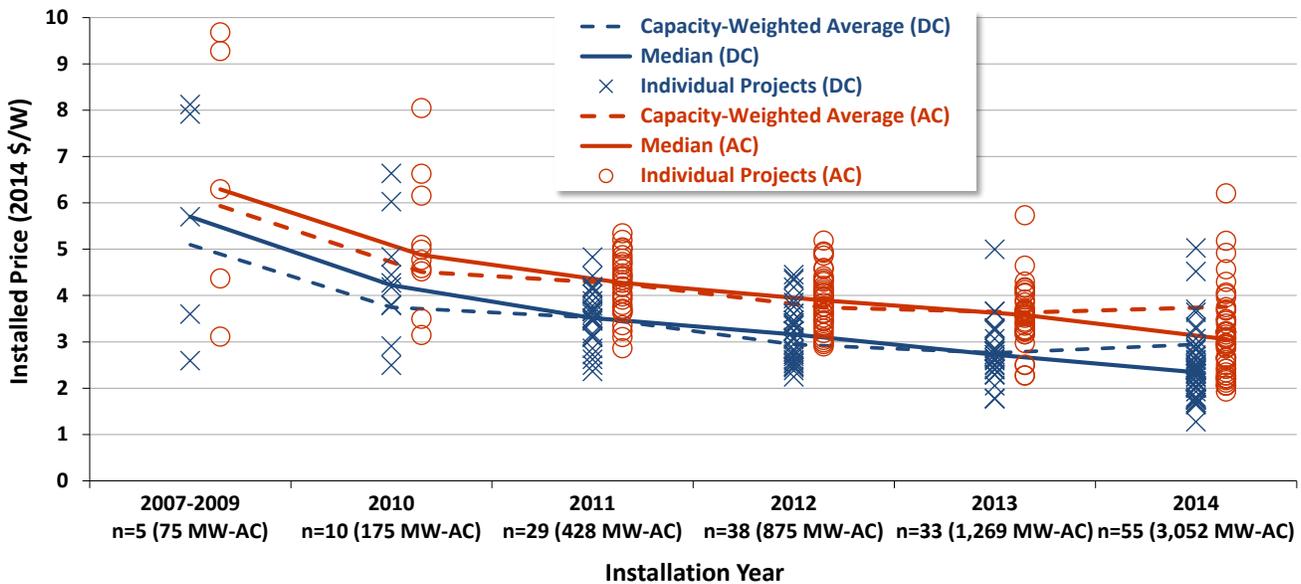
Figure 6. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

As shown, the median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to $3.1/W$_{AC}$ (or $2.3/W$_{DC}$) in 2014. This represents a price decline of more than 50% since the 2007-2009 period (and 37% since 2010). The lowest-priced projects among our 2014 sample of 55 PV projects were ~$2/W$_{AC}$, with the lowest 20th percentile of projects having fallen considerably, from $3.2/W$_{AC}$ in 2013 to $2.3/W$_{AC}$ in 2014.

In contrast, capacity-weighted average prices (dashed lines) have declined more slowly through 2013, and even increased slightly in 2014 to $3.8/W$_{AC}$ (or $2.9/W$_{DC}$). The divergence between median and capacity-weighted average prices in 2014 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 so only entered our sample in 2014). 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.[21] Although in general we prefer capacity-weighted averages over medians,[22] the next graph will focus on medians rather than capacity-weighted averages in order to avoid the apparent distortion seen in Figure 6 for 2014.

While median prices in the sample have generally declined over time, 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., 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.
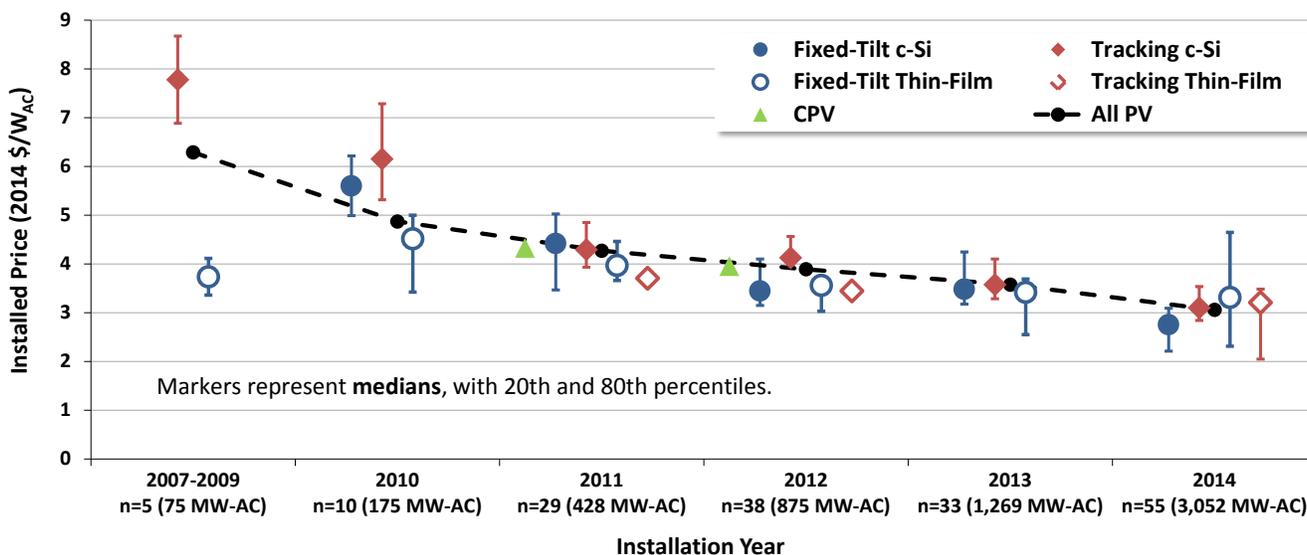
Figure 7. Installed Price of Utility-Scale PV and CPV Projects by Project Design and Installation Year

Figure 7 breaks out installed prices over time among these four combinations (and also includes the two CPV projects in the sample – but excludes several "hybrid" projects that feature a mix of

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[21] For example, within our PPA price sample (described later in Chapter 6), the longest span between PPA execution date (as a proxy for EPC contract execution date) and commercial operation date for projects that came online in 2014 is 5 ¾ years, with the average lag for systems larger than 100 MW_{AC} being 3 ¾ years, compared to 2¼ years for systems smaller than 100 MW_{AC}. Because of their size, very large projects dominate the capacity-weighted average price in 2014 (eight projects larger than 100 MW_{AC} represent 74% of the capacity additions, but only 12.5% of new projects, in 2014).

[22] 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 chapter – 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 (e.g., see Barbose and Darghouth 2015).

module and/or mounting types, and so do not fit neatly into these four combinations). In 2014, the median price was $2.8/W$_{AC}$ for fixed-tilt c-Si projects, $3.1/W$_{AC}$ for tracking c-Si projects, $3.3/W$_{AC}$ for fixed-tilt thin-film projects, and $3.2/W$_{AC}$ for tracking thin-film projects.

Trends of particular note include:

- Although projects using c-Si modules were more expensive than projects using thin-film modules (e.g., by ~$1.1/W$_{AC}$ on average in 2010 for fixed-tilt projects), the average installed price of fixed-tilt c-Si and thin-film projects has converged over time, and even reversed in 2014 when c-Si held a ~$0.6/W$_{AC}$ advantage over thin-film projects completed in the same year (although some smaller fixed-tilt thin-film projects are offered at prices similar to the cheaper c-Si projects). This convergence has been led by the falling price of c-Si modules over time. As the price of c-Si projects has converged with thin-film, the predominance of c-Si projects has grown in both the installed price sample and the broader population (although this is not necessarily true for total interconnected capacity, given several very large thin-film projects that came online in 2014).

- Tracking systems remain slightly more expensive than fixed-tilt systems within the sample – a difference of about $0.3/W$_{AC}$ in 2014 among c-Si projects. As shown later in Chapter 5, however, this higher up-front expenditure results in greater energy production. In contrast, fixed-tilt thin-film projects do not appear to have a similar cost advantage over tracking thin-film projects, though this may be attributable to the previously noted price lags associated with several very large fixed-tilt thin-film projects (as well as perhaps to the vertical integration of First Solar and RayTracker).

- The two high-concentration CPV projects built in 2011 and 2012 exhibit installed prices that are comparable to the average PV pricing in the sample (yet, as shown later in Chapter 5, these two CPV projects have not performed as well as the average PV project). One or more low-concentration CPV projects (e.g., SunPower's new C7 technology powering an Apple server farm in Nevada) will enter the sample in 2015, providing additional data points.

Differences in project size may also explain some of the variation in installed prices, as PV projects in the sample range from 5.1 MW$_{AC}$ to 585 MW$_{AC}$. Figure 8 investigates price trends by project size. To minimize the potentially confounding influence of price reductions over time, Figure 8 focuses on just those PV projects in the sample that became fully operational in 2014.
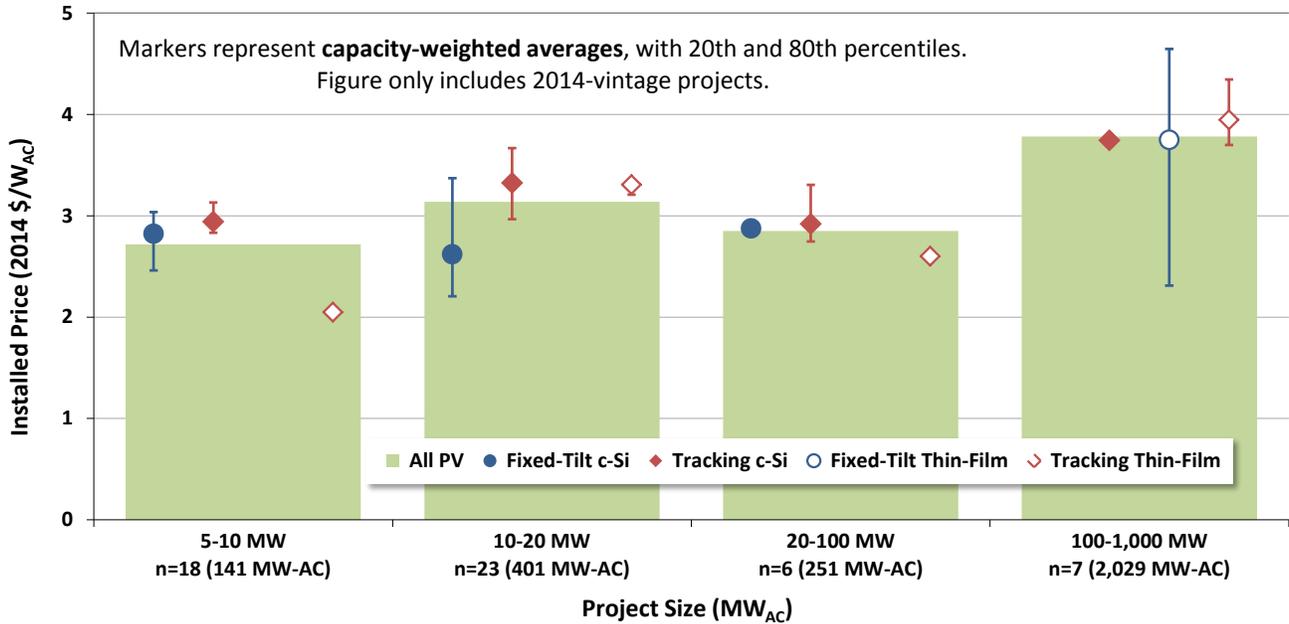
Figure 8. Installed Price of 2014 PV Projects by Size and Project Design

