Utility-scale PV surges onward in the United States

Project economics | As utility-scale PV projects continue to spread across the United States, Mark Bolinger, Joachim Seel, and Dana Robson of the Lawrence Berkeley National Laboratory cover key technology and market trends in this synopsis of their annual "Utility-Scale Solar" report series

Credit: BHE Renewables

Only a little more than a dozen years old, the utility-scale PV sector in the United States has grown rapidly. Just five years after the first two utility-scale projects achieved commercial operations in late 2007, the utility-scale sector became the largest segment of the overall US PV market (in terms of new capacity) in 2012, and has since shown no signs of relinquishing its market-leading position. In 2018, the utility-scale sector accounted for nearly 60% of all new PV capacity built in the United States, and more than three quarters of all states were home to one or more utility-scale PV projects (defined here as any ground-mounted project larger than $5MW_{AC}$).

Figure 1 plots the 690 utility-scale PV (and in some cases, PV plus battery) projects totaling $24,586MW_{AC}$ that were operating in the United States at the end of 2018 by location and technology configuration. While the sector got its start in sunny southwestern states like Nevada, Arizona, and California, declining installed costs have enabled it to expand to less-sunny regions of the country—even recently including northerly states like Washington, Minnesota, Michigan, and Vermont. Some of these more-recent northerly projects are even using single-axis tracking, which in earlier days had been reserved primarily for the sunniest sites (i.e., where the solar resource was strong enough to justify tracking it).

The US utility-scale PV sector is maturing and expanding outside of its traditional comfort zones

Since 2015, though, single-axis tracking has become the dominant mount type in most parts of the country, and was used for nearly 70% of all new capacity—including virtually all new thin-film (primarily CdTe, but with some CIGS) capacity—added in 2018 (Figure 2). Fixed-tilt projects are increasingly only built in less-sunny regions, even while tracking projects continue to push into those same regions.

Meanwhile, the median inverter loading ratio ("ILR")—i.e., the ratio of the DC capacity of a project's PV array