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 2014.[23] 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 shown in Figure 8, which range from 5 MW$_{AC}$ up to 100 MW$_{AC}$. One possible explanation for this lack of trend is that economies of scale may be limited primarily to projects smaller than 5 MW$_{AC}$ – which are excluded from our sample – given that the standardized and modular "power blocks" of module manufacturers like SunPower and First Solar are sized below this 5 MW$_{AC}$ threshold. Another possibility is potential inconsistency in what costs or prices are captured among projects; e.g., some of the larger projects may include interconnection and transmission costs that are not present (or at least not reported) for smaller projects.

More notable in Figure 8 are the price *penalties* for projects larger than 100 MW$_{AC}$; two factors may contribute to these apparent *dis*economies of scale for very large projects. As discussed earlier, 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. Moreover, these mega-scale projects – some of which involve more than 8 million modules and project sites of nearly 10 square miles – may face greater administrative, regulatory, and interconnection costs than do smaller projects.

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[23] These empirical findings more or less align with recent modeling work from NREL (Fu et al. 2015), which also finds only modest scale economies for a 100 MW project compared to a 10 MW project, and no additional scale economies for projects larger than 100 MW.

16

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

The installed prices analyzed in this chapter 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 recent publications (Fu et al. 2015; GTM Research and SEIA 2015; Bloomberg New Energy Finance 2015) 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, while bottom-up estimates provide more detail but rely on modeling.

This text box explores to what extent the two different types of price estimates are in alignment, and where any differences lie. To aid in this comparison, LBNL obtained a detailed project cost breakdown for one of the PV projects in its price sample: a 20 MW$_{AC}$ (25 MW$_{DC}$) single-axis tracking c-Si project that came online in the Southwest in 2014. The reported total installed price of this project – $2.37/W$_{DC}$ or $2.97/W$_{AC}$ – is comparable to other similar 2014 projects in the LBNL sample, suggesting that this project's detailed cost breakdown may be representative of other similar projects.
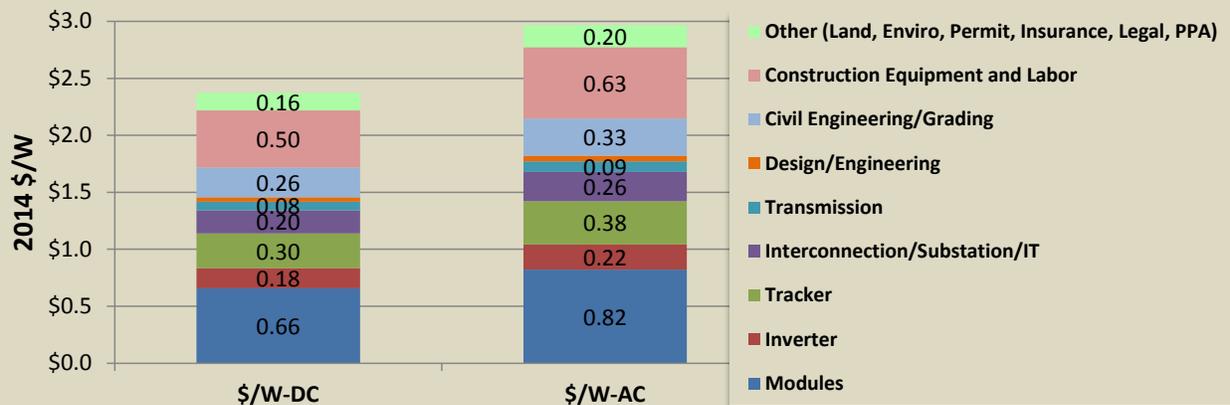
Representative Bottom-up Price of 2014 20 MW$_{AC}$ Single-Axis Tracking System

The original cost breakdown for this project reported costs in 67 different categories that, for ease of presentation, are grouped into 9 larger cost bins in the figure above. As shown, the three major hardware components account for almost half of total costs, with 28% ($0.66/W$_{DC}$ / $0.82/W$_{AC}$) coming from the modules, 13% ($0.30/W$_{DC}$ / $0.38/W$_{AC}$) from the tracking/racking system, and 7.5% ($0.18/W$_{DC}$ / $0.22/W$_{AC}$) from the inverters. Construction equipment and labor accounts for another 21% ($0.50/W$_{DC}$ / $0.63/W$_{AC}$), while 11% ($0.26/W$_{DC}$ / $0.33/W$_{AC}$) is attributable to civil engineering and grading.

The figure on the next page compares the cost breakdown for this seemingly representative project with modeled bottom-up estimates from NREL (Fu et al. 2015), BNEF (Bloomberg New Energy Finance 2015), and Greentech Media (GTM Research and SEIA 2015). Because each of these publications reports costs slightly differently, we had to create fairly broad (and hence rough) cost bins that reflect the "lowest common denominator" in order to compare them. In contrast to the rest of this report, costs in the next graph are shown exclusively in $/W$_{DC}$ to align with how they are reported in these other publications.
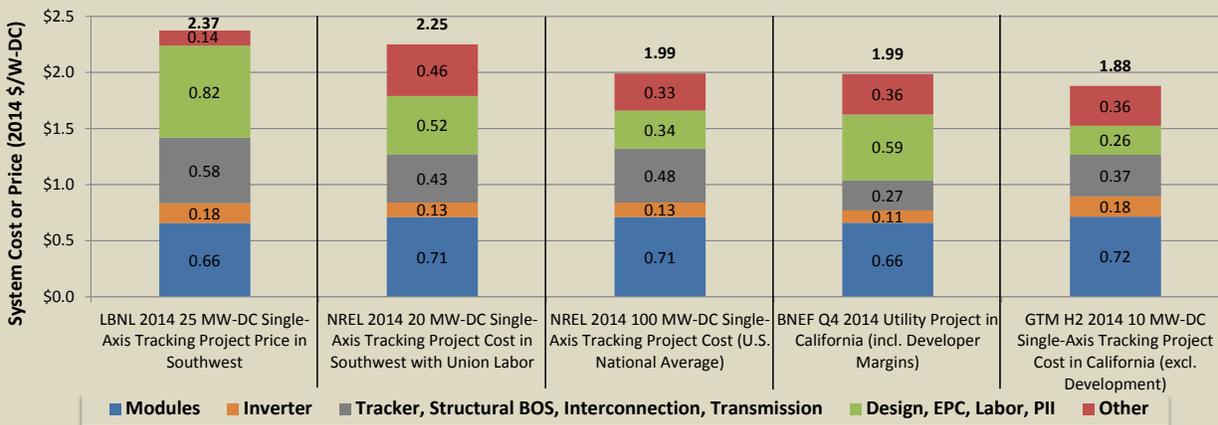
Comparison of Bottom-Up Utility-Scale PV Project Cost Estimates

As shown, the sample LBNL project has the highest installed price – despite reporting among the lowest module costs. That said, the total installed price of $2.37/W_{DC} is not too dissimilar from NREL's modeled bottom-up estimate of $2.25/W_{DC} for a similar project (i.e., a 20 MW_{DC} tracking c-Si project located in the Southwest and built with union labor). The other three estimates are all lower, with the NREL national and the BNEF model both arriving at about $2/W_{DC}. The GTM estimate is the lowest as it excludes development costs (captured by the LBNL empirical breakdown); meanwhile, GTM's relatively high inverter costs include the AC subsystem, which other estimates include within interconnection costs. Finally, there are probably other differences in costs captured by the various estimates (e.g., financing costs, developer profit margins, transaction costs) that impede straightforward comparisons.

Among cost categories, the largest discrepancy between the sample LBNL project and the modeled bottom-up prices comes from the category that includes project design, EPC, labor, and permitting, interconnection and inspection ("PII"). One potential explanation for this discrepancy is that the bottom-up models may be modeling current EPC (or other) costs for projects that will be built in the future, whereas the sample LBNL project achieved commercial operation in 2014 and may therefore reflect, for example, EPC costs from some time ago (e.g., from before the project entered the construction phase).

Although it's difficult to pin down the exact reason for the discrepancy in installed prices shown in the figure above, this analysis nevertheless highlights the potentially substantial variation between empirical top-down and modeled bottom-up installed price estimates (and even among the various modeled bottom-up price estimates themselves), as well as the importance of understanding what each price estimate represents.

CSP (6 projects, 1,270 MW$_{AC}$)

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other concentrated solar thermal power (CSP) projects, totaling 1,270 MWAC, that were commercially operational at the end of 2014 and larger than 5 MW$_{AC}$. Five of these six projects feature parabolic trough technology, while the sixth uses power tower technology (consisting of a total of 3 solar towers). Another large solar tower project that had finished major construction activities in early 2014 but that had not yet entered commercial operation by the end of 2014 has been excluded from the sample.

Figure 9 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2014),[24] and also compares their installed prices to the median installed price of PV (from Figure 6) in each year from 2010 through 2014. The small sample size makes it difficult to discern any trends. In 2014 alone, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($5.10/W vs. $6.16/W). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $6.76/W), while the 2014 power tower project was priced at the higher end of the range of the two trough projects. In general, CSP prices do not seem to have declined over time to any notable extent, in stark contrast to the median PV prices included in the figure.
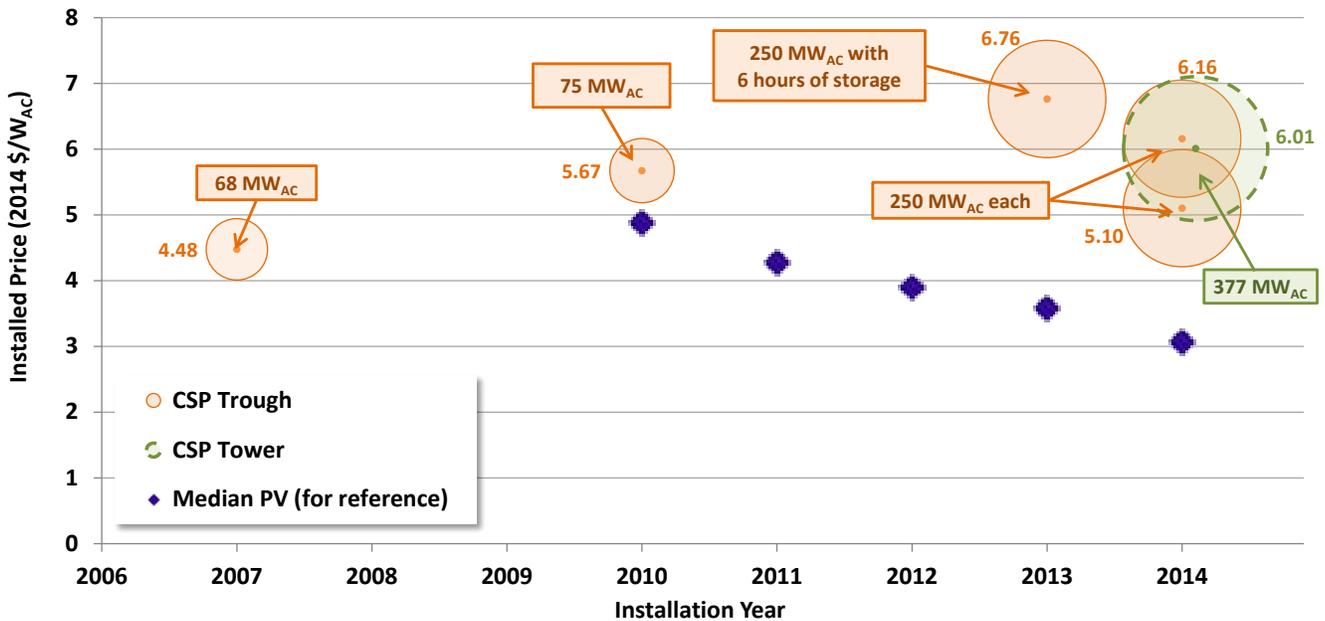
Figure 9. Installed Price of Utility-Scale CSP Projects by Technology and Installation Year

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[24] The installed CSP prices shown in Figure 9 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

4. Operation and Maintenance Costs

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 incurred 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 investor-owned utilities, which FERC requires to report on Form 1 the O&M costs of the power plants that they own.[25] 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 most investor-owned utilities (with the exception of Florida Power & Light) do not report empirical O&M costs for individual solar projects, but instead report average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. Table 1 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Year	PG&E[26]		PNM		APS[27]		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	20	4	96	4	110	3
2013	100	6	42	4	136	6	110	3
2014	N/A	N/A	65	6	168	7	110	3
predominant technology	fixed-tilt c-Si		fixed-tilt thin-film		primarily tracking c-Si		mix of c-Si and CSP	

Table 1. Operation and Maintenance Cost Sample

Despite these limitations, Figure 10 shows average utility fleet-wide annual O&M costs for this small sample of projects in $/kW$_{AC}$-year (blue solid line) and $/MWh (red dashed line)[28]. The

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[25] 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).

[26] As PG&E does not report operating costs for its solar projects on FERC Form 1, we turned to O&M costs reported in a CPUC compliance report (Middlekauff and Mathai-Jackson 2015) that unfortunately did not include usable cost data for 2014.

[27] 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 168 MW$_{AC}$ of total PV capacity (including residential and commercial) as a proxy for the 7 utility-scale solar plants with a combined capacity of 158 MW$_{AC}$.

whiskers represent both the lowest and the highest utility fleet-wide cost in each year. The dotted line refers to FP&L's project-specific annual O&M costs of its 75 MW CSP plant.

Average O&M costs for the PV plants within this sample have steadily declined from about $30/kW$_{AC}$-year (or $19/MWh) in 2011 to about $17/kW$_{AC}$-year ($8/MWh) in 2014. This decline could potentially indicate that utilities are capturing economies of scale as their PV project fleets grow over time, although the most recent drop from 2013 to 2014 may simply be a result of missing PG&E's costs for 2014 (PG&E's reported costs for 2012 and 2013 were above average). In 2014, all but one PV project had O&M costs of less than $20/kW$_{AC}$-year (or $11/MWh), which is lower than recent medium-term projections by bond rating agencies (see the O&M cost section of Bolinger and Weaver (2014)).

The only CSP plant in our sample reports higher O&M costs, in the $40-$50/kW$_{AC}$-year range for 2013 and 2014.
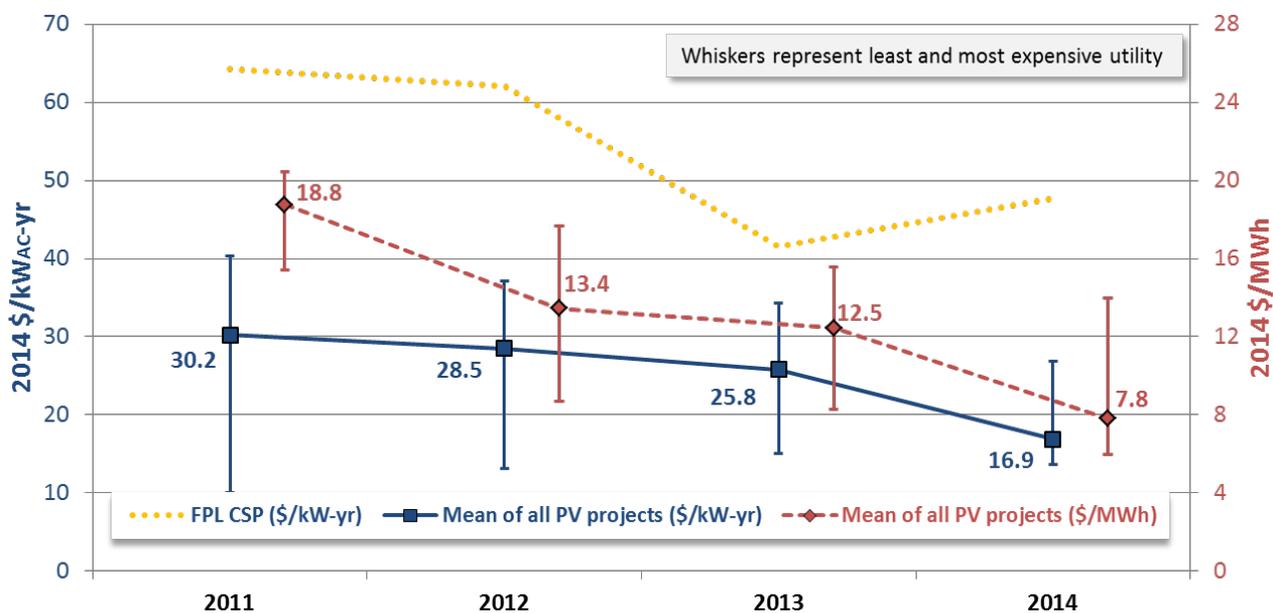
Figure 10. Empirical O&M Costs Over Time

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.

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[28] O&M costs for the single CSP project (a 75 MW parabolic trough project) are only shown in $/kW-year terms because this project provides steam to a co-located combined cycle gas plant.

5. Capacity Factors

At the close of 2014, more than 140 utility-scale solar projects (again, ground-mounted projects larger than 5 MW_{AC}) had been operating for at least one full year (and in some cases for many years), thereby enabling the calculation of capacity factors.[29] Sourcing net generation data from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and state regulatory filings, this chapter presents net capacity factor data for 128 PV projects totaling 3,201 MW_{AC}, two CPV projects totaling 35 MW_{AC}, and thirteen CSP projects (a mix of parabolic trough and power tower projects, with and without thermal storage) totaling 1,390 MW_{AC} (and for which only the solar generation is reported here – no gas or oil augmentation is included). The PV sample size of 128 projects totaling 3.2 GW is double the amount analyzed in last year's edition of this report, and should once again increase significantly in next year's edition (along with more CSP as well), as the record amount of new utility-scale solar capacity that came online in 2014 will have its first full operating year in 2015.

PV (128 projects, 3,201 MW_{AC})

Project-level capacity factors for utility-scale PV projects can vary considerably, based on a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site (measured in GHI with units $kWh/m^2/day$); whether the array is mounted at a fixed tilt or on a tracking mechanism; the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or ILR); and the type of modules used (e.g., c-Si versus thin-film). Other factors such as tilt and azimuth will also play an obvious role, though since we focus only on ground-mounted utility-scale projects, our operating assumption is that these fundamental parameters will be equally optimized to maximize energy production across all projects.

One might also expect project vintage to play a role – i.e., that newer projects will have higher capacity factors because the efficiency of PV modules (both c-Si and thin-film) has increased over time. As module efficiency increases, however, developers simply 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). In other words, 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 noted above – e.g., towards higher inverter loading ratios or greater use of tracking.

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[29] Because solar generation is seasonal (generating more in the summer and less in the winter), capacity factor calculations should only be performed in full-year increments.