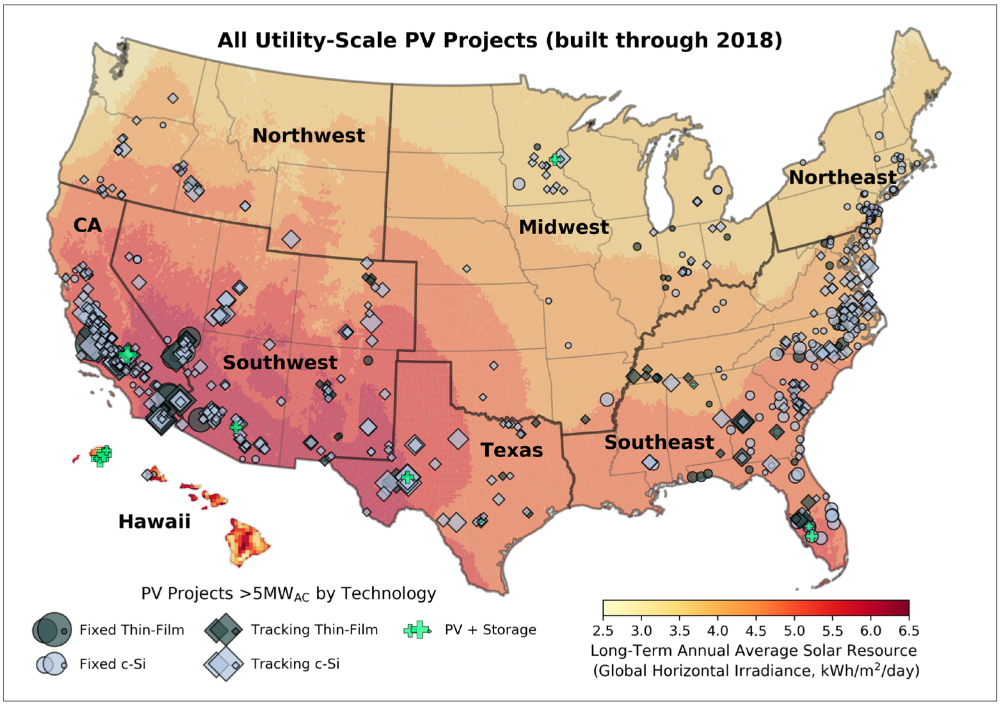

Figure 1. Utility-scale PV projects (>5MW$_{AC}$) in the United States

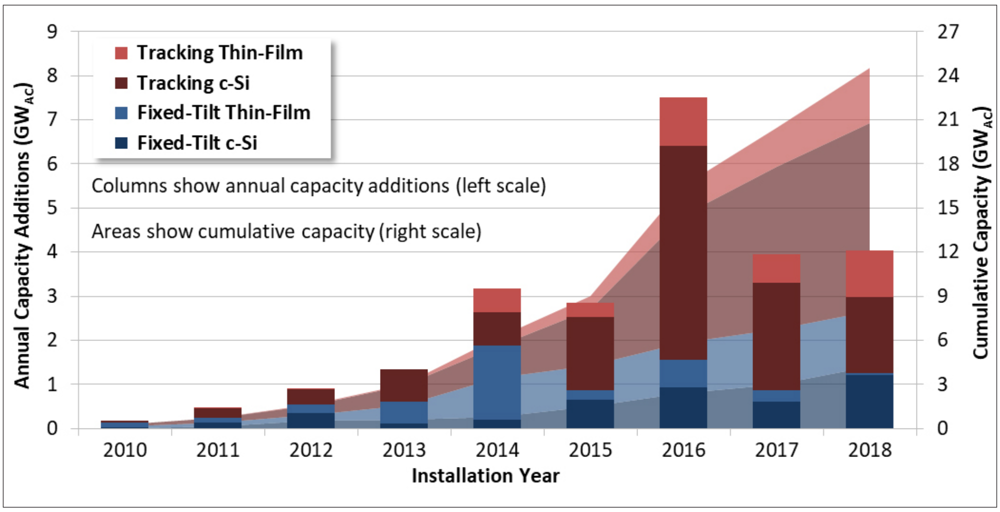

Figure 2. Annual and cumulative utility-scale PV capacity by module and mounting type

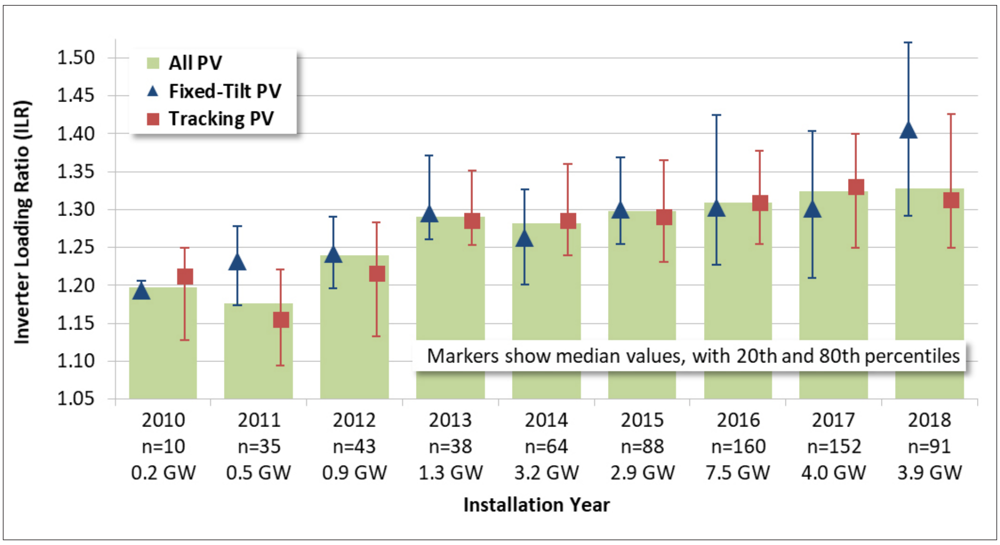

Figure 3. Trends in inverter loading ratio by mounting type and installation year

relative to the AC capacity of its inverters—has risen steadily, from around 1.2 in the early days of the sector to more than 1.3 in 2018 for both tracking and fixed-tilt projects (Figure 3). Higher ILRs allow inverters to operate closer to (or at) full capacity for more of the day, but as the DC:AC ratio increases, the extra generation during the morning and evening "shoulder hours" must be balanced against any mid-day power clipping that occurs to ensure that there is a net gain in production. For a standalone PV project, an ILR in the range of 1.3-1.4 seems to be the sweet spot, but this ratio could go significantly higher (e.g., to 2.0 or more) with the addition of a DC-coupled battery that is able to capture and store mid-day solar generation that would otherwise be clipped.