Figure 11 illustrates and supports this hypothesis, by breaking out the average net capacity factor ("NCF") by project vintage across the sample of projects built from 2010 through 2013 (and by noting the relevant average project parameters within each vintage). The capacity factors presented in Figure 11 represent *cumulative* capacity factors – i.e., calculated over as many years of data as are available for each individual project (a maximum of four years, from 2011 to 2014, in this case), rather than for just a single year (though for projects completed in 2013, only a single year of data exists at present) – and are expressed in *net*, rather than *gross*, terms (i.e., they represent the output of the project net of its own use). Notably, they are also calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[30] yielding higher capacity factors than if reported in DC terms,[31] 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.

As shown, the average capacity factor increases only slightly from 2010- to 2011-vintage projects, due primarily to a higher proportion (in capacity terms) of projects using tracking among 2011-vintage projects, given virtually no change in the average ILR or GHI across these two vintages. Projects built in 2012 and especially 2013, however, have progressively higher capacity factors on average, driven by an increase in both average ILR and GHI in each year.
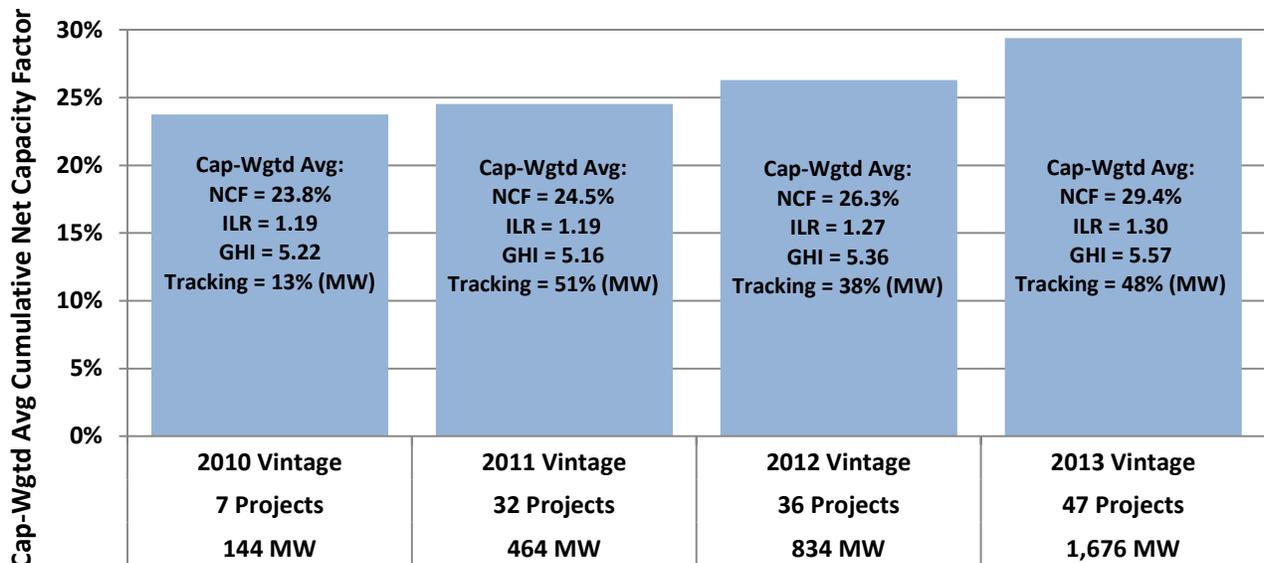
Figure 11. Cumulative PV Capacity Factor by Project Vintage: 2010-2013 Projects Only

Because Figure 11 analyzes *cumulative* capacity factors, one other possible explanation for the upward trend by vintage could be if the solar resource across the United States were significantly stronger in 2014 than in 2011-2013. If this were the case – which seems unlikely based on ex-post annual solar resource data (3Tier 2013; Vaisala 2014; Vaisala 2015) – then 2013-vintage projects might be expected to exhibit higher cumulative capacity factors than 2010-2012

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[30] 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].

[31] 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.

projects, given that 2014 is the only applicable performance year for a 2013-vintage project. To check against this possibility, Figure 12 replicates Figure 11, but based on single-year 2014 capacity factors rather than cumulative capacity factors. In other words, each vintage is measured based on its performance during the same single year – 2014 – rather than over a one- to four-year period, depending on vintage. As shown, the upward trend still holds, suggesting that ILR, GHI, and tracking are the true drivers.[32]
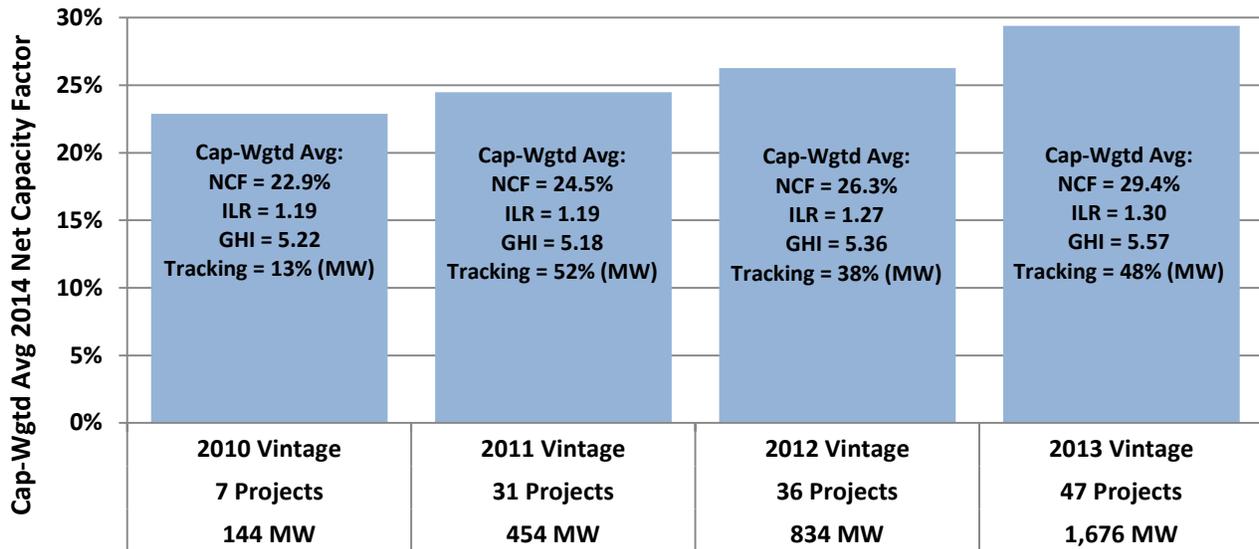
Figure 12. 2014 PV Capacity Factor by Project Vintage: 2010-2013 Projects Only

To the extent that this observable time trend in net capacity factor by project vintage is, in fact, attributable to a time trend in one or more of the other variables noted, it is perhaps best to measure the effect of those other variables directly. Figure 13 does just that, by categorizing the entire data sample in four different ways: by solar resource strength (in GHI terms), by fixed-tilt versus tracking systems, by the inverter loading ratio, and by module type (c-Si versus thin-film). The capacity-weighted average net capacity factor across the entire sample is 27.5%, the median is 26.5%, and the simple average is 25.6%, but there is a wide range of individual project-level capacity factors (from 14.8% to 34.9%) around these central numbers.

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[32] There is one less project in the sample for Figure 12 than for Figure 11, due to 2014 net generation data not yet being available for one project in New Jersey.
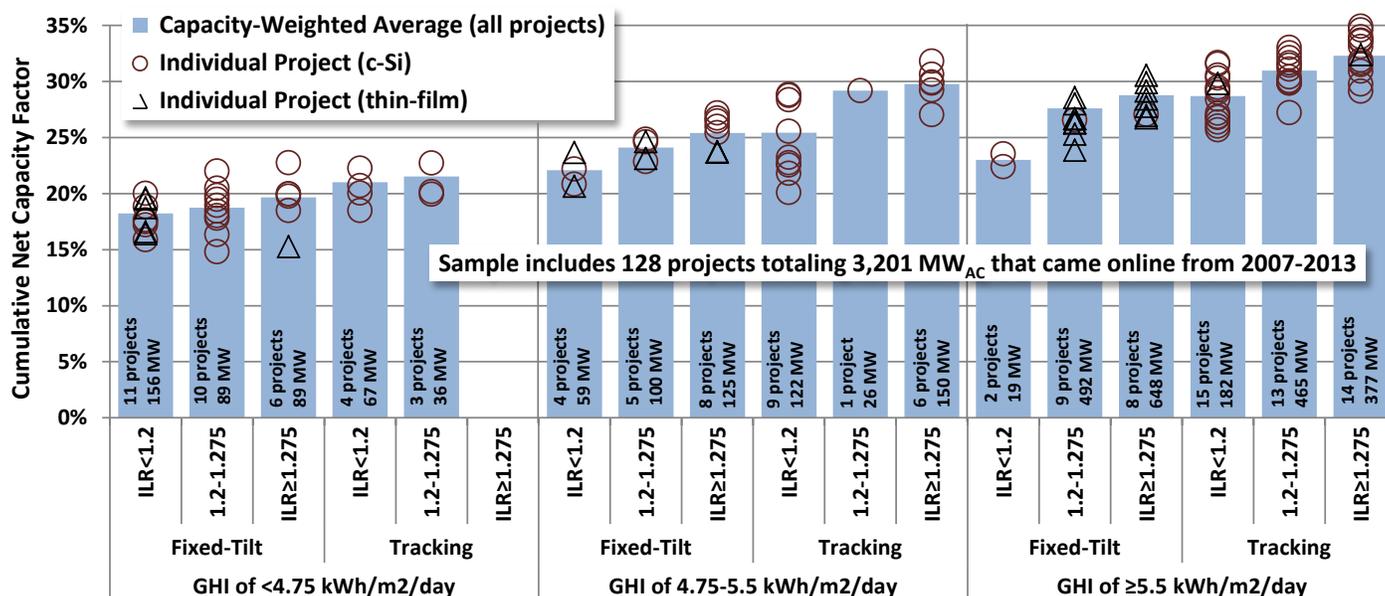
Figure 13. Cumulative PV Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, Inverter Loading Ratio, and Module Type

Each of the four variables explored in Figure 13 is discussed in turn below.

- **Solar Resource:** Each project in the sample is associated with a global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Solar resource bin thresholds (<4.75, 4.75-5.5, and ≥5.5 kWh/m^2/day GHI) were chosen to ensure that a sufficient number of projects fall within each bin.[33] Not surprisingly, projects sited in stronger solar resource areas have higher capacity factors, all else equal. The difference can be substantial: the capacity-weighted average net capacity factors in the highest resource bin, for example, average 8% higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending 5-9% depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** Tracking (all single-axis in this sample) boosts average capacity factor by 3-4% on average (in absolute terms), depending on the resource bin (4% on average across all three resource bins).

- **Inverter Loading Ratio (ILR):** Figure 13 breaks the sample down further into three different inverter loading ratio bins: <1.2, 1.2-1.275, and ≥1.275.[34] The effect on average capacity factor is noticeable: across all resource bins and fixed/tracking bins, the absolute difference in capacity factor between the highest and lowest inverter loading ratio bin ranges from 1% to 6% (for an average of 4%).

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[33] Thirty-four projects totaling 436 MW fall into the lowest resource category of less than 4.75 kWh/m^2/day, 33 projects totaling 582 MW fall into the middle resource category of between 4.75 and 5.5 kWh/m^2/day, and 61 projects totaling 2,183 MW fall into the highest resource category of at least 5.5 kWh/m^2/day.

[34] These ILR bins were chosen to ensure a roughly equal number of projects in each bin. The lowest ILR bins include 45 projects totaling 605 MW$_{AC}$, the middle bins include 44 projects totaling 1,208 MW$_{AC}$, and the highest bins include 42 projects totaling 1,388 MW$_{AC}$.

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- **Module Type:** Figure 13 differentiates between projects using c-Si and thin-film modules by the shape and color of the markers denoting individual projects (the capacity-weighted averages include *both* c-Si and thin-film projects). Though somewhat difficult to tease out, the differences in project-level capacity factors by module type are generally small (smaller than for the other variables discussed above), and do not appear to exhibit any sort of pattern. That said, the prevalence of fixed-tilt thin-film projects within the highest resource bin is noticeable. As mentioned in an earlier section of this report, however, many of the new thin-film projects completed in 2014 (which will enter our capacity factor sample in next year's report) have deployed single-axis trackers.

CPV (2 projects, 35 MW$_{AC}$)

The two CPV-only projects in the sample (the 5 MW$_{AC}$ Hatch and the 30 MW$_{AC}$ Cogentrix Alamosa projects) use virtually the same high-concentration technology (from Amonix), and both appear to be underperforming – both relative to publicly stated expectations and to how a single-axis tracking PV project would probably have performed in similar conditions. In November 2011, a few months after Hatch came online and a few months before Alamosa went online, a conference presentation from Amonix suggested a 31.5% capacity factor for Hatch and a 32.5% capacity factor for Alamosa (Pihowich 2011).[35] This 31.5-32.5% range is consistent with the empirical PV capacity factors seen in the second column from the right in Figure 13, which – except for the fact that they feature dual-axis, rather than single-axis, tracking – is where these two CPV projects would otherwise fall based on resource strength and inverter loading ratio. Actual experience to date, however, has been below this range: Hatch's 20.9% capacity factor in 2012 dropped to 18.5% in 2013 and 18.1% in 2014, while Cogentrix Alamosa posted a 24.9% capacity factor in 2013, followed by 24.2% in 2014.[36] The 2013 and 2014 capacity factors may have been reduced somewhat by the reportedly below-average insolation levels in the southwestern United States during the summers of 2013 and 2014 (3Tier 2013; Vaisala 2014; Vaisala 2015).[37]

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[35] The Amonix slide deck (Pihowich 2011) contains conflicting information: it lists expected generation numbers that equate to a 31.5% capacity factor for Hatch, yet also states a slightly lower capacity factor estimate of 29.4% – either of which is higher than actual experience. Meanwhile, documents from El Paso Electric (the offtaker) list 9,189 MWh, or a 20.8% capacity factor, as the expected output of Hatch (the project met this expectation in 2012, but fell short in 2013 and 2014). For Cogentrix Alamosa, an April 2011 environmental assessment prepared for the DOE's Loan Program Office assumed a 29% capacity factor, although the current Loan Program Office project description notes annual generation of 58,000 MWh, equivalent to just 21.9% (well below the >24% achieved to date). The reason for these disparate expectations (for both projects) is not clear, though one potential explanation might have to do with timing – i.e., the current El Paso Electric and Loan Program Office numbers might be more recent, therefore potentially reflecting some degree of actual experience.

[36] A third project that includes a mix of PV and CPV technologies – the 6.9 MW$_{AC}$ SunE Alamosa project – has performed better than the two CPV-only projects, having logged a 28.7% cumulative capacity factor over six full years of operation (from 2008-2013). The CPV portion of the project, however, only accounts for about 12% of the project's total capacity (the rest being PV with diurnal (~80%) or seasonal (~7%) tracking), and unfortunately, the project-level net generation data are not granular enough to enable a determination of how the CPV and PV portions of this project have performed independently.

[37] The entire year 2014 was an average to slightly above average solar year in the West, and an average to slightly below average solar year elsewhere in the continental United States. These annual averages mask important seasonal divergences, however – e.g., the above-average insolation tended to be concentrated in the less-important

CSP (13 projects, 1,390 MW$_{AC}$)

Three new CSP projects totaling 892 MW$_{AC}$ achieved commercial operation in late 2013, providing a significant boost to this year's CSP capacity factor sample. Solana is a 250 MW$_{AC}$ (net) parabolic trough project with six hours of molten salt storage located in Arizona; Genesis is a 250 MW$_{AC}$ (net) parabolic trough project without storage located in California; and Ivanpah is a 377 MW$_{AC}$ (net) power tower project without storage located in California.
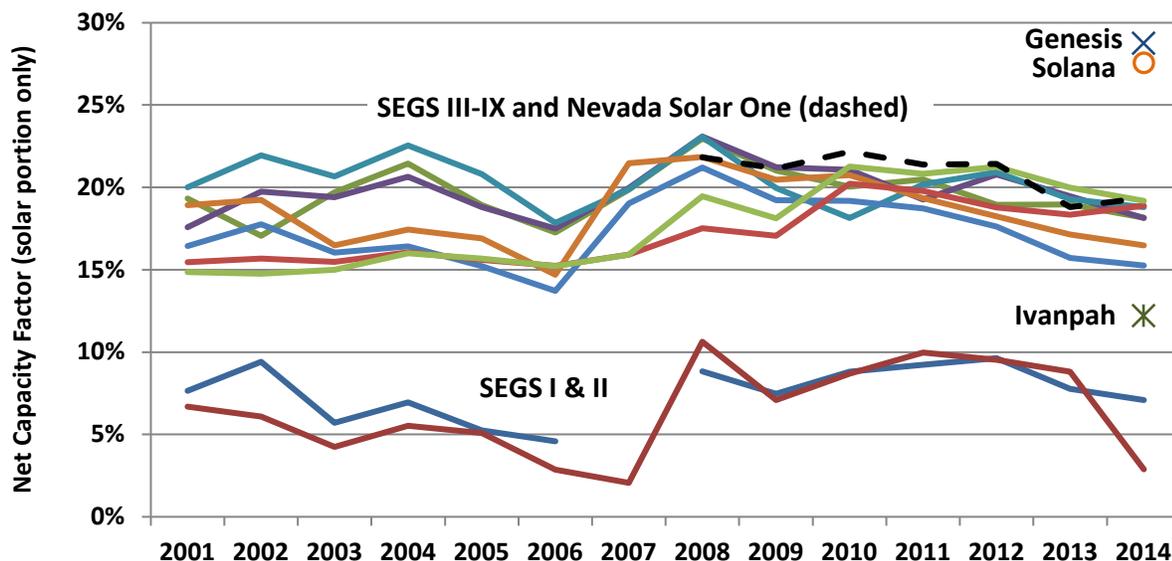
Figure 14. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

Figure 14 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 14 [38]) of our CSP project sample. The two new trough projects performed at roughly 28-29% capacity factors in 2014, while the Ivanpah power tower project performed at ~12% capacity factor. For at least Solana (with 6 hours of storage) and Ivanpah, these first-year numbers are below long-term expectations of 41% and 27%, respectively, and are projected to improve in future years as these projects overcome typical start-up challenges and are fine-tuned for optimal performance (Danko 2015; Stern 2015).[39] Indeed, the performance of these two projects has already improved somewhat in the

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non-summer months, while the critical months of May through September were generally below average across much of the United States, including the Southwest (Vaisala 2014; Vaisala 2015).

[38] 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 19.4% solar-only to 19.8% gas-included in 2014), 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 60-200 basis points in 2014, depending on the project. The Ivanpah power tower project also burns gas – and reportedly more than originally anticipated (Danko 2015) – though data on its gas-fired generation in 2014 were not available at the time of writing.

[39] Ivanpah documentation suggests that this initial ramp-up could last as long as four years (Danko 2015).

first half of 2015.[40] Even despite these teething issues, however, the two new trough projects performed significantly better in 2014 than the existing fleet of ten older trough projects in the sample, including the nine SEGS plants (totaling 392 MW$_{AC}$) 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.[41]

These ten older trough projects tend to fall into two groupings, with SEGS I and II set apart from the rest by significantly lower capacity factors, perhaps attributable to some combination of separate ownership from SEGS III-IX as well as different plant characteristics (such as the size of the collector field relative to the capacity and efficiency of the steam turbine). Nearly all of these projects experienced lower solar-only capacity factors in 2013 and 2014 than in other recent years. This decline is potentially attributable in part to inter-year variations in the solar resource, which was below average in the southwestern United States (where these projects are located) during the summers of 2013 and 2014 (3Tier 2013; Vaisala 2014; Vaisala 2015), with summer being particularly important for CSP projects.

Looking ahead, another 250 MW$_{AC}$ (net) parabolic trough project in California without storage (Mojave) achieved commercial operation in late 2014, and so will enter our capacity factor sample in 2015. A second power tower project – the 110 MW Crescent Dunes project in Nevada, with 10 hours of storage – is expected to be placed in service later in 2015 after a prolonged commissioning process. Along with the three new projects added to the sample this year (which should continue to mature over the next few years), these two new additions will expand the CSP performance data set in future years.

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[40] For example, Ivanpah generated 309,913 MWh in the first six months of 2015 (for an annualized capacity factor of 18.2%), compared to 173,138 MWh in the first six months of 2014 (an annualized capacity factor of 10.2%). For Solana, the corresponding numbers are 352,569 MWh (32.5%) vs. 314,906 MWh (29.0%).