Median installed prices have steadily fallen by nearly 70% since 2010, to US\$1.6/W$_{AC}$ (US\$1.2/W$_{DC}$) among 60 utility-scale projects (totaling 2.5GW$_{AC}$) completed in 2018 (Figure 4). In a sign of a maturing market, price dispersion across the sample has narrowed in each year since 2013—e.g., the standard deviation of installed prices declined from US\$0.9/W$_{AC}$ in 2013 to US\$0.5/W$_{AC}$ in 2018.

To assess how these projects have performed, we rely on capacity factors—a measure of the amount of electricity generated in a given period relative to how much electricity could have been generated if the generator was operating at full capacity for the entire period. Because solar generation varies seasonally, capacity factor calculations for solar are typically performed in full-year increments. Figure 5 shows that the capacity factors of individual projects in our sample vary widely, from 12% to 35% (in AC terms), with a sample median of 25% and a capacity-weighted average of 27%. A good deal of this project-level variation can be explained by the three primary drivers of capacity factor that are tracked in Figure 5: the average quality of the solar resource at the site (broken out into quartiles), whether the project tracks the sun or is mounted at a fixed-tilt, and the ILR (also divided into quartiles). Curtailment and degradation—both of which are baked into the capacity factors shown in Figure 5—can also play a role, and may be partly responsible for some of the apparent outliers.