[41] 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.

6. Power Purchase Agreement ("PPA") Prices

The cost of installing, operating, and maintaining a utility-scale solar 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 solar projects in the U.S. The sample includes a total of 109 contracts totaling 8,578 MW_{AC} and broken out as follows: 100 PV PPAs totaling 7,234 MW_{AC}, two CPV PPAs totaling 35 MW_{AC}, one 7 MW_{AC} PPA that is a mix of PV and CPV, and 6 CSP PPAs (four parabolic trough, two power tower) totaling 1,301 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). In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[42] 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.[43] As a practical matter, this means that we exclude "avoided cost" contracts – discussed in the text box on the next page – from our PPA price sample as well.

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[42] 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).

[43] 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 specifically solar power development. 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 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.

As discussed in the text, virtually all of the PPAs analyzed in this chapter result from competitive solicitations or some other form of bilateral negotiation. Yet as the cost of solar has fallen to more-competitive levels, a "new" market for utility-scale solar (which is actually one of the *oldest* markets for renewables in the United States, in existence ever since the Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978) has emerged over the past year or so. Specifically, PURPA requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects) 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. As a matter of policy, we exclude these "avoided cost" contracts from our PPA price sample, because they are FiT-like and, in some states, also involve unbundling RECs; yet, as discussed below, this growing market is not to be ignored.

Solar developers have been capitalizing on these avoided cost contracts for several years now in North Carolina, though the 5 MW capacity limit in that state means that most of the more than 150 projects that are operational in North Carolina fall below our threshold of what is considered to be "utility-scale." But in the past year, numerous avoided cost contracts for larger projects have been announced in other states that had not previously seen any solar development to speak of. For example:

- In Utah, at least two new 80 MW_{AC} PV projects (in addition to a number of smaller projects) should begin commercial operation by the end of 2015, selling electricity to PacifiCorp through 20-year avoided cost contracts. More than 700 MW of additional solar capacity is under development in Utah and could come online in 2016 under these same avoided cost contracts. Although the prices for these larger contracts are subject to negotiation, they are based loosely on PacifiCorp's published avoided cost rates, which are in the neighborhood of $50-$60/MWh when averaged over the 20-year contract term.

- Just to the north in Idaho, Idaho Power announced in late 2014 that it had recently entered into avoided cost contracts for 461 MW of utility-scale PV, and that another 885 MW was actively seeking such contracts. Idaho Power's avoided cost contracts feature pricing that varies by time of day and season, but averages out to about $60-70/MWh over the 20-year term.

This recent onslaught of applications for avoided cost contracts has prompted the utilities involved and their state utility regulators to re-evaluate these contracts and the utilities' PURPA requirements. In early 2015, for example, Idaho Power requested that its standard avoided cost contract term be reduced from 20 to just 2 years; regulators subsequently reduced the term to 5 years while they examined the issue, and in August 2015 agreed to impose a 2-year term. Around the same time, regulators in North Carolina rejected a similar utility request to lower the capacity threshold, shorten the contract term, and reduce contract pricing for solar projects. Meanwhile in Utah, PacifiCorp is also pushing back (as developers with Idaho projects that were stranded by the reduction in contract term are now looking south to PacifiCorp as a more-viable market), and would like to reduce solar compensation via a reduction in the capacity credit assigned to solar within the avoided cost calculation. How these various proceedings play out could significantly affect the future of utility-scale solar within these states. In the near term, however, grandfathered contracts will fuel a frenzy of new PV project construction in these emerging states through 2016.

For each of the contracts in the sample,[44] we have collected the contractually locked-in PPA price data over the full term of the PPA,[45] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed.[46] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum

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[44] 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.

[45] The minimum PPA term in the sample is 10 years (though the two 10-year contracts in the sample are effectively 4-year "bridge" PPAs with a California municipality, whereby the buyer takes 100% of the output for the first four years and then, once a long-term contract with an investor-owned utility begins in 2019, just 1% of the output in the last six years). The maximum is 34 years, the mean is 22.8 years, the median is 25 years, and the capacity-weighted average is 23.4 years.

[46] 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 2015* 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.

amount of revenue required by[47]) 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)[48] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[49,50] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized levelized cost of energy ("LCOE").
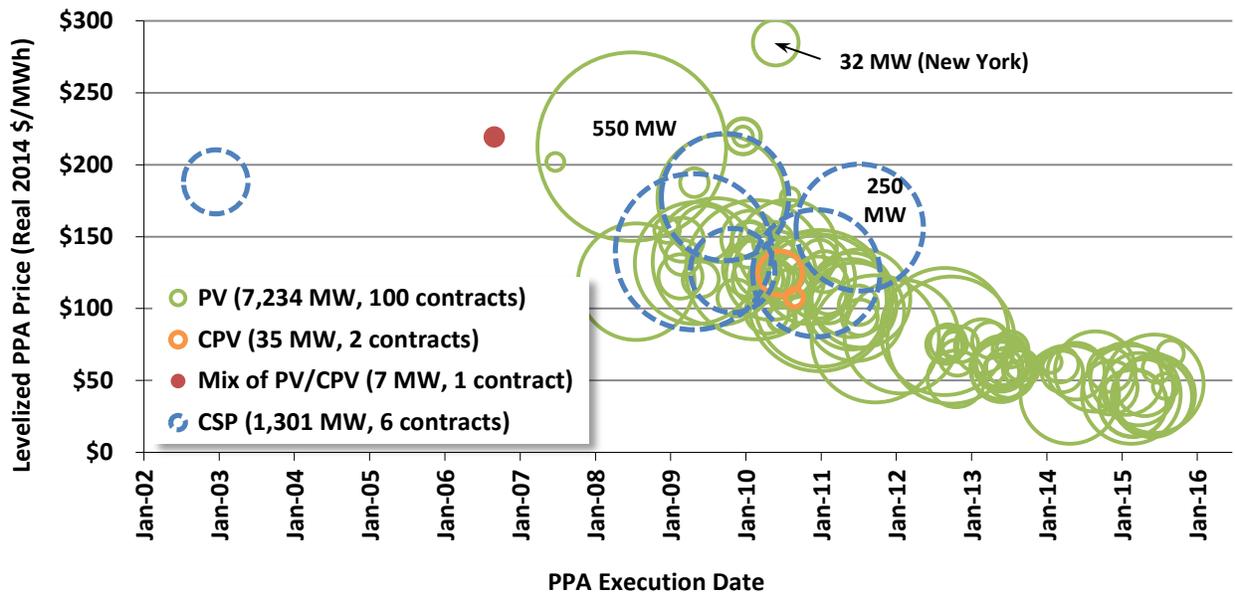
Figure 15. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

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[47] 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.

[48] 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 didn't affect the PPA price.

[49] 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 limited 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).

[50] 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.

Figure 15 shows trends in the levelized (using a 7% real discount rate) PPA prices from the entire sample over time. Each bubble in Figure 15 represents a single PPA, with 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).[51] Different solar technologies (e.g., PV versus CPV versus CSP) are denoted by different colors and patterns.

Figure 15 provides a number of insights:

- PPA pricing has, in general, declined over time, to the point where recent PPAs have been priced as aggressively as $40/MWh levelized (in real, 2014 dollars), or even lower. In the Southwest (where these low-priced projects are primarily located), pricing this low is, in some cases, competitive with in-region wind power.[52] This is particularly the case when considering solar's on-peak generation profile, which can provide ~$25/MWh of TOD value relative to wind.[53]

- Although at first glance there does not seem to be a significant difference in the PPA prices required by different solar technologies, it is notable that all of the recent PPAs in the sample employ PV technology. Back in 2002 when the Nevada Solar One (CSP) PPA was executed, PV was too expensive to compete at the wholesale level, but by 2009-2011 when the other five CSP PPAs in the sample were executed, PV pricing had closed the gap. Since then, virtually all new contracts have employed PV technology, while a number of previously-executed CSP contracts have been either canceled or converted to PV technology. CPV was seemingly competitive back in 2010 when the two contracts in the sample were executed, but lack of any new contracts since then (at least within the sample) prevents a more-recent comparison – and is perhaps telling in its own right.[54]

- Smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are just as competitive as larger projects. 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.

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[51] 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.

[52] 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.

[53] 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 Figure 15 (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.

[54] That said, SunPower has been quietly rolling out its new low-concentration (7 suns) C7 CPV technology, with a 1 MW_{AC} pilot project at Arizona State University (online in early 2013); a contract with Apple for the 20 MW_{AC} Fort Churchill Solar Project (scheduled to come online in 2015) to power its data center near Reno, NV; and a sale of technology to a project in China. At present, no cost or price information is available for these projects.

- Not surprisingly, the highest-priced contract in the sample comes from Long Island, which does not enjoy the abundant sunshine of the Southwest (where most of our sample is located – 93% of the total capacity within the PPA sample is located in CA, NV, AZ, or NM), and where wholesale power prices are high due to transmission constraints.

Not all of the projects behind the contracts shown in Figure 15 are fully (or even partially) operational, though all of them are still in play (i.e., the sample does not include PPAs that have been terminated). Figure 16 shows the same data as Figure 15, but broken out according to whether or not a project has begun to deliver power.[55] Understandably, most of the more-recently signed PPAs in the sample pertain to projects that are still in development or under construction, and have not yet begun to deliver electricity under the terms of the PPA. Given that many of these same PPAs are also the lowest-priced contracts in the sample, it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown here.[56] That said, a recent and related 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 the text box on the next page, a survey of recent solicitation responses reveals a deep field of projects bidding into solicitations at these low prices – i.e., the recent low prices shown in Figure 15 and Figure 16 do not appear to be one-off anomalies.
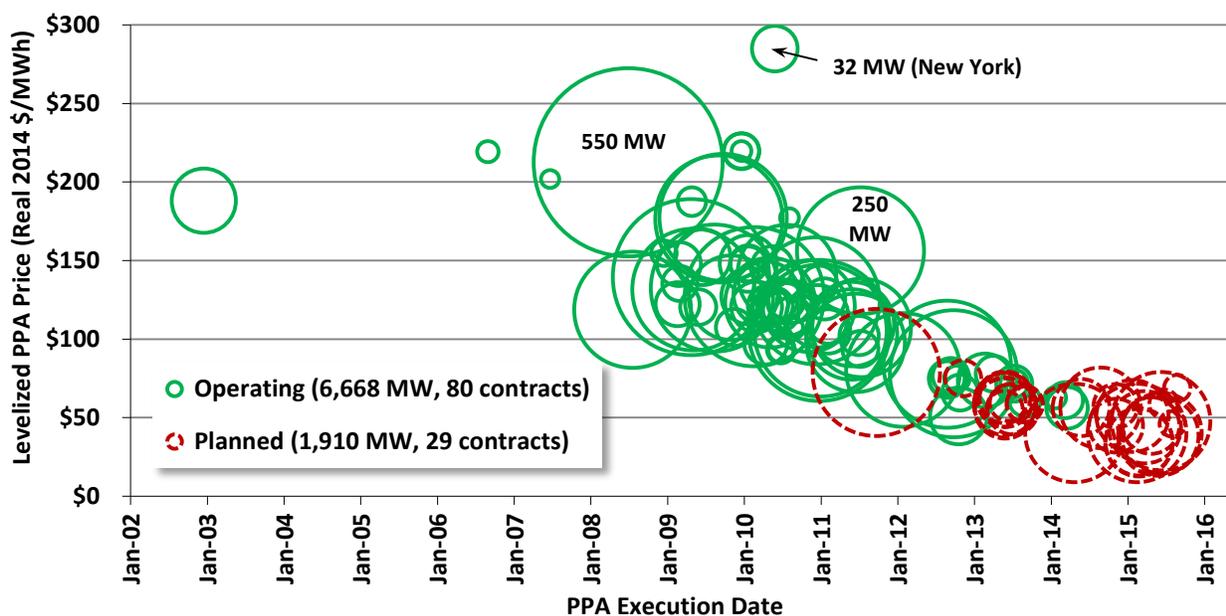
Figure 16. Levelized PPA Prices by Operational Status and PPA Execution Date

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[55] If a project had begun to deliver power by August 2015 – even if not yet fully operational or built out to its contractual size – it is characterized as "operating" in Figure 16. Only those projects that were still in development or were under construction but not yet delivering power are characterized as "planned."

[56] There is a history of solar project and PPA cancellations in California, 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 – e.g., if the solar trade dispute with China were to harm existing module supply contracts.

More than two-thirds of the PV contracts in the 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 17 illustrates this decline by plotting over time, in real 2014 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts).
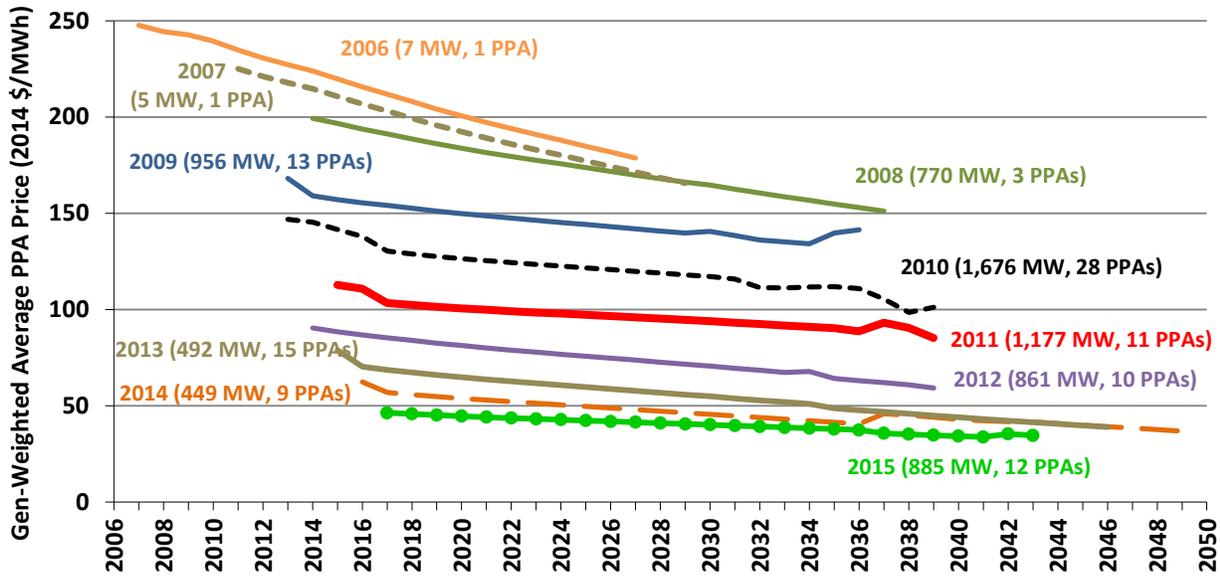
Figure 17. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

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 18 illustrates this potential value by plotting the future stream of average PV PPA prices from contracts executed in 2014 and 2015 (i.e., the same two lines as the 2014 and 2015 vintage PPA lines in Figure 17 above) against a range of projections of *just the fuel costs* of natural gas-fired generation.[57] Focusing on the 2015 PPA vintage in particular, average PPA prices from PV contracts executed in 2015 start out higher than the range of fuel cost projections in 2017, but decline (in real 2014 $/MWh terms) over time and eventually fall below the reference case gas price projection by 2021 (and below the *entire range* of gas price projections by 2037). On a levelized basis from 2017 through 2040, the 2015-vintage PV PPA prices come to $42.1/MWh (real 2014 dollars) compared to $48.1/MWh for the reference case fuel price projection, suggesting that PV may be able to compete with even just the fuel costs of *existing* gas-fired generators (i.e., not even accounting for the recovery of fixed capital costs incurred by *new* gas-fired generators).

Moreover, it is important to recognize that the PV PPA prices 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.

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[57] The national average fuel cost projections come from the Energy Information Administration's *Annual Energy Outlook 2015* publication, and increase from around $4.67/MMBtu in 2015 to $8.83/MMBtu (both in 2014 dollars) in 2040 in the reference case. The range around the reference case is bounded by the high oil and gas resource case on the low end, and the greater of the high oil price or high economic growth cases on the high end (since AEO 2015 does not include a low oil and gas resource case), and ranges from $4.98/MMBtu to $10.75/MMBtu (again, all in 2014 dollars) in 2040. These fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (these start at roughly 8,100 Btu/kWh and gradually decline to around 7,200 Btu/kWh by 2040).
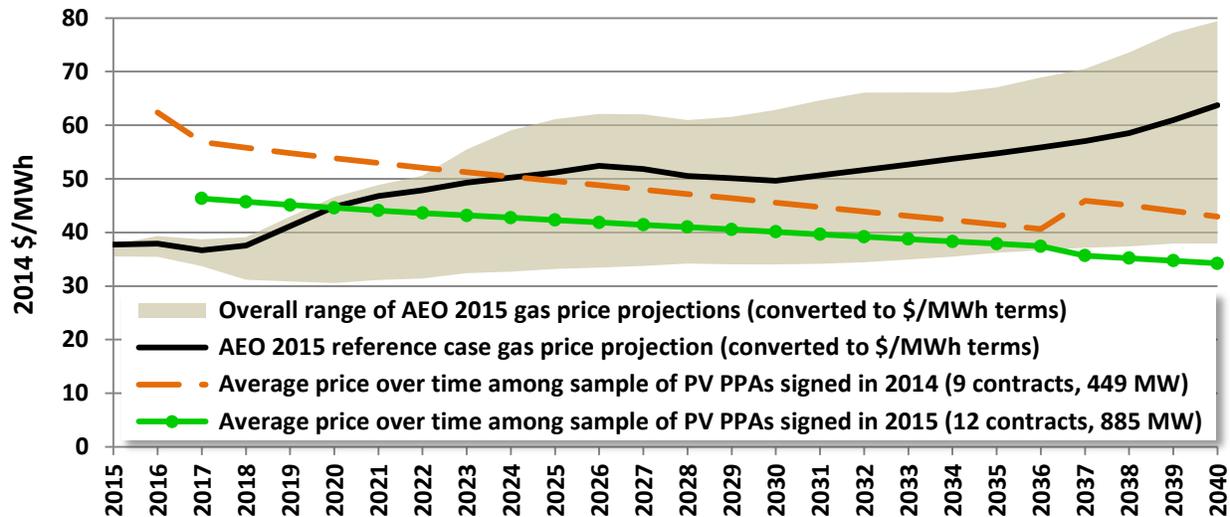
Figure 18. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

In addition to the declining real prices over time within each PPA vintage shown in Figure 17 and Figure 18, the steady march downward across vintages is also evident in Figure 17, demonstrating substantial reductions in pricing by PPA execution date.[58] To provide a clearer look at the time trend, the blue-shaded columns in Figure 19 simply levelize the price streams shown in Figure 17. Based on this sample, levelized real PPA prices for utility-scale PV projects consistently fell by almost $25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples. With levelized real PPA prices now below $50/MWh on average (based on the combined 2014/2015 sample), future price declines are likely to be much smaller than in the past.