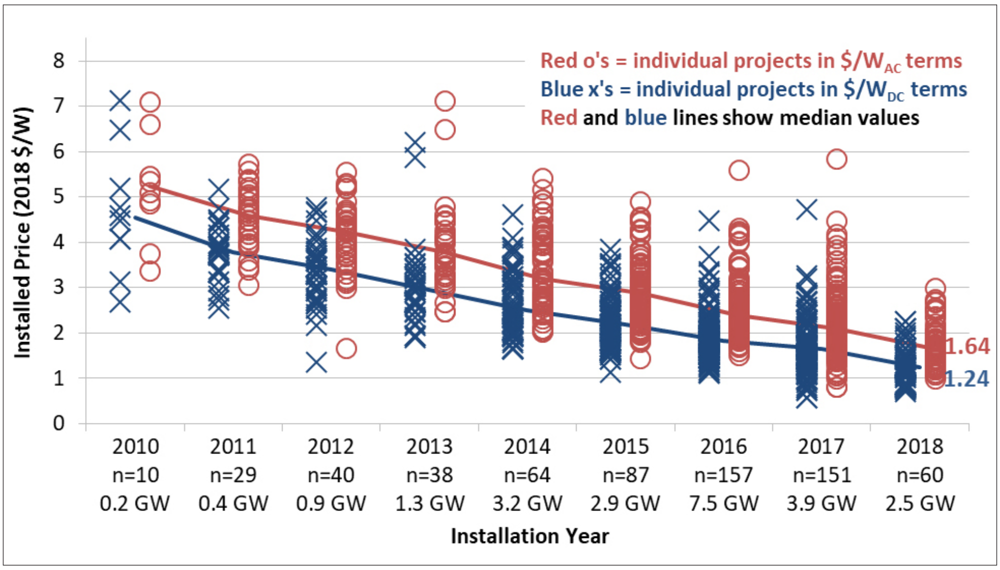

Figure 4. Installed price of utility-scale PV projects by installation year

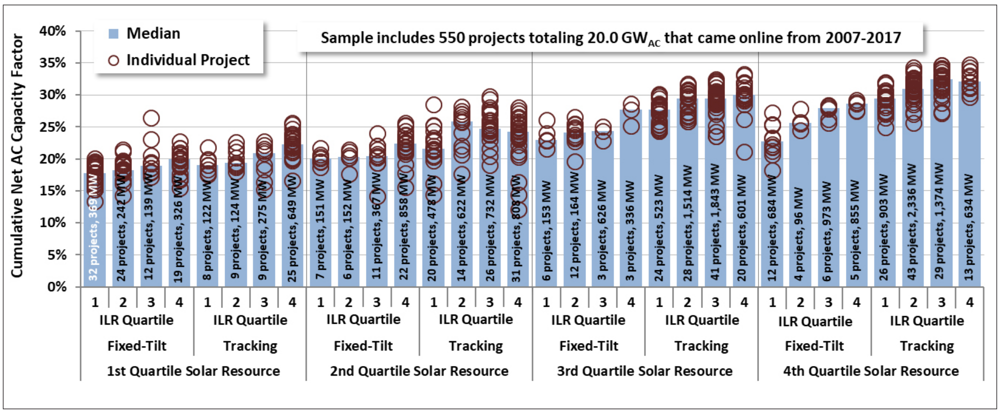

Figure 5. Cumulative capacity factor by resource strength, fixed-tilt vs. tracking, and inverter loading ratio

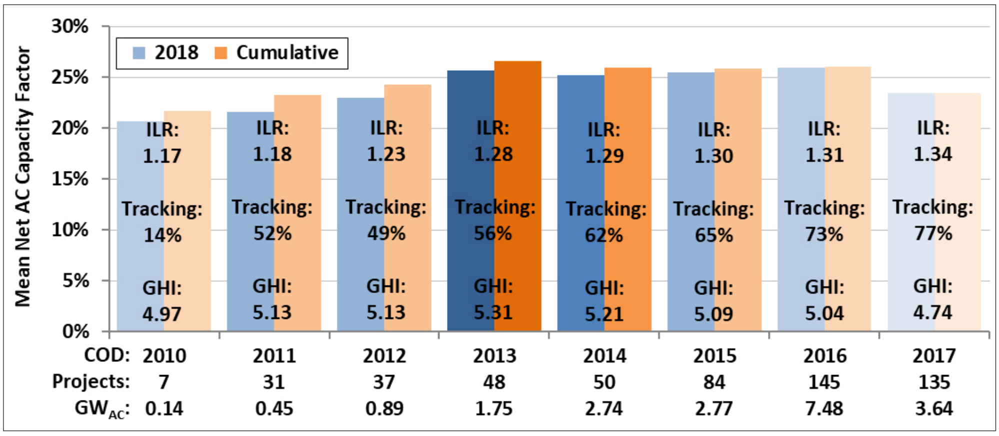

Figure 6. Cumulative and 2018 capacity factor by project vintage: 2010-2017 projects

Figure 6 breaks out average capacity factor by project vintage (based on commercial operation date, or COD). The steady improvement from 2010-vintage through 2013-vintage projects was driven by increases in all three of the drivers shown in Figure 5 and again in Figure 6—long-term average global horizontal irradiance (GHI) at each site, the prevalence of tracking, and the average ILR. Since 2013, though, average ILRs have held fairly steady around 1.3, while the two other drivers—prevalence of tracking and long-term average GHI—have moved in opposite directions, largely canceling each other out and resulting in stagnant capacity factors among more-recent project vintages. The lower long-term average GHI since 2013 (indicated numerically but also visually by the fading intensity of the blue and orange shading) reflects the geographic expansion of the market from California and the Southwest into less-sunny regions of the United States—this is a positive trend, despite having a negative impact on average fleet-wide capacity factor.

Figure 7 graphs both the median (with 20th and 80th percentile bars) and capacity-weighted average "irradiance-normalised" (i.e., to correct for inter-annual variability in the strength of the solar resource) capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values). The dashed red line approximates the slope of both the median and capacity-weighted average and depicts a straight-line degradation rate of -1.2%/year—i.e., worse than the -0.5%/year to -0.8%/year range that often serves as conventional wisdom. It is important to recognise, however, that Figure 7 is capturing plant-level degradation from all possible degradation pathways—including (but not limited to) module degradation, balance of plant degradation (e.g., from trackers), soiling, and downtime (e.g., due to outages, scheduled maintenance, or curtailment)—and so should not be confused with the more-commonly measured (and typically more modest) module degradation rate.

Driven by lower installed project prices and, at least through 2013, improving capacity factors, levelised power purchase agreement (PPA) prices for utility-scale PV projects in the United States have fallen dramatically over time, by US$20-30/MWh per year on average from 2006 through 2012, with a smaller price decline of ~US$10/MWh per year evident in most years since 2013 (Figure 8). Aided by the 30% federal investment tax credit (ITC), most recent PPAs in our sample—including many outside of sunny California and the Southwest—are priced below US$40/MWh levelised (in real 2018 dollars), with many priced below US$30/MWh and a few even priced below US$20/MWh.

Particularly within higher-penetration

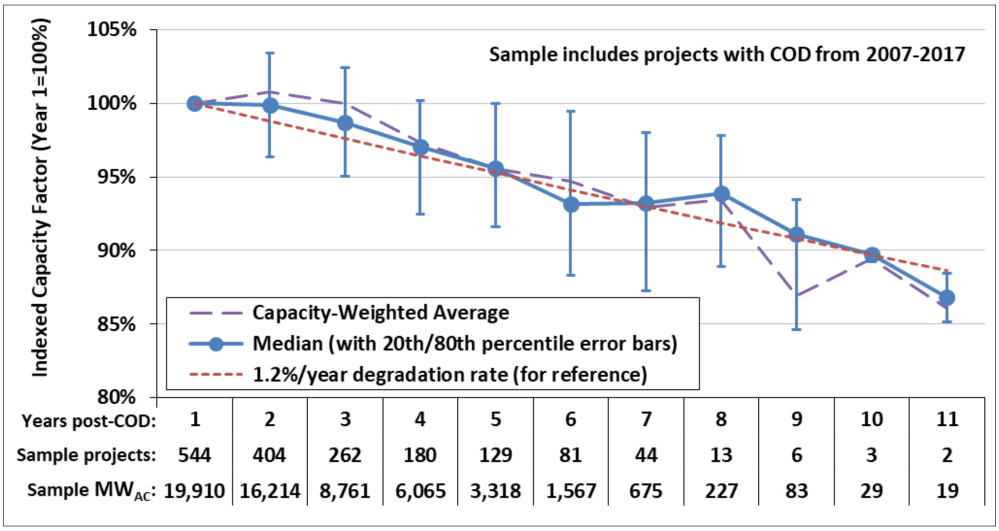

Figure 7. Fleet-wide performance degradation

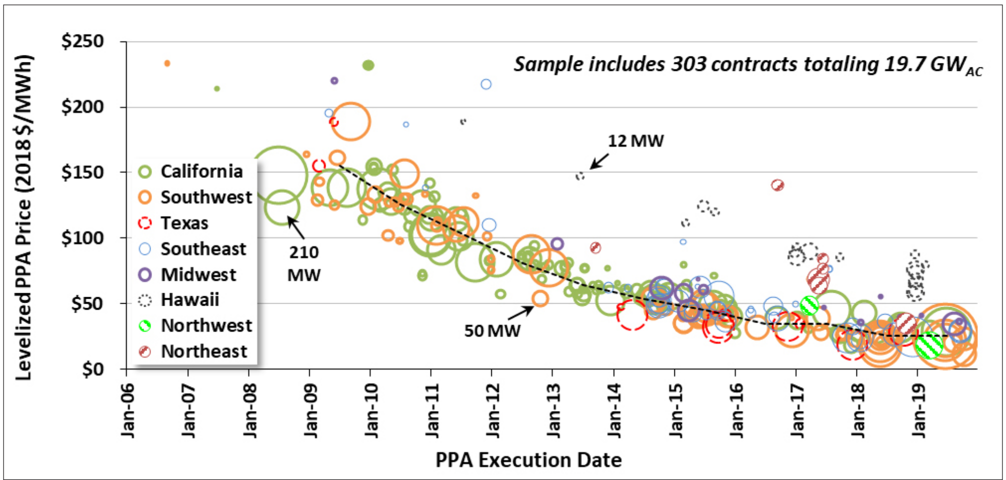

Figure 8. Levelised PPA prices by region, contract size, and PPA execution date

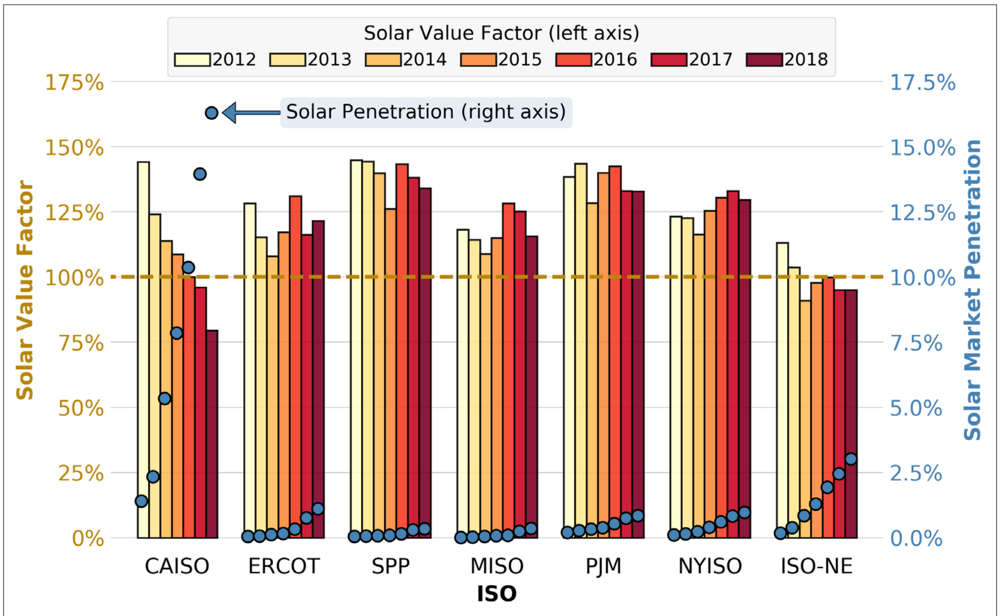

Figure 9. Solar's "value factor" and market penetration by independent system operator (ISO)

solar markets like California, these falling PPA prices have been matched, to some degree, by a decline in the wholesale market value (i.e., the energy and capacity value) of solar. Due to an abundance of solar energy pushing down mid-day wholesale power prices, solar generation in California earned just 79% of the average energy and capacity value within the California Independent System Operator's (CAISO's) wholesale power market in 2018—down from 146% back in 2012 (Figure 9). However, in five of the six other independent system operator (ISO) markets analysed—all of which still have solar penetration rates of 1% or