Figure 19 also shows that the overall spread in pricing has narrowed over time – e.g., the 2013-2015 samples show a tighter range of levelized prices than do the 2009-2011 samples – suggestive of an increasingly mature and transparent market. Moreover, this narrowing has occurred despite the fact that the geographic scope of the market (and sample) has broadened with time. Although the PPAs in our sample are still heavily concentrated in the Southwest, the market is beginning to expand to new parts of the country – notably the Southeast (see the text

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[58] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength (though again, 93% of the capacity in the PPA price sample is in the high-insolation states of CA, NV, AZ, and NM), tracking versus fixed-tilt, and c-Si versus thin-film. 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 PV contracts 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 Chapter 3) that are recouped over time through greater energy yield (see Chapter 5), 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 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).

box below) but also states like Utah and Idaho where utilities have had attractive avoided cost rates (see earlier text box on "avoided cost" markets). For example, the 2015 PPA price sample includes contracts not only in the usual Southwestern states, but also in Florida, Arkansas, and Alabama – and at prices not too far above those seen in the Southwest.
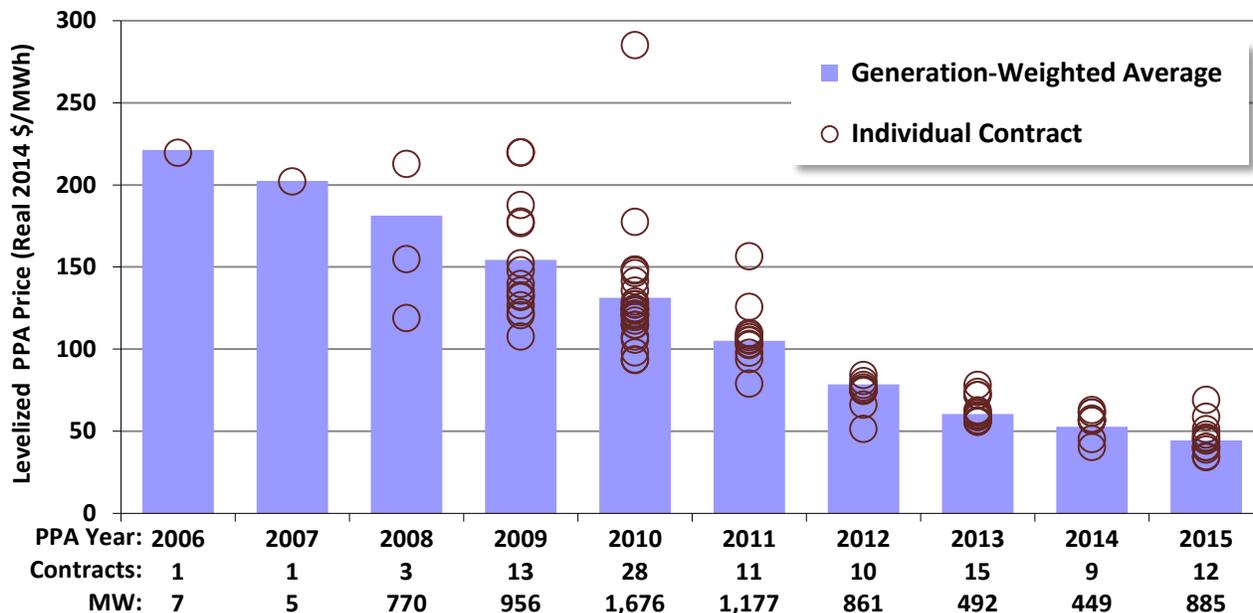

Figure 19. Levelized PV PPA Prices by Contract Vintage

Trend to Watch: The Rise of the South

Although the sample of PPA prices analyzed in this chapter is highly concentrated in the southwestern United States – i.e., 97% of the 8.7 GW of capacity in the sample is located in CA (68%), NV (11%), AZ (11%), TX (4%), NM (3%), and CO (1%) – there have been a number of notable announcements over the past year about new utility-scale solar PPAs being signed at competitive prices in several *southeastern* states that have not previously seen much development. The following non-exhaustive list of new contracts (only three of which are currently included in our PPA price sample, due to lack of sufficient information on the others) illustrates this expansion of the market to the Southeast:

- In October 2014, Georgia Power announced long-term PPAs with four "smaller" PV projects totaling 76.5 MW and six "larger" projects totaling 439 MW. Although pricing for individual projects has not been disclosed, the average PPA price among the "smaller" projects is reportedly $65/MWh.
- In February 2015, the Tennessee Valley Authority announced that it had signed a 20-year PPA with an 80 MW PV project in Alabama at a price of $61/MWh.
- In April 2015, NextEra and Entergy Arkansas announced a PPA for the 81 MW Stuttgart Solar Project in Arkansas; the price is reportedly just north of $50/MWh.
- Highlighting yet another notable trend towards direct corporate purchases of renewable power, in June 2015, Community Energy and Amazon Web Services announced a PPA for an 80 MW PV project in Virginia (pricing was not disclosed).
- In July 2015, the Orlando (Florida) Utilities Commission announced a 20-year PPA with a 13 MW PV project priced at $70/MWh, which is less than half the $194/MWh it is paying for a similar 5.5 MW$_{AC}$ project that came online in late 2011.

This trend – also evident in regional interconnection queues, as shown later in Figure 20 – is all the more notable because the Southeast has historically not seen much renewable energy development at all (other than in North Carolina, which has had an active solar market for a number of years, primarily featuring "avoided cost" PURPA contracts for projects of 5 MW or less that fall below our utility-scale size threshold), due in part to fewer state-level policies like renewable portfolio standards, as well as wind resource constraints. For example, unlike in much of the rest of the country, wind power has yet to gain much of a foothold in the Southeast – and may find it hard to compete with solar at the price levels evident in some of these solar contracts.

7. Conclusions and Future Outlook

Other than the SEGS I-IX parabolic trough CSP projects built in the 1980s, virtually no utility-scale PV, CPV, or CSP projects existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in 2013 and 2014 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including storage – either achieving commercial operation or entering the commissioning phase. Although the operating history of many these newer PV, CPV, and CSP projects is still very limited, a critical mass of data nevertheless enables empirical analysis of this rapidly growing sector of the market.

This third 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 (but perhaps showing signs of slowing), relatively modest O&M costs, solid performance with improving capacity factors, and record-low levelized PPA prices of around $40/MWh in some cases and under $50/MWh on average (again, with the steady decline over the years perhaps showing signs of slowing). Meanwhile, the other two utility-scale solar technologies – CPV and CSP – have also made strides in recent years, but are finding it difficult to compete in the United States with increasingly low-cost PV.[59]

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry – both in terms of volume and geographic distribution – over the next few years. Specifically, Figure 20 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 2014.[60]

These data should be interpreted with caution: 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.[61] That said, efforts have been made by the FERC, ISOs, RTOs,

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[59] 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.

[60] 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 20 only includes projects that were active in the queue at the end of 2014 but that had not yet been built; suspended projects are not included.

[61] 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

and utilities to reduce the number of speculative projects that have, in recent years, clogged these queues.

Even with this important caveat, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2014, there were 44.6 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 44.6 GW (19.5 GW of which first entered the queues in 2014) represented nearly 14% of all generating capacity within these selected queues at the time, in third place behind natural gas at 45% and wind at 30% (see Figure 20 inset). The end-of-2014 solar total is also more than 5 GW higher than the 39.5 GW of solar that were in the queues at the end of 2013, 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 2014, as well as the impending reversion of the 30% ITC to 10% scheduled for the end of 2016.
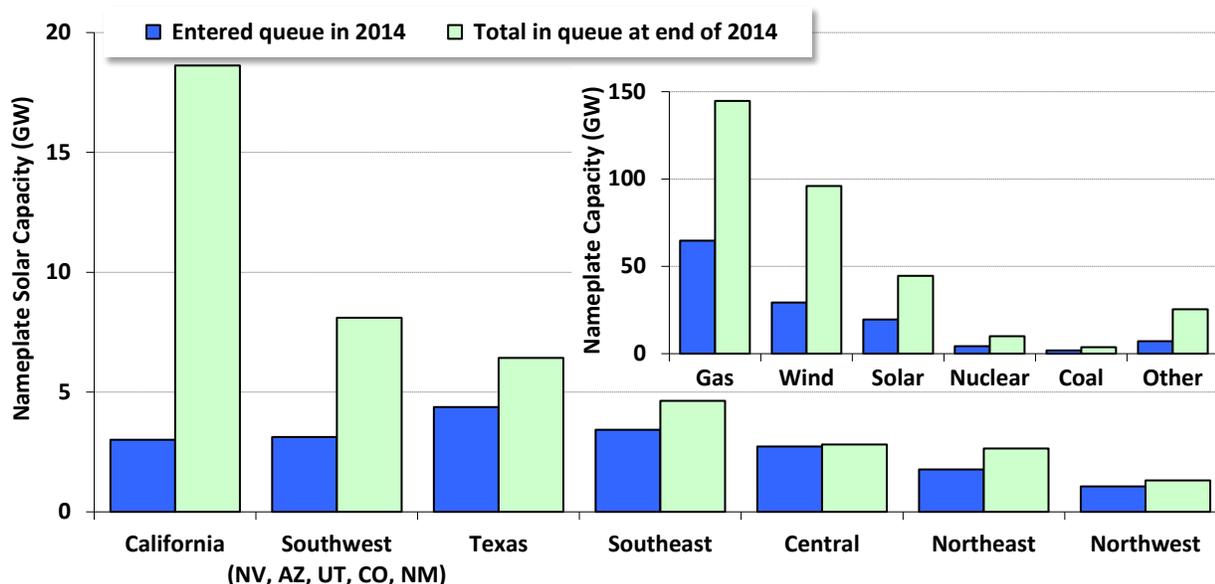
Source: Exeter Associates review of interconnection queue data

Figure 20. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 20 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 project location shown in Figure 3, earlier), 60% of the total solar capacity in the queues at the end of 2014 is within California (42%) and the Southwest region (18%). This combined 60% is down from 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, 14% of the solar capacity in the queues at the end of 2014 resides in Texas, followed by 10% in the Southeast and 6% in each of the Central and Northeast regions.

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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.

Moreover, in terms of *new* solar capacity entering the queue in 2014, Texas ranked first (22%), followed by the Southeast (18%), Southwest (16%), California (15%), and Central (14%) regions. As the competitiveness of solar continues to improve, the market is spreading to still-untapped parts of the country.

Though not all of the 44.6 GW of planned solar projects represented within Figure 20 will ultimately be built, presumably most of what is built will come online prior to 2017, given the scheduled reversion of the 30% ITC to 10% at the end of 2016. To that end, as of the end of 2014, GTM/SEIA (2015) projected a utility-scale solar pipeline of 26.7 GW in 2015-2016 (9.1 GW in 2015 and 17.6 GW in 2016), 14.1 GW of which was already contracted (6 GW in 2015 and 8.1 GW in 2016). Even if only this 26.7 GW – or, for that matter, even just the contracted 14.1 GW portion – came online prior to 2017, it would still mean an unprecedented amount of new solar construction in 2015 and 2016. Of course, accompanying all of this new capacity will be substantial amounts of new operational data, which we will 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 (Chapter 2):
>   Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), trade press articles

Installed Prices (Chapter 3):
>   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 (Chapter 4):
>   FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors (Chapter 5):
>   FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices (Chapter 6):
>   FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

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

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