less, compared to California's 16%—solar still provides above-average value (i.e., solar's "value factor" remains above 100%). The exception is in New England (ISO-NE), where the highest wholesale power prices typically occur during winter cold snaps when the heating and power sectors compete for a tight supply of natural gas, driving up both natural gas and wholesale power prices. In the depths of a dark and snowy New England winter, PV is often not in a good position to capitalise on these price spikes, which, in turn, results in below-average market value (at least when measured over the course of a full year).

To date, falling PPA prices have largely kept pace with the dramatic decline in solar's market value in California, thereby maintaining solar's relative competitiveness over time. In the other six ISOs, solar offers higher value yet, in some cases, similar or even lower PPA prices than in California—which is perhaps the primary reason why the market has been expanding beyond California and into these other regions.

Adding battery storage is one way to increase the market value of solar, and there has been a notable proliferation of PV plus battery PPAs (e.g., 23 of the PPAs shown in Figure 8 include battery storage) and project announcements in the United States over the past few years. Data from 38 completed or announced PV hybrid projects totaling 4.3GW$_{AC}$ of PV and 2.6GW$_{AC}$ of battery capacity (and with storage duration ranging from two to five hours, with four hours being by far the most common) suggests that sizing of the battery capacity relative to the PV capacity varies widely, depending on the application and specific situation.

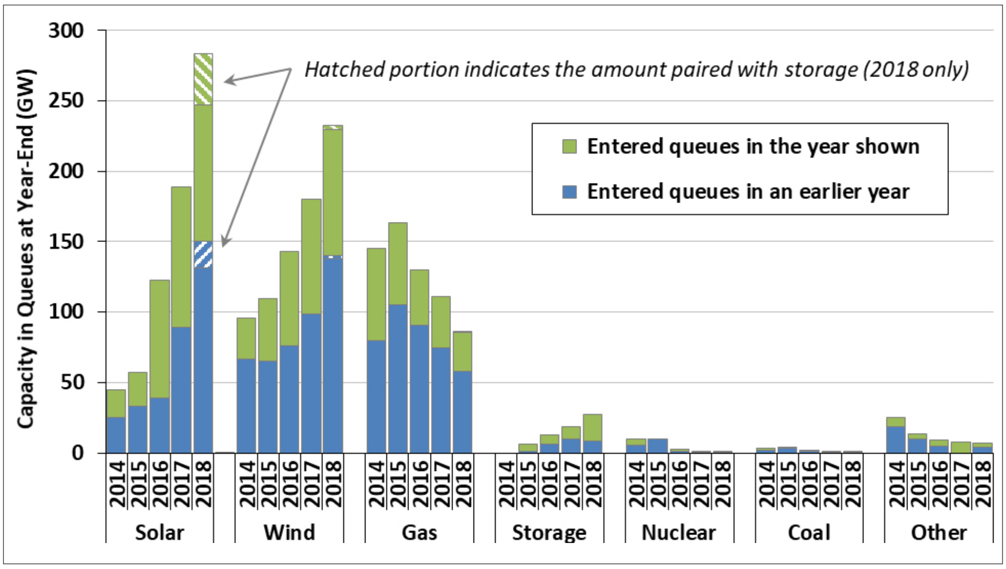

Figure 10. Solar and other resource capacity in 37 selected interconnection queues across the US

For example, in Hawaii—an isolated island grid grappling with a high PV penetration rate—this ratio is typically 1:1 so that all mid-day PV generation can be stored and shifted into the evening and overnight hours, whereas in the continental United States, batteries are more-commonly smaller, sized from 25-50% of the PV capacity. Moreover, data suggest that the incremental PPA price adder for four-hour storage varies linearly with this ratio, ranging from ~US$5/MWh for batteries sized at 25% of PV capacity up to US$15/MWh for batteries sized at 75% of PV capacity. As battery storage becomes more cost-effective, many developers now offer it

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as a standard upgrade to standalone PV, and many project owners are revisiting their existing fleets of standalone PV projects in search of opportunities to retrofit a battery.

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years (Figure 10). At the end of 2018, there were at least 284GW of utility-scale solar power capacity within the interconnection queues across the nation, 133GW of which first entered the queues in 2018 (with 36GW of this 133GW including batteries). Solar is now the largest resource within these queues, ahead of both wind and natural gas (though as recently as 2016, solar was in third place, behind the other two).

Moreover, the growth of solar within these queues is widely distributed across all regions of the country, and is most pronounced in the up-and-coming Midwest region, which accounts for 26% of the 133GW that first entered the queues in 2018, followed by the Southwest (21%), Southeast and Northeast (each with 15%), California (10%), Texas (9%), and the Northwest (5%). Though not all of these projects will ultimately be built as planned (i.e., entering the queues is a necessary but not a sufficient condition for development success), the ongoing influx and widening geographic distribution of solar projects within these queues is as clear a sign as any that the utility-scale PV sector in the United States is maturing and expanding outside of its traditional high-insolation comfort zones. ■

LNBL's 2019 "Utility -Scale Solar" report is available at utilityscalesolar.lbl.gov

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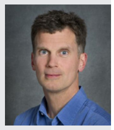

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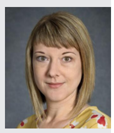

Turn to p.75 for analysis of how the step-down of the solar investment tax credit is expected to affect the US industry.